GRID INTERFACES FOR FLEXIBLE AND RESILIENT DISTRIBUTION SYSTEMS

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Nishant Bilakanti

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Approved by:

Dr. Deepak Divan, Advisor
School of Electrical and Computer Engineering
Georgia Institute of Technology

Dr. Santiago Grijalva
School of Electrical and Computer Engineering
Georgia Institute of Technology

Dr. Maryam Saeedifard
School of Electrical and Computer Engineering
Georgia Institute of Technology

Dr. Daniel Molzahn
School of Electrical and Computer Engineering
Georgia Institute of Technology

Dr. Marilyn Brown
School of Public Policy
Georgia Institute of Technology

Date Approved: April 27, 2023

Dedicated to my beloved parents and my sister for their selfless love and endless support in all my endeavors

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LIST OF SYMBOLS AND ABBREVIATIONS

AMI	Advanced metering infrastructure
AVR	Automatic voltage regulator
DER	Distributed energy resource
DERMS	Distributed energy resource management system
DMS	Distribution management system
DTT	Direct transfer trip
EMT	Electromagnetic transient
FLISR	Fault location, isolation, and service restoration
GFOV	Ground fault overvoltage
IEEE	Institute of Electrical and Electronics Engineers
IID	Island interconnection device
LTC	Load tap changer
LVR	Line voltage regulator
NEETRAC	National Electric Energy Testing, Research and Applications Center
OMS	Outage management system
PLL	Phase-locked loop
POI	Point of interconnection
PSPS	Public safety power shutoff
REC	Resilient energy community
RoCoF	Rate-of-change-of-frequency
RMS	Root mean square

RTU	Remote terminal unit
SCADA	Supervisory control and data acquisition
STATCOM	Static synchronous compensator
UFLS	Under-frequency load-shedding
1LG	Single line-to-ground
μG	Microgrid

SUMMARY

The growing penetration of distributed energy resources (DERs) and microgrids is leading to fundamental changes in power system planning, operations, and control at unprecedented scope and speed. Utilities and their interconnection processes are struggling to cope with the numerous issues associated with high DER and microgrid penetration. Current interconnection practices for large-scale DERs and microgrids involve detailed system impact studies that require advanced skill sets, are time-consuming, costly, and do not guarantee compliance with the utility interconnection rules. Moreover, it can be challenging to model the highly customized and proprietary hardware and controls of microgrids characterized by emergent behavior. Furthermore, the ever-evolving interconnection standards with 6-8 year development and adoption timelines significantly inhibit the deployment of advanced DER and microgrid solutions necessary for the widespread adoption of renewables. It is imperative that a solution is developed where DERs and microgrids can be safely, cost-effectively, and reliably integrated with the grid without requiring lengthy and expensive detailed interconnection impact studies.

With the increasing frequency of extreme weather events resulting in prolonged grid outages, there is a growing interest in utilizing DERs and microgrids as a cost-effective means to improve the resilience of the distribution system. However, current utility practices for distribution system restoration do not leverage the use of DERs and their ability to form microgrids to reduce the frequency and duration of outages and expedite distribution system restoration. With the current rules and practices, DERs are expected to shut down or disconnect following outages and are only allowed to reconnect with the grid

after the utility supply is restored. Instead of a complete loss of service following grid outages, DERs and microgrids must be leveraged to serve loads until the utility supply is restored. Moreover, during grid outages, an approach is needed to prioritize supply to critical loads and provide non-critical loads with limited electric service.

This work proposes Island Interconnection Devices (IIDs) as standardized utility-owned and utility-controlled grid interfaces to simplify the grid integration of DERs and microgrids by eliminating the requirement for detailed system impact studies. The IID solution is a forward-thinking, streamlined, and proactive approach to accelerating the deployment of DERs and microgrids while guaranteeing compliance with the ever-evolving utility interconnection rules and managing integration and operational risks. If any utility interconnection rule is violated, the IID disconnects the DER or islands the microgrid to ensure the integrity of the grid and reports interconnection violations to the utility. The IID approach also provides utilities with a standardized communication interface for monitoring and control, flagging and reporting violations, changing thresholds and setpoints, and modifying the logic of the IID remotely. In addition to providing grid-support and ancillary services, it also serves as an effective mechanism for advanced utility functions such as load-shedding, bottom-up black-start, service restoration, and forming microgrid clusters. Furthermore, this approach unleashes innovation in DERs and microgrids and enables rapid deployment without limiting functionality, affecting grid operations, or being held back by slowly moving interconnection standards.

Furthermore, this work proposes a distribution system architecture consisting of IIDs, smart electrical distribution panels, and DERs to enable flexible and resilient distribution systems. It enables the operation of the distribution system as an interconnected network of microgrids with bottom-up black-start and service restoration functions. Upon loss of utility supply, this approach can black-start feeder segments, form microgrids, and rapidly restore service with priority given to critical loads. With increasing DER output compared to prevailing loads, an increasing fraction of low-priority loads is served without requiring communications. Furthermore, by networking neighboring microgrids to form a microgrid cluster, the proposed grid architecture provides increased reliability and resilience benefits to customers within their footprint and surrounding areas. By isolating failures and providing alternative pathways for the continuity of electricity supply, the proposed architecture is expected to enhance the resilience of the distribution system by minimizing the magnitude, frequency, and duration of power outages.

CHAPTER 1. INTRODUCTION

1.1 Problem Statement

The rapidly declining costs of distributed energy resources (DERs) such as solar PV and battery energy storage have resulted in solar PV systems, and in many regions, solar PV coupled with storage reaching grid parity. The resulting growing penetration of DERs and microgrids is leading to fundamental changes in power system planning, operations, and control at unprecedented scope and speed. DER and microgrid interactions with the grid, especially under transient and fault conditions, may have unforeseen impacts on grid operations, protection, and stability and necessitate extensive interconnection studies and remediation measures before large DERs and microgrids can be interconnected with the grid. Performing interconnection studies is time-consuming and requires accurate system knowledge, detailed DER and network models, and advanced skill sets and resources unavailable at most utilities. The rapid influx of interconnection requests is causing long queues and requiring additional efforts to perform detailed interconnection impact studies resulting in lengthy approval, integration, and testing times and at a high cost.

Traditional approaches adopted by utilities to manage the challenges associated with high DER and microgrid penetration and emerging strategies have their own implementation and operational challenges. Moreover, they do not fully address the interconnection risks and impacts. Furthermore, challenges with the slowly but ever-evolving interconnection standards inhibit innovation in DERs and microgrids and do not always guarantee compliance with interconnection rules. An approach is needed where large DERs and microgrids can be interconnected without having to perform detailed system impact studies while guaranteeing compliance with evolving utility interconnection rules.

Recent extreme weather events such as hurricanes and the risk of wildfires sparked by utility equipment have resulted in extensive and sustained interruption of service, lasting several days and leaving millions of people in the dark. Today's centralized, top-down grid architecture and operating practices make achieving resilience very challenging. Following large-scale grid outages, utilities use a top-down approach to service restoration. In this approach, once the distribution substation is energized by the bulk power system consisting of large generators, transmission, and sub-transmission networks, service is restored to the distribution feeders and end-use consumers in a sequential process through a series of sectionalization and switching actions. These distribution system restoration practices do not leverage DERs and their ability to form microgrids. DERs and microgrids can significantly improve resilience by minimizing the frequency, magnitude, and duration of power outages, providing power to critical loads, and rapidly restoring service to the rest of the distribution system.

Most of the work proposed in the literature utilizing DERs and microgrids for distribution system restoration relies on situational awareness, centralized decision-making, and extensive use of communications which are not always available during large-scale blackouts. Furthermore, these approaches do not consider resource flexibility during the distribution system restoration process. The limited generation capacity in the distribution system compared to loads and the increased demand with cold load pickup following extended outages make distribution system restoration with DERs and microgrids challenging. With critical loads being a small proportion of the total consumer load, flexibility from DERs and loads can significantly improve microgrid survivability and ensure the continuity of electricity supply for critical loads. An approach is needed where supply to critical loads is prioritized during outages, and non-critical loads are provided with limited electric service.

There is also an increasing interest in forming and operating microgrid clusters by interconnecting neighboring microgrids in distribution systems during outages. This can significantly enhance reliability and resilience cost-effectively by enabling access to increased flexible resources. Microgrid clusters bring about technical and operational challenges, such as transient interactions during the synchronization and connection process when forming clusters. Most commercially available microgrids operate with centralized control and communicate with every DER within the microgrid. To achieve seamless transitions between the islanded and grid-connected modes of operation, the microgrids either operate in or switch into the isochronous control mode to synchronize generation resources and maintain phase angle, frequency, and voltage magnitude differences within limits specified by the utility before reconnecting with the grid. Using a centralized microgrid controller and communicating with every DER works well in small localized microgrids. However, centralized control and real-time communication become very challenging when considering large, geographically dispersed microgrids or microgrid clusters with numerous DERs, such as community- and utility-scale microgrids.

1.2 Research Scope and Objectives

The objective of this research is to develop standardized grid interfaces to simplify the integration of DERs and microgrids with the grid and enable flexible and resilient distribution systems.

The major integration and operational challenges faced by utilities with high DER and microgrid penetration, the ever-evolving standards, and challenges with current solutions are first investigated. Island Interconnection Devices (IIDs) are then proposed as standardized utility-owned and utility-controlled grid interfaces to simplify integrating DERs and microgrids with the grid by enforcing the ever-evolving interconnection rules and not requiring a detailed system impact study. Finally, a resilient distribution system architecture consisting of IIDs, smart electrical distribution panels, and DERs is proposed to enable operating the distribution system as an interconnected network of microgrids with bottom-up black-start and service restoration functions.

The primary scope and objectives of this research are summarized into the following three categories:

1. Identifying the impacts of high DER and microgrid penetration on grid operations:
    a. Identify the major integration and operational challenges utilities face when integrating DERs and microgrids with the grid and the potential impacts on distribution system operations.
    b. Study the potential for transient overvoltages during faults and the impact of out-of-phase reclosing on utility and customer assets.
2. Simplifying the integration of DERs and microgrids with the grid:
    a. Develop Island Interconnection Devices (IIDs) as standardized utility-owned and utility-controlled grid interfaces to simplify the grid

integration of DERs and microgrids by enforcing utility interconnection rules and eliminating the need to perform detailed system impact studies.

   b. Develop the rules for interconnection, various types of IIDs and their use cases, communication architecture, and the benefits of the IID approach.

   c. Demonstrate through simulations the efficacy of the IID approach in mitigating distribution system impacts for grid and microgrid events.

3. Enabling flexible and resilient distribution systems:

   a. Develop a distribution system architecture consisting of IIDs, smart electrical distribution panels, and DERs to operate the distribution system as an interconnected network of microgrids to minimize the impact of power outages, rapidly restore service, and provide power to critical loads.

   b. Develop a methodology for distribution system-level bottom-up black-start and service restoration and a methodology utilizing under-frequency and RoCoF-based load-shedding for load-level restoration implemented in the smart electrical distribution panels.

   c. Demonstrate through simulations the ability of the proposed distribution system architecture to enhance resilience upon loss of utility supply by rapidly restoring service through bottom-up black-start and prioritizing supply to critical loads without requiring any communications.

d. Develop the operational stages and demonstrate through simulations the ability to seamlessly synchronize and interconnect neighboring islanded microgrids to form a microgrid cluster and reconnect with the grid.

1.3 Outline of Chapters

In Chapter 2, the state-of-the-art approaches to integrating DERs and microgrids with the grid and leveraging DERs and microgrids to enhance distribution system resilience are presented. Challenges with existing and emerging approaches adopted by utilities and those proposed in the literature are discussed.

In Chapter 3, the major integration and operational challenges that utilities face when integrating DERs and microgrids with the grid and their potential impacts on distribution system operations are identified and presented. Transient overvoltages during ground faults and the impacts of reclosing out-of-synchronism are studied through modeling and simulations.

In Chapter 4, Island Interconnection Devices (IIDs) are proposed as standardized grid interfaces to simplify the integration of large-scale DERs and microgrids with the grid. The IID solution is a forward-thinking, streamlined, and proactive approach to integrating DERs and microgrids without requiring detailed system impact studies while guaranteeing compliance with the ever-evolving utility interconnection rules. The rules for interconnection, use cases, communication architecture, and the benefits of the IID approach are presented. Simulation results demonstrating the efficacy of IIDs in mitigating distribution system impacts for grid and microgrid events are presented to validate the proposed concept.

In Chapter 5, a resilient distribution system architecture consisting of IIDs, smart electrical distribution panels, and DERs is proposed to enable the operation of the distribution system as an interconnected network of microgrids. The methodologies for system- and load-level bottom-up black-start and service restoration and the control of IIDs, smart electrical panels, and DERs to restore service on the loss of utility supply are presented. Simulation results are presented to demonstrate enhanced resilience upon loss of the grid by rapidly restoring service through bottom-up black-start and prioritizing supply to critical loads over low-priority loads without requiring any communications. Furthermore, the operational stages and simulation results demonstrating the ability of IIDs to form a microgrid cluster by seamlessly synchronizing and connecting neighboring islanded microgrids and reconnecting with the grid are presented.

In Chapter 6, the conclusions, contributions, and suggested topics for future work are presented.

CHAPTER 2. BACKGROUND AND LITERATURE REVIEW

2.1 Grid Integration of Distributed Energy Resources and Microgrids

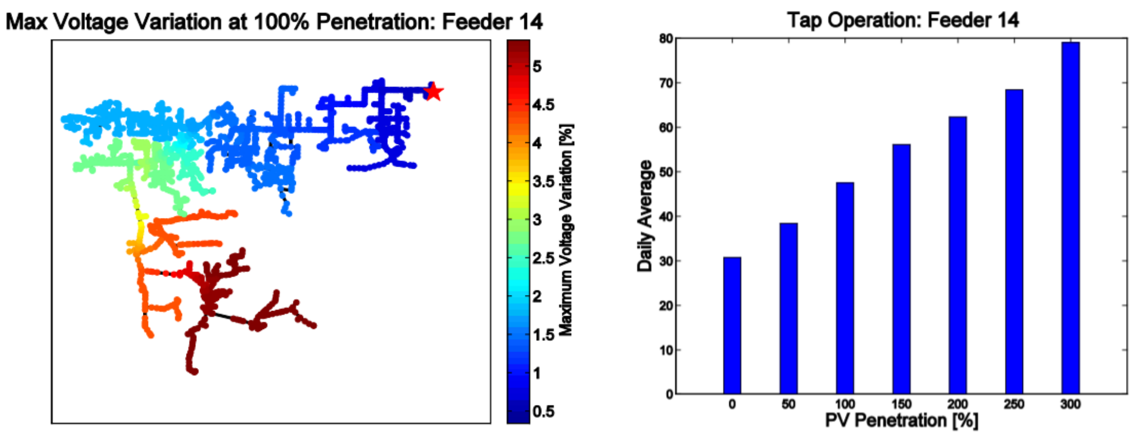
The past decade has seen rapid growth and widespread deployment of DERs such as solar PV, wind, fuel cells, batteries, and microgrids. This transition is mainly due to an increased focus on sustainability, drastic price reductions, and legislation incentivizing localized renewable generation and storage [1]–[3]. Given the ever-increasing penetration levels and the variable nature of renewables, distribution systems face several operational challenges such as voltage violations [4]–[11], thermal violations [5], [6],[8]–[11], reverse power flows [12], and protection coordination issues [5], [6], [8], [10]–[12]. Operating distribution systems with increasing levels of DERs, such as solar PV and microgrids, requires advances in grid integration methodologies and technologies to accelerate the evolution toward a cleaner, more cost-effective, reliable, and resilient power system.

Utilities in Hawaii and California, which have the highest levels of DER penetration in the U.S., are assessing a wide variety of technologies to help manage the associated integration challenges - including demand response, grid-edge solutions, smart inverters, and energy storage [4], [13]–[15]. Some utilities have gone a step further to manage the challenges with high solar PV and microgrid penetration by discontinuing net-metering and encouraging self-generation [14], [15]. In extreme cases, utilities even limit new installations by requiring significant network upgrades and charging departing load and standby fees [16].

Grid interactions of DERs and microgrids, especially under transient and fault conditions, may have unforeseen impacts on grid operations and require extensive interconnection studies before they can be authorized to interconnect with the grid [1], [4]–[13], [17]–[28]. Performing interconnection studies requires accurate knowledge of the distribution system, such as feeder topology, location, and the control and settings of customer-owned DERs (solar PV inverter, battery, microgrid, etc.) and utility equipment (load tap changers, line voltage regulators, capacitor banks, etc.) [5], [10], [25]–[27], [29], [30]. The detailed control logic of DERs is proprietary and not readily available to utilities in most cases [10], [25], [31]. The significant increase in interconnection requests and detailed impact studies is resulting in long integration times and at a high cost [5], [25]–[28]. Moreover, the proprietary nature of the inverter and microgrid hardware and control software makes the emergent behavior at the point of interconnection (POI) very difficult to model and predict [25], [31].

The impacts due to DER and microgrid penetration can be broadly categorized into voltage-related, protection-related, reverse power flow-related, and load-related impacts [5], [10]. While the conventional distribution systems were designed for uni-directional power flow, the bi-directional power flow due to high DER penetration can interfere with the distribution system's loading patterns, voltage regulation, and protection mechanisms. This may result in feeder voltage violations [4]–[11], ampacity violations [5], [6],[8]–[11], excessive operation of utility equipment such as tap changers and line voltage regulators [4]–[11], flicker [5], [10], feeder unbalance issues [5], [10], and protection miscoordination [5], [6], [8], [10]–[12]. The extent to which distribution system violations are observed on a feeder depends on several factors, such as feeder configuration, location, type, and control of DERs and utility equipment [5], [10], [32], [33].

Figure 2.1 shows the voltage profile and the number of daily tap operations in a 12 kV distribution feeder in California with an on-load tap changing transformer at the distribution substation and high penetration of residential solar PV systems [34]. Figure 2.1 (a) shows that several nodes experience voltage violations as high as 5%, which violates the ANSI C84.1-2016 standard's Range A definition [35] with a significant increase in the number of daily tap operations, as shown in Figure 2.1 (b). With load tap changers and line



(a) (b)

Figure 2.1: Feeder profile in SDG&E service territory [34] a) Voltage violations, and b) Daily tap operations

voltage regulators originally designed for 3-5 operations per day, the drastic increase in their daily operations with rising solar PV integration can significantly reduce their life.

The following sections present a review of the traditional and emerging approaches adopted by utilities to mitigate the potential impacts of integrating DERs and microgrids with the grid and the interconnection approval process used by utilities.

2.1.1 Traditional Solutions

2.1.1.1 <u>Load Tap Changers and Line Voltage Regulators</u>

On-load tap changers (OLTCs) and line voltage regulators (LVRs) are the most common mechanical voltage regulation mechanisms used by utilities [5], [17], [36]. On a typical distribution feeder, the OLTC is located at the distribution substation, while LVRs, if any, are located downstream of the substation. Voltage control along the feeder is achieved by changing the tap settings or setpoints of the OLTC and LVRs. These utility assets can operate autonomously based on local measurements, such as bus voltages, or through inputs from the utility distribution management system (DMS), in coordination with other voltage regulation devices such as switched capacitor banks [5], [36].

In distribution feeders with a very high penetration of solar PV, the inherent mechanical delays and intentional delays for LTCs and LVRs result in them operating in an uncoordinated manner, significantly increasing their number of operations, resulting in deterioration and premature failures [5], [10], [37], [38]. LVRs using line-drop compensation or end-of-line sensors to control the feeder voltage profile are also severely impacted by large amounts of solar PV sited near the substation or immediately downstream of the LVR due to masked load [5], [10]. These challenges result in ineffective voltage regulation as the local grid conditions, such as solar PV output and loads, would have changed by the time the previously computed tap setting is reached.

In distribution feeders not configured for bi-directional power flow, there is potential for LVRs to saturate if the direction of power flow reverses due to downstream solar PV generation [5], [10], [39]. The saturation of the LVR results in a runaway tap changer condition that may cause severe voltage violations along the feeder and damage to equipment.

2.1.1.2 Capacitor Banks

Fixed and switched capacitor banks are widely used in distribution systems for feeder voltage support, reactive power support, and reduction of power system losses [40]. Switched capacitor banks work by operating switching devices that energize and de-energize shunt capacitor banks [41]. More capacitor banks are connected in parallel to increase reactive power injection, while fewer are connected when there is a requirement for reduced reactive power support. Similar to OLTCs and LVRs, capacitor banks can operate autonomously based on local information or through inputs from the utility DMS to achieve a centralized Volt/VAR strategy by coordinating with other voltage regulation mechanisms such as LVRs.

Compared to OLTCs and LVRs, capacitor banks require special attention due to the inrush and local overvoltages that occur during switching transients when switching on and off the shunt capacitor banks [41]. These switching transients can magnify when resonating with a nearby transformer or customer-sited power-factor correction capacitors resulting in excessive voltage distortion and nuisance tripping of equipment [42], [43]. During voltage sags, capacitor banks do not inject the pre-event reactive power and cannot adequately regulate the local voltage due to their passive and discrete nature and slow response, causing voltage violations and tripping of customer equipment [42].

2.1.1.3 Direct Transfer Trip

Direct transfer trip (DTT) is a highly specialized communication-aided protection scheme required by many utilities where a large DER or microgrid can form and sustain an islanded section of the distribution feeder following the loss of upstream utility service [44]–[46], [48]. DTT is also required in situations where a large DER or microgrid cannot timely detect and trip for faults in the distribution system [5], [47].

Following a fault, the tripped circuit breaker or recloser sends a trip signal to all downstream DERs via the supervisory control and data acquisition (SCADA) system. Depending on the feeder configuration and location of protection devices, the utility may require DERs and microgrids to trip on the opening of every upstream line recloser and the substation circuit breaker and, in some cases, on the opening of the high-side circuit breaker at the substation [48].

DTT requires low-latency, secure, and redundant communications for reliable protection resulting in a high interconnection cost [44]–[48]. The communications media commonly used include leased telephone lines, dedicated fiber, radio, and cellular communications. DTT system costs ranging from about $120K to $600K have been reported in the literature [49]–[50]. The long DTT installation time, which can take 18-24 months to complete, and the high costs that can be a substantial part of the overall project cost can affect project viability [51]. Furthermore, ensuring reliable DTT protection can be challenging when considering reconfigurable feeders with auto-loop schemes where the utility substation source may change [44].

2.1.1.4 Protection Upgrades

To mitigate potential protection challenges with DERs such as reverse power flows, reduced fault current contribution, out-of-phase reclosing, unintentional islanding concerns, and grounding issues, many distribution utilities are augmenting and upgrading their protection schemes by adopting advanced relay functions and system-level protection strategies [5], [10]–[13], [19]–[21].

Commonly used utility and DER protection relay functions include phase overcurrent, overvoltage, undervoltage, overfrequency, underfrequency, ground fault protection, etc. [5], [10]. Protection devices such as circuit breakers and fuses are replaced when their full-load or interrupt rating is exceeded [5], [10], [48]. To mitigate utility relay desensitization impacts due to fault current contribution from DERs, some solutions include adjusting the relay pickup values and trip times and adopting communication-assisted distribution protection schemes such as DTT [10]. Advanced protection schemes such as state estimation and synchrophasor techniques are also being developed [51], [52].

To minimize the risk of out-of-phase reclosing, utilities are adopting reclose blocking and sync-check functions for the substation breaker and line reclosers [10]. In cases where the risk of out-of-phase reclosing due to large DERs and microgrids is very high, utilities install expensive centralized DTT protection schemes [10], [44].

2.1.1.5 Network Upgrades

As the penetration of DERs and microgrids rises significantly, there is a high likelihood that the utility may require changes to the proposed project and mitigation measures in the form of distribution system upgrades to allow the proposed system to interconnect. Typically, the cost of the distribution system upgrades required to interconnect the proposed system or group of systems is to be borne by the project or group of projects that trigger and benefit from the upgrade [26], [54]. In a study performed by the National Renewable Energy Laboratory (NREL) that analyzed interconnection studies from 92 solar PV projects spread across the western US with capacities ranging from 100 kW to 20 MW, 57% of the projects required major distribution system upgrades [26]. The total system upgrade costs in the NREL study vary significantly, with the cost per study ranging from $23,000 to $19.7 million, with a median of $306,000 [26]. A similar study performed by Sandia National Laboratories (SNL) analyzed 100 Small Generator Interconnection Procedure (SGIP) studies from three western utilities and PJM and found adverse system impacts in 56% of the projects that required distribution system upgrades [55].

To provide a basis for comparing the cost of distribution system upgrades to mitigate various distribution system impacts, the upgrade costs from the NREL study in [26] and the SNL study in [55] are referenced. To mitigate thermal impacts where a utility asset such as a conductor or transformer is loaded beyond its thermal limit, some of the measures include reconductoring the affected feeder segment and upgrading the LVRs, distribution and substation transformers, and other affected utility assets [26], [54], [55]. Mitigation costs for thermal impacts ranged from $20,000 to $2,415,100 [55]. Thermal impacts were the most expensive to mitigate, with the average system upgrade costing around $1.2 million per project [26]. To mitigate the impacts of DERs on the utility's protection strategy, measures adopted by utilities include adjusting protection relay settings, equipment modifications, and installation of new equipment [10], [55]. New equipment may include relays with advanced protection functions, DTT, and low-latency communications links [26], [55]. The cost of utility measures to mitigate protection impacts varied significantly from $74,600 to $1,300,00, with a majority of the cost coming from implementing advanced protection relay functions to detect and trip on grid-side faults [55]. Measures adopted by utilities to mitigate voltage-related impacts include adjusting the settings of utility equipment, equipment modifications to account for bi-directional power flow, and installation of new equipment to regulate the feeder voltage profile [10], [55]. To minimize the number of LTC, LVR, and capacitor bank operations and avoid negative interactions with other connected equipment, utilities typically adjust the deadband and intentional delays in the control logic [10], [37]. To mitigate transient overvoltages during load-rejection and ground faults in feeders with a high penetration of solar PV, utilities have traditionally installed surge arresters and grounding banks [10], [18]–[20]. The cost of mitigation measures for voltage-related impacts ranged from $434,800 to $5 million [55].

The considerable uncertainty in distribution system upgrade costs presents a major barrier to interconnecting DERs and microgrids as it causes significant delays and increases the project's total cost.

2.1.2 Emerging Solutions

Utilities are increasingly pursuing cost-effective alternatives to traditional distribution system upgrades to mitigate the integration and operational issues with DERs and microgrids. Some of these emerging mitigation strategies include utilizing the advanced functions of smart inverters, installing energy storage for upgrade deferral, advocating for self-generation, and several non-wire alternatives [5], [14], [17].

2.1.2.1 Smart Inverters

Smart inverters with advanced functions listed in Table 2.1 and capable of two-way communications with the utility could mitigate many technical and operational challenges associated with high DER penetration [10], [33], [56]. By utilizing the active and reactive power control capabilities of smart inverters, utilities can potentially regulate the entire feeder voltage profile [5]. By providing grid-support functions and riding through system disturbances, DERs interfaced through smart inverters could also provide bulk power system benefits similar to large generators [5], [33]. Leveraging smart inverters to mitigate technical issues associated with high DER penetration can significantly minimize the cost to utilities and end-use customers.

Table 2.1: Smart inverter functions

Volt/VAR	Ramp-rate control	Voltage ride-through
Volt/Watt	Watt/VAR	Frequency ride-through
Frequency/Watt	Fixed power factor control	Real Power Smoothing

Smart inverters with autonomous local control functions are, to a certain extent, effective in resolving local issues but require a coordinated control platform to provide system-level benefits [5], [57]. However, there are several challenges with effectively integrating smart inverters. Preventing undesirable interactions with neighboring inverters and utility equipment requires complex tuning of smart inverter settings considering existing and planned inverters and utility equipment [57].

With most smart inverters being customer-owned, there are controllability concerns in providing the functionalities listed in Table 2.1 [57]. Additionally, communication latencies, cybersecurity concerns, and challenges with developing and adopting standardized communications protocols exist. Furthermore, the ever-evolving IEEE 1547 interconnection standards for DERs, which operate on 6-8 year cycles, impede the rapid innovation necessary to resolve the technical challenges as we move to a more renewable, distributed, and inverter-based power grid [58].

2.1.2.2 Energy Storage

With rapidly declining battery energy storage prices and incentives from states to integrate solar PV with batteries, the penetration of battery storage as a DER is steadily increasing [14]. Although a high penetration of DERs such as solar PV may impact distribution system operations, when coupled with battery storage that can charge and discharge, the combination presents an effective mitigation strategy to operational challenges compared with solar PV only. An integrated solar PV plus battery storage system with limited to no energy exports to the grid mitigates most distribution system violations without requiring distribution system upgrades [5]. However, energy export from these systems may be required when grid-support services are needed for grid reliability and resilience. While customer-sited solar PV plus storage systems may avoid the need for expensive distribution system upgrades, the reduced system load and energy sales may impact utility revenue.

Utilities are also considering installing utility-owned battery storage systems on the distribution system to defer large-scale and expensive distribution and transmission system upgrades that would otherwise be required [5]. For example, to resolve overloading of the substation transformer due to reverse power flow from downstream DERs during certain times of the day, it may be cost-effective to install a substation-sited battery storage system rather than performing an upgrade of the substation transformer. Furthermore, battery energy storage can be used for other use cases, such as resolving feeder unbalance issues, reducing distribution systems losses, and absorbing the variability of solar PV.

2.1.2.3 Distributed Energy Resource Management System

While smart inverters can autonomously respond to local measurements, a coordinated system-level control platform like distributed energy resource management system (DERMS) is required to address dynamic grid conditions and optimize system operation. DERMS is a software platform that provides an innovative approach to modeling, forecasting, optimizing, monitoring, and controlling various DERs [5], [59].

Some use cases for DERMS are listed in Table 2.2 [5], [59]. For instance, to achieve an optimized Volt/VAR strategy along a distribution feeder, DERMS can take measurements from multiple points of the system, control voltage regulation equipment, and provide set points to smart inverters. Furthermore, adopting a DERMS solution may be a cost-effective non-wires alternative if a proposed DER or group of DERs undergoing

Table 2.2: DERMS use cases

Aggregation and optimization of DERs
Load and DER output control
Managing DER setpoints, settings and constraints
Voltage management
DER output and load forecasting
Situational awareness
Increased reliability, resilience, and system utilization
Enabling distribution grid services and wholesale market participation

an interconnection study causes system violations only at certain times of the day, which can be avoided by sending dispatch commands through DERMS [59].

Although DERMS provides a promising approach to integrating DERs with the grid, several challenges must be addressed [17]. In order to optimize the operation of the entire distribution network, an accurate representation of the distribution system is required, including the location of customer DERs and utility assets. High network observability and low-latency, high-reliability communication links are needed to achieve a given control objective [17]. It can also be challenging to integrate, optimize, and coordinate millions of DERs at the system-level [17]. Furthermore, DERMS does not consider the fast interactions between DERs and the grid.

2.1.2.4 Grid-Edge Solutions

Smart inverters with active and reactive power support functions mainly provide local benefits and may fail to fully address system-level voltage impacts without a coordinated utility platform such as DERMS [5], [57]. Moreover, as smart inverters are typically customer-owned, the utility does not know where the next smart inverter will be installed [57]. While IEEE 1547-2018 specifies communication capabilities for smart inverters for utility control through platforms such as DERMS, a full-scale rollout could take several years. Furthermore, there are several challenges with DERMS presented in section 2.1.2.3.

As a near-term solution to mitigating voltage violations and allowing continued solar PV integration, utilities are deploying solutions on the grid-edge, such as D-STATCOMs and secondary VAR controllers in combination with customer-owned smart inverters [57], [60]. Utility-owned secondary VAR controllers installed on the secondary of distribution transformers have shown the ability to regulate feeder voltage [61] and improve the feeder solar PV hosting capacity while reducing the number of LTC tap operations [60].

2.1.2.5 Innovative Regulations and Service Agreements

To ensure the safe and reliable operation of the distribution system while managing the challenges of high DER penetration without limiting their rapid growth, electric utilities are starting to discontinue net-metering and encourage feed-in tariffs and self-generation/self-supply programs [5], [14], [54]. By limiting or avoiding grid exports, utilities can continue to allow DER interconnections with little to no system upgrades [5]. In some states, non-exporting systems undergo an expedited interconnection review process where certain technical screens are bypassed, allowing faster interconnection [54].

Utilities are also experimenting with flexible interconnection agreements where projects would be allowed to interconnect without system upgrades in exchange for the ability to curtail their output when necessary to prevent system violations [62]. A DERMS platform can be used to control DERs to mitigate system violations [59]. However, with DERMS, there are challenges with accurately representing the distribution system, location of DERs, and communication latencies. Although the traditional distribution system upgrade is avoided, there can be additional costs in deploying solutions such as DERMS to implement flexible interconnection agreements.

2.1.2.6 Feeder Hosting Capacity Analysis

As the penetration of DERs increases, utilities are beginning to use hosting capacity maps as a proactive approach to DER integration. Hosting capacity maps provide information on locations where DERs can be interconnected without negatively impacting the distribution system. Customers and project developers can use hosting capacity maps to make informed decisions on interconnecting DERs and potentially fast-track DER interconnection requests in locations with no existing interconnection challenges [5], [54].

Hosting capacity analysis can be combined with DER deployment and load forecast to preemptively upgrade the distribution system to increase the penetration of DERs rather than perform a system upgrade when triggered by an interconnection request [5]. However, the need for accurate system knowledge, such as feeder topology, location of DERs and utility equipment and their settings, and modeling capabilities that are not readily available to most utilities, makes this approach challenging [5], [10], [25]–[27], [29], [30].

2.1.3 Interconnection Studies

To integrate DERs and microgrids with the grid and ensure minimal impacts on grid operations and reliability, utilities put DER and microgrid interconnection requests through an interconnection approval process to identify and address the potential impacts of the proposed installation on the distribution system. Depending on the size and complexity of the proposed system, the utility conducts a series of technical screens to evaluate its potential impacts on the distribution system. If any negative system impacts are detected during the screening process, the utility identifies strategies for mitigating them. Mitigation strategies include redesigning and downsizing the DER and microgrid, changing system configuration and equipment settings, and upgrading the distribution system [5]. If the proposed installation triggers distribution system upgrades, the individual customer/developer, and in some cases, a cluster of projects already in the interconnection queue and benefitting from the distribution system upgrades, are responsible for the cost of the upgrades [54]. Several utilities are also experimenting with innovative cost-allocation mechanisms to ensure fair allocation of capital costs by charging future projects that benefit from the system upgrades and reimbursing the redistributed cost difference to developers initially charged for the system upgrades [54].

2.1.3.1 Interconnection Approval Process

Once a utility receives an interconnection request for a proposed DER or microgrid, it goes through an interconnection process consisting of a series of steps, as shown in Figure 2.2 [5]. The proposed system initially goes through 10 FERC-recommended fast-track

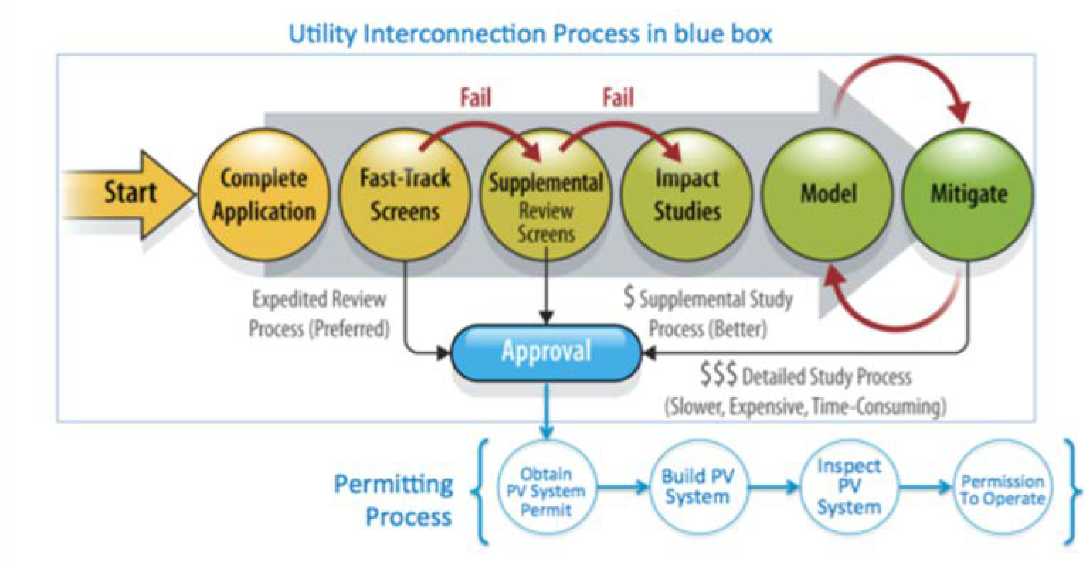


Figure 2.2: Typical utility interconnection process [5]

static technical screens, as shown in Figure 2.3 [5], [26]. Most small DERs and non-exporting systems usually pass the fast-track screens resulting in expedited approval and reduced overall installation and interconnection costs. If an interconnection application fails any fast-track screen, it goes through a supplemental review screening process to determine whether the interconnection can be approved without a detailed impact study. The supplemental review process screens for potential power quality concerns, risk of unintentional islanding, voltage violations, and protection miscoordination and may include additional screens [5]. If any supplemental review screens fail, the interconnection application goes through a more complex, time-consuming, and expensive detailed system impact study process.

System impact studies involve detailed modeling and simulations of the advanced DER protection and control functions and the distribution system to study the impact of the proposed system on grid operations. Large DERs and microgrids, owing to their size

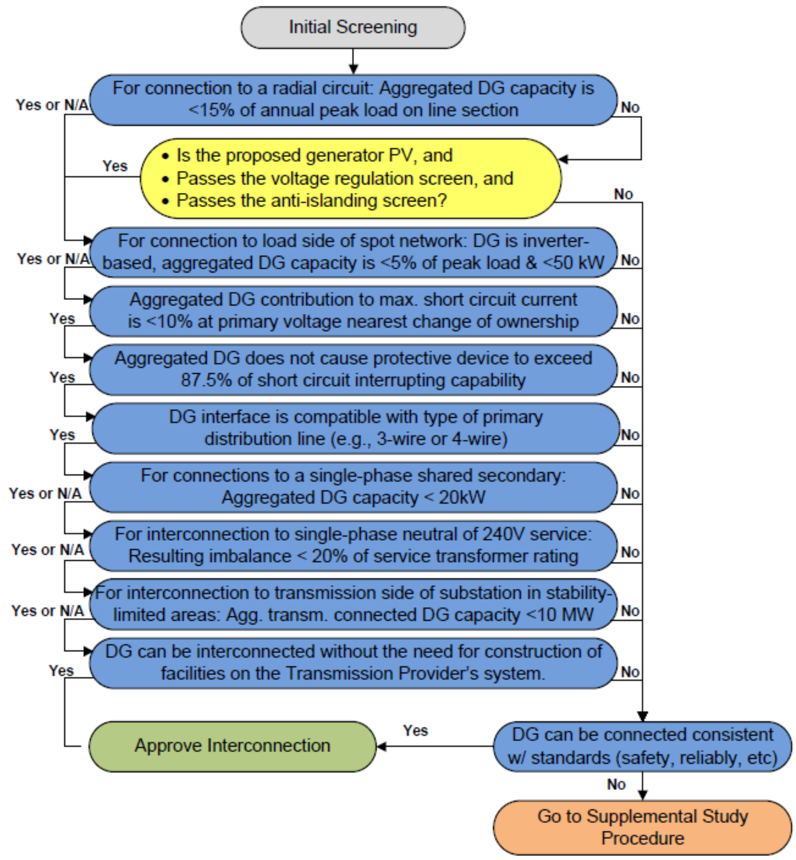


Figure 2.3: FERC fast-track screens [5]

and complexity, almost always go through detailed system impact studies resulting in long interconnection timelines as it requires advanced engineering analysis to identify and address potential system impacts [25]. At this stage, the utility may recommend changes to the proposed system and mitigation measures through distribution system upgrades to allow the proposed system to interconnect.

In addition to the application fee, customers requesting interconnection are also responsible for the cost of supplemental screening and detailed impact studies during the interconnection review process. The high-cost uncertainty of these additional studies and uncertain timelines affect the economic feasibility and viability of the proposed system [54].

2.1.3.2 Challenges with Interconnection Studies

The FERC-recommended fast-track screens in Figure 2.3 were initially designed to streamline the interconnection of small DERs that are unlikely to cause grid impacts. The limits were designed for low-penetration cases and to screen for the potential for unintentional islanding, voltage control issues, and protection miscoordination. However, as the penetration of DERs, mainly solar PV, increases, it is very likely that most interconnection requests will fail the current fast-track screens and require additional review unless revised. For instance, in states with high solar PV penetration, such as California, the capacity penetration fast-track screen that identifies situations where the aggregate DER capacity on a line section exceeds 15% of the annual peak load is the leading cause of flagging interconnection requests for further review [27]. Furthermore, accurately determining the limits in fast-track screens requires extensive distribution system modeling and simulations to know the prevailing grid conditions and possible system impacts. This is a cause of concern as many utilities have limited distribution system information [5].

Microgrids and large complex DER installations often go through costly, onerous, and time-consuming detailed impact studies that may involve power flow, electromagnetic transient (EMT), short-circuit, and stability analysis [54]. Detailed impact studies require advanced skill sets and resources unavailable at most utilities [25]. Performing transient and dynamic impact studies to assess system impacts with a microgrid interconnection request requires detailed EMT modeling of the advanced DER controls and higher-level supervisory controls (e.g., central microgrid controller). With microgrids being a system of systems, it is very challenging to fully capture their emergent behavior with the simulation tools and modeling practices widely used by utilities today [31]. Moreover, the highly customized nature of most microgrids requires a case-by-case detailed impact analysis that significantly slows down the interconnection approval process and does not guarantee compliance with the interconnection rules [25], [31].

Even with modular microgrids that benefit from standardized designs, models, and lower costs, detailed impact studies are required by utilities to study their impact on grid operations. Limited information sharing between utilities and microgrid vendors reduces the fidelity of system impact studies as most vendors do not share the proprietary models and controls with utilities [24], [25]. Instead, vendors more often share representative models developed by third parties based on test results provided by the vendors. This approach masks the DER proprietary controls but may not fully represent the actual DER behavior at the time scales of interest. In general, the models are very challenging to develop because there can be significant differences between manufacturers in terms of the design (single-, split-, and three-phase inverters), control (grid-following, grid-forming), and the type of sources (solar PV, energy storage, etc.).

Furthermore, the ever-evolving interconnection standards (IEEE 1547, IEEE 2030.7, etc.) that operate on a 6-8 year life cycle pose additional challenges in integrating DERs and microgrids with the grid. Lengthy standards development and adoption timelines inhibit the deployment of advancements in DER and microgrid technologies moving in a 1-2 year cycle necessary to integrate significantly growing penetration of renewables with the grid reliably.

2.2 Distribution System Restoration and Resilience

Extreme weather events, such as hurricanes Sandy in New York, Maria in Puerto Rico, and Harvey in Texas, caused extensive and sustained service interruptions and massive destruction of power delivery infrastructure that took several months to restore. In California, the threat of wildfires caused by utility equipment under dry and windy conditions has prompted local electric utilities (Pacific Gas and Electric, Southern California Edison, and San Diego Gas and Electric) to preemptively initiate Public Safety Power Shutoffs (PSPS) where utility power lines and other equipment are intentionally de-energized to prevent them from sparking fires [63], [64]. PSPS events have resulted in rolling blackouts lasting several days and leaving millions of people without electricity [64]. Most recently, severe cold weather conditions in Texas caused generators in the bulk power system to trip offline, triggering statewide blackouts with uncertain restoration timelines [65]. In all the above cases, unless equipped with standby generators and/or battery energy storage, all end-use customers, including those with only standalone solar PV panels, were without power. Most solar PV inverters are typically controlled and operated in the grid-following mode, requiring electric utility service to operate [64], [66].

The existing centralized, top-down grid architecture and operating practices make achieving resilience very challenging. Such an architecture where the transmission network is the backbone for power delivery to end-use consumers will not adequately ensure reliability and resilience when an increasing fraction of generation sources are on the distribution system (i.e., DERs). While transmission networks are meshed/networked and can reliably handle N-1 contingencies, most distribution systems are radial in design with a single substation feed and consist of overhead distribution lines, making them more fragile and vulnerable to outages [66], [67]. In power systems, reliability is defined by the adequacy of generation capacity to meet the loads with minimum load-shedding and the ability of the bulk power system to withstand sudden disturbances without adversely impacting the system [66]. On the other hand, resilience is defined as the ability to prepare for and avoid outages, reduce the duration and severity of outages, and restore as much load as possible in the shortest time [66]. Designing distribution systems for improved resilience through targeted capital upgrades such as underground power distribution, stronger utility poles, automatic reclosers, sensors, and communications for improved situational awareness can only address specific issues [66], [67]. However, these measures alone may not be cost-effective approaches to improving resilience at scale [66]–[70].

While the increasing penetration of DERs on the distribution system may cause grid integration and operational challenges, they also present significant potential opportunities. DERs can provide backup power to local loads when the larger grid is unavailable and improve the reliability and resilience of the power system by forming microgrids in the distribution system and participating in black-start and service restoration procedures [66]–[75]. Although DERs can provide these functions, challenges in integrating DERs with distribution system operations present a barrier when considering communications, control, coordination, safety, protection, existing policies, and regulations [66]–[74]. On the other hand, microgrids present an incredible opportunity to cost-effectively integrate DERs to provide local and distribution system-level flexibility, reliability, and resilience benefits [64], [66]–[75].

The following sections present a review of the current distribution system restoration practices and existing work in using DERs, microgrids, and microgrid clusters (also known as networked microgrids) for distribution system service restoration and enhancing the reliability and resilience of distribution systems. Finally, a summary of the limitations of existing approaches is presented.

2.2.1 Current Distribution System Restoration Practices

In modern economies with increased living standards, the need for continuity of high-quality electricity service is higher than ever. For fast fault isolation and reduced service interruptions, utilities are deploying advanced metering infrastructure (AMI), outage management systems (OMS), fault location, isolation, and service restoration (FLISR) systems, and more sensors to promote visibility into distribution systems and support the restoration process to improve reliability and resilience [66], [67], [71], [73].

Following a power outage on the distribution system, the utility receives outage notifications or failed ping messages from the smart meters of affected customers and utility sensors and may also receive phone calls from customers experiencing outages. The FLISR system may automatically attempt to re-route power to the outage area by operating switches and reclosers to reconfigure the network (i.e., network configuration) and transfer the healthy portion of the outage area to a healthy, energized feeder. The improved system visibility with smart meters (with AMI) and distribution automation helps the utility define and locate the outage area and the fault and dispatch crew for repairs and service restoration [66], [67]. Once the utility crew identifies and repairs the faulted section, the outage area is restored by transferring the feeder back to its normal network configuration.

Distribution system restoration approaches have been extensively studied in the literature. In most approaches, distribution system restoration has been framed as a multi-objective, multi-constraint optimization problem focusing on network reconfiguration, optimal placement and switching operation strategies of remotely controlled switches, and prioritized load restoration [76]–[80]. Authors in [76] proposed network reconfiguration methodologies that combine optimization techniques with heuristic rules and fuzzy logic. In [77], a restoration methodology was proposed using multi-objective evolutionary algorithms to prioritize restoring critical customers by operating remotely controlled switches. In [78], a mixed-integer linear programming approach that includes variable and fixed time-step models to generate optimal switching sequences and the estimated restoration time is presented. The authors in [79] framed service restoration as a combinatorial optimization problem and compared the performance of heuristic algorithms. Other approaches for distribution system restoration include dynamic programming [80], multi-agent systems [81], [82], and expert systems [83]. In addition to the distribution system restoration approaches mentioned above, during PSPS events seen in California and extreme weather events where there is severe damage to transmission and distribution infrastructure, the deployment of mobile fossil-fuel generators and provisional lines have been proposed [84], [85].

Current utility practices for distribution system restoration do not leverage the use of DERs and their ability to form microgrids to reduce the magnitude, frequency, and duration of outages and expedite distribution system restoration due to several technical, regulatory, and financial barriers [66], [67], [73], [86].

