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Microgrid Protection:

Advancing the State of the Art

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ABSTRACT

This report discusses the challenges and complexities in protection design for microgrids that have come into focus with the growth in the number and variety of microgrids being deployed. It addresses protection issues for microgrids in connected and islanded operational modes and the transition between them. It also examines adaptive protection; fault conditions of power electronic grid interfaces based on fast energy converters used for Distributed Energy Resources (DER); sensing and control issues; architecture; and the coordination of communication schemes used for microgrid protection systems. The report discusses the need for innovative technologies, control algorithms, sensors, and protection schemes to advance microgrid protection systems and to maximize customer and system resilience, reliability, efficiency and to minimize cost in the context of grid modernization. The report concludes by pointing out the need for guidelines for microgrid protection and identifies areas for R&D for microgrid protection.

ACKNOWLEDGEMENTS

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The authors would like to express their appreciation to Dan Ton, DOE Microgrid Program Manager, Office of Electricity for his leadership in identifying the need for a report to advance protection to meet the evolving needs of microgrids and their interconnection to the distribution system.

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EXECUTIVE SUMMARY

Microgrids are defined in this report as "A group of interconnected loads and distributed energy resources with clearly defined electrical boundaries that acts as a single controllable entity with respect to the grid and can connect and disconnect from the grid to enable it to operate in both grid-connected or island modes."

With modern technologies and Distributed Energy Resources (DER) penetrating the utility system, and with the growth in the number and variety of microgrids being deployed, it is imperative that the critical issue of protection be identified to pave ways to achieve efficient and effective means of realizing them. *System protection is both an art and a science involving protective devices which are like silent sentinels.* While protection practices vary widely among utilities and is challenging even for classical, passive and radial distribution systems, protection practices for microgrids are even more disparate and challenging. This report is intended to examine the state of the art and current challenges in microgrid protection.

To allow islanded and autonomous operation, microgrids need to incorporate local DER, which include renewable energy resources (wind and solar), and the associated electrical storage required for balancing and firming intermittent generation. From this perspective, a microgrid is a means to aggregate DER. In the microgrid islanded operation, the local distribution system is no longer connected to the larger power grid provided by central generation. This makes the design of protection systems for a microgrid in islanded mode different from that in grid-connected mode.

The challenges in microgrid protection design result from the combination of a dominance of DER using power electronic interfaces and the absence of a connection to the larger distribution grid in islanded operation. In addition, the protection schemes, or minimally the protection system settings, must be changed and adapted when transitioning from grid-connected to islanded modes including transitions, requiring the design of adaptive protection systems. The combination of the dominance of inverter-based DER and the absence of a strong grid in islanded mode results in a microgrid protection design that significantly departs from conventional power system protection philosophy.

DER are often interfaced with the distribution grid using power electronic-based energy converters. The presence of these types of DER requires approaches to protection that are different from conventional rotating DER, such as combined heat and power (CHP), diesel generators or small hydro-electric generators. Among the significant differences are the limited fault current capacity provided by the power electronic converters and the attendant performance that is determined by the design of the inverter interface controller. The resulting performance is highly variable and dependent on design and implementation choices.

This report presents the complexities and specific protection requirements that are unique to microgrid systems, including protection of the distribution and microgrid systems in both connected, islanded modes and transition between them. It discusses the need for adaptive protection solutions in the transition from one mode to the other and presents the specificities of the operation under fault conditions of power electronic grid interfaces. This is based on fast energy converters used for DER, the sensing and control issues, the selection of the architecture and the coordination of communication schemes used for microgrid protection systems.

The report stresses the need for new and advanced technologies along with new digital hardware designs and software operational algorithms, new sensors and measurement units, including optical voltage and current sensors, and advanced, secure, compatible and reliable communications where needed. Grid forming inverters need to be developed, particularly for islanded operation, as well as new algorithms allowing a mix of grid forming and grid following inverters in the grid-connected or the utility interactive mode.

The report demonstrates that microgrid protection issues have not been properly addressed in the literature or in published standards such as IEEE Std 2030.7 and Std. 2030.8 for the specification of microgrid controllers. The report stresses the need for guidelines for the protection of microgrids, as a complement to the existing IEEE Standards mentioned above. It also recommends that inverter control schemes and their performance under fault conditions be standardized to the extent possible. This would simplify the design of adequate, reliable and secure protection schemes for microgrids.

The authors of this report encourage participation in the IEEE Std P2030.12 Working Group on the development of the Guide for "The design of Microgrid Protection," sponsored by the IEEE PES Committee on "Power System Relaying and Control (PSRCC)," and approved by the IEEE SA on September 27, 2018.

Finally, the report presents recommendations for the development of protection systems tailored to microgrids and their specific requirements; for research and development; and for standards for some of the required hardware, software and control approaches that would simplify and accelerate the deployment of new microgrid protection systems.

ACRONYMS

Abbreviation	Definition
CIP	Critical infrastructure protection
DER	Distributed energy resources
DMS	Distribution management system
DNP3	Distributed network protocol
DOE OE	U.S. DOE Office of electricity delivery and energy reliability
DSO	Distribution system operator
EMS	Energy-management system
EPRI	Electric Power Research Institute
EPS	Electric power system
IEC	International Electrotechnical Commission
IEEE	Institute of Electrical and Electronic Engineers
ISO	International Organization for Standardization
LVRT	Low-voltage ride through
MEMS	Microgrid energy management system
MIT	Massachusetts Institute of Technology
NEC	National Electrical Code
NERC	North American Electric Reliability Corporation
NIST	National Institute of Standards and Technology
PCC	Point of common coupling
PMU	Phaser measurement unit
POI	Point of interconnection
PSRC	IEEE Power System Relaying and Control Committee
PV	Photovoltaic
ROCOF	Rate of Change of Frequency
RTO	Regional Transmission Operators
SCADA	Supervisory control and data acquisition
T&D	Transmission and distribution
TOV	Transient overvoltage
VAR	Volt-Ampere reactive
VLAN	Virtual local-area network

DEFINITIONS

Distributed Energy Resources (DER): Sources and groups of sources of electric power that are not directly connected to the bulk power system; they include both generators and energy storage technologies capable of exporting power.

Distribution Management System (DMS): A collection of software applications designed to monitor and control the distribution network in a predefined manner.

Initiating Event: A condition that triggers the sequence of actions of a microgrid control system for dispatch and/or transition core function operation.

> Note: An abnormal operation or parameter, dispatch command or request, setpoint change, trip of DERs or loads, or power system disturbance are examples of trigger conditions.

Microgrid Control System: A system that includes the control functions that define the microgrid as a system that can manage itself, operate autonomously or grid-connected, and seamlessly connect to and disconnect from the main distribution grid for the exchange of power and the supply of ancillary services.

> Note: It includes the functions of the Microgrid Energy Management System (MEMS). It is the microgrid controller if implemented in the form of a centralized system.

Point of Interconnection (POI): The electrical point at which the microgrid connects or disconnects from the larger distribution grid.

Seamless Transition: The connection and disconnection of a microgrid to and from the larger grid accomplished without voltage and frequency transients that exceed the specifications of the microgrid design and the interconnection requirements.

Test Procedure: A generic approach used to specify the conditions under which core functions are to be tested and establish scenarios to which metrics can be applied.

Contents

1. INTRODUCTION

1.1. Objectives

The primary objective in developing this roadmap report, "Microgrid Protection: Advancing the State-of-the-Art," is to maximize customer and system resilience, reliability, efficiency and to minimize cost as part of future grid modernization effort.

1.2. Definition of a Microgrid

The Department of Energy's (DOE) definition of a microgrid is "a group of interconnected loads and distributed energy resources with clearly defined electrical boundaries that acts as a single controllable entity with respect to the grid and can connect and disconnect from the grid to enable it to operate in both grid-connected or island modes" [1]. This is a universally accepted definition. Microgrids can also be classified by modes of operation, e.g., grid-connected or islanded. The types and operating modes of microgrids are discussed in detail in Section 4.

Microgrids can be operated connected to the main network or autonomously. They have been proposed to integrate high penetrations of distributed generation sources that are becoming more commonplace on the distribution system [2], [3]. Another advantage of microgrids is that they can increase system reliability by reducing customer outage and service restoration time [4]. However, one major issue with implementing microgrids is their protection when operating in the islanded mode. This is a result of the fault currents being lower than steady state currents from voltage-source inverter connected devices. These devices include battery energy storage systems and photovoltaic panels that are often the dominant sources in low and medium voltage microgrids [5].

1.3. Microgrid Basics:

The purpose of this section is to provide the basics of microgrid types and modes of operation. These are covered in detail in Appendix A.

1.3.1. Microgrid Types

These can be broadly classified based on electric supply as

- AC microgrids
- DC microgrids
- Hybrid microgrids
- Networked microgrid

These are described in detail in Section 4. They can also be classified in other ways as described in Appendix C.

1.3.2. Microgrid Modes of Operation

The modes of operation can be summarized as

- Grid-connected mode
- Islanded mode
- Unplanned islanding
- Transitional mode from grid-connected to islanded, and vice versa
- Mixed mode

These are also treated in detail in Section 4.

1.4. Microgrid Protection Challenges and Requirements - The State-of-the-Art

As innovative technologies and DER, including renewable, penetrate the system making it more complex, it is imperative that the critical issue of protection be identified to pave ways to achieve efficient and effective means of realizing them. System protection is both an art and a science involving protective devices which are like silent sentinels [6]. Even the protection of a classical, passive and radial distribution system has always been very challenging. The practices vary widely even within a utility, and more so among utilities.

Protection challenges in the distribution systems abound now with the challenges of DER including inverter-based generation and storage and new configurations for aggregation and microgrids [7]-[14]. The microprocessor relay of today is a mature and reliable technology. However, the technology must be adapted to the needs of the distribution networks as they have evolved with high penetrations. The starting point for this adaptation is microgrids with unique protection requirements.

Protection requirements for microgrid systems are unique. They are different from general protection issues, known and applicable to distribution systems, because of the large amount of DER present and because the microgrid control systems oversee the overall operation. Because of the absence of a strong voltage source, the design of protection systems for a microgrid in islanded mode is different from that of the grid in connected mode. The unique protection requirements for microgrids are the subject of this report.

Multifunctional Microprocessor relays as Intelligent Electronic Devices (IEDs) are the primary microgrid control, protection, metering, and monitoring devices for some of the most successful microgrids. They deserve a closer inspection as a solution to the problems. This report provides an overview of protection systems today and the advancements required to meet the challenges for protection in the distribution system, starting with microgrids.

The focus on modes of operation and transitions is paramount. It is essential to protect a microgrid for all modes of operation including transitions against all types of faults, and this is a real challenge. The fundamental premise for microgrid protection is to have the same protection architecture for both islanded and grid-connected operations. A fast-acting smart switch, such as a solid-state circuit breaker, needs to be developed for all faults that could occur in a microgrid.

1.5. Report Contributions

This report includes:

- Protection Relays for Microgrids (Chapter 2).
- Microgrid Protection Relays (Chapter 3).
- Microgrid Modes of Operation (Chapter 4)
- Challenges in Microgrid Protection (Chapter 5)
- Microgrid Protection Schemes and Advanced Strategies (Chapter 6)
- Microgrid Protection Standards (Chapter 7)
- Protection of AC, DC, Hybrid and Networked Microgrid Systems (Chapter 8).
- Communication Architecture for Microgrid System Protection (Chapter 9).
- Research Needs and Recommendations (Chapter 10)
- References (Chapter 11)

1.6. Microgrid Protection: Simulation Case Studies and Industry Perspective

This report includes three case studies by simulation.

The first two examples of microgrid protection: (1) Study on a Practical Design for Microgrid Protection and (2) Study on Communication-Assisted Microgrid Protection are presented in Appendix D and Appendix E.

A third case on utility perspective on microgrid protection is discussed in Appendix F [73], taken from a paper by George W. Sey Jr., at Philadelphia Electric Company (PECO) on “Microgrid Protection Considerations: From a Utility Perspective.” The complete paper is included in this appendix. In this paper, the high priority loads at campuses commonly are protected by differential protection schemes. The lower priority systems use simple time-overcurrent protection.

The results of these simulated case studies will be useful in providing proper guidance for R&D and future projects to validate the unique solutions for microgrid protection issues.

2. MICROGRID PROTECTIVE DEVICES

2.1. Microprocessor Relays

Protection systems for the bulk electric power system are mature and reliable technologies. The modern multi-functional microprocessor protective relays (IEDs) are a comprehensive protection, automation, controls, equipment monitoring, metering, and integration devices. These modern relays protect electrical equipment from damage, provide human safety, the environment from damage, prevent blackouts, and much more.

Microprocessor relays are also called digital, numeric, or multifunction relays. These were introduced in mid- 1980's due to the availability of microprocessors. These have become the preferred choice for all new facilities worldwide because of their multi-function capabilities and accuracy. They are now the preferred choice for protection of circuits from 480V to 765kV. Modern microprocessor relays are now more reliable than electromechanical relays, they advise operations if they are failed, and they can perform the most complicated protection and control functions. Microprocessor relays are now commonly used as both protective relays and microgrid controllers. The digital relay has revolutionized protection with functions never possible including breaker failure, digital communications, adaptive protection, sub-cycle FAST protection, harmonic restraints, to name a few. These multifunction devices represented a significant reduction in parts, cost, and maintenance in a substation. Before the microprocessor relay substations were commonly manned. These new relays have provided better data collection for continuous monitoring and event root cause analysis than ever before possible, and they do not require as much testing as other types of relays.

2.1.1. Smart Fuses

A smart fuse device is a combination of a conventional fuse with intelligent sensor that simulates conventional current limiting characteristics during high current faults and has the inherent ability to self-monitor and the capability to be triggered from an external source. The fuse still needs to be replaced manually after it melts when it blows following a fault. The smart fuse can be used for both substation transformer and secondary conductor overcurrent protection.

The design, development, and application of the smart fuse in medium voltage distribution systems and equipment protective schemes are described in [15]. The device allows the medium voltage system to be grounded with a low resistance to minimize ground fault currents while still allowing coordination between upstream and downstream devices. It provides protection against single phasing without sacrificing current limiting features.

2.2. Smart Reclosers (Interrupters)

A smart recloser is a combination of a recloser with some form of intelligence and control incorporated to achieve automation. One such device was developed by S&C Electric in 2008 [16]. This Wi-Fi-enabled electrical equipment is a kind of "smart switch" that utilities use to more quickly to detect and correct outages along their distribution systems. [16].

2.2.1. Smart Circuit Breakers

Most AC circuit breakers are simple, electromechanical devices that sit idle most of the time. However, the latest versions are coming with features like wireless connectivity and computing power that are meant to turn them into something more like a smart meter or a smartphone.

2.2.2. Smart Switching Devices

The concept of smart switching devices is still in several stages of development. A lot more research needs to be done before one could realize an automated fuse or a similar device.

3. MICROGRID SENSORS AND MEASUREMENT UNITS

While standard instrument transformers, namely CTs and VTs, will continue to exist, a tremendous effort is being made by all stake holders to capitalize on new digital technologies for improving the real-time sensing and monitoring for achieving truly smart grid systems. This is a key technology required for achieving the real time protection and control of intelligent distribution systems. The DOE is leading this development as part of the grid modernization effort.

3.1. Phasor Measurement Units (PMUs)

Synchrophasors are time-synchronized numbers that represent both the magnitude and phase angle of the sine waves found in electricity and are time-synchronized for accuracy. They are measured by high-speed monitors called Phasor Measurement Units (PMUs) that are 100 times faster than SCADA. PMU measurements record grid conditions with great accuracy and offer insight into grid stability or stress. Synchrophasor technology is used for real-time operations and off-line engineering analyses to improve grid reliability and efficiency and lower operating costs [17].

3.2. Micro-Phasor Measurement Units (µPMUs):

PMUs installed in the power grid are currently positioned mainly on the transmission system or in substations. A PMU creating real-time synchrophasor data from the consumer voltage level, called µPMUs, could provide new insight into modern power systems. These units can be created more cheaply, an order of magnitude less, than current commercial PMUs. For this reason, many more PMUs could be deployed and provide a much higher resolution of the distribution grid. There are many new applications for such a visible grid in post-mortem event analysis and identification, as well as near real-time monitoring [18].

One such application is the fault location on a distribution grid or microgrid with µPMUs provide very accurate results. Additional information is covered in Section 5.5 below.

3.3. Optical Line Current Sensors

These are directly hung from an overhead line to obtain direct, digital current signals in each phase. These pole-top units use Faraday effect to get accurate and precise current measurements of line currents. Thus, three sensors will be required for a three-phase system. These can be used for overhead lines from 120-V up to 34.5-kV levels. These could also facilitate power quality measurements via a PQ meter. Soon, it is likely to adopted for underground systems [19].

3.4. Optical Voltage Sensors

These utilize Pockel's effect to derive voltage signals. Here also three sensors will be required to seek digital and accurate voltage values from each of the three-phases in overhead lines first and subsequently for underground distribution systems [19].

3.5. Digital Pressure and Temperature Sensors

Though these are not common yet, a lot of research and development work is underway in developing these newer sensors by both utilities and equipment manufacturers. It is a matter of time before they become a reality [20].

3.6. Evolving Sensors

Several new and modern sensors have been identified by DOE in a comprehensive report [21]. Some of them include the state-of-the art-sensors such as extremely high frequency point on wave, dynamic high range sensors [22], optical PMU, MagSense and others should be considered for adoption as time passes on. As nanotechnology matures, it is possible to envisage the development of newer sensors such as nano-sensors for all sensing and measurement of electrical and nonelectrical smart connect system in the smart grid system. One could even expect genetic sensors such as bacterial nanobionics sensors to penetrate future distribution systems to improve the speed, precision and accuracy of electrical variables mentioned above. Recently, Wireless Sensor Networks [23] have been widely recognized as a promising technology that can enhance various aspects of today's electric power systems, including generation, delivery, and utilization, making them a vital component of the next-generation electric power system, the smart grid.

4. MICROGRID MODES OF OPERATION

4.1. Introduction

As mentioned in Chapter 1, the modes of operation of microgrids are typically divided into three generalized categories: grid-connected, islanded or mixed mode operation [2], [7]. These are covered more in detail in this Chapter. The modes of operation are influenced by a variety of coordinated dispatch functions and control functions that may be scheduled, autonomous, or responsive to local out-of-specification or abnormal conditions either on the interconnected distribution grid or within the microgrid. The modes of operation are often much different in that the voltage regulation for the loads are based on either very low impedance power source (the utility) or a higher impedance power source (DER related) with resource-limited energy.

4.2. Grid-connected Mode

The grid-connected mode is typically the prevalent operating mode for microgrids that are interconnected to the local grid. Energy flow is predominantly from the local grid to local loads within the microgrid. Other important flows of energy include charging of batteries, conditioning of thermal storage, providing house-keeping for microgrid controllers, and communications equipment.

Transitions to and from the grid-connected mode will often utilize communications for dispatch, synchronization, critical protection data, and data handling requirements.

4.3. Islanded Mode

The islanded mode is used for a variety of conditions. Internal supply of power to microgrid loads during utility outages are used to maintain loads (reliability resiliency) that are typically segregated into critical loads or loads that may be shed according to a schedule of priorities. Other reasons for operating in the islanded mode are becoming increasingly important. A utility may dispatch a microgrid to curtail reverse power flow when the distribution system can no longer accept power from distributed generation such as photovoltaics or wind. Such curtailed generation is likely a situation where advanced information is needed to optimize the operations of the microgrid and the interconnected utility. Another important reason for operation in the islanded mode is to better optimize charges that are being implemented as demand charges or even standby charges.

The scenarios for transitions to islanded mode include the following:

4.3.1. Planned Islanding

The process and steps for a planned islanding event include: a) receive islanding command either as a scheduled event or as dispatch from the Distribution System Operator (DSO); b) balance the load and generation (adjust P and Q to both be 0 at the point of interconnection (POI)); c) set local controllers and protection devices appropriately; d) create the island; e) transition to steady state islanded dispatch mode.

4.3.2. *Unplanned Islanding*

The process and steps for unplanned island events include a) detect the need for islanded conditions; b) create the island; c) set local controllers and protection devices appropriately; d) execute required preplanned actions such as load shedding (and/or implement a black start if required); e) transition to steady state islanded dispatch mode.

4.3.3. *Reconnection to Grid*

The process and steps include a) resynchronize, set/match voltage, phase angle, and frequency within prescribed limits specified by applicable grid codes or requirements; b) set local controllers and protection devices appropriately; c) reconnect; d) transition to steady state connected dispatch mode and restore non-critical loads as appropriate.

4.4. Transition from Grid to Islanded Operation and Vice-versa

The modes and methods for transitions with an electrical grid must be well-coordinated processes that involve communications in the form of dispatch requests. A simple scheduled transition is an option if the protocols for the transitions are predetermined. Transitions typically include a verification of a completed process and reporting on the resulting conditions after the transition is completed. The timing and synchronization are often a range of values. The criteria for transitions are followed by the microgrid controller.

Table 1 shows examples of processes, parameters used before the transition, the needed characterizations of the parameters, and applicable protection requirements.

Table 1. Typical Criteria Used for a Transition Process

Processes	Parameters	Characterization of Parameters	Protection Requisites
Transition Initiation	Receive transition request or command	Predetermined operational values, limits, and timing needs	Predetermined protection capabilities and limitations.
Load/Primary source balancing	Assess microgrid loads, microgrid generation, energy storage status and data collection systems	Adjust loads and generation to values to assure stable operation	V, f, P, Q, settling time, overshoot, time to island, and steady state values within contractual requirements and equipment limitations
Transaction to new operating conditions	Transition timing and speed of transfer	Measure and evaluate transients and any oscillations	Communicate with protection equipment on the utility infrastructure and within the microgrid
New settings	Assess stability, generation and energy storage values	Measure the new stable values	New V, f, P, Q, settling time, overshoot, time to island, and steady state values within contractual requirements and equipment limitations

Processes	Parameters	Characterization of Parameters	Protection Requisites
Data acquisition and analysis	Assess dynamic values	Record values before, during and after transition	Store and analyze new data

Typical metrics for transitions includes:

- Directly measurable quantities: voltage and current (time-domain waveforms).
- Derived quantities: frequency, RMS voltage, RMS current, phase angle, real power (including direction of power flow), reactive power (leading or lagging), energy exchanged at the POI (grid-connected mode), Power Quality indices (voltage and current harmonic distortion, individual harmonics, voltage sags, voltage swells), reference tracking errors.

Metrics are typically specified by the interconnection requirements of the distribution system operator to which the microgrid is connected, applicable codes and/or standards, or state or local mandates for interconnectivity.

Scenarios are typically defined for the following basic transitions:

- Grid-connected to islanded – planned islanding – This transition is initiated upon receipt of an external request, typically sent by the distribution system operator.
- Grid-connected to islanded – unplanned islanding – This transition is the result of an event on the distribution grid. It can involve a black start if the control system is designed in this manner.
- Islanded to grid connection – This transition involves resynchronization and reconnection of the microgrid.

Test scenarios for transitions typically consider the conditions indicated below. They are chosen to allow a complete and comprehensive testing of the transition function, including the required and relevant features of the dispatch function.

- The initial operating conditions of the microgrid – These include the operating conditions before the transition occurs: level of local generation and generation mix (dispatchable and non-dispatchable), operation of the storage device (mode of operation, state of charge), load composition (constant impedance, constant P-Q and active loads) and load mix (percentage composition), status of breakers, switches and voltage control devices, power (P, Q) exchanges between the microgrid and the grid (prior to a transition from grid-connected to island mode).
- The state of the grid at the time of the transition – These include the voltage at the POI and any disturbances occurring on the grid at the time of the transition. In the case of an unplanned islanding event, the nature of the event (typically a fault or an open connection on the feeder connected to the POI) initiating the islanding transition is considered.

4.4.1. Mixed Mode

A microgrid control system set up in mixed mode still must contain the island and grid-connected functions and supports all forms of planned and unplanned islanding and resynchronization [24]. The difference is that the controls of DERs never change regardless of grid or island mode connection. [The 2018 NREL microgrid shootout was won using this technique. MIT campus project example is using this technique.]

5. CHALLENGES IN MICROGRID PROTECTION

The need and nature of system protection for distribution networks is changing because of the growing penetration of DERs. Conventional protection schemes are designed for radial distribution systems with unidirectional fault current flow. In the presence of Distributed Generations (DGs), the flow of fault currents becomes bi-directional and the level of fault currents is undetermined with the utilization of inverters and fault current limiters (FCLs). In addition, the levels of fault current vary with the changing operations status (output level of DGs), operational mode (grid-connected or islanded), and network topology (radial, looped, or meshed). The result is an extensive range of fault characteristics. The new characteristics found in these distribution systems are [25]:

- Bi-directional flow of fault currents
- Undetermined directions and limited level of fault currents
- Large variation of fault current capacity
- Various operation modes: grid-connected and islanded (grid-isolated)
- Diverse network configurations: radial, looped, and meshed

Conventional protection schemes likely will have difficulty handling the emerging changes. For some distribution networks, the protection issue can be resolved by coordination among relays [26]. However, for systems with high penetrations of DGs, protection cannot be implemented simply by coordination [27], [28]. One option to resolve the problem of bi-directional fault current flow is to use direction-sensitive and differential relays. Unfortunately, the variations of operating states affect the performance of conventional directional protection.

The deficiencies in conventional protection schemes are:

1. Fixed (Inflexible) tripping characteristics: predefined protection zones cannot correctly perform protections under varying operating conditions and network topologies;
2. Reduced fault current level prolongs the tripping time in conventional overcurrent relaying;
3. The sensitivity of conventional directional relaying is reduced substantially on symmetrical faults occurring close to line exit;

For protecting single-phase lines, the conventional directional relay may fail when a fault occurs at or close to the line exit.

Based on the inadequacy's discussion, requirements posed to new protection paradigms are:

1. The protection is minimally affected by different system operating conditions; therefore, the protection should automatically adapt to changes resulting by different operating conditions;
2. The directional element should have consistent sensitivity under range of disturbances for both three-phase and single-phase lines;
3. Fast response and less communication assistance should be an objective;
4. Providing adequate backup protection for local and remote devices improves protection reliability.

5.1. Grid-connected and Islanded Modes:

The grid-connected mode is typically the prevalent operating mode for microgrids that are interconnected to the local grid. Energy flow is predominantly from the local grid to local loads within the microgrid. Other important flows of energy include charging of batteries, conditioning of thermal storage, providing house-keeping for microgrid controllers, and communications equipment.

Transitions to and from the grid-connected mode will often utilize communications for dispatch, synchronization, critical protection data, and data handling requirements.

5.2. DER Based Inverter Challenges [29]:

DERs provide power to customer loads in microgrids or are alternately interconnected to distribution networks. The differences in operation and loads require system protection that are unique to both operational configurations. When inverters are used in microgrids, they need to be designed to be compatible for all modes of operation and provide quality power equal to or better than that or the utility.

All types and legacies of protection relays (electromechanical, solid state, or digital) depend on the consistency in behavior of generation sources with consistency in waveform during normal and abnormal operation. Sources that act unpredictably make it very difficult for a protective relay to discriminate normal from abnormal conditions. The following characteristics that create inconsistent system protection have been observed with most of today's inverter technology:

- Inter-Oscillations:
- Limited Kinetic Energy
- Thermal limits of Inverters
- Inconsistent Behavior Under Faults
- Inconsistent Transient Behavior
- High Efficiency Challenges

These characteristics are discussed in detail in Appendix B.

5.3. Relay Interoperability:

The interoperability issues are of paramount importance for all smart grid devices. This is also true for digital relays [30]. The purpose of this section is to address various utility protection practices and investigate the ways to integrate new digital protective devices with classical devices and coordinate them in the most effective manner keeping all the current and future developments to occur in the next 20 years. While they are making efforts to upgrade their respective distribution systems to keep up with the developments happening in the introduction of new smart grid technologies, it will perhaps happen gradually based on the annual capital investments they can make. This is true for all types of utilities whether they are small or large, investor-owned or public utilities.

