ABSTRACT

JAIN, RISHABH. Distributed Fault Management for Enhanced Protection and Resiliency of Active Distribution System with Nested Microgrids. (Under the direction of Srdjan M. Lukic and David L. Lubkeman).

The protection and operational aspects of the distribution systems are getting increasingly intertwined as they evolve into a prosumer (producer-consumer). Advanced prosumer schemes make two vital assumptions: the protection works reliably, and the system is resilient to one or more contingencies. However, these assumptions are becoming more vulnerable with increasing distributed generation, grid intelligence and interoperability with the grid to encourage microgrids. IEEE 1547 (2018) introduces the ride-through requirements for distributed energy resources (DERs), which means that the adaptive protection strategies need to detect faults in presence of DERs. Existing adaptive protection strategies do not fully address the upcoming concerns with ride-through, are mostly centralized and focused on grid-only or microgrid only modes. Similarly, most of the service restoration strategies are grid-centered, or for microgrid modes only, and not aimed to operate the largest connected system.

This research focuses on distributed fault management solutions to address the looming challenge of maintaining reliable system protection and improving the post-fault system resiliency. The first part discusses the deficiencies in fault detection using state-of-the-art protection schemes. In this light, a dynamic adaptive protection scheme is presented to address the upcoming and existing challenges. The scheme can be implemented locally (within a relay) with minimal dependence on communication which improves robustness. In view of the challenges with approaches using phasor based approaches, the second part presents a proof-of-concept for a new protection element based on transient frequency...
analysis. It performs reliably for downstream faults with and without DER penetration, and can reliably distinguish between fault and non-fault transients. The final part presents the novel multi-agent contingency management scheme following successful fault isolation. It steers the system from the moment when a contingency occurs [breaker(s) tripped] to a reconfigured system with maximum utilization of the available generation. First, the proposed fast microgrid transition scheme helps the system to proactively balance the resulting microgrid(s), should a contingency occur. A novel underlying system architecture is developed to integrate this transition with service restoration applications. Finally, upon settling into a post-fault steady state, the “automated service restoration; reconfigures the sections to maximize the support of more critical loads given the available generation, and tie-lines. The proposed ASR scheme is a greedy algorithm which forms the largest possible electrically connected system(s) subject to the operational constraints. Matlab/Simulink is the choice for transient and steady-state simulation models and tools developed for the analysis.
DEDICATION

To Ma, Papa, and Shubham
BIOGRAPHY

Rishabh was born in a small village ‘Dakra’ in Jharkhand, India. He received his Bachelors in Technology from Indian Institute of Technology, Dhanbad in 2011, and Masters in Science from University of Idaho, US in 2014.

His research interests are in protection challenges of high renewable penetration for active distribution networks, stable microgrid operation, and improving resiliency and robustness of microgrids.
ACKNOWLEDGEMENTS

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Chapter 1

Introduction

The share of distributed energy resources (DERs) in the electric power systems (EPS) is increasing rapidly. The availability of DERs allows for multiple sources of generation which weren’t available before. This presents the EPS with both challenges and opportunities regarding system efficiency, operation, resiliency, and reliability. In an effort to improve the integration of DERs, and modernize the aging power infrastructure, ‘Smart grids’ (SG) officially became a part of the policy for the United States with the Energy Act 2007. It (SG) is characterized by the increased use of digital information and controls, integration of DERs including renewables, deployment of smart technologies for metering, distribution automation, communication and others. SGs allow the utilities to deploy better demand response schemes and improve system operation and resiliency to faults and other disturbances by distribution automation routines. These include advanced load shedding schemes, and/or self-healing sections which can reroute the power to the consumers in event of a partial outage.

Such distribution networks, which comprise of the utility grid and DERs, and have systems in place to allow for a flexible topology, and different distribution automation and
optimizations are referred to as Active Distribution Networks (ADN) [1]. However, the
distribution systems were originally designed for radial operation (unidirectional power
flow). Therefore, DERs were interconnected with an anti-islanding requirement [2], mean-
ing that all the islands were considered unintentional. The DERs in the islands, therefore,
have to be disconnected when there is a fault in any part of the system. As a result, the
utility protection schemes can operate without accounting for the influence of DERs.
This maintained utility grid as the only source of power, as DER penetration wasn’t as
significant.