2.2.2 DERs and Microgrids to Improve Distribution System Resilience

Today, in the event of grid outages, customers without backup generation and most customers with solar PV systems (and no battery storage) are without power until the utility service is restored [66], [67], [87]. Combining behind-the-meter solar PV with battery storage systems could provide individual customers with limited and short-term continuity of service during grid outages. However, to sustain long-duration outages, behind-the-meter solar PV plus battery storage systems for every customer can be cost-prohibitive. Although most behind-the-meter DERs have the potential to provide backup power for local individual customers, they lack the functionality to support external loads and larger communities on distribution feeders due to utility technical, operational, regulatory, and safety protocols and constraints [66], [67], [73], [87].

With the rapid growth of DERs, mainly solar PV and increasingly battery energy storage serving a significantly growing proportion of loads at the distribution level, they provide a cost-effective means for improving restoration and overall system resilience by reducing the frequency and duration of grid outages and rapidly restoring power to critical loads following outages. However, the small size and sheer number of DERs, and the lack of visibility, particularly in low-voltage secondary networks, can be challenging. The complexities in monitoring, controlling, and coordinating the operation of numerous DERs with the grid can overwhelm existing utility systems, including DMS and DERMS [66], [67], [73], [88]. Moreover, it can be very challenging for a conventional DMS or DERMS that is highly centralized to optimize and securely communicate with a large number of DERs under limited connectivity during outages [66], [88].

Microgrids with hierarchical monitoring, control, and coordination architectures provide a means to manage the rapidly increasing complexity of integrating DERs with the grid, especially in geographically dispersed settings, while meeting overall grid reliability and resilience needs [66], [67], [73], [88]. The U.S. Department of Energy defines a microgrid as "a group of interconnected loads and distributed energy resources within clearly defined electrical boundaries that acts as a single controllable entity with respect to the grid. A microgrid can connect and disconnect from the grid to enable it to operate in both grid-connected or island mode" [89]. By aggregating the control of multiple DERs and interacting with the utility as a single controllable entity, microgrids can simplify the integration of DERs with the grid [90]. The increasing frequency of extreme weather events has also spurred and renewed interest in microgrids at the customer, community, and utility levels [66]–[75], [87]–[90]. In addition to resilience, other key drivers for microgrids include improved reliability, demand charge reduction, improved power quality, energy arbitrage, fuel diversity, and greenhouse gas (GHG) reduction [66]–[75].

Microgrids can be used as local, community, and black-start resources to improve distribution system restoration and resilience [75]. During grid outages, a facility microgrid, as seen in hospitals, water treatment plants, military bases, and other critical facilities, can island/disconnect from the grid and supply all critical or end-use loads with local generation sources. In the event of widespread and extended grid outages due to severe weather events, a facility microgrid can operate as a community resource to pick up external loads in addition to its own loads by operating facility breakers and utility reclosers and switches [75]. For example, a microgrid at a university or military base could use its excess capacity and fuel reserves to serve critical loads such as hospitals and police stations outside its boundary [66], [67], [75]. With appropriate DER functionalities such as grid-forming control and utility upgrades, DERs and microgrids could become a valuable resource for utilities in their distribution and bulk power system black-start and service restoration plans [66], [67], [88]. In addition to supplying local critical loads during outages, DERs and microgrids can speed up the black-start and system recovery process by providing capacity to startup generators that require external cranking power.

Microgrid clusters, also known as networked microgrids, are a cluster of physically interconnected and functionally interoperable microgrids that have gained traction recently [70], [73], [88]. With access to more generation sources and higher load diversity compared to individual islanded microgrids, microgrid clusters provide a means to achieve an even higher level of grid reliability and resilience with flexibility in topology and operations [70], [88]. Depending on the operational and resilience objectives to be achieved with networked microgrids, different bandwidth and latency requirements for communication with the utility monitoring and control platforms, individual microgrids, and between microgrid assets will be required [71], [88]. In coordination with remotely controlled utility switches, reclosers, and neighboring individual microgrids, microgrid clusters can dynamically expand electrical boundaries and change network topologies to restore more customer loads, including those normally only served from the utility substation [88]. Commonwealth Edison (ComEd), the largest electric utility in Illinois, USA, is building one of the first microgrid clusters in the world [91]. The Bronzeville microgrid owned by ComEd will cluster with a campus microgrid owned by the Illinois Institute of Technology to provide service to several critical facilities and community centers, including a hospital and a police station, during outages [91].

Most of the existing work in using DERs and microgrids for distribution system restoration focuses on using various optimization approaches such as mixed-integer linear programming and steady-state (phasor-domain) simulations for the placement and operation of remotely controlled switches and DERs [68], [92], [93], scheduling of DERs [68], [94], optimal switching operations and sectionalization into microgrids [68], [72], [74], [92]–[97], load prioritization [72], [74], [77], [86], [98], finding alternate paths for fault isolation and load restoration [68], [72], [74], [97], forecasting of generation and load [72], [86], and energy management [72], [86], [98]. In most cases, system restoration using DERs and microgrids is formulated as a multi-objective multi-constraint optimization problem. The objective function consists of maximizing the restoration of critical loads and the total restored power and energy while minimizing the number of switching events, unserved load, duration of the outage, and total system losses subject to the constraints of the network, loads, and DERs [68], [72], [74], [76]–[78], [86], [92]–[95].

A majority of the approaches in the literature for distribution system restoration using DERs and microgrids utilize centralized decision-making based on steady-state simulations to operate network switches and reclosers, dispatch generation, and connect or disconnect loads. These centralized approaches require complete and timely knowledge of the distribution system, including the available generation capacity, the current status of network switches, reclosers, customer loads and their priority level, and extensive communications between the utility, DERs, and loads. However, during outages and resilience scenarios, the limited connectivity between the utility and DERs may severely impact distribution system restoration with these centralized approaches.

Compared to phasor-domain (RMS) modeling and simulations, there is limited work using transient analysis to study the technical issues associated with the black-start and service restoration of distribution feeders using DERs and microgrids [72], [74], [75], [99]–[103]. The unbalanced dynamics, inrush currents during energization of lines, transformers, and loads, cold load pickup, and limited generation capacity with respect to loads must be considered when using DERs and microgrids for the bottom-up black-start and service restoration of the distribution system [66], [67], [72]–[75], [87]–[90], [99]–[103]. Furthermore, it is critical to consider the potential stability issues, protection challenges, and transients during the synchronization and connection of DERs and microgrids with the grid and when forming microgrid clusters [66], [67], [72]–[75], [87]–[90], [99]–[103].

To minimize the inrush currents during the energization of lines and transformers, soft energization techniques where the supply voltage is gradually ramped up from zero instead of energizing at rated voltage have been proposed in [75], [99], [104]. The increased demand, better known as cold load pickup, when restoring loads following an extended outage can be significantly higher than the pre-outage level, making distribution system restoration with DERs and microgrids challenging [67], [88], [105]. In addition to the magnetizing inrush currents and motor starting transients, the significantly increased demand with cold load pickup is mainly due to the loss of diversity in loads, especially thermostatically controlled loads which may start simultaneously on restoring service after an extended outage [88]. Current utility practices for distribution system restoration manage the cold load pickup issues by sequentially energizing feeder segments using reclosers and sectionalizers to minimize the thermal loading of equipment. However, when considering islanded utility-scale microgrids, the maximum demand can be significantly higher than the available generation capacity. In that case, the load steps during the sequential energization and restoration process can be large enough to cause severe voltage and frequency transients and potentially the collapse of the microgrid [66], [99]–[101]. A significant contributor to this issue is that most loads running before the outage continue to stay connected and turned on during the outage and when the utility service is restored.

Under-frequency load-shedding (UFLS) has been widely used as an emergency operating measure to stabilize the balance between generation and load during large disturbances and the unexpected loss of generation by automatically disconnecting predetermined groups of loads if the frequency falls below pre-specified thresholds [106].

However, its use in distribution systems to manage the generation-to-load balance following the formation of a microgrid on the loss of the utility supply is very limited. In [107]–[110], load-shedding schemes based on under-frequency and rate-of-change-of-frequency (RoCoF) are proposed to balance loads with generation and stabilize the frequency when operating as a microgrid. UFLS was applied to an industrial microgrid in [111] and off-grid microgrids in [112]. In [113], grid-friendly appliance controllers are proposed to realize UFLS at the appliance level to provide bulk power system stability and frequency control benefits without disconnecting DERs. In [114], [115], grid-friendly appliance controllers are adapted to mitigate the transient and dynamic instabilities that may occur when performing switching operations to connect neighboring microgrids to form a microgrid cluster. Although these load-shedding techniques have been extensively studied in bulk power systems and islanded microgrids, there is very limited analysis in using under-frequency- and RoCoF-based load-shedding schemes for the black-start and service restoration of distribution feeders with DERs and microgrids. Moreover, several of the techniques proposed in the literature are centralized and require real-time load and generation data and knowledge of system topology and configuration, which can be challenging during resilience scenarios.

When interconnecting an islanded microgrid with the grid or another microgrid to form a microgrid cluster, they must be synchronized by minimizing the differences in voltage magnitude, phase angle, and frequency before connection. Interconnecting a microgrid with the grid or another microgrid without ensuring synchronization may result in high inrush currents, loss of dynamic stability and microgrid collapse, and potentially major damage to utility and microgrid equipment [102], [103], [114]. A significant amount of work has been done in the area of microgrids with a major emphasis on decentralized control using various forms of droop, stability issues, and energy markets [116]. Comparatively, there has been a lesser focus on microgrid transient interactions and strategies to synchronize and connect microgrids with the grid or another microgrid to form a microgrid cluster.

Most commercial microgrid solutions operate with centralized control and communicate with every DER in the microgrid [117]–[119]. To achieve seamless/bumpless/transient-free transitions between the islanded and grid-connected modes of operation, the microgrids either operate in or switch into the isochronous control mode to synchronize generation resources and to maintain phase angle, frequency, and voltage differences within utility-specified limits before reconnecting the microgrid with the grid [117]–[119]. This method of using a centralized microgrid controller and communicating with every DER works well in small localized microgrids. However, centralized control and real-time communication become challenging when considering large, geographically dispersed microgrids with numerous DERs, such as utility-scale microgrids and community microgrids. To avoid instabilities during synchronization, the communication latency between the central microgrid controller and DERs must be small [102]. With only droop-controlled inverters and without a central microgrid controller, it is possible to achieve near-seamless transitions in microgrids in some operating conditions [120]. However, when considering rotating machines as well, the resulting inrush current can be significant enough to result in the collapse of the microgrid and damage the rotating generators and switchgear [121], [122]. Moreover, cyberattacks on the central microgrid controller and false data injection into the synchronizing signal during the synchronization phase can potentially result in microgrid blackout and damage to equipment [123].

Several challenges exist with power electronics-based solutions proposed in the literature as well. Authors in [124] have proposed a utility interface (UI), a three-phase three-wire multi-stage inverter integrated with storage, connected across the step-down transformer feeding the microgrid to achieve seamless transitions. This approach requires the installation of storage specifically for the UI, which increases cost. Moreover, when the microgrid is islanded and the battery (or any storage device) is depleted, achieving a seamless transition to the grid-connected mode is not always possible. In [125], the authors have proposed using a unified power quality conditioner (UPQC) introduced in [126] but integrated with storage as a means for achieving seamless transitions. In addition to the challenges with storage mentioned above, the combination of series and shunt transformers and converters results in high cost, reliability issues, poor fault current management, and a lengthy repair/replacement time due to the customizations involved.

2.3 Summary

The current utility planning, control, operating, and protection practices were never designed to handle DERs and microgrids. Utilities and their interconnection processes are struggling to cope with the proliferation of DERs and microgrids. In addition to the ever-evolving interconnection standards and requirements, fundamental differences between DER manufacturers and utilities are complicating the power system transition. To manage the growing integration and operational issues with DERs and microgrids, utilities are evaluating many solutions ranging from deploying smart inverters with grid-support functions to DERMS with varying levels of success.

To identify and address the potential impacts of large DERs and microgrids on distribution system operations, utilities currently perform detailed interconnection impact studies that may involve power flow, EMT, short-circuit, and stability analysis. These studies require detailed models and advanced skill sets unavailable at most utilities, are time-consuming, costly, and do not guarantee compliance with the utility interconnection rules. Moreover, the uncertainties in the cost of the study, system upgrade costs, and deployment timelines can severely impact a project's viability.

To enable the rapid and widespread deployment and integration of DERs and microgrids to achieve deep decarbonization targets, we must move towards more forward-looking and proactive approaches to streamline the interconnection of DERs and microgrids with the grid. These approaches must aim to avoid lengthy and expensive detailed interconnection impact studies while managing DER and microgrid complexity and their risk of causing system violations and equipment damage. An approach is needed to allow utilities to integrate tomorrow's DERs and microgrids cost-effectively with the grid while continuing to fulfill their grid reliability and service quality obligations.

With the growing penetration of DERs and microgrids, there is an increasing interest in utilizing them to improve system-level reliability and resilience by participating in black-start and service restoration procedures. However, current utility practices for distribution system restoration do not leverage the use of DERs and their ability to form microgrids to reduce the magnitude, frequency, and duration of outages and expedite distribution system restoration. With the current rules and practices, DERs are expected to shut down or disconnect following outages and are only allowed to reconnect with the grid after the utility supply is restored.

Most of the approaches proposed in the literature for distribution system restoration using DERs and microgrids utilize centralized decision-making frameworks to operate network protection devices, dispatch generation, and control loads. These centralized approaches require accurate knowledge of systems status, including available generation capacity, the status of protection devices, customer loads and priority level, and extensive communications. The limited connectivity during outages can be challenging for these centralized approaches. Furthermore, extending the popular central microgrid controller approach to form microgrid clusters consisting of numerous geographically dispersed DERs can be challenging.

Instead of a complete loss of service following grid outages, DERs and microgrids must be leveraged to provide electric service to feeder loads until the utility supply is restored. Moreover, during grid outages, an approach is needed to prioritize supply to critical loads and provide non-critical loads with limited electric service. Furthermore, by configuring and operating the distribution system as an interconnected network of microgrids with bottom-up black-start and service restoration functions, the reliability and resilience of the distribution system can be significantly improved.

CHAPTER 3. IMPACT OF HIGH DER AND MICROGRID PENETRATION ON GRID OPERATIONS

The existing century-old centralized power system planning, operations, and control paradigm was never designed to handle DERs and microgrids on the distribution system. The main objective of power system planning and operations was to economically meet existing loads and plan for peak loads and load growth. The proliferation of DERs and microgrids can potentially cause several integration and operational issues in the distribution system, such as voltage violations, thermal violations, and protection miscoordination, while also affecting the bulk power system.

Fundamental issues separate inverter manufacturers and power systems planners and operators, further complicating the transition to a more renewable and inverter-dominated power system. For instance, most grid-connected three-phase inverters are designed and operated as three-leg balanced sources assuming stiff grid conditions to minimize the DC-link capacitance and total cost [4]. This has resulted in several issues, including feeder voltage violations [4]–[11], grounding challenges [18]–[20], overvoltages under line-to-ground faults [19]–[22], and instability of the phase-locked loop [23].

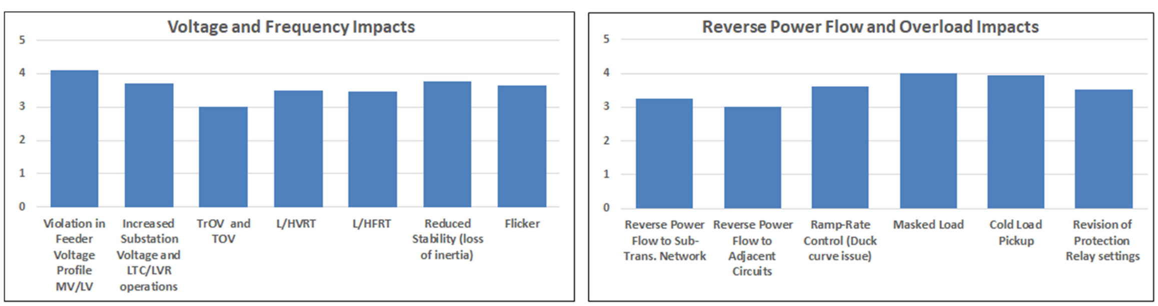
A large variation in the characteristics of DERs and the presence of multiple moving standards (IEEE 1547-2003, IEEE 1547a-2014, IEEE 1547-2018, Rule 21, SunSpec, etc.) further complicates the situation resulting in long interconnection study, integration, and testing times [5], [33], [54], [56]. The IEEE 1547 standard, which provides the technical interconnection and interoperability specifications and testing requirements for DERs interconnected with the grid, has undergone several revisions since its inception in 2003. IEEE 1547-2003 only specified the trip requirements for abnormal voltage and frequency conditions and did not mandate voltage and frequency ride-through or permit a DER to regulate the voltage [127]. With increasing DER penetration, an amendment was passed in 2014 through IEEE 1547a-2014 that specified voltage ride-through, frequency ride-through, and voltage regulation requirements [128]. Subsequently, in 2018, a full revision was released through IEEE 1547-2018 that specified active and reactive power support functions, detailed ride-through requirements, and interoperability requirements, among others [56]. However, even with the newest standard (i.e., "smart inverter" functions), several integration issues remain unresolved [5], [10], [11], [13], [33]. Moreover, with an increasing need to operate microgrids at the feeder level for resilience purposes, there is concern that today's DERs with stringent anti-islanding requirements may not be able to be integrated into such microgrids [51]. Furthermore, implementing retrofits on large DER installations and microgrids at the multi-GW scale to comply with ever-evolving standards is infeasible.

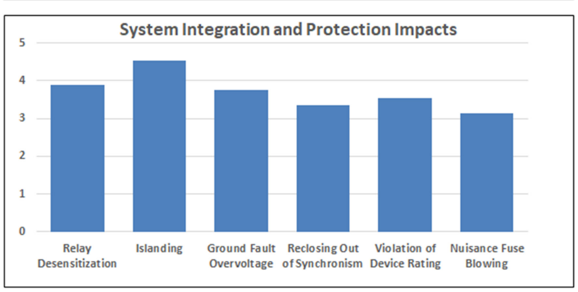
This chapter presents the major integration and operational challenges utilities face when integrating DERs and microgrids with the grid and their potential impacts on distribution system operations depending on the penetration level. Based on stakeholder inputs on the challenges related to the grid interconnection of DERs and microgrids, results from the modeling and simulations of two major unresolved issues: transient overvoltages during ground faults and reclosing out-of-synchronism are presented.

3.1 Utility Concerns and Inputs from Stakeholders

To identify the challenges and concerns related to the grid integration of DERs and microgrids, input was elicited from electric utilities and vendors through a project titled "Microgrid-to-Grid Interface Issues" funded by the National Electric Energy Testing, Research and Applications Center (NEETRAC) at Georgia Tech [129].

Figure 3.1, on a scale of 5, presents the curated utility concerns with the broad range of challenges associated with the impacts of high DER and microgrid penetration on grid operations. The challenges are categorized into system integration and protection impacts, voltage and frequency impacts, and reverse power flow and overload impacts. In the system integration and protection impacts category, unintentional islanding, relay desensitization, ground fault overvoltage, violation of utility device ratings, and reclosing out-of-synchronism (also known as out-of-phase reclosing) are the top 5 concerns. In the voltage and frequency impacts category, feeder voltage violations, reduced stability due to loss of





Major Impacts by Category

System Integration and Protection	Voltage and Frequency	Reverse Power Flow and Overload
Islanding	Voltage Violations	Masked Load
Relay Desensitization	Reduced Stability (Loss of inertia)	Cold Load Pickup
Ground Fault Overvoltage (Temporary overvoltage)	Increased LTC/LVR operations	Ramp-rate Control
Violation of Device Rating (fuse, ckt. breaker etc.)	Flicker	Revision of Relay Settings
Reclosing Out of Synchronism	L/HVRT, L/HFRT	Reverse Power Flow to Sub-Trans. Network

Figure 3.1: Major utility concerns with high DER and microgrid penetration

inertia, increased LTC and LVR operations, flicker, and L/HVRT and L/HFRT are the top 5 concerns. In the reverse power flow and overload impacts category, masked load, cold load pickup, ramp-rate control requirements, the need to revise protection relay settings and controls, and reverse power flow to the sub-transmission network are the top 5 concerns. Based on recent trends and utility challenges, these impacts continue to be of concern. Additionally, grid-forming control of DERs and the impacts of extensive electrification initiatives such as electric vehicles have gained attention [73].

There are several integration challenges raised by utilities in addition to the distribution system impacts with high DER and microgrid penetration. With respect to the interconnection process, there are concerns with the incomplete modeling of the distribution network, inaccurate impact studies, and the inability to model and study impacts such as unintentional islanding risks and ground fault overvoltage with current engineering tools used by utilities. The lack of advanced skill sets required for detailed interconnection analysis and resulting interconnection delays are significant concerns. Furthermore, utilities have expressed the need to ensure continuous interconnection compliance. Installing new DERs, such as solar PV inverters, battery energy storage, etc., within a microgrid may cause distribution system violations necessitating the need to perform interconnection studies again and, in some cases, recommissioning tests. Many respondents from utilities suggested automating and streamlining the interconnection review process and the requirement for standard protection devices such as reclosers to be installed at the point of interconnection (POI) for large DERs and microgrids for monitoring, protection, and control. Additional concerns raised by utilities when approving and interconnecting DERs and microgrids include the lack of a standardized DER-to-grid/microgrid-to-grid interface, protection challenges, lack of visibility and control over DERs, and microgrids, communication reliability issues, and integration challenges with the utility DMS. The complete results of the survey are presented in Appendix A.

While several system impacts in Figure 3.1 are known to utilities, the individual impacts and mitigation measures are usually studied in isolation from the rest of the system impacts and associated mitigation measures, which poses challenges in addressing them. Furthermore, there is limited information regarding the system impacts that utilities and project developers can expect with the rising penetration of DERs and microgrids in the distribution system.

3.2 Potential Grid Impacts with High DER and Microgrid Penetration

This section presents the potential impacts of high DER and microgrid penetration on grid operations. Most utilities face the same operational issues at low DER penetration levels, such as voltage violations, protection miscoordination, and reverse power flow in sections of the distribution system during periods of light loads and high DER output. At higher penetration levels, the potential network issues depend on the feeder configuration, such as the length of the feeder, the location of DERs and existing voltage control devices, and the type of customers on the feeder. Even the bulk power system (i.e., sub-transmission and transmission network) may be impacted at high DER penetration levels.

Figure 3.2 presents the potential impacts of high DER and microgrid penetration on grid operations at different penetration levels, along with a degree of severity. This

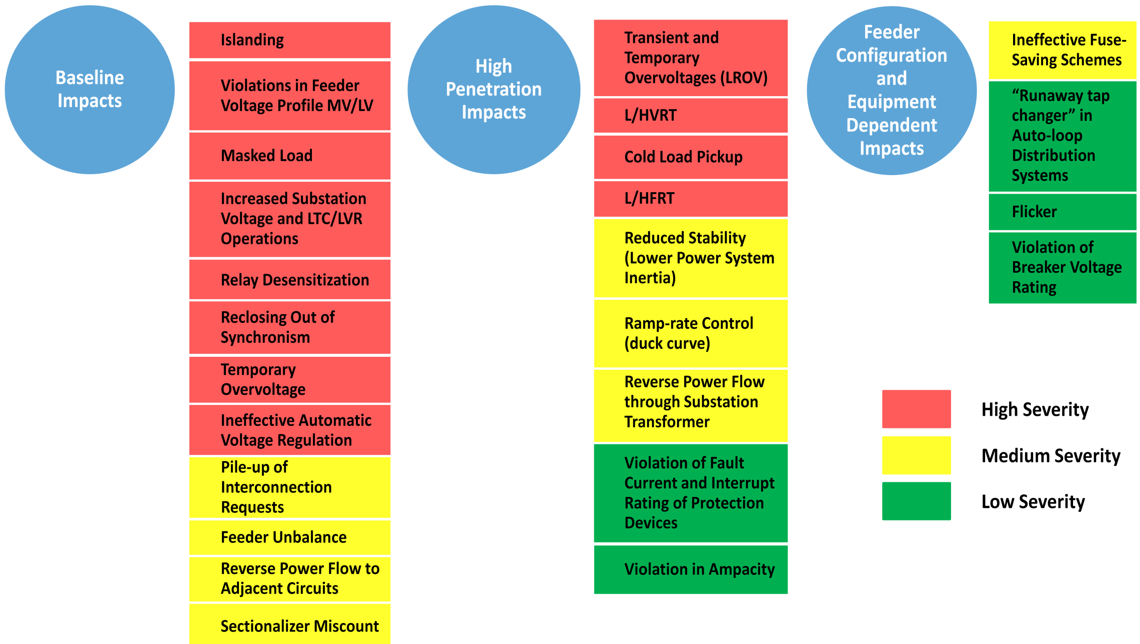


Figure 3.2: Potential impacts of high DER and microgrid penetration on grid operations

provides utilities with good guidance and understanding of the network issues expected at different DER and microgrid penetration levels. The grid impacts are classified into the following three categories:

1. Baseline Impacts: System issues that arise at low levels of DER penetration but intensify at higher levels. Addressing these issues from the start can enable utilities to manage increasing penetration levels better.

As the integration of DERs increases, the feeder loading pattern is altered, and the operation of the distribution system is affected. This may require modifications to the existing utility equipment to mitigate voltage, protection, and reverse power flow impacts even at low DER penetration levels. Mitigation measures to resolve voltage issues include revising settings such as voltage setpoints, control bandwidth, and time delays for LTCs, LVRs, and switched capacitor banks. Emerging strategies to resolve voltage issues include using smart inverters and grid-edge solutions in the form of secondary VAR controllers and D-STATCOMs. To mitigate protection challenges with the additional fault current contribution from DERs, modification of protection relay settings and replacement of utility protection devices such as fuses, reclosers, and circuit breakers may be required. To account for the reverse power flow with DERs, utilities may have to modify LTCs, LVRs, and other voltage regulation mechanisms to be bi-directional. Existing protection relays may also need to be modified or replaced to be bi-directional for proper protection.

2. High Penetration Impacts: System issues that become significant at higher penetration levels and may impact the sub-transmission and transmission network.

With increasing DER penetration levels, the potential baseline system impacts that mainly affect the distribution system may aggravate, with additional impacts seen in the bulk power system. In the distribution system, thermal (or ampacity) violations such as line overloading and violation of other utility equipment ratings may occur, requiring expensive upgrades such as reconductoring, replacing utility assets, and reconfiguring distribution feeders for phase balancing. Protection and relay coordination studies will become more complex at high DER penetration levels and with limited fault current contribution from inverter-based DERs. This will necessitate a move from purely current-based or voltage-based sensing and tripping to more advanced adaptive protection schemes employing both. To mitigate voltage-related impacts, smart inverter capabilities such as Volt/VAR, Volt/Watt, Watt/VAR, and fixed power factor control modes will need to be considered in concert with existing utility voltage regulation devices.

The transition from high penetration of conventional, synchronous generator-based resources to grid-following inverter-based resources with variable output may result in bulk power system issues such as reduced inertia, stability challenges, and ramp-rate constraints. To support bulk power system needs, ride-through capabilities such as L/HVRT and L/HFRT from smart inverters are essential. Furthermore, DERs with advanced grid-forming controls, fast-acting dispatchable sources, and load flexibility will be required for power system balancing and maintaining reliability and resilience.

3. Feeder Configuration and Equipment Dependent Impacts: System impacts that are greatly dependent on the network configuration, such as the length, voltage level, impedance, and phase configuration of the feeder. The type, location, and settings of voltage control devices, such as LTCs, LVRs, capacitor banks, etc., and other utility equipment, such as reclosers and sectionalizers, influence these impacts. Additionally, the size, location, and settings of installed DERs, and the size, location, and type of loads on the system also play a role.

The DER hosting capacity of a distribution feeder depends on several feeder and equipment characteristics, settings, and configurations. Some feeders may be capable of DER penetrations exceeding 100% of the feeder's peak load without any system impacts. On the other hand, some feeders may experience system impacts such as voltage violations and protection challenges even at penetration levels as low as 15% of the peak feeder load. With DERs, for a fault on a feeder lateral, the effectiveness of fuse-saving schemes wherein the feeder recloser upstream of the fault operates faster than the downstream lateral fuse is compromised. Fuse-saving schemes could fail when DERs downstream of the recloser continue to operate and provide fault current, potentially blowing the lateral fuse and causing a sustained outage instead of a momentary outage for customers downstream of the fuse. In feeder configurations, such as auto-loop distribution systems where the distribution feeder can be energized by multiple sources but one at a time, the reverse power flow from DERs can result in a runaway tap changer condition where the feeder LVRs may saturate, causing voltage violations. To prevent runway tap changer conditions in such situations, improved distribution system visibility and voltage control schemes are required to distinguish between power reversal due to DERs and auto-loop operation.

Table 3.1 summarizes the analysis of the impacts of high DER and microgrid penetration on grid operations emphasizing the causes and current solutions. In addition to the numerous operational challenges with high DER and microgrid penetration, as shown here, there are several additional grid integration and operational challenges with microgrids. Distribution utilities have minimal visibility into microgrids and their impacts on the distribution system. In many cases, the cost of installing a SCADA-connected remote terminal unit (RTU) or a power quality monitor outweighs the benefits [46]. The evolving specification and compliance targets (IEEE 2030.7-2017), testing procedures for microgrid controllers (IEEE 2030.8-2018), and still emerging protection considerations (IEEE P2030.12) further add to the complexities in integrating microgrids. The highly customized nature of microgrids makes central microgrid controller integration with the DMS complicated, time-consuming (over 6 months), and expensive [31]. Moreover, there are no guarantees on interconnection compliance.

Table 3.1: Analysis of the impacts of high DER and microgrid penetration on grid operations – A summary

Network Issue	Causes: Grid	Causes: Interface	Current Solutions (Used by utilities/vendors)
Ground Fault Overvoltage	High gen:load ratio in the feeder section, high proportion of delta-connected loads in a wye-grounded network under faults	Most PV inverters are 3 phase 3-leg, operated in the grid-feeding mode and don't produce zero seq. components	1) Grounding of interconnection transformer, grounding banks 2) Direct transfer trip **(Unresolved)**
Unintentional Islanding	Gen:load ratio =1 in the feeder section (both P, Q), high percentage of rotating machines (load+gen) in the feeder section	Active islanding detection techniques (widely used) don't work well at high DER penetrations and may not work against each other	1) Most inverters continue to use active islanding techniques 2) For large DERs and microgrids, many utilities mandate expensive direct transfer trip **(Unresolved at high DER penetration)**
Fault Current Management (Relay desensitization)	Fault currents from DERs (up to 1.5pu) can result in relay misoperation and in extreme cases, exceed the interrupt rating of the protective devices.	Requirement for L/HVRT support conflicts with relay desensitization	1) In most cases, utilities only rely on the inverters (conforming to IEEE 1547- which is a moving standard) 2) For large DERs and microgrids, some utilities mandate reverse power protection and expensive direct transfer trip **(Unresolved at high DER penetration)**
Violations in Feeder Voltage Profile	Utility voltage regulation equipment and control mechanisms are ineffective as they are centrally located and controlled	Legacy inverter-based DERs operate in the grid-following mode without voltage support (Volt/VAR, Volt/Watt)	1) Most utilities perform network upgrades (grid-edge solutions, install distribution STATCOMs, etc.) 2) Smart inverters with dynamic voltage support functionalities are a potential solution **(Several issues e.g. setting inverter parameters, the interaction between inverters, etc. are still unresolved)**
Reclosing Out-of-Synchronism (Out-of-Phase Reclosing)	If the DER/microgrid tries to reconnect out of synchronism, it will result in severe inrush, which can damage customer and utility equipment	Improper resynchronization, insufficient generation in the island to match voltage, frequency, and phase without load-shedding	1) Most utilities cannot monitor this issue in real-time but mandate proper resynchronization in the interconnection agreement 2) Most microgrids with a central controller match voltage, frequency, and phase prior to re-connecting **(Unresolved when considering microgrids with decentralized controls and dispersed microgrids)**
Low/High Voltage Ride Through (L/HVRT) Requirement	In high penetration scenarios, the tripping of a large number of DERs and microgrids for temporary faults can potentially affect power system stability.	Requirement for L/HVRT support conflicts with relay desensitization	1) Most legacy inverters cannot provide grid-support 2) Smart inverters are capable of grid-support 3) When the risk of power quality/ reliability issues is high, utilities install distribution STATCOMs **(Can be resolved)**

To cope with the ever-evolving standards and increasing instances of violations such as unintentional islanding, transient overvoltages, and protection miscoordination [5], [10], [21], [24], [31], [49], many utilities make it mandatory for microgrids and large DER installations to install DTT, and in some cases, a SCADA-connected power quality monitor [44]–[46], [48]. In addition to representing a high incremental cost for the project, these measures limit operational flexibility and benefits to the grid. Moreover, even with DTT, several network operational issues and violations cannot be mitigated or well managed [46].

While many distribution system impacts with the integration of high penetration of DERs, such as solar PV and microgrids, are well studied, there are several emerging impacts for which there is no clear consensus on the mitigation measures. The following sections examine two impacts through modeling and simulations: transient overvoltages during ground faults and reclosing out-of-synchronism.

3.2.1 Transient Overvoltages During Ground Faults

3.2.1.1 <u>Background</u>

Several utilities continue to express concerns over transient overvoltages during line-to-ground faults (also known as ground fault overvoltage) on distribution feeders with solar PV inverters [129]. Ground fault overvoltage (GFOV) may occur in situations where an ungrounded voltage source energizes a four-wire distribution circuit during a single line-to-ground (1LG) fault [18]–[21]. In such situations, the loads connected between the unfaulted phases and the neutral can be exposed to high transient overvoltage conditions, especially with a high generation-to-load ratio in the islanded section [19]–[21].

3.2.1.2 Mechanism

Figure 3.3, adapted from [10], shows the sequence of events leading to a GFOV event. Following a 1LG fault on Phase C (i.e., Phase C to ground fault) along the feeder, the upstream protection device, i.e., the utility circuit breaker, opens. When the utility breaker opens, the normally grounded feeder neutral becomes ungrounded, and the ungrounded PV inverter now energizes the islanded section. At this point, the faulted Phase C voltage drops to nearly zero, while the unfaulted Phase A and Phase B can see significant overvoltage. A solution currently being piloted by utilities is to install a wye-grounded-broken delta voltage transformer and monitor the 3V0 (i.e., zero-sequence) voltage with a 59N (neutral overvoltage) relay [10]. Under normal unfaulted conditions, the 3V0 voltage

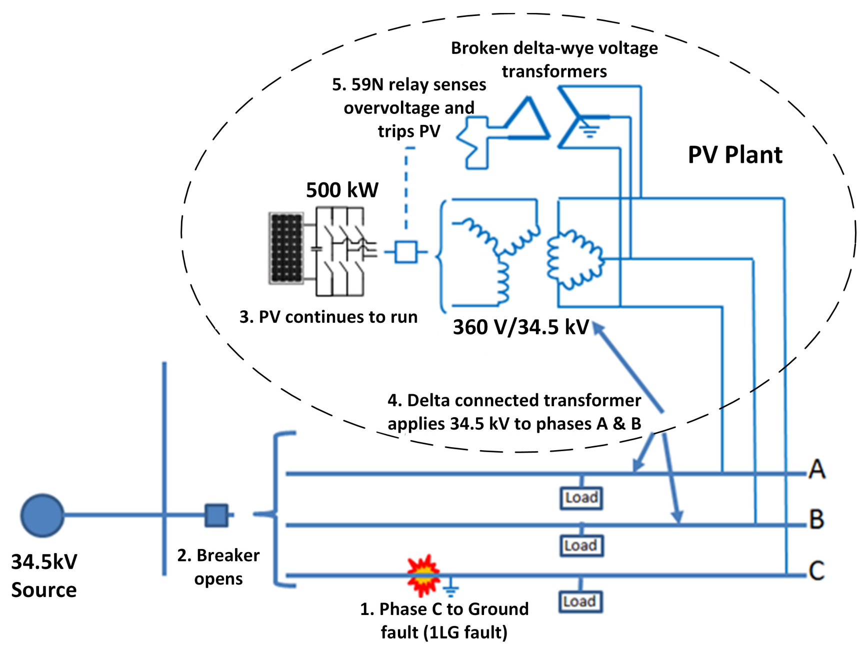


Figure 3.3: Sequence of events leading to a ground fault overvoltage event [10]

monitored by the 59N relay is very low. When a ground fault occurs, the 3V0 voltage increases significantly, and the 59N relay detects the fault and isolates the PV inverter. However, in the time between when the utility breaker opens, and the solar PV inverter is isolated, the loads on the unfaulted phases can be exposed to significant overvoltage. Furthermore, the requirement for sensing on the high-voltage side of the distribution transformer makes this solution very expensive and, in many cases, impacts the viability of the project [55].

Most three-phase grid-tied solar PV inverters are operated in the grid-following mode as power-regulated current-controlled voltage source inverters. They mainly produce positive-sequence components and very limited, if any, negative-sequence components and no zero-sequence components. This is because solar PV inverters are designed and operated as three-phase three-leg balanced sources to reduce the DC-link capacitance and minimize costs. The traditional GFOV mechanism of neutral-point voltage shifting observed in synchronous generators does not exist in inverters because, unlike synchronous generators, inverters do not inherently enforce a specific phase-to-neutral-point voltage relationship [19], [20].

Figure 3.4, adapted from [20], shows the simplified representation of a three-phase solar PV inverter as a balanced current-source supplying a balanced constant impedance load. The inverter filter impedance and the virtual impedances from the inverter control algorithm are represented by Z_{inv}. In Figure 3.4, other series impedances, such as line impedances usually present in reality, are not included, and the load impedance is assumed to be resistive. A bolted 1LG fault on Phase C (i.e., Phase C to ground fault) is applied. It

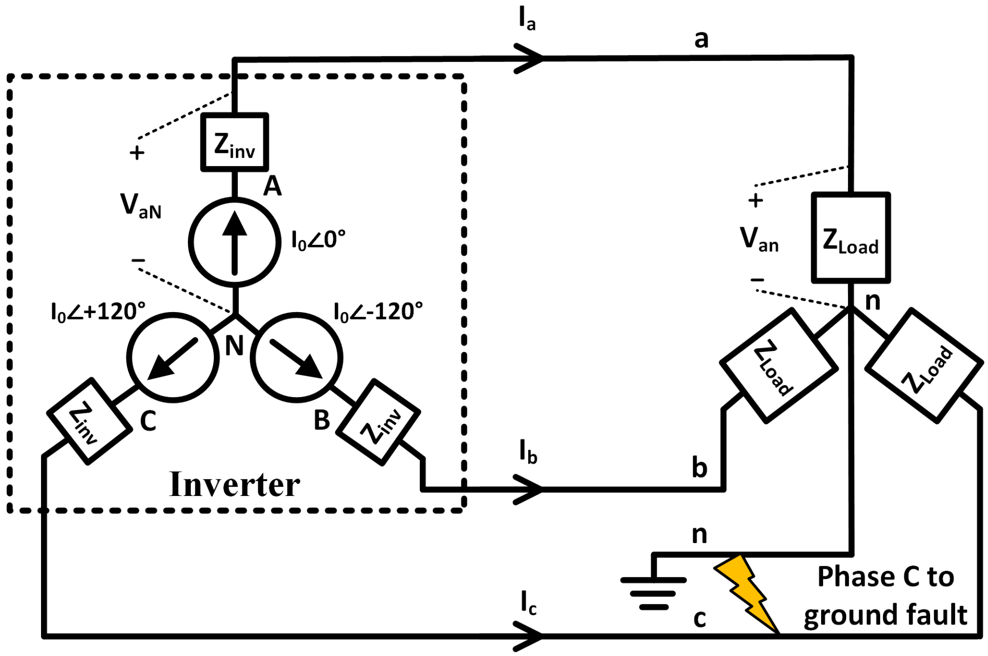


Figure 3.4: Inverter-based DER serving a load during a 1LG fault

is assumed that the upstream utility protection device has opened, isolating the circuit in Figure 3.4 with the Phase C to ground fault present.

As the inverter is operated as a current-controlled source, it continues to inject current during the fault. The line-to-ground voltages on the unfaulted Phase A and Phase B, and faulted Phase C are given in equations (3.1)–(3.3). These equations show that the voltages of the unfaulted phases depend on the inverter current output and the load. To simplify the analysis, it is assumed that the voltages of the unfaulted phases are equal, as shown in equation (3.4).

$$V_{an} = I_a Z_{Load} \tag{3.1}$$

$$V_{bn} = I_b Z_{Load} \tag{3.2}$$

$$V_{cn} = 0 \tag{3.3}$$

$$V = |V_{an}| = |V_{bn}| \tag{3.4}$$

Equation (3.5) is used to transform the phase-to-neutral voltages in (3.1)–(3.3) to symmetrical components, as shown in equations (3.6)–(3.10).

$$V_{120} = T^{-1} V_{abc} \tag{3.1}$$

where

$$V_{120} = \begin{bmatrix} V_1 \\ V_2 \\ V_0 \end{bmatrix}, V_{abc} = \begin{bmatrix} V_a \\ V_b \\ V_c \end{bmatrix}, T^{-1} = \frac{1}{3}\begin{bmatrix} 1 & a & a^2 \\ 1 & a^2 & a \\ 1 & 1 & 1 \end{bmatrix}, and\ a = e^{j120°}$$

$$\begin{bmatrix} V_1 \\ V_2 \\ V_0 \end{bmatrix} = \frac{1}{3}\begin{bmatrix} 1 & a & a^2 \\ 1 & a^2 & a \\ 1 & 1 & 1 \end{bmatrix} \begin{bmatrix} V\angle 0° \\ V\angle -120° \\ 0 \end{bmatrix} \tag{3.6}$$

$$\begin{bmatrix} V_1 \\ V_2 \\ V_0 \end{bmatrix} = \frac{1}{3}\begin{bmatrix} 2V\angle 0° \\ V\angle 60° \\ V\angle -60° \end{bmatrix} \tag{3.7}$$

$$V_1 = \frac{2}{3} V\angle 0° \tag{3.8}$$

$$V_2 = \frac{1}{3} V\angle 60° \tag{3.9}$$

$$V_0 = \frac{1}{3} V\angle -60° \tag{3.10}$$

From equations (3.8)–(3.10), during a 1LG fault, the positive-sequence voltage component reduces while the negative- and zero-sequence voltage components increase. The load unbalances, line impedances, and the DER interconnection transformer configuration not considered in Figure 3.4 will cause the resulting voltages to differ from equations (3.8)–(3.10).

Figure 3.5 shows the sequence network for the simplified system in Figure 3.4 during a 1LG fault. In Figure 3.5, the line impedance excluded from Figure 3.4 is included. As most solar PV inverters are designed and operated as three-phase three-leg sources without a neutral connection made available, the inverter zero-sequence impedance is high enough to be considered an open-circuit. The positive-sequence representation of the inverter consists of a current-source in parallel with an impedance ($Z_{inv,1}$). Since most solar PV inverters mainly produce positive-sequence current with very limited negative-sequence current, the negative-sequence impedance ($Z_{inv,2}$) of the inverter is generally very high [20]. As the response of the DER to faults depends on the physical and control implementation, which can vary widely between manufacturers, additional elements may be required to be added to Figure 3.5 for accurate representation. The DER interconnection transformer not considered in Figure 3.4 and Figure 3.5 can impact the zero-sequence continuity. For example, a Y (PV plant)-Yg (grid) or Y (PV plant)-Delta (grid) transformer configuration will not pass zero-sequence components between the primary and secondary sides of the transformer. Furthermore, with increased delta-connected loads characterized by infinite zero-sequence impedance, the impedance of the zero-sequence network in

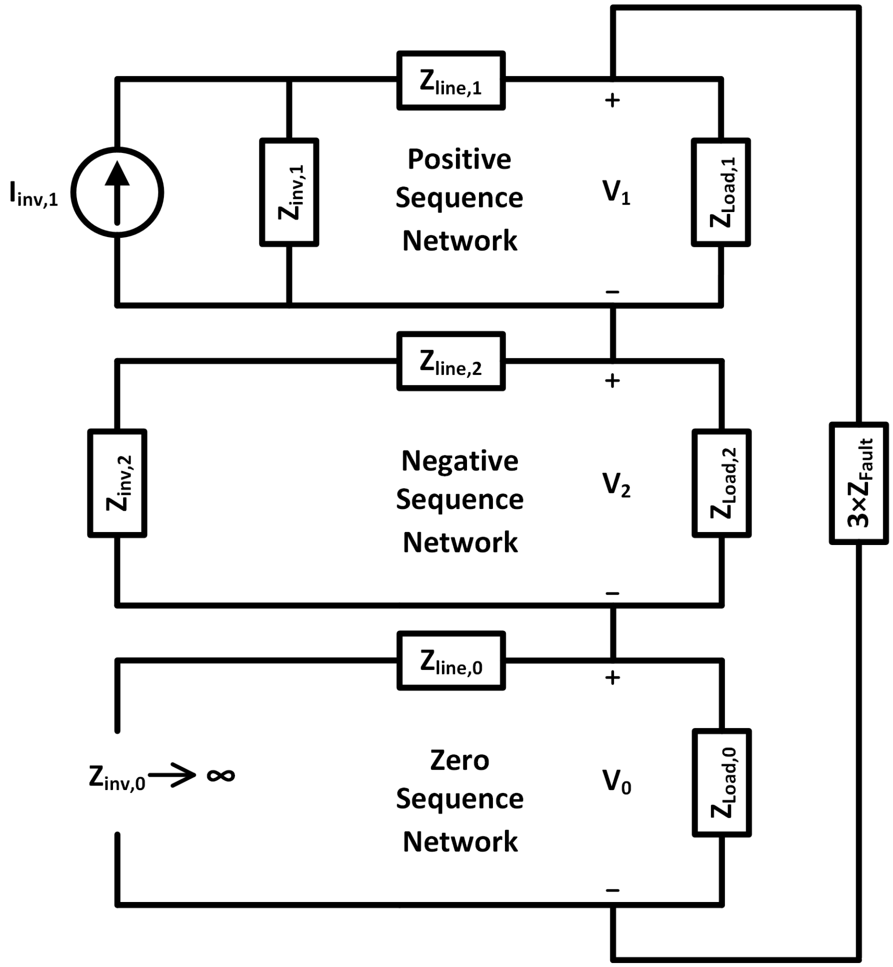


Figure 3.5: Sequence network with an inverter-based DER during a 1LG fault

Figure 3.5 effectively increases, resulting in higher overvoltages compared to the case with only Yg-connected loads.