5.4. Fault Location, Isolation and System Restoration:

Fault location, isolation and system restoration (FLISR) schemes depend heavily on communication to protective relays throughout the power system [78]-[80], which is very useful for some microgrids with complex distribution. The protective relay shares the status of the recloser lockout and fault directions, thus allowing a centralized controller to isolate faulted segments and re-energize power system. There is still room to improve this challenging problem from the microgrid protection point of view. Section 6.3 discusses the microgrid protection from the Adaptive Protection perspective.

5.5. Fault location using PMUs and μPMUs:

Many efforts have been made in developing and improving fault location techniques for distribution systems [31]-[44]. The impedance-based methods proposed in references [31]-[33] use voltage and current measurements. In terms of the varying network topologies, the method suffers from multiple estimated locations. The traveling-wave or high frequency transient based method proposed in references [38]-[68] requires a high sampling rate for the current signal. The method's accuracy can be severely affected by the reflections of the signal waveform traveling along highly branched distribution networks. Using measurements from field devices such as voltage sensors can improve the fault location performance in complex system conditions by comparing calculated and sensed voltages [84]-[85]. These methods require a minimum number of sensing devices and are limited to the device location. Several types of strategies are also leveraged either to improve the accuracy [40], [68]-[71], [39]-[41], [48],[71] or to lessen the number of input signals [49]. This reference also introduces a fault diagnosis process and considered load variation effects on different fault types. Additionally, in reference [42] eliminating multiple locations using a conceptual algorithm was tried using intelligent field devices and event reports [40]. The number of input signals was reduced in the fault current profile-based method in reference [49]. The commonly used practices in utilities, such as line investigation by repair crews and fault analysis-based methods, are time consuming, less accurate, or both. For example, some short-circuit faults due to insulator breakdown are difficult to spot visually. Using fault indicators can help to narrow the faulted area [53], however, the range of the estimated area depends on the deployment of these devices. In addition, fault indicators may fail in tracing the fault location under bidirectional current flow conditions. The works all suffer from shortcomings with respect to the three key issues for locating a fault in emerging distribution systems: multiple location results, high impedance faults, and bidirectional current flow. This approach is an extension of the paradigm introduced in reference [44].

6. MICROGRID PROTECTION SCHEMES AND ADVANCED STRATEGIES

Several methods have been proposed for protecting microgrids in the last few years. These can be grouped by those that do not require communications [109],[113] and those that do [110]-[113]. Those that do not require communications are usually unable to completely protect a microgrid in all cases. For example, the scheme in [113] cannot detect all fault types and the scheme in [109] does not operate quickly enough for medium voltage networks. Existing schemes that rely on communications have drawbacks as well. The adaptable distance relay scheme in [110] and the comparative voltage scheme in [111] will fail to detect high-impedance faults. The differential line protection scheme proposed in [49] can accurately detect all faults but is very expensive. The scheme proposed in [117] divides the microgrid into smaller zones, with each zone protected by its own microgrid protection relay. This method, while requiring fewer relays than the scheme in [81] still requires a substantial number, especially in looped or meshed grids, and is costly.

Once a fault is detected, knowing the faulted segment can help to minimize the outage area and expedite the repair and service restoration. Several methods have been developed for locating a fault in distribution systems [118]. The impedance-based methods proposed in this reference use voltage and current measurements. In terms of network topology variations, the method suffers from multiple estimated locations. The traveling-based method proposed in [61] requires a high sampling rate for the current signal. The method's accuracy can be severely affected by the waveform reflections on highly branched distribution networks. The diverse types of strategies are also leveraged to improve the accuracy (such as the fault diagnosis process in [46] to eliminate multiple locations using a conceptual algorithm in [47] or to lessen the number of input signals (such as the fault current profile-based method in [47]). These methods only work in radial and passive distribution networks.

6.1. Existing Protection Schemes for Microgrids [6]

6.1.1. Time Overcurrent

Perhaps the most commonly used methods in distribution and microgrid systems today are the time over-current coordination of multiple relays, fuses, and other fault interrupting equipment. This method, as applied in the modern microprocessor relay, is basically simulating the behavior and timing of legacy electromechanical relays. Time over-current schemes commonly are unusable on microgrids that have bi-directional flow of fault currents, limited levels of fault currents, large variation of fault capacity, changing grounding conditions, various operation modes (grid-connected and islanded), and diverse network configurations (radial, looped, and meshed).

6.1.2. Distance

These are not very useful for microgrids as the impedances must be large for these systems to function. Some industrial microgrids use these protection methods to look for faults in large, custom, high-cost transformers.

6.1.3. *Differential*

Line, bus, generator, and transformer differential schemes are the most common forms of this protection. These are popular for microgrids because these relays can be set regardless of DER performance inconsistencies. These are fewer complex alternatives to adaptive protection schemes.

6.1.4. *Current Differential*

In general, differential relaying is not suitable for protecting a device that spans a long distance because of the difficulty in transmitting instantaneous samples or phasors. Thus, it is used mainly to protect power equipment such as transformers, bus bars, and generators. In smart distribution, exchanging bulk data over advanced communication infrastructure becomes real. A microgrid protection using current differential relaying is proposed in [49]. As mentioned previously, deploying protection devices for every line is not economic. Conventional current differential relaying cannot be used to cover branched lines. An example is given in Figure 1. During normal state the equation $I_1 + I_2 = 0$ no longer holds. Even though the branch current can be measured, the current on line B1-B2 may flow two ways due to the DGs, which makes the setting very complex.

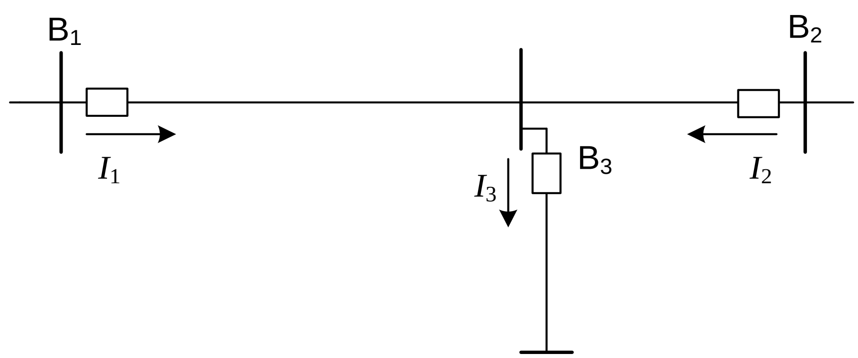

Figure 1. An Example of Current Differential Protection for a Branched Line

Using the fault component of the current to form the differential algorithm is barely affected by the branch. In normal state, the fault components at both ends are zero while during a fault, the fault currents are contributed by Thevenin source at the fault point, as shown in Figure 2. Therefore, the differential protection using current fault component is:

During normal state: $I_{f1} + I_{f2} = 0$;

During fault within protected zone: $I_{f1} + I_{f2} => I_{set}$.

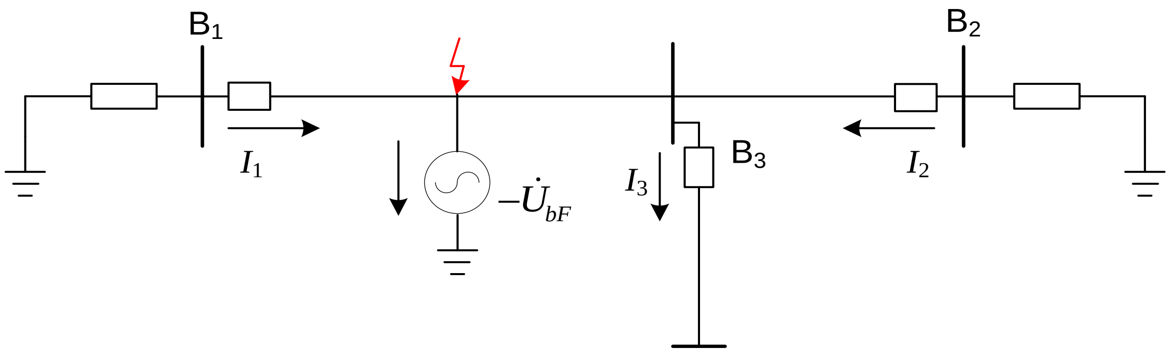

Figure 2. Current Differential Relaying using Fault Component

6.1.5. Pilot Protection

Pilot relaying is one of the main protection schemes widely used for transmission lines. As smart grid technology develops, distribution systems have been presenting features like transmission systems. This brings new requirements for the smart distribution systems in monitoring, control, and protection. This section is an introduction to the concept of pilot relaying to the distribution systems to solve the emerging challenges. Optimization methods may be used to balance the cost and performance due to the characteristics of distribution networks. This will be discussed in the next stage.

6.1.5.1. Directional Comparison

Directional comparison relaying uses voltage and current at both line terminals to calculate the phase relationship (between voltage and current) and impedance to a forward or reverse fault. This information is exchanged between the two terminals in the form of a blocking signal, if the fault is behind the relay, or a permissive trip signal, if the fault is in front of the relay.

Based on the type of information transferred to the remote terminal and the way that the terminal processes such information, the protection schemes can be of many types: blocking, unblocking, permissive overreaching transfer trip, permissive under reaching transfer trip, etc. Instead of illustrating each scheme in detail, this paper only describes how to apply directional comparison relaying to distribution networks. The tripping scheme can be selected for the specific type of communication channel. All the schemes are based on the directional elements and the location elements respectively.

6.1.6. Travelling Wave

Travelling wave (TW) technology operates fundamentally different from all other relaying methods. TW relays sample at MHz, while another microprocessor relays sample at kHz. Faults in power transmission lines cause transients that travel at a speed close to the speed of light and propagate along the line as traveling waves. Double-ended TW uses precise measurements of the traveling-wave arrival times at both ends of the transmission line to locate faults accurately. Single-ended TW sorts out multiple wave reflections to accurately calculate the distance to the fault using the TW line propagation time. Traveling-wave fault locators built into transmission line protective relays and using standard current transformers determine locations of faults to within a tower span while adding very little cost.

Travelling wave technology does not suffer from the known DER deficiencies, as they are immune to fault levels or dynamic inconsistencies. This technology requires more research and pilot projects to provide its effectiveness in microgrids.

6.1.7. Arc Flash

Arc-flash relaying techniques use current, sound, light, or a combination of these measurements to detect these dangerous events. By detecting these events faster than conventional current-only techniques, these relays save lives. This is mature technology and used throughout the industry.

6.1.8. Zone interlocking

Zone interlocking is a communication scheme used between protective relays to improve the level of protection in a power distribution system. Upstream relays communicate with downstream relays to determine the location of a fault. By so doing, these systems operate faster than time-coordinated schemes but slower than true differential schemes. These schemes are complicated but offer a low-cost solution to some microgrid protection challenges.

6.1.9. Seamless islanding

This is most commonly done by a combination of protective relay actions. The sequence usually goes like this:

1. Fault on the utility system is detected by a microgrid point of common coupling (PCC) relay and the PCC CB is opened.
2. A load shedding relay detects the PCC CB opened and equalizes load to generation inside the microgrid. The microgrid seamlessly stays online.

6.1.10. Synchronization

There are several flavors of synchronization being used in microgrid relays today. This includes the following:

1. Unit synchronization is when a relay closes a DER into a live power system.
2. System synchronization is when a relay closes a microgrid PCC into a live utility power system.
3. Sync check is when a relay only confirms the conditions on both sides of the CB are acceptable for close.
4. Automatic synchronization is where the relays dispatch DER in the microgrid to put the conditions across the CB into a condition where a sync check can allow a CB close.

6.1.11. Summary of findings

Conventional protection designed for passive radial networks is insufficient for the increasingly complex active networks. These may have radial and looped topology integrated with diverse distributed generation sources, storage, and controllable loads. The design of such protection systems for emerging distribution systems needs a very new protection paradigm, architecture, and philosophy making use of new protective devices and sensors such as digital relays, Phasor Measurement Units (PMUs), intelligent reclosers, and line sensors.

Regarding the new requirements posed in the protection scheme for emerging distribution systems, this section introduces a series of new relaying algorithms that can be adopted to fulfil the concept of advanced and adaptive protection. With these technical approaches, the new protection paradigm can adaptively respond to changing operation conditions and network topologies. With the proposed novel approaches interacting with the advanced communication infrastructure, the disturbances can be interrupted more accurately and quickly, thus expediting service restoration.

Each microgrid has differing priorities and complexities, all of which affect protection, islanding, synchronization, and DER functionality. Therefore, skilled protection engineers skilled must participate in the design phase of microgrids to ensure success. Protection engineers must utilize a detailed checklist of issues to analyze during the design phase.

This chapter discusses protection schemes suitable for microgrid protection and advanced strategies:

6.2. Emerging Protection Schemes for Microgrids

With all the remarkable system changes that have occurred in the last 20 years, the distribution system protection design and coordination deserve a more radical approach. The authors believe that (1) computer models for all protective devices is the way to select device settings and (2) adopt and automate the device coordination process. These can be done for local coordination of any two adjacent devices or the global coordination using effective computer-communication systems. With this recommend approach and philosophy, the authors will describe the entire process below for the emerging distribution systems. This approach is valid for systems of any size that is at the feeder level, substation level or even for several substations at a control center level. This approach can be applied for grid and microgrid system and their transitions from one to the other. Finally, it should be an effective tool for both planning and automation of any given distribution system.

6.3. Adaptive Protection

The most common application of adaptive protection is to change the relay settings as a microgrid is islanded or as DER go on and offline. These settings changes can require advisement from a central control, and commonly require communications. Most protection engineers are familiar with the technique of modifying settings groups in a relay to provide adaptive protection. Adaptively changing protection settings per system operating status is intuitive but can become time-consuming and costly due to additional engineering labor, more communication equipment, and increased equipment counts.

Adaptive protection can automatically alter its operating parameters to maintain optimal performance in response to changing conditions of the system operations [82]-[83]. Many efforts have been made in developing adaptive protection techniques. Reference [81] proposes a method for microgrid protection using differential current relaying. The plan for optimally deploying protection equipment is desired to reduce the overall cost. Changing protection settings per system operating status is intuitive but costly, due to the reduced latency requirements for communication. The methods include performing changes in demand using pre-defined setting groups [84] and [85] and calculating operation parameters based on real-time learning of the system status [86]-[89]. The sensitivity of a protection scheme can easily be kept in a system with a single operation mode. The relays can be configured to trip only in low level fault current [90]-[92] by using fault current limiters, or in normal level by increasing fault current capacity [93], [94]. The author suggests performing intentional islanding whenever a fault occurs so that the relay is only set for island protection. This may result in poor operations, even for momentary faults.

Brahma and Girgis proposed an adaptive protection scheme that detects faulted zones, so that the coordination among relays can be realized [95], [96]. This method requires enormous measurements (such as voltages and currents from all connected DGs) as well as synchronization. References [97] and [98] present coordination schemes adapting to changing networks. However, the enforced delay prolongs the fault clearing time. In North America, the distribution systems are designed unbalanced; therefore, protection algorithms based on negative and/or zero sequence components (which have been widely used in Europe and Asia) cannot be adopted to the systems, as discussed in references [99]-[110].

The following issues deserve consideration in the design of adaptive protection systems for micro grid modes of operation:

- Operator Issues
- Commissioning
- Maintenance
- DER mode control
- Fault detection
- Fault location methods
- Multiple-terminal approach
- Impedance based formulation
- Eliminating impact of fault resistance
- Sensitivity analysis
- Impact of measurement error
- Impact of line parameter error
- Method validation

6.4. Adapting existing relays – relay load shedding

Conventional generation allows relays to be set with UF elements in a staggered fashion. The staggering can be in both UF trigger point and in pickup timers. This simple method is in service throughout the world and implemented dominantly in microprocessor relays. This technique falls when faced with inverters based DERs and electronic loads with -R. It is for this reason that UF load shedding becomes an impractical solution for many microgrids with large renewable penetration. There are two proven, practical solutions for this: 1) make the inverters droop in frequency as their power output increases, and 2) utilize sub-cycle fast (and enormously intelligent) contingency load shedding systems. These two techniques were used to win the NREL microgrid shootout.

The droop solution has been shared by Lasseter with his CERTS concepts for years, and the results are promising [119]. The fast load shedding has been in service for years at oil and gas facilities and is now gaining traction in the microgrid protection world. These load shedding schemes are implemented in the protective relays and therefore requires mention. The preferred solution is to use both the droop solution and the contingency based relay-based load shedding.

6.5. Microgrid Protection Example

6.5.1. Microgrid Protection Paradigm

The microgrid protection scheme proposed in this work is distributed differential protection using digital sensors, relays, and communications. In the proposed scheme, the microgrid is divided into differential zones, comprising multiple devices. This is an extension of the proposed paradigm given in [47]. It is developed here in fuller detail.

The protection scheme can be implemented on multiple types of devices if they fulfill the functional requirements. The main requirement is that the sample rate and response time are within the stability requirements of the microgrid. The microgrid stability depends largely on the number of synchronous and induction generators and induction motors on the system, and ranges from tens of milliseconds to seconds [51]-[53].

6.5.2. Fault Detection and Isolation

Faults are detected in this scheme by using predetermined distributed differential zones. Each zone has a device on all nodes where current and power can flow in or out of the zone. In this way, the sum of all currents and powers measured at the devices is ideally zero. There is one zone controller for each zone. The zone controller receives the measurements from all the devices and evaluates the sum of all the measurements against the fault threshold. If several consecutive samples are found to be above the threshold, a tripping signal is sent from the zone controller to all relays in the zone. If angle or high frequency (>1 kHz) waveform measurements are present, differential current can be used. However, if only rms values are present, differential power must be used instead.

Differential protection is not without its own drawbacks, such as measurement mismatch, restraint current, dependence on communication, and multi-terminal operation. To account for measurement mismatch and restraint current, the threshold must be set to be higher than the combined maximum measurement errors of all the devices while also considering the impact of the restraint current. This can constrain the size of a zone, as too high a threshold will make detecting low current/power faults difficult.

A problem with multi-terminal operation is that it increases the potential impact of a device failure. To address this, the zone controller communicates with adjacent zone controllers in case one of the relays fails to open. In such a case the zone controller will instruct the adjacent zone controllers to trip their relays. This backup will increase the size of the outage of the affected network.

Various communications systems can be used for the distributed differential protection. Each has its advantages and drawbacks. The lowest latency systems, such as dedicated fiber optics or Ethernet, can respond the quickest (within milliseconds) but these systems are also the most expensive. Lower cost, higher latency wireless networks can transmit the measurements to localized controllers in tens to hundreds of milliseconds, depending on the quality of the transmitters. In addition to higher latency, the wireless networks are more prone to packet loss and corruption. This can cause nuisance tripping or failure to detect a fault. The network latency must be sufficiently low compared to the sampling rate or the response time will be adversely affected.

Each protection zone controller must identify communications network failures and alert the microgrid centralized controller, so repairs can be made as quickly as possible. In this case the zone controller will operate on voltage protection, sending trip signals whenever the voltage at the remaining operational nodes is below a given threshold. This method cannot detect all fault types but is a communications failure backup.

The choice of communication network will be based on the microgrid's reliability and speed requirements. Microgrids that are prone to instability will require faster fault isolation times and thus lower latency networks are required. Microgrids with more nodes and longer distances between them will also require faster and more reliable communication networks. For systems without stability problems, slower speeds comparable to classical fuse and reclose operation time may be acceptable.

6.5.3. *Optimal Protection Design Example*

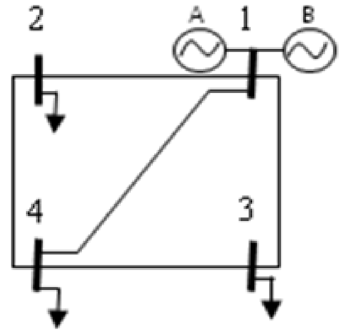

Figure 3. Four-Bus Microgrid: Source B Is an Inverter Connected Storage Unit

To illustrate this protection scheme, consider the four-bus microgrid in Figure 3. In this simple microgrid, the primary distribution system interconnect is source A and source B an inverter connected backup battery. To protect this system using the method in [81] will require a digital relay with high frequency current sampling at the end of each line, as shown in Figure 4 (a). In this case the relays communicate primarily to their differential partner. For example, the relay at bus 1 on line 1-2 will communicate with the relay at bus 2 on line 2-1.

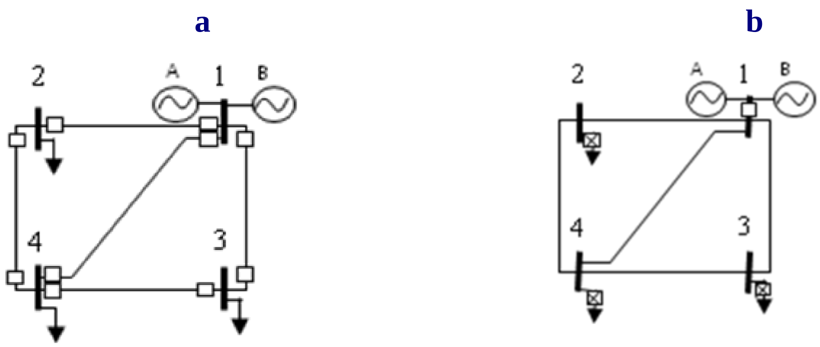

Figure 4. Four-Bus Microgrid Protected by the Method (a) and the New Paradigm (b)

In Figure 4, sensors are shown as squares with an 'X' while intelligent relays are empty squares.

Figure 4 (b) shows an example placement of the proposed paradigm on this system. In this case a current sensor, instead of a relay, is placed on the secondary side of the transformers for each load and on the connection of the sources to node 1. The sum of all the currents from the different devices, including capacitive charging currents, is zero. With sensors and relays in this arrangement, any fault in the system will cause the current measured at bus 1 to be higher than the sum of the currents at the loads at buses 2 through 4, which will indicate a need to trip the source. The same functionality could be achieved by using an intelligent relay at bus 1 and sensors at the load buses and using differential power measurements.

One disadvantage of the device placement in Figure 4 (b) is that any fault will result in the loss of all loads. The placement in Figure 4 (a) is more reliable but also more expensive in terms of equipment costs, while the placement in Figure 4 (b) is the less expensive in equipment costs and less reliable. For any general system, an optimal device placement can be found which minimizes the equipment costs and the outage costs to customers, as described below.

6.5.4. *Optimal Relay Placement Formulation*

The problem of optimizing the positions of the standalone sensors and those that are connected to relays depends largely on system topology. Consider a network connectivity matrix [C] where the diagonal entries represent loads and sources connected at that bus and the off-diagonal entries represent line connections. The rows correspond to the sending bus and the columns to the receiving bus. For the microgrid in Figure 3, the connectivity matrix would be:

$$[C] = \begin{bmatrix} 1 & 1 & 1 & 1 \\ 1 & 1 & 0 & 1 \\ 1 & 0 & 1 & 1 \\ 1 & 1 & 1 & 1 \end{bmatrix} \tag{6-1}$$

The decision variables for the optimization are the locations of sensors and relays on the network and can be represented by a protection device matrix $[D]$ where the rows correspond to the sending bus and the columns to the receiving bus. The problem of differentiating sensors from relays will be covered later. For the device layouts in Figure 4 (a) and (b) the device matrices are given in (6-2) and (6-3), respectively.

$$[D] = \begin{bmatrix} 0 & 1 & 1 & 1 \\ 1 & 0 & 0 & 1 \\ 1 & 0 & 0 & 1 \\ 1 & 1 & 1 & 0 \end{bmatrix} \tag{6-2}$$

$$[D] = \begin{bmatrix} 1 & 0 & 0 & 0 \\ 0 & 1 & 0 & 0 \\ 0 & 0 & 1 & 0 \\ 0 & 0 & 0 & 1 \end{bmatrix} \tag{6-3}$$

To adequately detect faults under this protection paradigm, every bus must either have a device on its secondary side, or on each line connected to it. Mathematically, this constraint is for row 'i' of the device matrix,

$$[D]_i = \ diag\{[C]\}_i + ([C] - diag\{[C]\})_i \tag{6-4}$$

Note that the '+' is not an exclusive 'OR'. Therefore, if one condition is satisfied the other may be partially satisfied.

Another constraint comes if some buses in the system are single-phase and others are three-phase. In this case, each phase on a bus is represented as a separate node in the connectivity matrix. If three-phase relays are used, all three nodes on the same bus must have the same device placement values. This constraint is given by

$$[D]_{[I]k,1} = \ [D]_{[I]k,2} \tag{6-5}$$

$$[D]_{[I]k,2} = \ [D]_{[I]k,3} \tag{6-6}$$

where $[I]$ is an h-by-3 matrix containing the indices of the three-phase bus nodes in the connectivity matrix and h is the number of three-phase buses in the microgrid. The k^{th} bus will have an entry in each column $[I]$ matrix corresponding to phases A, B, and C, respectively.

Within these constraints on the placement of the devices, the objective is then to minimize the annualized costs of the protection scheme over an operating period. The total cost comes from two sources: the investment capital cost of the devices, sensors and relays (C_{INV}), and the costs of customer interruption from outages (C_{CI}).

The investment costs, which include the installation and maintenance over the lifetime, are given by

$$C_{INV} = \sum_i \sum_j C_{INV\_D_{i,j}} \tag{6-7}$$

where C_{INV} is the total investment cost and $C_{INV\_D_{i,j}}$ is the investment cost of the device at location (i, j) in the network. This cost can be further divided into the costs of the different devices; in this case, sensors ($S_{i,j}$) and relay ($R_{i,j}$) to give

$$C_{INV} = \sum_i \sum_j C_{INV\_S_{i,j}} + \sum_i \sum_j C_{INV\_R_{i,j}} \tag{6-8}$$

Since the objective is to minimize cost, an optimal placement of a sensor and a relay at the same position is unlikely. This is because the relay has all the functionality of the sensor plus a breaker to trip the line. In addition, a relay will not be placed at a node that has no active source. This is because relays are needed to interrupt current from active sources to the fault and passive loads do not have any fault current emanating from them. In addition, a relay on the load does not reduce the C_{CI} since the customer will be lost by the tripping. Lines, however, will only have relays on them [50]. This leads to a condition to determine which devices should be sensors and which should be relays. For a given distributed generation matrix, $[DG]$, where all buses with a DG source are denoted as '1' and all other entries are '0' (including the system interconnect as a DG source), the rule states that the sensor locations [S] are given by

$$[S] = diag\{[D]\} - [DG] \tag{6-9}$$

where the DG matrix for Figure 3 is

$$[DG] = \begin{bmatrix} 1 & 0 & 0 & 0 \\ 0 & 0 & 0 & 0 \\ 0 & 0 & 0 & 0 \\ 0 & 0 & 0 & 0 \end{bmatrix} \tag{6-10}$$

In addition, relay locations $[R]$ are given by

$$[R] = [D] - [S] \tag{6-11}$$

The annualized total investment cost given in (6-8) then is given by (6-12).

$$C_{INV} = \sum_{\substack{i \\ i \neq j}} \sum_{j} D_{i,j} \cdot cost_R + \sum_{i} \left(D_{i,i} - DG_{i,i}\right) \cdot cost_S + DG_{i,i} \cdot cost_R \tag{6-12}$$

Where $cost_R$the investment is cost of a single relay device and $cost_S$ is the cost of a single sensor. The customer interruption cost C_{CI} is calculated by the cost of outages from faults, C_{CIf}, and the cost of outages caused by relay and breaker failure and malfunctions, C_{CIm}.

$$CCI{=}CCIf{+}CCIm \tag{6-13}$$

The costs from network faults can be computed by the formula given in [55].

$$C_{CIf} = \sum_{j=2}^{n} \sum_{i=1}^{j-1} \lambda_{i,j} \cdot l_{i,j} \left(\sum_{k=1}^{n} IC_{i,j,k} \cdot L_k \right) \tag{6-14}$$

Where:

n is the total number of nodes

$\lambda_{i,j}$ is the outage rate (failure per year/km) of line segment i, j

$l_{i,j}$ is the length of line segment i, j

$IC_{i,j,k}$ is the interruption cost of load at node k due to an outage on line segment i, j

L_k is the total load at node k

Note that different loads have different interruption costs. Certain priority loads, such as hospitals, and commercial customers, such as server farms, will have much higher interruption costs than residential customers. The interruption cost at each node, *IC*, is the combined cost of all the load types. Therefore, it can be different at each node.