Now, as the DER penetration is rising to significant levels, a system may lose too
much generation if the DERs are disconnected during faults, and increase the time of
fault recovery or even lead to a complete blackout. Further, with the available technol-
ogy, advanced DER controllers, and grid intelligence, power system sections can operate
as microgrids. According to DOE, a microgrid is a localized grid which can operate au-
tonomously or when connected to the grid, and help mitigate grid disturbances to improve
resiliency. But, this means that the system needs to operate in both grid-connected and
microgrid modes, and allow transition from one mode to another reliably. The grid in-
terconnection codes (like IEEE 1547) are undergoing drastic revisions to specify require-
ments and provisions for smoother microgrid interconnection. The DER ride-through
during system disturbances is also being mandated for a minimum time before they
(DERs) disconnect. The revised DER interconnection standard, IEEE 1547 (2018) [3]
specifies the minimum interconnection time of low capacity DERs (Category I, II) to
0.16 seconds, and Category III to 2 seconds [3].

As a result, the system operators and utilities have to reevaluate their strategies for
operation, planning, and protection, especially for power systems. For instance, a radial
operation of distribution systems was the basis for power system protection and voltage
regulation schemes. With the increasing DER capacity located across the system, not too long from now, this assumption wouldn’t be true as it is. This is a major concern for the utilities when accommodating DERs while ensuring the reliable system operation and protection. Similarly, for contingency management, the operation of the intentional islands as microgrids should be considered as a transition state with the available generation.

With the objective of improving system resiliency and robustness by harnessing the DERs and smart grid infrastructure, this chapter presents an overview of the dissertation. First, the key challenges and opportunities are introduced (Section 1.1), followed by a summary of the revisions in IEEE 1547 (2018) relevant to the problem statement in Section 1.2. Finally, Section summarizes the novel contributions of this dissertation and introduces the chapter composition.

1.1 Challenges and Opportunities

1.1.1 Challenge: Distribution System Protection

Increasing DER penetration levels affect the distribution system operation in multiple ways and cause deviation from the conventional behavior. As a result, system protection is affected in multiple ways. Some important concerns are discussed below.

- **Sympathetic Tripping**: When the grid feeds two or more radial circuits, with DERs present on some of them, it is possible that the DERs will feed the fault depending on the impedance between them and the fault point. Fig. 1.2 presents one such case, where the fault is on Feeder 1, and DER from Feeder 2 is feeding the fault. Both the feeders have their respective overcurrent relays (OCRs). Unlike
radial circuits, in this case, OCR for feeder 2 can see a higher than nominal current, and mistake it for a fault, if the remote infeed is high enough, and the characteristics of OCR1 are slower than OCR2. This is called ‘Sympathetic Tripping’. As the DER penetration increases, it is becoming an important concern. Some of the ways to avoid this is using directional supervision, and use of communication-based interlock to prevent the healthy feeder relay from responding.

- **Failure to Trip (Relay Blinding):** Remote infeed from the DERs also decreases the fault current contribution from the grid. With high enough infeed, the OCRs may fail to detect the fault, as the line current seen by them may not be as high as the minimum pickup settings. Fig. 1.1 presents one such case, where the fault is on Feeder 2, and both the grid and the DER on Feeder 2 are feeding the fault. Given the remote infeed from the DER (higher for higher capacity), the current seen by OCR2 decreases, and may lead to a failure to trip situation.

- **Loss of Coordination:** Relay coordination is the process of estimating the trip characteristics for backup protection relays such that they allow sufficient time for the primary relays to trip. This essentially means using slower trip characteristics for backup relays, so that there is a minimum coordination delay time (usually 10-20 cycles) from the operating time of primary relays. This method, however, assumes that there is a noticeable difference between the current seen by the primary and backup protection relays. Therefore, slowing the relay characteristics doesn’t affect the primary characteristics. However, remote infeed from DERs changes the fault currents seen by the primary and backup relays and may cause loss of coordination between primary and backup zones.

- **Change in Voltage Levels:** Radial operation of distribution system resulted in
a gradual decline of the system voltage given the line current from the source to different loads, and the impedance in between. DERs supply reactive power and support the local bus voltage. As a result, the voltage profile across the system isn’t linear and can be higher than usual, even during faults. This can negatively affect the voltage based protection and supervision elements.