The inverter control implementation significantly influences the response to faults and the consequent overvoltages. A typical three-phase grid-following inverter control implementation in the dq-frame, as shown in Figure 3.6, consists of an outer power control loop and an inner current control loop [138]. The active power control loop in a solar PV inverter tracks the maximum power point corresponding to the irradiance level and generates current references based on the grid voltage. The reactive power control loop, not considered in this discussion, tracks reactive power references to provide grid-support functions such as Volt/VAR. The inner current control loop regulates the current output by tracking the current references from the outer power control loop corresponding to the maximum power point. The inner current control loop typically runs much faster than the outer power control loop. During a 1LG fault, the voltage of the faulted phase drops, and as a result, the total inverter power output drops. However, the outer power control loop continues to track the pre-fault active power reference, and with the decreased d-axis voltage component (V_d), it produces an increased current reference. The current control loop now tracks the increased current reference limited by the maximum inverter output

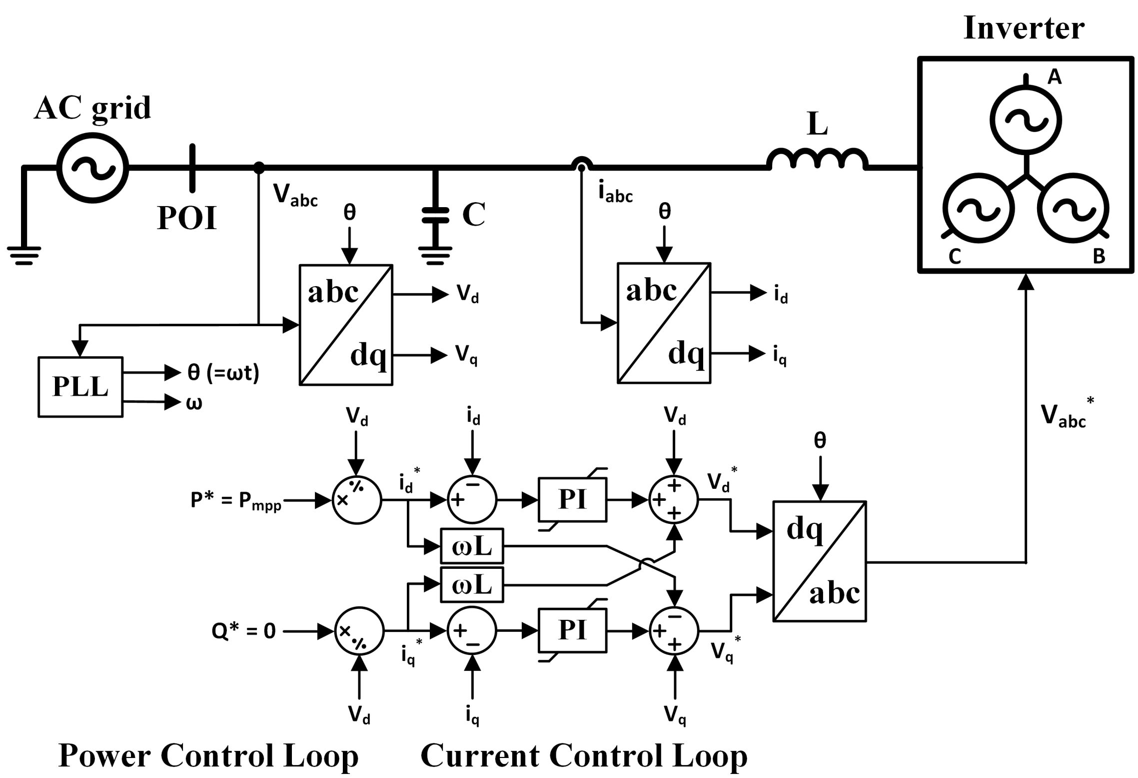


Figure 3.6: Control structure of grid-following solar PV inverter [138]

current, and as a result, the active power injection in the unfaulted phases increases. With increased active power injection in the unfaulted phases, overvoltages can occur in the unfaulted phases.

In reference to Figure 3.4, assuming that the balanced load is resistive and the output of the inverter is balanced with a generation-to-load ratio of 1 in the pre-fault scenario, equation (3.11) describes the relationship between the inverter output and the phase-to-ground voltages across the load. In equation (3.11), $P_{inv,phase}$ is the pre-fault per-phase active power output of the inverter, and Z_{Load} is the phase-to-ground impedance of the load. During the bolted 1LG fault on Phase C, V_{cn} drops to zero, and inverter control attempts to regulate the power output to the pre-fault level. The inverter pre-fault power output in faulted Phase C is transferred to the unfaulted phases causing overvoltages on the unfaulted phases as shown in equations (3.12)–(3.15). Assuming that the voltages of the unfaulted phases are equal (i.e., $|V_{an}|= |V_{bn}|$), from equation (3.15), the transfer of power from the faulted phase to the unfaulted phase causes the voltage of the unfaulted phases to increase to 122%. Furthermore, equations (3.11)–(3.15) also describe how the generation-to-load ratio impacts the magnitude of overvoltage during 1LG faults. With a higher generation-to-load ratio in the islanded section experiencing a 1LG fault, higher overvoltages in the unfaulted phases occur.

$$3 \times P_{inv,phase} = \frac{V_{an}^2}{Z_{Load}} + \frac{V_{bn}^2}{Z_{Load}} + \frac{V_{cn}^2}{Z_{Load}} \tag{3.11}$$

$$3 \times P_{inv,phase} = \frac{V_{an}^2}{Z_{Load}} + \frac{V_{bn}^2}{Z_{Load}} \tag{3.12}$$

$$3 \times P_{inv,phase} = 2 \times \frac{V_{an}^2}{Z_{Load}} \tag{3.13}$$

$$V_{an}^2 = \frac{3}{2} \times P_{inv,phase} \times Z_{Load} \tag{3.14}$$

$$V_{an} = V_{bn} = 1.224 \times \sqrt{P_{inv,phase} \times Z_{Load}} \tag{3.12}$$

3.2.1.3 Simulation Results

To study the potential for overvoltage with three-phase three-leg inverters, a four-wire 34.5 kV test circuit, shown in Figure 3.7 with the detailed switching model of a solar PV inverter, is simulated in MATLAB/Simulink. The solar PV inverter is modeled with the control structure in Figure 3.6 using the parameters in Table 3.2. A Phase C to ground fault (fault resistance = 2.5 ohm) is applied at location F1 along the feeder, and the resulting overvoltages are presented in Figure 3.8. Figure 3.8 shows that the unfaulted phases A and B along the feeder can reach overvoltages (measured at Point B) as high as 2 pu. As a result, the loads and utility equipment on the unfaulted phases can be damaged due to

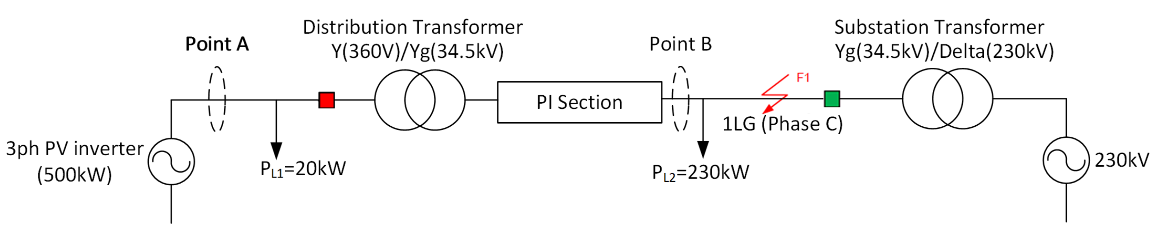


Figure 3.7: Test system for transient overvoltage during a 1LG fault

significant overvoltages. Furthermore, the overvoltages that occur with solar PV inverters or any other DER built and operated as a three-phase three-leg source can be attributed to the significant negative-sequence voltage and current components during the 1LG fault. Additionally, Figure 3.9 shows the dependence of transient overvoltage on the generation-to-load ratio and the type of loads. Higher overvoltages occur with a higher generation-to-load ratio and a higher proportion of delta-connected loads.

Table 3.2: Parameters of grid-following solar PV inverter for transient overvoltage study

Parameter	Value
Rating (kVA/kW)	500 kVA/500 kW
Nominal voltage (line-to-line)	360 V
L	1 mH
C	50 μF
P_{mpp}	500 kW
$k_{p,PI\_I\_control}$	1
$k_{i,PI\_I\_control}$	5
$k_{p,PLL}$	180
$k_{i,PLL}$	3200
$k_{d,PLL}$	1

The absence of zero-sequence components from the DER makes effective grounding on the DER side, currently an industry-standard practice, an ineffective overvoltage mitigation strategy. There is significant confusion among utilities and project developers regarding this practice. Many utilities continue to mandate effective grounding of the distribution transformer on the solar PV inverter side when approving interconnection requests, even though it provides little benefit in mitigating overvoltages during faults on the distribution system [19].

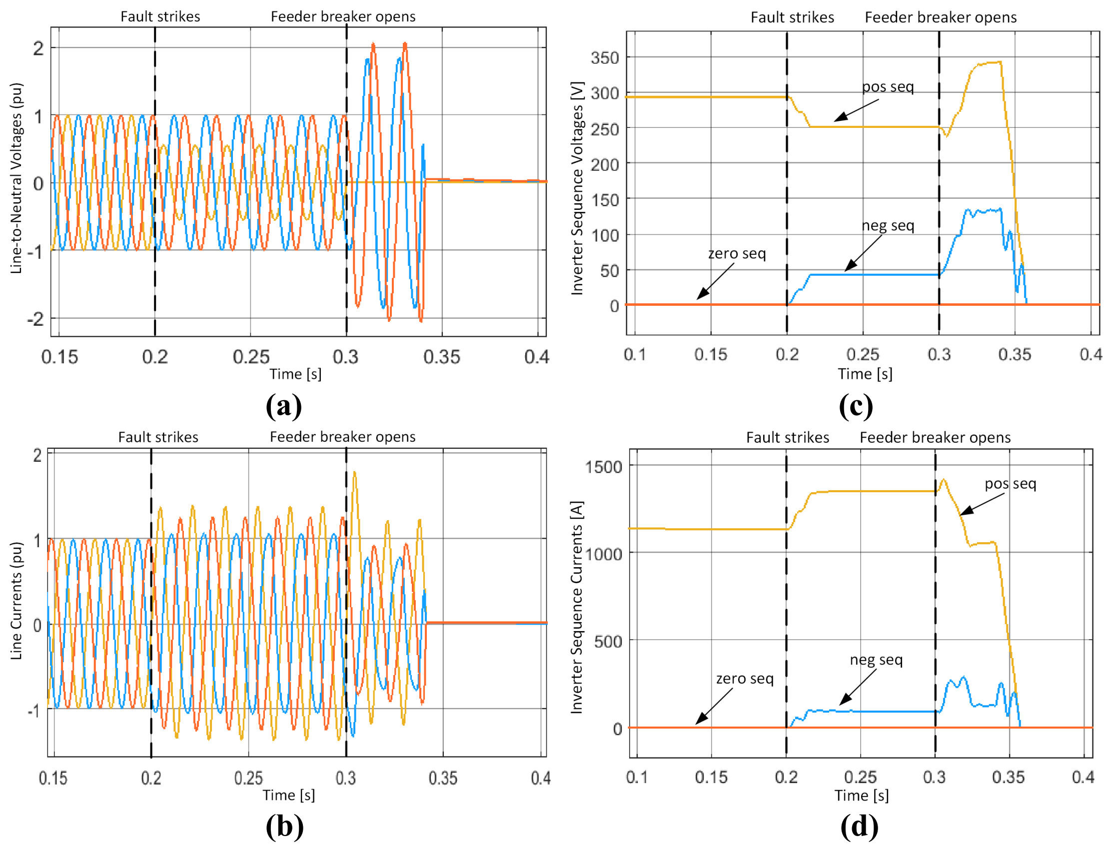


Figure 3.8: Transient overvoltage during 1LG faults (a) Feeder line-to-neutral voltages at Point B, (b) Feeder line currents at Point B, (c) Inverter sequence voltages at Point A, and (d) Inverter sequence currents at Point A

Although inverter-based DERs (in this case, solar PV inverters) do not have an inherent GFOV mechanism during 1LG faults, the following factors impact the magnitude of transient overvoltage following the opening of the substation breaker or upstream protection device [11], [20], [129]:

- Ratio of generation-to-load in the islanded section: From Figure 3.9, it is clear that higher overvoltages occur with a higher generation-to-load ratio in the islanded section. This mechanism is a major contributor to the overvoltages with inverter-based sources and has recently been referred to as load rejection overvoltage [22].

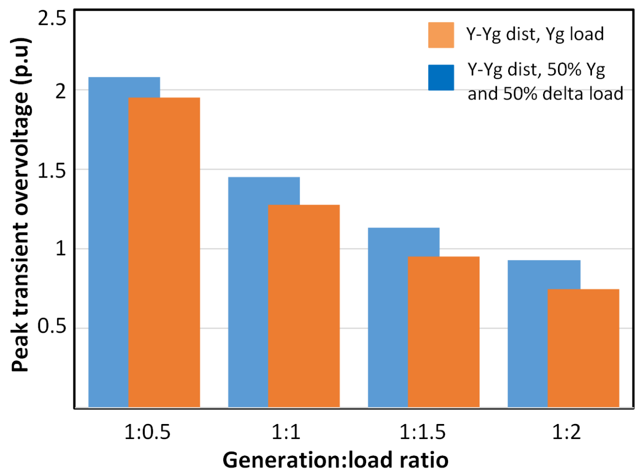


Figure 3.9: Dependence of transient overvoltage during 1LG faults on generation-to-load ratio

- Type of loads: High fractions of delta-connected load in a wye-grounded (Yg) circuit will increase overvoltages. Delta-connected loads have an infinite zero-sequence impedance, and as a result, the net zero-sequence impedance increases.
- Transformer configuration: Lower overvoltages occur with transformers that either source or provide a zero-sequence circulation path to the grid-side (e.g., Delta (PV plant)-Yg (grid), etc.).

Table 3.3 shows the dependence of overvoltage on the transformer configuration, with the delta (PV plant)-Yg (grid) transformer having the least potential for overvoltage among the applicable configurations. The legend '*' implies that the respective transformer configuration is not applicable as most three-phase solar PV inverters are built and operated in the three-phase three-leg configuration with the neutral either floating or not made available outside the inverter unit. To limit the fault current contribution of the delta (PV plant)-Yg (grid) transformer for faults on the grid-side and the amount of unbalance the

Table 3.3: Dependence of transient overvoltage during 1LG faults on transformer configuration

Transformer configuration (Primary [PV]-Secondary [Distr.])	Passes Zero-Seq. Current	Source of Zero-Seq. Current	Potential for Overvoltage
Y-Y	No	No	High
Y-Yg	No	No	High
Yg-Y	No	No	High*
Yg-Yg	Yes	No	Low*
Delta-Delta	No	No	High
Delta-Y	No	No	High
Y-Delta	No	No	High
Delta-Yg	No	Yes (to secondary side)	Medium (Best)
Yg-Delta	No	Yes (to primary side)	High*

transformer has to handle, a neutral grounding reactor can be used. With appropriately sized neutral grounding reactors, utilities can ensure a controlled transformer interface that sources zero-sequence current or provides a zero-sequence current circulation path. This allows utilities to continue integrating DERs and microgrids without excessive fault current contribution from the DERs, which can severely impact relay coordination schemes and necessitate protection relay coordination studies that add to interconnection approval costs and delays.

To mitigate the potential for transient overvoltages during 1LG faults with a solar PV inverter, the inverter negative-sequence voltage component with a trip setting of 22 V and a time delay of 16 ms is incorporated into the inverter protection logic. Figure 3.10

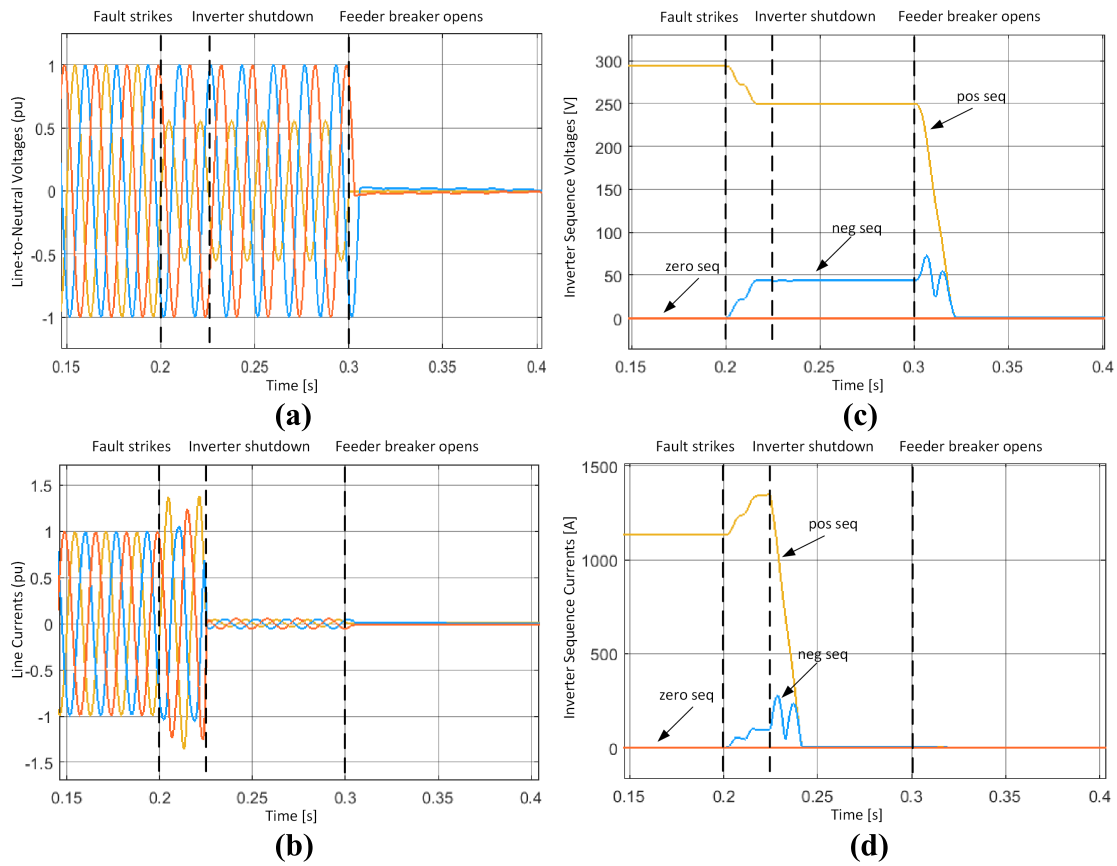


Figure 3.10: Mitigation of transient overvoltage during 1LG faults (a) Feeder line-to-neutral voltages at Point B, (b) Feeder line currents at Point B, (c) Inverter sequence voltages at Point A, and (d) Inverter sequence currents at Point A

shows the voltage and current components measured at Point A and Point B in the test circuit of Figure 3.7, but with the protection scheme incorporating the negative-sequence voltage component. From Figure 3.10, it is clear that the inverter shuts down even before the substation breaker opens. As a result, the loads on the circuit are not exposed to any overvoltage. As this protection logic can be implemented in the solar PV inverter or the facility's utility interconnection circuit breaker utilizing low-voltage measurements, there is no need for sensing on the high-voltage side of the distribution transformer.

3.2.2 Reclosing Out-of-Synchronism

3.2.2.1 Background

Modern distribution feeders use reclosers to isolate faults and limit customer service interruptions for temporary faults in the distribution system. Reclosers sense and interrupt fault currents and automatically restore service following a momentary outage through a sequence of trip and reclose operations. The initial reclose attempt can range from 0.2 s to 15 s following the first trip operation of the recloser on a fault [130]. If the fault clearing is unsuccessful in the initial reclose attempt, it is usually followed by more time-delayed attempts. If the reclose attempts exceed a preset number of operations, the fault is considered permanent, and the recloser locks open for fault clearing by the utility crew.

With most distribution feeders being radial and the substation being the primary power source in normal operations, reclose operations are generally performed without synchronism-check or voltage-check supervision between the upstream and downstream sections of the recloser [130]. But with the increasing penetration of DERs and their ability and need to form microgrids for reliability and resilience reasons, there are concerns with reclosing out-of-synchronism (also known as out-of-phase reclosing). After a recloser on a distribution feeder opens, the downstream DERs may form an island under certain conditions and continue supplying the loads. With the recloser opened, the islanded section downstream of the recloser energized by DERs will likely drift out-of-synchronism with the utility source. If the reclose attempts are performed when the upstream and islanded downstream sections are energized and out-of-synchronism, the resulting transients can potentially damage utility equipment, customer loads, and DERs [121].

IEEE 1547 mandates unintentional islanding detection for DERs and requires them to trip within 2 s to 5 s of forming an island [24], [56]. However, they can fail under certain operating conditions that fall under the non-detection zone of the implemented islanding detection algorithm [24]. For large DERs and microgrids where the risks and consequences of reclosing out-of-synchronism are very high, utilities use communications-based techniques such as DTT, where a trip signal is sent to the DER or microgrid when an upstream recloser or breaker trips. Although DTT has no non-detection zone, its dependence on low-latency communications raises reliability and economic feasibility concerns [46].

3.2.2.2 Simulation Results

To study the impact of reclosing out-of-synchronism on circuit breakers, transformers, and synchronous generators, the test system in Figure 3.11 is simulated in MATLAB/Simulink using the parameters in Table 3.4. The 2.4 kV, 2 MVA synchronous generator is modeled without the automatic voltage regulator (AVR) and governor controls as they may saturate and become unstable on reclosing out-of-synchronism. Instead, a fixed mechanical input power of 1 pu and field excitation of 1.6 pu is used.

Initially, the circuit breaker in the 2.4 kV feeder section is open, and the synchronous generator supplies the local load of 2 MW and 0.1 MVAR. At t = 30.822 s, the breaker is closed. The voltage across the Phase A circuit breaker contacts and the

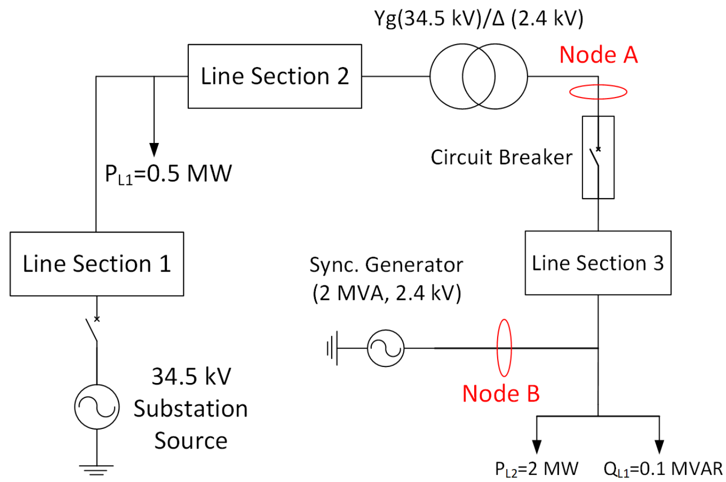


Figure 3.11: Test system for reclosing out-of-synchronism

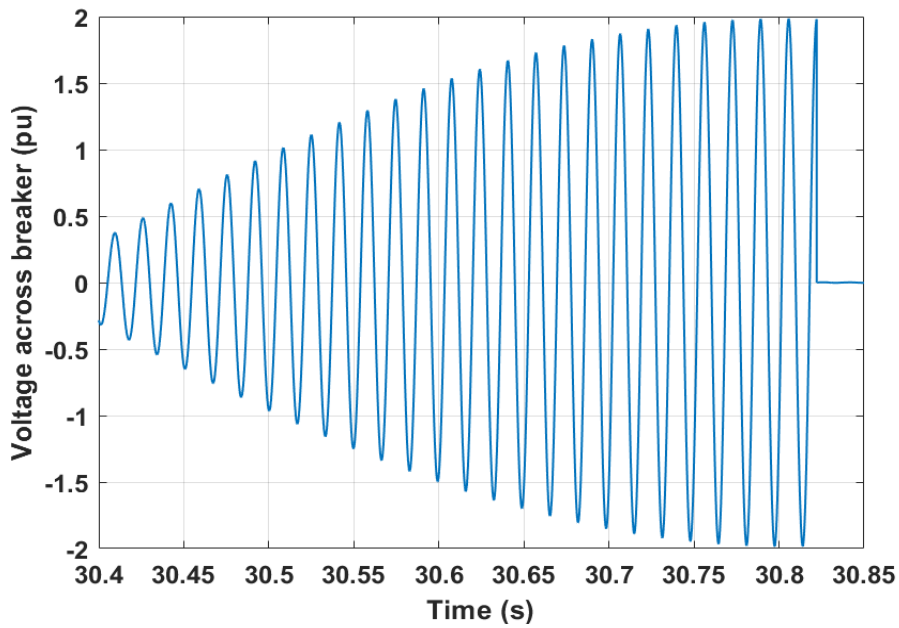
Table 3.4: System parameters for reclosing out-of-synchronism

Source	Parameter	Value
Grid	Nominal voltage	34.5 kV
	Short-circuit level	20 MVA
	X/R ratio	10
Generator	Rating	2 MVA
	Nominal voltage	2.4 kV
	Xd, Xd', Xd'' (pu)	1.56, 0.296, 0.177
	Xq, Xq'', Xl (pu)	1.06, 0.177, 0.052
	Td', Td'', Tqo'' (pu)	0.5, 0.05, 0.05
	H(s), F(pu), Pole pairs	0.35, 0.009, 2

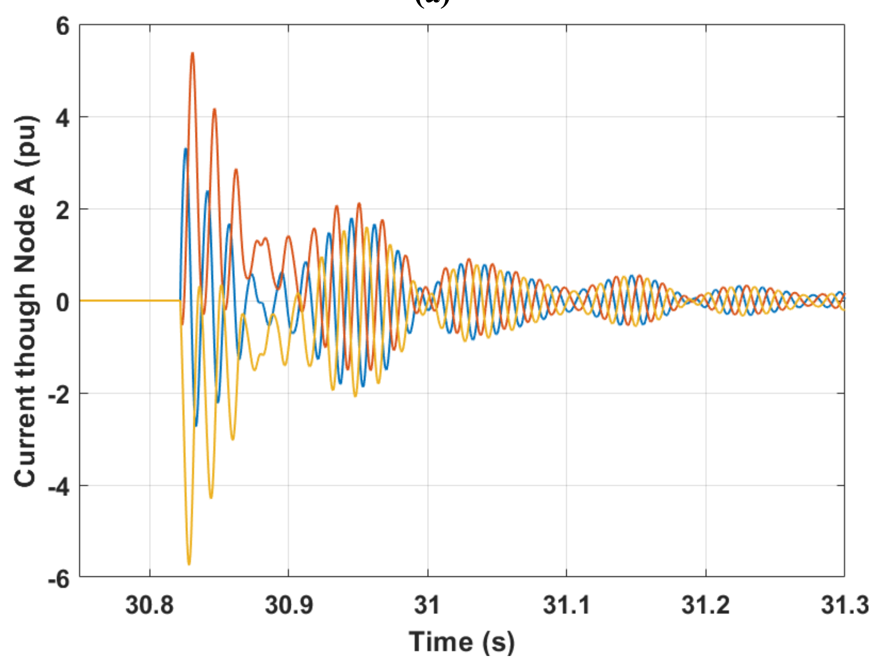
currents through the transformer and circuit breaker measured at Node A are shown in Figure 3.12. The circuit breaker is subjected to 2 pu voltage across the breaker contacts when the phase angle difference between the nominal voltage vectors on either side of the circuit breaker is 180 deg, as shown in equation (3.16). In (3.16), $V_{Node\ A}$ and $V_{Node\ B}$ are the voltages at Nodes A and B, respectively, and θ is the phase angle difference between them. The inrush current through the circuit breaker and transformer is 5.74 times the nominal current. The stator currents measured at Node B and the electromagnetic torque of the synchronous generator are shown in Figure 3.13. The synchronous generator stator currents reach 11.24 times the rated current, and the peak electromagnetic torque is 5.73 times the rated torque.

$$V_{Ckt\ Breaker} = \sqrt{|V_{Node\ A}|^2 + |V_{Node\ B}|^2 - 2|V_{Node\ A}||V_{Node\ B}|\cos\theta} \qquad (3.16)$$

While reclosing out-of-synchronism, except for overvoltages, has little to no damaging effects on inverter-based DERs and passive loads, its impact on transformers, circuit breakers, motors, and synchronous generators can be detrimental [121], [122]. The severe inrush current through transformers on reclosing out-of-synchronism produces magnetic forces that can displace conductors and cause winding deformation, thereby impacting the life of the transformer [121]. The high transient current and torque in motors and synchronous generators can produce torque reversals and damaging levels of mechanical stresses that may require complete replacement of the stator and rotor [122]. IEEE C37.04-2018, the standard for AC high-voltage circuit breakers, specifies a preferred out-of-synchronism switching current rating of 25% of the breaker's symmetrical short-circuit current rating [131]. When reclosing a line section with a high percentage of rotating machines downstream of the recloser at the instant the voltage difference between the circuit breaker contacts is maximum, the inrush current on reclosing out-of-synchronism may exceed the breaker's capacity [132].



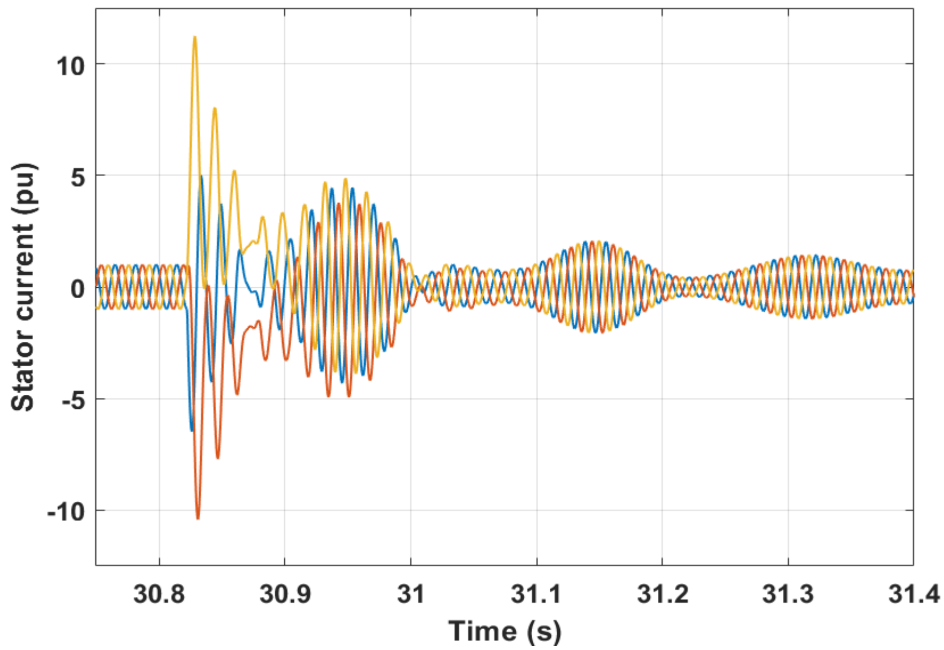
(a)



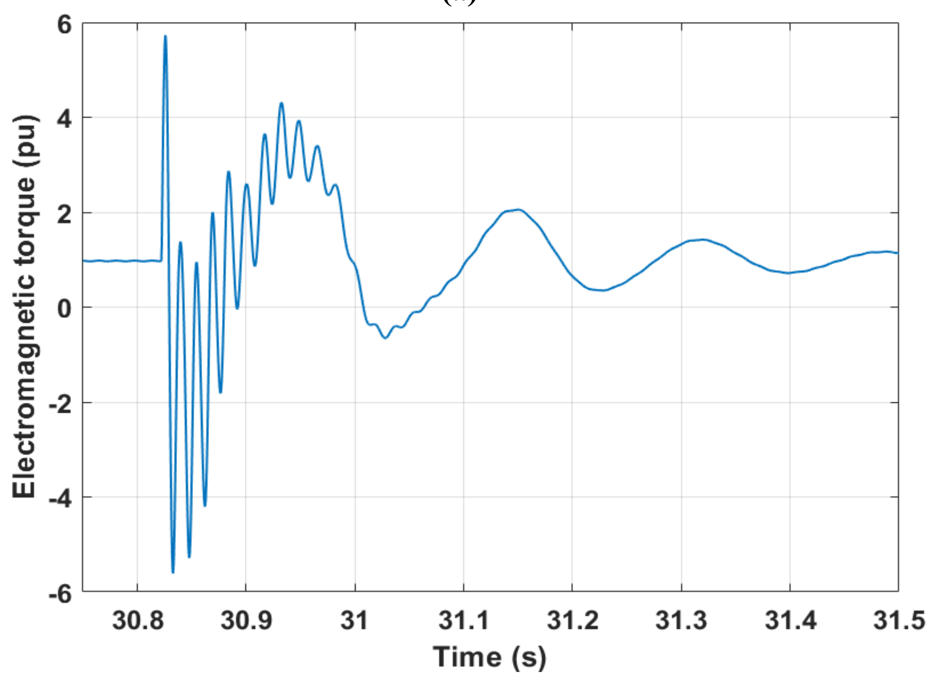
(b)

Figure 3.12: Impact of reclosing 180° out-of-synchronism on the circuit breaker and transformer (a) Voltage across the Phase A circuit breaker contacts, (b) Current through Node A

Medium-voltage circuit breakers can handle 2-2.5 pu voltage across them for as long as one minute [133]. However, when reclosing out-of-synchronism and under



(a)



(b)

Figure 3.13: Impact of reclosing 180° out-of-synchronism on the synchronous generator (a) Stator currents, (b) Electromagnetic torque

overvoltage conditions, as shown in section 3.2.1, the voltage across the breaker contacts can reach 3 pu and higher. This may result in dielectric breakdown and breaker flashover.

Most reclosers and circuit breakers are not tested under these conditions and must be considered by utilities and switchgear manufacturers for DER and microgrid applications.

To prevent reclosing out-of-synchronism, utilities are beginning to modify their protection and restoration practices by setting reclose times in harmony with IEEE 1547-2018 and incorporating reclose blocking where the reclose operation is delayed until after the voltage downstream of the recloser falls below 10% of the nominal [48]. By this point, most downstream DERs would have shut down [48]. While this approach may prevent equipment damage and adverse system disturbances, it results in service interruptions. The downstream section must be completely de-energized before being re-energized by the utility to restore the grid service. With an increasing need to operate utility-scale microgrids for resilience purposes, this approach of requiring the DERs to shut down before reconnection with the grid or another microgrid may be undesirable. Furthermore, in distribution systems frequently reconfigured through tie switches, coordinating feeder switching operations with DERs to prevent reclosing out-of-synchronism can be challenging.

Despite IEEE 1547-2018 compliant inverter functions and detailed interconnection impact studies, utilities are experiencing several distribution system violations. DER and microgrid integration and operational challenges coupled with the standards (IEEE 1547, 2030.7, 2030.8, 2800, etc.) being a work in progress and an ever-evolving target raises the following unanswered questions:

1) Which rules/standards apply on a given date?

2) What should be done with inverters complying with older interconnection standards?

3) How to ensure compliance with the ever-evolving standards? Do the standards solve the integration and interconnection issues?

4) Is the grid protected at a specific location?

5) How can a utility be sure that a large DER installation (e.g., utility-scale solar PV) or microgrid can connect/disconnect and operate without problems and not interfere with grid operations?

6) What tests are needed and who pays for them?

7) How can utilities, project developers, and owners simplify DER and microgrid interconnection and reduce integration time, cost, and risk?

8) Who should be accountable for operational violations and damages to the customer and utility equipment?

3.3 Summary and Contributions

There are several challenges with integrating DERs and microgrids with the distribution system. The increasing deployment of DERs and microgrids and the ever-evolving interconnection standards put utilities in a challenging position, meeting renewable portfolio standard requirements and, at the same time, ensuring safe, reliable, and resilient grid operation. Given that interconnection standards move slowly with a 6-8 years timeline for development and full-scale rollout, they may fall behind in solving the challenges of integrating DERs and microgrids with the grid and delay the transition to a sustainable, flexible, and resilient power grid.

This chapter presented the major integration and operational challenges utilities face when integrating DERs and microgrids with the grid and their potential impacts on distribution system operations. Two major distribution system impacts that are largely unresolved, transient overvoltages during grounds faults and reclosing out-of-synchronism, are studied are detail.

With the rapid evolution of the distribution system, it is imperative that solutions be developed to allow for the cost-effective and unhindered integration of DERs and microgrids. These approaches must guarantee compliance with the ever-evolving interconnection rules without requiring lengthy and expensive detailed impact studies.

CHAPTER 4. ISLAND INTERCONNECTION DEVICE – ENABLING A SIMPLIFIED APPROACH TO INTEGRATE MICROGRIDS WITH THE GRID

This chapter proposes a standardized grid interface called an Island Interconnection Device (IID) to provide a pathway to simplify the integration of DERs and microgrids with the grid by enforcing utility interconnection rules and enabling interconnection without requiring detailed system impact studies. The rules for interconnection, types of IIDs and their use cases, communication architecture, and the benefits of IIDs are presented, followed by simulation results demonstrating their efficacy in mitigating distribution system impacts for grid and microgrid events.

4.1 Concept

An Island Interconnection Device (IID) is proposed as a universal standardized utility-owned and utility-controlled DER-to-grid/microgrid-to-grid interface to simplify the grid integration of DERs and microgrids. It consists of a smart switch and, in some configurations, integrated with a power electronic converter and enforces the utility interconnection rules. The IID monitors and manages all the interconnection, power flow, protection, transient, and fault current issues between the utility grid and the microgrid. The IID also provides a standardized and secure communication interface between the utility or external entity and the local DER controller or central microgrid controller, thereby enabling interoperability. The IID could serve as a black-box to the microgrid owner/operator and ensure the integrity of the grid regardless of the topology, configuration, and control of the microgrid (assets) by disconnecting the microgrid when the utility interconnection rules are compromised. In addition to protecting the grid from microgrid-related disturbances, the IID can support the grid and microgrid and provide useful signals to microgrid elements such as the central microgrid controller for planned islanding, seamless reconnection, grid services, and market participation.

Figure 4.1 shows the typical implementation of an IID in a customer, community, or utility-scale microgrid and the proposed types of IIDs ranging from a smart circuit breaker to a fully-rated power electronic converter. In addition to enforcing the rules for interconnection set by the utility, the IIDs integrated with a power electronic converter can provide grid-support (L/HVRT, L/HFRT, etc.) and several ancillary services (Volt/VAR, harmonics mitigation, phase balancing, etc.). The standardized interface provides the utility with complete control over the IID and the microgrid. Integration with the utility's monitoring and control infrastructure allows power flow and quality monitoring, the ability to change thresholds, setpoints, and modify control algorithms/logic of the IID remotely.

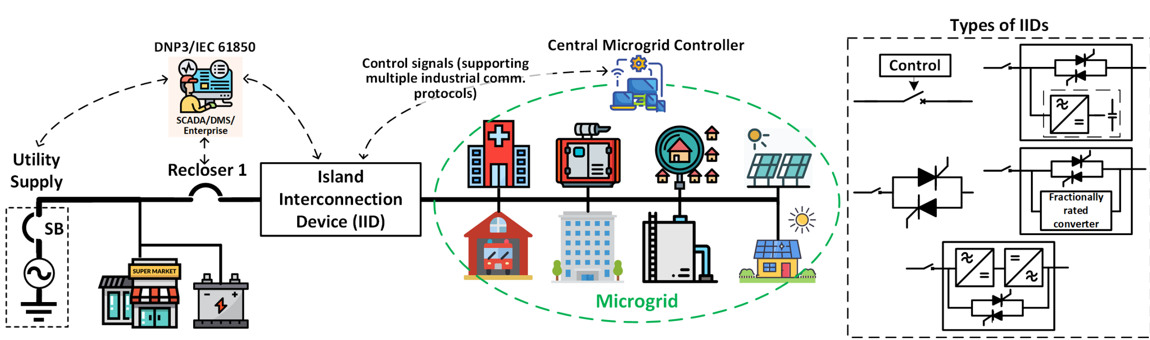


Figure 4.1: Typical implementation of an Island Interconnection Device (IID) in a customer, community, or utility-scale microgrid

This simple microgrid-to-grid interface assures the utility of full compliance with the interconnection rules and minimal to no negative impacts of a microgrid on their system while eliminating the need to perform detailed system impact studies. The IID also serves as an effective mechanism for advanced utility functions such as load-shedding, bottom-up black-start, service restoration, and forming microgrid clusters.

Table 4.1 lists the utility-friendly and microgrid-friendly attributes of an IID necessary to simplify the integration of microgrids with the grid and mitigate any impacts on system operations while providing benefits to both the grid and the microgrid. With the IID implementing the utility's evolving interconnection rules, the utility and microgrid owners/operators are assured of interconnection compliance. This frees microgrid owners/operators from any liability and allows them to deploy DERs and advanced control algorithms without requiring any impact study. The IID also enables flexible interconnections wherein microgrids can provide evolving grid services such as ancillary and grid-support services, with the IID measuring and validating the quality of service delivered by the microgrid for a request from the grid. With flexible interconnections, rules such as limits on active power export and import can be varied and enforced by the IID, allowing DERs and microgrids to interconnect without causing system violations and deferring or eliminating the need to upgrade the distribution system.

4.2 Rules for Interconnection

With the IID implementing and enforcing the rules for interconnection set by the utility, the utility can be assured of no negative impacts of the DER or microgrid on grid operations. The IID ensures full compliance with the interconnection rules and disconnects

Table 4.1: Utility-friendly and microgrid-friendly attributes of an IID

Utility-Friendly Attributes	Microgrid-Friendly Attributes
Standardized communication, monitoring, and control interface to simplify interconnection without requiring knowledge of microgrid configuration and components	Streamlined and transparent interconnection approval with consistent rate-structures resulting in no additional cost or delays
Auto/commanded disconnect for violating evolving interconnection rules, load-shedding	Free from liabilities as compliance with the utility interconnection rules is guaranteed
Automatic, disturbance-free entry/exit into/from an energized or de-energized grid or island	Automatic resynchronization before forming a microgrid cluster and when connecting with the grid
Utility access/disconnect to ensure safety and network reliability during maintenance	Rapid (sub-cycle) connect/disconnect under abnormal conditions and upon command
Utility supplies load and fault current to the microgrid in the grid-connected mode	Management of inrush currents at start-up and after voltage sags
Microgrid contributes limited to no fault currents during grid-side faults	Voltage management during faults, voltage sags, and brownouts
Facilitation of ancillary and grid-support services, storage and reverse power flow capabilities	Voltage and frequency support, phase balancing, harmonics cancellation, and power factor support
Microgrid cluster formation, black-start, and service-restoration capability	Flexible interconnection allowing participation in evolving grid services
Event logging, verification of interconnection compliance and grid services, and status reporting	Flexibility in controls and customization of microgrid components unleashing innovation

Table 4.2: Rules for interconnection

Limits on export/back-feed and import (active power, reactive power, apparent power)	Limits on voltage flicker
Enforce synchronization/sync-check before microgrid clustering and grid connection	Trip/island on the detection of an unintentional island
Feeder reclosing coordination	Open-phase detection
Limits on positive-, negative-, and zero-sequence voltage and current injection	Ramp-rate limits
Limits on DC current injection	Detect and trip/island on disturbances caused by the grid or microgrid to block power swings/oscillations
Limits on harmonics injection	Standard protection functions (OC, UV, OV , UF, OF, etc.)
Loss of synchronism detection and tripping	Limits on transient and temporary overvoltages

the DER or microgrid when the rules are violated. Table 4.2 presents a non-exhaustive list of interconnection rules that utilities can implement and strictly enforce with the IID. In addition to the standard protection functions such as overcurrent (50/51), undervoltage (27), overvoltage (59), etc., the IID can implement advanced protection functions such as unintentional islanding detection and open-phase detection.

A utility can dynamically change the IID settings, limits, etc., in response to prevailing and forecasted grid conditions and the need for grid services for reliability and resilience purposes. For instance, when a bulk power system event such as the loss of generation occurs, the utility may request reduced electricity use and encourage power exports as a grid service wherein the utility may change the active power import and export limits in the IID. The local DER plant controller or central microgrid controller can then respond to the new active power import and export limits by reducing the load and dispatching DERs to increase export to the grid. If a DER or microgrid wants to island, the local DER plant controller or central microgrid controller can overrule utility commands and disconnect the IID at will, regardless of the grid and microgrid conditions.

Furthermore, to ensure interoperability through standard definitions and operational rules and objectives, the IID can enforce data sharing and information exchange rules for communication with the utility and field devices in the system.

4.3 Utility Use Cases of Island Interconnection Devices

Based on inputs from 16 major electric utilities and vendors in the U.S. and an extensive study through a NEETRAC project [129], the IID functionalities required to manage and mitigate the major integration and operational issues with high penetration of DERs and microgrids were determined. Figure 4.2 presents the utility use cases of IIDs and compares the capabilities of the five proposed IIDs in providing the top 10 desirable functionalities.

Table 4.3 compares the characteristics of the five proposed IIDs and the traditional circuit breaker. IID 1 is a traditional mechanical circuit breaker augmented with the necessary control and communication capabilities to implement the DER and microgrid interconnection rules set by the utility. The traditional circuit breaker and IID 1 have high

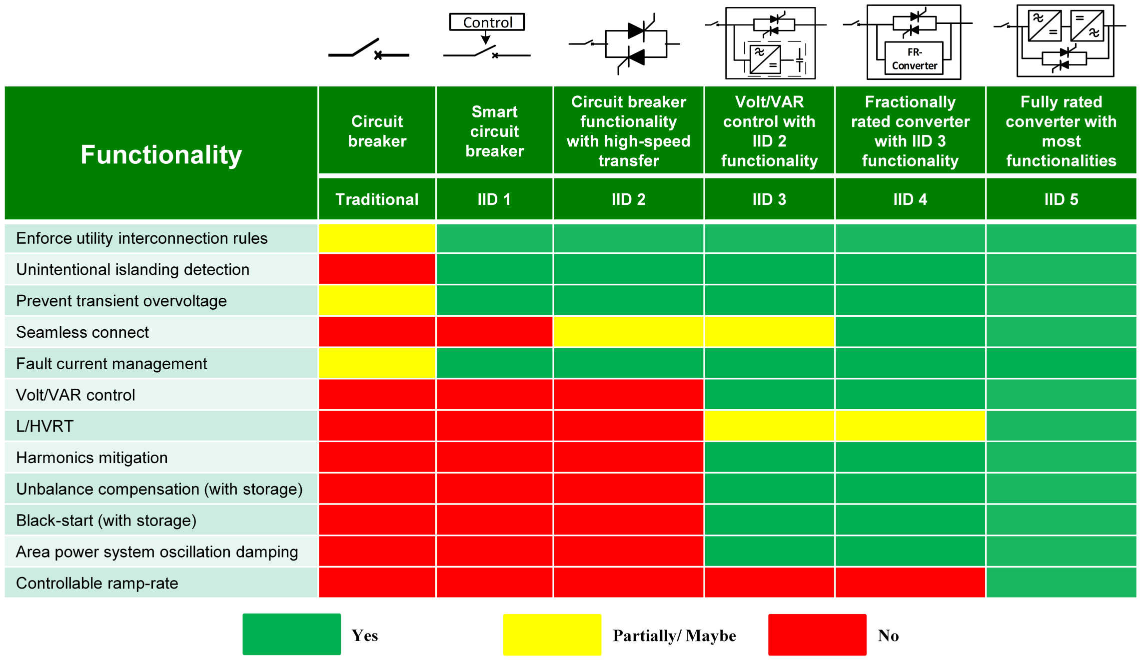


Figure 4.2: Utility use cases of IIDs

fault current handling capability, low losses, and slow response times (< 100 ms) due to their mechanical nature. IID 2 is a solid-state circuit breaker (thyristor, MOSFET, or IGBT based) with limited fault current handling capability, higher losses, and fast (sub-cycle) response (< 4-16 ms) for fault interruption and minimum inrush on connecting with the grid or another microgrid. Depending on the type of semiconductor devices, circuit configuration, and commutation method used, connect/disconnect times of less than 4 ms can be achieved.

IID 3 and IID 4 consist of a fractionally-rated power electronic converter with a solid-state circuit breaker and can provide several grid-support and ancillary services. In IID 3, the power electronic converter is connected in parallel (i.e., in shunt configuration) with the grid at the point of interconnection of the microgrid. In this configuration, IID 3 provides the functionalities of a D-STATCOM, such as voltage support, reactive power

Table 4.3: Comparison between the types of IIDs

Parameter	Traditional ckt breaker	IID 1	IID 2	IID 3	IID 4	IID 5
Speed of response	Slow, < 100 msec	Slow, < 100 msec	Fast, < 4-16 msec	Fast, < 4-16 msec	Fast, < 4-16 msec	Fast, < 4-16 msec
Fault current handling capability	Yes	Yes	Limited	Limited	Limited	Limited
System efficiency	Highest	Highest	High	Medium	Medium	Lowest
Converter rating	NA	NA	NA	Fractionally-rated	Fractionally-rated	Fully-rated
Ancillary and grid-support services	No	No	No	Limited w/o storage	Limited w/o storage	Yes
Full asynchronous/ decoupled operation	No	No	No	No	Limited by size of converters	Yes
Relative cost	Lowest	Low	Medium	High	High	Highest

compensation, and harmonics filtering. Furthermore, IID 3 integrated with battery energy storage provides black-start functions and enables the seamless connection of an islanded microgrid with the grid or another microgrid.

IID 4, consisting of a fractionally-rated back-to-back converter and a solid-state circuit breaker, can provide all the functionalities of IID 3. IID 4 also allows partial-asynchronous/decoupled operation of the microgrid with power exchange with the grid limited by the rating of the back-to-back power electronic converters. This partial-asynchronous/decoupled operation with IID 4 enables seamless synchronization and connection of an islanded microgrid with the grid or another microgrid without requiring battery energy storage, as shown in section 4.6.4. In the normal grid-connected mode, the fractionally-rated back-to-back converter is bypassed by the circuit breaker and can be operated as a shunt converter to provide the functionalities listed in Figure 4.2.