The costs from relay failures come from relays not operating correctly to open and isolate a fault. In this case the zone controller will trip the adjacent zones, causing an enlarged outage area. This cost can be computed by

$$C_{CIm} = \sum_{\xi=1}^{n} \sum_{\iota=1}^{n} \tau_{\iota,\xi} \cdot \rho_{\iota,\xi} \left(\sum_{k=1}^{n} IC_{\iota,\xi,k} \cdot L_k \right) \tag{6-15}$$

where:

$IC_{\iota,\xi,k}$ is the interruption cost of the load at node k due to a failure of relay ι,ξ

$\tau_{\iota,\xi}$ is the total yearly trips of relay ι,ξ

$\rho_{\iota,\xi}$ is the yearly failure rate of relay ι,ξ

Computing $\tau_{\iota,\xi}$ requires finding the yearly fault rate of each line in the zone of relay ι,ξ. Calculating $IC_{\iota,\xi,k}$ requires computing whether the zone of relay ι,ξ is adjacent to the zone of node k.

Since the customer interruption cost is calculated over a period of years, its Net Present Cost (C_{NP}) is computed by using the yearly customer interruption cost in the formula below:

$$C_{NP} = \sum_{t=0}^{years} \frac{C_{CI\,t}}{(1+i)^t} \tag{6-16}$$

where i is the risk-free interest rate.

This gives the formulation

$$\underset{D}{\text{minize}} \; \left(C_{INV} + C_{NP}\right) \tag{6-17}$$

Subject to (6-4)-(6-6).

This optimization procedure requires a full fault analysis to calculate the C_{ICf} for each potential device placement and an analysis of the zones to calculate C_{ICm}. It is therefore a non-convex problem that must be solved through heuristic methods. In this work a binary genetic algorithm is used.

6.5.5. *Optimal Device Placement Algorithm*

The optimal placement is solved with a binary genetic algorithm [50]. Once the population is randomly initialized, each chromosome is evaluated for fitness. A complete fault analysis is then performed by simulating a fault on each line and, assuming the protection system works as designed, determining which buses are de-energized and which remain isolated from the fault. The DGs and loads in each sub-island (remaining connected portions of the network that are energized by fault isolation) are then calculated to see if the resulting sub-islands can operate independently. The cost of customer interruption is calculated based on the average repair time for the line. A yearly customer interruption cost is then calculated by multiplying the cost of each fault by the yearly average fault rate of the line.

The final cost is obtained by adding the net present lifetime cost with the cost of all the devices. If the microgrid can operate in both grid-connected and islanded mode, the lifetime cost for each mode of operation is computed; the total cost is then calculated by multiplying the cost of each mode by the percentage of time the microgrid operates in that mode.

After the fitness of each chromosome is evaluated, a certain percentage of the least fit are eliminated and replaced by 'children' of the most fit. These children result by trading genes between two 'parents' to give chromosomes to the children. Each gene also has a small probability of mutation, where the gene will switch values, which occurs next. The resulting generation is then evaluated, and the process continues until a specified tolerance is reached.

A detailed simulation case study example with results is presented in Appendix D [49].

6.6. Microgrid Fault Location Example

To speed the restoration procedure resulting from a fault, a new fault location algorithm is developed that requires no other measurements than $|V|$, P and Q that can be provided by the sensors mentioned previously. A four-bus microgrid shown in Figure 5, describes the fault location method. In Figure 5 a fault denoted as F takes place on line 1-2 installed at the protection zone border.

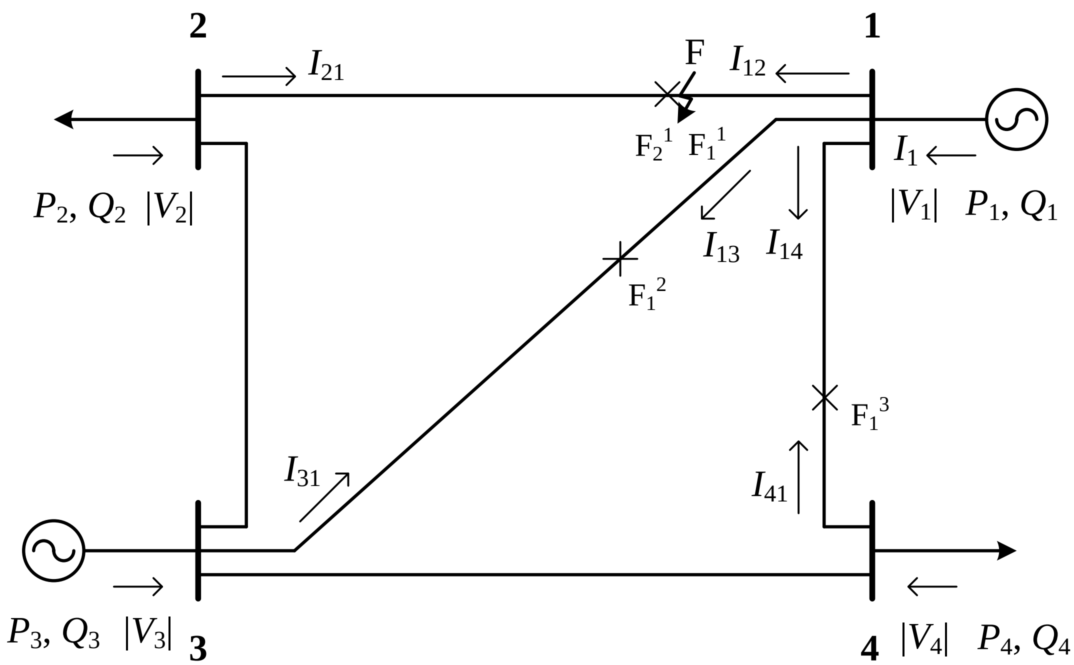

Figure 5. Four-Bus Microgrid with a Fault on Line 1-2

The fault location process is activated once a fault has been detected. In addition, the goal is to locate the faulted line. The proposed fault location method consists of the following three steps:

1. Determining the starting bus: Find the bus, designated as bus S, which has the greatest voltage sag or voltage magnitude variation;
2. Finding candidate location(s): Starting from an initial bus S, find all possible fault point(s) based on apparent impedance by iterating every adjacent line;
3. Identifying the actual location: For each candidate, starting from its remote bus with available measurements, validate if a fault takes place at the same location with this candidate. If no, eliminate it from the candidate list; if yes, the actual location is found.

Consider the fault F on line 1-2 shown in Figure 5 as an example to illustrate the above procedures. The bus 1 is determined as the starting bus S, for finding candidate fault points due to the greatest voltage sag. The current injection to bus 1 can be calculated as $I_1 = [(P_1 + jQ_1)/V_1]^*$. The apparent impedance is a function of relative angle between voltage and current. Therefore, the voltage angle can be arbitrary. In this paper, zero degrees are used as the reference.

A candidate location is found when the estimated fault point is within a line. For line 1-2, current I_{12} is calculated by assuming that the lines 1-3 and 1-4 are healthy. A Thevenin equivalent circuit is formed to calculate the line current as $I_{13} + I_{14} = (V_1 - E_1^{eq}) / Z_{12}^{eq}$, where E_1^{eq} and Z_{12}^{eq} are the open-circuit voltage at bus 1 and the short-circuit impedance looking from bus 1 towards line 1-3 and 1-4, respectively. Then, current I_{12} is calculated as $I_1 - I_{13} - I_{14}$. The currents on line 1-3 and 1-4 can be calculated in the same way. After iterating every adjacent line (in this case they are lines 1-2, 1-3, and 1-4), three candidate points denoted as F_1^1, F_1^2, and F_1^3 are found. In the designation of the fault candidate, the subscript shows the number of the starting bus while the superscript stands for the number of a candidate.

For F_1^1, F_1^2, and F_1^3, repeat the above process by searching from bus 2, bus 3, and bus 4, respectively. For candidate F_1^1, starting from remote bus 2, line 1-2 is searched and a fault point, denoted as F_2^1, is found, as shown in Figure 5. For candidate F_1^2, line 1-3 is searched and no fault is found because the apparent impedance calculated from bus 3 is greater than the impedance of line 1-3. Thus, F_1^2 is removed from the list. Similarly, F_1^3 is also removed because no fault is found on line 1-4 from bus 4. In this case, F_1^1 is the actual fault location.

The system short circuit model is used to calculate the Thevenin equivalent voltage E^{eq} and impedance Z^{eq}. For the system in Figure 6, the model includes:

- the source voltage and impedance at bus 1 (denoted as E_{s1} and Z_{s1}) and bus 3 (denoted as E_{s3} and Z_{s3})
- the load admittance at bus 2 and bus 4 (denoted as Y_{ld2} and Y_{ld4} respectively)
- the line admittance (denoted as $Y_{ln1\text{-}2}$, $Y_{ln1\text{-}3}$, $Y_{ln1\text{-}4}$, $Y_{ln2\text{-}3}$ and $Y_{ln2\text{-}4}$).

The dimension of each parameter depends on the number of system phases. For a three-phase system, source voltage is a three-element vector while the impedance and admittance are three by three matrices. The network admittance matrix is formed with lines and loads: $Y_{Net} = [Y_{mn}]$, $m, n = 1, 2 \dots 4$. This is essentially Y_{BUS} combined with load admittances.

Computing the current I_{12} for line 1-2 is used as an example to describe the procedure for calculating the equivalent voltage E_1^{eq} and impedance Z_{12}^{eq}:

1. Modify the network admittance matrices. The modified Y'_{Net} ($Y'_{Net} = [Y'_{mn}]$, $m, n = 1, 2 \dots 4$.) is obtained by replacing Y_{11} and Y_{12} with $Y_{11} - Y_{ln1\text{-}2}$ and $Y_{12} + Y_{ln1\text{-}2}$ in Y_{Net}. The modified Y''_{Net} is obtained by replacing Y'_{33} with $Y'_{33} + Y_{s3}$ in Y'_{Net}, where Y_{s3} is the inverse of Z_{s3}.
2. Obtain the impedance matrices of the modified network: $Z'_{Net} = [Z'_{mn}] = \mathit{Inverse}\,(Y'_{Net})$, $Z''_{Net} = [Z''_{mn}] = \mathit{Inverse}\,(Y''_{Net})$, $m, n = 1, 2 \dots 4$.
3. Compute current injection (denoted as I_{In3}) at bus 3 from source E_{s3}: $I_{In3} = E_{s3} / (Z'_{33} + Z_{s3})$.
4. The open circuit voltage E_1^{eq} at bus 1 is obtained as $E_1^{eq} = Z'_{13} \times I_{In3}$.

5. The equivalent impedance is obtained as $Z_{12}^{eq} = Z''_{11}$.

Then, $I_{12} = I_1 - (V_1 - E_1^{eq}) / Z_{12}^{eq}$.

In Figure 6 a line segment is used to illustrate how to calculate the fault distance provided the voltage and current at one terminal. This line can be a single-, two- or three-phase circuit. In this figure, V_S, I_S, I_F and Z_L are bus voltage, line current, fault current phasors, and line impedance, respectively. E_R and Z_R are remote equivalent voltage and impedance. R_F is fault resistance. D is the distance of the fault, varying from 0.0 to 1.0. The governing voltage equation for the condition shown is given as:

$$V_S = d \cdot (Z_L \cdot I_S) + R_F \cdot I_F \tag{6-18}$$

where $I_F = I_S - I_R$. The voltage drops over the line $Z_L I_S$ is designated as V_L and the equation is rewritten in real and imaginary parts as follows:

$$\begin{aligned} V_S^{\mathrm{Re}} &= d \cdot V_L^{\mathrm{Re}} + R_F \cdot I_F^{\mathrm{Re}} \\ V_S^{\mathrm{Im}} &= d \cdot V_L^{\mathrm{Im}} + R_F \cdot I_F^{\mathrm{Im}} \end{aligned} \tag{6-19}$$

Eliminating R_F and solving equation for the distance "d" yields

$$d = \frac{V_{Sph}^{\mathrm{Re}} \cdot I_{Fph}^{\mathrm{Im}} - V_{Sph}^{\mathrm{Im}} \cdot I_{Fph}^{\mathrm{Re}}}{V_{Lph}^{\mathrm{Re}} \cdot I_{Fph}^{\mathrm{Im}} - V_{Lph}^{\mathrm{Im}} \cdot I_{Fph}^{\mathrm{Re}}} \tag{6-20}$$

The "*ph"* specifies the *ph* for single-line-to-ground faults (S-L-G), line-to-line and line-to-line-to-ground faults (L-L and L-L-G), and three-phase faults.

Table 2. Specification of *ph* for Different Types of Faults

Fault Type	*ph*
S-L-G	A-G or B-G or C-G
L-L / L-L-G	A-B or B-C or C-A
Three-Phase	Same as L-L/L-L-G

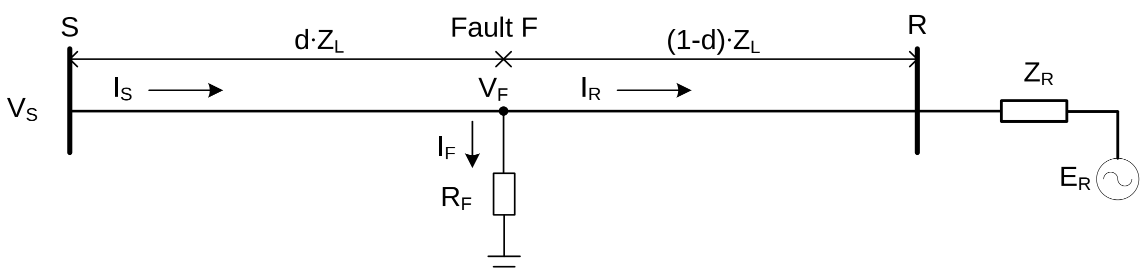

Figure 6. One-Line Diagram of a Line with Remote Equivalent Circuit Model

For a give line segment, if the calculated distance d is less than or equal to 1.0, then a fault is found; otherwise the next adjacent line will be examined. The fault resistance may influence the estimated distance when using voltage and current from one terminal. To eliminate this impact, the following iterative procedure is employed (the superscript represents the iteration number):

1. Start from $d^0 = 0.0$, then $V_F^0 = V_S$, and $I_R^0 = (V_F^0 - E_R)/(Z_L + Z_R)$
2. Compute $I_F^1 = I_S - I_R^0$, then use equation to obtain distance d^1
3. Update $V_F^1 = V_S - d^1 \cdot Z_L \cdot I_S$, and $I_R^1 = (V_F - E_R)/[(1 - d^1) \cdot Z_L + Z_R]$
4. Repeat steps 2 and 3 until $|d^k - d^{k-1}|$ is less than a pre-set threshold (tolerance).

6.7. Role of Controllers and Algorithms [120]-[126]

The emerging smart grid is going to require a focused melding of new and advanced technologies along with new hardware designs and operational algorithms to be successful. Advanced and reliable communications may be required for some protection schemes. Innovative designs of equipment such as inverters that are more utility friendly, energy storage systems, and controllers that are used in microgrids are needed. The melding process must be compatible with legacy equipment and operation, and the emerging hardware associated with advanced protection architecture.

Inverters and the microgrid controllers provide limited levels of protection for smart grid applications. Virtually all microgrid inverters connected to a utility in an interoperable mode are self-commutated. Most use some variation of a current-sourced device that have a wide variation of control strategies for grid following connections. Grid forming inverters are becoming the preferred inverter for microgrids, but they are just emerging as available devices. Grid forming inverters will operate in the grid forming mode for islanded operation and in a mix of grid forming and grid following in the utility interactive mode.

Microgrids that are interconnected to a larger electrical distribution system are generally required to meet a set of interconnection requirements such as IEEE Std 1547 and additional State or local mandates. Similarly, islanded microgrids must be designed and constructed to meet local internal microgrid requirements to serve the local critical or non-critical loads. The two sets of requirements are always different and often not compatible with the other.

Transitions are necessary when switching between grid-connected (interconnected) to an islanded mode of operation, and that transition is required to be completed within milliseconds. Transition functions are typically complex. Some renewable resources must convert from a voltage waveform following energy supplier to a voltage forming energy supplier as the transition from takes place. The transition is typically required to not cause or delay a disconnection in a manner inconsistent with the microgrid or utility requirements. All transitions must be compatible with protection for both the interconnected distribution grid and the local requirements of the microgrid.

The most advanced microgrid control schemes today do not require these transitions between grid forming, grid following, voltage source, or current source modes. These systems utilize inverters and generators set to operate continuously in a ‘mixed’ mode of operation. This mixed mode of operation promotes grid voltage and frequency curtailment functions while grid-connected, and native sharing and voltage and frequency control while islanded. The advantage to these methods is a simplified control system that works without communication. These robust control methods are used predominantly in the oil & gas industry but are gaining traction in the microgrid market.

7. MICROGRID PROTECTION STANDARDS

7.1. Introduction

The standard for the interconnection of inverter-based resources to the grid is IEEE Std 1547-2018 [131]. Microgrid controllers that are interconnected to the grid respect this standard and the interconnection agreements with utilities.

The IEEE Std P2030.7-2017 [132] and Std P2030.8-2018 [133] are the two approved standards exclusively addressing microgrids. These standards do not prescribe protection schemes deployed within the microgrid, including protection functions of individual components and assets, nor the adaptation of the protection scheme in transitions from grid-connected to islanded modes, nor the protection coordination that may be required with the distribution grid protection schemes.

7.2. Microgrid Related Standards

The IEEE P2030 series of smart grid standards includes many standards related to microgrids. These are summarized in Table 3.

The approved standards can now be adopted and referenced by regulators, utilities, microgrid developers and stakeholders. State regulators and utilities can refer to them for interconnection rulemaking and requirements for any tariffs related to microgrids for reliability or resiliency. Compliance with the standards can now be required in RFPs and contracts for microgrids.

The authors of this report encourage participation in the new IEEE Std P2030.12 Working Group on the development of the Guide for “The design of Microgrid Protection”, sponsored by the IEEE PES Committee on “Power System Relaying and Control (PSRCC)”, and approved by the IEEE SA on September 27, 2018. The working group has started its work, inviting members, and scheduling meetings. The first meeting took place on January 17, 2019 in Garden Grove, CA. The WG will be conducting meetings once in two months to accelerate the development of the Guide on or before December 2022.

Taken together, these two standards enable flexibility and customization of components, the control algorithms to be specified, certified and deployed in microgrids without sacrificing or limiting advanced functionality or compatibility with protection. Table 3 shows the list of Microgrid Related Standards in the IEEE P2030 Series:

Table 3. Microgrid Related Standards in the IEEE P2030 Series

IEEE Std #	Title
P2030.5-2013	Standard Protocol Certification Test Specification: Smart Energy Profile 2.0 Protocol
P2030.7-2017	Standard for the Specification of Microgrid Controllers
P2030.8-2018	Standard for the Testing of Microgrid Controllers
P2030.9	Draft Recommended Practice for the Planning and Design of the Microgrid
P2030.10	Draft Standard for DC Microgrids for Rural and Remote Electricity Access Applications
P2030.11	PAR Draft Guide: Distributed Energy Resources Management Systems (DERMS) Functional Specification
P2030.12	PAR Draft Guide for the Design of Microgrid Protection Systems

7.3. IEEE Standard 2030.7-for the Specification of Microgrid Controllers

As microgrids began emerging as more important and increasingly common elements of improved resiliency and grid reliability, it was determined that standards were needed to provide a means for specifying, testing, and comparing performance of microgrid designs. Microgrid research and development, applications and installations were being delayed or stymied because stakeholders were having difficulty defining what a microgrid should do or how to specify the operations. The microgrid controller is an essential technology for the implementation of Advanced Microgrids as part of the modernized power delivery system.

The Standard for the Specification of Microgrid Controllers (IEEE Std 2030.7) was approved as a new standard by the IEEE Standards Association (SA) Board on 6 December 2017, in the IEEE Std 2030 smart grid standards series. The Standard focuses on defining core functions of microgrids that are related to verifiable and quantifiable performance. This enables improved interoperability of many different controllers and components needed to operate the microgrid energy management system and to handle the transition between grid-connected and islanded modes, through cohesive and platform-independent interfaces. This approach enables flexibility and customization of components and control algorithms to be deployed without sacrificing or limiting advanced functionality.

The voltages, frequency, power, reactive power, settling time, overshoot, and steady state values, time to reconnect, and equipment limitations are all important parameters to be monitored and verified for reconnect transition events.

7.3.1. Purpose and Scope of Specifications

A key element to the functionality of microgrids is the controller, more generally called the control system, which manages transition and dispatch of various Distributed Energy Resources (DER) and loads within the microgrids. The controller integrates the distinct types of DER, including combined heat and power (CHP), renewable energy resources (such as photovoltaic and wind), energy storage and demand response, and the loads within the microgrid boundaries. The controller is the enabler for the interface between the microgrid and the distribution utility during normal operations under "blue sky" conditions and enables islanded operations during "black sky" conditions. These two operating modes offer optimization for energy management while connected to the grid and islanded, and the energy supply to critical loads when the microgrid is disconnected from the grid.

7.3.2. IEEE Standard 2030.8- Testing of Microgrid Controllers

A companion standard to IEEE Std 2030.7 in the IEEE Std 2030 standards series, IEEE Std 2030.8, Standard for the Testing of Microgrid Controllers, was approved by the IEEE SA Board on 14 June 2018. This standard focuses on testing core functions of microgrid controllers that are related to testable, verifiable and quantifiable performance. Goals are to insure interoperability of many different microgrid controllers that will be used to operate microgrid energy management systems, and to handle the transitions between connected and islanded operating modes. Dispatch of microgrid functionalities is included and coordinated with transitions through platform-independent testing descriptions as needed.

7.3.3. Summary

The suite of specification and testing standards is a first step in filling the void of standards for microgrids as new deployments become increasingly important contributors to smart grid adoption, and to provide a more resilient and reliable electric utility grid. The IEEE Std 2030.8 will be available after it is published in 8-10 weeks. The IEEE Std 2030.7 is available as a standard today through the IEEE. Both standards can now be adopted and referenced by regulators, utilities and, microgrid developers and stakeholders. State regulators and utilities can refer to them for interconnection rulemaking and requirements for any tariffs related to microgrids for reliability or resiliency. Compliance with the standards can now be required in RFPs and contracts.

The two standards one for the controller specification and the other for testing were developed on parallel tracks to speed the process to meet the industry needs for standards for this core technology for microgrids. Taken together, these two standards enable flexibility and customization of components, and control algorithms to be specified, certified and deployed in microgrids without sacrificing or limiting advanced functionality. The testing standard focuses on the core functions defined and specified in the specification standard.

7.4. IEEE Standard P2030.12 on Microgrid Protection

The authors of this report encourage participation in the IEEE Std P2030.12 Working Group on the development of the Guide for “The design of Microgrid Protection”, sponsored by the IEEE PES Committee on “Power System Relaying and Control (PSRCC)”, and approved by the IEEE SA on 27 September 2018. The working group has started its work, inviting members, and scheduling meetings. The first meeting took place on 17 January 2019 in Garden Grove, CA. The WG will be conducting meetings once in two months to accelerate the development of the Guide on or before December 2022.

8. PROTECTION OF AC, DC, NETWORKED AND HYBRID MICROGRID SYSTEMS

8.1. Introduction

AC power systems still dominate today because of several reasons: Transporting power over conductors is proportional to the voltage level. Low cost, simple, and reliable AC transformers easily increase the voltage to over 765-kV on the power system today. Raising and lower a DC voltage requires inverter type technology that is expensive, complex, and not as reliable. Faulted circuits on AC systems offer a zero-voltage crossing every 10 milliseconds and therefore AC circuit breakers are small and long-lived. Faulted circuits on DC systems require very large and expensive DC circuit breakers. The protection challenges, potential methods of protection, and gaps with research needs with DC, Networked, Hybrid microgrids are addressed below:

8.2. DC Microgrid Systems

DC systems in the laboratory are proven to be of similar power system transport efficiency as AC systems, however DC microgrid systems are most practical where distances are short, the conductors are not prone to faults (such as enclosed switchgear and short distances), and where inverters are acceptable. DC systems do offer faster response and do not have the complexity of AC frequency and reactive current controls. DC systems have been used since the 1970's for long distance transportation of power over long geographic distances; these DC lines are financially feasible because AC power transportation over long distances has other complexities and costs associated with voltage support as distances exceed about 500 miles. Therefore, DC has practical usage within a building system of a few kilowatts or in transporting gigawatts over long distances. The in between is the domain of AC power systems for the foreseeable future.

The market for DC power systems is so small that few DC relays are in production today.

8.3. Challenges of DC Microgrid Systems

According to a recent Sandia National Laboratory Technical Report [134], one fundamental challenge with DC protection is that there is no zero crossing of current in DC as in AC, therefore faults are more difficult to interrupt with fuses and circuit breakers. The following sections describe some other main challenges of DC protection.

8.3.1. Arcing and Fault Clearing Time

The size, system components, and configuration are the key parameters for the selection of the protective devices for a DC microgrid. High fault clearing time and arcing phenomena are the main drawbacks of the conventional DC circuit breaker (CB). Therefore, to improve the protection, solid-state circuit breakers (SSCBs) or hybrid CB technologies with less/no arcing and minimum fault clearing time should be used. The economic feasibility of these breakers should be considered while designing the protection system for DC microgrids.

8.3.2. Stability

Variations in DERs input power, disturbances in the AC grid, changes in the load power, etc., may cause temporary faults and disturbances in DC microgrid systems. Therefore, stability is a major issue during the fault and restoration process. The instability may arise due to the controllability of power converters, resistive nature of line impedances, lack of physical inertia, etc. As a result, better system control strategies (such as virtual inertia [135], virtual impedance [136]) with good protection schemes are necessary for the stable operation of a DC microgrid.

8.3.3. Multi-Terminal Protection

When considering the design of a LVDC microgrid, experience from existing DC power systems, such as traction power systems, can be useful. However, because existing systems largely use current-limiting rectifiers during DC faults, which only allow current to flow in one direction, a different protection design will be needed to accommodate for the fact that DC microgrids are AC grid-connected through converters with bidirectional power flow [25]. This would require a more flexible protection scheme to accommodate for multiple terminals with multi-directional power flow. Protection challenges may arise from supply-and-demand control, such as maintaining energy storage state-of-charge, DER control.

8.3.4. Ground Fault Challenges

Power conversion devices, such as DC-DC and AC-DC converters, contain capacitive output filters. These capacitive filters present a protection challenge in that they can rapidly discharge into a fault, resulting in large current surges. Depending on the filter design, fault location, and installed capacity of the converter, the current surges can have amplitudes of 10,000 to 50,000-A. For circuit breakers, the greatest challenge posed by the high capacitive discharges is coordination because they can cause both upstream and downstream breakers to trip, or only the upstream breaker, increasing the loads impacted. There is also a potential of damage to the circuit breakers due to the high currents. Additionally, because loads on a DC microgrid are likely to have significant input capacitance, capacitor discharge from loads into adjacent faults exacerbates the problem and can cause unwanted circuit breaker trips. 24 There are two significant operation challenges to consider with DC circuit breakers, failure to open and the risk of welding-closed. The risk of failure to open is related to the capacitive discharge issue, where there may be enough current to initiate opening, but if not sustained long enough, may not deliver enough force for opening the contacts completely. In the case of highly inductive systems, there is a potential for the contacts to then weld-closed during a fault. Time/trip coordination becomes virtually impossible with circuit breakers in DC microgrids unless larger, more expensive low voltage power circuit breakers are used, because they can ride through initial capacitor discharges.