Figure 1.1: Relay Blinding due to Remote Infeed from the DERs in the ADN

In view of the changing system operation conditions, the two most popular schemes used for protection of distribution systems are:

- Differential Current Protection
- Overcurrent Protection

Differential current based protection asserts a fault in the net current in the system is
not zero (or close, except for the unbalance and losses). This is achieved by synchronizing the measurements of the currents across the zone using high-speed communication relays. The schemes are much more resilient to DER infeed, and therefore reliable, and can issue a trip in 2-3 cycles. However, differential currents can only detect internal faults and cannot be used as backup protection. In addition, they need a high speed dedicated communication network (often fiber optic). Overall, the scheme is more expensive, and given the nature of it, more difficult to adapt to any changes in system topology. Since overcurrent relays (OCRs) do not have these limitations, they will still be needed for backup protection. OCRs do, however, have a slower response time and are more sensitive to the line load, short circuit capacity, and remote infeed from DERs. To address these challenges for OCRs, adaptive schemes are being proposed. The idea is to adjust (usually...
reduce) the relay pickup to account for remote infeed from the DERs to maintain the sensitivity and coordination of the protection relays.

1.1.2 Challenge & Opportunity: Formation of stable microgrid(s)

When a portion of an EPS is electrically separated from the main grid and energized solely by one or more DERs, it is said to have formed ‘an island’. The island formation is initiated by tripping of a switch and may/may not be intended for continued operation. Accordingly, the islands are classified as ‘intentional’ or microgrids, and ‘unintentional’. As per IEEE 1547 (2018) [3], microgrids will be connected to the rest of the system using ‘Intentional Island Interconnection Devices’ (IIIDs). To form a stable microgrid, the islanded section must have sufficient generation to support the loads, and ability to regulate the voltage and frequency. However, it is not likely that the section to be islanded is operating with zero power exchange at the point of common coupling (PCC). Therefore, to operate the intentional island stably in microgrid mode, additional actions will be required to balance the section. Accordingly, ‘intentional islanding’ can be classified into two types:

- **Scheduled Intentional Islanding**: When the power system is purposefully sectionalized using IIIDs to operate as microgrid(s), the process of intentional islanding is scheduled. In this case, the microgrid controller has sufficient time to estimate the available generation and demand. In response, it (the controller) can ramp up the generation from DERs as needed and/or perform load shedding to achieve zero power exchange at PCC. The microgrid thus formed will see minimal swings in system voltage/frequency and be stable.

- **Unscheduled Intentional Islanding**: When the power system is sectionalized
using IIIDs in response to a fault or other disturbance, the islanding is unscheduled. In this case, the microgrid controller doesn’t have time to estimate the available generation/demand and achieve zero power exchange at PCC. Ramping up generation is not immediate, and therefore, the controller needs to shed sufficient amount of load to achieve immediate power balance in the formed island for a stable intentional island.

Unscheduled Intentional islanding is a critical challenge for ADNs from a reliability standpoint. Because the section is already islanded, the loss of voltage and/or frequency will depend on many factors like the size of the island, power unbalance, delay in islanding detection and load shedding response time. As a result, the formation of a ‘microgrid’ can be challenging.

1.1.3 Opportunity: Automated Service Restoration

Fault Location, Isolation, and Service Restoration (FLISR) schemes have always been of primary importance in improving the resiliency and reliability for utilities. As a result, automated service restoration (ASR) was initially mainly limited to grid-connected systems. However, with increasing DER penetration, and distributed intelligence and measurements across the system, the means to and challenges for resiliency and robustness of the system are changing. It is now plausible to operate sections as microgrids and allow distributed management schemes to achieve more complex system level goals like demand-side response (DSR), efficiency, reliability, and robustness. ASR is defined as the ability of a system to change its topology post outage for restoring service to unfaulted sections operating as grid-connected or independent microgrids. Under the assumption of being able to form stable microgrids, ASR offers a unique potential for improving system
robustness and resiliency to disturbances and faults.

Initially, FLISR had been mostly implemented as a centralized distribution automation function. With the help of advanced metering infrastructure and other SCADA measurements, it is possible for operators to automate the process. This is both resource intensive and can fail during extreme events when the failures are more probable. With the improvements in the internet of things (IoT), decentralized schemes are being proposed. The key objective is still being able to maximize the support for system load post contingency.

In view of the above challenges and opportunities associated with the increasing DER penetration, the revised IEEE 1547 (2018) [3] is discussed.

1.2 Revised IEEE 1547 (2018)

The revised IEEE 1547 (2018) - Standard for Interconnecting Distributed Resources with Electric Power Systems is crucial to shaping the way DERs and power systems interact with each other around the world. It is a technology neutral standard which establishes the criteria and requirements at the PCC of the DERs and the area EPS for interconnection and interoperability. Fig. 1.3 presents the scope of the standard. Tables 1.3 and 1.2 present the voltage and frequency ride through requirements for the Cat-II DERs. Cat-II applies to all the renewable based DERs. The most crucial proposed changes given the scope of this research are as under.