IID 5 consists of a fully-rated power electronic converter and solid-state circuit breaker capable of mitigating most integration and operational challenges with microgrids. IID 5 allows full-asynchronous microgrid operation, effectively decoupling the microgrid from the rest of the system but at a much higher cost. However, challenges with sourcing fault currents and inrush currents to the microgrid, even in the grid-connected mode, exist with IID 5.

4.4 Communication Architecture

With the rapid deployment of microgrids on the distribution system, there is increasing interest in monitoring, controlling, and coordinating their operation with the utility for enhanced grid efficiency, reliability, and resilience. Most utilities use DNP3 or

IEC 61850 as the communication protocol to integrate substation systems, RTUs, field devices (also known as intelligent electronic devices), and utility master controllers (SCADA/DMS/DERMS/Enterprise systems) [134]. Communication media typically used by utilities include cellular networks, fiber, microwave, meshed radio networks, and power line carrier communication [135]. Field devices, such as reclosers, sectionalizers, capacitor banks, and line voltage regulators, mainly operate autonomously and are connected to the utilities' monitoring and control infrastructure for situational awareness and remote control. However, most microgrid vendors use IEC 60870-5 and Modbus, with newer products now supporting DNP3, IEC 61850, IEEE 2030.5, and SunSpec Modbus [136]. As a result, interoperability challenges exist in integrating microgrids with the utility monitoring and control infrastructure.

Figure 4.3 shows the integration of the IID in a typical peer-to-peer communication architecture used by utilities to integrate SCADA/DMS/DERMS/enterprise systems with field devices. The IID provides a standardized and flexible communication interface

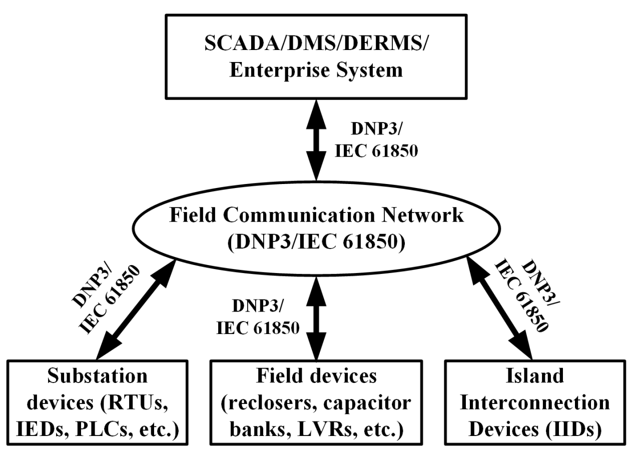


Figure 4.3: Utility communication architecture integrating IIDs

between the utility and microgrid by supporting a wide range of communication protocols (DNP3, IEC 61850, SunSpec Modbus, etc.) and transmission media (fiber optics, meshed radios, etc.). With most microgrids in the U.S. being brownfield projects that may be using different communication protocols and transmission mediums, the standardized IID can support this diversity and seamlessly integrate microgrids with utility operations.

Integrating the IID as a utility-owned and utility-controlled asset into the utilities' monitoring and control infrastructure introduces complexity similar to adding any other field device. The IIDs can communicate and coordinate with the utility master controller, utility protection devices, and neighboring IIDs using the utilities' existing field communication network. The ability of the IID to communicate via DNP3 or IEC 61850 avoids the lengthy and expensive protocol migration and customization effort needed when integrating today's central microgrid controllers. Standardized protocols, function definitions, and information models ensure interoperability with microgrid vendors without requiring any custom mapping between the communication encodings.

As the system conditions evolve with changing loads and DERs being integrated, a utility may want to effectively manage, optimize, and control various system assets to maximize grid economic benefits, reliability, and quality of service. Depending on the type of ancillary and grid services required, utilities can dispatch assets and issue commands to modify the IID limits and settings for the required duration of the service request.

Table 4.4 lists the information exchange between the IID and utility DMS and between the IID and central microgrid controller for effective and seamless integration of microgrids with the grid. The bandwidth and latency requirements for the communication

Table 4.4: Communication of the IID with the utility DMS and central microgrid controller

Communication between the IID and utility DMS	Communication between the IID and central microgrid controller		
All modes	**Grid-connected**	**Transitions**	**Islanded**
Voltage, current, frequency, phase angle, kW, kVAR, kVA at point of interconnection (POI)	Export/import power flow constraints/ setpoints	Indicate island/ connect intention (unplanned and planned)	Frequency control (grid-forming) using existing μG assets
Power quality (harmonics, unbalance, voltage sags/swells, flicker, etc.) monitoring at POI, event logging and reporting	Voltage setpoints at POI commanded by utility DMS for voltage regulation	Resynchronization and reconnect success/failure	Resynchronize and reconnect request (provide grid voltage, phase angle, and frequency information to μG controller)
Connect/disconnect commands and status reporting	Indicate planned islanding/ disconnect to enable managed transition of μG assets.	Abort transition due to abnormal grid/microgrid conditions	Black-start for distribution system service restoration (auto or utility commanded)
Level of masked load and anticipated cold load pickup	Indicate mode of operation (grid-connected)		Indicate mode of operation (islanded)
Characteristics of microgrid (droop or isochronous, type of sources and loads, mode of operation, etc.)	Forced transition by μG controller to islanded mode		Forced (seamless) transition by μG controller to grid-connected mode
Interconnection rules (update and compliance verification), setpoints, thresholds, updated protection and control logic, verification of performance standards	Interconnection rules, setpoints, thresholds, verification of performance standards		Support islanded operation thorough Volt/VAR control, harmonics compensation, etc.
Grid services such as voltage and frequency regulation, load-shedding, load restoration through black-start (auto or utility commanded sequence)	Participation in ancillary and grid-support services		

network depend on the application, monitoring, and control needs. For example, for DER monitoring and control, the U.S. Department of Energy specifies bandwidth requirements from 9.6 kbps to 56 kbps and latency requirements between 20 ms and 15 s [137]. For seamless grid connection of an islanded microgrid or forming microgrid clusters, IIDs can tolerate low-bandwidth, high-latency (several minutes) communication links as only connect/disconnect messages are exchanged between the utility DMS and IIDs.

4.5 Benefits of Island Interconnection Devices

As a standardized utility-owned and utility-controlled grid interface, the IID assures the utility of minimal negative impact of the large DER or microgrid installation on their system while eliminating the need to perform a detailed system impact analysis. The standardized grid interface ensures streamlined and transparent microgrid interconnection approval without requiring knowledge of the microgrid configuration and its components. If any utility interconnection rule is violated, the IID disconnects/islands the microgrid to ensure the integrity of the grid and reports interconnection violations to the utility. Furthermore, instead of firm utility interconnection rules, the IID enables flexible interconnections where the utility can dynamically change the interconnection rules and limits for DERs and microgrids in response to the grid conditions. By doing so, distribution system upgrades previously required for installations with firm interconnection rules can be avoided or deferred.

Integrating the IID as a utility-owned and utility-controlled asset enables simplified integration with the utility's DMS/DERMS/SCADA system while providing the utility complete control over the potential capabilities of the IID. In addition to enforcing the evolving utility interconnection rules, the IID can be used to track and validate the performance of grid services offered by the microgrid or large DER installation. By monitoring the real-time operational conditions and analyzing the committed schedules, the IID reports any violations to the utility DMS. The IID also provides rich data to the utility's monitoring and control infrastructure, enabling power flow and quality monitoring, fault-recording capability, flagging and reporting violations, load analysis, changing thresholds, setpoints, and modifying control algorithms/logic of the IID remotely. By supporting multiple industrial communication protocols, including IEC 61850 and DNP3, the IID can provide inputs/guidance to the central microgrid controller for advanced features and capabilities such as seamless/bumpless transitions between the grid-connected, islanded, and microgrid cluster modes of operation.

With microgrids being large concentrated loads and sources, the IID serves as an effective mechanism for advanced utility functions, such as load-shedding, bottom-up black-start, and service restoration. The IID also provides several ancillary services and grid-support functions when integrated with a power electronic converter, as shown in Figure 4.2. Moreover, with the ability to make decisions locally and implement utility interconnection rules with reduced dependence on fast communications, the IID is an ideal replacement for DTT and power quality monitors, which are often required by utilities for large DER installations and microgrids.

There are currently several challenges in operating microgrids with low inertia that require advanced inverter control capabilities, such as grid-forming and virtual inertia emulation functions that may not comply with the prevailing interconnection standards. With the IID being the decoupling point that enforces the utility interconnection rules and prevents microgrid-related issues from passing to the grid-side and vice-versa, this approach allows for flexibly customizing microgrid components and control algorithms without potentially affecting grid operations or limiting microgrid functionality. For microgrid system owners and developers that operate in various states and utility service territories, the IID also provides a straightforward approach to adapting to multiple utility interconnection rules, procedures, and processes resulting in predictable and consistent costs and timelines. Furthermore, this approach unleashes innovation allowing microgrid owners and developers to acquire, deploy, interconnect, and modify behind-the-meter technologies, including generation sources, with zero liability for any damage to the grid as the IID protects the grid from every microgrid-related disturbance.

4.6 Simulation Studies

In order to validate the transient and dynamic performance of the proposed IIDs during different grid and microgrid events, the test system in Figure 4.4 is simulated in the EMT domain using MATLAB/Simulink. The 34.5 kV radial distribution feeder network consists of loads, a 0.5 MW solar PV inverter, and a 2.4 kV, 2.25 MW microgrid with a 0.75 MVA synchronous generator and a 1.5 MW solar PV inverter.

For these simulations, the diesel engine-driven synchronous generator model in [139] with automatic voltage regulator (AVR) and governor controls is adapted to include droop control. The simplified representation of the engine-driven synchronous generator model with droop, governor, and AVR controls is shown in Figure 4.5. The droop controller generates a frequency bias for the governor to implement active power-frequency droop and generates a voltage bias for the AVR to implement reactive power-voltage droop. The AVR and exciter regulate the terminal voltage while the governor adjusts the engine throttle to regulate the shaft speed. The synchronous generator

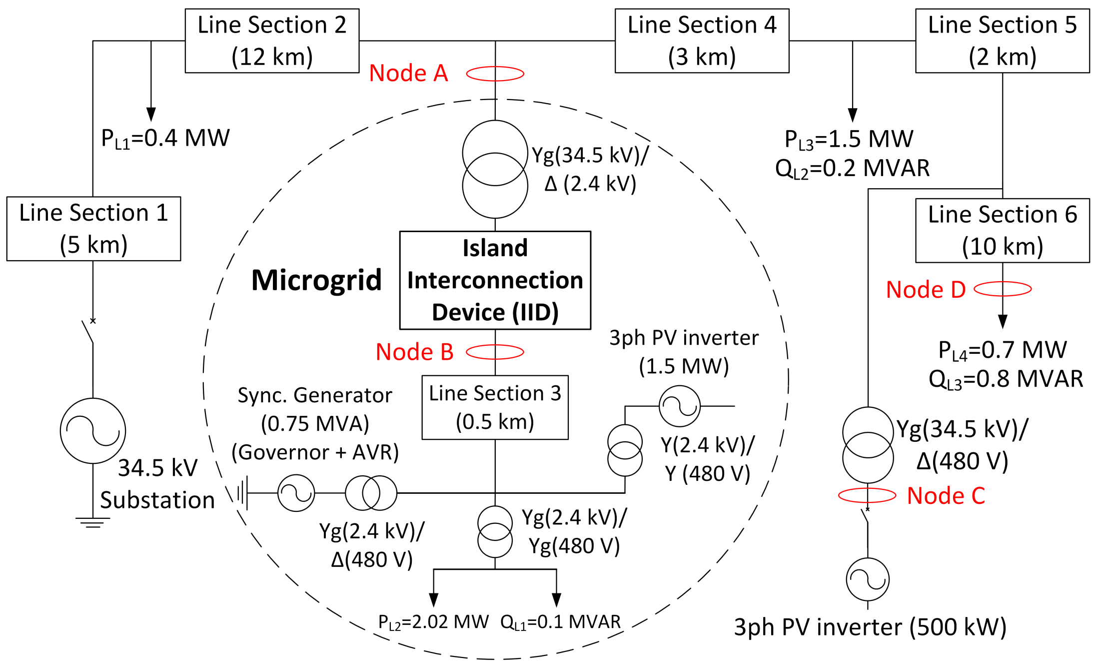


Figure 4.4: 34.5 kV test system with a 2.4 kV, 2.25 MW microgrid

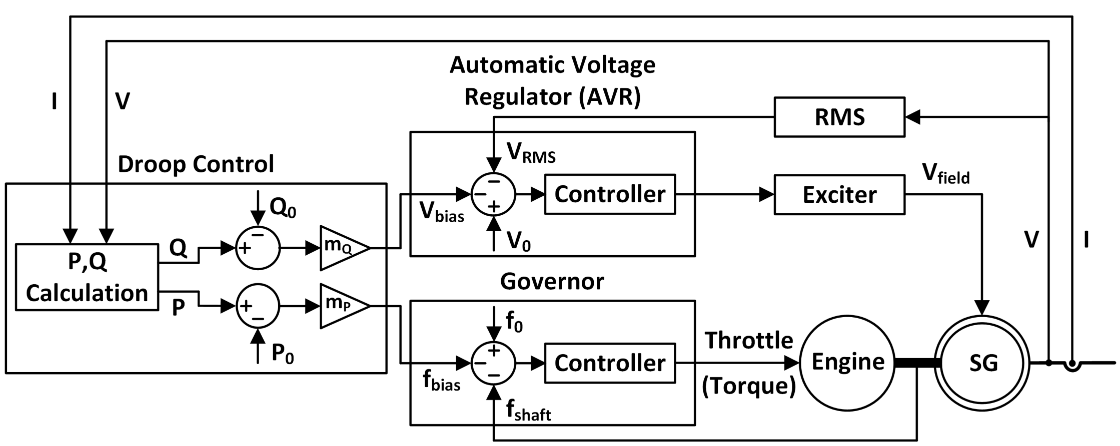


Figure 4.5: Synchronous generator with droop, governor, and AVR controls

parameters used are presented in Table 4.5. The generator operates with a 5% droop (m_P) in frequency (active power-frequency droop) and a 3% droop (m_Q) in voltage (reactive power-voltage droop). The active power reference (P_0) for the synchronous generator at the nominal frequency (f_0) of 60 Hz is 0.285 MW (0.38 pu) in all simulation cases except for the unintentional islanding detection case, where it is 0.56 MW (0.75 pu). In all cases, the reactive power reference (Q_0) for the synchronous generator at the nominal voltage (V_0) of 1 pu is 0 pu.

Table 4.5: Parameters of synchronous generator and solar PV inverters

Source	Parameter	Value
Synchronous generator in the microgrid	Rating	0.75 MVA
	Nominal voltage	480 V
	m_P	5%
	P_0	0.285 MW (0.38 pu)
	f_0	60 Hz (1 pu)
	m_Q	3%
	Q	0 MVAR (0 pu)
	V_0	480 V (1 pu)
Solar PV inverter in the microgrid	Rating	1.5 MVA
	Nominal voltage	480 V
	P^*	1.5 MW
	Q^*	0 MVAR
Solar PV inverter at Node C	Rating	0.5 MVA
	Nominal voltage	480 V
	P^*	0.5 MW
	Q^*	0 MVAR

The three-phase three-leg solar PV inverters on the feeder and in the microgrid are operated in the grid-following mode using the control structure in Figure 4.6 adapted from [138]. The inverter parameters are given in Table 4.5. Each solar PV inverter's active power reference (P*) is set to the nominal rating, and the reactive power reference (Q^*) is

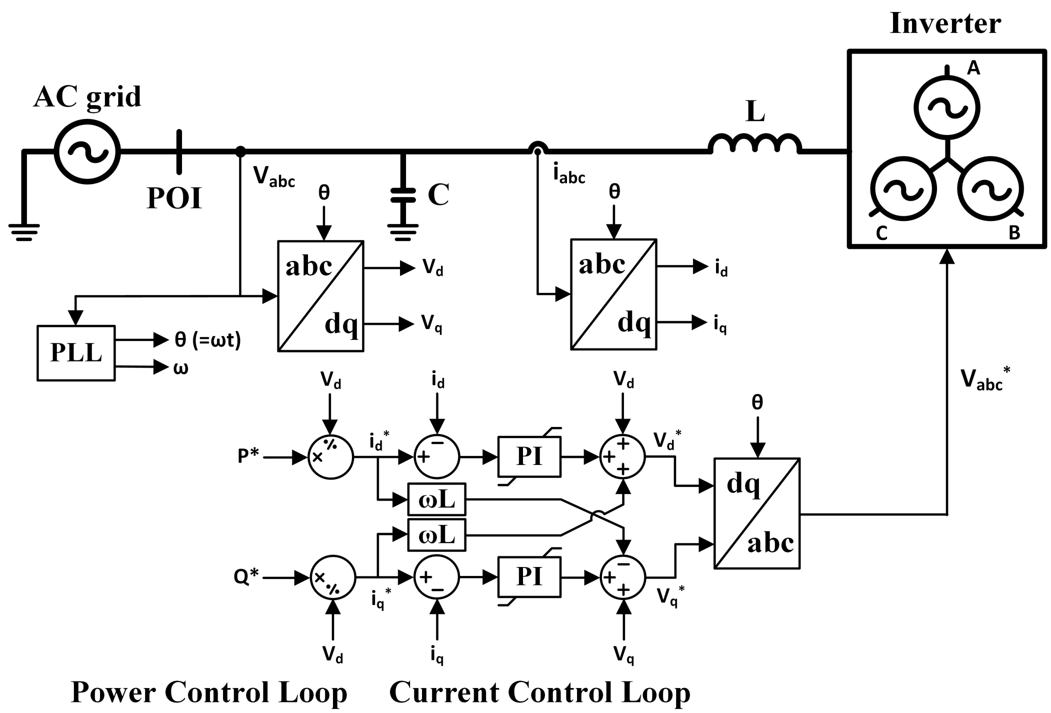


Figure 4.6: Control structure of grid-following inverter [138]

set to zero. A constant-impedance load model is used for the loads on the feeder and in the microgrid.

Simulation results demonstrating the ability of IIDs to achieve unintentional islanding detection, Volt/VAR control, fault current management, and seamless/bumpless connection of an islanded microgrid with the grid are presented in the following sections. Different types of IIDs, as shown in Figure 4.1 and Figure 4.2, are implemented depending on the functionality required. A methodology using the negative-sequence voltage component to prevent transient overvoltages during line-to-ground faults in distribution networks with high DER penetration was previously presented in section 3.2.1. Using IID 1 (or IID 2 for sub-cycle disconnection/tripping), the same functionality of preventing transient overvoltages with microgrids consisting of solar PV inverters and synchronous generators can be provided.

4.6.1 Unintentional Islanding Detection

Unintentional islanding refers to the condition where a portion of the distribution system continues to be energized by local DERs following its isolation from the larger grid [56]. Unintentional islanding is undesirable for the following reasons [24]:

1) Safety hazards to utility personnel and customers

2) Damage to utility equipment and customer DERs when reclosing out-of-synchronism

3) Power quality problems in the islanded section, which can damage customer loads

4) Interference with the utility's protection devices and restoration sequence

The potential to form and sustain an islanded section depends on the following factors [24], [140]:

1) Generation-to-load ratio in the islanded section

2) Reactive power balance in the islanded line section

3) Percentage of inverter-based generation and synchronous generation in the island

The techniques used to detect and prevent unintentional islanding can be divided into active, passive, and remote (communication-based) techniques. Each method has drawbacks when considering cost, reliability, size of the non-detection zone, and detection time [24], [141]. Remote (communication-based) unintentional islanding detection schemes such as DTT rely on the SCADA system to monitor the status of utility protection devices (e.g., circuit breakers, reclosers, etc.) and send trip commands to the downstream DERs in the islanded sections. DTT has traditionally been used for large DER installations (such as utility-scale PV farms) and when integrating microgrids. Although well-implemented remote techniques do not have a non-detection zone, their high cost, complexity, reliability of communication links, and scaling challenges are slowly shifting electric utilities away from DTT [5], [24].

Today's DERs mostly use active methods, which work best on "stiff" grids. Active anti-islanding methods detect the loss of utility supply (i.e., the grid) by actively trying to change the voltage and/or frequency of the grid and then detecting whether the grid conditions at the POI have changed. However, with the future power system not being as "stiff" due to the high penetration of inverter-based generation, the role of active anti-islanding techniques at higher DER penetration levels is questionable [24], [140]. Furthermore, with an increasing need to operate distribution system-level microgrids for resilience reasons, there is concern that active anti-islanding algorithms might prevent DERs from operating in such configurations [51]. On the other hand, passive methods that rely on the measurements of the local grid condition at the POI of the DER do not have the flaws of active methods at higher DER penetration levels [24], [142]. Except for longer trip times, passive methods are promising for the future inverter-dominated power system [140], [142].

For this study, a type 2 Island Interconnection Device (IID 2) consisting of a solid-state switch (in this case, anti-parallel thyristors), as shown in Figure 4.7, is simulated. The passive method of monitoring the rate-of-change-of-frequency (RoCoF) for unintentional islanding detection is implemented. The frequency and RoCoF are calculated using the block diagram in Figure 4.8 with the parameters specified in Table 4.6. The frequency is calculated using a standard three-phase phase-locked loop (PLL). The time-derivative of the frequency is passed through a moving average block with a sliding window length of 2 cycles (i.e., 33 ms) to filter the fast frequency dynamics in the calculation of RoCoF. When the RoCoF exceeds 2 Hz/s, the IID disconnects/islands the microgrid.

In this simulation case, the load within the microgrid is reduced to 1.8 MW. Figure 4.9 shows the line-to-ground voltages at Node B, active and reactive power exported by the microgrid into the grid measured at Node B, frequency in the microgrid measured at Node B, and the RoCoF in the microgrid measured at Node B. Prior to the loss of the utility supply (i.e., 34.5 kV substation source) at t = 10.003 s, the microgrid was exporting 0.263

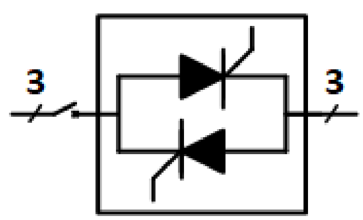


Figure 4.7: IID 2 consisting of anti-parallel thyristors

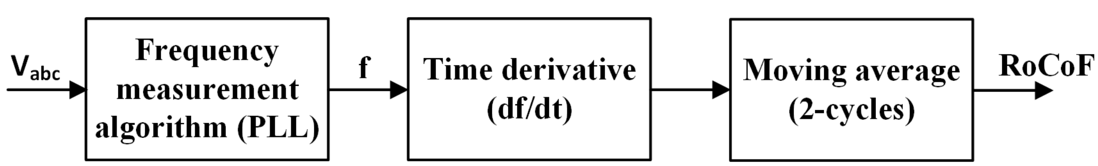


Figure 4.8: Frequency and RoCoF calculation

MW into the grid. At t = 10.012 s, the 0.5 MW solar PV inverter at Node C is disconnected through DTT. Following the loss of utility supply and the 0.5 MW PV inverter at Node C tripping, the active power imbalance causes frequency transients in the islanded network. At t = 10.017 s, when the RoCoF measured over a 2-cycle moving average measurement window at Node B exceeds 2 Hz/s, the command to disconnect/island the microgrid is initiated. From t = 10.017 s to t = 10.023 s, there is active and reactive power exchange between the microgrid and the rest of the system as the IID opens at the zero-crossing of the respective phase currents. At t = 10.023 s, following the disconnection of all the IID phases, the microgrid continues to operate in the islanded mode. This approach of using a passive islanding detection method provides utilities with a replacement/backup for expensive remote techniques and active anti-islanding algorithms that may fail in high DER penetration scenarios [140].

Table 4.6: Parameters to calculate frequency and RoCoF

<table>
<tr><th colspan="2">Parameter</th><th>Value</th></tr>
<tr><td rowspan="3">Frequency</td><td>$k_{p,PLL}$</td><td>180</td></tr>
<tr><td>$k_{i,PLL}$</td><td>3200</td></tr>
<tr><td>$k_{d,PLL}$</td><td>1</td></tr>
<tr><td rowspan="2">Rate-of-change-frequency (RoCoF)</td><td>Moving average window length</td><td>33.33 ms (2-cycles)</td></tr>
<tr><td>Threshold</td><td>2 Hz/s</td></tr>
</table>

Although the RoCoF-based technique presented in this section successfully detected the unintentional island, there can be challenges with only using passive islanding detection methods in certain scenarios. In the simulation case considered in this section, following the loss of utility supply, the frequency and RoCoF dynamics in the island are

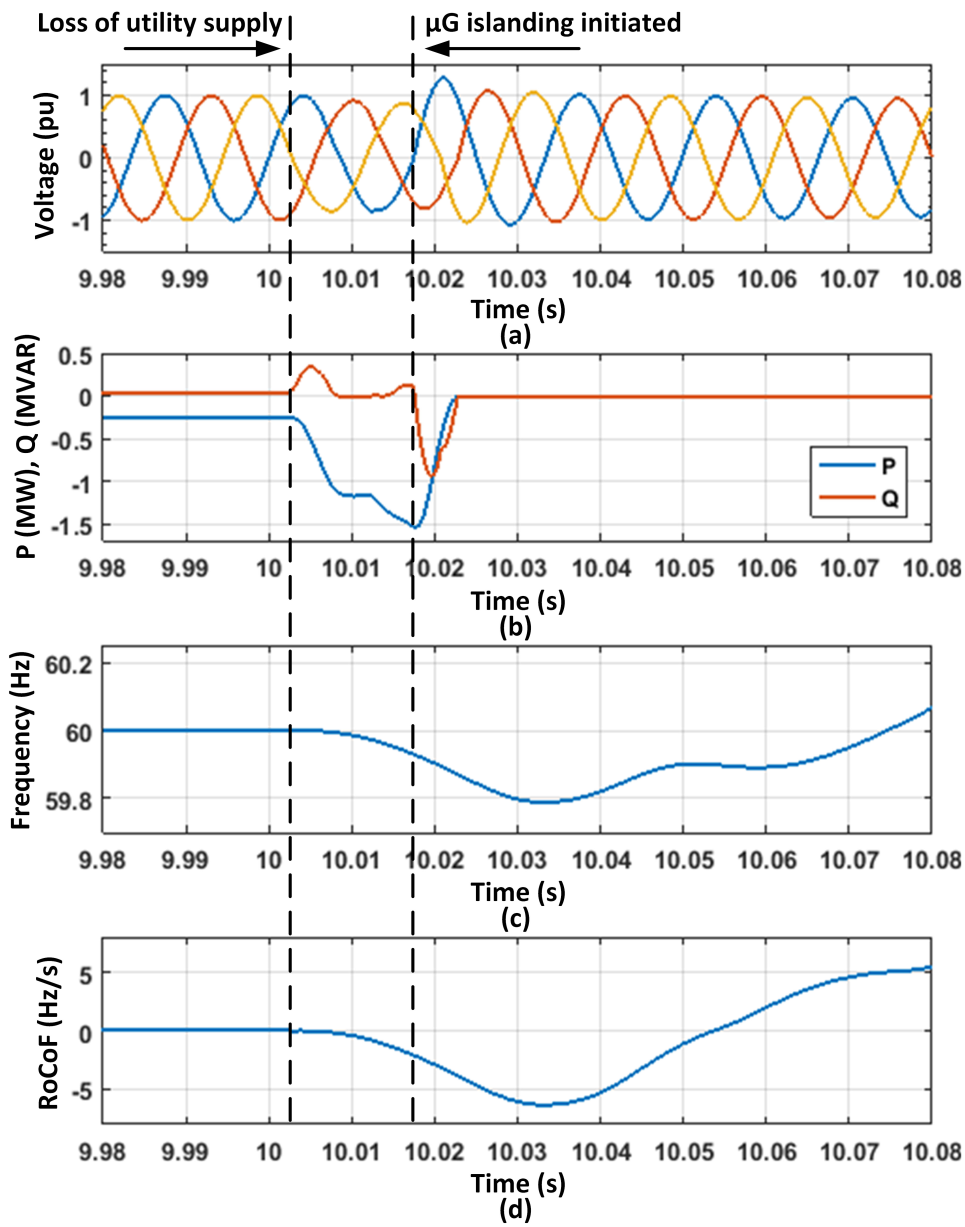


Figure 4.9: Unintentional islanding detection (a) Line-to-ground voltages at Node B, (b) Active and reactive power exported by the microgrid into the grid measured at Node B, (c) Frequency in the microgrid measured at Node B, and (d) RoCoF in the microgrid measured at Node B

described by the swing equation in (4.1) [143]. In (4.1), ΔP is the active power imbalance in the system following the disturbance, H is the combined inertia constant of the engine-driven synchronous generator, $f_{nominal}$ is the nominal frequency of the system, and df/dt

is the resulting RoCoF from the active power imbalance. The RoCoF following the loss of utility supply depends on the active power imbalance and the inertia of the generator. In scenarios where the active power imbalance on islanding is minimal, resulting in the generation-to-load ratio being very close to 1, relying on the RoCoF can fail to detect the unintentional island and disconnect quickly. However, the probability that balanced conditions are present when the utility supply is lost is very small [24]. Furthermore, using only RoCoF-based detection techniques can be ineffective when operating in high-inertia systems or with significant motor loads.

$$\frac{2H}{f_{nominal}}\frac{df}{dt} = \Delta P \tag{4.1}$$

4.6.2 Volt/VAR Control

The conventional approaches adopted by electric utilities for voltage control in distribution systems rely on centralized means such as transformer load tap changers (LTCs), line voltage regulators (LVRs), and switched capacitors. Voltage control along the feeder is achieved by changing the tap settings/setpoints of LTCs and LVRs, and switching the capacitor banks on/off to regulate the voltage for customers to be within the ANSI limits [17]. With their inherent mechanical delays, these utility assets are slow and are designed to operate/switch only a few times a day to ensure a long life [17], [57]. With the ever-increasing penetration of distributed solar PV and microgrids, the resulting high levels of variability in power injection into the grid may lead to overuse and reduced life of traditional utility Volt/VAR equipment. On the other hand, several implementation and operational challenges exist with emerging solutions, such as smart inverters [5], [11], [33], [57]. With smart inverters not being utility-owned and/or utility-controlled assets, their ability to provide distribution system-level Volt/VAR benefits is questionable [57].

To demonstrate the ability of the IID to provide voltage regulation functions through Volt/VAR control, the feeder network in Figure 4.4 with a type 3 Island Interconnection Device (IID 3) shown in Figure 4.10 is simulated. To regulate the voltage at the terminals of the IID (i.e., Node B), a simplified representation of IID 3 as an averaged three-phase three-wire shunt converter model with only the voltage control loop shown in Figure 4.11 with the parameters in Table 4.7 is simulated. The PI controller tracks the IID terminal d-axis voltage reference to generate the q-axis current reference, which is used to synthesize the current references in the ABC reference frame. The reactive power output of the IID is given by equation (4.2). The d-axis control for active power control not considered in this discussion is used to regulate the DC-link voltage similar to a STATCOM. To handle the neutral current associated with nonlinear loads, unbalanced conditions, and faults, a three-phase four-wire IID 3 configuration is required. In order to emphasize the voltage drop across the distribution feeder in Figure 4.4, a 2.5 MW load is

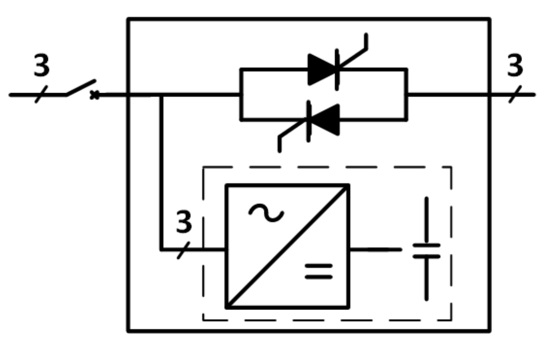


Figure 4.10: IID 3 for Volt/VAR control

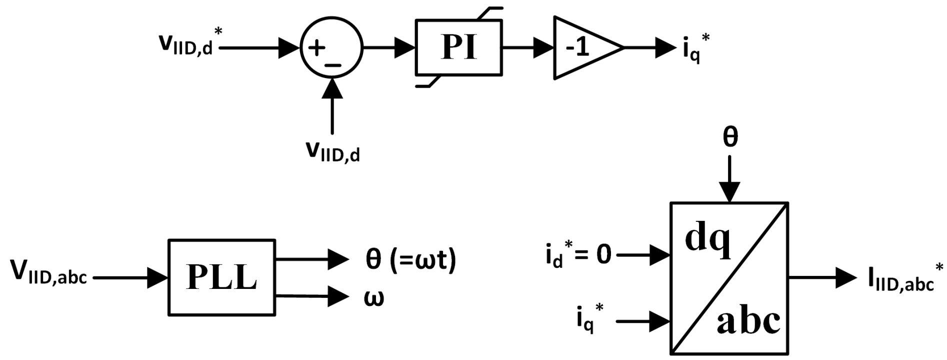


Figure 4.11: Voltage control loop for IID 3

Table 4.7: Control parameters of IID 3

Parameter		Value
Phase-locked loop	$k_{p,PLL}$	180
	$k_{i,PLL}$	3200
	$k_{d,PLL}$	1
Voltage control loop	$V_{IID,d}{}^*$	1.96 kV (1 pu)
	$k_{p,PI\_V\_control}$	30
	$k_{i,PI\_V\_control}$	115
	$Limit_{upper,PI\_V\_control}$	800 A
	$Limit_{lower,PI\_V\_control}$	-800 A

added at Node D, and a 0.3 MW load is added in the microgrid for this simulation case. Additionally, to allow the IID to perform voltage regulation, the AVR in the synchronous generator is effectively desensitized by changing the reactive power-voltage droop setting from 3% droop in voltage to 20% droop.

$$Q_{IID} = -\frac{3}{2}V_{IID,d}I_{IID,q} \tag{4.2}$$

Figure 4.12 shows the average RMS line-to-ground voltage at Node B, active power imported by the microgrid from the grid, reactive power injected by the IID to regulate the

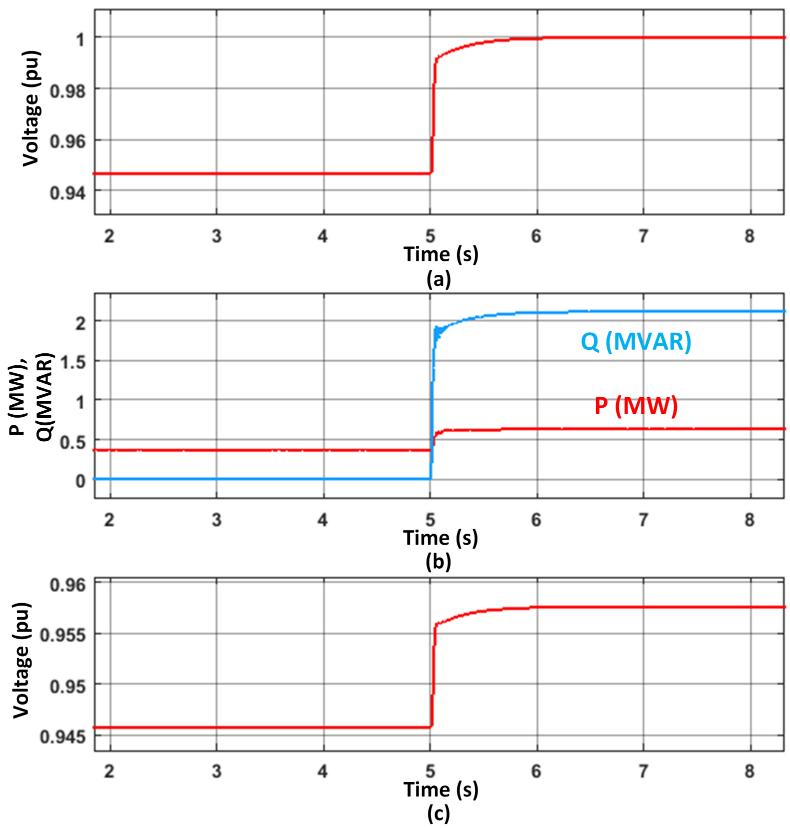


Figure 4.12: Volt/VAR control using IID 3 (a) Voltage at Node B, (b) Active power drawn from the grid, Reactive power injected by the IID, and (c) Voltage at Node D

voltage at the POI, and the average RMS line-to-ground voltage at Node D. Prior to the IID regulating the voltage at Node B, the microgrid was importing 0.366 MW from the grid. At t = 5 s, the IID starts regulating the voltage at Node B to 1 pu by injecting reactive power. With the loads represented by constant-impedance models, the increase in the voltage at Node B results in the microgrid importing more active power from the grid (0.635 MW from 0.366 MW). The voltage at Node D also improves from 0.946 pu to 0.958 pu, which is within the ANSI-A limit. The reactive power rating of the IID and the network characteristics limits the voltage regulation capability. In weak grid conditions characterized by a low short-circuit ratio, the instability of the PLL can potentially cause controllability issues for the IID and must be considered.

This approach of positioning the IID as a utility-owned and utility-controlled asset delivers both local and system-level benefits. It empowers utilities to manage reactive power flows, achieve dynamic voltage regulation, and ultimately relieve the operational burden on traditional utility equipment (LTCs, LVRs, etc.). It also enables utilities to achieve conservation voltage reduction (CVR) goals and peak demand reduction while supporting high PV penetration.

4.6.3 Fault Current Management

Integrating DERs and microgrids can potentially alter the fault currents in the distribution system, leading to relay desensitization and nuisance fuse blowing and requiring the replacement of protection devices due to interrupt capacity constraints [10]. Although the fault current contribution from inverter-based resources is typically 1.2 to 1.5 times the rated current, the total contribution from clustered/concentrated solar PV systems and microgrids can be substantial at high penetration levels. Most utilities prefer minimum fault current contribution from DERs and microgrids for faults in the distribution system but are comfortable sourcing fault currents for faults within the microgrid.

To demonstrate the ability of the IID (in this case, IID 2, as shown in Figure 4.7) to manage fault currents for faults in the distribution feeder and within the microgrid, the test system in Figure 4.13 with the location of the faults specified is simulated. As utilities prefer to minimize fault contribution from the microgrid for faults in the distribution feeder (i.e., reverse direction limits), the directional overcurrent protection relay function (ANSI 67) is implemented in the IID. The directional overcurrent protection relay function

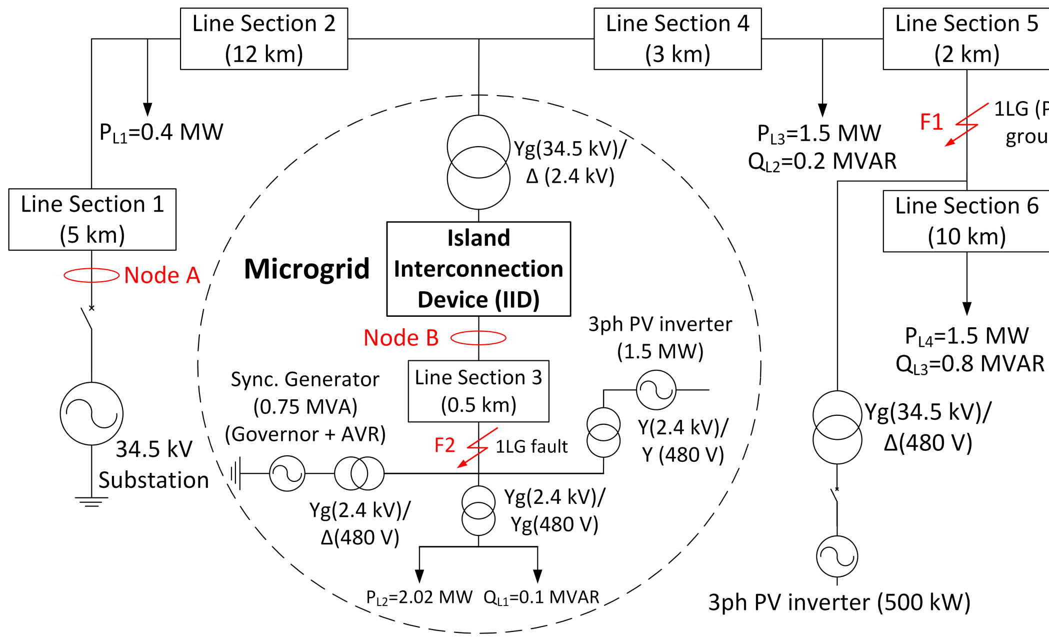


Figure 4.13: Test system for fault current management

measures the RMS current of the phases, detects the direction of the fault, and trips if the fault current exceeds the threshold longer than the time delay. The directional overcurrent protection relay function settings implemented in the IID and the fault parameters in each scenario are listed in Table 4.8. For the scenario with a Phase A to ground (1LG) fault at location F1 in the distribution feeder, the reverse directional overcurrent protection function with a conservative threshold of 300 A and a time delay of 33.33 ms (2-cycles) is implemented to minimize fault current contribution from the microgrid. On the other hand, for the scenario with a Phase A to ground (1LG) fault at location F2 within the microgrid, the forward directional overcurrent protection function with a threshold of 700 A and a time delay of 83.33 ms (5-cycles) is implemented to reflect the ability to source fault currents from the grid.

Table 4.8: Parameters for fault current management studies

Scenario	Parameter	Value
Phase A to ground (1LG) fault at location F1 in the distribution feeder	Fault impedance	2 ohm
	Relay function	Reverse directional overcurrent protection
	Relay threshold	300 A
	Relay time delay	33.33 ms (2-cycles)
Phase A to ground (1LG) fault at location F2 within the microgrid	Fault impedance	1 ohm
	Relay function	Forward directional overcurrent protection
	Relay threshold	700 A
	Relay time delay	83.33 ms (5-cycles)

Figure 4.14 and Figure 4.15 show the grid currents measured at Node A, microgrid currents measured at Node B, and the status of the IID and the substation circuit breaker for a fault at locations F1 and F2, respectively. In Figure 4.14, a Phase A to ground fault with a fault impedance of 2 ohm is applied at location F1 in the distribution feeder at t = 5 s. At t = 5.035 s, the IID using directional overcurrent protection disconnects/islands the microgrid. At t = 5.25 s, the substation circuit breaker opens, de-energizing the feeder. In this case, the 500 kW solar PV inverter at the end of the feeder contributes to the fault current. To further reduce the fault current contribution from the microgrid, the reverse directional overcurrent protection threshold and time delay can be reduced. However, care must be taken to ensure that the IID does not trip on exports to the grid under normal conditions.

Figure 4.15 shows the response for a Phase A to ground fault with a fault impedance of 1 ohm at location F2 within the microgrid at t = 5 s. At t = 5.098 s, the IID using directional overcurrent protection disconnects/islands the microgrid and isolates the fault

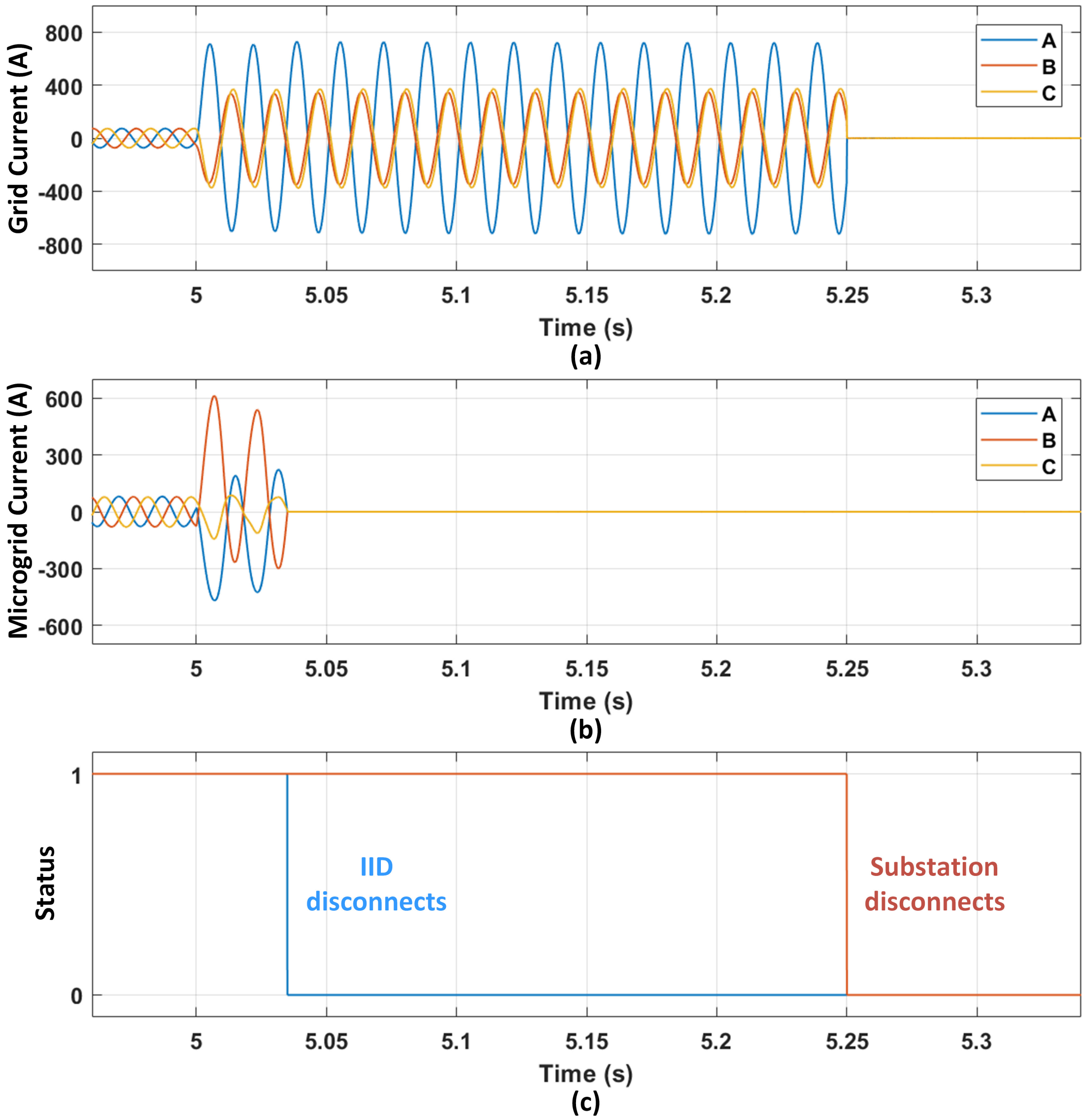


Figure 4.14: Fault current management for a fault at location F1 in the distribution system (a) Grid currents measured at Node A, (b) Microgrid currents measured at Node B, and (c) Status of IID and substation breaker

from the distribution feeder. To limit fault current contribution from the grid for faults within the microgrid, the forward directional overcurrent protection threshold and time delay must be reduced. However, these settings must be selected such that the IID does not trip on imports from the grid under normal conditions.