8.3.5. *Faster Speed Requirements and Communication Challenges*

Power flow management is realized by the power electronic interface units to ensure effective extraction and storage of power from DERs and energy storage systems (ESS). This could be achieved by selection of suitable control principles and coordination. In other words, each DER local controller can share the control parameters/information with the other converter's local controllers. Therefore, from a communication perspective, operating principles of DC microgrid control strategies are divided into three categories

- Decentralized DC microgrid system
- Centralized DC microgrid system with communication network
- Distributed DC microgrid system with communication network

The communication networks can also be used for DC microgrid protection. For a double-ended protection scheme, the system voltage and current information need to be shared for fault isolation; however, time requirements for protection are much faster than controls. Therefore, faster communication protocols need to be developed to improve the efficiency of the DC microgrid.

8.4. Principles and Methods of Protection

Several articles discuss fault detection and protection schemes [29], [61], [62], [63], [64] based on different measurement and calculations. There is a range of research on DC system protection, including DC microgrids and HVDC line protection systems, listed in this subsection. More details can be obtained from [134].

- Magnitude of Voltage
- Magnitude of Current
- Impedance Estimation Method
- Power Electronic De-Energization
- Power Probe Unit Method
- Virtual Impedance Method
- Differential Current-Based Fault Detection
- Transient-Based Fault Protection
- Voltage and Current Derivative Supervised Protection
- Handshaking Method
- Fault Detection Techniques for PV

8.5. Gaps and Research Needs

The DC microgrid literature review reveals that effective protection strategies, standards, and guidelines should be developed to improve the performance of the DC microgrid. The parameters related to the system protection are size, configuration, voltage rating, components, and load and control strategies of the system. Therefore, while designing DC microgrid protection, all these parameters determine the probability of occurrence of a fault and need more attention toward the selection of proper detection schemes and devices. The gaps and research need for a DC microgrid protection scenario can be discussed based on:

- Fault detection
- Fault analysis
- Fault isolation
- System restoration
- Protection coordination
- Communication protocols
- Stability

As discussed in this report, the voltage and current are the two parameters available for the DC microgrid fault detection. There are many detection techniques reported in the literature and the popular schemes with pros and cons are discussed in Section 4. However, fast fault detection schemes need to be developed to minimize the fault clearing time. Fault analysis is another wide area where proper standards and guidelines are required. There should be a clear understanding between temporary and permanent faults and the controller needs to generate the trip command to isolate the faulted portion. Therefore, the analysis techniques and reclosing strategies should be more focused on time and fault characteristics, and the component that need to be protected. Isolation of a fault mainly influenced by the performance of the protection devices are discussed in Section 6. Due to the nature of power electronic devices and its control techniques, the DC microgrid components are very sensitive to disturbances and faults. This may lead a voltage collapse of the DC microgrid. Therefore, the fault clearing, and restoration time should be kept to a minimum to improve the performance of the system. The application of solid-state technologies for faster protection devices with low on-state resistance need to be investigated. Without appropriate standards and guidelines, it is difficult to address the DC microgrid system restoration strategies. There should be more research on this topic to develop proper guidelines for the closing sequence of primary and backup protection devices based on the fault characteristics and system components. There are many communication standards available for DC power distribution, but they need to be modified for the DC microgrid system. Protection schemes relying on a communication network generally increase the fault clearing time. Therefore, communication protocols should be focused on the size of the DC microgrid and system components. Due to the resistive impedance nature of DC microgrid systems and lack of physical inertia, system stability is a major issue during fault conditions. The system stability during fault and restoration is another topic that needs more focused investigations and guidelines.

9. COMMUNICATION ARCHITECTURE FOR MICROGRID SYSTEM PROTECTION

9.1. Introduction to Communication Schemes

This section discusses the communication architecture for microgrid protection systems.

9.2. Standards and Protocols for Communications Schemes:

Networking for the power grid continues to attract considerable interest; a recent overview of the transmission and distribution network of smart grid is contained in a PSERC report [137]. Reference [138] provides a good discussion of various communication technologies from generator to customer. The use of communication networks for utility and substation automation is discussed in [139]. In [140], the authors introduce network architecture and design principles for smart grids. In [141] and [142], the authors describe important systems design criteria such as the delay performance for real-time operation, while more bandwidth-heavy applications are explored in [143]. Several wireless communication technologies are compared, and their challenges discussed in [144]. A summary of smart grid communications standards is presented in [145] and [146]. The authors in [147] and [148] describe the communication architecture and protocols for AMI network and relevant standards such as ANSI C12.18, C12.19, and C12.22. The performance analysis of AMI networks based on IP-based internet, ZigBee, Power line communication and TV band communication is introduced in [149] to [152], respectively.

The Internal Substation Automation network is designed to operate the system automation inside the substation. IEC 61850 clearly specifies the communication protocols and data format. In [153], the authors present the internal substation communication requirements and solutions. The performance analysis of IEC61850 based substation communication is evaluated in [154]. Wireless communication as a communication technology for SCADA systems is investigated in [155]. References [156] and [154] show that 10/100 Mbps Ethernet in general can provide satisfactory delay performance for the communication inside the substation. The data from smart meters reaches a local data collector in the first step (for example, usually located at a Distribution Transformer) [157]. Further, the installation of smart meters with wireless communication technologies is more prevalent than that with Power Line Carrier (PLC), especially in such countries as the United States, Russia, and Australia [149], due to the enhanced flexibility and potential for ready scalability.

9.3. Communication schemes for protection to assure advance distribution automation

9.3.1. Line Differential

In this method, relays mounted on each end of line communicate their current and voltage measurements over a devoted communication link. This allows fast (< 2 cycles) determination of faults as being in the cable/overhead line. These schemes are simple to implement, but the cost of adding communication fiber optics can be significant. Modern cables or overhead lines with OPGW fiber optics embedded reduce these costs. Microgrid installations should closely consider adding these fiber optics for critical cables sections as these systems work regardless of DER behavior.

9.3.2. Zone interlocked

These schemes are typically accomplished with IEC61850 GOOSE, hardwired DIO signaling, or proprietary peer-peer serial communications. These are especially useful as lost cost alternatives to bus or transformer differential. These are complicated and only the most experience protection engineers should take these on. These systems work regardless of DER behavior.

9.3.3. Breaker Failure

These systems are important to prevent complete power outages when a circuit breaker does not open. Historically used at transmission voltages, these are becoming more commonplace for mission critical microgrid applications and where MCCB were selected with slim engineering margins (aka the MCCB are prone to destruction). Communicated signals are usually accomplished with IEC61850 GOOSE, hardwired DIO signaling, or proprietary peer-peer serial communications.

9.3.4. Adaptive Protection

The state of utility interconnection and DERs is communicated to protective relays to ensure the protection is adapted.

9.3.5. FLISR

Fault location isolation and restoration (FLISR) schemes depend heavily on communication to protective relays throughout the power system, which is very useful for some microgrids with complex distribution. The protective relay shares the status of the recloser lockout and fault directions, thus allowing a centralized controller to isolate faulted segments and re-energize power system.

9.3.6. PMU

PMU data has the advantage of being fast, deterministic, and time-synchronized. This has advantages for time synchronized inverter control by eliminating the problematic PLL angle tracking systems. PMU measurements are typically accomplished in relays.

9.4. Communication and Cyber Security

A tendency of microgrid protection engineers is to depend on communication systems for critical protection data and control information. Most commonly today the communication used in a business place is Ethernet, or in a home is IT (internet technology). Whereas Ethernet used in a mission critical facility (aka microgrids) is OT (operational technology), using IT in an OT environment is completely unacceptable. IT systems do not have the required determinism, network healing time, physical hardening, reliability, latency times, security, packet prioritization all required for a protection system to function.

For these reasons, all protection schemes used at a microgrid must be OT hardened. All cyber-security policy, plans, and procedures must be implemented on this OT kit. All of this puts significant strain on the microgrid protection engineer who already had more than enough set of challenges on their hands. Especially complicating this is that IT engineers rarely understand the requirements of OT, leaving the protection engineers no choice but to put their own OT networks together.

Advanced communications will be required for new strategies of protection. Examples include signaling and dispatch requests, coordination of transitions with and within microgrids, synchrophasors and phasor measurement units (PMUs), adaptive load and resource logic for predictive and economic schemes, and customized logic for fault detection and mitigation processes. The advanced communications must be reliable and hardened to foil cyber-attacks. There will be instances where one-way communications are necessary to improve cyber-attack immunity, but some form of isolated feedback will be required as well. An additional feature that must be considered is self-diagnosis of anomalies within the communications hardware and from the connected equipment.

One advanced communications method is mesh network communications with monitoring of individual system and providing input to ancillary protection systems. Mesh networks have been used for microinverters with PV systems using ac modules or microinverters where each device can communicate with its neighbor(s). During a need for detecting and mitigating a fault, each device reports a status to an accumulator that, in-turn can be used to determine where and in which direction faults or other anomalies are located. All devices use this information to either block or permit action to quickly isolate a fault. The accumulator system can also determine which devices to trip to isolate the fault while recording the event.

A drawback of any communication system are cyber-security concerns. Systems must operate without communications, albeit possibly in some curtailed fashion.

Software Defined Networking (SDN) offers one solution to most of these concerns. Another cybersecurity consideration to interface with industry grade software will be guided by North American and International Security Standards such as NERC CIP-009-3, NIST SP 800 series (800-171, 800-53, 800-82), IEEE P 2030 and ISO/IEC 27002:2005.

A communication-assisted microgrid protection case study via simulation is presented in Appendix E.

10. RESEARCH NEEDS AND RECOMMENDATION

This section provides a list of challenges and recommendations for microgrid protection R&D. Many elements of the necessary technology exist today from other research, but broad-based R&D on the combinations of new sensors, communication, and algorithms is needed. This R&D provides a path to advancing microgrid protection coordination with clear objectives.

10.1. Current Challenges

The following challenges are relevant to the design of microgrid protection systems.

a) Changing load types can reduce power system stability margins, making protection systems challenging because of the interaction between loads and power system stability and their protection systems.

b) DER dynamic and transient inconsistencies make protection coordination more difficult. Inverters that act predictably to ensure that relays act predictably are needed.

c) Low- or variable-inertia power systems can be unstable with high penetrations of grid-following inverters trying to track and follow the system during disturbances.

d) Large X/R ratios of high efficiency equipment is causing ferro resonance and equipment damage. Conventional protection cannot detect these events and protect for Transient Over voltage (TOV), breaker restrike, cable insulation deterioration, equipment degradation, cable junction failures, insulator failure, inverter failure type problems.

e) There are no testing and certification standards for microgrid protection, and microgrid protection systems put into service without adequate testing endanger lives, businesses, and national grid stability.

f) Cyber-attack surface is increasing with distributed generation. The more the DER, the more potential cyber-attack vectors. Rarely is the cyber security of small DER given the same scrutiny as large, conventional generation systems.

g) Legacy low voltage molded case circuit breaker (MCCB) safety and operational problems endanger lives and businesses. For example, many MCCB are worn out and cannot interrupt fault current and replacements are not readily available.

10.2. Recommendations and R&D Needs

The following is a list of current recommendations and R&D needs to help solve microgrid protection challenges.

1) Research and development of new microgrid protection schemes that are more robust to changing conditions such as load types, inverter-based resources, and networked microgrids. New microgrid protection schemes could include travelling wave, PMU-based protection, pilot-protection, and setting less protection. Development of protection algorithms for microgrid stability when conventional power swing and out-of-step protection functions may no longer apply with inverter-based microgrids. In addition, locating the fault is often challenging in microgrids, and new microgrid fault location algorithms should be developed.

2) Algorithms for optimal protection design in microgrids based on generation locations, PCC, fault current, and critical loads. This includes design techniques to determine appropriate protection settings for real-time applications, planning, or adaptive protection. The design and setting algorithms could include machine learning algorithms using historical fault and outage data.

3) Develop algorithms to predict faults and detect incipient equipment failures using real-time monitoring and data analytics of high frequency measurements. These algorithms would increase reliability by improving maintenance, replacing equipment before failure, and determining tree trimming schedule.

4) Sponsor real-world pilot projects to provide a base level of IEEE 1547, 2030.7, and 2030.8 compliance at a utility PCC. Sponsor projects to evaluate the viability and risks of automated relay coordination with the objective to reduce overall cost of microgrid protection/integration/automation/control systems and to develop simpler, flexible, and more easily replicated systems.

5) Improved power electronics controls for inverter-based resources to provide better coordination with protective equipment. This includes more consistent fault behavior, negative and zero sequence current injections, and appropriate grid-forming inverter controls.

6) Develop universal DER controller standards that go beyond IEEE 1547 and require specific control loops and methods that are applicable to all inverters, generators, turbines, and engines. Standardization of the fault current contributions will significantly improve the implementation of microgrid protection with decreased costs. A pilot project could prove the efficacy of simplifying protection with standardized inverter control methods. The new standards are required for interoperability and compatibility between different vendors.

7) Research for improved cyber security of protection communication and communication between the protective devices and the microgrid controller or DMS.

8) Sponsor real-world pilot projects for HIL testing of several different protection schemes for typical microgrid projects. This includes the use of real protection relays (equipment) for each test of each “style” of protection and evaluate performance of each type of protection scheme. Test high fidelity/MHz sample rate relays to identify and quantify the ferro resonance phenomena, transient over voltage (TOV), breaker restrike, cable insulation deterioration, equipment degradation, cable junction failures, insulator failure, inverter failure type problems.

9) Research on communication protocols and mediums to decrease the impacts of communication latency, jitter, packet loss, corruption, and bandwidth on efficacy of microgrid protection systems.

10) Microgrid protection standards and real-world power pilot projects that identify gaps in current solutions and direct future research and future PAR for IEEE standardization.

11) Design of next-generation current interrupting equipment. This includes solid-state circuit breaker technologies, pulse reclosing technologies, and improved safety of MCCB.

12) New sensing and measurement equipment and techniques. This includes higher frequency sensing, non-electrical sensors, dynamic high-range sensors for variations in fault current and improved directional elements.

13) Research and designs of new protection techniques, schemes, and equipment for DC, networked, and hybrid microgrids.

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APPENDIX A. MICROGRID BASICS

A.1. Why Microgrids?

Microgrids can be operated connected to the main network or autonomously. They have been proposed to integrate high penetrations of distributed generation sources that are becoming more commonplace on the distribution system [105], [106]. Another advantage of microgrids is that they can increase system reliability by reducing customer outage and service restoration time [107]. However, one major issue with implementing microgrids is their protection when operating in an islanded mode. This is a result of the fault currents being lower than steady state currents from voltage-source inverter connected devices. These devices include battery energy storage systems and photovoltaic panels that are often the dominant sources in low and medium voltage microgrids [108].

A.2. Microgrid Types by Supply and Structure

A.2.1. AC microgrids

The best way to address this issue is to consider the following hypothetical example shown in Figure 7 which is an 18-Bus radial/looped distribution system with four different microgrids. This is a modified system presented in Cooper's Electrical Distribution-System Protection [52]. This smart grid system has both conventional and renewable generating sources with distinct types and ratings. This system has many single-phase laterals, both overhead and underground. Please note that the line connection between buses 6 and 13 to close the loop of otherwise radial system.

The selection of microgrids is based on the matching the available local distributed generation with the local loads. One could conceive of selecting different microgrids for the same distribution system, but these must be selected *a priori* and analyzed in detail as identified in Figure 7 so that appropriate real-time actions could be taken when a fault or a disturbance occurs. In this figure four distinct microgrids are identified. The three smaller microgrids and nested within the entire substation microgrid when isolated form the rest of the grid for islanded operation.

Figure 8 shows the location of protective devices for the example system of Figure 7 for radial operation topology only. Most of these laterals (overhead lines connected between buses 3-4, 3-5, 5-6, 5-7 and 5-8) are protected by fuses which are hard to justify for upgrading with reclosers or other digital options because of the high capital cost consideration. Many of the existing protective devices on the three-phase lines could be justified for upgrade and they could be automated. The issue is how to coordinate the new devices with existing fuses? It is possible that many fuses could have backup fuses on the source side in which case, the coordination issue could get more complicated.

One possible solution could be to coordinate all new devices with a microgrid controller at the substation and all radial lines with fuses locally. This may create some miscoordination issues operationally. Further research is warranted to explore this problem further.

Coming to DG sources and loads in the system, each of them may be protected either by a breaker, recloser, sectionalizer or a fuse depending upon the size and other considerations. Here again, the issue is the coordination of the concerned devices locally or globally along with other protective devices in the distribution system.

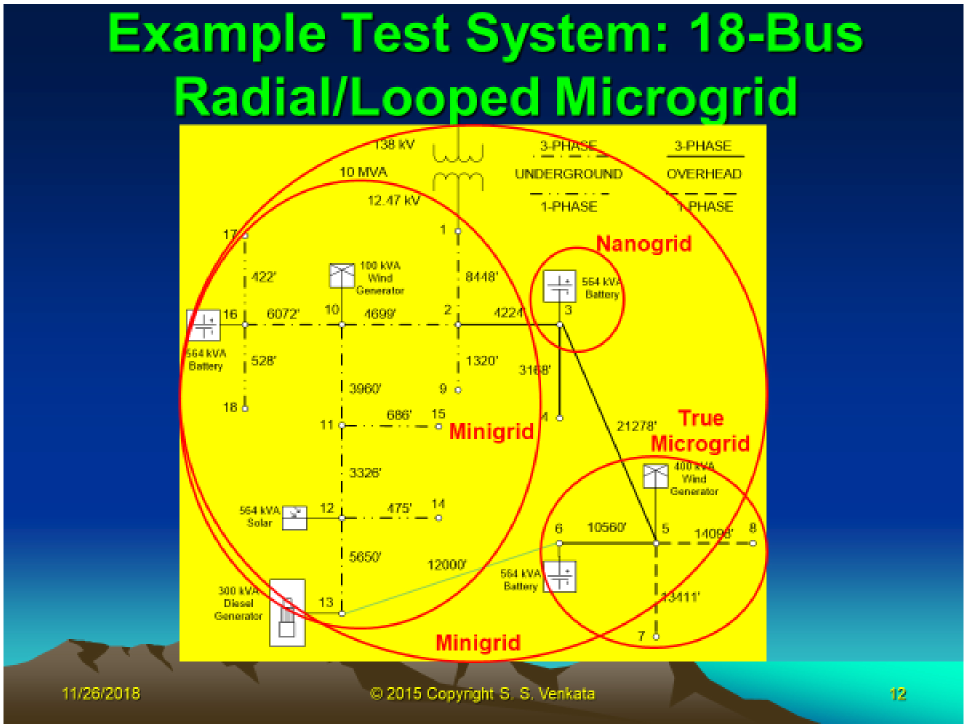

Figure 7. Hypothetical 18-Bus Radial/Looped Example Test System with Several Microgrids

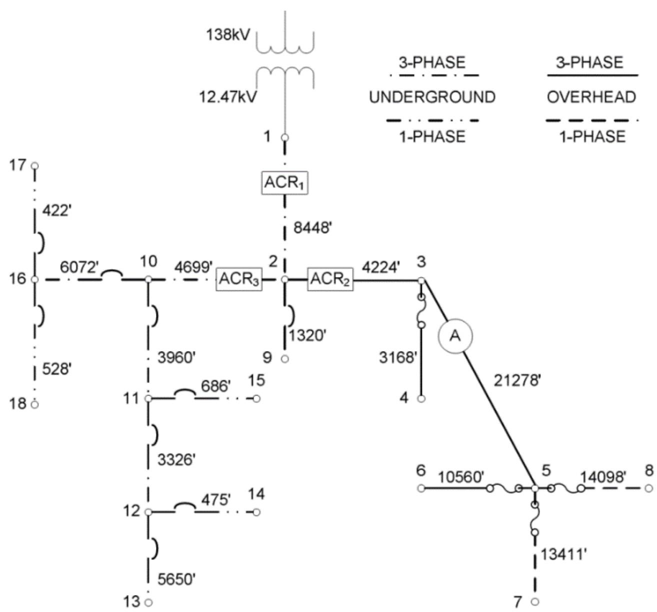

Figure 8. Location of Protective Devices for the Example System of Figure 7 for Radial Operation Topology

A.2.2. DC microgrids

These are slowly evolving to supply dc loads directly from the dc DG sources such as solar and batteries without the need for power convertors to ensure higher efficiency. The major problem with a dc microgrid is the lack commercial fast breakers or switches. Some of have been developed for low voltage applications. This is an area that needs additional research in the development of fast and cost-effective solid-state dc breakers at the medium-voltage levels.

Another principal issue is the coordination of dc protective devices, a subject not yet attempted well.

A.2.3. Hybrid microgrids

A significant amount of research and development is being carried out in the development of hybrid microgrids. From protection point of view these are in the infant stage. One could conceive of many topologies which are still being investigated and understood. These microgrids involving both ac and dc DG sources, loads and their protection could become a complex issue and need R&D investigations. In this type of microgrids, the role of converters/inverters, their efficient operation including protection need to be well understood. One possible problem is the coordination of a dc breaker with ac protective devices in vogue and future ones to be developed.

A.2.4. Networked microgrids

Tremendous amount of R&D efforts going on in several National labs and other R&D institutions. However, this concept of networked microgrids need to understood first before embarking on the protection issues.

APPENDIX B. PROTECTION INTERACTIONS WITH INVERTERS AND RELAYS

B.1. Generic Inverter Types

The emerging smart grid is going to require a focused melding of new and advanced technologies along with new hardware designs and operational algorithms to be successful. Advanced and reliable communications may be required for some protection schemes. Innovative designs of equipment such as inverters that are more utility friendly, energy storage systems, and controllers that are used in microgrids are needed. The melding process must be compatible with legacy equipment and operation, and the emerging hardware associated with advanced protection architecture. Inverters and the microgrid controllers provide limited levels of protection for smart grid applications. Virtually all microgrid inverters connected to a utility in an interoperable mode are self-commutated. Most use some variation of a current-sourced device that have a wide variation of control strategies for grid following connections. Grid forming inverters are becoming the preferred inverter for microgrids, but they are just emerging as available devices. Grid forming inverters will operate in the grid forming mode for islanded operation and in a mix of grid forming and grid following in the utility interactive mode.

It must be noted that the control algorithms and logic differ considerably from brand to brand, and even models with the same model designation may have different control characteristics if they are listed to a different version of the listing standard. The listing of an inverter often depends on the version of software and firmware, but the model number may be identical. The listing label provides the version details. Table 4 provides a rough snapshot of generic examples of inverter types. The columns provide comments on status of products, smart grid viability, examples of applications and estimates of power ratings for the generic types of modern inverters. Only self-commutated inverters are listed in the table and the typical capabilities, applications and examples of ratings and outputs are examples derived from product specification sheets and application information.

Table 4. Generic inverter identification and comparisons

Generic Type of Inverter	Smart Grid Capabilities	Microgrid and Other Applications	Rating, Output,
Residential Central Inverter Notes: Commercially available. Uses a single string of PV or parallel strings combined at the inverter or string combiner. Provide a unidirectional ac output. Labeled interactive inverter in the 2017 NEC.	Limited, but many have autonomous capabilities such as ride-through, curtailment, and power factor control per IEEE 1547-2018. Most have limited communications capabilities, but dispatch is usually not available. Performance data may be collected.	Microgrid application for smaller microgrids but mostly grid-connected PV. Some use PV optimizers. Sone use energy storage but the systems are rarely microgrids	(<20kW); 120 or 240V, single phase, (ungrounded devices are becoming commonplace). New rooftop installs provide dc arc-fault mitigation and use rapid shutdown for first responder safety.

Generic Type of Inverter	Smart Grid Capabilities	Microgrid and Other Applications	Rating, Output,
Commercial Central Inverter Notes: Commercially available. Uses a single of PV or parallel strings with dc combiners and provide a unidirectional ac output. These inverters are labeled interactive inverter in the 2017 NEC.	Most new installations have IEEE Std1547-2018 autonomous capabilities such as ride-through, curtailment, and power factor control. Performance data is almost always collected.	Microgrid application for commercial size microgrids, but mostly grid-connected PV. This type of inverter is also used for wind farms.	(20kW- 500kW with a few exceptions); 240V single phase, 208, 480 three-phase, (ungrounded devices are becoming commonplace). New rooftop installs provide dc arc-fault mitigation and use rapid shutdown for first responder safety.
Utility-scale Inverter All are string inverters of distinctive designs that operate at >480Vdc. Generally unidirectional ac output. Labeled interactive inverter in the 2017 NEC. These and the previous interactive inverters are also classified as grid following inverters	New installations are IEEE 1547-2018 capable, but some capabilities are not used. Dispatch and communications for controls are common features. Performance data is collected	Applications for utility scale are limited but may be used for energy storage systems. Not applied as bi-directional inverters at this time.	Individual inverters ratings into the 1-10 MW rating. Typically, 480V and greater. Some are connected to Medium Voltage distribution.
String Inverter The term is often misunderstood. These inverters typically are connected strings of PV modules to increase the dc voltage and then through combiners that combine multiple dc sources. There is typically one inverter for each combiner. DC voltages up to 1500V are now allowed in ground-mounted PV systems. Labeled interactive inverter in the 2017 NEC.	New installations are IEEE 1547-2018 capable but some of the capabilities are not used. Dispatch and communications for controls are common features. Performance data is collected. The inverters are typically unidirectional power flow.	Applications are very common for all size ranges of systems. The inverters can be integrated into microgrid systems. The inverters are typically unidirectional power flow.	The string inverter is used in most applications for PV. The maximum power point tracking can be within the inverter or via separate devices. An inverter operating with a very narrow voltage range is typically more efficient.

Generic Type of Inverter	Smart Grid Capabilities	Microgrid and Other Applications	Rating, Output,
Bi-directional Inverter Has the capability of delivering power to an interactive grid or drawing power from the grid to charge an energy storage device. Can exhibit the same functionalities as the other grid following interactive inverters.	New installations are IEEE 1547-2018 capable but some of the capabilities are not used for grid support. Dispatch and communications for controls are common features. Performance data is collected.	Applications are preferred for all size ranges of UPS, power backup and microgrid systems. The inverters provide bi-directional power flow. Dispatch and communications for controls are often necessary features. Performance data is collected.	Individual inverter ratings into the 1-10 MW rating. Typically, 480V and greater. Most are connected to low voltage distribution
Grid-forming Inverter Has the capability of forming and regulating voltage waveforms on an ac bus such as a microgrid?	Grid forming inverters are increasingly being installed in microgrids. Grid forming inverters can influence frequency and voltage of the ac bus in the islanded mode. They are IEEE 1547-2018 capable and have communications with limited dispatch capabilities.	The inverters may provide bi-directional power flow. Dispatch and communications for controls are included as necessary features. Performance data is collected.	Inverter ratings range for 10s of kW into the 1-10 MW rating. Typically, 480Vac and greater. Most are connected to low or medium voltage distribution. Operation in the islanded mode can regulate individual phase voltage. Can regulate frequency in islanded mode but also assist in grid connect.
Microinverter Used primarily as grid following inverters that are connected to individual or a few PV modules. There are millions of microinverters connected to utilities worldwide.	They are IEEE 1547-2018 capable and have communications with dispatch and firmware update capabilities.	Innovative designs can be integrated into microgrids with a reference voltage and sync capabilities.	The ratings range from 200 to 300 W. Each inverter is autonomous but master slave systems are possible.

The control algorithms, strategies, speed, defaults, dispatch, and communications capabilities are complex and often not compatible with legacy protection equipment. Those details are not included in this table.

B.2. DER Based Inverter Challenges

B.2.1. Inter-Oscillations

Inverters are used as both loads and sources, and both are creating problems for microgrid protection. Oscillations due to sub-synchronous torsional interaction (SSTI), sub synchronous resonance (SSR), and negative '-R' loads cause protective relaying problems. Protective relays track the power system frequency with elaborate filtering techniques, and some power system oscillations can deceive protective relays. Standardization of both source and load inverter control methods must be instituted to prevent these problems.

Inverters in industrial facilities are causing sub-synchronous torsional interaction (SSTI) problems. These are generally caused by large inverter motor drive systems with control tuning modes that interact with generator shaft's modes. These problems can generally be prevented by standardizing on inverter control algorithms that do not inter-oscillate.

Inverters in utility systems and microgrids are causing SSR, which are undesired oscillations between inverter controllers, wind turbine controller, governor, and AVR systems. One especially interesting inverter inter-oscillation, which occurs inside small microgrids, is associated with the method of frequency tracking and phase locked loops (PLL) utilized by most grid following inverters. This is commonly referred to as a 'tuning' problem by microgrid commissioning engineers. These problems can generally be prevented by standardizing on inverter control algorithms that are designed with compatible protection functionalities.

Negative '-R' loads are loads that increase their current as the voltage drops. Many power electronic loads are -R loads because they are constant power loads. The increasing proliferation of -R loads has proven to cause frequency instability with DER control systems operating in grid following mode. These de-stabilizing problems will become more common as proliferation of inverters provide for soft start systems, variable speed drives, and electronic power supplies.

B.2.2. Limited Kinetic Energy

Conventional rotating generators and their associated engines or turbines contain considerable mass. This mass carries kinetic energy which is transferred to an electric power system during transient conditions. For example, when a small CHP is islanded and then a large load is added the generator will slow down momentarily until the fuel delivery system can catch up. During the time between instantaneous addition of electric power and the lag in fuel delivery to the engine, the engine slows down as kinetic energy is extracted from the spinning inertia and pushed into the electric power system. Conventional power generation is quite literally a massive energy storage flywheel. The kinetic energy transfer from a generator can be on the order of ten times the nameplate rating on the generator for a few seconds.

Batteries have stored energy, but typically cannot deliver the current times time characteristics equivalent to that of the massive flywheel of a rotating generator. Renewable sources such as PV and wind have no stored energy for such events. Because of this, microgrids with large renewable penetration have little inertia ride through. They will exhibit frequency decay at much higher rates than conventional power systems. For example, a full rated load pickup for a small microgrid with diesel generators will exhibit momentary frequency decays on the order of 10 Hz/second. That same microgrid with all inverters will exhibit closer to 100 Hz/sec.

The rapid rate of change of frequency (ROCOF) associated with inverter based microgrids causes protective relays other problems. First, most frequency tracking methods do not track decays faster than 30 Hz/sec, hence the relay will not accurately track. This creates inaccuracies in the voltage and current magnitude measurements because the frequency tracking is used in the advanced filtering of said current and voltage. This means delayed operation, mis-operation, or loss of coordination. It also means under frequency (UF) load shedding schemes will not work.

B.2.3. Thermal limits of Inverters

Inverters have short term overload capacities that are typically on the order of 20% over continuous ratings. Generators have overload capacities on the order of 600% under similar conditions. For this reason, automatic voltage regulation (AVR) technology drives generators into significant over-excitation for such events as magnetization of transformers or starting large motors. Inverters commonly struggle under these same conditions because of their limited short-term overcurrent capacity. This creates another significant problem for protective schemes that are expecting significant inrush. The harmonics from inverters associated with DC offsets are different, and the amplitudes are very different. For example, a microgrid with high renewable penetration with direct connected motors will be a challenge because motor protective relays will trip the motor due to the prolonged start times caused by the inability of the inverters to supply cold load pickup currents. A potential solution to this is to require motors above a certain size to be soft started or have a variable frequency drive (VFD), both of which add cost and reduce reliability.

B.2.4. Inconsistent Behavior Under Faults

As an example, two competing four-quadrant inverter manufacturers herein called company A and B have very different ride-through behavior during faulted conditions. This example is based on two real manufacturers with similarly sized products. As shown below, these varying behaviors make it very difficult for an engineer to perform a protection coordination study. Every inverter manufacturer and sometimes every model a manufacturer makes has a diverse set of characteristics. Even firmware changes between revisions of inverters will have distinct characteristics. This becomes a protection nightmare and requires custom protection work for every unique make, model, and version of inverter. Some utilities have gone so far as to sole-source all inverters to a single model made by a specific plant at a specific manufacturer.

When inverters cannot be standardized, the typical solution required when mixing these manufacturers on the same microgrid is to use a 100% differential protection scheme. Line, bus, transformer, DER are all differential protective schemes. Table 5 shows the wide range of inverter reactions with three different line conditions.

Table 5. Examples of inverter reactions to faulted lines

Event	Inverter A	Inverter B
Bolted 3 phase short circuit at terminals	Limit current to 3x rated, then trip after 30 seconds	Limit current to 1.5 x rated for a few seconds, then 1x rated for 10 seconds, then shutdown.
High voltage condition at terminals	Absorb 3x rated VARs then shutdown after 30 seconds.	Trip offline in < 10 seconds based on a time-over voltage
Single phase to ground fault on terminals	Limit the faulted phase to 3x rated current and keep the other phases carrying load at nominal voltage and current. Asymmetrical output of voltage and current.	Only output symmetrical voltages and currents. All voltages reduced to keep faulted phase within thermal limits.

B.2.5. *Inconsistent Transient Behavior*

Placing a diesel genset in parallel with an inverter using a battery dc source is an interesting experience in root locus tuning, time constants, and adaptive protection. The inverter is typically much faster than the governor, so transiently when a load is added, the inverter typically picks up all the load, then the governor picks up as the fuel valving responds. This sort of behavior becomes dangerous when the loads are bigger than the inverter, at which point the inverter will current limit, expel harmonics, or just trip offline. The transients occur on a timescale of < 50 ms. One alternative is to use a very fast microgrid control scheme with time of responses ~ 20 ms. Another solution to this transient problem is to tune the inverter to respond at the same rate as the generator, thus allowing the generator to expel kinetic energy for load additions. A preferred technique may be to use both methods to ensure stability.

Should neither method be employed, then the protection can be a challenge. First, the oscillations in voltage frequency and amplitude cause relay frequency tracking algorithms issues. Second, the heavy harmonic content that some inverters can expel when saturated requires consideration when selecting the right relay. Not all protection relays handle this scenario and differences between the two methods are often substantial.

B.2.6. *High Efficiency Challenges*

Higher efficiency and microgrids go hand in hand. Improving the return on investment (ROI) for most community microgrids is a significant challenge. It can be improved by reducing power losses in transformers and motors. To improve motor and transformer efficiency, better steel is used, better winding methods are used, and in the case of motors, smaller air-gaps are used. All these changes generally increase the reactance/resistance (X/R) ratio of the power system.

As DERs are distributed throughout a microgrid, the X/R ratios can vary dramatically from conventional power systems. Although the fault currents are usually smaller with DERs, the DC offsets from large X/R can be significant.

The increase in X/R has several significant effects that affect circuit breaker (CB) and protective relays. These effects have caused ferro resonance incidents to be on the rise, and there are no relays that detect or protect against ferro resonance.

CB sizing, cost, and damage is directly proportional to the level of DC offset that a CB must interrupt. Large X/R ratios causes larger DC current components, which destroy CBs much faster. Molded case circuit breakers (MCCB) type, constructed current interruption devices, are mandated for human safety and fire avoidance by the National Electrics Code (NEC), however these same MCCBs are the most susceptible to being damaged under these conditions. MCCBs are the most common life safety device in a microgrid. A new MCCB will interrupt a fault in < 10 ms, whereas a worn MCCB may never be able to interrupt a fault. Protective relays at the high voltage (HV) and medium voltage (MV) levels are typically tasked with monitoring CB health. With MCCBs and microgrids and large X/R ratios, these same CB monitoring techniques previously used at only high voltage transmission stations must be used for microgrids.

Modern relays contain logic called ‘breaker failure’ which acts to trip upstream CB should a local CB not open on time. This is now required at low voltage unlike any time before. This increases the cost of microgrids because today most MCCBs do not have protective relays controlling them.

Large DC offsets have caused many mis-operations in relays not originally configured for the higher level of DC waveform components. Only some microprocessor relays have elements that detect and reject these DC components. A microgrid designer may be advised to use these relays but over-simplified relaying schemes will mis-operate.

Another frequent problem with microgrids are static switches (aka solid-state switches, or back-back thyristors). These have the advantage of fast turn-on/turn-off times. They however fail shorted when experiencing excessive currents or kick-back voltages associated with interrupting even small faults currents under large X/R ratios. Static switches require a MCCB in series for human safety, and a protective relay for monitoring and control. This is worthy of note because these complexities did not exist before applications of microgrids.

APPENDIX C. PROTECTION OF MICROGRID SYSTEMS BY USER TYPE

C.1. Types of microgrid systems

Unless otherwise noted, all the microgrids shared below are AC power systems. These categories are shared from the author's experience.

C.1.1. Renewable interconnection

Small wind, solar, or conventional generation that is connected to the utility distribution system are a form of microgrid. These systems proactively separate from the utility for faults and other disturbances. These systems generally trip DERs offline when islanded. When connected to a utility, these DER are commonly dispatched or curtailed by Utility SCADA/ EMS operators. These are typically less and 5 MW.

C.1.2. Networked Systems

'Networked' or 'clustered' microgrids use utility infrastructure for power wheeling between DERs and a small load base. These systems use publicly owned distribution conductors to transport power from source to load. These systems sometimes seamlessly island and resynchronize to utilities. These grids vary typically from 1 to 10 MW.

C.1.3. Essential Services

These microgrids usually contain a few diesel generators, a police station, hospital, and other essential services. These systems run off utility power. The diesel generators are typically run in parallel iso load sharing and are not allowed to operate in parallel to the utility system. These systems typically do not seamlessly island and resynchronize to utilities. These systems focus on reliability and do not concern themselves with efficiency. These facilities can handle up to 30 seconds of power outage. They drop all local load when islanding and resynchronization is only done via dead bus pickup. These grids vary typically from 10 to 2,000 kW.

C.1.4. Industrial facility

These microgrids are the most complicated: they have mixed manufacturers of generators from several generations, their bus work, cabling, and distribution systems are very complex. These facilities have single shaft industrial turbines, multi-shaft aero derivative turbines, steam turbines, and diesel reciprocating black start generators. Ultra-reliability is required (a 1 second outage at an oil refinery costs 10s of millions of dollars). Even short power outages in these facilities cause loss of life, environmental damage, and significant revenue loss. These systems focus on reliability and do not concern themselves with efficiency. For this reason, very few renewables are present in these grids. These systems are by far the most advanced in technology adoption, far exceeding the technology used by the macrogrid or other microgrid system. These systems seamlessly island and resynchronize to utilities. These grids vary typically from 10 to 3,000 MW.

C.1.5. Data Centers

These microgrids include large UPS to carry critical computers over for up to a minute. They also have many onsite diesel generator sets. Most data centers have between 10 and 100 diesel gensets and hundreds of UPS. There are generally two types of loads at these facilities: 1) building load which is mostly HVAC and 2) critical computers. Critical computers are on UPS and cannot tolerate any outages without revenue loss. Building loads can generally be shut down for < 1 minute. These systems actively separate from the utility, shed their building load, and then start their diesel generators. Prolonged islanding at these facilities is undesirable as EPA emissions regulations govern these gensets. These systems focus on reliability and do not concern themselves with efficiency. For this reason, very few renewables are present in these grids. These systems seamlessly island and resynchronize to utilities. These grids vary typically from 10 to 200 MW.

C.1.6. Universities

Larger universities throughout the US have both steam and electrical utilities system. Many have onsite generation, especially in the northern tier with boiler systems and co-generation. These facilities are highly intertwined with local utility systems and clear demarcations of utility point of interconnects are blurred. Many facilities have need for reliable power due to long term experiments and computational simulations. Secondary reliability is required during times of extreme weather or on a Saturday large sporting event. Most of the campus load is HVAC and lighting and can handle prolonged outages. These campuses therefore desire seamless islanding and synchronization for part of the campus, and generally something far less complex for the remainder of campus. Smaller turbines up from 5-20MW are common on these campuses. Renewables, if present, are usually place on the lesser reliable parts of campus. These grids vary typically from 10 to 50 MW.

C.1.7. Emergency Relief Services

FEMA, national guard units, red-cross hospitals, and forward operating military bases fall in this category of small microgrid. These power systems are mobile, must be dis-assembled and re-assembled within minutes or hours, and are generally not manned by skilled personnel. Nurses may be asked to start generators. Young infantrymen may be asked to assemble this power systems. These power systems are generally composed of trailer mounted diesel gensets ranging from 5 to 200 kW each, and the loads range from a single tent of 10 kW to a field hospital of 200 kW. Fuel efficiency is desired, and renewables are viable for these operations because the cost and danger of delivering fuel to these facilities is significant. These grids wish to connect to utility power (aka ‘host nation power’) but rarely do because the iso-parallel diesel generator sets do not abide by utility interconnect rules. These systems are the furthest behind in technology. Recent significant advances from the USACE tactical microgrid system (TMS) provide a promising future of simplicity, reliability, and fuel efficiency.

C.2. Protection of different microgrid systems

C.2.1. Renewable interconnection

For renewables less than 5 MW, reclosers with protective relays at the PCC of these microgrids is the most common. These relays have the islanding and resynchronization functions to ensure compliance with 1547 and 2030.8 and most interconnect contract requirements. These are popular because they provide a low cost, proven, readily available solution for the utility engineer.

For wind or renewable stations exceeding a few MW, substation style circuit breakers and distribution class protective relays are used.

The protective relay in both these systems provide about the same functionality. This includes open- and closed- circuit protection, directional elements, and time overcurrent protection. The indeterminant behavior of inverters is the largest protection complexity at these facilities.

C.2.2. Networked Systems

These commonly use the same protection techniques as the renewable interconnections.

C.2.3. Essential Services:

These commonly use the same protection techniques as the renewable interconnections. One complexity that arises in these systems are the extensive use of MCCB instead of oil, gas, or vacuum CB technology. These MCCB typically offer a lower cost installation but suffer many of the deficiencies of MCCB. For this reason, smaller, low voltage protective relays typically associate with smart motor controls (MCC) are in use for controlling and protecting at these facilities.

C.2.4. Industrial Facility

The relaying at these facilities is very diverse. Oil transformers have differential relays. Cable sections have line differential. Bus work is typically high impedance differential. Feeders are usually time overcurrent coordination. Generators have special purpose generator relaying. Low voltage smart MCCs have thousands of smart relays. High voltage transmission up to 345 kV is common at these facilities, and as such contain the same transmission protection schemes are in place in these facilities as in utilities.

C.2.5. Data Centers

Complex transfer schemes are common at these facilities; the transfer schemes are typically performed in protective relays. The protection functions at these facilities include differential bus, line, and transformer technologies. The feeder protection is time over current. Motors are usually low voltage (< 690V); the larger motors will have advanced protection relays.

C.2.6. Universities

The high priority loads at campuses commonly are differential protection schemes. The lower priority systems are simple time-overcurrent. [See the attached MIT campus case study – this system is a pure differential system.]

C.2.7. Emergency Relief Services

Plug and play TMS challenges make the protection a coordinated system of dumb MCCB and smart relays. MCCB are used at load feeders, whereas relays and contactors are used at generator connection points and bus-coupler cable sections. The first TMS microgrid system recently was accomplished with relay based microgrid controls.

APPENDIX D. A PRACTICAL CASE STUDY ON MICROGRID PROTECTION

D.1. Microgrid System Description:

The microgrid protection scheme device placement, fault response, and fault location are tested on a practical 18-bus looped microgrid shown in Figure 9. The loads at each bus are given in Figure 10. For this case study, customer interruption cost curves are linearized versions of those given in [55] for residential and level 3 priority customers. These curves were derived from a Canadian customer survey on the economic costs of outages in the loads at all buses except bus 4 are assigned the residential outage cost given in equation (D.1) and bus 4 is assigned the level 3 priority customer given in equation (D.2).

$$IC = 0.025t \ \$/\text{kW} \qquad \text{(D.1)}$$

$$IC = (0.503t + 8.5) \ \$/\text{kW} \qquad \text{(D.2)}$$

where *t* is the outage time in minutes.

The other system parameters are given in Table 7.

For this study, two device types are considered for placement: intelligent relays and sensors.

- The relays are assumed to have monitoring and communication functionality that allows them to measure and transmit timestamped rms voltage and current as well as real and reactive power wirelessly every 0.1 second, using the DNP3 protocol. Each relay controls a breaker on each phase independently. The relays have a GPS clock to timestamp the measurements accurately. The breakers can be tripped in response to an external signal.
- The sensors can measure rms voltage, current, and power every second. Though they do not have GPS clocks, their clocks can be synchronized with that of another device, such as the relays. They can transmit timestamped measurements every 0.1 second over a wireless network using the DNP3 protocol. They can also receive transmitted measurements. They can be programmed to perform various functions using the measurements received and to send control signals to other devices. These specific sensors will be referred to as Smart Nodes.

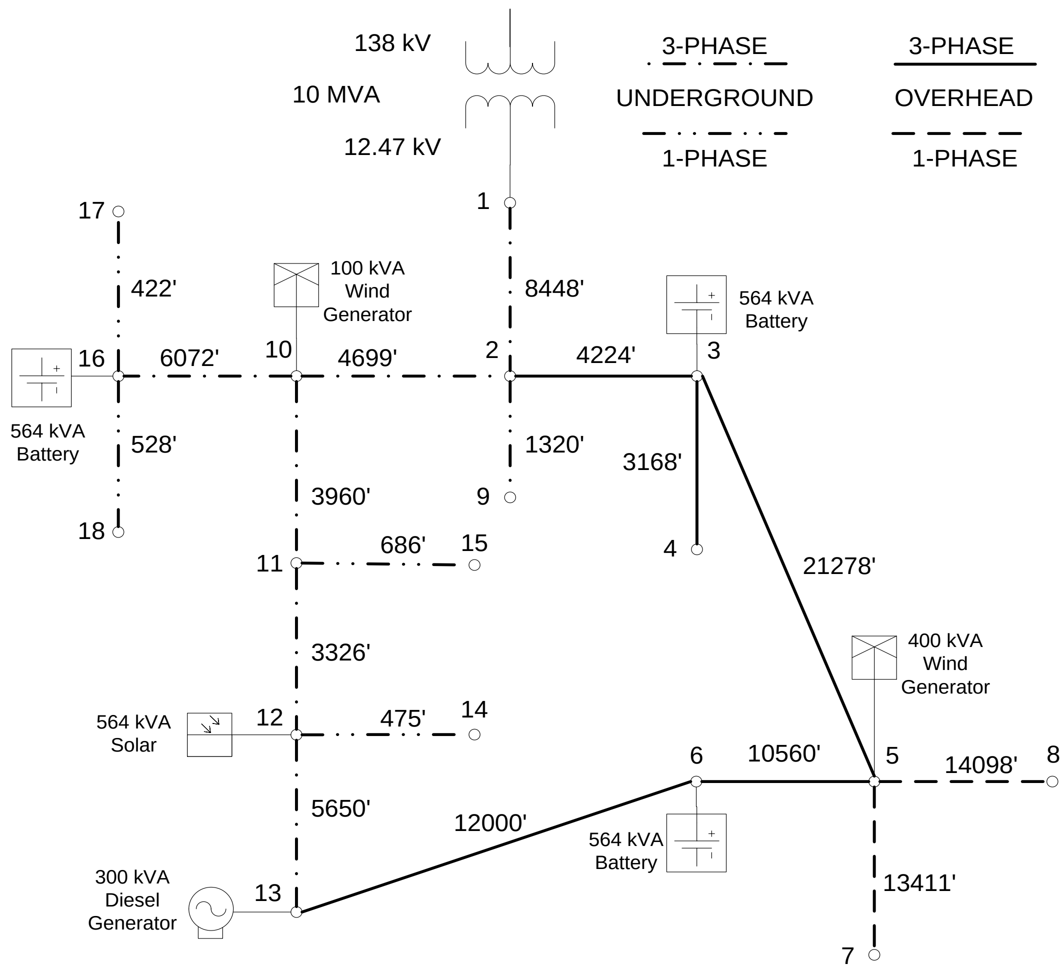

Figure 9. Microgrid Test System [49]

The protection scheme synchronizes all the Smart Node clocks to the relays. Each distributed differential zone uses one Smart Node as a zone controller; all the other Smart Nodes and relays send the timestamped measurements to it every second. The zone controller looks at the differential real power and sets the threshold to be 50% greater than the nominal losses and the combined measurement errors of all the devices. All devices are assumed to have a measurement error of ±1%. If three consecutive measurements are above the threshold, the tripping signal is sent to all relays. Accounting for network latency, this will clear the fault in 0.4 seconds or less, which was found to be enough to avoid instability in the distributed diesel and wind generators.

Table 6 shows the bus loads for the Microgrid in Figure 9; blank areas indicate unconnected phases.

Table 6. Bus Loads for the Microgrid in Figure 9.

BUS	Phase A		Phase B		Phase C	
	P (kW)	Q (kvar)	P (kW)	Q (kvar)	P (kW)	Q (kvar)
3	117	73	121	65	190	98
4	97	33	86	35	91	36
6	46	15	77	23	64	19
7	100	65				
8			85	32		
9					354	180
13	75	34	75	34	75	34
14	111	53				
15					176	34
16	89	63	89	63	89	63
17			314	126		
18	210	99				

Table 7. Microgrid System Parameters

Parameter	Overhead	Underground
Average Fault Rate (faults/year-km)	0.149	0.0298
Average Repair Time	60 min	180 min
Smart Node Cost (per phase)	\$2,000	\$2,000
Relay Cost (three-phase)	\$12,000	\$12,000
Relay Failure Rate [40]	0.0032/year	0.0032/year

D.2. Protection Device Placement

The first test is optimally placing the Smart Nodes and the relays. Two cases are examined. The first is for the microgrid islanding only 1% of the time; the second is for an extreme case of the microgrid islanding for 10% of the time. In each case, a 10-year lifecycle cost is assumed to evaluate the different placements [55]. The risk-free rate is 2.81% for this study; that was the average yield of a 10-year treasury bond during the month of September 2013 [49]. Figure 10 shows the device placements for this microgrid in the 1% islanding case; Figure 11 shows the placements for the 10% case. In each case, the microgrid is divided into two main distributed differential zones; the largest, Zone 1, encompasses buses 1, 2, 3, 6, 9, and 10 to 18. The border is bus 5 in the 1% islanding case and bus 6 in the 10% case. Zone 2 is composed of the remaining buses except for bus 4, the most critical; it exists in its own zone denoted as Zone 3, which has no generation. However, for a fault on any line other than line 3-4, bus 4 will remain energized. The borders differ between the two cases as the result of a tradeoff between having enough generation on phase C (which requires all DGs) when islanded and reducing the total fault rate of Zone 1 when grid-connected.

Table 8 shows the resulting 10-year costs of the protection scheme in the different cases. While those numbers seem high, note that when using an energy price of $0.12/kWh, the microgrid load of 2.7 MW will purchase $28,708,272 of electricity over the 10-year period and thus the costs in Table 8 are less than 2% of that total. Note also that these costs are used in this case study only to demonstrate the efficacy of the optimization method. The algorithm will work equally well for any device and customer outage costs. Additionally, the lifetime costs of the protection scheme can be longer or shorter than 10 years.

Table 8. Ten Year Microgrid Protection Scheme Costs

Cost	1% Islanding	10% Islanding	Most Reliable [9]
NPC	$26,980.52	$32,009.24	$16,213.01
Device	$152,000.00	$152,000.00	$304,000.00
Total	$178,980.52	$184,009.24	$320,213.01

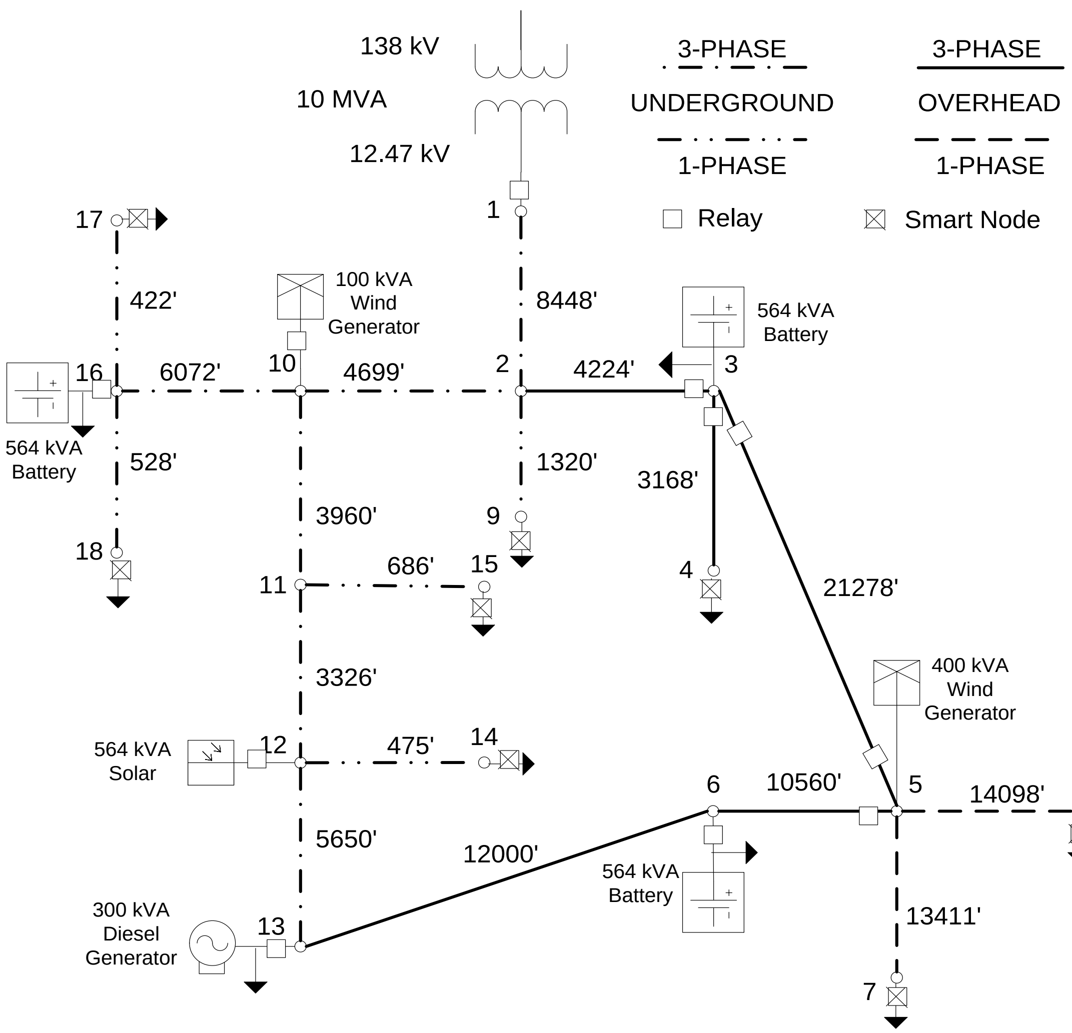

Figure 10. Microgrid with Loads and Protection Device Placements for 1% Islanding

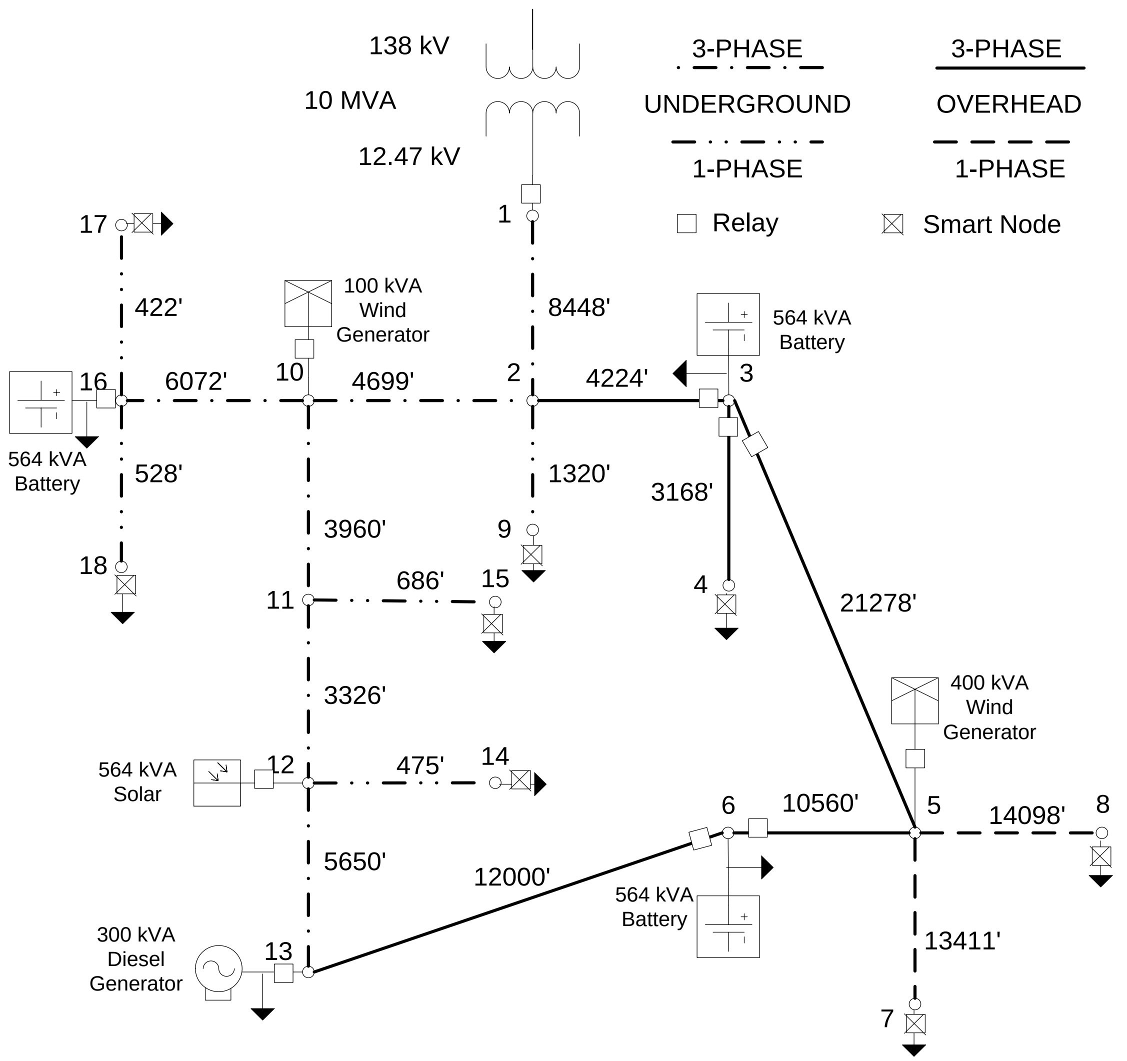

Figure 11. Microgrid with Loads and Protection Device Placements for 10% Islanding

D.3. Fault Detection and Location Simulation

To test the efficacy of the protection method, a fault analysis is performed for each line of each zone and for how the zones respond to a fault outside of the zone. The microgrid is modeled in Matlab Simulink SimPowerSystems using the models in [2] and [81] for the protection scheme placements of the 10% islanding case. The faults simulated are L-G, L-L, L-L-G, three-phase with 1-ohm and 100-ohm, and High Impedance Faults (HIFs). The HIFs are modeled using the stochastic model developed in [81] which is a time varying resistance value between 200 Ω and 1000 Ω. For each zone, the faults are simulated at different lines. For each line, the fault point varies from 0.0 to 1.0 of the line length. Each device sends a timestamped voltage, current, and power measurement every 0.1 second to the zone controller. The network latency and computation time at the controller are modeled as a random time delay in the signal that varies between 0.01 and 0.03 s.