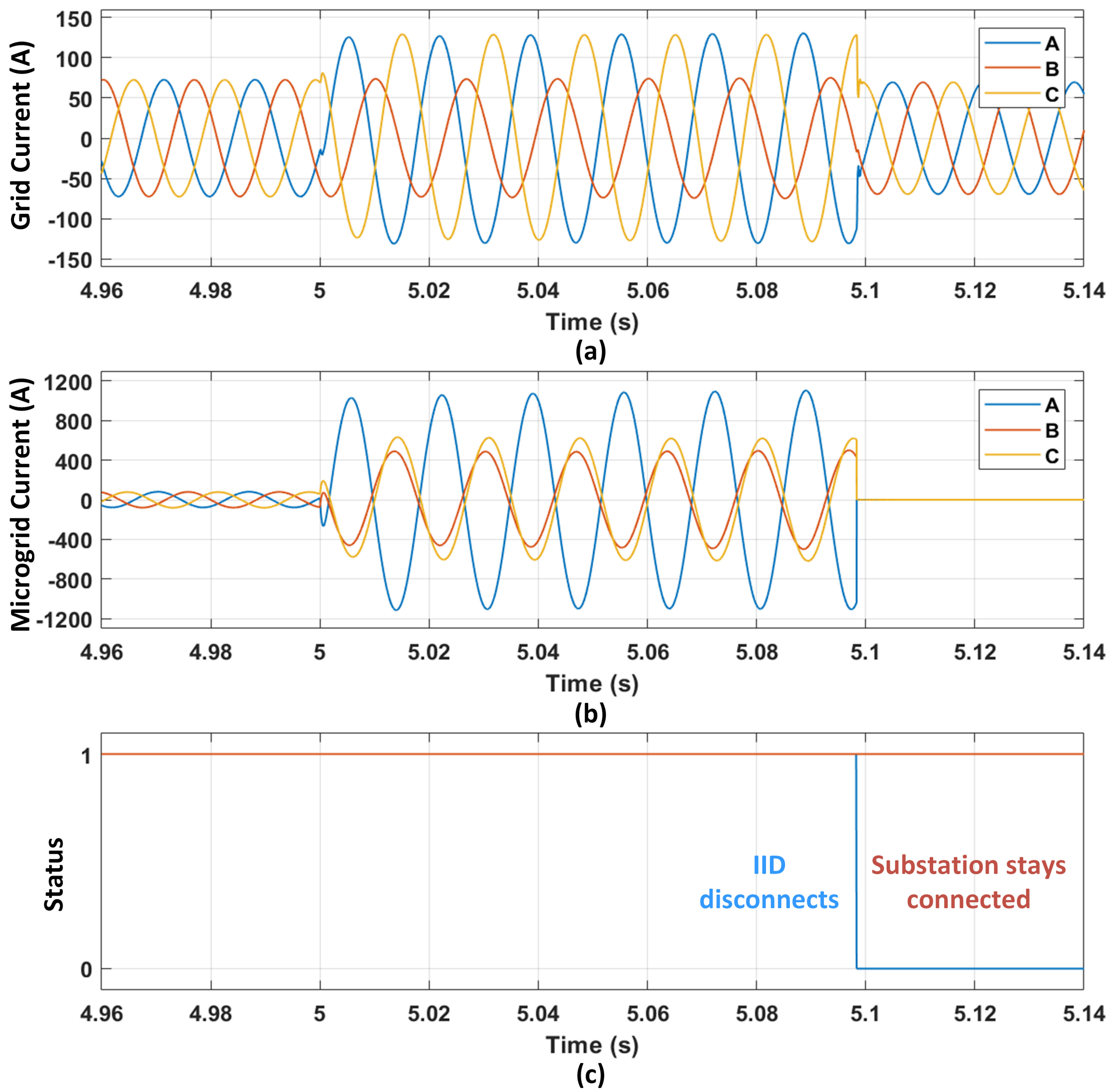


Figure 4.15: Fault current management for a fault at location F2 within the microgrid (a) Grid currents measured at Node A, (b) Microgrid currents measured at Node B, and (c) Status of IID and substation breaker

Although utilities prefer minimum fault current contribution from DERs and microgrids for faults on the distribution system, ride-through (L/HVRT, L/HFRT) requirements require continued operation similar to synchronous generators, which conflicts with the reduced fault current requirement. This is a significant conflict between distribution system benefits and the stability of the overall power system and is often not considered by distribution system planners, operators, and inverter manufacturers. The IID, being a utility-owned and utility-controlled DER-to-grid/microgrid-to-grid interface, provides an approach to change the interconnection trip parameters and manage fault contributions from large DERs and microgrids on the distribution system.

4.6.4 Seamless/Bumpless Connection of Islanded Microgrids with the Grid

To achieve a seamless/bumpless connection of an islanded microgrid with the grid, most commercial microgrids rely on centralized control and communicate with every DER within the microgrid [117]–[119]. A central microgrid controller synchronizes generation resources to maintain phase angle, frequency, and voltage magnitude differences within utility-specified limits before connecting the islanded microgrid with the grid [117]–[119]. Using a centralized microgrid controller to coordinate all DERs for synchronization and reconnection with the grid becomes infeasible when considering geographically dispersed microgrids with numerous DERs, such as utility-scale microgrids and community microgrids [144].

Using a type 4 Island Interconnection Device (IID 4), the seamless connection of an islanded microgrid with the grid or another microgrid can be achieved in a truly decentralized fashion without requiring communication with DERs. The proposed IID 4 configuration, presented in Figure 4.16, consists of fractionally-rated standard two-level voltage source converters connected back-to-back at low-voltage (480 V in this case) with isolation and step-up/step-down provided by 60 Hz transformers. The basic insulation level (BIL) requirements for the IID are met with the power electronic converters at ground level

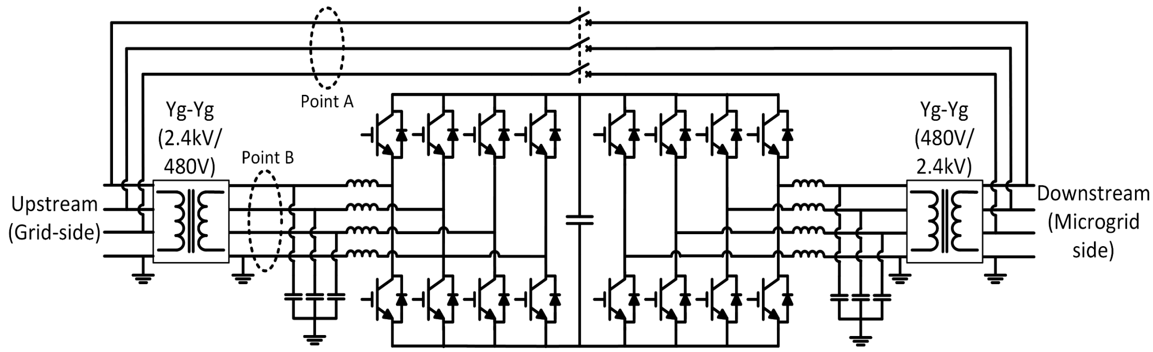


Figure 4.16: IID 4 for seamless connection of a microgrid with the grid

and the Yg-Yg transformers. In the normal grid-connected mode, the fractionally-rated back-to-back converter is bypassed by the vacuum circuit breaker, and the IID can be operated as a shunt converter to provide the functionalities listed in Figure 4.2. If sub-cycle fault current interruption and connect/disconnect times are required, a solid-state circuit breaker can be used instead of the vacuum circuit breaker.

The proposed flowchart in Figure 4.17 is used to synchronize and connect an islanded microgrid with the grid (or a neighboring microgrid). First, the utility and the local microgrid controller must agree upon the intention to connect the microgrid with the grid. To synchronize and connect the islanded microgrid with the grid, the IID matches the microgrid's frequency, phase angle, and voltage magnitude with the grid by adjusting active and reactive power injection through the fractionally-rated back-to-back converter. When the voltage magnitude, frequency, and phase angle differences between the microgrid to be connected (referred to as the reference microgrid) and the grid (referred to as the target microgrid) are within limits specified by the utility interconnection rules (i.e., ε_1, ε_2, and ε_2), the vacuum circuit breaker is closed bypassing the back-to-back power electronic converter. If the voltage synchronization time limit ($t_{v\ limit}$) or the frequency and phase

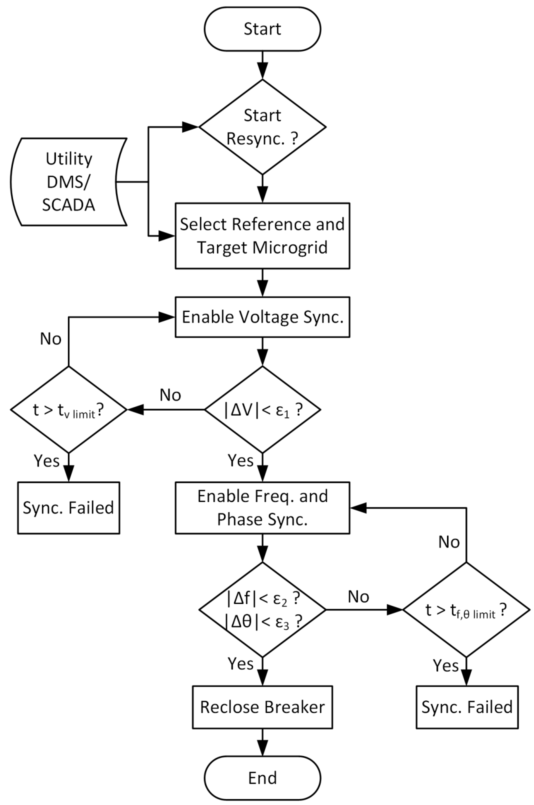


Figure 4.17: Flowchart for seamless connection of an islanded microgrid with the grid or a neighboring microgrid using IID 4

angle synchronization time limit ($t_{f,\theta\ limit}$) is reached, the synchronization attempt is considered a failure, and a new attempt can be made. Since only connect/disconnect signals are exchanged for transitions between the grid-connected and islanded modes of operation without requiring communications with local DERs, low-bandwidth high-latency communication links can be used.

4.6.4.1 Sizing Type 4 IIDs

To determine the rating of the type 4 IID (IID 4) to achieve a seamless connection of an islanded microgrid with the grid, the ratings and droop characteristics of the DERs within the microgrid must be known. Most microgrids operate with active power-frequency and reactive power-voltage droop characteristics to achieve stable active and reactive power sharing between DERs without communications by relying on the local frequency and voltage measurements [90], [138]. With droop-controlled microgrids following active power-frequency droop, the microgrid frequency when islanded depends on the droop characteristics and the electrical loading relative to the generation. With IID 4, perturbations in active power injection/absorption into/from the islanded microgrid can produce desired changes in the microgrid frequency for seamless synchronization and connection of the islanded microgrid with the grid or another microgrid.

Using equation (4.3) from [145], the active power change (ΔP) required to produce a desired frequency change ($\Delta\omega$) within the microgrid can be determined. In (4.3), R, which is equal to the per-unit change in frequency divided by the per-unit change in the output of the DER, determines the slope of the active power-frequency droop characteristic. For example, with R equal to 5% for a DER, a 100% change in DER active power output occurs for a 5% change in frequency. From equation (4.3), the maximum active power injection/absorption into/from an islanded microgrid required to produce the maximum desired frequency change can be determined and used to size the type 4 IID. If the microgrid consists of several DERs, with each having its own droop characteristic, equation (4.4) can be applied where R_n is the slope of the droop characteristic of the nth DER. It must be noted that the active power change (ΔP) from (4.3) and (4.4) refers to the steady-state active power injection/absorption corresponding to the desired steady-state frequency change ($\Delta\omega$). However, depending on the type and control of the DER, control of the IID, and load changes, the transient active power injection/absorption to achieve the desired steady-state frequency change can vary. For instance, to achieve a fast frequency change in a predominantly synchronous generator-based microgrid, the peak active power injection/absorption higher than that from (4.3) and (4.4) will be required due to the associated inertia. In this analysis, the impact of under-frequency load-shedding and frequency-sensitive loads, such as directly-connected motor loads, on the rating of IID 4 are not considered.

$$\Delta P = \frac{\Delta\omega}{R} \tag{4.3}$$

$$\Delta P = \frac{\Delta\omega}{\frac{1}{R_1} + \frac{1}{R_2} + \cdots + \frac{1}{R_n}} \tag{4.4}$$

Figure 4.18 using (4.3), illustrates the dependence of the active power rating of the type 4 IID on the required frequency change and the droop characteristics of a single DER within the microgrid on a per-unit basis. With a smaller R, a higher IID 4 rating is required to produce the desired frequency change when compared to a higher R. For example, from Figure 4.18, to produce a 0.02 pu change in frequency, a 0.66 pu change in active power is required for a DER with a 3% droop characteristic. On the other hand, a 0.2 pu change in active power is required for a DER with a 10% droop characteristic.

Similarly, to match the voltage magnitude of the microgrid with that of the grid before connection, the microgrid-side of IID 4 can be oversized using the reactive power-voltage droop relation to meet the required reactive power requirements.

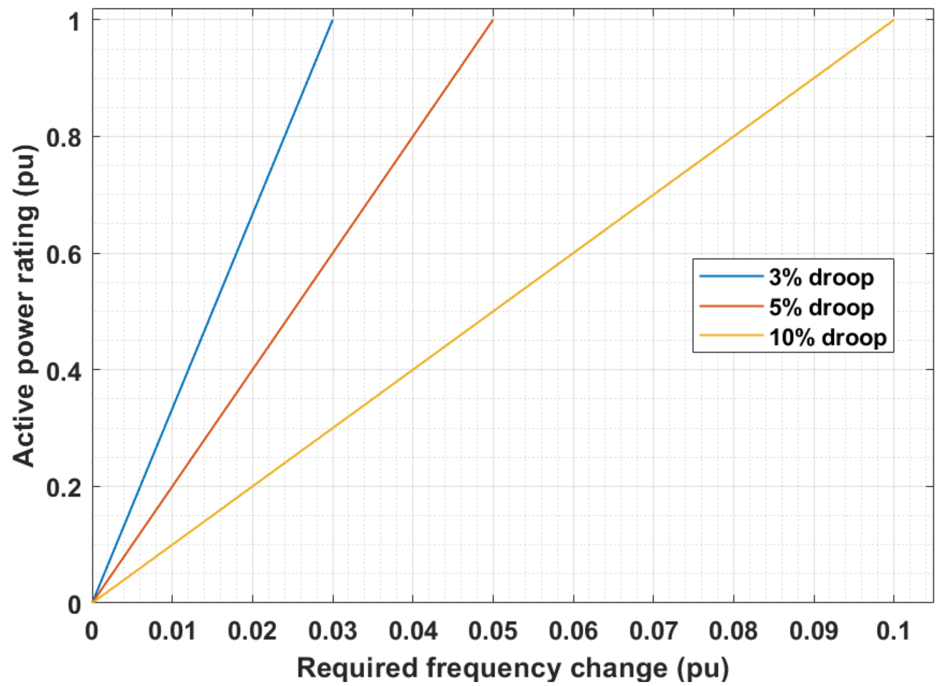


Figure 4.18: Dependence of type 4 IID (IID 4) rating on the required frequency change

4.6.4.2 Test Results

To demonstrate the ability of the IID to achieve a seamless/bumpless connection of an islanded microgrid with the grid, the feeder network in Figure 4.4 is simulated. The microgrid interconnected with the grid through IID 4 initially operates in the islanded mode. Figure 4.19 shows the frequency in the microgrid, phase angle difference of the microgrid with respect to the grid, active power injected by IID 4 from the grid into the microgrid (measured at Point B in Figure 4.16), and the line currents at the POI during reconnection (measured at Point A in Figure 4.16). At t = 2.5 s, the IID initiates the synchronization of the microgrid to match the phase and frequency of the microgrid with that of the grid by injecting active power from the grid into the microgrid through the fractionally-rated back-to-back converter. At t = 2.87 s, when the voltage magnitude

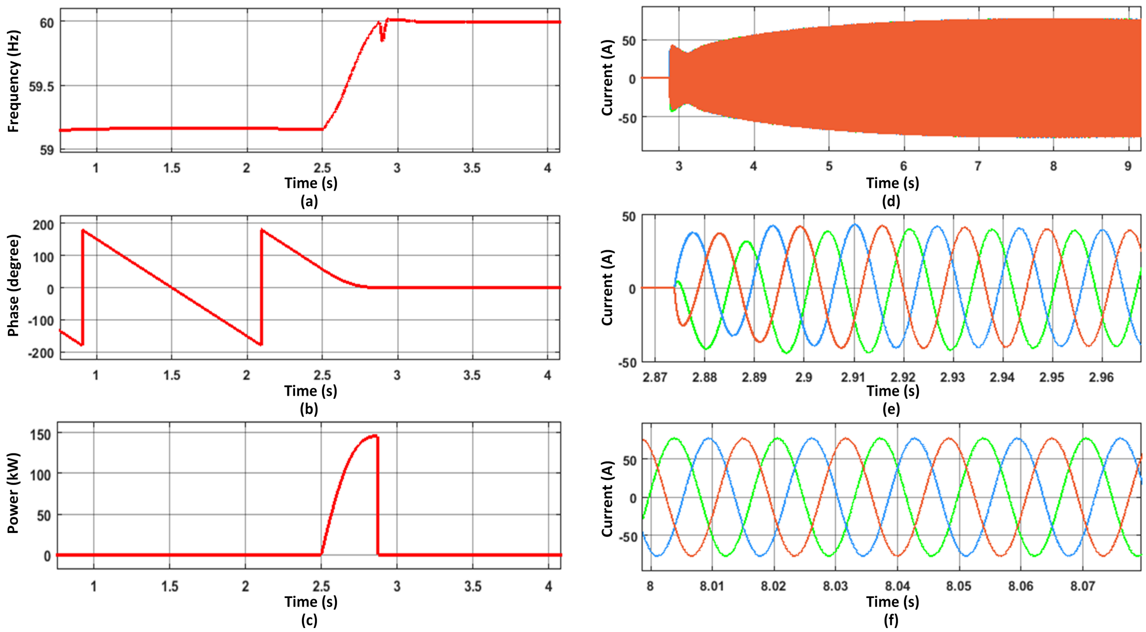


Figure 4.19: Reconnection of the islanded microgrid with the grid (a) Frequency of the microgrid, (b) Phase angle difference between the microgrid and the grid, (c) Active power injected by the IID from the grid into the microgrid, (d) Line currents at the POI of the IID, (e) Inrush current at the POI of the IID during reconnection, and (f) Steady-state current at the POI of the IID after reconnection

difference between the microgrid and the grid is within 3% of the nominal line-to-ground voltage (i.e., $\varepsilon_1 = 42$ V), the frequency difference is within 0.01 Hz (i.e., $\varepsilon_2 = 0.01$ Hz), and the phase angle difference is within 0.2 deg (i.e., $\varepsilon_3 = 0.2$ deg), the vacuum circuit breaker is closed. The peak inrush current at the POI of the IID is 41.25 A which is 8.48% of the continuous current rating of the switchgear in the microgrid (continuous current rating= 486 A, peak load= 2.02 MW at 2.4 kV). The peak power injected by the IID from the grid into the microgrid for synchronization is 146 kW which is 7.22% of the peak load in the microgrid.

For synchronization and reconnection of an islanded microgrid with the grid, the proposed approach using IID 4 does not require integrated battery storage. Unlike commercially available microgrids, it does not require any communications with the DERs in the microgrid for synchronization, resulting in significantly improved reliability and scalability of the proposed solution. Moreover, the seamless synchronization and reconnection of the islanded microgrid with the grid ensures no local stability or power quality issues.

4.7 Summary and Contributions

This chapter proposed the concept of an IID and presented the rules for interconnection, types of IIDs and their use cases, communication architecture, and the benefits of IIDs, followed by simulation results demonstrating their efficacy in mitigating distribution system impacts for grid and microgrid events.

The IID solution provides utilities and key stakeholders, including customers, regulators, and vendors, with a forward-thinking, streamlined, and proactive approach to integrating large-scale DERs and microgrids with the grid without requiring detailed system impact studies. The IID approach mitigates existing and future integration and operational risks by guaranteeing compliance with the ever-evolving utility interconnection rules. By guaranteeing compliance with utility interconnection rules and protecting the grid from every microgrid-related disturbance, the IID can exempt microgrid owners and operators from any liabilities for any impact or damage to the grid. Furthermore, this approach facilitates the accelerated adoption and deployment of microgrids by unleashing innovation allowing microgrid owners and developers to deploy, interconnect, modify, and operate advanced DER technologies.

CHAPTER 5. FLEXIBLE AND RESILIENT DISTRIBUTION SYSTEMS

Today's centralized, top-down grid architecture and operating practices make achieving resilience down to the grid-edge very challenging. Current utility practices for distribution system restoration do not leverage using DERs and load flexibility to prioritize supply to critical loads during outages. Furthermore, these approaches do not consider the ability of DERs to form feeder- and substation-level microgrids to minimize the magnitude, frequency, and duration of power outages and expedite distribution system restoration.

This chapter proposes a distribution system architecture utilizing Island Interconnection Devices (IIDs), smart electrical distribution panels, and DERs to enable flexible and resilient distribution systems by operating distribution feeders as an interconnected network of microgrids with bottom-up black-start and service restoration functions. During grid outages, these microgrids operating individually or as a microgrid cluster powered by local customer- and utility-owned DERs close to loads can enhance distribution system resilience. The proposed architecture for such a resilient distribution system and the methodologies for bottom-up black-start, service restoration, microgrid cluster formation, and grid connection are presented, followed by simulation results.

5.1 Grid Architecture for Flexible and Resilient Distribution Systems

A distribution system architecture consisting of Island Interconnection Devices (IIDs), smart electrical distribution panels enabling load flexibility, and DERs is proposed to achieve high reliability and resilience by operating the distribution system as a cluster of microgrids with flexible electrical boundaries. Figure 5.1 shows the proposed architecture for a distribution feeder consisting of single-customer microgrids such as university campuses, military bases, and industries, a multi-customer microgrid such as community and utility microgrids, and feeder loads not in the footprint of any individual microgrid. This architecture enables distribution systems to be operated in a manner similar to today but with a higher level of flexibility, reliability, and resilience by providing bottom-up black-start and service restoration functions.

In addition to existing utility equipment, the proposed architecture consists of several key elements: IIDs, smart electrical distribution panels, and DERs. The IIDs located at specific points of the distribution feeder and in every microgrid enforce utility interconnection rules, isolate faulted sections of the network, form microgrids, and reconnect with the grid in a decentralized fashion [11], [129]. Smart electrical distribution panels installed at the end-use customers' site enable the connection/disconnection of loads based on user preferences, such as on/off commands, load priority levels, utility

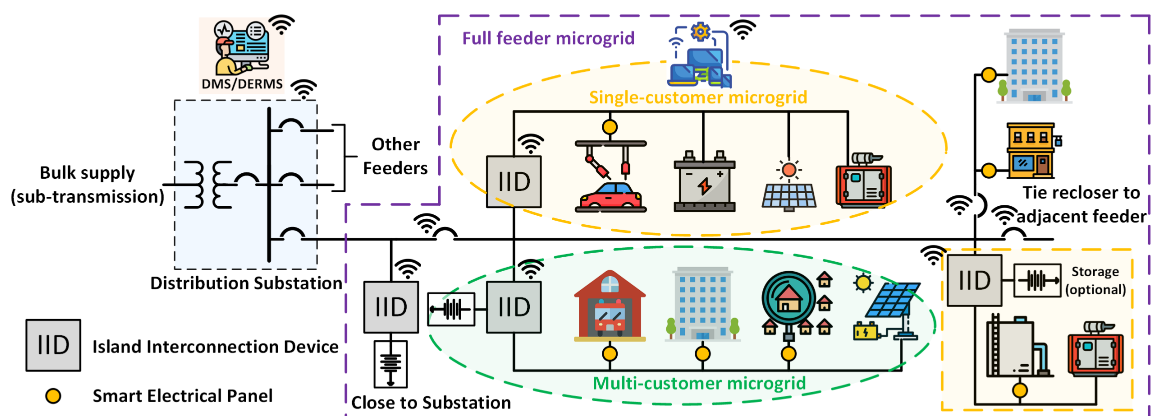


Figure 5.1: Grid architecture for flexible and resilient distribution systems

commands, and system conditions. Local customer- and utility-owned DERs can supply loads and provide electric service for extended periods on the loss of utility supply. Through the coordinated operation of utility reclosers, IIDs, and microgrids, the proposed architecture can be extended to include multiple distribution feeders and substations, providing access to more resources. The increased diversity in generation and load further improves flexibility, reliability, and resilience.

In the normal grid-connected mode, the IIDs enforce utility rules for DER and microgrid interconnection with the grid and provide utilities with a single point for coordination for grid-support, ancillary services, and advanced functions such as load reduction. In this mode, utilities can also use the smart electrical distribution panels for demand response functions and control non-essential customer loads in response to grid needs such as load-shedding.

In the event of a grid outage where the electrical network upstream of the substation is de-energized or under utility command to provide load-shedding support for the grid, utility reclosers, and IIDs can operate to split the distribution feeder into several autonomously operating islanded microgrids. In this mode, the microgrids utilize DERs such as behind-the-meter solar PV, energy storage, load flexibility, and utility-owned generation sources to prioritize supply to critical loads over sustained periods. Depending on the generation and load conditions and the physical integrity of the grid, microgrids operating independently in the islanded mode can coordinate with each other and the utility to form a microgrid cluster. By expanding/shrinking the boundaries of the microgrid cluster to increase/decrease the number of dispersed generation sources and customer loads benefiting from limited electric service, the diversity in generation and loads can be controlled. Once the grid is restored, the utility coordinates the operation of reclosers, IIDs, and microgrids to transition to the normal grid-connected mode.

The proposed highly flexible and scalable architecture enables the operation of distribution systems as an interconnected network of microgrids that significantly increases distribution system reliability and resilience. The two main components proposed in this architecture, IIDs, and smart electrical panels, are described in the following sections.

5.1.1 Island Interconnection Devices to Enable Flexible and Resilient Distribution Systems

Island Interconnection Devices proposed in Chapter 4 as a utility-owned and utility-controlled microgrid-to-grid interface to simplify the grid integration of DERs and microgrids by enforcing utility interconnection rules can be extended to improve distribution system resilience. Configurations of the IID integrated with a power electronic converter can provide grid-support services, black-start, form microgrids, restore loads, and enable seamless synchronization and interconnection of neighboring microgrids to form a microgrid cluster and reconnect with the grid.

Figure 5.2 presents the proposed types of IIDs to enable flexible and resilient distribution systems. The type 3 Island Interconnection Device (IID 3) consists of a fractionally-rated power electronic converter with battery storage connected in parallel (i.e., in shunt configuration) with the grid at the point of interconnection (POI) of the microgrid. The type 4 Island Interconnection Device (IID 4) consists of a fractionally-rated

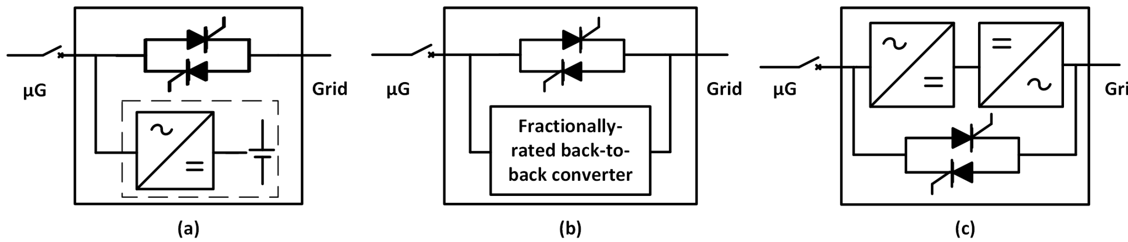


Figure 5.2: Island Interconnection Devices to enable flexible and resilient distribution systems (a) IID 3, (b) IID 4, and (c) IID 5

back-to-back converter as the microgrid-to-grid interface. IID 4 can be bypassed by the circuit breaker and operated with the grid-side converter connected in parallel with the grid/microgrid to provide the functions of IID 3. The type 5 Island Interconnection Device (IID 5), which is not considered in this thesis, consists of a fully-rated power electronic converter that allows complete asynchronous/decoupled operation of the microgrid. Although IID 5 can provide all the functions of IID 3 and IID 4, limited fault current and inrush current capability present challenges.

On the loss of utility supply, IID 3 and IID 4 (with battery energy storage) can black-start a microgrid, stabilize the microgrid by dynamically balancing generation with load, and synchronize and connect the respective islanded microgrid with the grid. Even without integrated battery energy storage, IID 4 can use active power from a neighboring energized microgrid or feeder section to black-start a microgrid, restore loads, and seamlessly reconnect with the neighboring microgrid to form a microgrid cluster and transition to the grid-connected mode. Furthermore, when operating in the islanded and grid-connected modes, IID 4 allows partial asynchronous/decoupled operation of the respective microgrid with the power exchange limited by the rating of the back-to-back power electronic converters.

To connect an islanded microgrid following active power-frequency droop and reactive power-voltage droop with the grid or a neighboring islanded microgrid, the IID first synchronizes the microgrid with the grid or neighboring microgrid. IID 3 (with battery energy storage) injects/absorbs active power into/from the microgrid by discharging/charging the battery to match the frequency and phase angle. On the other hand, IID 4 (without battery energy storage) can match frequency and phase angle by importing/exporting active power from/into the grid or neighboring microgrid. In both configurations, the voltage magnitude can be matched by injecting or absorbing reactive power. When the voltage, frequency, and phase angle differences between the microgrid to be connected and the grid or neighboring microgrid are within limits specified by the utility, the circuit breaker is closed.

In the grid-connected mode, as listed in Table 4.4, the utility can communicate with the IIDs to monitor grid conditions, update interconnection rules and limits, and issue commands for grid services. During a grid outage and when restoring supply, the utility coordinates the operation of reclosers, IIDs, and microgrids. Since only connect/disconnect signals are exchanged between the utility and IIDs for transitions between the grid-connected, islanded, and microgrid cluster modes of operation with no communications required with local DERs, low-bandwidth high-latency communication links can be used.

5.1.2 Smart Electrical Distribution Panel

The traditional electrical distribution panel installed at every customer site to distribute utility power through circuit breakers to different customer load circuits presents challenges in transitioning to a resilient distribution system. With traditional electrical distribution panels, the loads connected before the outage stay connected during the outage and may turn on simultaneously when service is restored unless turned off by the user. This inflexible demand makes restoration challenging, especially when operating the distribution system as a network of microgrids with limited generation capacity. Furthermore, in the normal grid-connected mode, the lack of monitoring and control capabilities with traditional electrical panels limits the potential to use behind-the-meter resources for demand response applications.

A smart electrical distribution panel, as shown in Figure 5.3, is proposed to overcome the limitations of the traditional electrical panel. The smart electrical panel consisting of controllable circuit breakers integrates circuit-level monitoring and controls with utility and end-use customer inputs. The utility can communicate with the behind-the-

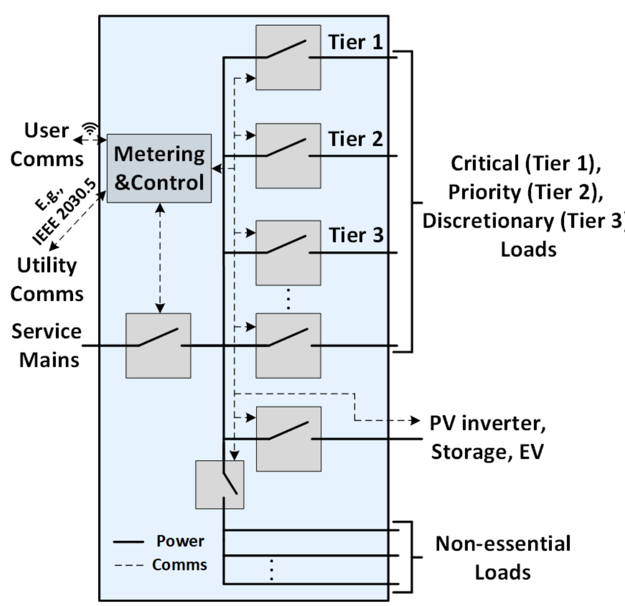


Figure 5.3: Smart electrical distribution panel

meter loads and DERs through the smart electrical panel using communication protocols such as IEEE 2030.5 [146]. End-use customers can interact with the smart electrical panel for monitoring and control purposes, such as assigning priority levels to loads and scheduling loads. Users can dynamically assign loads into one of the four categories: tier 1 (critical), tier 2 (priority), tier 3 (discretionary), and non-essential loads. Tier 1 loads are considered critical and must be served at all times to the extent possible, including when the utility supply is lost. When operating in the islanded microgrid mode following a grid outage, the smart electrical panels ensure that generation sources first connect, followed by loads. In the islanded mode, all non-essential loads are disconnected and are allowed to only reconnect in the normal grid-connected mode. Tier 1 loads are given the first opportunity to connect, followed by tier 2 and 3 loads. When there is insufficient generation, the connected tier 3 loads are shed first, followed by tier 2 and tier 1 loads.

The smart electrical distribution panel provides the following benefits:

1) Simplified integration of behind-the-meter DERs- With integrated circuit-level monitoring and controls, the smart electrical panel simplifies the integration of DERs, such as solar PV and batteries. Instead of requiring a separate electrical panel for DERs and critical loads, as is the case today, a smart electrical panel can be used to integrate DERs and all loads. Moreover, as the customer can assign priority levels to loads on the fly, no hard-wiring of dedicated loads that require backup during a grid outage is required.

2) Reliable under-frequency load-shedding (ULFS)- The traditional UFLS practices implemented at the substation level where pre-set groups of customers are disconnected at

predetermined frequency setpoints become ineffective if customer DERs are disconnected. On the other hand, in response to a frequency decline, UFLS, when implemented at the customer smart electrical panel, will only disconnect loads in the reverse order of priority while the DERs remain connected. This provides a more reliable approach to arresting the frequency decline and contributing to frequency recovery.

3) Simplified black-start and service restoration- During service restoration following a utility outage or blackout, the smart electrical panel can limit the load imposed by individual customers. Moreover, when operating in the islanded microgrid mode with limited generation resources, the power supply can be cycled among customers over time for equitable access.

4) Enables direct load control- Unlike traditional pricing-based demand response approaches, direct control of loads is a more dependable approach to managing the load on the grid. In response to a grid requirement, such as reducing the peak demand, which requires the disconnection of loads, a utility can implement local control logic and command the smart electrical panels to shed non-essential and low-priority loads.

The smart electrical panel uses under-frequency and RoCoF-based load-shedding to disconnect low-priority loads when the system is experiencing low generation and high load conditions. When operating in the islanded microgrid or microgrid cluster mode following the loss of utility supply, the smart electrical panels enable sustained islanded operation with limited generation by prioritizing supply to critical loads over low-priority loads and disconnecting non-essential loads. The algorithm for the proposed load-shedding method and restoration technique implemented in the smart electrical panel is discussed in the following section.

5.2 Bottom-up Black-start and Service Restoration in Distribution Feeders

The increasing penetration of DERs and microgrids can be leveraged to supply critical loads and restore service to the distribution system on the loss of utility supply. However, during outages, the lack of local power availability compared to load and load inflexibility presents challenges in service restoration. An approach to distribution system restoration is needed where loads can be restored with minimum intervention from customers and the utility. The end-use customers must only be required to select load preferences such as on/off statuses and priority levels. At the same time, the system operational rules and constraints set by the utility or distribution system operator must be enforced.

This section proposes an approach to perform bottom-up black-start and distribution system restoration utilizing IIDs, load flexibility enabled by smart electrical distribution panels, and DERs upon the loss of utility supply.

Figure 5.4 shows the flowchart for bottom-up black-start and service restoration at the distribution system-level using the proposed approach. In reference to Figure 5.1, following a substation outage, the substation switchgear opens and islands the distribution feeder. Utility protection devices such as reclosers, switches, etc., and IIDs operate to island segments of the distribution system to form and operate as microgrids. If the entire distribution feeder or a segment of the distribution feeder experiences a blackout, IIDs

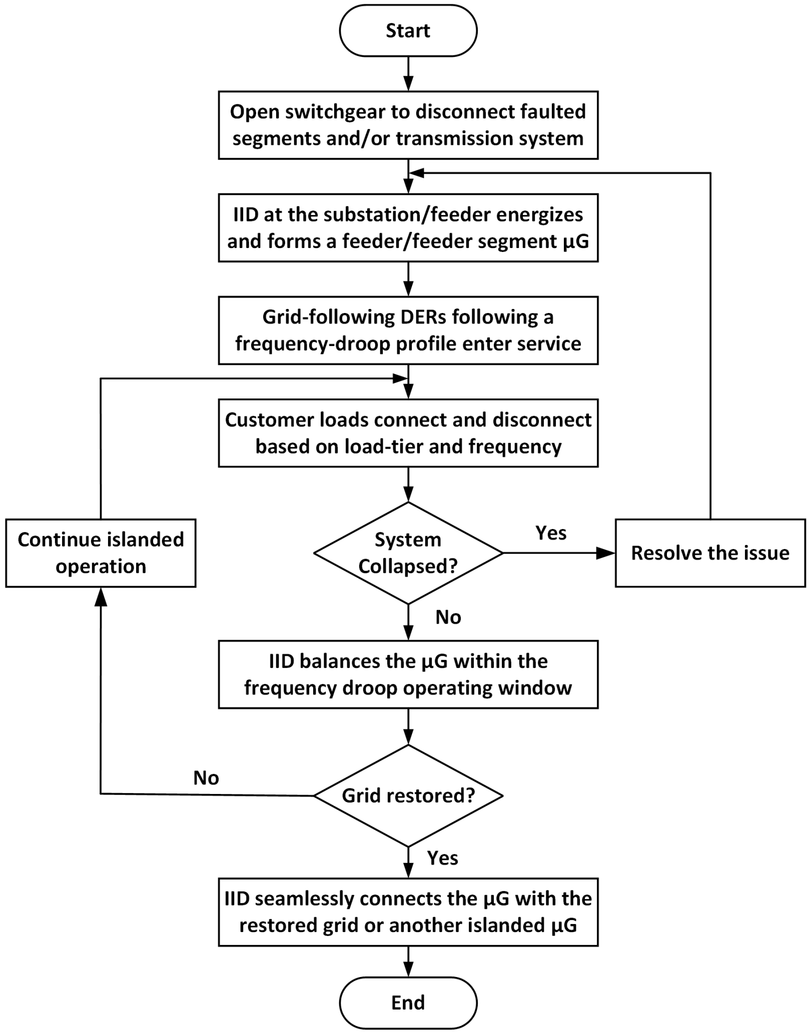


Figure 5.4: Flowchart for bottom-up black-start and service restoration at the distribution system-level

integrated with battery storage can re-energize the islanded segment forming a microgrid. Once the voltage and frequency of the islanded microgrid are within the normal ranges, utility- and customer-owned grid-following DERs following frequency-active power droop (i.e., Frequency/Watt control function) connect with the grid following a randomized intentional delay. Customer loads interfaced through the smart electrical distribution panel then connect and disconnect based on user preferences (on/off statuses, priority level), system frequency, and RoCoF on connection. The IID dynamically balances generation with load and stabilizes the microgrid frequency within the islanded mode's frequency droop operating window. When a neighboring microgrid is energized, the IIDs coordinate with each other and the utility to form a microgrid cluster and connect with the grid when the utility supply is restored.

By performing bottom-up black-start and restoring service in individual and feeder-level microgrids, the proposed approach can supply critical loads and rapidly restore service to the rest of the distribution system. The following sections describe the role and control of IIDs, grid-following DERs, and the proposed load-level restoration methodology implemented in the smart electrical distribution panels to restore loads during the bottom-up black-start and service restoration process.

5.2.1 Control and Operation of Island Interconnection Devices as a Grid-Forming Source

In the event of a grid outage or under utility command, segments of the distribution system and microgrids interfaced through IIDs disconnect and transition to operate in the islanded mode if there is sufficient generation to meet the load. If the microgrid collapses on islanding due to inadequate generation compared to load or fault conditions, a bottom-up black-start followed by service restoration is required.

To black-start and operate in the islanded mode, a microgrid requires at least one DER to operate in the grid-forming mode and regulate the voltage and frequency. DERs, such as batteries, and even solar PV inverters to a certain extent, can provide grid-forming functions. If no grid-forming DER source is available, IID 3 and IID 4 in Figure 5.2 with battery storage can be operated in the grid-forming mode to black-start and restore loads in the microgrid. If a grid-forming DER source is present, the IID can operate in the grid-following or grid-forming mode with appropriate droop settings. Furthermore, in cases where a neighboring microgrid is energized, IID 4, consisting of a fractionally-rated back-to-back converter without battery storage, can draw power from the energized microgrid and perform bottom-up black-start and service restoration in the collapsed microgrid.

Figure 5.5 shows the proposed control structure adapted from [138] to operate the IID as a grid-forming voltage source inverter to actively regulate the voltage and frequency and dynamically balance generation with the load. The control is based on the traditional grid-forming control framework proposed in [138], which consists of an outermost power

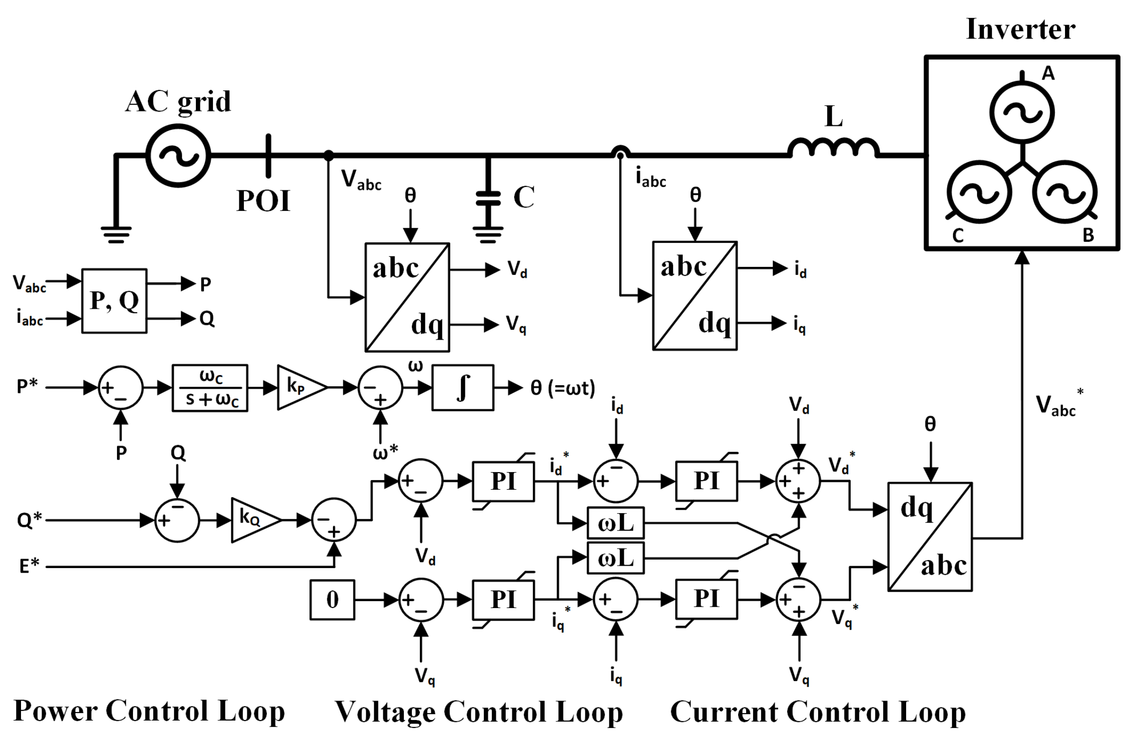


Figure 5.5: Control structure of IIDs operated as a grid-forming source to black-start and restore service following the loss of utility supply

control loop followed by inner voltage and current control loops. In Figure 5.5, ω^* is the reference nominal grid frequency, P^* is the active power setpoint (or bias) at nominal frequency, P is the measured active power output, k_P is the active power-frequency droop coefficient (or slope), E^* is the reference nominal grid voltage, Q^* is the reactive power setpoint (or bias) at nominal voltage, Q is the measured reactive power output, and k_Q is the reactive power-voltage droop coefficient (or slope). The power control loop implementing droop control generates frequency and voltage references based on the active and reactive power exchange. Droop control provides a means to achieve stable active and reactive power sharing between DERs without communications by relying on local frequency and voltage measurements [138]. The voltage control loop regulates the output voltage by generating current references in response to the measured and reference voltages. The innermost current control loop regulates the current output by tracking the current references from the voltage control loop. The dq voltage and current controllers use synchronous frame proportional-integral (PI) controllers.

The active power-frequency control loop in Figure 5.5 is augmented with a low-pass filter block to provide virtual inertia, which influences the RoCoF during changes in generation and load when operating in the islanded mode. The dynamics of the low-pass filter emulates virtual inertia, similar to the virtual synchronous machine, where the low-pass filter cut-off frequency (ω_c) in Figure 5.5 is analogous to the inertia constant (H) of the virtual synchronous machine [147]–[149]. The virtual inertia, and consequently the RoCoF, can be changed by varying the filter cut-off frequency. For example, a low cut-off frequency filters out fast changes in the active power output measurement, producing slow changes in the frequency reference corresponding to higher inertia. Virtual inertia can also be emulated in several other ways, including the emulation of a synchronous generator [149], synchronous power controller [149], and transient droop characteristics [150].

To minimize the transformer and cable inrush current during black-start, the grid-forming IID ramps its terminal voltage from zero to the nominal value with a pre-defined ramp rate instead of energizing the network directly at the rated voltage. Soft-start also avoids oversizing the IID and other grid-forming DERs to supply the inrush current during energization. Once the network is energized with the voltage and frequency within the normal range, the grid-following DERs connect following a randomized intentional delay, followed by the loads in the decreasing order of priority.

In the islanded mode with the microgrid following active power-frequency droop, the frequency reflects the instantaneous generation-to-load balance. The grid-forming IIDs within the microgrids collectively regulate the frequency and RoCoF through primary frequency control utilizing virtual inertia. In the case of high load compared to the available generation capacity, the frequency drops to the lower end of the droop curve, where tier 1 (critical) loads are prioritized over tier 2 and tier 3 loads. To avoid excess DER generation under light load conditions and not overcharge the battery integrated within the IID, the IID can adjust the microgrid frequency to invoke the curtailment of behind-the-meter DERs. Additionally, when the state-of-charge of the battery is low, the frequency can be adjusted to signal DERs to increase generation and low-priority loads with high under-frequency trip points to disconnect. The grid-forming IID can adjust the microgrid frequency by changing its active power-frequency droop parameters in Figure 5.5, namely, the active power bias (P^*), reference nominal grid frequency (ω^*), and active power-frequency droop coefficient (k_P). Furthermore, energy management functions such as battery state-of-charge management can be implemented by mapping the battery state-of-charge to the active power-frequency droop parameters.

5.2.2 Control and Operation of DERs as a Grid-Following Source

Today, most DERs are operated in the grid-following mode and act as current-controlled sources that track active and reactive power references. A major distinguishing factor between grid-following and grid-forming sources is that the former requires a phase-locked loop (PLL) to track and synchronize with the grid, while the latter does not require it [138]. Moreover, a grid-following inverter requires an existing grid voltage to synchronize and inject power and cannot operate in the islanded mode without a grid-forming source regulating the voltage and frequency.

As the penetration of inverter-based DERs increases, it has become necessary to integrate grid-support functions such as Volt/VAR, Frequency/Watt, etc., in DERs. IEEE 1547-2018, the latest US standard for interconnecting DERs, requires all DERs to provide grid-support functions to prevent violations in voltage and frequency [56].