Table 9. Differential Power Measured in Zone 1 Phase A for Faults Inside the Zone and Outside the Zone and the Tripping Threshold

Fault Type	Impedance	In Zone	Out Zone	Threshold
L-G	1 ohm	36.1 kW	2.8 kW	7.51 kW
	100 ohms	301.9 kW	0.5 kW	7.51 kW
	HIF	8.9 kW	0.5 kW	7.51 kW
L-L	1 ohm	400.9 kW	3.2 kW	7.51 kW
	100 ohms	294.7 kW	0.5 kW	7.51 kW
L-L-G	1 ohm	20.1 kW	1.7 kW	7.51 kW
	100 ohms	304.9 kW	0.5 kW	7.51 kW
Three-phase	1 ohm	21.0 kW	0.0 kW	7.51 kW
	100 ohms	217.7 kW	0.5 kW	7.51 kW

Table 10. Differential Power Measured in Zone 2 Phase A for Faults Inside the Zone and Outside the Zone and the Tripping Threshold

Fault Type	Impedance	In Zone	Out Zone	Threshold
L-G	1 ohm	30.1 kW	0.8 kW	2.52 kW
	100 ohms	301.9 kW	0.2 kW	2.52 kW
	HIF	6.4 kW	0.2 kW	2.52 kW
L-L	1 ohm	171.3 kW	1.0 kW	2.52 kW
	100 ohms	297.9 kW	0.2 kW	2.52 kW
L-L-G	1 ohm	47.1 kW	0.5 kW	2.52 kW
	100 ohms	304.1 kW	0.2 kW	2.52 kW
Three-phase	1 ohm	23.5 kW	0.0 kW	2.52 kW
	100 ohms	271.0 kW	0.2 kW	2.52 kW

Table 11. Fault Location Result for Faults in Zone 1 and Zone 2

Fault Line	Type	Loc.	R_F (Ω)	Candidate	Result
Line 2-10	A-G	0.9	100	Line 2-10, Line 10-16, Line 10-11	Line 2-10 at 0.74
Line 1-2	C-A	0.5	100	Line 1-2	Line 1-2 at 0.63
Line 11-12	B-C-G	0.8	1.0	Line 11-12, Line 12-13	Line 11-12 at 0.70
Line 5-3	C-G	0.4	1.0	Line 5-3, Line 5-6	Line 5-3 at 0.52
Line 5-6	A-B-C	0.2	1.0	Line 3-5, Line 5-6	Line 5-6 at 0.26

In all cases the protection scheme works as designed. Differential power measured in phase A of Zone 1 and Zone 2 is shown in Table 9 and Table 10, respectively, for faults inside the zone and outside the zone during islanded operation. All other zones, phases, and modes of operations have comparable results to these and so they are omitted. The selected fault location results for Zone 1 and Zone 2 are provided in Table 11, in which the lines are expressed using their bus numbers of two terminals and the fault location (represented as Loc.) is expressed as a percentage of the line from the first bus. For example, a fault 0.9 on Line 2-10 represents the fault is located at 90% of the distance from Bus 2 to Bus 10. The protection Zone 3 has only one line, thus locating the faulted line is unnecessary. As can be seen, the protection scheme correctly identifies and clears faults within the zone and does not respond to faults outside of the zone. In addition, the faulted lines can be accurately located to assist in the repair and restoration. It is interesting to note that for differential power, short-circuit ground faults are harder to detect than medium resistance faults because of the system voltage collapse at that location reduces the available power measured. However, the power is still sufficiently above the threshold for detection. HIFs are still the hardest to detect but they can be detected with the scheme.

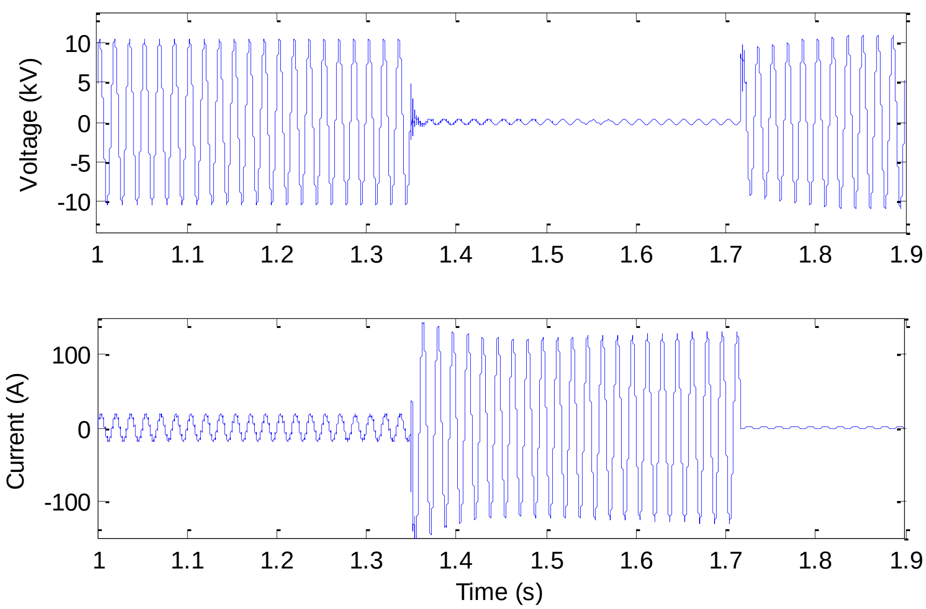

Figure 12. Phase A Voltage and Current for a 1 Ohm L-G Fault on Line 3-5 Measured at Bus 3 in Islanded Mode

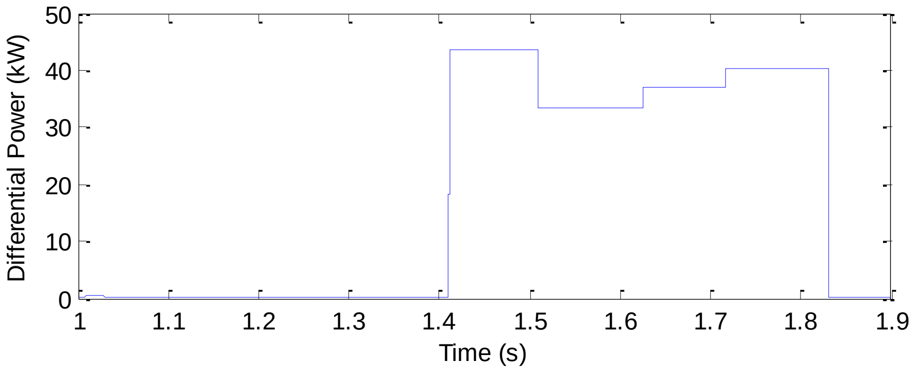

Figure 13. Differential Power Measurements at the Zone Controller for a 1-Ohm L-G fault on Line 3-5 in Islanded Mode

Figure 13 shows the voltage and current waveforms measured at bus 3 for a 1-ohm L-G fault on line 3-5 in islanded mode. Figure 14 shows the differential power at the controller. In addition to the voltage collapse due to the short-circuit fault, the communication lag can be seen such that even though the fault is isolated after 0.35 seconds, the controller sees the fault for four samples. While the faulted current in Figure 14 many times the load current, this is because there is very little power flow in the islanded mode between buses 3 and 5 since they both have generators and loads. The maximum load current of the inverter systems is 89 A and thus the fault current of 120 A is a realistic response. Current waveforms and differential power for a HIF under the same conditions and location as above can be seen in Figure 15 – Figure 16. Even though the fault current is very small, the power is enough to be detected by the protection system because the system voltage does not change. Therefore, in this case the voltage is not shown.

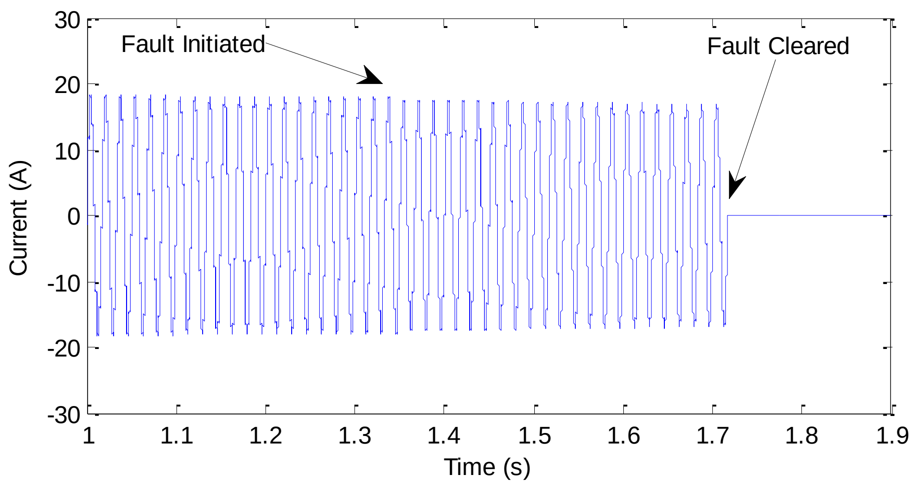

Figure 14. Phase A Current for HIF L-G Fault on Line 3-5 Measured at Bus 3, Islanded Mode

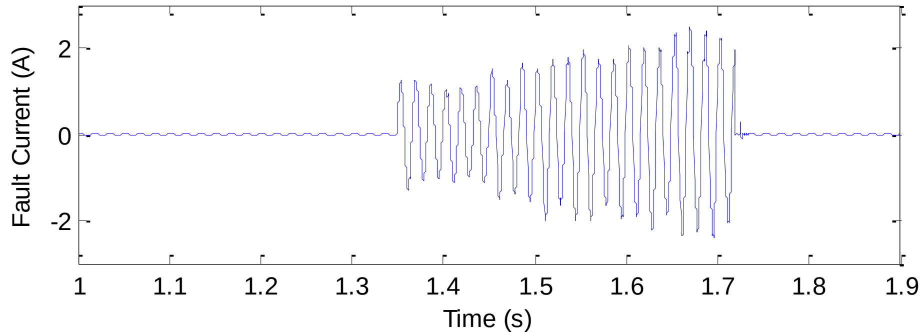

Figure 15. High Impedance Fault Current in Islanded Mode

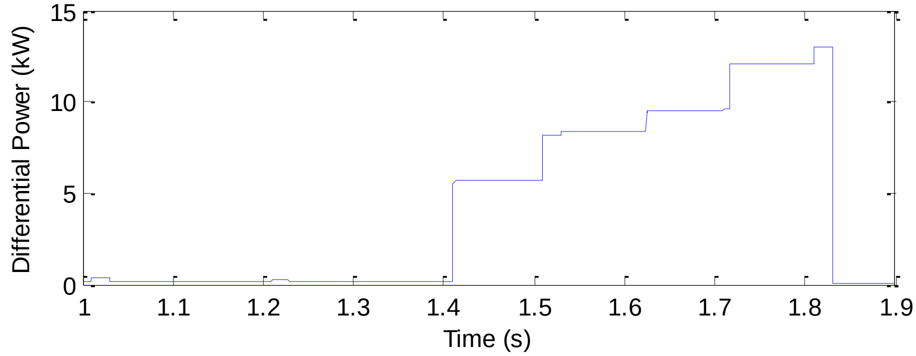

Figure 16. Differential Power Measurements at the Zone Controller for a HIF L-G Fault on Line 3-5 in Islanded Mode

APPENDIX E. A CASE STUDY ON COMMUNICATION ASSISTED MICROGRID PROTECTION

E.1. Introduction

One proposed way of integrating high penetration of DG sources is through microgrids. A microgrid is defined as a low to medium voltage network of small load clusters with DG sources and storage [1]. Microgrids can operate in islanded mode or grid-connected mode. If a microgrid is connected to the system, it is seen as a single aggregate load or source. One of the potential advantages of a microgrid is that it could provide more reliable supply to customers by islanding from the system in the event of a major disturbance. The microgrid protection in islanded operation poses a fundamental problem. It was shown in [2], [3] that the fault currents for a grid-connected and islanded microgrid are significantly different. Additionally, high penetration of inverter connected DG sources lead to conditions where no standard overcurrent protection methods will suffice.

Protection of microgrids cannot be achieved with the same philosophies that have been used to protect traditional distribution systems. At the very least, a system designed to protect a microgrid should take the following into account: (a) bidirectional flow in feeders; (b) looped feeders; (c) reduced fault levels in islanded operation. In this work, therefore, every one of these three factors are described in greater detail in the next section; the essence of this work is summarized by stating that these factors are addressed through the following contributions: (1) A protection scheme using digital relays with a communication overlay is proposed for the protection of the microgrid system. A practical system is chosen from [3], [4] to investigate the protection scheme. (2) The increased reliability of adding an additional line to form a loop structure is explored. (3) A novel method for modeling high impedance faults is demonstrated to show how the protection scheme can protect against them. This is important in microgrid protection not only because the percentage of high impedance faults on the distribution system is not insignificant [5], but also because microgrids, in the islanded mode, typically have lower fault currents, and methods of high impedance fault detection will be useful for the detection of these faults.

E.2. Protection Scheme

E.2.1. The Case for a New Protection Paradigm

Most distribution systems are operated in radial mode. The majority of these are radially connected; others may have loop closing feeders, but the loops are kept open by normally open switches that are closed only when other parts of the loops are opened because of faults. Hence the radial structure is preserved. Consequently, in these systems, the protection is designed for radial operation. However, as the penetration of distributed resources increases, these systems will experience two critical changes: (a) bi-directional flow in the feeders, and (b) looped operation. Traditional protection schemes for radial operation will no longer be adequate, nor can one apply traditional protection schemes that are in use even in meshed distribution systems today because the new protection systems will have to be adaptive, since as the system switches between grid-connected and islanded (as single or multiple islands) modes, the (i) configuration and (ii) fault levels will change. A logical solution that accommodates all these changes is a communication-assisted system.

E.2.2. General Microgrid Protection Philosophy

Since a microgrid can operate in a grid-connected mode and in an islanded mode, it is necessary to protect it in both modes of operation. The general philosophy is to find a method that will work equally well in both modes of operation. There are different philosophies of protecting islanded microgrids. One is to simply trip the entire microgrid offline once the fault is detected during islanding since it is an (N-2) failure; the first failure being the loss of the feeder. For additional reliability, the faulted line will need to be removed from service and the remaining connected loads and sources will operate as two smaller islands. This will only work if the generation and load in each smaller system match. If higher reliability is required, the feeders can be connected as a loop, so the loss of a feeder or a lateral will not result in service disruption to customers. The higher reliability, however, comes at a higher cost.

Several methods of protecting microgrids have been previously proposed. One scheme is to have each DG source have its own relay and operate without communications [6]. This works well for single line-to-ground faults and line-to-line faults. It relies on the sum of the phase and neutral currents as well as zero sequence currents. However, it fails to detect some high impedance faults. Another proposed scheme is to use a voltage protection scheme [7]. In this case, the phase voltages at the DG source are transformed into the 'dq0' synchronous frame, and then compared against a reference. A voltage drops against the reference initiates switching device tripping. For multiple DG sources, the voltages are compared via an undefined communication link and the lowest relative voltage part is tripped. This method is also ineffective against high impedance faults. An additional protection scheme utilizes standard overcurrent differential protection on each line with backup voltage and frequency protection at each DG source [8]. This scheme is also unable to detect high impedance faults (HIF's). In addition, each of the schemes have only been tested on relatively small systems with few buses and undefined distances between distribution lines.

Additionally, it has been proposed that replacing overcurrent relays with directional relays in instances where a problem of directionality exists is possible; but this comes at an excessive cost. Individual DG's could also be tripped at the first detection of a fault before the distribution relays can operate [9]. The problem with directional relays is that they will also not detect HIF's. Tripping DG sources also reduces the reliability of service to the customer.

It has also been proposed that microgrids could participate in remedial action schemes using synchronized phasor measurements to determine the appropriate islanding and restoration strategies. These protection schemes however are under development and currently not ready for deployment [9].

E.2.3. Proposed Protection Scheme

The protection scheme proposed in this work utilizes some of the principles of synchronized phasor measurements and microprocessor relays to detect all types of fault conditions including HIF's. It is based on the deployment of digital distribution feeder relays that are currently offered by some of the major manufacturers. These digital relays include standard overcurrent and over/under voltage protection methods. They are programmable and have fiber optic and Ethernet communication links. They are self-metering and have oscillographic event reports [10]. By using these relays on the end of each line segment, a very robust protection scheme can be developed. Although the work reported in this paper used digital relays, it is conceivable that the use of properly designed sensors and switches will perform adequately for faults encountered in distribution systems and enable cost-effective protection schemes. The costs can be further controlled by not using specific communication channels, but by ‘piggy-backing’ on any available channels already deployed in that part of the system. For instance, if ‘smart grid’ technologies have already been deployed, the corresponding communication channel can be used. The primary protection scheme utilizes a relay that measures absolute current sampled at 16 or higher number of samples per cycle and then transmitted via communication link to the relay on the other side of the line. For distances under 18 miles, the transmission takes less than 0.1 ms based on the speed of light for signal transmission and several additional microseconds for processing time. This is enough for most distribution systems. This means that there is no need to get time-synchronized measurements from both sides of the line for short distribution lines. For lines longer than 18 miles, however, a Phasor Measurement Unit (PMU) may be required. In this way a differential relaying scheme is successfully created.

The primary protection for each feeder relies on instantaneous differential protection. If absolute values of two samples are found to be above the trip threshold, the tripping signal is sent to the switching device. It is anticipated that these switching devices will benefit from recent advances in switching technologies (such as vacuum interrupters) and higher sampling rates, and it should soon be possible to interrupt currents much faster than the present-day norm of 3–5 cycles. The expected fault currents can vary over a wide range: less than too many times greater than the nominal load current (0.5-20 p.u.). The current transformers will therefore need to have accurate operation over this wide range of fault currents.

In the event of a switching device failure, a backup trip signal will be sent to the adjacent relays on the same bus. This signal is sent after a certain time delay, greater than 0.3 seconds but less than 0.6 seconds if the measured differential current is still above the threshold. This is the normally accepted practice, but with the advent of high-performance relays and breakers the delay could be significantly shorter. If the relay or the communication link fails, this will alert all other connected relays that the differential scheme is lost. An alarm will be sent to the distribution control center. The remaining relays will rely on comparative voltage protection until the system is restored. The comparative voltage protection compares the relative rms voltage at each relay with every other connected relay. For voltages less than 0.7 p.u., the relay with the lowest voltage will trip after a 0.6 second but less than 0.9 second time delay. This allows the first two schemes to operate. Each DG source is also equipped with undervoltage tripping for voltages less than 0.7 p.u. and after one second delay. This protection scheme is depicted in Figure 17.

The protection scheme can detect HIF’s in two ways. The first way relies on the high sensitivity of the current transformers. If the HIF current magnitude is at least 10% of the nominal current, the HIF will be detected by the differential protection scheme. The other method relies on programming the relays to recognize certain HIF characteristics that have been observed and then tripping when those characteristics are present in the differential current.

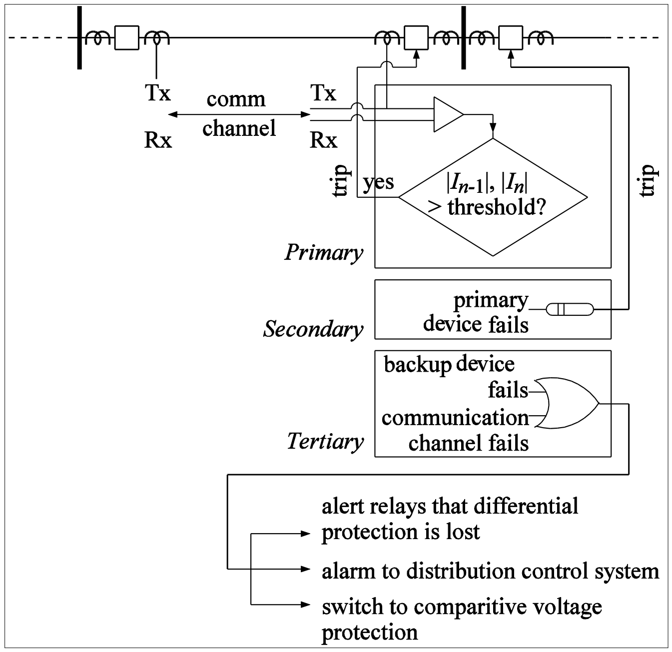

Figure 17. Conceptual representation of proposed protection scheme.

E.3. A New Model for High Impedance Faults

High impedance faults (HIF's) have traditionally been difficult to model and detect. They exhibit buildup, shoulder, non-linearity, and asymmetry. Additionally, they are stochastic or nonlinearly deterministic in nature [11]-[13]. The bulk of the work on HIF's has been on modeling the waveform and the harmonics for detection purposes [5], [13]-[16]. The problem with these methods of HIF modeling is that they neglect the stochastic elements inherent in the fault conditions such as 'dancing' wires on asphalt or trees blowing in the wind. Because of these conditions, the HIF's will also have completely random elements that can drastically change the current envelope, as well as add small variations to it.

Therefore, in this paper a novel way of modeling HIF's is proposed to provide further insight into the HIF fault behavior. This model relies on randomly varying the magnitude of the fault resistance and its duration. The resistance is varied randomly between 50 and 1000 Ω. The duration of each resistance value is randomly varied between 10 μs and 5 ms. This way the true randomness of HIF's can be captured. A deterministic time-decay component is added in series with the fault resistance to model the buildup and shoulder behavior. Two additional deterministic resistances assure negative cycle asymmetry and zero crossing clipping.

To test the HIF model proposed here, a simple test system with a 564-kVA source feeding two 282 kVA loads connected radially with two distribution lines is constructed. The fault is initiated midway on the furthest line from the source. A simulated fault current waveform is shown in Figure 18. The expanded fifth through seventh cycles of this waveform can be seen in Figure 19. From these figures the model captures both the deterministic and stochastic elements of HIF's described in the literature [5], [11]-[16]. However, further field or high-voltage laboratory testing will be required to validate this model for specific HIF types. These tests will be conducted using varied materials with high impedance. Specific conditions (tree falling on wire, cut wire from automobile collision) will also need to be simulated to tune the model parameters to these specific types of HIF's. The model can then be used to simulate the desired HIF.

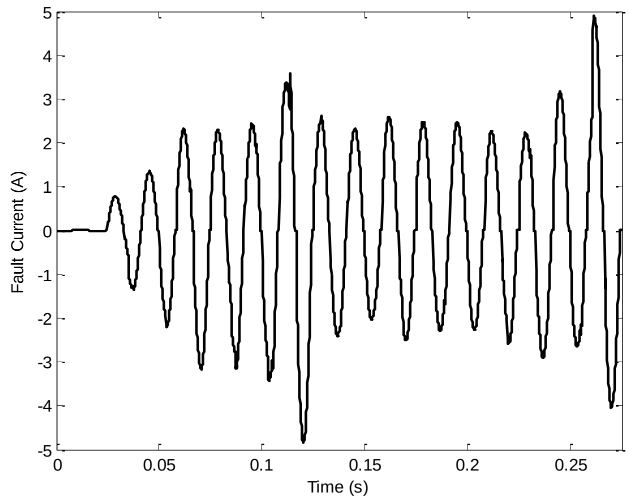

Figure 18. Current waveform of randomly varying HIF resistance.

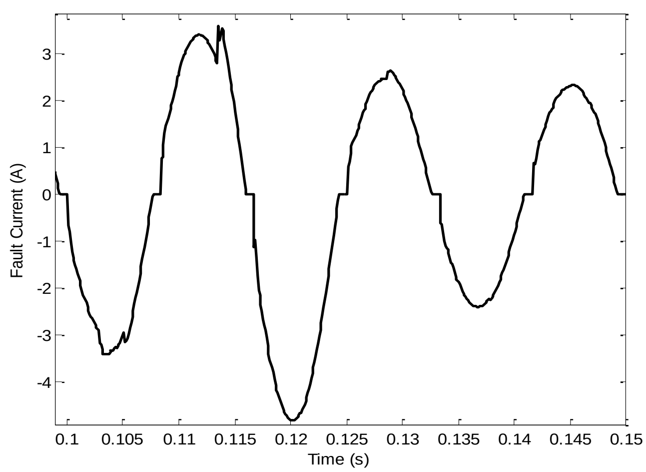

Figure 19. The fifth through seventh cycles of the HIF current in Fig. 18.

E.4. Microgrid Application System

A practical test system is used in this study. It is an 18-bus distribution system shown in [4] that has been converted to a microgrid by adding multiple DG sources [3]. The source models are taken from standard Matlab Simulink blocks and examples. A more detailed description of the models is given in [3]. The system carries 3.03 MVA of unbalanced load and is connected to a 10 MVA transformer. Bus loads are shown in Table 12. There are four inverter-connected solar arrays; two wind turbines, and one diesel generator connected at different buses. The solar arrays are connected to three-phase inverters and provide a total of 2,256 kW. The wind turbines are induction generators and provide 500 kW. When islanded, additional generation is provided by the 300-kW diesel generator. This attempts to model a realistic distribution system that, through the addition of customer owned DG, is converted to a microgrid.

Table 12. Bus loads for the microgrid. Blank areas indicate unconnected phases

BUS	Phase A P (kW)	Phase A Q (kvar)	Phase B P (kW)	Phase B Q (kvar)	Phase C P (kW)	Phase C Q (kvar)
3	117	73	121	65	90	98
4	97	33	86	35	91	36
6	46	15	77	23	64	19
7	100	65				
8			85	32		
9					354	180
13	75	34	75	34	75	34
14	111	53				
15					176	34
16	89	63	89	63	89	63
17			314	126		
18	210	99				

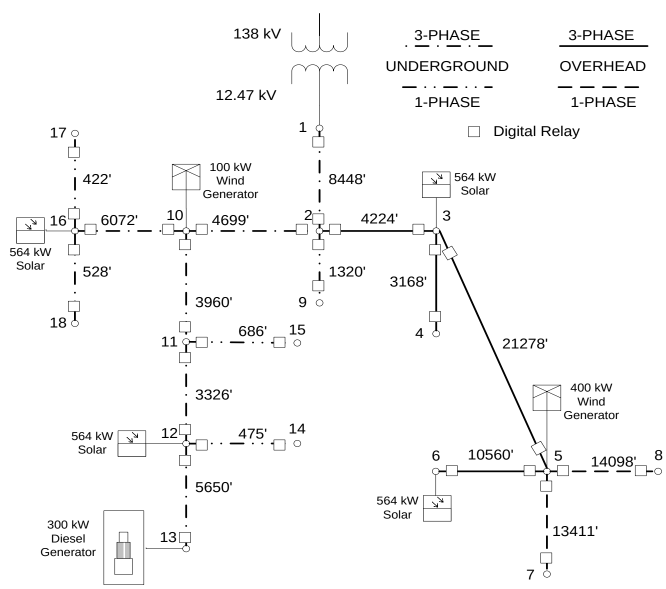

Figure 20. One-line diagram of the microgrid with added DG sources.

With the microgrid radially connected as in Figure 20, the reliability is easily compromised with any fault. A fault on the line between busses 5 and 6, for example, will remove a large solar array from service. This will result in an approximately 350 kW generation deficiency for the microgrid if it is islanded. Similar generation deficiencies will be observed for a removal of any line while operating in an islanded mode. To mitigate this problem an additional line is added to form a loop structure. This line should be added where it connects as many DG sources as possible to the central ring of the loop for maximum reliability. For the test system used in this study, this is between buses 6 and 13. This new system is shown in Figure 21. A microgrid with a loop structure is protected against (N-2) contingencies or failures. Additionally, a loop structure will also help the reliability of the system in steady state operation, though it is not the focus of this paper.

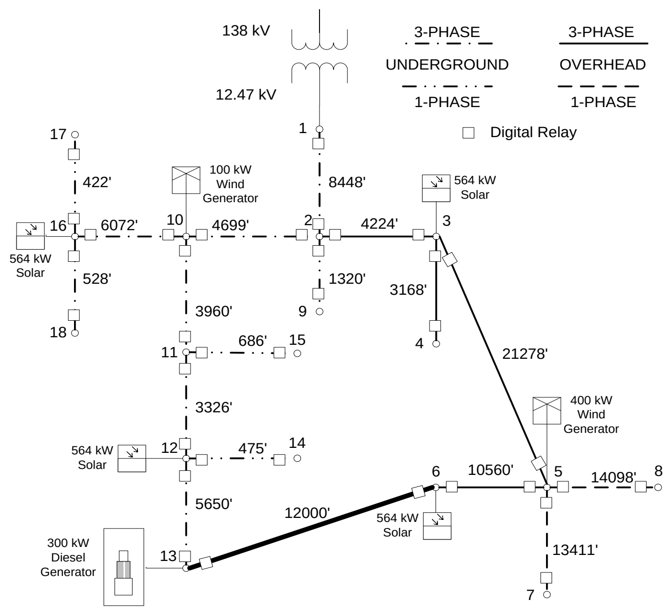

Figure 21. One-line diagram of the microgrid with an additional line between buses 6 and 13 making a loop structure.

E.5. Simulation and Results:

The test system is simulated in Matlab Simulink's SimPowerSystems. The system is simulated using Simulink's ode3 with a fixed time step of 1 microsecond. A comprehensive fault analysis is for all locations on the system and all four fault types. Single line-to-ground high impedance faults are also simulated. Additionally, the cases of switching device and relay failure are simulated to test the efficacy of backup protection system. The case of a line-to-ground (L-G) fault midway between busses 3 and 5 is described in detail for all the four cases discussed below. Voltage and current measurements are taken on bus 10 to demonstrate the effectiveness of the proposed scheme. The system is simulated on four different scenarios; grid-connected and islanded with the system configured radially, as in Figure 20, and grid-connected and islanded configured in a loop structure, as in Figure 21.

E.5.1. Radial and Islanded Case

In this case, the primary protection scheme has no difficulty isolating all fault types. The relays can detect all solid faults after two samples and trip within the cycle. The current and voltages as measured at bus 10 for normal relay operation for an L-G fault on the 'A' (solid line) phase are shown in Figure 22 on line 2-10. The differential fault current as measured at the bus 3 relay on line 3-5 is shown in Figure 23. It can be seen from Figure 22 that after the fault is cleared, there is voltage droop due to under generation on the remaining islanded network. This type of waveform is typical for the radial connected system. In all fault locations, there is a resulting over generation on one sub-island and an under generation on the other. This scenario demonstrates the need for a loop structure which can maintain the generation balance under loss of line conditions.

The case of a primary switching device failure at the same location as above is shown in Figure 24 and 25. The fault persists for an additional 0.3 s before being cleared. Also, since the secondary or backup operation trips additional loads and generation offline, the only current flowing on line 2-10 is to feed the 'C' phase load at bus 9. Similar voltage waveforms are observed at all other locations for this case with different current flows depending on the location.

The case of a relay failure, tertiary protection, is shown in Figure 26. The fault current in this case persists for 0.6 s before it is cleared. The resulting voltages and currents are otherwise the same as in the case of the switching device failure.

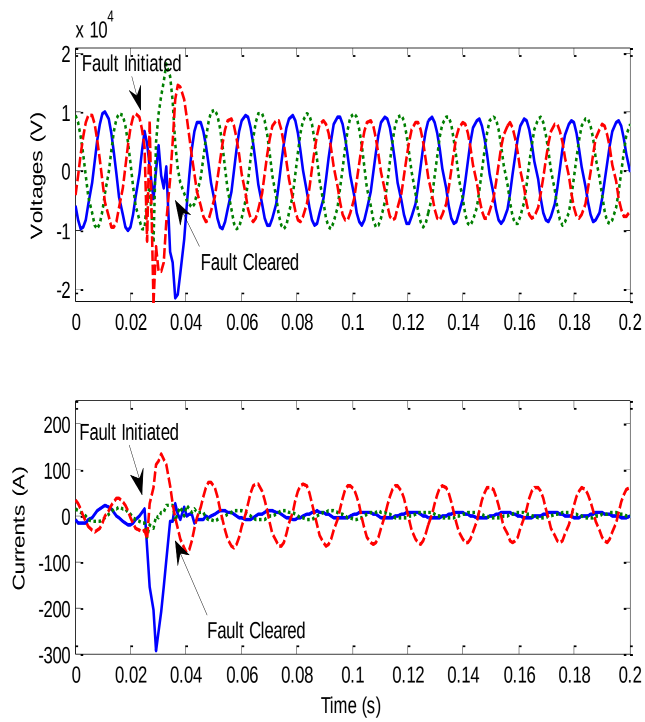

Figure 22. Voltages and Currents for line 2-10 for an L-G fault on line 3-5 with primary relay operation. Microgrid state is islanded with radial structure.

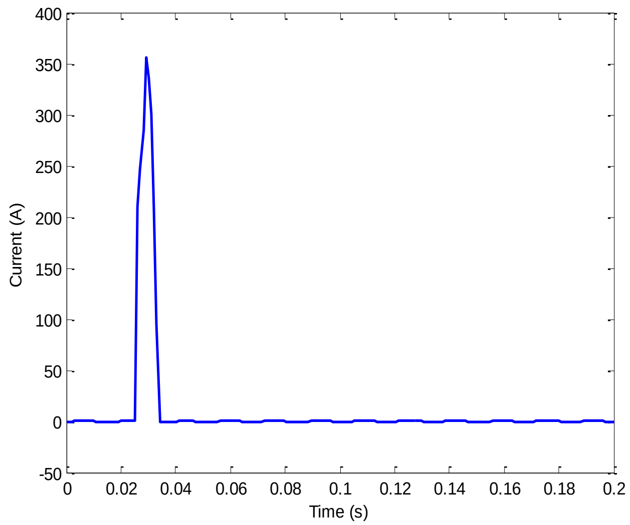

Figure 23. Differential current measured at the relay at bus 3 on line 3-5. Microgrid state is islanded with radial structure.

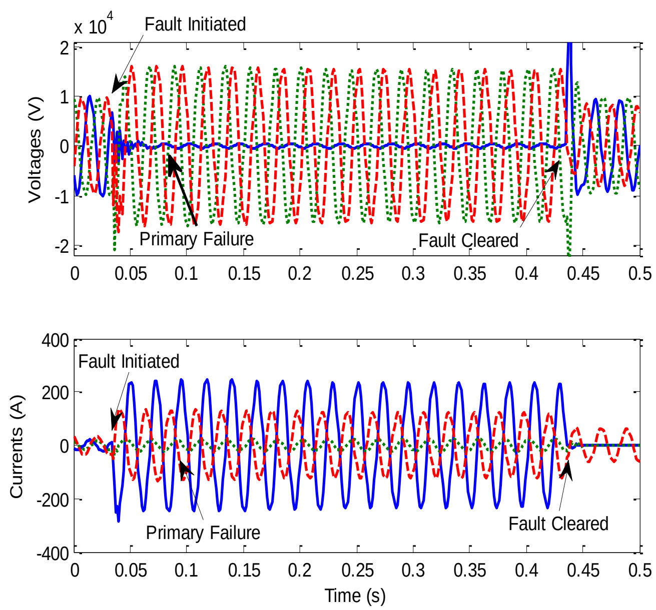

Figure 24. Voltages and currents for line 2-10 for an L-G fault on line 3-5 with the primary switching device failure and successful backup trip. Microgrid state is islanded with radial structure.

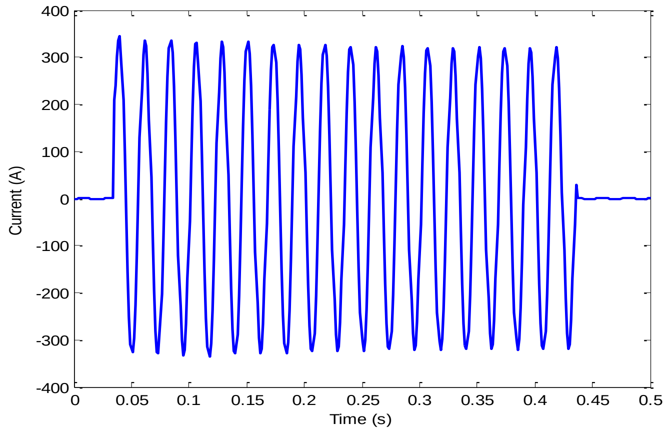

Figure 25. Differential current at the relay at bus 3 on line 3-5 with a switching device failure and a successful backup trip. Microgrid state is islanded with radial structure.

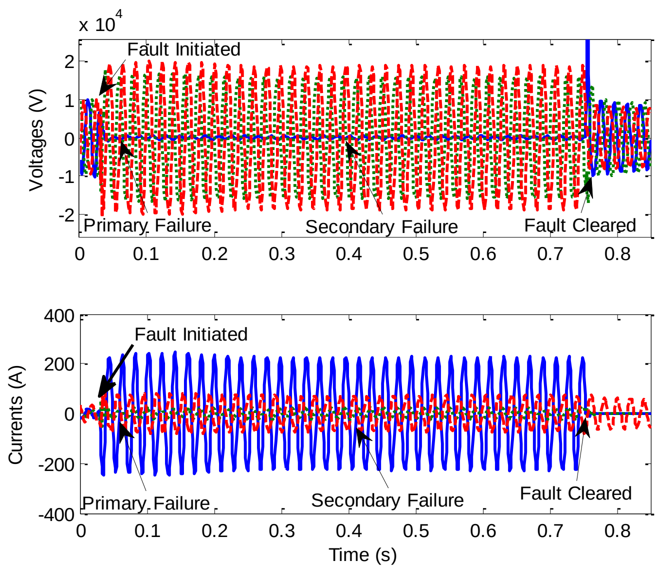

Figure 26. Voltage and currents for line 2-10 for an L-G fault on line 3-5 with primary relay failure and backup voltage operation. Microgrid state is islanded with radial structure.

E.5.2. Radial and Grid-Connected Case

The main difference in the grid-connected mode of operation to the islanded mode is that the portion of the microgrid still connected to the main grid has a perfect generation load match since the additional power can either be sent to the system or received from it. However, that portion separated from the grid in this case always has too much or too little generation which can cause a loss of the load. The transients experienced by the system are also larger since the system has a much larger short-circuit capacity than the DG sources. Voltage and current waveforms for the L-G fault are shown in Figure 27. Notice there is no voltage droop associated with clearing the fault.

E.5.3. Loop Structure and Islanded Case

The loop structure allows additional reliability, especially to loads in the main loop. For faults on any of the loop lines, all loads remain in service and the generation load balance is maintained if the primary protection operates. The transients are greater largely due the reversal of power flow along many of the lines the instant the switching devices open. Voltages and currents for the L-G fault with normal operation are shown in Figure 28. After the switching device opens, there is no accompanying voltage droop on the lines verifying the additional reliability added to the system by the loop.

E.5.4. Loop Structure and Grid-Connected Case

This is largely the same as the loop structure when islanded. The transients are larger due to the higher short circuit capacity of the system. The voltages and currents for the L-G fault on with successful primary relay operation are shown in Figure 29. Notice the unusually high 'A' phase current (solid line) due to the reduced line impedance to the fault because of the connecting loop.

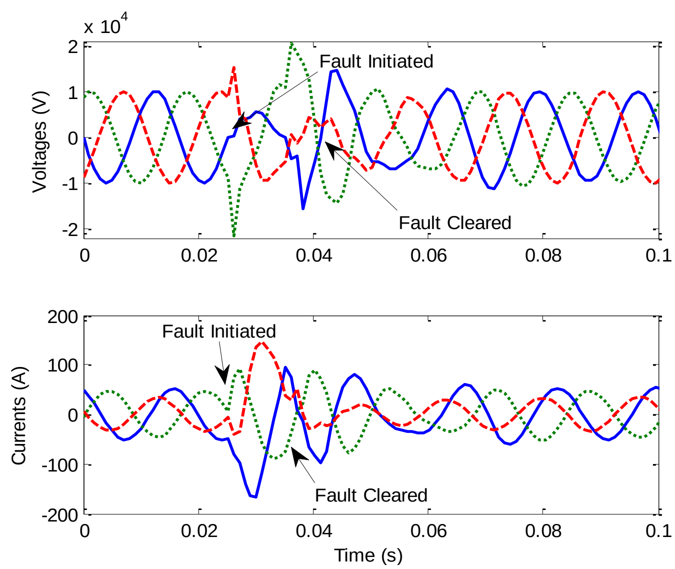

Figure 27. Voltages and currents for line 2-10 for an L-G fault on line 3-5 with primary relay operation. Microgrid state is grid-connected with radial structure.

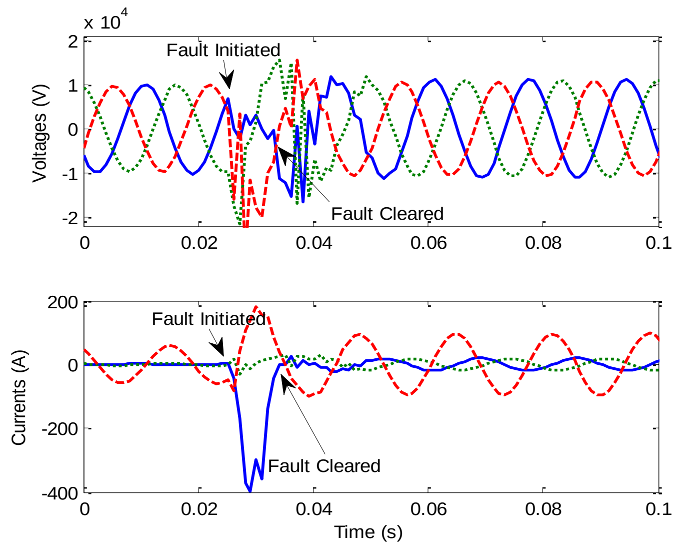

Figure 28. Voltages and currents for line 2-10 for an L-G fault on line 3-5 with normal relay operation. Microgrid state is islanded with loop structure.

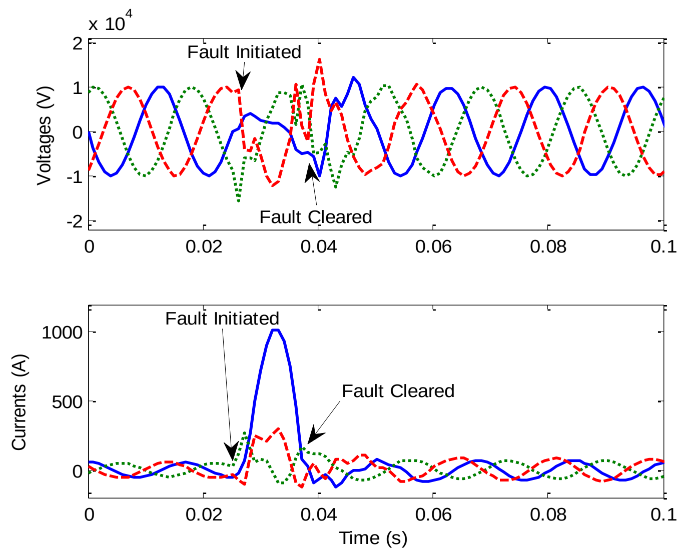

Figure 29. Voltages and Currents for line 2-10 for an L-G fault on line 3-5 with normal relay operation. Microgrid state is grid-connected with loop structure.

E.6. High Impedance Faults (HIF's)

For HIF's, the relays can detect the current difference if the total fault current is greater than 10% of the nominal primary current. This nominal current in some cases is only 20 A. These differences can be detected since the current transformers are operating near their nominal level and thus are in the linear region where error is small. Voltage and current waveforms for a high impedance line to ground fault on 'A' phase is shown in Figure 30 and differential current at the relay is shown in Figure 31.

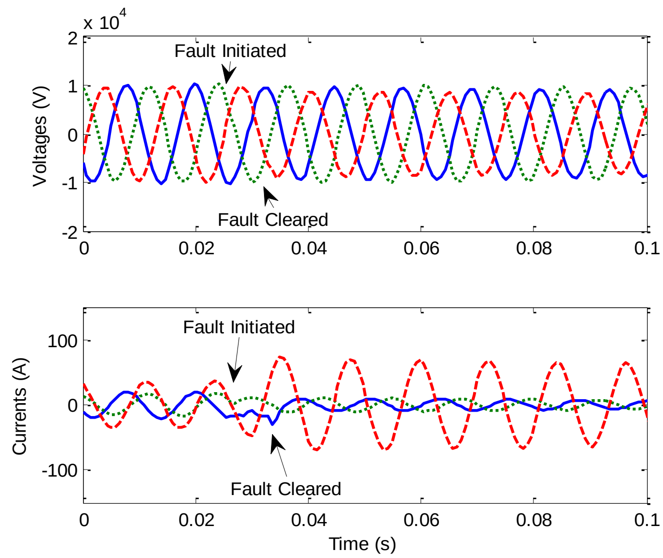

Figure 30. Voltages and currents for line 2-10 for a HIF on line 3-5 with normal relay operation. Microgrid state is islanded with radial structure.

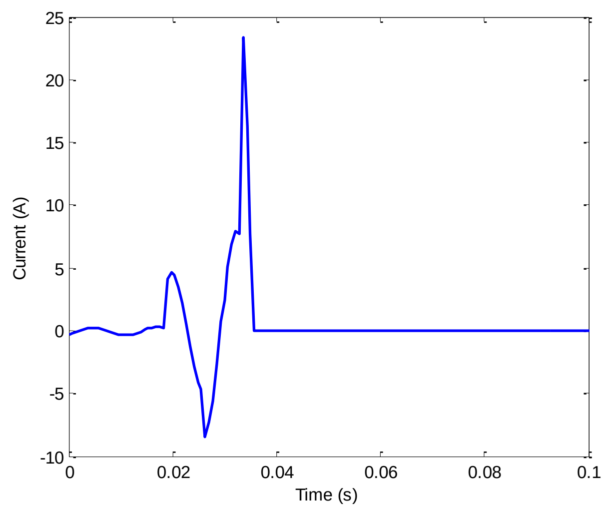

Figure 31. Differential current the relay at bus 3 on line 3-5 for a HIF with normal operation. The current threshold was 6 A.

E.7. Discussion

The proposed protection scheme is clearly able to protect a microgrid in all modes of operation with an improvement in reliability. This is especially true with the loop configuration as the radial configuration usually has generation-load imbalance with the removal of any line due to a fault. However, placing these relays and switching devices on each line tap in a distribution system would, in most cases, not be economically justifiable. Another method that uses the same principles is to have only sensor units at the buses with a communication link to the substation. At the substation, a central controller or logic processor such as the one described in [18] can monitor the current and voltage differences and remotely operate the switching devices. Additionally, any lines that will not experience bi-directional current flow will only need one switching device instead of two, thus further reducing the cost. This scheme will work the same as with multiple relays and for similar faults, similar responses as those previously discussed will be observed. In the event of a communication failure, however, the only protection will be on the sources which will work for all but HIF's. Though even this scheme is still more expensive than traditional protection methods, it is justified if the customers require the additional reliability of islanding.

E.8. Conclusion

In this section, a digital relay scheme with a communication overlay is proposed to protect microgrids with customer owned DG sources. The proposed protection system relies primarily on differential protection based on sampling the current waveform at 16 samples per cycle or more. A new and novel model for HIF's using random duration and time varying resistances is also presented. This model is shown to accurately capture the behavior of HIF's which has been observed in previous literature. A loop structure is also shown to increase reliability against (N-2) contingencies while a radial configuration is shown to easily collapse when islanded. The loop structure is shown to be most effective when it connects that maximum possible number of DG sources to the central loop. The simulation of the protection scheme shows that it can quickly detect and clear all faults including HIF's with current of at least 10% of the nominal current, at all locations. Based on the research work and results presented in this paper, the improved reliability can be obtained with a central controller with communication to multiple measurement units for a reduced cost without installing explicit relays at each end of every line. An optimum strategy for the number of relays and their location can be evaluated based on the network topology at the location and ratings of the DG sources.

APPENDIX F. MICROGRID PROTECTION: A UTILITY PERSPECTIVE [73]

F.1. Preface

Microgrid (MG) systems pose great potential to benefit both the private/electric customer sector and utility service provider in many aspects, with the mostly referenced benefit being local distribution system support of reliability and/or resiliency during catastrophic system events. To safely and effectively realize these benefits in practice though, numerous technical interconnection challenges must be addressed. Many of these risk areas are closely related to the known issues captured within the IEEE 1547 and 2030 series of interconnection standards, while some are referenced minorly without a detailed solution within since those methods can vary greatly dependent upon location, microgrid systems design specifics, local electric distribution company (EDC) design practices, etc.

Power flow on the EDC distribution system with a grid-connected MG and distributed energy resource (DER) assets online is no longer unilateral but is now multi-directional in nature with short-circuit levels in varying capacities generally from ~1 kA to ~30 kA range. In MG islanded mode, the EDC's system is effectively returned to traditional operation overall, and power flow originates solely from within the MGs smaller footprint with short-circuit levels in varying degrees of reduced capacities (depending on the EDC design) in comparison to grid-connected mode. In many instances, the fault current profile is modified to levels possibly indistinguishable from load current within the MG footprint. These conditions lend themselves to the development of two different protective design strategies if each MG operating state were designed in silos. The necessary approach for a successful EDC integration requires a collaborative approach between the EDC and microgrid owner/operator to develop a uniform protective scheme with flexibility to accommodate a wide range of fault current levels experienced during grid-connected and islanded modes.

The following document proceeds to outline a sampling of the primary challenges from a system protective standpoint, rationale for the necessity of identifying these risk areas early in design phase, and current mitigation practices recommended for DER and microgrid system integration into the EDC distribution system. There are many more considerations outside the scope of the paper which could be considered part of protection, such as:

- Microgrid controller communications infrastructure, latency, and reliability
- MG controller situational awareness of all critical devices such as breakers and DER asset(s) statuses within the MG footprint, as well as potentially select devices on the EDC system
- Point of common coupling (PCC) breaker isolation speed to realize uninterruptible islanding operations successfully

The above items are very critical to a successful MG project, heavily interdependent with the use cases being established and purpose of the MG. But this paper will focus the conversation to the core fundamental protective risk areas from a utility perspective, as it is my belief that the fundamental risk areas must be identified and addressed to realize success of the project at large.

F.2. Microgrid Protection Philosophy

F.2.1. Time Overcurrent Coordination

Traditionally, time overcurrent protection has been designed based on the predictable possible system configurations, fault current levels, and current flow direction(s) primarily originating from the EDC source transmission system and subsequent local serving substation. As DER systems begin to interconnect onto the EDC's infrastructure, fault current predictability becomes more complex and no longer a status quo fully known variable as historically been the case. Singular installations or aggregated DER systems paired with loads in a microgrid configuration impact the EDC in similar ways, albeit not completely identical, and therefore there is an opportunity to adapt some strategies employed for singular system installations for the larger microgrid ecosystem. These adaptations must be reviewed from both sides of the MG PCC breaker, in both grid-connected and islanded modes of operation.

F.2.1.1. Grid-Connected Mode of Operation

The instances where microgrid interconnection may impact local EDC time overcurrent protection while in grid-connected mode can be numerous and depends upon specific feeder operational characteristics, protective relay limitations (if present), etc. The existence of 3-phase series line reactors utilized to reduce fault current magnitudes for example are beneficial to the EDC but may be non-supportive to achieving adequate coordination with a microgrid located far downstream a feeder with other upstream protective devices. Stock must be taken of all devices on the normal configuration "host" feeder *at a minimum* to understand what the impacts to the EDC are and how can they be best addressed during design.

Typical EDC primary voltage (typically 4kV – 34kV level) feeders are designed for segmenting capability in response to faults via distributed recloser devices as shown in Figure 31. For the purposes of this paper, we will assume a case where these reclosers are operating in a decentralized, feeder-level logical fashion based primarily on undervoltage (ANSI function "27"), inverse time overcurrent (ANSI function "51"), or a combination of the two functions. This is a robust scheme when fault current contribution paths/levels are predictable and sourced from the substation(s) to the fault.