The control structure of a grid-following inverter following frequency-active power droop (Frequency/Watt) and voltage-reactive power droop (Volt/VAR) is shown in Figure 5.6 [138]. In Figure 5.6, ω^* is the nominal grid frequency, P^* is the active power reference at nominal frequency, ω is the measured grid frequency, k_P is the frequency-active power droop coefficient (or slope), V^* is the nominal grid voltage, Q^* is the reactive power

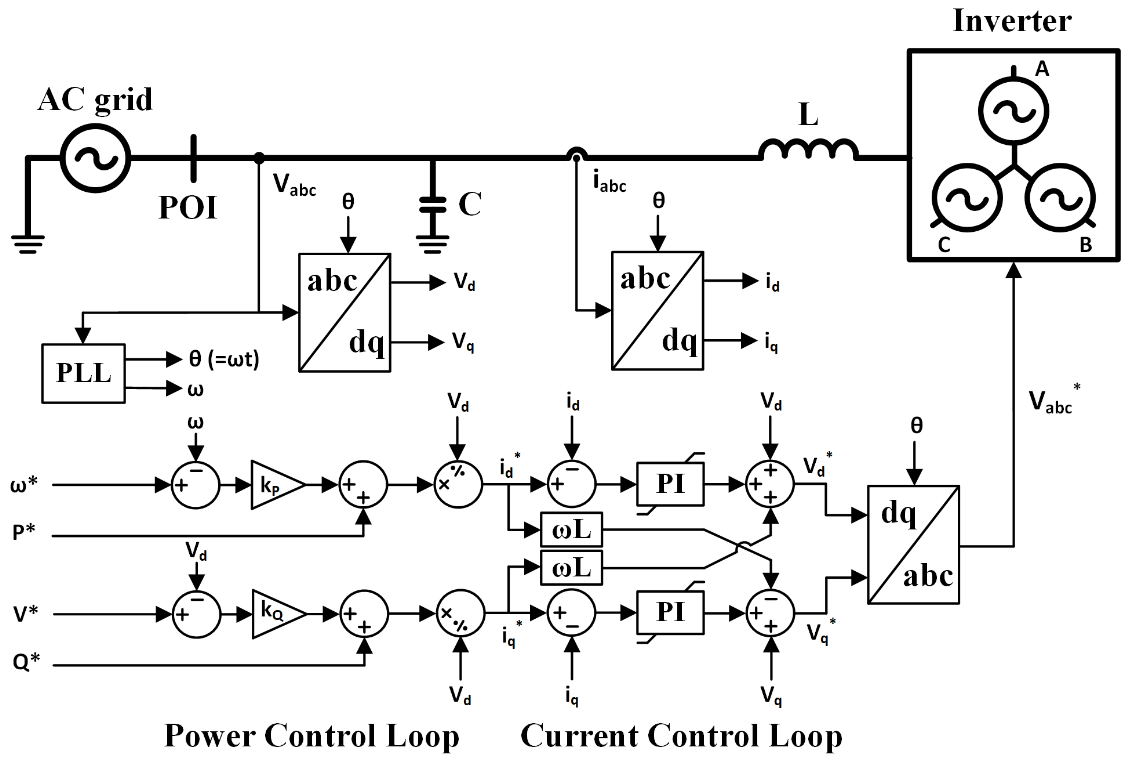


Figure 5.6: Control structure of grid-following DERs with droop [138]

reference at nominal grid voltage, and k_Q is the voltage-reactive power droop coefficient (or slope). The PLL tracks the instantaneous phase angle of the measured inverter terminal voltage and aligns the dq transformation angle with the grid such that the d- and q-axis currents correspond to active and reactive currents [138]. The outer power control loop generates the active and reactive power references based on the grid frequency and voltage, which are then converted to d- and q-axis current references. The inner current control loop then regulates the current output by tracking the d- and q-axis current references from the power control loop.

The Frequency/Watt grid-support control function utilized in this work allows grid-following DERs to balance generation with load by reducing the output power for overfrequency events to mitigate excess generation conditions. The Frequency/Watt control function measures the grid frequency and limits the maximum active power output following a frequency-active power droop curve such as the one shown in Figure 5.7 used in this work. When operating in the islanded microgrid mode with the voltage and frequency regulated by the grid-forming IID, the microgrid frequency continuously varies depending on the instantaneous balance between generation and load. Up to 63.5 Hz, the grid-following DERs can inject active power up to their rated capacity. As the frequency increases further, the maximum active power output allowed drops progressively to reach zero at 64.5 Hz. Above 64.5 Hz, the DER can be required to trip or stay connected without producing power.

To avoid operating in the over-frequency region requiring the curtailment of the grid-following DERs, the grid-forming IID can adjust its active power-frequency droop parameters to lower the system frequency and charge its battery for future use.

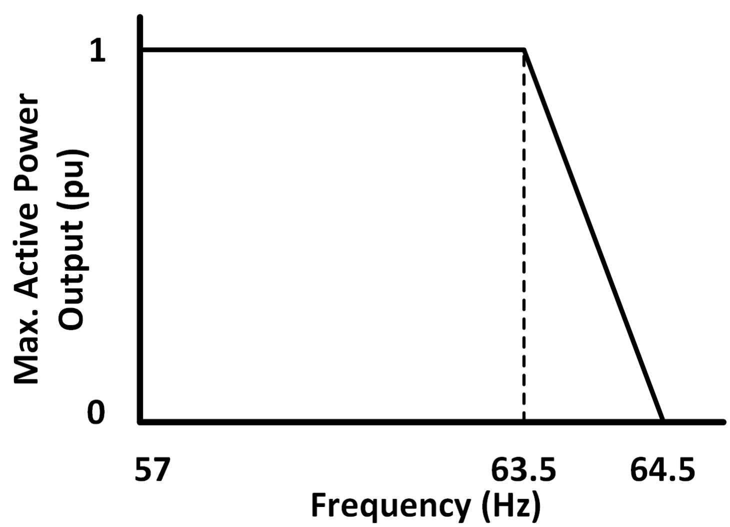


Figure 5.7: Frequency-active power droop curve for Frequency/Watt grid-support control function

5.2.3 Methodology for Load-level Restoration

This section proposes a local load-level restoration methodology implemented in the customers' smart electrical distribution panel for bottom-up black-start and service restoration of the distribution system with DERs. When operating in the islanded microgrid mode on the loss of utility supply, the proposed restoration approach prioritizes supply to tier 1 (critical) loads over lower priority tier 2, tier 3, and non-essential loads. The decision to connect/disconnect loads is made based on customer and utility inputs and the locally measured frequency and rate-of-change-of-frequency (RoCoF) on connection.

The proposed load-level restoration algorithm consisting of three stages is illustrated as a flowchart in Figure 5.8. The symbols in the flowchart are described in Table 5.1. In stage 1, the customer and distribution system operator inputs are utilized to initialize the load restoration logic. In stage 2, if the system frequency is above the locally assigned turn-on frequency ($f_{i,b}$), an attempt to connect the load is performed. If the frequency and RoCoF on connection violate the locally calculated limits and utility provided limits in stage 1, the load is disconnected, and an attempt to reconnect is performed. In stage 3, the load stays connected and operates in the islanded individual microgrid or microgrid cluster mode as long as the frequency is above the locally calculated turn-off frequency ($f_{i,a}$) which is within the operating window ($[F_{i,a}, F_{i,b}]$) specified by the utility for the respective load tier. When the system frequency falls below the turn-off frequency, the load is disconnected, and an attempt to reconnect is performed.

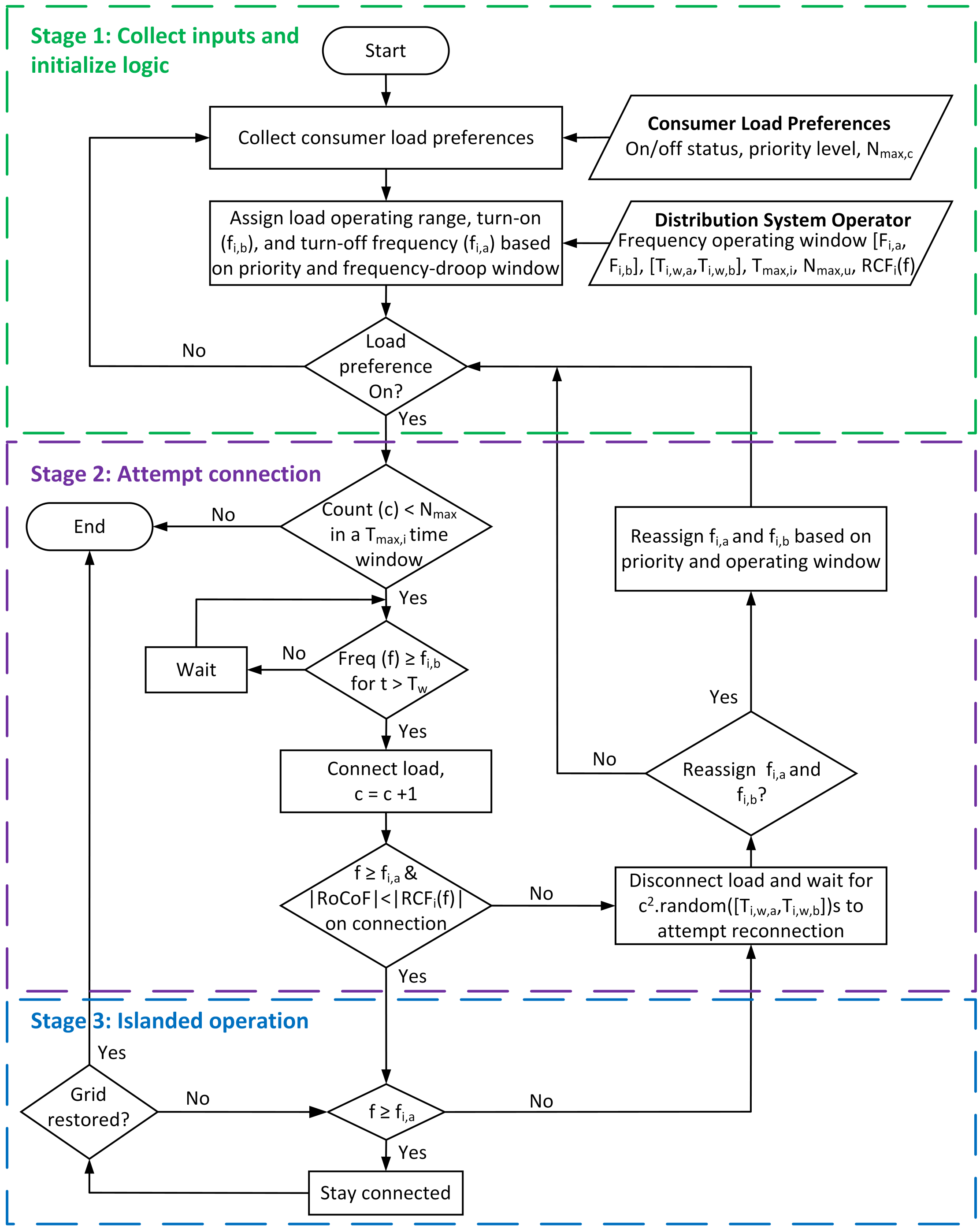


Figure 5.8: Flowchart for load-level service restoration

Table 5.1: Description of symbols in the proposed load-level restoration methodology

Symbol	Description
i	Load priority level ($i = 1$ for tier 1 loads, $i = 2$ for tier 2 loads, etc.)
$N_{max,c}$	Maximum number of connection attempts specified by the customer over a $T_{max,i}$ time window
$F_{i,a}$	Lower-limit of the allowable frequency range $[F_{i,a}, F_{i,b}]$ specified by the utility for tier i loads within which $f_{i,a}$ and $f_{i,b}$ are assigned
$F_{i,b}$	Upper-limit of the allowable frequency range $[F_{i,a}, F_{i,b}]$ specified by the utility for tier i loads within which $f_{i,a}$ and $f_{i,b}$ are assigned
$T_{i,w,a}$	Lower-limit of the allowable range of wait times $[T_{i,w,a}, T_{i,w,b}]$ specified by the utility for tier i loads for which the frequency should be above $f_{i,b}$ before attempting to connect the load
$T_{i,w,b}$	Upper-limit of the allowable range of wait times $[T_{i,w,a}, T_{i,w,b}]$ specified by the utility for tier i loads for which the frequency should be above $f_{i,b}$ before attempting to connect the load
$T_{max,i}$	Time-window over which the maximum number of connection attempts is imposed for a tier i load
$N_{max,u}$	Maximum number of connection attempts specified by the utility over a $T_{max,i}$ time window
$RCF_i(f)$	Dynamic frequency-RoCoF curve specified by the utility for every tier i load to limit the maximum load that can be connected and allowed to operate in the islanded mode
$f_{i,a}$	Locally assigned turn-off frequency value for the respective tier i load within the utility specified frequency range $[F_{i,a}, F_{i,b}]$ below which the load is disconnected
$f_{i,b}$	Locally assigned turn-on frequency value for the respective tier i load within the utility specified frequency range $[F_{i,a}, F_{i,b}]$ above which the load can attempt to connect
c	Counter tracking the number of connection attempts in a $T_{max,i}$ time window
N_{max}	Maximum number of connection attempts in a $T_{max,i}$ time window imposed by the smart electrical panel for the respective load. Minimum of $N_{max,c}$ and $N_{max,u}$
T_w	Locally assigned wait time within the utility specified range $[T_{i,w,a}, T_{i,w,b}]$ for which the frequency should be above $f_{i,b}$ before attempting to connect the load

The following sections describe the individual stages in the proposed load-level restoration algorithm.

5.2.3.1 Stage 1: Collecting Load Preferences from the Customer and Inputs from the Utility

In stage 1, customer preferences consisting of load on/off statuses, priority levels (i), and the maximum number of connection attempts ($N_{max,c}$) in a utility-specified time window ($T_{max,i}$) are collected for all the loads connected through the smart electrical distribution panel. The distribution system operator or utility specifies the allowable range of frequencies ($[F_{i,a}, F_{i,b}]$) for every load tier i within which the load turn-on frequency ($f_{i,b}$) and turn-off frequency ($f_{i,a}$) are locally assigned, the range of wait times $[T_{i,w,a}, T_{i,w,b}]$ for which the frequency must be above $f_{i,b}$ before attempting to connect the load, the time window ($T_{max,i}$) over which the maximum number of connection attempts (N_{max}) is imposed for a tier i load, and the dynamic frequency-RoCoF curve ($RCF_i(f)$) that imposes a RoCoF limit following the connection of the load based on the frequency before attempting connection.

Using inputs from the customer and the utility, the load turn-on frequency ($f_{i,b}$) and turn-off frequency ($f_{i,a}$), the maximum number of connection attempts (N_{max}), and wait time (T_w) are locally assigned. The turn-on frequency ($f_{i,b}$) and turn-off frequency ($f_{i,a}$) are calculated using a uniform distribution, as shown in equations (5.1) and (5.2). $U(0,1)$ is a uniform random distribution between 0 and 1. $f_{i,a}$ and $f_{i,b}$ are selected such that the minimum difference between them is 0.3 Hz and that they are within the frequency range $[F_{i,a}, F_{i,}]$ specified by the utility for the respective load tier i. The maximum number of connection attempts (N_{max}) allowed in a $T_{max,i}$ time window imposed by the smart electrical panel is assigned using (5.3). The wait time (T_w) which is the time for which the frequency must be no less than $f_{i,b}$ before attempting to connect the load is calculated using (5.4). The wait time delays the energization of the load when power is restored, introduces load diversity, and mitigates cold load pickup. If the load preference stays on, the control progresses to stage 2. Otherwise, it returns to collecting the consumer and utility inputs.

$$f_{i,a} = \left(F_{i,b} - F_{i,a}\right) \times U(0,1) + F_{i,a} \; s.t. f_{i,a} \in [F_{i,a}, F_{i,b} - 0.3] \tag{5.1}$$

$$f_{i,b} = \left(F_{i,b} - f_{i,a}\right) \times U(0,1) + f_{i,a} \; s.t. f_{i,b} \in [f_{i,a} + 0.3, F_{i,b}] \tag{5.2}$$

$$N_{max} = \min\left(N_{max,c}, N_{max,u}\right) \tag{5.3}$$

$$T_w = \left(T_{i,w,b} - T_{i,w,a}\right) \times U(0,1) + T_{i,w,a} \tag{5.4}$$

5.2.3.2 Stage 2: Attempt Connection of Loads

In stage 2, an attempt to connect the load is performed. If the number of connection attempts (c) is less than the maximum number of connection attempts (N_{max}) over a $T_{max,i}$ time window and the frequency measured over a 3-cycle moving average window is above the turn-on frequency ($f_{i,b}$) continuously for more than the wait time (T_w), the load is connected. On connection and up to 3 cycles (i.e., 3/60 = 0.05 s) after connection, if the frequency measured over a 3-cycle moving average window falls below the turn-off frequency ($f_{i,a}$) or the RoCoF measured over a 1-cycle moving average window exceeds the limit from the utility-provided frequency-RoCoF curve ($RCF_i(f)$), the load is disconnected, and an attempt to reconnect is performed. Disconnecting the load affects the frequency immediately and contributes to restoring the balance between the load and generation.

The dynamic frequency-RoCoF curve ($RCF_i(f)$) maps the frequency prior to connection to the maximum allowed RoCoF on connecting the load. As the RoCoF is proportional to the amount of power imbalance, the frequency-RoCoF curve limits how large a load can be connected at a specific frequency without causing the frequency to drop so low that other already connected loads disconnect. Representative dynamic frequency-RoCoF curves for each load tier are shown in Figure 5.9, but the same curve can be used for all load tiers. The dynamic frequency-RoCoF curves must be set considering the type of generation sources (synchronous generator or inverter-based resource) and the type of control, such as grid-forming and grid-following inverter control dynamics, including virtual inertia and ramp-rate requirements. These curves can be updated periodically as the resource mix, the settings of the IIDs and DERs, and other parameters such as ramp-rates change. Integrating the fixed frequency load-shedding method commonly used in the bulk

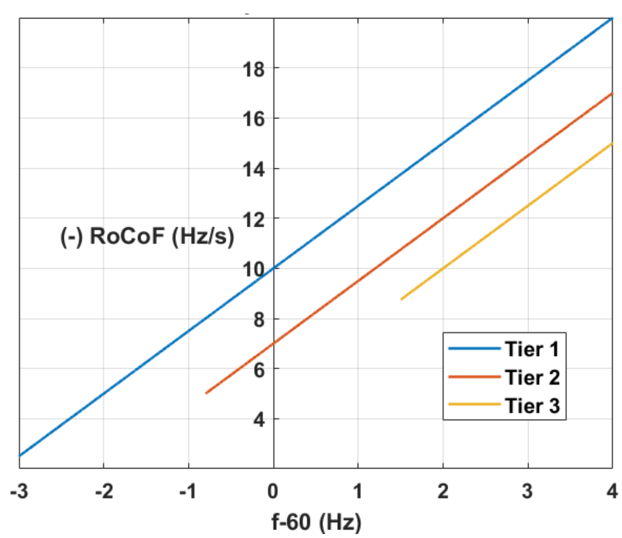


Figure 5.9: Dynamic frequency-RoCoF curves

power system with RoCoF-based load-shedding provides a more robust approach to load restoration, supplying critical loads, and dynamically stabilizing the system by disconnecting low-priority loads.

In the reconnection attempt, an additional wait time is added, as shown in (5.5), to delay reconnection based on the number of connection attempts and an option to reassign the turn-on frequency ($f_{i,b}$) and turn-off frequency ($f_{i,a}$) is provided. If the frequency and RoCoF on connecting the load and up to 3 cycles after connection are within limits, the load continues to stay connected, operating in the islanded mode, and transitions to stage 3 of load restoration.

$$T_w = c^2 \times \left(T_{i,w,b} - T_{i,w,a}\right) \times U(0,1) + T_{i,w,a} \tag{5.5}$$

5.2.3.3 Stage 3: Islanded Operation

In stage 3, when operating in the islanded individual microgrid or microgrid cluster mode following active power-frequency droop, the frequency reflects the instantaneous generation-to-load balance and constantly varies as the generation and load vary. When the active power demand is high compared to generation, the microgrid frequency drops to the lower end of the frequency operating window, where supply to tier 1 (critical) loads is prioritized over low-priority tier 2 and tier 3 loads. This ensures that critical loads are always served if sufficient generation is available.

As long as the frequency is no less than the turn-off frequency ($f_{i,a}$), the load stays connected and operates in the islanded mode. If the frequency drops below $f_{i,a}$, the load is disconnected, and an attempt to reconnect is performed. On restoring the utility supply and seamlessly interconnecting the islanded microgrid with the grid, the frequency dynamics are much slower and smaller than in the islanded mode. When the frequency stays close to the nominal value of 60 Hz with minimal variations for extended periods, the connected loads stay connected and transition to the grid-connected mode.

The following section demonstrates the application of grid-forming IIDs, grid-following DERs, and the proposed load-level restoration scheme for bottom-up black-start and service restoration of a distribution feeder segment following the loss of utility supply.

5.2.4 Simulation Results

To validate the proposed approach for bottom-up black-start and service restoration presented in the previous sections, EMT simulations are conducted on OPAL-RT using MATLAB/Simulink with eMEGASIM. The test system in Figure 5.10, consisting of a feeder segment with a grid-forming IID (integrated with storage), grid-following DER, and loads distributed throughout the feeder, is simulated. The grid-forming IID is modeled with the control structure shown in Figure 5.5 using the physical and control parameters listed in Table 5.2. The active power-frequency droop coefficient (k_P) and reactive power-voltage

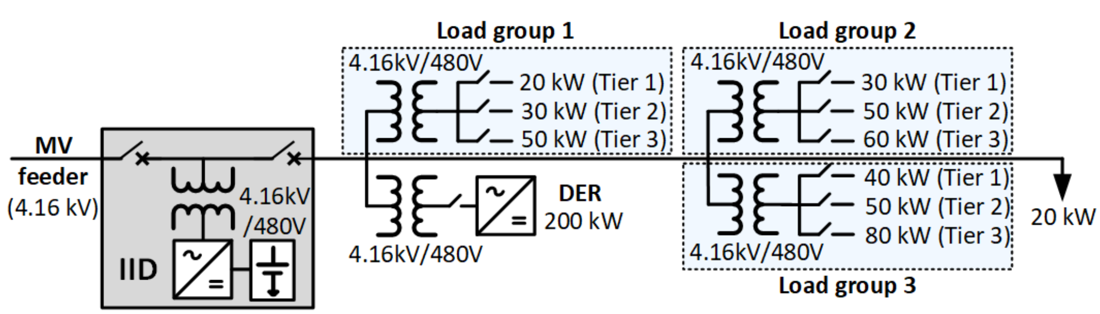


Figure 5.10: Test system for bottom-up black-start and service restoration

droop coefficient (k_Q) of the IID are selected to achieve a 7.5% droop (i.e., 4.5 Hz) in the active power-frequency characteristic and a 5% droop in the reactive power-voltage characteristic. The grid-following DER is modeled with the control structure in Figure 5.6 with the frequency-active power droop coefficient (k_P) reflecting the frequency-active power droop curve in Figure 5.7 and the voltage-reactive power droop coefficient (k_Q) set to zero. An additional 20 kW load at the end of the feeder segment is added to reflect a load that is always connected, including in the de-energized state. The loads are modeled with constant impedance characteristics.

Table 5.2: Parameters of grid-forming IID

Parameter	Value
Rating (kVA/kW)	120 kVA/120 kW
Nominal voltage (line-to-line)	480 V
L	0.05 mH
C	20 μF
ω^*	2π*60 rad/s
P*	0
E*	392 V
Q*	0
ω_c	10 rad/s
k_P	−0.2356 (rad/s)/kW
k_Q	−0.1633 V/kVAR
$k_{p,PI\_V\_control}$	0.75
$k_{i,PI\_V\_control}$	8
$k_{p,PI\_I\_control}$	10
$k_{i,PI\_I\_control}$	160

Table 5.3 summarizes the three simulation scenarios and lists the IID and grid-following DER ratings and the maximum tier 1, tier 2, and tier 3 loads. The rating of the grid-forming IID with battery energy storage and the maximum tier 1, tier 2, and tier 3

loads are the same in all scenarios. In scenarios 1 and 2, the IID reference nominal grid frequency (ω*) is changed from 2π*60 rad/s to 2π*63 rad/s at t = 500 s, while it is fixed at 2π*60 rad/s in scenario 3. The rating of the grid-following DER is varied in each case. The total load of 410 kW connected through the smart electrical panels roughly reflects serving 80-140 homes.

Table 5.3: Simulation scenarios

Scenario	Rating of IID	Change in IID reference frequency (ω*)?	Rating of DER	Maximum load		
				Tier 1	Tier 2	Tier 3
Scenario 1	120 kW	Yes	200 kW	90 kW	130 kW	190 kW
Scenario 2	120 kW	Yes	400 kW	90 kW	130 kW	190 kW
Scenario 3	120 kW	No	500 kW	90 kW	130 kW	190 kW

The range and value of parameters provided by the utility for the load-level restoration algorithm are listed in Table 5.4. Figure 5.11 shows the common frequency-RoCoF curve (i.e., $RCF_1(f) = RCF_2(f) = RCF_3(f)$) used for all tier 1, tier 2, and tier 3 loads. Table 5.5 lists the initial value of turn-on and turn-off frequency parameters for load-level restoration calculated locally in the smart electrical distribution panels for every load in each scenario based on inputs from the utility. To evaluate the performance of the proposed bottom-up black-start and service restoration methodology with varying DER output, the normalized solar PV output over a 30 min time frame, as shown in Figure 5.12, is used in all scenarios [151].

Table 5.4: Range and value of parameters provided by the utility for the load-level restoration algorithm

Parameter	Value
$N_{max,u}$	3
$[F_{1,a}, F_{1,b}]$	[57, 59] Hz
$[F_{2,a}, F_{2,b}]$	[59.2, 61.2] Hz
$[F_{3,a}, F_{3,b}]$	[61.5, 63.5] Hz
$[T_{1,w,a}, T_{1,w,b}]$	[0, 60] s
$[T_{2,w,a}, T_{1,w,b}]$	[60, 120] s
$[T_{1,w,a}, T_{1,w,b}]$	[120, 180] s
$T_{max,1}$	1800 s
$T_{max,2}$	1800 s
$T_{max,3}$	1800 s

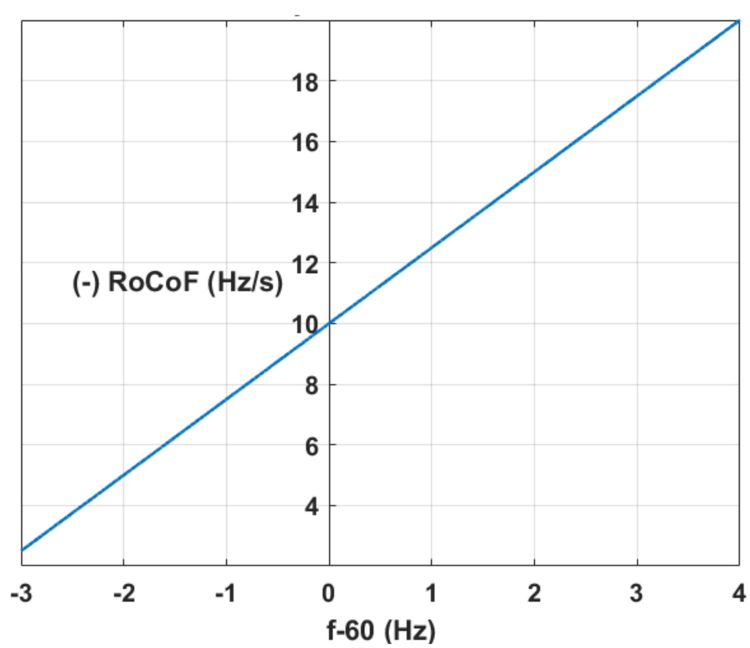


Figure 5.11: Common frequency-RoCoF curve for all loads

Table 5.5: Initially assigned value of parameters in the load-level restoration algorithm implemented in the smart electrical panels

Load		Parameters	
		$f_{i,a}$ (Hz)	$f_{i,b}$ (Hz)
Load group 1	$Tier$ 1	57.83	58.67
	$Tier$ 2	59.22	60.21
	$Tier$ 3	61.61	62.29
Load group 2	$Tier$ 1	58.11	58.44
	$Tier$ 2	59.42	60.48
	$Tier$ 3	62.4	62.73
Load group 3	$Tier$ 1	58.04	58.71
	$Tier$ 2	59.79	60.54
	$Tier$ 3	61.69	63.45

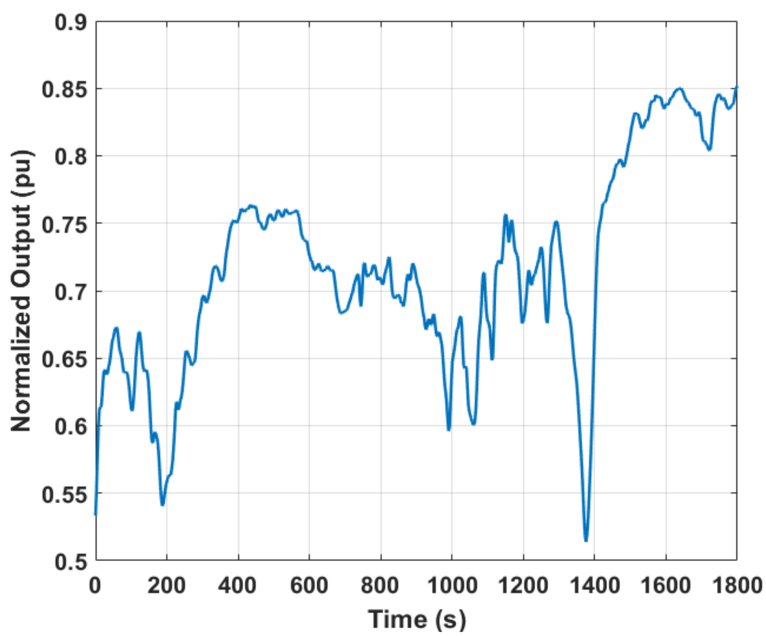


Figure 5.12: Normalized solar PV output

Every scenario begins from an initial de-energized state following the loss of utility supply. All loads connected through the smart electrical panels are initially disconnected, only leaving the 20 kW load at the end of the feeder connected. However, the customer preference is to turn-on every load with the maximum number of connection attempts over a $T_{max,i}$ time window set to 3 (i.e., $N_{max,c} = 3$ for every load).

To minimize the transformer inrush during black-start in every scenario, the terminal voltage of the grid-forming IID is slowly increased by ramping up its voltage reference (E*) from zero to the rated voltage over 1 s. In this stage, the grid-forming IID energizes the distribution transformers, lines, and the 20 kW load at the end of the feeder segment. As shown in Figure 5.13, with soft-energization, there is no inrush current. After the network downstream of the IID is energized, the grid-following DER connects after a delay of 2.5 s.

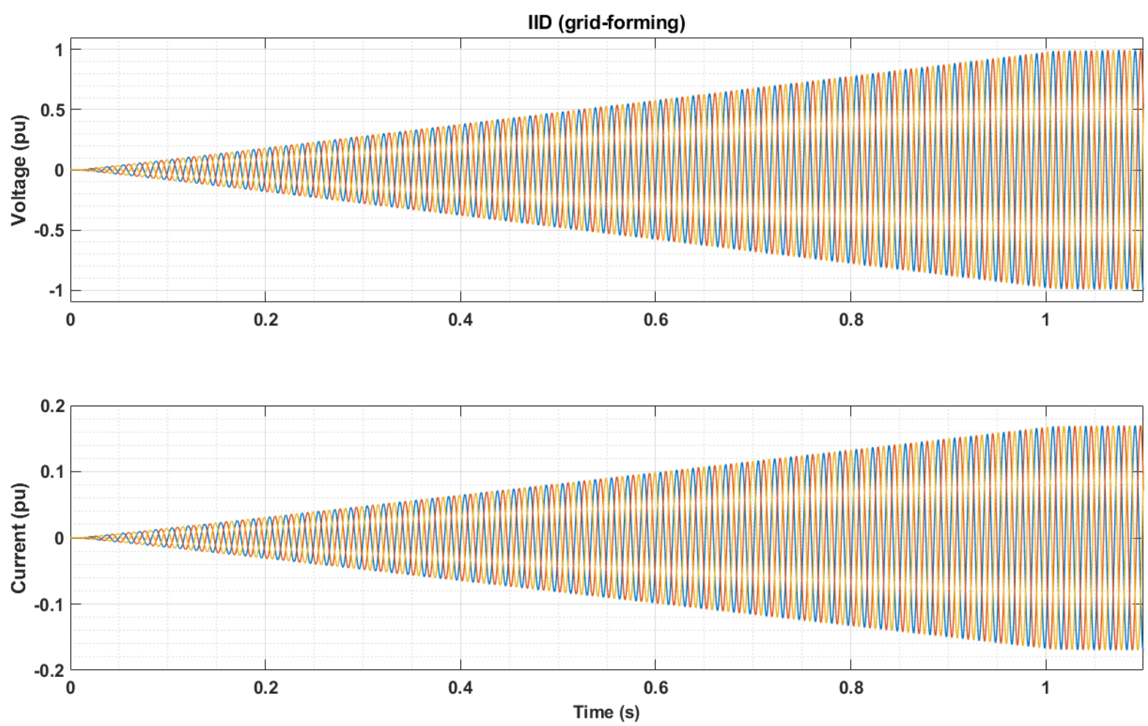


Figure 5.13: Soft-energization using grid-forming IID during black-start and service restoration - Ramp-up of voltage and current at IID terminals

5.2.4.1 Scenario 1: DER Rating = 200 kW, Step-change in IID Reference Frequency

In scenario 1, the rating of the grid-following solar PV inverter is 200 kW. Figure 5.14 shows the active power output and frequency of the grid-forming IID at the head of the feeder segment, the active power output of the grid-following DER, and the total tier 1, tier 2, and tier 3 load supplied.

At t = 0 s, the grid-forming IID initiates a black-start of the feeder segment and slowly ramps its terminal voltage from zero to the nominal value over 1 s. At this stage, the 20 kW load at the end of the feeder segment that is always connected is energized. At t = 2.5 s, the grid-following DER connects with the active power output following the irradiance profile in Figure 5.12, subject to the frequency-active power droop curve in Figure 5.7. Soon after the DER starts injecting active power, the IID transitions to the charging mode, and the microgrid frequency increases due to increased generation compared to load. At t = 5 s, load-level restoration is initiated by the smart electrical panels, where the turn-on frequency ($f_{i,b}$), turn-off frequency ($f_{i,a}$), and wait time (T_w) are assigned for every load. The tier 1 critical loads first connect within 120 s of the smart electrical panels initiating load-level restoration, followed by the tier 2 loads attempting connection. As the microgrid frequency varies with generation and load and falls below the turn-off frequency for the connected loads, they disconnect. As shown in Figure 5.14, at t= 158 s, when the frequency falls below 59.2 Hz, the connected 30 kW tier 2 load in load group 1 is disconnected. At t= 500 s, the IID reference grid frequency (ω*) is increased from 2π*60

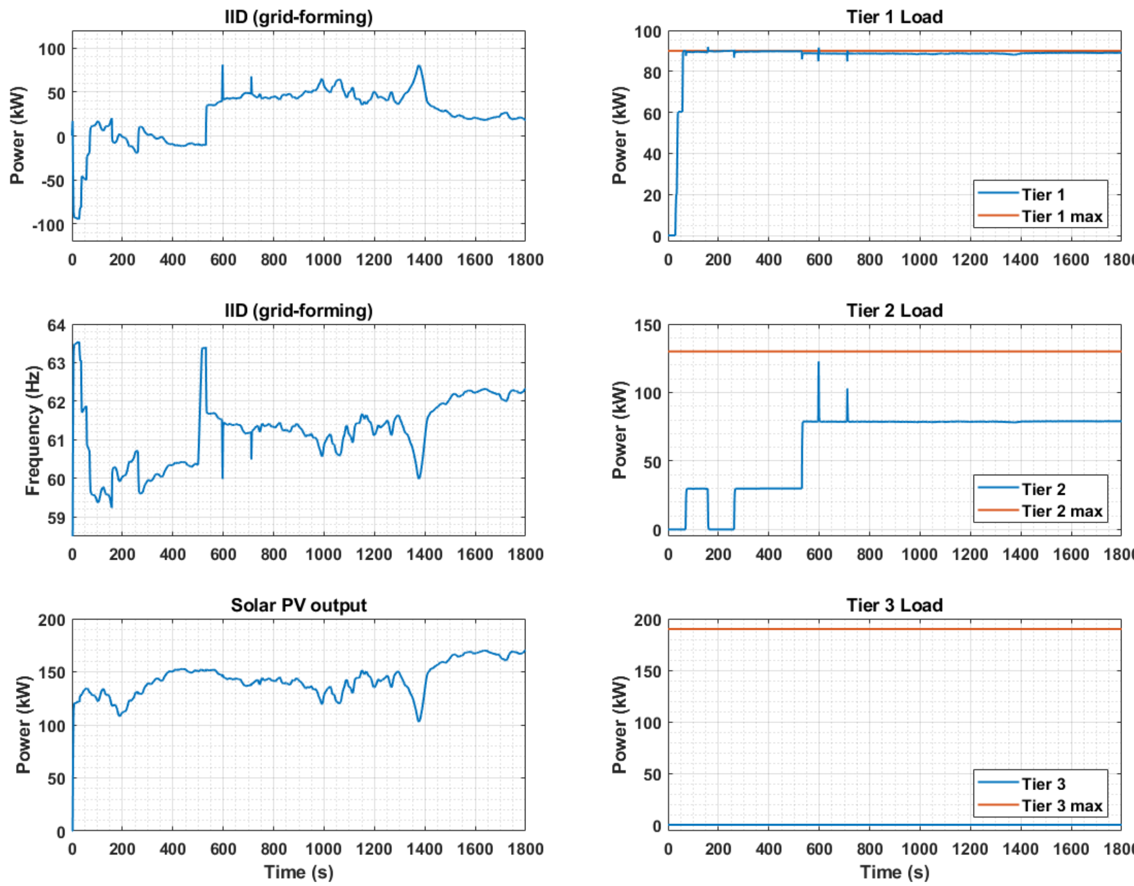


Figure 5.14: Scenario 1 (DER Rating = 200 kW) a) Active power output of IID, b) Frequency of IID, c) Active power output of solar PV inverter, d) Total tier 1 load, e) Total tier 2 load, and f) Total tier 3 load

rad/s (60 Hz) to 2π*63 rad/s (63 Hz) at a rate of 1.25 rad/s (0.2 Hz/s), leading to increased system frequency. As a result, the lower priority loads attempt to connect.

In this scenario, all tier 1 critical loads totaling 90 kW and some tier 2 loads totaling 80 kW are served while no tier 3 loads attempt to connect.

5.2.4.2 Scenario 2: DER Rating = 400 kW, Step-change in IID Reference Frequency

In scenario 2, the rating of the grid-following solar PV inverter is 400 kW. Figure 5.15 shows the active power output and frequency of the grid-forming IID at the head of the feeder segment, the active power output of the grid-following DER, and the total tier 1, tier 2, and tier 3 loads served with varying DER generation.

At t = 0 s, the grid-forming IID initiates a black-start of the feeder segment and slowly ramps its terminal voltage from zero to the nominal value over 1 s. At this stage, the 20 kW load at the end of the feeder segment that is always connected is energized. At t = 2.5 s, the grid-following DER connects with the active power output subject to the frequency-active power droop curve in Figure 5.7. Soon after the DER starts injecting active power, the IID transitions to the charging mode, and the microgrid frequency increases due to increased generation compared to load. At t = 5 s, load-level restoration is initiated by the smart electrical panels, where the turn-on frequency ($f_{i,b}$), turn-off frequency ($f_{i,a}$), and wait time (T_w) are assigned for every load. All the tier 1 critical loads connect within the first 120 s of the smart electrical panels initiating load-level restoration, followed by the tier 2 and tier 3 loads attempting connection. As the microgrid frequency varies with varying generation and load and falls below the turn-off frequency for the connected loads, they disconnect. As shown in Figure 5.15, at t= 176 s, when the frequency falls below 59.79 Hz, the connected 50 kW tier 2 load in load group 3 is disconnected. At t = 500 s, the IID reference grid frequency (ω*) is increased from 2π*60 rad/s (60 Hz) to 2π*63 rad/s (63 Hz) at a rate of 1.25 rad/s (0.2 Hz/s), leading to an increased system frequency. As a result, the lowest priority tier 3 loads attempt to connect.

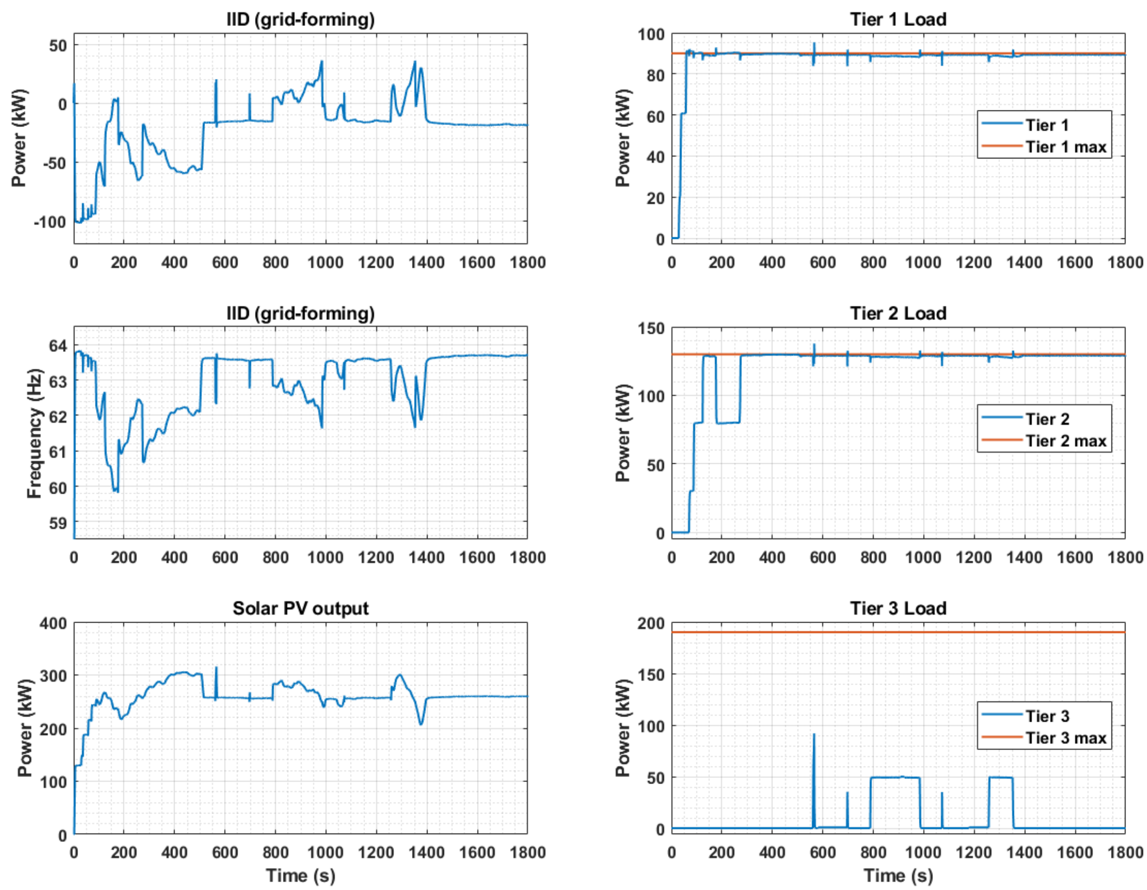


Figure 5.15: Scenario 2 (DER Rating = 400 kW) a) Active power output of IID, b) Frequency of IID, c) Active power output of solar PV inverter, d) Total tier 1 load, e) Total tier 2 load, and f) Total tier 3 load

In this scenario, all tier 1 critical loads totaling 90 kW and all tier 2 loads totaling 130 kW are served, while only some tier 3 loads are briefly served.

5.2.4.3 Scenario 3: DER Rating = 500 kW, Fixed IID Reference Frequency

In scenario 3, the rating of the grid-following solar PV inverter is 500 kW. Figure 5.16 shows the active power output and frequency of the grid-forming IID at the head of the feeder segment, the active power output of the grid-following DER, and the total tier 1, tier 2, and tier 3 loads served with varying DER generation.

At t = 0 s, the grid-forming IID initiates a black-start of the feeder segment and slowly ramps its terminal voltage from zero to the nominal value over 1 s. At this stage, the 20 kW load at the end of the feeder segment that is always connected is energized. At t = 2.5 s, the grid-following DER connects with the active power output subject to the frequency-active power droop curve in Figure 5.7. Soon after the DER starts injecting active power, the IID transitions to the charging mode, and the microgrid frequency increases due to increased generation compared to load. At t = 5 s, load-level restoration is initiated by the smart electrical panels, where the turn-on frequency ($f_{i,b}$), turn-off

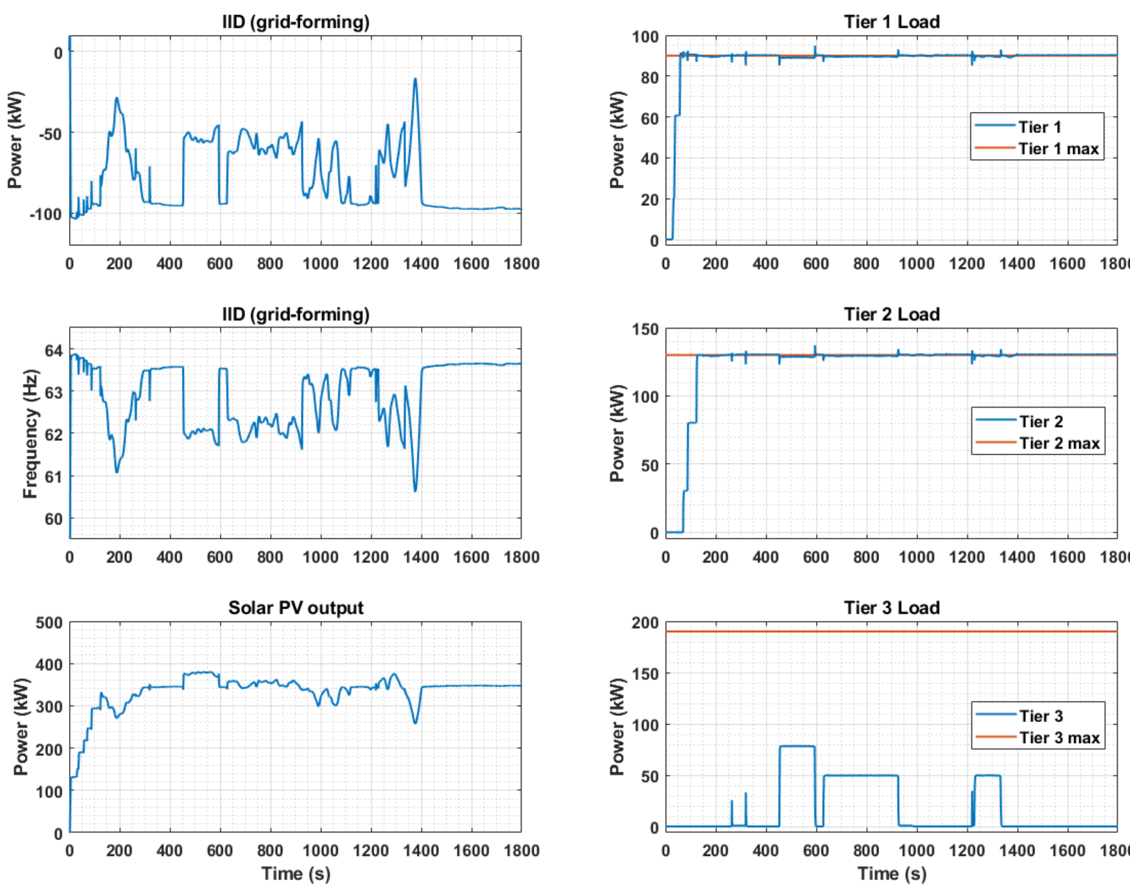


Figure 5.16: Scenario 3 (DER Rating = 500 kW) a) Active power output of IID, b) Frequency of IID, c) Active power output of solar PV inverter, d) Total tier 1 load, e) Total tier 2 load, and f) Total tier 3 load

frequency ($f_{i,a}$), and wait time (T_w) are assigned for every load. All the tier 1 critical loads connect within the first 120 s of the smart electrical panels initiating load-level restoration, followed by the tier 2 and tier 3 loads attempting connection. As shown in Figure 5.16, some tier 3 loads attempt to connect when the frequency is above their respective turn-on frequency for the pre-calculated wait time. However, if the RoCoF limit is violated in the time interval between connecting the load and up to 3 cycles after connection or the frequency falls below the turn-off frequency, the load is disconnected.

In scenario 3, all tier 1 critical loads totaling 90 kW and all tier 2 loads totaling 130 kW are served, while some tier 3 loads are briefly served. In comparison to scenario 2, the tier 2 and tier 3 energy demand served is higher in scenario 3.

Table 5.6 summarizes the simulation scenarios in terms of the DER output, net energy from the grid-forming IID integrated with storage, the peak demand, and the percentage of energy demand served for each load tier. In all the simulation scenarios, over 96% of the critical tier 1 energy demand is served. With an increased capacity of DERs, an increasing fraction of tier 2 and tier 3 loads are served. It must be noted that in scenarios 1 and 2, at t = 500 s, the IID reference grid frequency (ω*) is increased from 60 Hz to 63 Hz to signal lower priority loads to connect. To preserve battery capacity, signal loads, or invoke the curtailment of DERs to avoid excess generation conditions, the IID can regulate the microgrid frequency by dynamically adjusting its active power-frequency droop curve. Moreover, it is shown that a fractionally-rated 120 kW grid-forming IID combined with a grid-following DER can support a total load of 320 kW.