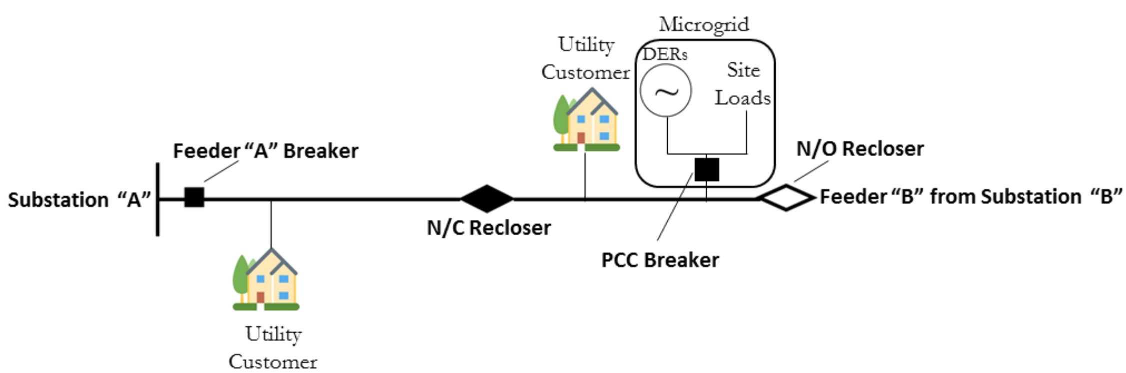

Figure 32. Simplified Distribution Line Recloser Scheme – Non-Faulted Condition

In the depicted feeder in Figure 31, the normally closed (N/C) recloser may operate based on protective function "27" if the fault is located on facilities between feeder "A" breaker and the N/C recloser *after a finite time delay*, or function "51" for faults between the N/C recloser and normally open (N/O) recloser *with minimal time delay based on the selected time current characteristic (TCC) curve*. Many other functions are available, but these will be the primary functions cited within this example. These functions are also paired with non-TCC based timing delays between devices to allow for coordinated isolation & restoration of feeder segments, which allows other devices to "try back" for restoration of non-faulted portions of the line. Where faults are located upstream of the midpoint N/C recloser while the microgrid DER assets are operating in grid-connected mode as reflected in Figure 32, the recloser may operate more immediately based on its "51" function (as opposed to the planned "27" function for this fault location) if enough current contribution is measured through its current transformers (CTs) and no directional qualifier is present. Without the presence of the grid-connected microgrid, this would not be a concern, but now this scenario must be assessed for "over-tripping" risk and mitigated appropriately through additional logic or alternate relay functionality (i.e. – directional element) at the necessary EDC or MG devices.

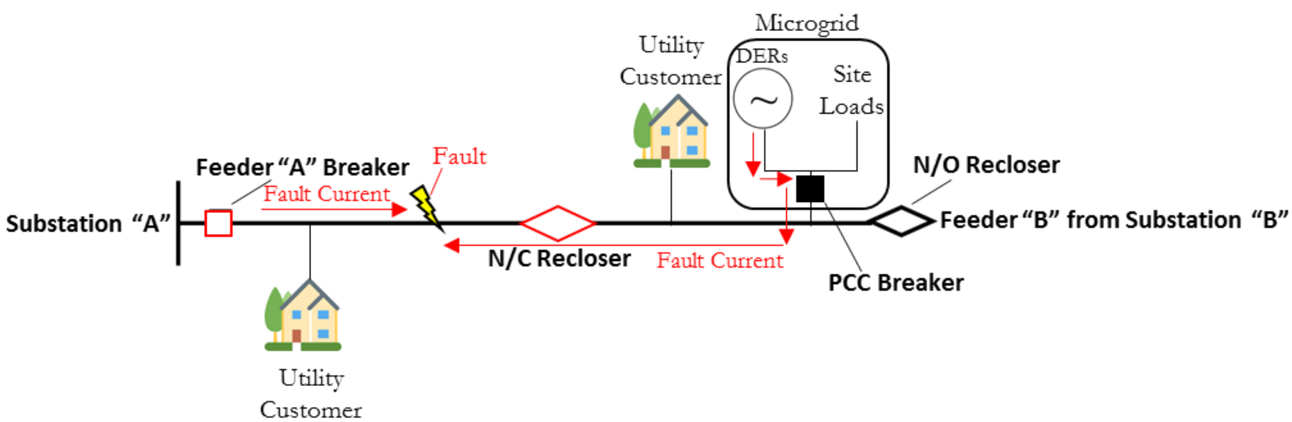

Figure 33. Distribution Line Recloser Scheme – Faulted Conditions with Grid-Connected MG

In the same vicinity of the above protective risk, the EDC's distribution system is dynamic as opposed to the more static transmission system. The distribution system can be viewed as the "front lines" of the electrical power generation & delivery system for all practical purposes, often found radial in configuration, the closest facilities electrically to customer utilization equipment in general, and most susceptible to necessary reconfigurations. These reconfigurations can be in response to many conditions, emergent and non-emergent. Regardless of the reasoning, these reconfigurations are positioned naturally in opposition to an always predictable fault current profile at a single fixed location, from a current level and direction perspective. As a result of this natural behavior of the distribution grid, any distribution-level interconnected microgrid is liable to be relocated to an alternate feeder-location or a different feeder entirely away from its current "home" feeder, on a temporary or permanent basis.

With this condition in mind, the microgrid may require a means of adapting its protective scheme as necessary or inhibiting operation when operating under the differing EDC source characteristics. Protective coordination for the microgrid site needs critical input from the EDC to not only understand the current EDC system impedance details and available fault currents to the microgrid currently, but also what is the maximum available fault current an EDC can provide at any point in their system. EDC distribution systems are not all designed identical, for example one EDC may not use series reactors with distribution system fault currents in the ~10-30 kA range, and another EDC may use a reactor in the neutral point limiting only line-to-ground (L-G) fault magnitudes, and another utility may use 3-phase series line reactors limiting magnitudes for all fault types. Therefore, microgrid protective device selection and scheme design will be site specific with elements for that microgrid site being unique to that installation in part due to that EDC's electrical design.

Moreover, breaker interrupting ratings, CT ratios, pickup values, etc. are all impacted by the maximum feasible fault current available from the EDC and should be referenced during design phase for all internal microgrid protective elements. These will be important considerations when transitioning the focus to isolation of faults internal to the microgrid. Much like the EDC distribution system, the microgrid must also protect for internal faults beyond the EDC/MG service and interconnection demarcation point.

F.2.1.2. Islanded Mode of Operation

Operating as a temporary isolated electrical entity from the local EDC presents a unique alternative mode to accommodate in the microgrid protection scheme. Usually orders of magnitudes difference exists between fault current levels in grid-connected and island mode. Due to the reduced available fault current, detection of fault currents that are close in magnitude to load currents becomes challenging. One approach that can be utilized when in island mode is differential scheme protection.

The primary advantage of this method resides in its ability to discern fault current values that are close to load values with good performance and reliability. Implementation of this approach to radial or network topologies is possible with a clear understanding of nodal points of electrical current input(s)/output(s) within the MG electrical system. One limitation of the method is the flexibility constraints to accommodate all permutations of internal reconfigurations of the MG system that increases or decreases the required protective zone(s). If not properly accounted for in the protective scheme design, false or missed operations are possible due to the excessive or deficient currents flowing in the differential scheme the unanticipated condition causes.

F.2.2. Ground Fault De-Sensitivity

Microgrids, analogous to smaller distributed DER system installations, pose a risk of desensitization of the local EDC's ability to detect single line-to-ground (L-G) faults external to the microgrid where a 4-wire multi-grounded electric distribution system exists, which is the most prevalent system configuration in the US. While the L-G fault condition is present, generally most of the fault current is sourced from the utility along the faulted phase to the fault location, and the appropriate protective relay designed to protect that zone will initiate a trip command to the interrupting device after a finite fault duration. This protective relay trip function signal "delay" is pursuant to the designated TCC plot-based coordination of all upstream protective devices from the fault location.

When DERs are interconnected onto the local EDC distribution infrastructure, particularly as a microgrid that may employ multiple point of connection (PoC) transformers, L-G fault current may be sourced by those same PoC transformers with or without active DER output depending on transformer winding configuration. If this fault current "diversion" is not actively monitored and maintained to acceptable limits within the interconnecting utility feeder, the local EDC protection may not register adequate fault current levels through its current transformers, resulting in a fault condition with a risk of prolonged isolation or non-detection completely. This is a risk to not only EDC and customer equipment, but also the safety of the public during the fault persistence (i.e. – electrical primary wire at ground level due to vehicle-inflicted pole damage).

Based on the risk associated with these fault current "diversions", it is paramount that the microgrid owner/operator interacts with the utility early in the electrical design of the microgrid. During this phase, pointed care should be given to the transformer winding configuration(s) being proposed by the microgrid owner/operator, among other system parameters. Grounding banks should raise concerns for fault current diversion, particularly if multiple banks of this type are being proposed. Generally, these are characterized as grounded-wye, delta configuration, with the cause for utility concern resulting from the EDC-side winding presented as the grounded-wye. Deliberate fault current analysis should be conducted to understand contribution levels, as this may inform the microgrid owner to possibly adopt an alternate winding configuration or include additional impedance elements in the EDC-side winding neutral-to-ground connection.

F.2.3. Transient Overvoltage (TOV) Management

F.2.3.1. "Effectively Grounded" Requirement

The term "effectively grounded" can be used and interpreted in numerous fashions, primarily influenced by the experience of the interpreter within the electric industry. Some non-utility personnel may view the term as a means of qualifying adequate grounding and bonding on the 600V, utilization voltage level facilities. There may be some utility personnel not intimately familiar with the detailed analysis of a power system that may be more familiar with the construction-based term indicating the necessary number of grounding points along a feeder's neutral conductor extension.

All the above interpretations are correct and can easily be encountered through various discussions of the term in relation to DER interconnections with the EDC, which therefore also impacts microgrid interconnections as well. From a DER-focused perspective though, these terms are relating to the electrical properties of a system's symmetrical component impedances, and how those electrical properties dictate behavior during faults within said system. The term "effectively grounded" relating to DER / microgrid interconnections is more officially defined in IEEE C62.92.1, with a paraphrased definition being the system is "effectively grounded" when the necessary zero sequence impedance components (R_0 and X_0) each in relation to the positive reactance (X_1) are within certain conditions ($0 < R_0/X_1 < 1$ and $0 < X_0/X_1 \leq 3$) to mitigate TOVs in excess of ~138% of nominal within the system due to any fault condition. These ratio conditions must be adhered to by the system <u>*as a whole*</u> to achieve an "effectively grounded" system. This implies that these ratios must be achieved with consideration to <u>*both*</u> the utility and the microgrid "source(s)" as parallel contributors to any faults going forward when in grid-connected mode.

This grounding status is another previous status quo of the utility system, as the EDC can dictate the impedances and winding configurations of the substation transformer(s), line conductors, and feeder series reactors (if applicable), where the "effectively grounded" ratios are met and over voltages are controlled during any fault since the utility was the sole source for many years. This is particularly important where the utility is a 4-wire, multi-grounded system, as this implies the existence of single-phase loads susceptible to potentially damaging TOV magnitudes during L-G faults.

F.2.3.2. Zero-Sequence Continuity

Seldom are microgrids proposed for new service installations where service transformers can be relatively easily specified prior to installation. More often the case, microgrids are intended to support existing critical customers (i.e. – police & fire, supermarkets, etc.) or private campus-style customers such as a university, which often also includes their existing electrical infrastructure to some degree.

If the microgrid site is utilizing transformation that lacks a ground reference on the EDC-side winding, there is a lack of zero sequence “continuity”. Generally, this occurs when a delta winding is utilized as the EDC-side winding(s) of the PoC or PCC interconnection transformer(s). From a symmetrical components aspect, the microgrid asset(s) appear as an open circuit in the zero-sequence network to L-G faults external to the microgrid electrical boundary, therefore, appears as an infinite zero sequence impedance. This condition, without any other system design modification(s), by default does not allow the microgrid system to contribute fault current towards the fault location. Therefore, the aggregate system (inclusive of both the utility and microgrid system impedances as reflected upon the fault location in parallel) cannot achieve compliance with the “effectively grounded” conditions previously discussed. TOV risks are present in these scenarios and must be mitigated, with the solutions ranging from high-speed $3V_0$ protection to alternate transformer configurations as outlined in Section 3.

F.3. Transformer Selection & “Effective Grounding” Compliance

Some utilities may have specific winding configurations they prefer on their system based on their protective philosophies and system design. For a 3-wire, single-point grounded EDC feeder, EDC-side transformer configuration may be less of a concern since all the equipment on the lines (i.e. – residential service transformers, lightning arrestors, etc.) are likely rated at 173% (L-L rating) of nominal L-G voltage. This example utility may have less restrictions on the zero-sequence continuity requirement.

Alternatively, a 4-wire, multi-grounded EDC feeder where equipment is likely rated to 100% or 133% of nominal L-G voltage, the transformer configuration is of greater concern to the EDC. The latter case is more prevalent of a scenario in the U.S., with EDCs beginning to employ greater attention to this design detail more and more as DER & microgrid system penetration increases. From a microgrid protective design standpoint, this item can have a minor to major impact upon the protective scheme implemented for ground fault detection, isolation, and subsequently TOV management as previously discussed. For transformer configurations where the interconnection is being proposed via a delta EDC-side winding for example, violating the “effectively grounded” criteria, the following paths outlined in Table 1 are generally available options of rectification.

Table 13. "Effectively Grounded" Requirement – Transformer-Level Options

Interconnection Option	Advantage(s)	Disadvantage(s)
Install a $3V_0$ (59G) detection scheme on the EDC-side of the interconnection	• Provides a means for detecting L-G fault conditions without changing the winding configuration, allowing for protective device isolation	• The overvoltage condition may still be present during the necessary operational time periods of the entire protection scheme, still capable of causing damage to equipment & present public safety issues • If the $3V_0$ scheme is not operational for any reason, the microgrid system must be islanded from the EDC or if grid-connected, the integrated DER must be disabled until the detection scheme is placed back in-service • Sensitivity may be negatively impacted if not presented with adequately balanced 3-phase voltages
Install a grounding bank at the EDC-side primary voltage level to establish a zero-sequence path for fault current flow from the microgrid to the utility during a L-G fault	• Establishes a zero-sequence path to allow for fault current to flow during L-G faults - supports creating an "effectively grounded" system • Offers an option with possibly less physical disruption of existing infrastructure modification (if required)	• Requires additional transformation equipment to achieve compliance, which adopts more maintenance costs • Requires a shunt trip protective scheme between the grounding transformer's overcurrent protective device, and the protective device(s) of the microgrid DER asset(s) and/or PCC breaker
Revise/replace the impacted interconnection transformer(s) to one with an EDC-side winding configuration with a ground reference to establish zero sequence continuity from the microgrid system to the utility/EDC	• Path for fault current to flow during a L-G fault on the utility/EDC infrastructure, better stabilization of TOV magnitudes • Mitigates the reliance on $3V_0$ scheme for detection of L-G faults • No reliance on external grounding transformer to provide zero sequence path	• May be costly if an existing transformer requires replacement • Harmonics present within the microgrid from switching devices (such as inverters) are easier to be transferred onto the utility/EDC side of the "system"

There are many potential paths to resolution to address lack of zero sequence continuity in the effort to achieve an "effectively grounded" system. The options selected will result from a necessary balance among EDC system design characteristics, EDC feeder load composition and phase balance, EDC neutral-grounding method employed, MG owner/operator DER asset types and winding configurations, acceptable budgetary spends, etc. Suffice it to say, there is no one solution that works for every microgrid site, but instead, a set of solutions that can be deployed with careful planning. Diligence must be present to analyze each system as unique, particularly when venturing across multiple geographic areas (i.e. – cities, states, countries, continents) where EDC feeder designs and topologies can vary widely.

F.4. Closing Remarks

Microgrid protection for grid-connected systems is an important and paramount area worthy of heightened understanding in both the utility and private sector arenas. Effective implementation will necessitate a blending of the two schools of thought and require more insight into the utility protective design by the MG owner/operator and vice-versa. This can only be brought into reality through clear and open lines of communication, particularly during early conceptual design phase of the MG project. Many nuances in the utility world exist, some widely implemented by numerous EDCs, and others unique to an EDC. Assumption cannot be made that any EDC is designed the same as another, and in some cases, disparity can exist even between two feeders served by the same EDC.

This open communication requirement does not only apply to the MG owner/operator and the EDC, but also the DER asset manufacturers. Greater levels of detail regarding system dynamic performance, control algorithms and methods, etc. are becoming increasingly important to more accurately model steady-state and transient behaviors of DER for both stand-alone and microgrid implementations. Protection engineers would benefit from this granular level of detail to design the most appropriate schemes for system protection. Microgrid controllers also need to better understand the capabilities of the assets which it is expected to manage/monitor, sometimes on a time basis down to a few cycles when dealing with seamless islanding away from the EDC.

Once these hurdles are overcome, many opportunities for successful MG project integration into the EDC infrastructure can be achieved, benefiting international and local standards development committees, emergency preparedness organizations, business continuity planning, and many other beneficiaries.

APPENDIX G. BASICS OF SYSTEM PROTECTION

In this section the basics of conventional distribution systems are briefly covered.

G.1. Distribution Protection Overview and Philosophy

The renowned protection engineer Mason wisely mentioned in his classic book [1] that power system protection is more an "art" than "science". It is perhaps one of the most complex and difficult topics in power system engineering. Though scientific principles provide the needed guidance to design a proper protection system, one can only master it through practical experience and through the lessons learned. The first step is to learn the basic principles and understand them thoroughly. To protect the same system, each protection engineer could arrive at different solution than his/her counterparts, but they all could be valid solutions. This is unlike other topics such as power flow, short-circuit and stability studies for which unique solutions exist.

The primary philosophy of protection is to preserve sensitivity, selectivity, minimum time of operation reliability residence and above all safety. Quite often these considerations could be conflicting, and protection engineers must make proper compromise and trade-off to achieve proper protection of a distribution system.

Distribution systems need protection against both overcurrent and overvoltage. Here protection will be limited to overcurrent considerations only. Normally, overvoltage protection is covered separately as an electromagnetic transient phenomenon.

During the past 25 years, distribution systems have experienced unprecedented transformation under the "Smart Grid" rubric with the infusion of innovative technologies in every automation domain: sensors, generation, control, communications and computing. With the introduction of microprocessor-based protection devices, the existing protection systems need gradual changes. Advanced strategies and adaptive protection ideas need to be explored. With these changes in mind, the protection of both classical and emerging distributions will be covered in this roadmap report limiting to the basic principles, design and coordination. The detailed treatment of this subject for classical systems are covered in "Distribution Protection Manual developed by Cooper Power Systems [2]. Other resources and references are included under "References".

G.2. Why perform protection studies? Reasons of conducting protection studies are

The result of protection studies is a coordination of 'setpoints' or 'settings' for all the protective relays in a power system. Properly coordinated relay settings provide the following benefits.

- prevent damage to circuits, transformers, generators, and loads,
- prevent hazards to the public and utility personnel,
- maintain the highest of service reliability, safety and resilience by preventing power interruption
- minimize the effects of damage when an interruption occurs.
- minimize the duration of a fault and to minimize the number of customers affected.

G.3. Objectives

The primary objectives of performing protection studies which are part of comprehensive distribution planning and/or design studies of a given system are:

- basic addition or expansion of a distribution system
- manual and automatic sectionalizing of portions of a system
- decide on proper phase spacing between conductors and selection of insulation
- vegetation management to assure the highest level of system reliability
- inspection for other potential problems such as salt deposition on conductors, dust accumulation on insulators etc.
- preventive equipment maintenance

G.4. Protection of Power Carrying Devices

Adequate protection must be provided for all types of all power carrying equipment such as:

- Lines, feeders, laterals etc.
- Distribution substation transformers and distribution transformers
- Capacitors
- Voltage regulators
- Segments of the system itself
- Conventional and Distributed Energy Sources (DERs)
- Loads

G.5. Classification of Classical Protective and Switching Devices

Protective devices or systems are weak links intentionally created to save expensive power carrying assets such as lines (feeders and laterals), transformers (both substation and distribution)

1. A <u>single-action fuse</u> must carry the expected load of a distribution line such as a feeder or a lateral. A fault occurring at the end of the line should be cleared by the fuse. The fuse performs both sensing and fault interrupting functions. The real drawback with this device is that they must be replaced after one operation. Although fuses are inexpensive, the labor associated with changing fuses is not. Fuses are overcurrent protective devices with a circuit-opening fusible part that is heated and severed by the passage of current through it.
2. <u>A recloser</u> is a multi-function protective device which has both fault sensing and fault clearing capabilities. It has built-in intelligence unlike the fuse. Some reclosers are not as intelligent as modern microprocessor protective relays. Many reclosers now have fully capable microprocessor relays. Reclosers with advanced microprocessor protective relays are commonly used at PCC (point of common coupling) to microgrids. Reclosers have considerable ability to distinguish between temporary and permanent faults, unlike fuse links, which interrupt either type indiscriminately. After a fault is detected, reclosers automatically re-energize, or ‘test’ the line by successive ‘reclose’ operations, giving temporary faults

repeated chances to clear or be cleared by subordinate protective devices. Should the fault not clear, the recloser recognizes it as a permanent fault and locks open or 'locks out'. Single-phase reclosers have usually hydraulic control, but three-phase reclosers may be either hydraulically or electronically controlled. Most reclosers interrupt fault current in oil-filled chambers, but recent designs have been built around vacuum circuit interruption. A drawback of many reclosers is limited fault interruption capability. Reclosers must be coordinated with upstream protective relays controlling circuit breakers in a substation; these circuit breakers are designed for interrupting fault currents.

3. A <u>sectionalizer</u> applied in conjunction with a circuit breaker has the memory of counting the number of operations of the upstream and it does not have any fault-interrupting capability of its own. It counts the number operations of the backup device (recloser or circuit breaker) during fault conditions After a pre-selected number of current-interrupting operations (reclose attempts), the sectionalizer opens and isolates the faulted section of line. It resembles an oil circuit recloser but lacks all fault interrupting capability. Its operating controls are set to count current surges and locks open its contacts after a set number of surges (reclose operations) have occurred. If the fault is temporary, both the sectionalizer and the recloser reset, ready for the next fault. If the fault is persistent, however, the recloser operates on its sequence but the sectionalizer isolates the fault before the recloser starts it final reclose operation; thus, recloser lockout is avoided, and only that portion of the circuit beyond the sectionalizer is interrupted.

4. A <u>circuit breaker</u> is normally employed at the substation level for the overcurrent protection of the feeders connected to them. It is a mechanical switching device, capable of making, carrying, and breaking currents under short-circuit conditions. (The medium in which circuit interruption is performed may be designated by a suitable prefix, e.g., air-blast circuit breaker, gas circuit breaker, etc.). The breaker is expensive and bulky protective device which can only be cost-justified at the substation level. The opening and closing of substation circuit breakers are always controlled by protective relays. Circuit breakers_are equipped with a trip coil connected to a relay designated to open the breaker automatically under abnormal conditions, such as faulted circuit conditions.

The breakers are classified by interrupting medium and method of storing energy. These are;

- Oil interruption
- Vacuum interruption
- Air-blast interruption
- SF_6 (gas) interruption
- Air-magnetic interruption

Within the distribution systems, feeder breakers normally utilize oil, vacuum or air-magnetic interrupting medium and method of storing energy.

5. A <u>disconnecting switch</u> is a mechanical device having a movable member adapted to connect or disconnect contact members to which conductors are securely bolted; they are usually operated on dead circuits only but are sometimes operated on energized low-capacity circuits and short-times. Switches were used generally for the earliest low-voltage circuits. As currents and voltages increased, it was found that the arc burns while opening the switch damaged or

destroyed the contacts. Disconnection switches are either manually or motor operated. Motor operated disconnecting switches are usually controlled by protective relays.

G.6. Protective Relays

As new minerals and materials evolve, new digital protective devices will evolve soon (say next 10-20 years based on prediction). These anticipated developments should be kept in mind in meeting microgrid protection R&D needs, challenges, strategies and solutions.

The purpose of this chapter is to review existing and evolving protection technologies for microgrid protection. This section is a quick summary of the diverse categories of protective relays being used today. The Microprocessor relay has largely replaced all other legacy relay types.

G.6.1. Electromechanical Relays

Electromechanical protective relays have been in existence since the dawn of electricity in early 1880s. Electromechanical relay designs evolved through the 1950's. Electromechanical relays cannot perform complex or adaptive protection and they cannot advise operations when they fail. Each relay performs a single function and consumes a great deal of physical space and wiring. These relays require frequent maintenance and must be tested regularly. These relays have substantial number of moving parts which must be cleaned, lubricated, and calibrated regularly. These are all factors to be considered when devising microgrid protection schemes.

G.6.2. Static relays

Unlike electromechanical, static relays do not have any moving parts. Static relays use transistors and analog circuits to make protection decisions. Though they are less reliable than electromechanical relays, they are more accurate and response times are faster. This classification of relays required very high-quality DC power supplies which is not so practical in a substation environment. Static or solid-state relays came into existence in early 1960's, however these devices were short lived due to their low reliability. These have been almost entirely replaced with microprocessor relays.

G.7. Operational Convention for Protective Devices

By conventional definition, when two or more protective devices are applied to a system the device nearest the fault on the supply side is the "primary" device. The other ones towards the upstream are the called "backup" devices.

G.8. Classification of Faults

Per International Standards such as IEEE Standard 1366, the faults that could occur in a power system are classified as:

1. <u>Temporary Faults</u>: Most faults on overhead distribution systems are temporary (70-85%). A temporary fault is one whose cause is transitory in nature. The examples include a brief contact between two conductors, a tree branch falling across two conductors, then dropping clear or a bird or small animal that causes a brief arc from the live terminal to ground. Relays which control reclosers or circuit breakers are configured to reclose the circuit in hopes the temporary fault has cleared.

2. Permanent Faults: One in which damage has occurred from the cause of the fault or the fault arc. Examples include a broken insulator, a broken conductor or an automobile knocking down a pole. When a permanent fault occurs, the line must be deenergized and a crew is dispatched to repair the damage. Relays which continue to observe fault currents during reclose operations go into lockout for these types of faults.

G.9. Faults Types

1. The type of fault depends on the distribution system topology, line construction and configuration. These could occur both on overhead or underground systems.
2. Single Line-to-Ground Faults: When one conductor of a three-phase system falls to ground or contacts the neutral wire. This is the most common type of fault (about 85 to 90%) that usually happens in a distribution system.
3. Line-to-Line Faults: When two conductors of a two- or three-phase systems are shorted together.
4. Double Line-to-Ground Faults: Two conductors of a two- or three-phase systems are shorted together fall and connected through ground. Or, two conductors contact the neutral and grounded.
5. Three-Phase Faults: When all the three conductors of a three-phase system get shorted and create a fault. If the three conductors fall to the ground, then it is called a three-phase-to-ground fault. For this fault, the fault impedance, which is mostly pure resistance, could be anywhere between zero for a bolted fault and up to 200 ohms depending upon the ground resistivity. For example, the ground medium soft soil, rocky surface or an asphalt surface.

G.10. Fault Causes

Faults can occur due to abnormal weather conditions such as lightning storms, wind storms, hurricanes, tornadoes and others which are nothing but the curse of nature. Unfortunately, faults could also occur due to human errors. While every attempt can be made to avoid the latter by best practices adopted of the electrical industry, they can and will happen. The best recourse is to be prepared to protect the valuable assets of the electrical power distribution system.

G.11. Coordination of Protective Devices

Protective relay coordination is a complex process. Here the art of protection comes into picture since there are many variables and valid solutions that exist based on the philosophy of the protection engineer. The coordination issue for both classical and emerging distribution systems are introduced below in this report for the benefit of all stock holders. The benefits of conducting proper coordination of protection devices are:

It helps to eliminate service interruptions due to temporary faults and to minimize number of customers affected and for service restoration optimally.

The following data will be needed for conducting the proper coordination:

- Feeder configuration diagram, also known as a single line diagram.
- Location, model, and wiring devices.

- Proper mathematical models for protective elements within the protective relays.
- Expected range of normal load currents at all locations throughout the system under consideration
- Expected range of fault currents at all locations throughout the system under consideration.

The coordination of two local devices are performed using time-current coordination characteristics which form the models for the devices. The objective is to keep a minimum coordination interval of say 0.3 seconds between the primary device close to the point of fault and the immediate backup device(s) depending upon the topology of the system under consideration. This can be best illustrated via several examples considering several types of devices namely fuses, reclosers, sectionalizers and circuit breakers.

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