Table 5.6: Summary of simulation results

Scenario	Output of DER (kWh)	Net Energy in/out of IID (kWh)	Peak demand served (kW)			Percentage of energy demand served (= 100*energy demand served/total energy demand)		
			Tier 1	Tier 2	Tier 3	Tier 1	Tier 2	Tier 3
1	71.4	12.6	90	80	0	96.6%	47.2%	0%
2	129.6	-10.6	90	130	50	96.8%	91.6%	4.3%
3	166.5	-38.6	90	130	80	97.6%	94.5%	9.1%

This section proposed and demonstrated an approach for the bottom-up black-start and service restoration of a feeder segment following an outage. The proposed methodology for load restoration implemented in the smart electrical distribution panels prioritizes supply to tier 1 (critical) loads over lower priority tier 2, tier 3, and non-essential loads and works with variable DER output. Moreover, all decisions are made locally based on user preferences, such as load on/off statuses, priority levels, one-time inputs from the utility, and real-time system conditions without requiring communications in the islanded microgrid mode. Furthermore, by cycling supply among customers, this approach can be used to operate islanded microgrids for extended periods while ensuring equitable access to the limited power available.

5.3 Decentralized Approach to Forming a Microgrid Cluster

This section proposes a novel approach using Island Interconnection Devices (IIDs) for seamless connection of multiple islanded microgrids to form a microgrid cluster (i.e., networked microgrid) and reconnect with the grid in a truly decentralized fashion. The operational stages and sequence of transitions between the modes are presented, followed by simulation results validating the proposed approach.

5.3.1 Formation of a Microgrid Cluster with Island Interconnection Devices

Figure 5.17 shows the implementation of two type 4 Island Interconnection Devices (IID 1 and IID 2) in a 13.8 kV, 10 MW distribution feeder with two utility-scale microgrids. The microgrids interface with the utility grid through type 4 IIDs, which, as shown in Figure 5.18, consists of a bi-directional power converter that is fractionally-rated for cost-efficacy and with isolation provided by step-up/step-down line-frequency transformers. Unlike existing solutions described in section 2.2.2, the presented approach can tolerate high-latency communication links and does not require battery energy storage for seamless

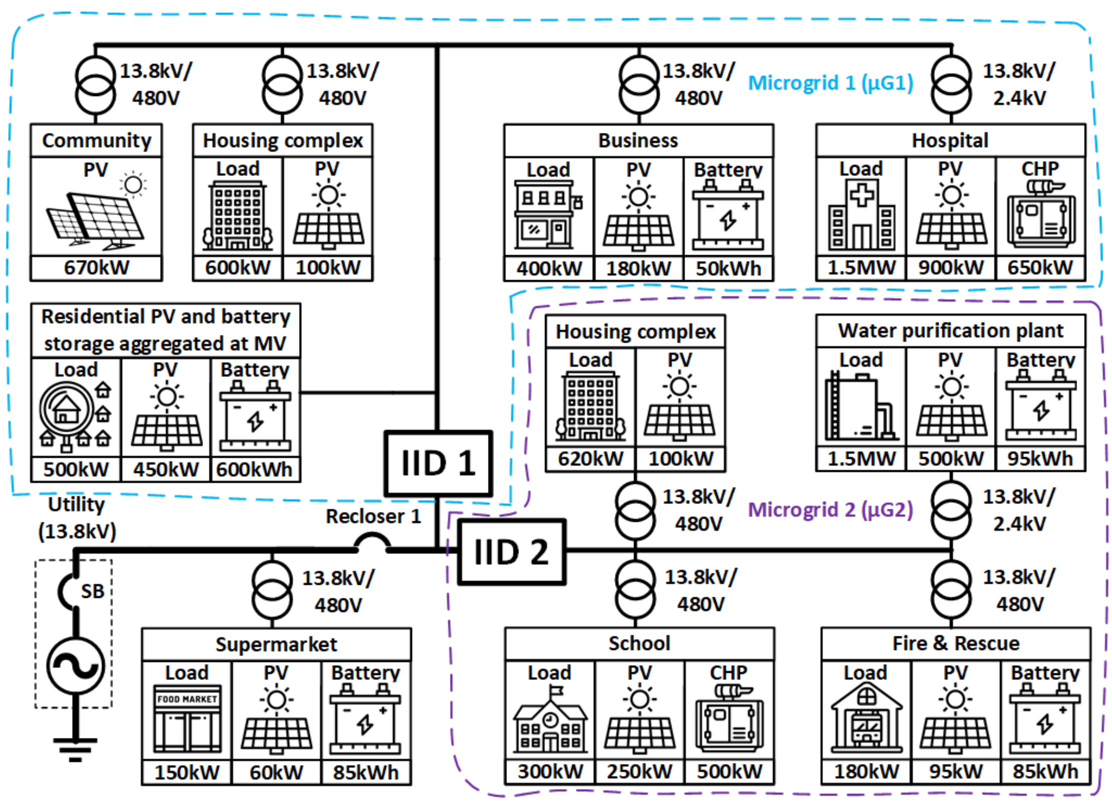


Figure 5.17: Test system with two utility-scale microgrids

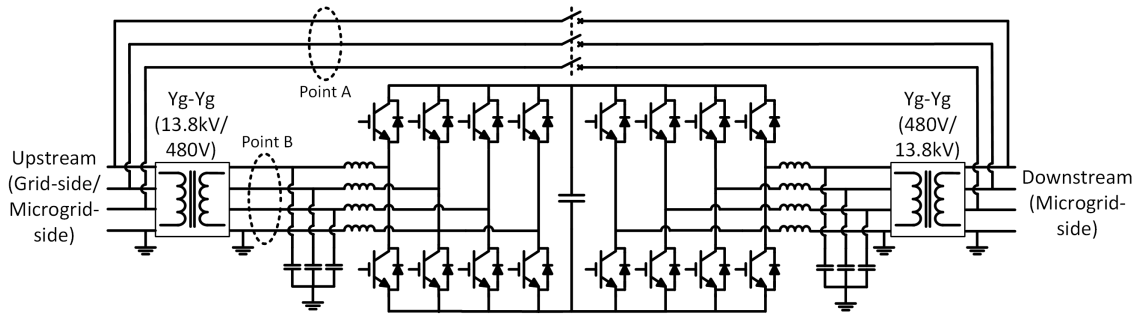


Figure 5.18: Type 4 IID for seamless formation of a microgrid cluster and reconnection with the grid

synchronization and connection of islanded microgrids to form a microgrid cluster and reconnect with the grid.

In the normal grid-connected mode, the fractionally-rated power converter is bypassed by the vacuum circuit breaker, and the IID can be operated as a shunt converter to provide the functionalities described in section 4.3. If sub-cycle fault current interruption is required, the vacuum circuit breaker can be replaced by semiconductor switches. In Figure 5.18, the IID, as a fractionally-rated back-to-back voltage source converter, operates at low-voltage (480 V in this case). On the other hand, switching and fault current interruption with vacuum circuit breakers are done at medium-voltage. Alternatively, with medium-voltage power semiconductor devices being developed, the IID could be implemented with medium-voltage power converters having high-frequency isolation, thereby avoiding line-frequency step-up/step-down transformers. However, the high cost and limited fault-handling capability of medium-voltage power semiconductors and power converters may impact feasibility.

Figure 5.19 and Figure 5.20 illustrate the operational stages and sequence of transitions between the grid-connected, islanded, and microgrid cluster (i.e., networked) modes of operation. To form a microgrid cluster, the neighboring IIDs communicate and

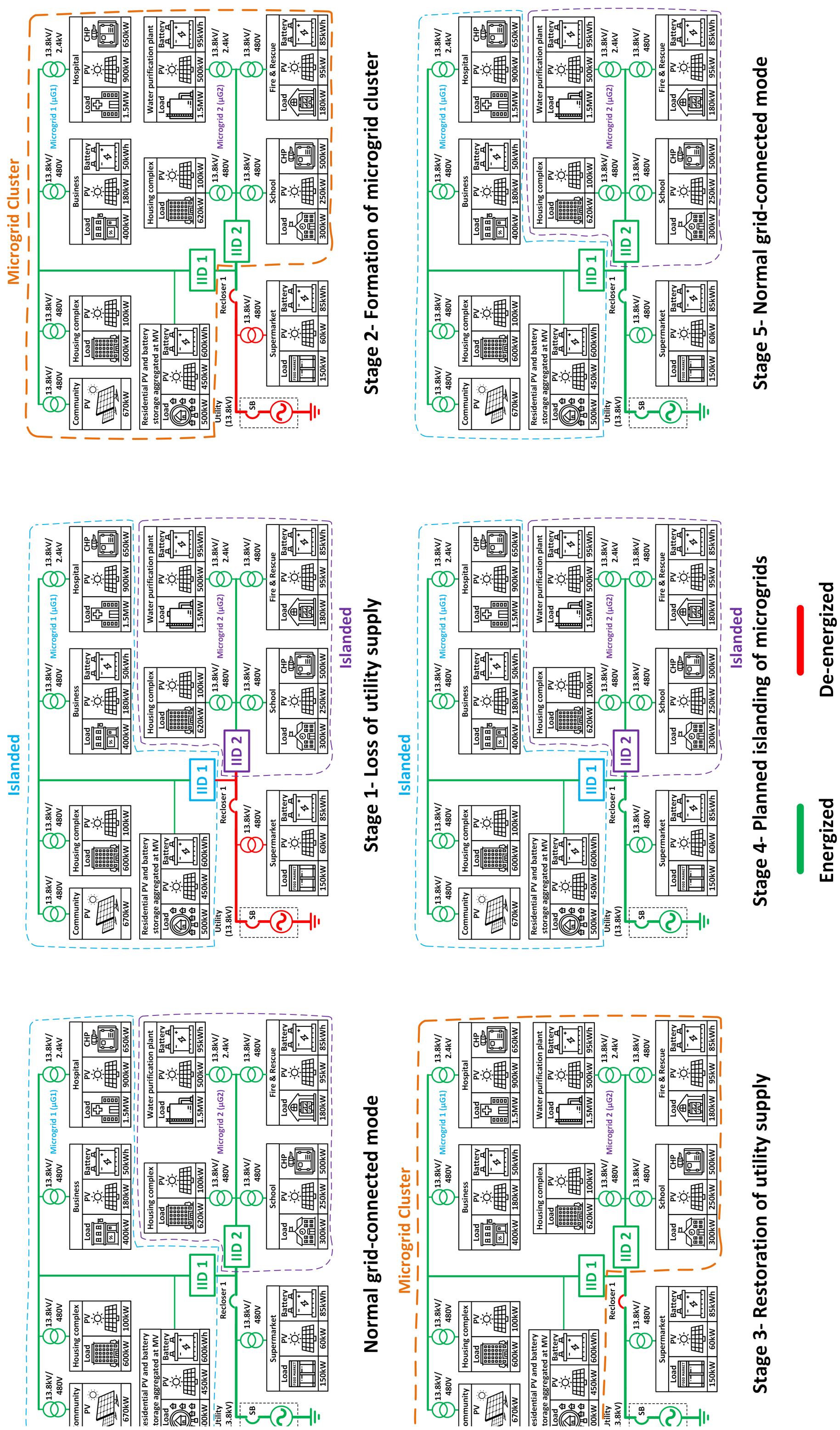


Figure 5.19: Stages in the formation of a microgrid cluster

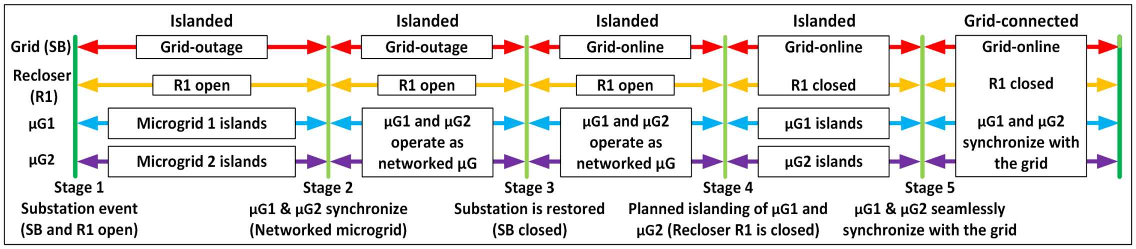


Figure 5.20: Seamless transitions (bump-less connect/disconnect) between grid-connected, islanded, and networked modes of operation during a substation event

coordinate with the upstream utility protection equipment via the utility's existing communication architecture. Following a grid outage (Stage 1- substation breaker (SB) and recloser 1 (R1) are opened), the individual IIDs (IID 1 and IID 2) autonomously isolate the microgrids based on the frequency and RoCoF parameters that are locally measured. Once the islanded microgrids stabilize subject to the prevailing generation and load conditions, the neighboring IIDs coordinate with each other, with one of them (here IID 1) energizing a part of the feeder downstream of recloser 1. IID 2 then begins synchronizing Microgrid 2 with Microgrid 1 and connects, forming a microgrid cluster consisting of Microgrid 1 and Microgrid 2 (Stage 2). Once the substation is restored (Stage 3- substation breaker (SB) is closed) and the utility supply is available upstream of recloser 1, the utility commands IID 1 and IID 2 to disconnect (Stage 4- planned islanding). After both the microgrids island, recloser 1 is closed. Finally, in Stage 5, the individual IIDs seamlessly synchronize and reconnect the individual microgrids with the grid by matching frequency, phase, and voltage magnitude. To island the microgrid, form a microgrid cluster and reconnect the microgrids with the grid, the methodologies presented in section 4.6 are used.

5.3.2 Simulation Results

The distribution feeder with two utility-scale microgrids, as shown in Figure 5.17, is simulated. Microgrid 1 (μG1) has an aggregate peak load of 3 MW with 2.3 MW solar PV capacity, 0.65 MW in combined heat and power (CHP), and 650 kW/650 kWh in battery storage capacity. Microgrid 2 (μG2) has an aggregate peak load of 2.6 MW with 1.8 MW solar PV capacity, 0.5 MW in CHP, and 180 kW/180 kWh in battery storage capacity. The CHP units in both microgrids are synchronous generators that operate with a 5% droop in frequency (active power-frequency droop) and 3% droop in voltage (reactive power-voltage droop). The solar PV inverters operate in the grid-following mode without any droop. The ability of the IID to achieve seamless transitions (i.e., bumpless connect/disconnect) between grid-connected, islanded, and microgrid cluster modes of operation in two different scenarios is presented in the following sections.

5.3.2.1 Case A: Formation of a Microgrid Cluster and Seamless Reconnection with the Grid

This simulation scenario demonstrates the ability of type 4 IIDs to island microgrids following the loss of utility supply, seamlessly form a microgrid cluster (i.e., networked microgrid), and reconnect with the grid with minimum inrush in a truly decentralized manner.

Following the loss of utility supply at t = 3 s (Stage 1), the individual IIDs autonomously isolate the microgrids using rate-of-change-of-frequency (RoCoF) as the passive method for detecting the formation of an island. IID 1 islands Microgrid 1 at t = 4

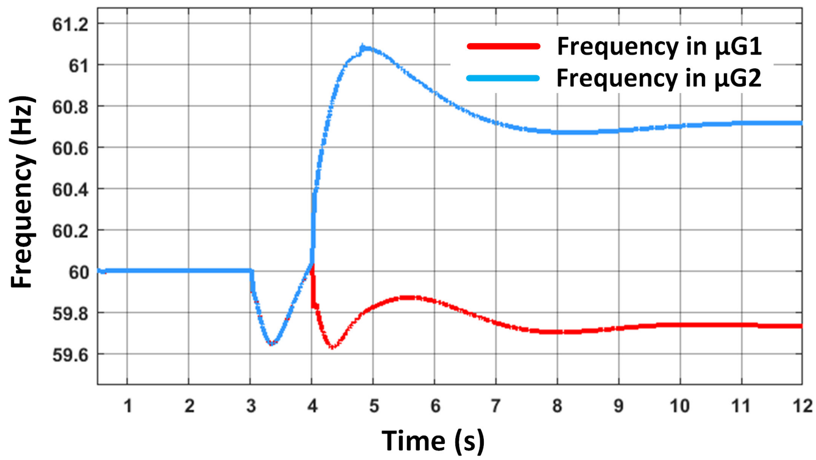


Figure 5.21: Frequency in Microgrid 1 and Microgrid 2 following the loss of utility supply (Stage 1)

s and IID 2 islands Microgrid 2 at t = 4.8 s. Figure 5.21 shows the frequencies of the two microgrids as they autonomously island following the substation event.

Once the microgrids stabilize and continue operating, the neighboring IIDs (IID 1 and IID 2) communicate via the utility's existing communication framework and form a networked microgrid at t = 17.691 s (Stage 2). This is done with one of the IIDs (here IID 1), first ensuring that the immediate upstream utility protection device (Recloser 1) is open and then energizing the feeder section upstream of the IID (IID 1). With the feeder section upstream of IID 1 and IID 2 but downstream of recloser 1 energized, IID 2 initiates the synchronization of Microgrid 2 with the energized feeder at t = 15 s. IID 2 matches the phase and frequency of Microgrid 2 with that of the feeder (and Microgrid 1) by pushing active power out of Microgrid 2 and into Microgrid 1 through the fractionally-rated back-to-back converter and matches voltage by injecting/absorbing reactive power into/from Microgrid 2, and finally closes the vacuum circuit breaker (at t = 17.691 s). Figure 5.22 shows the frequencies of the two microgrids, phase angle differences, active power injected by IID 2 from Microgrid 2 into Microgrid 1, line currents, phase-to-ground voltages, and active power at the point of interconnection (POI) of IID 2 during the formation of the microgrid cluster. When in Stage 2, a ramped load of 0.8 MW is applied in Microgrid 2, and Microgrid 2 draws 0.35 MW from Microgrid 1. A ramped load is used instead of a step-load to emphasize the inrush current on reconnection. In Figure 5.22 (a), it can be observed that a small frequency offset of 0.04 Hz is maintained between the two microgrids to minimize the phase mismatch prior to closing the vacuum circuit breaker (in Microgrid 2) and forming the microgrid cluster. From Figure 5.22 (d), the inrush (peak) current of 6.8 A at the POI during microgrid cluster formation is under 10% of the full-load rating of the

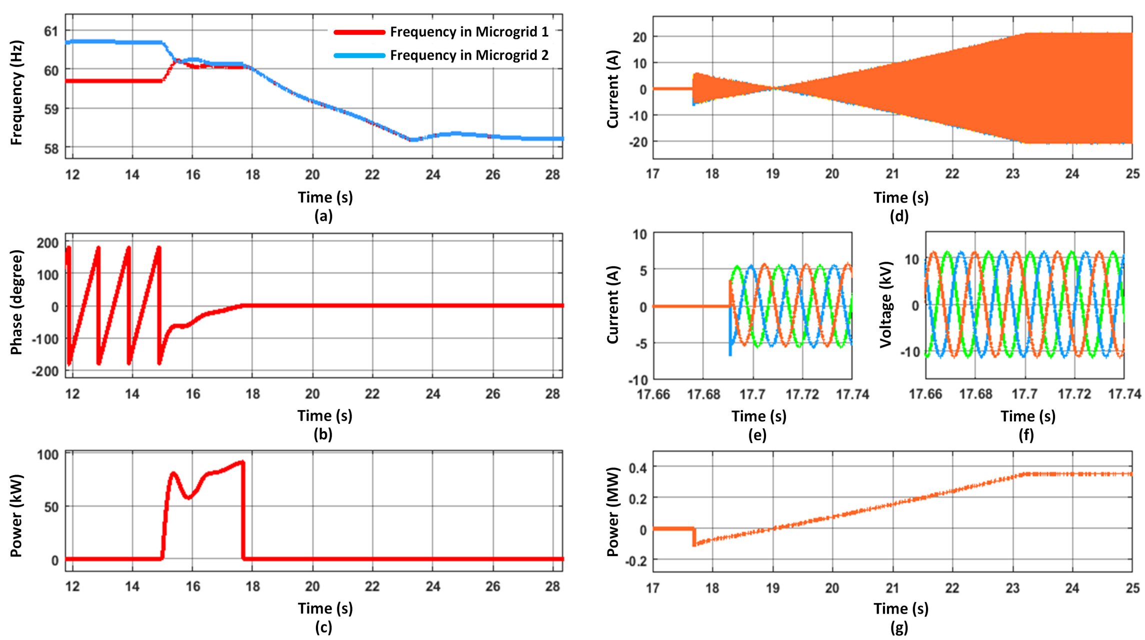


Figure 5.22: Formation of networked microgrid (Stage 2) (a) Frequency in Microgrids 1 and 2, (b) Phase angle difference between Microgrids 1 and 2, (c) Active power injected by IID 2 from Microgrid 2 into Microgrid 1, (d) Line currents at the POI of IID 2, (e) Inrush current at the POI of IID 2, (f) Phase-to-ground voltages in Microgrid 2, and (g) Active power flowing into Microgrid 2

vacuum circuit breakers in Microgrid 1 (full-load current rating = 125 A), and Microgrid 2 (full-load current rating = 108 A).

Once the substation is restored and the substation breaker (SB) is closed at t= 28 s (Stage 3), the utility supply is available upstream of recloser 1. The utility DMS then commands the IIDs (IID 1 and IID 2) to disconnect at t = 35 s (Stage 4-Planned islanding). Once both the microgrids island, the DMS commands recloser 1 to close. Now in Stage 5, the IIDs seamlessly synchronize and reconnect the individual microgrids with the grid by matching phase, frequency, and voltage in a truly decentralized fashion similar to section 4.6.4. Figure 5.23 shows Microgrid 2 seamlessly reconnecting with the grid at t = 41.25 s, and Figure 5.24 shows Microgrid 1 seamlessly reconnecting with the grid at t = 44.91 s. Following reconnection, each microgrid draws close to 0.6 MW from the grid.

The maximum inrush (peak) current at the point of interconnection (measured at the sensing point A as shown in Figure 5.18) from all operational stages is under 10% of the full-load rating of the vacuum circuit breakers in Microgrid 1 and Microgrid 2.

5.3.2.2 Case B: Performance Under Grid-side Faults

To validate the performance of the proposed approach under fault conditions, the same distribution feeder with two utility-scale microgrids, as shown in Figure 5.17, is simulated. To also examine the impact of increased synchronous generation on the inrush current during reconnection, the rating of the synchronous generator (CHP unit) in Microgrid 2 is increased from 0.5 MW to 1.5 MW. Additionally, the peak load in Microgrid 2 is increased to 3.6 MW. As similar performance is observed in Microgrid 1, only results

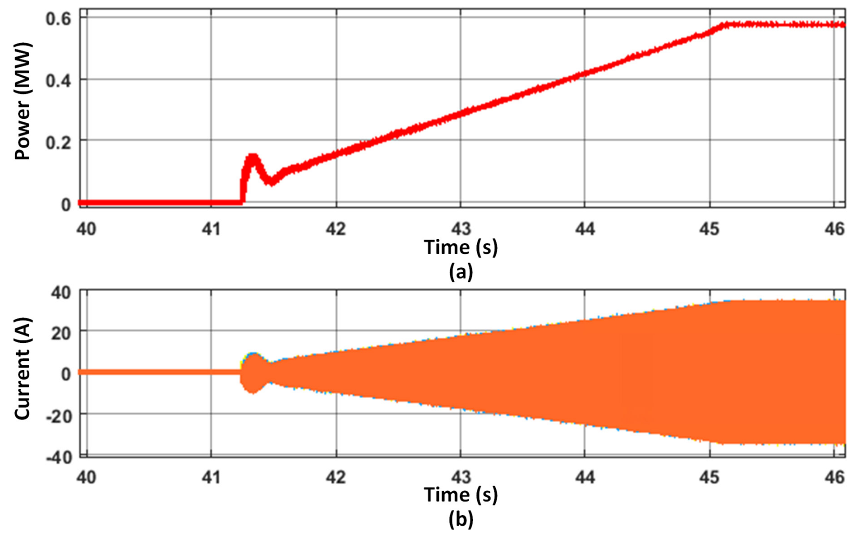


Figure 5.23: Reconnection of Microgrid 2 with the grid (Stage 5) (a) Active power, and (b) Line currents at the point of interconnection of IID 2

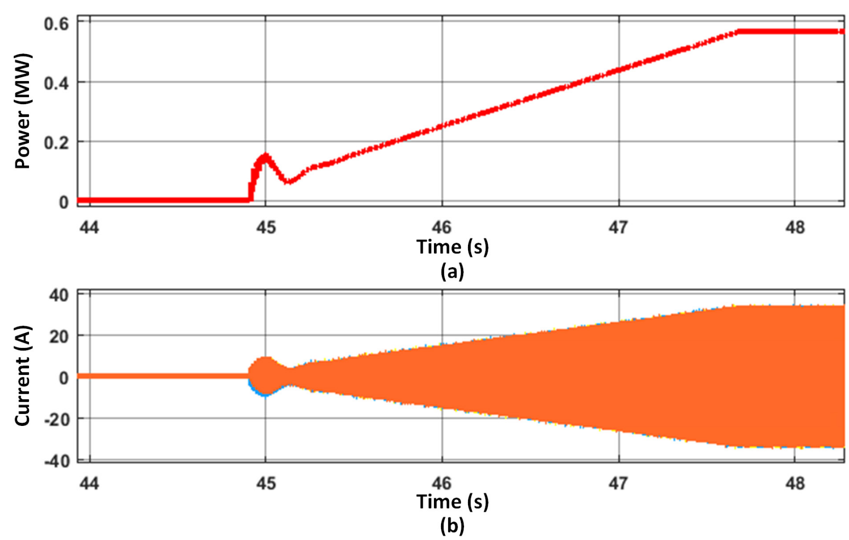


Figure 5.24: Reconnection of Microgrid 1 with the grid (Stage 5) (a) Active power, and (b) Line current at the point of interconnection of IID 1

concerning Microgrid 2 are presented here. For simplicity, it is assumed that the substation breaker (SB) and recloser 1 are closed before, during, and after the fault is cleared.

A single line-to-ground (1LG) fault on phase A is applied on the grid-side of Microgrid 1 and Microgrid 2 at t = 10 s. At t = 10.1 s, the individual IIDs isolate the microgrids, and the microgrids continue operating in the islanded mode. The fault is cleared at t = 12 s, and at t = 13 s, the IIDs initiate synchronization of the respective microgrids with the grid. At t = 24.97 s, Microgrid 2 reconnects with the grid and draws 1.05 MW from the grid. Figure 5.25 shows the active power and line currents at the POI of IID 2 (measured at sensing point A, as shown in Figure 5.18). The inrush (peak) current at the POI of IID 2 (measured at the sensing point A as shown in Figure 5.18) is 22.14 A, which is 14.7% of the full-load current rating of the switchgear in Microgrid 2 (full-load current rating = 150.6 A, Microgrid 2- 3.6 MW at 13.8 kV). Even in the presence of increased

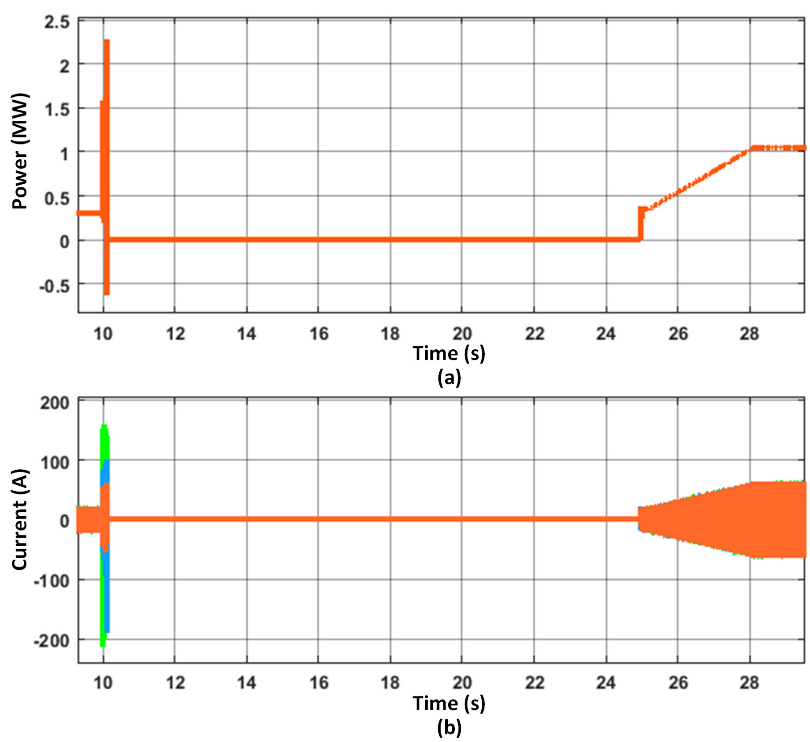


Figure 5.25: Performance under 1LG fault (a) Active power, and (b) Line currents at the point of interconnection of IID 2

synchronous generation, the proposed approach maintains the inrush current during reconnection to be well within the ratings of the switchgear.

Figure 5.26 shows the frequency of Microgrid 2, the phase angle difference of Microgrid 2 with respect to the grid, and the active power pushed by IID 2 from the grid into Microgrid 2 (measured at the sensing point B as shown in Figure 5.18) to bring Microgrid 2 in synchronism with the grid before reconnection to enable a seamless connection. The peak power injected by IID 2 from the grid into Microgrid 2 is 334 kW which is 9.28% of the peak load in Microgrid 2 (3.6 MW).

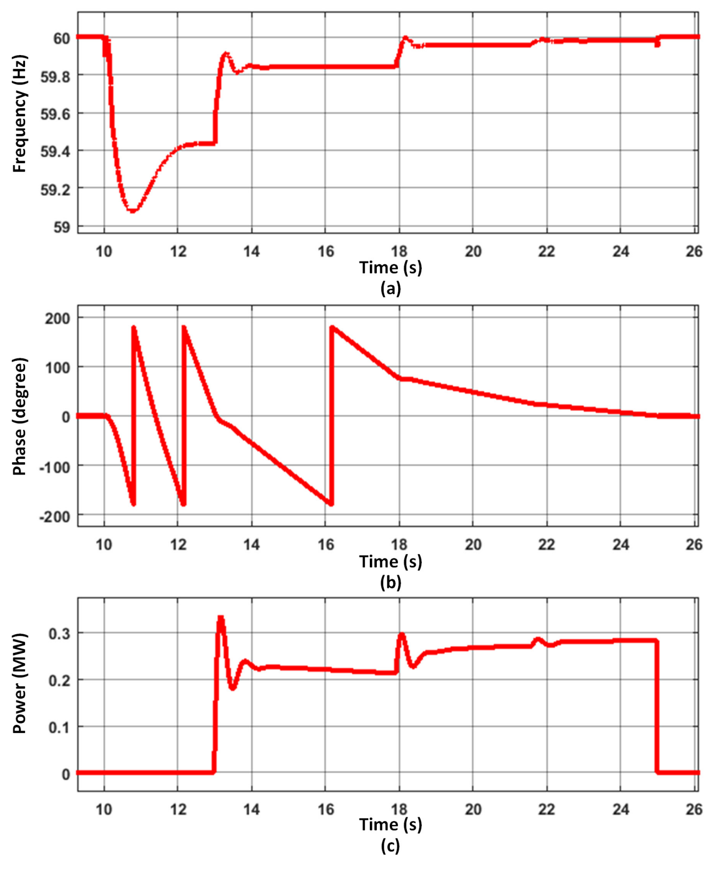


Figure 5.26: Performance under 1LG fault (a) Frequency of Microgrid 2, (b) Phase angle difference of Microgrid 2 with respect to the grid, and (c) Active power injected by IID 2 from the grid into Microgrid 2

This section proposed and demonstrated a novel approach using Island Interconnection Devices (IIDs) for the seamless connection of multiple islanded microgrids to form a microgrid cluster (i.e., networked microgrid) and reconnect with the grid in a truly decentralized fashion. To achieve seamless/bumpless transitions between the islanded, microgrid cluster, and grid-connected modes of operation, only connect/disconnect messages are exchanged with IIDs, making low-bandwidth and high-latency communication links suitable.

5.4 Summary and Contributions

Existing utility practices for distribution system resilience and restoration do not fully leverage using DERs and flexible loads and their ability to form microgrids and microgrid clusters following the loss of utility supply.

In this chapter, a flexible, scalable, and resilient distribution system architecture consisting of IIDs, smart electrical distribution panels, and DERs is proposed to enable the operation of the distribution system as an interconnected network of microgrids with bottom-up black-start and service restoration functions. Upon loss of the grid, the proposed architecture can form microgrids and provide continued electrical service to loads with priority given to critical loads and operate over extended periods of time with reduced capability compared to grid-connected operation. Furthermore, by networking neighboring microgrids to form a microgrid cluster, the proposed grid architecture provides increased reliability and resilience benefits to customers within their footprint and surrounding areas.

The methodologies for system- and load-level bottom-up black-start and service restoration and the control of IIDs, smart electrical panels, and DERs to restore service to loads following the loss of utility supply are presented. The efficacy of the proposed approach has been validated through simulations demonstrating the capabilities of the IID, smart electrical panels, and DERs to black-start, form microgrids, and restore service to loads on the distribution feeder. Furthermore, the methodology and simulation results demonstrating the ability of IIDs to form a microgrid cluster by seamlessly synchronizing and connecting neighboring islanded microgrids and reconnecting with the grid are presented.

Together, the proposed architecture with IIDs, smart electrical panels enabling flexible loads, and DERs provides a pathway to flexible and resilient distribution systems by rapidly restoring service, providing power to critical loads, and minimizing the impact of power outages.

CHAPTER 6. CONCLUSIONS, CONTRIBUTIONS, AND FUTURE WORK

6.1 Conclusions

The electric power system is currently undergoing a significant evolution with the integration of a wide variety of technologies, such as solar PV, battery storage, and microgrids, driven by cost declines, renewable energy mandates, and initiatives to create an affordable, sustainable, reliable, and resilient future grid. However, integrating these technologies with the existing power system presents technical challenges, can potentially impact system operations, and inadvertently limit further integration.

Electric utilities currently perform interconnection studies to analyze the impacts of DERs and microgrids on the distribution system before interconnecting them. Microgrids and large-scale DERs often go through expensive, onerous, and time-consuming detailed impact studies that involve dynamic and transient simulations. However, most utilities lack the advanced skill sets and resources required and are not adequately prepared to handle the increasing volume of interconnection requests. Moreover, the challenges with modeling the highly customized and proprietary hardware and controls of large-scale DERs and microgrids characterized by emergent behavior and associated modeling simplifications do not guarantee compliance with the interconnection rules. Furthermore, the ever-evolving interconnection standards with 6-8 year development and adoption timelines significantly inhibit the deployment of advanced DER and microgrid solutions necessary for the widespread adoption of renewables. It is imperative that a solution is developed where DERs and microgrids can be safely, cost-effectively, and reliably integrated with the grid without requiring lengthy and expensive interconnection impact studies.

This dissertation proposes Island Interconnection Devices (IIDs) as the standardized utility-owned and utility-controlled grid interface for DERs and microgrids that enforces the utility rules for interconnection and simplifies grid integration by eliminating the need to perform detailed system impact studies. If any utility interconnection rule is violated, the IID disconnects the DER or islands the microgrid to ensure the integrity of the grid and reports interconnection violations to the utility. Additionally, the IID enables flexible interconnections where the utility can dynamically change the interconnection rules for a DER facility or microgrid in response to prevailing grid conditions or network changes. IIDs integrated with a power electronic converter can also provide grid-support (L/HVRT, L/HFRT, etc.) and ancillary services (Volt/VAR, harmonics mitigation, etc.). The IID approach also provides utilities with a standardized communication interface for monitoring and control, enabling power flow and quality monitoring, flagging and reporting interconnection violations, changing thresholds and setpoints, and modifying the logic of the IID remotely. It also serves as an effective mechanism for advanced utility functions such as load-shedding, bottom-up black-start, service restoration, and forming microgrid clusters. Furthermore, this approach unleashes innovation in DERs and microgrids and enables rapid deployment without limiting functionality, affecting grid operations, or being held back by slowly moving interconnection standards.

This work presents the concept of an IID, the rules for interconnection, use cases of different types of IIDs, communication architecture, and the benefits of IIDs, followed by simulation results demonstrating their efficacy in mitigating grid-side and microgrid-side impacts. The IID solution is a forward-thinking, streamlined, and proactive approach to accelerate the deployment of DERs and microgrids while guaranteeing compliance with the ever-evolving utility interconnection rules and managing integration and operational risks.

With the increasing frequency of extreme weather events resulting in prolonged grid outages, there is growing interest in utilizing DERs and microgrids as a cost-effective means to improve the resilience of the distribution system. However, existing distribution system practices do not fully leverage using DERs, microgrids, and load flexibility to supply critical loads during outages, form microgrids, and enable bottom-up black-start and service restoration. This is mainly due to the lack of operational flexibility and scalability of conventional approaches coupled with complexities in monitoring, controlling, and coordinating system operation. Moreover, during outages, the limited communication capabilities can be challenging for conventional centralized approaches, which require complete and timely knowledge of the status of the distribution system, including available generation capacity and loads. Furthermore, while microgrid clusters offer a higher level of reliability and resilience with access to more generation sources and higher load diversity, there are challenges in forming them. When considering geographically dispersed microgrids with numerous DERs, such as utility-scale microgrids and community microgrids, the popular central microgrid controller approach that relies on centralized control and real-time communication with DERs becomes challenging.

To enable flexible and resilient distribution systems, this dissertation proposes a distribution system architecture consisting of IIDs, smart electrical distribution panels, and DERs. This architecture enables the operation of the distribution system as an interconnected network of microgrids with bottom-up black-start and service restoration functions. The IIDs black-start feeder segments and form microgrids, actively regulate voltage and frequency in the islanded microgrid mode, seamlessly form microgrid clusters, and reconnect with the grid. The smart electrical distribution panels enable connection/disconnection of loads based on on/off commands, load priority level, and utilize under-frequency and RoCoF-based load-shedding to sustain islanded microgrid operation for extended periods. The customer- and utility-owned DERs ensure continuity of power supply and follow frequency-active power droop to balance generation with the load. During grid outages, the distribution feeder can be operated as a cluster of microgrids to serve critical loads and provide limited electric service to non-critical loads resulting in a more reliable and resilient distribution system. By isolating failures and providing alternative pathways for the continuity of electricity supply, the proposed architecture is expected to enhance the resilience of the distribution system by minimizing the frequency, magnitude, and duration of power outages.

The methodologies for system- and load-level bottom-up black-start and service restoration following the loss of utility supply are presented. The proposed load-level restoration approach prioritizes supply to tier 1 (critical) loads over low-priority tier 2 and tier 3 loads without requiring communications when operating in the islanded microgrid mode. With increasing DER output, an increasing fraction of low-priority tier 2 and tier 3 loads are served. Simulation results demonstrating the ability of the proposed approach to enhance resilience upon loss of utility supply by performing bottom-up black-start, forming a microgrid, and rapidly restoring service to loads on a distribution feeder segment are presented. To preserve battery capacity, signal loads to connect/disconnect, or invoke the curtailment of DERs to avoid excess generation conditions, IID can dynamically adjust its active power-frequency droop curve to regulate the microgrid frequency. Furthermore, the methodology and simulation results demonstrating the capability of IIDs to form a microgrid cluster by seamlessly synchronizing and connecting neighboring islanded microgrids and reconnecting with the grid are presented.

The proposed architecture and capabilities present a pathway to realizing flexible, reliable, and resilient distribution systems by enabling bottom-up black-start and rapid service restoration of distribution feeders following the loss of utility supply, supplying critical loads, and forming microgrid clusters.

6.2 Contributions

A summary of the key contributions through this work is as follows:

1) Performed an extensive review of the approaches adopted by utilities to integrate DERs and microgrids, current practices in distribution system restoration, and state-of-the-art approaches in using DERs, microgrids, and microgrid clusters to enhance

the resilience of the distribution system. Significant limitations of existing approaches are identified and presented.

2) Identified the major integration and operational challenges utilities face when integrating DERs and microgrids with the grid through an extensive study that involved 16 major electric utilities and manufacturers in the US.

3) Two major distribution system challenges with integrating DERs and microgrids that are largely unresolved, transient overvoltages during faults, and reclosing out-of-synchronism, are studied through modeling and simulations.

4) Developed Island Interconnection Devices (IIDs) as a standardized utility-owned and utility-controlled grid interface to simplify the integration of large-scale DERs and microgrids with the grid by enforcing the ever-evolving utility interconnection rules and standards.

5) Developed the utility-friendly and microgrid-friendly attributes of an IID and proposed five types of IIDs ranging from a smart circuit breaker to a more capable fully-rated power electronic converter and compared their characteristics. Developed a list of rules for interconnection enforced by the IID and the utility use cases and capabilities of the proposed types of IIDs.

6) Demonstrated through simulations the dynamic performance of various IID configurations and their ability to perform unintentional islanding detection, Volt/VAR control, and fault current management.

7) Developed and demonstrated through simulations, a novel approach using a type 4 IID (IID 4), a fractionally-rated back-to-back power electronic converter, to achieve

seamless connection of an islanded microgrid with the grid in a decentralized fashion. This approach does not require integrated battery storage or communications with DERs.

8) Developed a distribution system architecture consisting of IIDs, smart electrical distribution panels, and DERs to provide a pathway to realize flexible and resilient distribution systems. It enables bottom-up black-start, rapid restoration of service, and the formation of microgrid clusters on the loss of utility supply. The role and control of key components in the proposed architecture are developed and presented.
9) Developed a methodology for distribution system-level bottom-up black-start and service restoration and a load-level restoration methodology implemented in the smart electrical distribution panels. When operating in the islanded microgrid mode following the loss of utility supply, the smart electrical panels utilize under-frequency and RoCoF-based load-shedding to balance load with generation and sustain extended islanded operation.
10) Demonstrated through simulations the ability of the proposed distribution system architecture to enhance resilience upon loss of utility supply by rapidly restoring service through bottom-up black-start using local DERs, and prioritizing supply to critical loads over low-priority loads without requiring any communications.
11) Developed the operational stages and sequences and demonstrated through simulations, the application of type 4 IID (IID 4) for seamless connection of

multiple islanded microgrids to form a microgrid cluster and reconnect with the grid in a truly decentralized fashion.

In the course of this research, six conference papers, one journal, and one technical report were published. Two more journals were under preparation at the time of submitting this document. The complete list of papers is presented in APPENDIX B.

6.3 Future Work

6.3.1 Enabling Resilient Energy Communities with IIDs

With the rapidly increasing number of residential utility customers installing solar PV plus battery systems, there is an increasing opportunity to operate feeder sections in residential communities as microgrids to improve reliability and resilience.

A resilient energy community (REC) is a self-reliant, decentralized, and dispersed community-microgrid interconnected to the utility grid through IIDs. It comprises predominantly residential customers with smart electrical distribution panels to interface DERs and loads. RECs will allow customers to make their own energy choices, adopt technologies without impacting the grid, and accelerate the transition to a more reliable and resilient grid from the bottom-up.

While there are several open research directions, the following are suggested in the context of this work:

1. Defining the REC system architecture, rules for participants, and performance expectations
2. Evaluate the feasibility of converting existing distribution feeder sections and feeders with a majority of residential customers into RECs
3. Evaluating system performance and resilience metrics under severe resource-constrained and resource-rich scenarios
4. Regulatory challenges, including ownership issues and tariff structures

6.3.2 Extending System Restoration to the Bulk Power System

The architecture for resilient distribution systems proposed in this dissertation can potentially benefit the bulk power system. During large-scale blackouts, power from the distribution system can be utilized to energize the high-voltage transmission system and provide cranking power to traditional synchronous generators for power system black-start and service restoration. The resulting power system will be resilient from the bottom-up with system-wide benefits such as accelerated restoration timelines following blackouts.

However, this will introduce complexities and require significant changes to existing bulk power system black-start and restoration plans. Technical evaluations that consider the weak system characteristics, control of DERs, cold load pickup, system stability, variable nature of renewables, communications requirements, island synchronization, and protection implications will be needed.

6.3.3 Analysis with Mixed DER Types and Controls and Under Fault Conditions

In this dissertation, for bottom-up black-start and restoration of a feeder segment, the IID is controlled as a grid-forming source using the conventional multi-loop droop control augmented with a low-pass filter block to emulate virtual inertia. It is shown that the grid-forming IID can support a peak load much larger than its capacity in combination with grid-following DER. However, further analysis is needed considering different types of DERs, such as synchronous generators and in combination with inverter-based DERs. Furthermore, the interactions between different grid-following and grid-forming control structures and their impact on the system- and load-level bottom-up black-start and service restoration must be studied.

The proposed load-level restoration logic implemented in the smart electrical distribution panel uses under-frequency and RoCoF-based load-shedding to make connect/disconnect decisions. While frequency and RoCoF provide a good measure of the balance between generation and load, calculating frequency and RoCoF can be challenging, especially during transient events such as faults where the frequency is not clearly defined. It is recommended that further studies be performed to address these concerns.

6.3.4 Experimental Validation and Field Demonstrations

Experimental validation and extensive field demonstrations of the proposed IID concept and the resilient distribution system architecture at different grid scales are required to build confidence with electric utilities and enable large-scale adoption.

It is recommended that variants of the IID without a power electronic converter (i.e., IID 1 and IID 2) be demonstrated at scale first to prove core functionality and benefits, followed by the other variants. Moreover, the monitoring, control, and communication capabilities required to enforce the utility interconnection rules for a DER or microgrid installation can be implemented in today's protection relays at a minimal incremental cost.

6.3.5 Regulatory Pathways

While the IID approach presented in this dissertation can simplify and accelerate the integration of DERs and microgrids with the grid, regulatory pathways considering performance guarantees and liabilities must be developed to achieve this. Furthermore, contractual and financial mechanisms are needed through which microgrids and IIDs can provide grid services when the utility requires them. Similar mechanisms must be developed to implement the architecture for flexible and resilient distribution systems proposed in this dissertation.

APPENDIX A: UTILITY SURVEY

This section presents the results of a survey conducted in 2017 as a part of the research presented in this dissertation through a project titled "Microgrid-to-Grid Interface Issues" funded by the National Electric Energy Testing, Research and Applications Center (NEETRAC) at Georgia Tech [129]. To understand the expectations and experiences and identify concerns with the grid integration of DERs and microgrids from the perspective of utilities and vendors and their impacts on grid operations, input was elicited from NEETRAC technical advisors and select IEEE 1547-2018 working group members.

Individuals in positions ranging from engineers to managers working in different sectors of the electric power industry ranging from electric utilities (transmission and distribution), manufacturers/vendors to consultants, participated in the survey. These organizations included Alabama Power Company, American Electric Power, Baltimore Gas and Electric Company, Doble Engineering, DTE Energy, Eversource, Georgia Power Company, Nashville Electric Service, PacifiCorp, Pepco, PPL Electric Utilities, Southern California Edison, Southern Company, S&C Electric Company, We Energies, and Xcel Energy. The expertise of the participants includes transmission and distribution system planning, protection, and operation, advanced technology deployment, strategy and regulations, and equipment design and manufacturing for components widely used in the electric power industry. Their contributions to this study were invaluable and are very much appreciated.

The key questions posed and findings from multiple stakeholders in the survey are presented below.

1. What would you consider as low/medium/high penetration for DERs/microgrids where the definition is given below?

(a) Penetration Level (in terms of peak feeder demand) = (Installed DER capacity) / (Peak Feeder Demand)

From Figure A.1, when the penetration level is considered in terms of peak feeder demand, around 67% of the respondents define under 10% as low DER penetration, 23% define under 15% DER penetration as low penetration, and about 10% define under 30% DER penetration as low penetration. Around 22% of the respondents define 10% to 15% DER penetration as medium penetration, 34% of the respondents define 15% to 30% as medium DER penetration, 33% define 30% to 50% DER penetration as medium

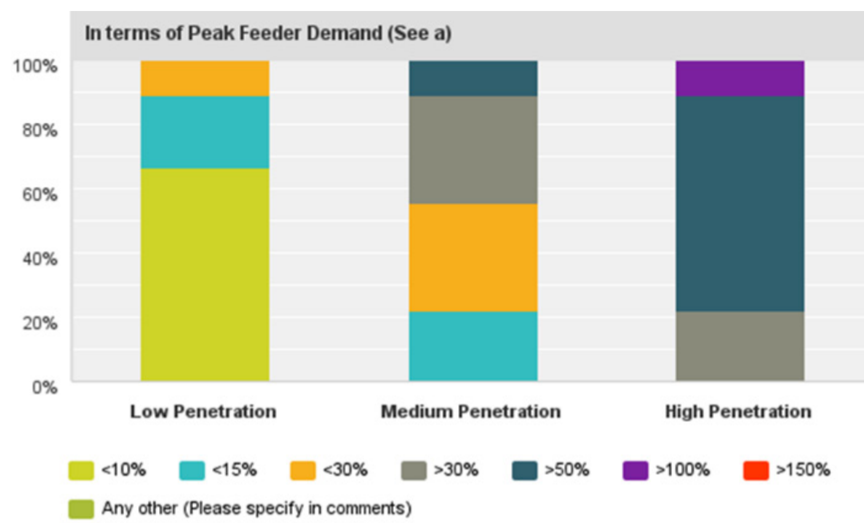


Figure A.1: Definition of low/medium/high DER penetration in terms of peak feeder demand

penetration, and 11% define 50% to 100% as medium penetration. About 67% of the respondents define over 50% DER penetration as high penetration.

(b) Penetration Level (in terms of daytime minimum loading) = (Installed DER capacity) / (Daytime Minimum Loading)

From Figure A.2, when the penetration level is considered in terms of daytime minimum loading, 50% of the respondents define under 10% as low DER penetration, 12% define under 15% DER penetration as low penetration, and 25% define under 30% as low DER penetration. 38% of the respondents define 15% to 30% as medium DER penetration, and 50% define 50% to 100% DER penetration as medium DER penetration. 25% define 50% to 100% DER penetration as high DER penetration and 50% define over 100% as high DER penetration.

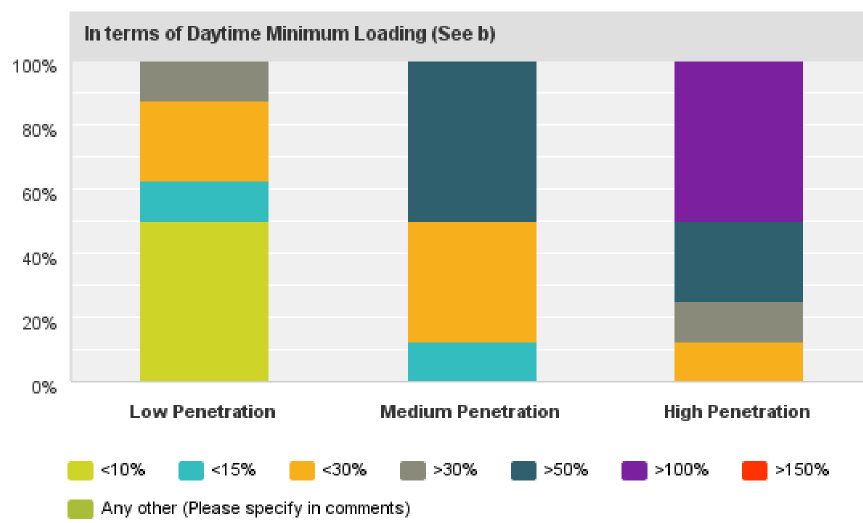


Figure A.2: Definition of low/medium/high DER penetration in terms of daytime minimum loading

There exists a significant variation among utilities in classifying DER penetration levels. Currently, most utilities define DER penetration level in terms of the peak feeder demand, daytime minimum loading, or sometimes both. However, some utilities use neither of these metrics but quantify the reverse power flow through the substation bus and up to the transmission system, which loosely correlates with the daytime minimum loading. When defining in terms of daytime minimum loading, the variation in definitions among utilities is more pronounced.

2. As a utility/vendor, how do you generally define the penetration level of DERs?

From Figure A.3, 47% of the utilities define DER penetration level in terms of the peak feeder demand, 18% of the utilities define DER penetration level in terms of the daytime minimum loading, and another 23% use both.

There are differences between defining DER penetration in terms of the peak feeder demand and daytime minimum loading. When defining the DER penetration level in terms

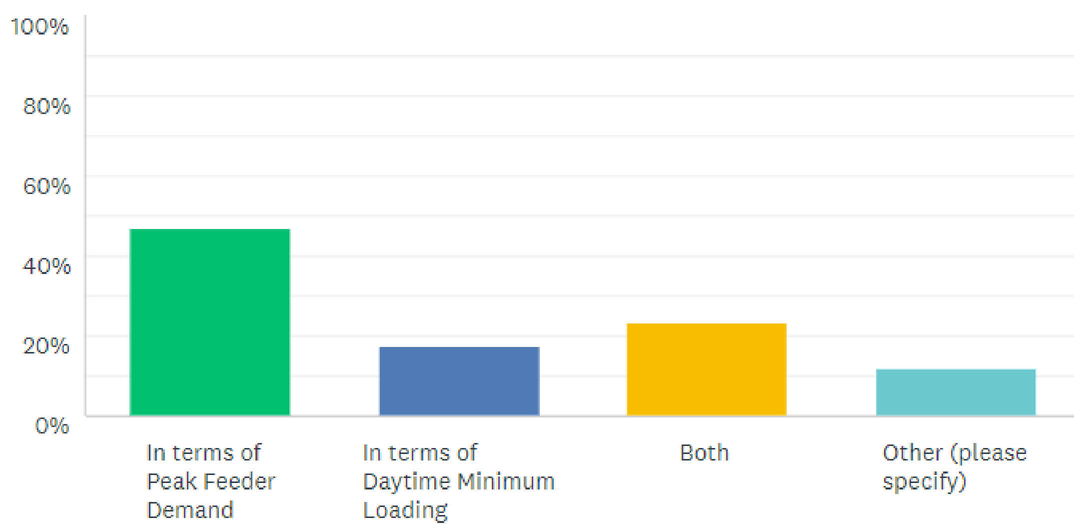


Figure A.3: Metrics to define the penetration level of DERs

of the peak feeder demand, system issues such as cold load pickup and masked load are more recognizable. Defining the DER penetration level in terms of daytime minimum loading gives the utility a reasonable picture of the potential operational impacts at the current and expected penetration level of DERs. Network issues such as reverse power flow through the secondary feeder (lateral), primary (main) feeder, and towards the substation (and associated issues), and feeder voltage violations are more predictable when defining in terms of daytime minimum loading.

3. **What percentage of feeders in your distribution network has low, medium, and high penetration of DERs and microgrids? What is it today, and what might it be three and five years from now?**

From Figure A.4, currently (i.e., in 2017) , 67% of the utilities have 0-20% of their feeders at a low penetration level, 8% of the utilities have 20-50% of their feeders at a low penetration level, and 25% of the utilities have over 50% of their feeders in the low

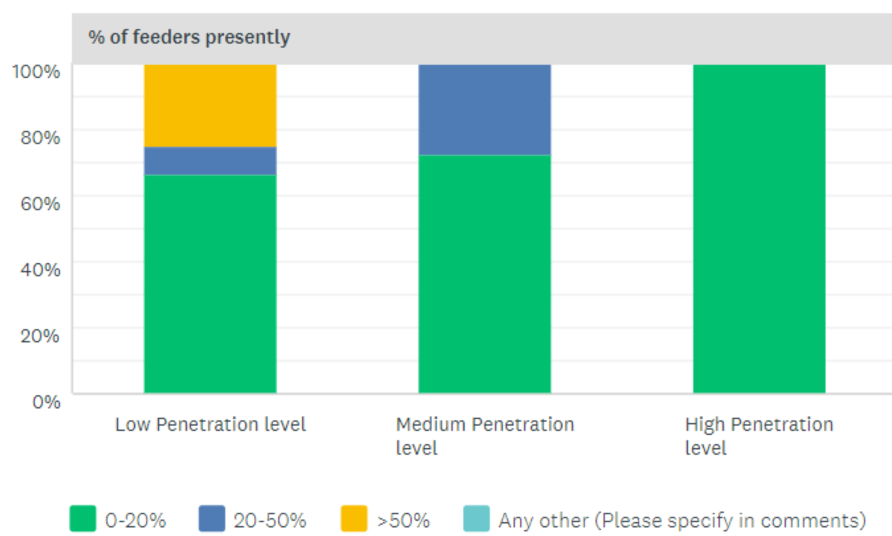


Figure A.4: Current DER penetration levels (i.e., in 2017)

penetration level. On the other hand, 27% of the utilities have 20-50% of their feeders at the medium DER penetration and have none to very few feeders in the high penetration scenario.

From Figure A.5, three years from now (i.e., in 2020), utilities expected a modest increase in the number of feeders in the medium and high penetration scenario. 33% of the utilities expected 20-50% of their feeders to have a medium penetration of DERs while the remaining 67% expected 0-20% of their feeders to have a medium penetration of DERs. 33% of the utilities expected 20-50% of their feeders to have a high penetration of DERs.

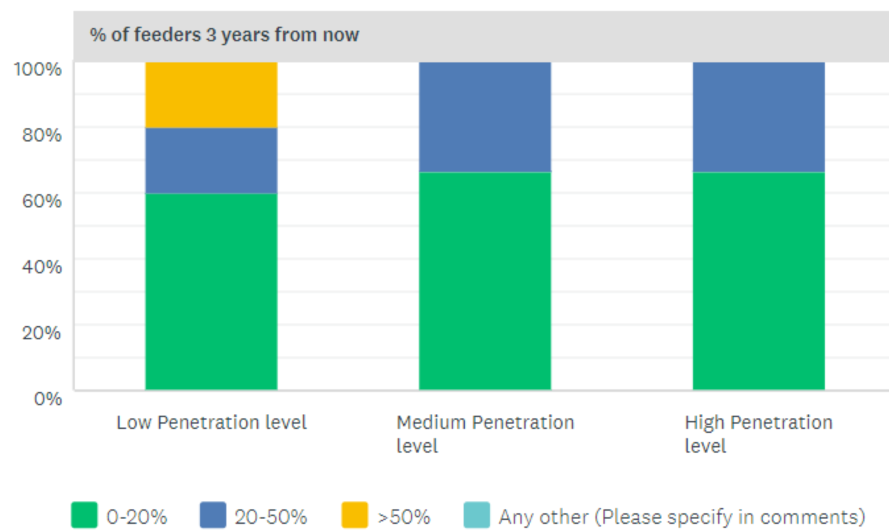


Figure A.5: DER penetration levels in three years (i.e., in 2020)

From Figure A.6, a significant increase in DER penetration is expected five years from now (i.e., in 2022). 20% of the utilities expected over 50% of their feeders to have a low penetration of DERs, and 60% of the utilities expected 20-50% of their feeders to enter the low penetration scenario. 11% of the utilities expected over 50% of their feeders to enter the medium penetration scenario while 22% of the utilities expected 20-50% of their

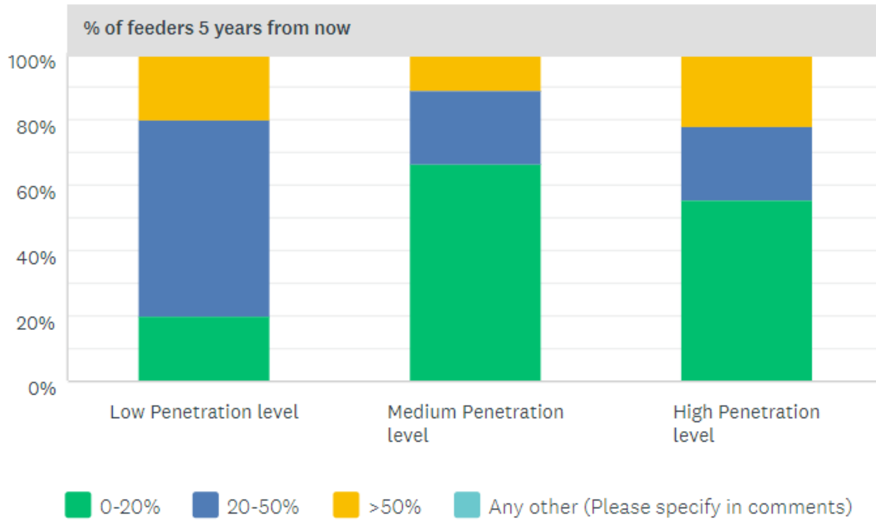


Figure A.6: DER penetration levels in five years (i.e., in 2022)

feeders to be in the medium penetration phase. 22% of the utilities expected over 50% of their feeders to enter the high penetration scenario, while 56% expected 0-20% of their feeders to have a high penetration of DERs.

4. **How prepared are you as a utility or vendor to manage low, medium, and high penetration of DERs and microgrids in terms of grid infrastructure, interconnection process, available solutions etc.?**

From Figure A.7, most utilities (94%) are prepared to handle a low penetration of DERs, while 56% of the utilities are prepared to handle a medium penetration of DERs on their network. About 19% of the utilities are currently prepared to handle a high penetration of DERs on their network. To cope with the rising penetration of DERs, several utilities have indicated a need to reform and streamline the interconnection process.

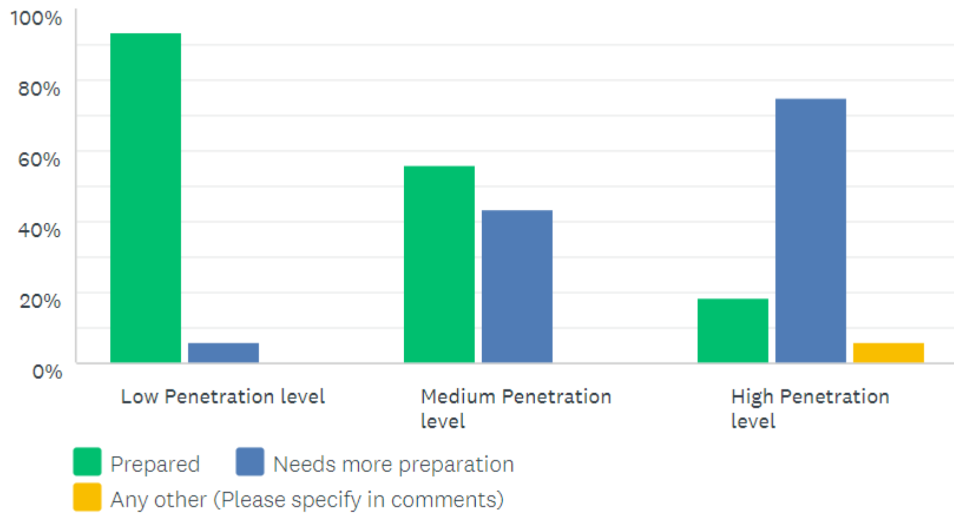


Figure A.7: Preparedness in managing low, medium, and high penetration of DERs and microgrids

5. Are there any significant issues with the interconnection process adopted by your utility that concerns you?

From Figure A.8, 47% of the respondents do not see significant issues with the interconnection process adopted by their utility. However, the respondents raised the following concerns:

1) Concerns over the level of workmanship, communication reliability, and continuous quality assurance of inverter settings at the DER sites.

2) Low voltage ride-through requirements in the newly adopted IEEE 1547-2018 Standard.

3) The re-commissioning testing that is required after a previously commissioned site has had to make repairs to the generation equipment (such as replacing a single inverter in a site with many inverters).

4) Currently, the process is not automated and depends on engineering review. There is concern regarding the inability to process a large number of applications in the future using this method.

5) Interconnection requirements for larger DERs (>250 kVA) are in the process of being prepared by the respective utility.

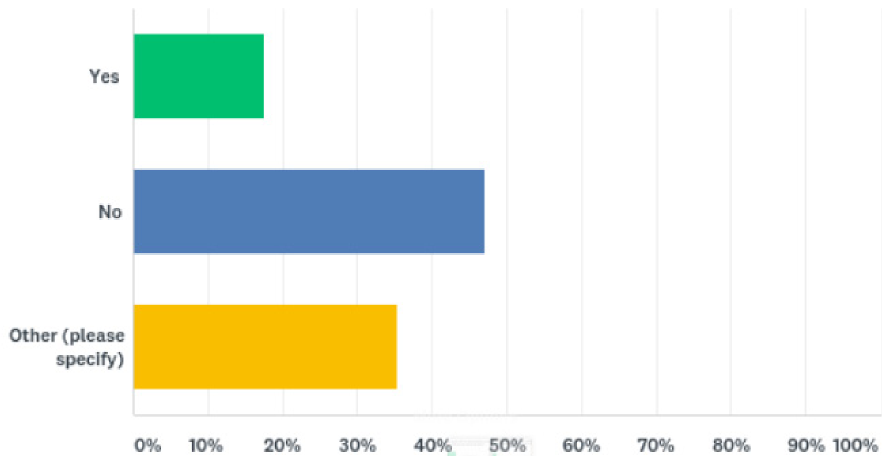


Figure A.8: Significant issues with the interconnection process adopted by your utility

6. What are the two most important issues with the interconnection process adopted by your utility?

The following are the prioritized responses:

1) Incomplete modeling of the distribution network.

2) Inaccurate impact studies.

3) High volume of applications which makes meeting time constraints challenging.

4) Not automated and requiring significant manual intervention, especially for large DERs.

5) Does not consider aggregation of DERs.

6) Not able to handle high penetration levels or accommodate large DERs.

7) Inability to accurately study protection miscoordination issues and islanding risks with the interconnection process.

8) Inability to study the potential for transient and temporary overvoltages (such as ground fault overvoltage) with the interconnection process.

9) Difficulty in studying and maintaining the feeder voltage profile and risk of violating voltage limits.

10) Concerns regarding improper protection settings and safety.

11) Requirement to test large DERs prior to commissioning.

12) Difficult to accurately estimate net loading on the distribution system with DERs.

13) Inability to perform preliminary interdependency tests to determine which interconnection (group) requests to study first.

14) Increasing penetration levels that may require and lead to advanced circuit redesign.

15) Need for additional (internal/external) staffing support when the number of interconnection applications rises significantly.

7. What two changes would you suggest to improve the interconnection process?

The following are the prioritized responses:

1) Better distribution system modeling and impact studies by using additional advanced simulation tools.

2) Automate and streamline the interconnection review process.

3) Standard protection devices for every large DER installation.

4) Electronic reclosers at the point of interconnection for installations above a certain size for visibility, relaying, and control.

5) Automation of the customer (grid) interface and regular updates.

6) Easy access to interval data for all DER locations.

7) Central reporting of DERs.

8) Area hosting maps to guide developers and dissuade them from applying in regions that require substantial network upgrades.

9) Determine a less conservative fast-track rating per feeder based on lessons learned.

10) Perform commissioning tests based on statistical past performance per equipment manufacturer and specifications.

11) Continued education for solar developers that abnormal operating conditions requiring temporary curtailment and disconnection can be prevalent with distribution voltage interconnections compared to transmission voltage interconnections.

12) A requirement for third-party inspection of the DER and microgrid facility to ensure physical and device quality assurance.

13) Requirement for a significant up-front deposit in all jurisdictions when submitting an interconnection request to guarantee cost recovery for the interconnection study.

14) Have more planning engineers performing the modeling and the principal engineer checking the models instead of the principal engineer performing all the modeling and impact studies.

15) Sharing best practices among utilities.

8. **Which of the following "System Integration and Protection Issues" are you most concerned about when approving and deploying DERs and microgrids? Rate on a scale of 1 to 5 where 5 means "Very Important" and a rating of 1 means "Not Important."**

In Figure A.9, the plot on the left shows a distribution, while the plot on the right shows the weighted averages of the "System Integration and Protection Issues." Unintentional islanding is of great concern, followed by relay desensitization, ground fault

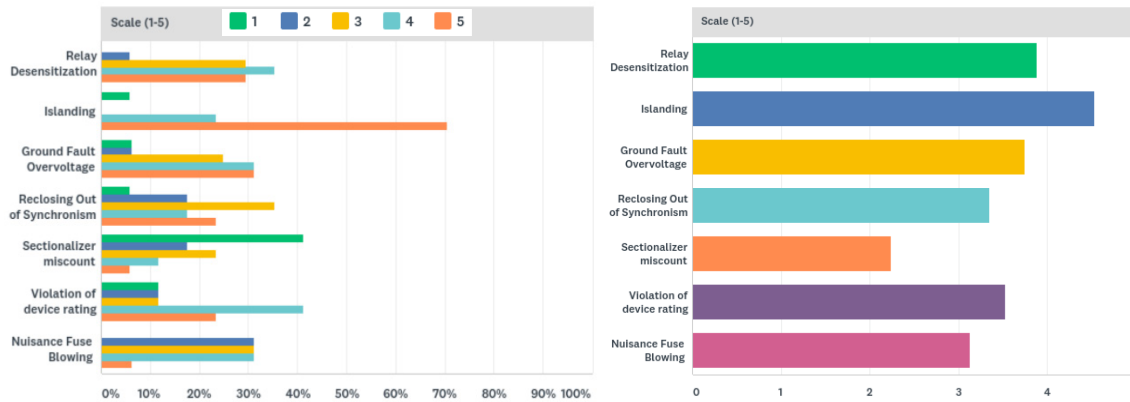
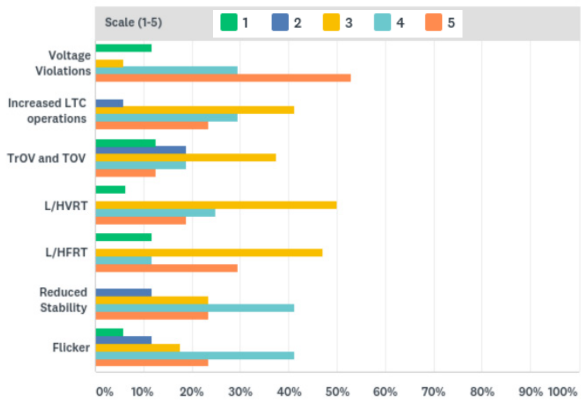


Figure A.9: System integration and protection issues

overvoltage, violation of device rating, reclosing out of synchronism, nuisance fuse blowing, and sectionalizer miscount.

9. Which of the following "Voltage and Frequency Issues" are you most concerned about when approving and deploying DERs and microgrids? Rate on a scale of 1 to 5 where 5 means "Very Important" and a rating of 1 means "Not Important."

From Figure A.10, most of the "Voltage and Frequency Issues" are of similar concern. Voltage violations in medium-voltage and low-voltage feeders are the primary concern, followed by reduced stability, increased LTC and LVR operations, flicker, L/HVRT, L/HFRT, and transient and temporary overvoltages. The plot shows that there is less concern regarding transient and temporary overvoltages, which includes ground fault overvoltage. However, based on extensive inputs from utilities and as seen in question 8, ground fault overvoltage is of serious concern for utilities and utility-scale PV farm developers.



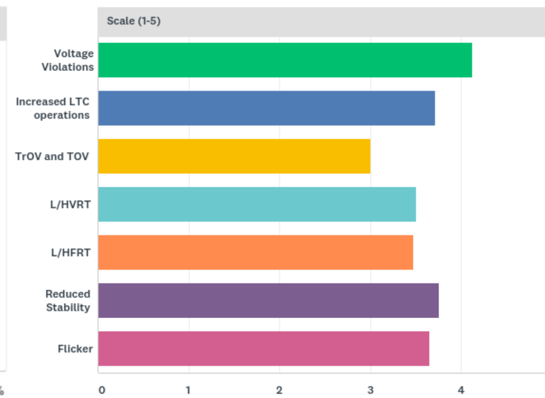
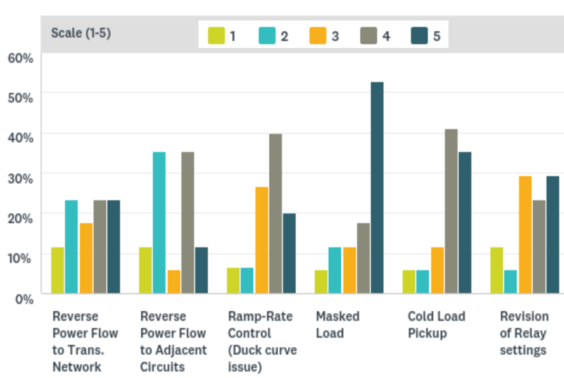


Figure A.10: Voltage and frequency issues

10. Which of the following "Reverse Power Flow and Overload Issues" are you most concerned about when approving and deploying DERs and microgrids? Rate on a scale of 1 to 5 where 5 means "Very Important" and a rating of 1 means "Not Important."

From Figure A.11, masked load and cold load pickup are the top concerns, followed by ramp-rate control requirements, the need to revise protection relay settings and control, reverse power flow to the sub-transmission network, and reverse power flow to adjacent circuits. There is significant diversity in responses when considering reverse power flow to adjacent circuits and the transmission network.



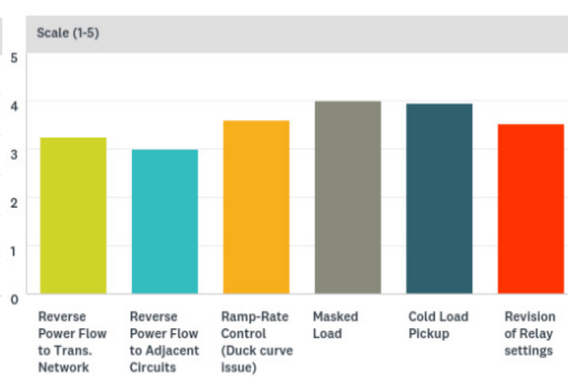


Figure A.11: Reverse power flow and overload issues

11. **The following concerns have been raised by utilities regarding DER and microgrid deployment. In your view, how important are these issues? (Rate using a 5-point scale, where a rating of 5 means "Very Important" and a rating of 1 means "Not Important")**

From Figure A.12, the top five issues raised by utilities when approving and deploying DERs and microgrids are protection challenges, lack of control over DERs, islanding concerns, a pile-up of interconnection requests, and no standardization of grid-DER/microgrid interface.

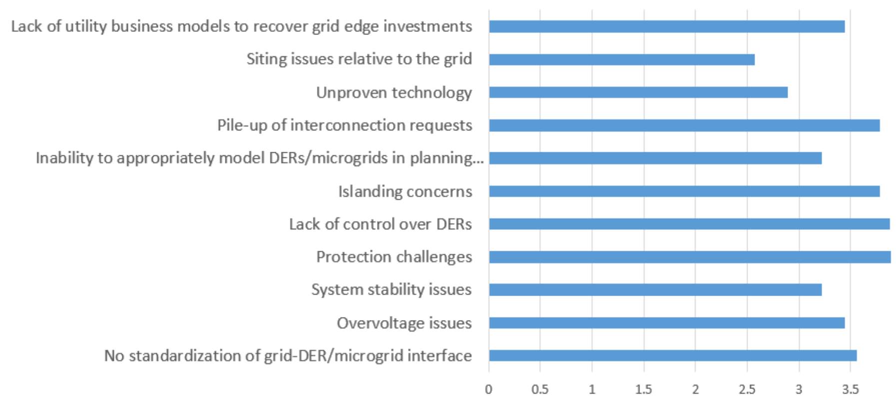


Figure A.12: Concerns raised by utilities when integrating DERs and microgrids

12. **Would you rely on customer-owned equipment (e.g., smart inverters complying with the revised IEEE 1547 standard) to mitigate operational issues (overvoltage, protection, and system stability related, etc.) caused by high DER and microgrid penetration?**

From Figure A.13, 31% of the respondents would not rely on customer-owned equipment (which includes smart inverters conforming to the revised IEEE 1547 standard) if operated by the customer only. This refers to the case where the settings and operational modes of the smart inverter are fixed as defined by the manufacturer in conformance with the IEEE 1547 standard. Here, the customer (e.g., a residential customer with solar PV) plays little to no role in operating the inverter subject to distribution and bulk power system conditions. 56% of the respondents would rely on customer-owned equipment if operated by a third party or the utility. Several utilities on the west coast favor this approach which has created a new market for DER aggregators.

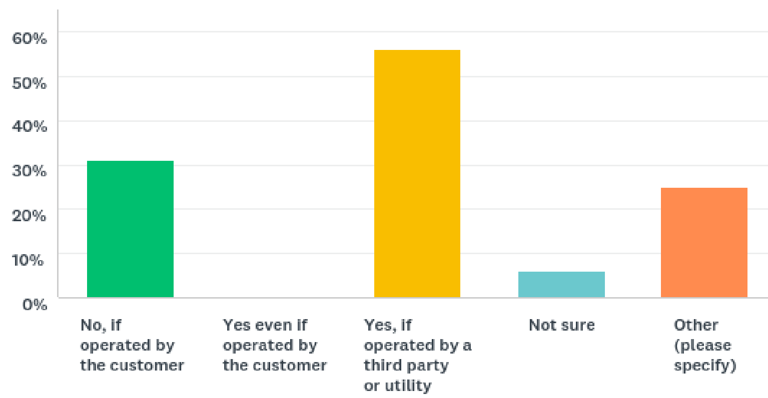


Figure A.13: Utilities' willingness to depend on customer-owned equipment

The following are additional inputs from the respondents:

1) Yes, we would rely on customer equipment provided they provide the certificates of compliance with IEEE 1547 and or UL 1741 up to a certain size. For larger installations, we may require equipment approved by our company that passes IEEE 1547 standard requirements. For some very large installations, we may have additional requirements, like direct transfer trip.

2) To the extent feasible as inverter-based generation, even deploying smart inverter capabilities may be insufficient to mitigate all issues unless additional supplemental equipment is also in use.

3) Yes, if the customer demonstrates the ability for the control to work and we start building a good track record.

4) Depends on the level of penetration. For high levels of DER, we would likely require a higher level of communications.

13. If your response to question 12 is yes, would you still require redundant protection to mitigate the operational issues (overvoltage, protection, and system stability related) associated with high DER penetration?

From Figure A.14, 36% of the respondents would still require redundant protection to mitigate the operational issues associated with high DER penetration, while 21% would not require redundant protection. It must be noted that 36% of the respondents are unsure of the best option. Several are of the opinion that redundant protection is necessary for large DERs and microgrids.

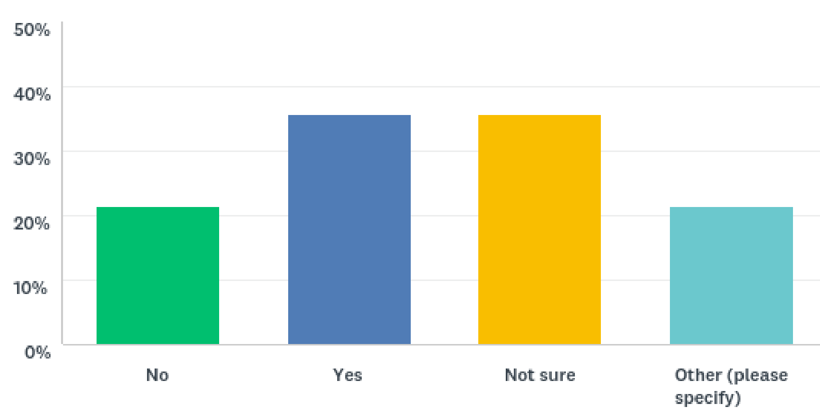


Figure A.14: Requirement for redundant protection with high DER penetration

Following are the additional inputs given by the respondents:

1) It depends on the size of the installation.

2) Probably yes until the technology and performance monitoring have proven redundancy is unnecessary.

3) Yes, redundant protection is needed for large installations.

14. Would you require redundant protection for every DER installation or only for DERs above a certain capacity?

From Figure A.15, only 7% would require redundant protection for every DER installation. However, 47% of the respondents would require redundant protection for DER installations above a certain capacity which ranged from 25 kW to 1 MW. Another 40% of the respondents would do it on a case-by-case basis.

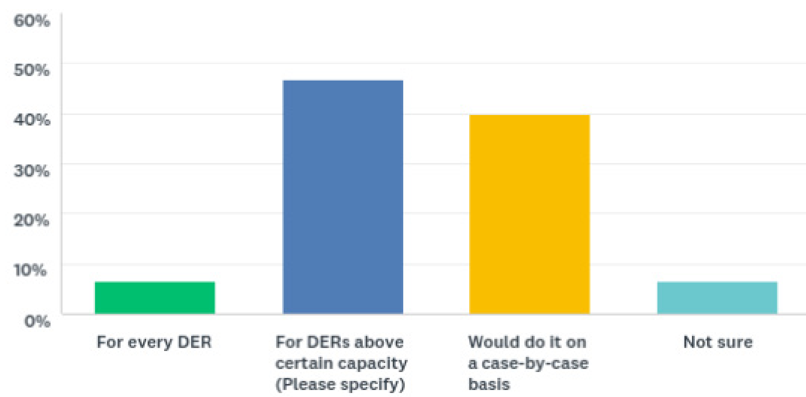


Figure A.15: Requirement for redundant protection for DER installations

Following are the additional inputs given by the respondents:

1) It would be based on a study for installations above 500 kW.

2) Yes, for installations 1 MW and above.

3) Yes, for installations above 25 kW.

4) The need for redundant protection would be feeder and location specific.

5) 1 MW in urban areas and maybe small in rural areas with weaker feeders.

15. What are the main concerns you have when interconnecting microgrids? Rate using a 5-point scale, where a rating of 5 means "Very Important" and a rating of 1 means "Not Important."

From Figure A.16, the main concerns raised by utilities and vendors when interconnecting microgrids are as follows in the decreasing order of priority: complicated fault coordination with microgrids, no real-time visibility into customer microgrids (and assets), lack of control over microgrids − unable to integrate every microgrid controller with the DMS, anti-islanding issues, local instability issues with large microgrids, damaging surge currents during reconnection, voltage transients when switching operating modes, and unable to recover grid-edge investments to ensure power quality.

A few respondents have specified that they currently do not have any operational or planned microgrids in their service territory.

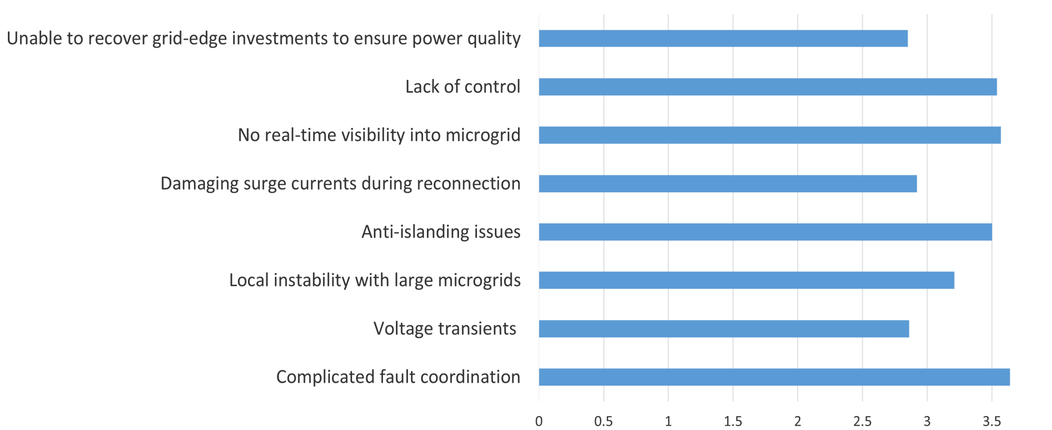


Figure A.16: Main concerns when interconnecting microgrids

16. How important are the following potential capabilities (Utility Friendly Attributes) of an advanced Island Interconnection Device (IID) when it comes to increasing the deployment of DERs and microgrids? Rate using a 5-point scale, where a rating of 5 means "Very Important" and 1 means "Not Important."

From Figure A.17, the preferred capabilities (Utility Friendly Attributes) of an advanced Island Interconnection Device (IID) in descending order of priority are as follows:

1) Provision for utility access to ensure worker safety during line maintenance

2) Automatic and disturbance-free entrance/exit from the island (seamless transitions)

3) Microgrid does not contribute fault currents to the grid

4) Utility supplies load and fault current to the microgrid in the grid-connected mode

5) Reactive VAR and harmonic support for grid and microgrid

6) Facilitation of ancillary services, storage, and reverse power flow capabilities

7) Black-start capability

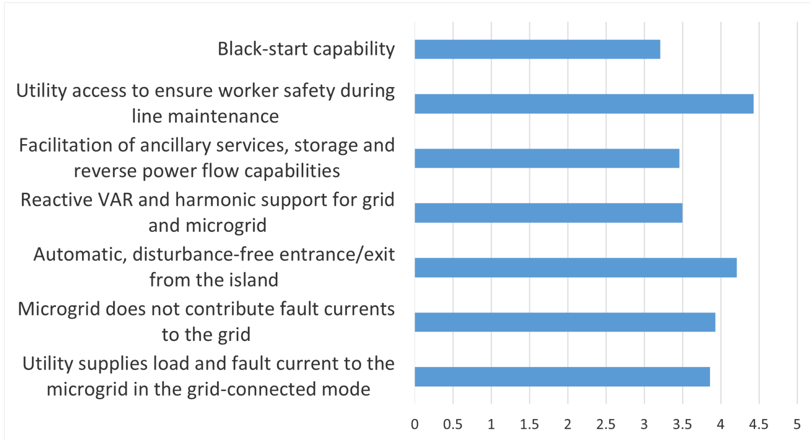


Figure A.17: Utility friendly attributes of an IID

17. How important are the following potential capabilities (Customer Friendly Attributes) of an advanced Island Interconnection Device (IID) when it comes to increasing the deployment of DERs and microgrids? Rate using a 5-point scale, where a rating of 5 means "Very Important" and 1 means "Not Important."

From Figure A.18, the preferred capabilities (Customer Friendly Attributes) of an advanced Island Interconnection Device (IID) in descending order of priority are as follows:

1) Automatic re-synchronization before closing (seamless)

2) Improved reliability and power quality

3) Simplified interconnection approval

4) Management of load inrush currents at start-up and after voltage sags

5) Voltage management during faults, voltage sags, and brownouts

6) Connect/disconnect in under 1 millisecond (normal/fault)

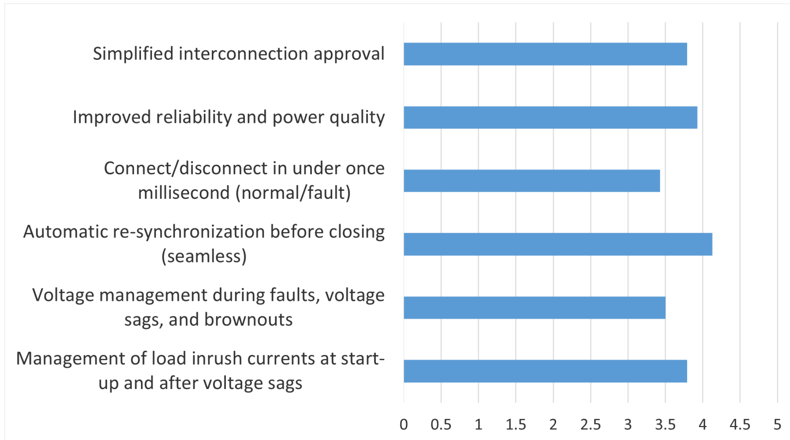


Figure A.18: Customer friendly attributes of an IID

18. What is the best mitigation strategy when dealing with feeders facing major operational issues (voltage violations, protection challenges, etc.) but with customer-owned inverters (microgrids or just DERs) conforming to older interconnection standards (IEEE 1547-2003, IEEE 1547a-2014)? You can select more than one choice.

From Figure A.19, the majority of the respondents are unsure of the best mitigation strategy when dealing with feeders facing major operational issues (voltage violations,

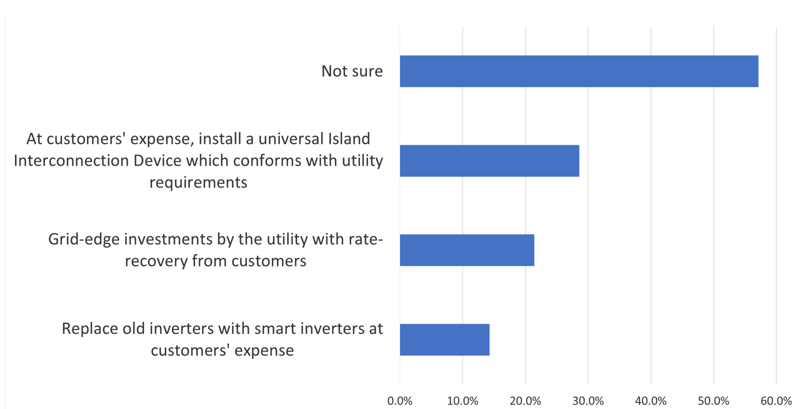


Figure A.19: Best mitigation strategy when dealing with legacy DERs

protection challenges, etc.) with customer-owned inverters conforming to older interconnection standards (IEEE 1547-2003, IEEE 1547a-2014).

The mitigation measures selected by the respondents in the descending order of priority are as follows:

1) At customers' expense, install a universal Island Interconnection Device which conforms to utility interconnection requirements.

2) Grid-edge investments by the utility with rate-recovery from customers.

3) Replace old inverters with smart inverters at customers' expense.

19. Who do you think should be the dominant owner/operator of DERs and microgrids in the future? You can select more than one choice.

From Figure A.20, it is clear that utilities would prefer having some control over the deployed DERs and microgrids. The following are the top 3 responses in the descending order of priority on who should be the dominant owner/operator of DERs and microgrids in the future:

1) Utilities partnering with third-party providers to deploy and operate DERs on the grid.

2) Owning and operating DERs as a regulated utility through rate-based investments.

3) Procuring or aggregating power from DERs owned by third-party providers.

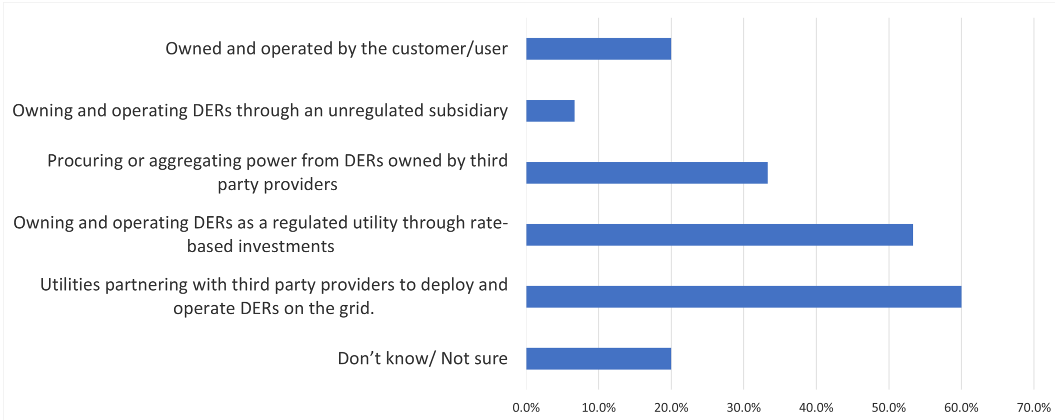


Figure A.20: Dominant owner/operator of DERs and microgrids

20. Will microgrids potentially be integrated with your black-start sequence?

From Figure A.21, the majority are not sure if microgrids will potentially be integrated with their utilities' black-start and service restoration plan. However, based on additional inputs, there is an increasing interest in utilities wanting to do so in the future.

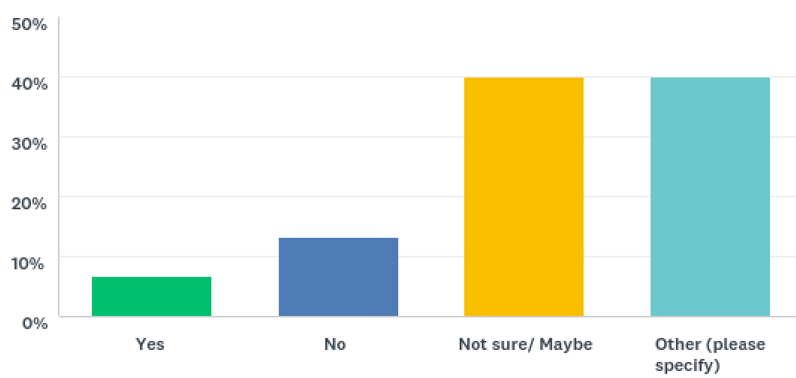


Figure A.21: Integration of microgrids with the utilities' black-start sequence

21. With the proliferation of microgrids, would you require a change in the rate design to account for diminishing kWh sales, increased grid-edge investments, etc.? If yes, please share in a few words your thoughts on tackling this issue (increased demand charges, fixed charges, etc.) in the comments section.

From Figure A.22, 84% of the respondents favor changing the rate design to account for diminishing kWh sales, increased grid-edge investments, etc., with the proliferation of DERs and microgrids. The following are the aggregated responses:

1) Most rates include a large portion of the fixed costs in the volumetric rate. This would need to be corrected.

2) The changes in rate design should provide appropriate value for the benefits provided by the customer and account for the costs of the grid, which is required to support the customer's DER.

3) Decoupled energy sales and charges.

4) Fixed connection and stand-by charges that may be based on the output/rating of the DERs and microgrids.

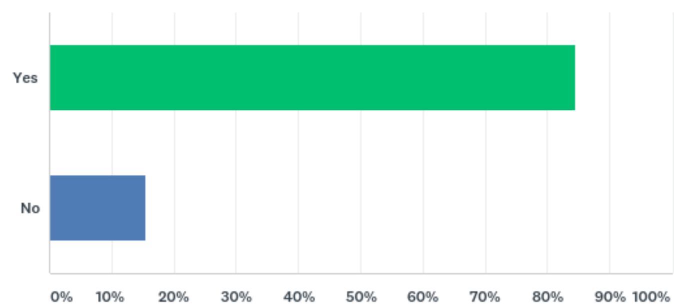


Figure A.22: Need for changes in utility rate design

APPENDIX B: PUBLICATIONS

Conference Publications:

1. **N. Bilakanti**, F. Lambert and D. Divan, "Island Interconnection Device - Enabling a Simplified Approach to Integrate Microgrids with the Grid," *2019 IEEE 10th International Symposium on Power Electronics for Distributed Generation Systems (PEDG)*, Xi'an, China, 2019, pp. 951-957.

2. **N. Bilakanti**, D. Divan and F. Lambert, "A Novel Approach for Bump-less Connection of Microgrids with the Grid," *2019 IEEE Decentralized Energy Access Solutions Workshop (DEAS)*, Atlanta, GA, USA, 2019, pp. 207-212.

3. **N. Bilakanti**, F. Lambert and D. Divan, "Integration of Distributed Energy Resources and Microgrids - Utility Challenges," *2018 IEEE Electronic Power Grid (eGrid)*, Charleston, SC, 2018, pp. 1-6.

4. **N. Bilakanti**, N. Gurung, H. Chen and S. R. Kothandaraman, "Priority-based Management Algorithm in Distributed Energy Resource Management Systems," *2021 IEEE Green Technologies Conference (GreenTech)*, 2021.

5. **N. Bilakanti**, L. Zheng, P. Kandula, K. Kandasamy and D. Divan, "Single stage soft-switching tri-port converter for integrating renewable source and storage with grid through galvanic isolation," *2017 19th European Conference on Power Electronics and Applications (EPE'17 ECCE Europe)*, Warsaw, 2017, pp. P.1-P.10.

6. **N. Bilakanti**, L. Zheng, R. P. Kandula, K. Kandasamy and D. Divan, "Soft-switching isolated tri-port converter for integration of PV, storage and single-phase AC grid," *2017 IEEE Energy Conversion Congress and Exposition (ECCE)*, Cincinnati, OH, 2017, pp. 482-489.

Journal Publications:

1. **N. Bilakanti**, F. Lambert and D. Divan, "Island Interconnection Device – An Approach to Simplify the Integration of Microgrids with the Grid," to be submitted to *IEEE Transactions on Smart Grid*.

2. **N. Bilakanti** and D. Divan, "Bottom-up Black-start and Service Restoration using Distributed Energy Resources for Resilient Distribution Systems," to be submitted to *IEEE Transactions on Smart Grid*.

3. L. Zheng, A. Marellapudi, V. R. Chowdhury, **N. Bilakanti**, R. P. Kandula, M. Saeedifard, S. Grijalva, D. Divan, "Solid-State Transformer and Hybrid Transformer With Integrated Energy Storage in Active Distribution Grids: Technical and Economic Comparison, Dispatch, and Control," in *IEEE Journal of Emerging and Selected Topics in Power Electronics*, vol. 10, no. 4, pp. 3771-3787, Aug. 2022.

Reports:

1. **N. Bilakanti**, D. Divan and F. Lambert, (2020), “Microgrid-to-Grid Interface Issues,” NEETRAC 16-172- Final Report.

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