1.2.1 Response to EPS Abnormal Conditions

- Acknowledges the possible impact of DERs towards desensitization of the protection relays, and recommends readjustment (adaptive settings) as needed to compensate.
Ride-through requirements are specified for the respective DERs. The DERs have been classified in three categories namely I, II, III, based on their size and type.

In-zone faults are the faults to which DERs can contribute even after feeder relay isolates the section from rest of the grid. In this case, DERs are required to disconnect from the system within 2 seconds unless specified otherwise by the system operator. This requirement is not applicable for faults that can’t be detected by the EPS protection systems.

### 1.2.2 Mandatory Voltage Tripping Requirements for Cat-II DERs

Table 1.1: IEEE 1547 (2018) Requirements - Category-II DER Response (shall trip) to Abnormal Voltages

<table>
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<th>Voltage (%p.u. of $V_{nom}$)</th>
<th>Clearing Time(s) $Default$</th>
<th>Voltage Range (%p.u. of $V_{nom}$)</th>
<th>Clearing Time Range(s)</th>
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<tr>
<td>OV2</td>
<td>1.20</td>
<td>0.16</td>
<td>Fixed at 1.20</td>
<td>Fixed at 0.16</td>
</tr>
<tr>
<td>OV1</td>
<td>1.1</td>
<td>2.0</td>
<td>1.10 - 1.20</td>
<td>1.00 - 13.0</td>
</tr>
<tr>
<td>UV1</td>
<td>0.7</td>
<td>10.0</td>
<td>0.0 - 0.88</td>
<td>2.00 - 21.0</td>
</tr>
<tr>
<td>UV2</td>
<td>0.45</td>
<td>0.16</td>
<td>0.0 - 0.50</td>
<td>0.16 - 2.00</td>
</tr>
</tbody>
</table>
1.2.3 Mandatory Frequency Tripping Requirements for Cat-II DERs

Table 1.2: Revised IEEE 1547 Requirements - Category-II DER Response (shall trip) to Abnormal Frequencies

<table>
<thead>
<tr>
<th>Shall Trip Function</th>
<th>Frequency (Hz)</th>
<th>Clearing Time (s)</th>
<th>Frequency Clearing Time Range (Hz)</th>
<th>Clearing Time Range (s)</th>
</tr>
</thead>
<tbody>
<tr>
<td>OF2</td>
<td>62</td>
<td>0.16</td>
<td>61.8 - 66.0</td>
<td>0.160 - 1000.0</td>
</tr>
<tr>
<td>OF1</td>
<td>61.2</td>
<td>300</td>
<td>61.0 - 66.0</td>
<td>180.0 - 1000.0</td>
</tr>
<tr>
<td>UF1</td>
<td>58.5</td>
<td>300</td>
<td>50.0 - 59.0</td>
<td>180.0 - 1000.0</td>
</tr>
<tr>
<td>UF2</td>
<td>56.5</td>
<td>0.16</td>
<td>50.0 - 57.0</td>
<td>0.160 - 1000.0</td>
</tr>
</tbody>
</table>

1.2.4 Ride-through specifications for under/over Voltage for Cat-II DERs

Table 1.3: Revised IEEE 1547 Requirements - Category-II DER Ride-through Requirements for Abnormal Voltage

<table>
<thead>
<tr>
<th>Voltage Range (p.u.)</th>
<th>Operating Mode or Response</th>
<th>Minimum Ride-through time(s) criteria</th>
<th>Maximum Response time(s) Criteria</th>
</tr>
</thead>
<tbody>
<tr>
<td>V &gt; 1.20</td>
<td>Cease to Energize</td>
<td>N/A</td>
<td>0.16</td>
</tr>
<tr>
<td>1.20 ≥ V &gt; 1.175</td>
<td>Permissive Operation</td>
<td>0.2</td>
<td>N/A</td>
</tr>
<tr>
<td>1.175 ≥ V &gt; 1.15</td>
<td>Permissive Operation</td>
<td>0.5</td>
<td>N/A</td>
</tr>
<tr>
<td>1.15 ≥ V &gt; 1.10</td>
<td>Permissive Operation</td>
<td>1</td>
<td>N/A</td>
</tr>
<tr>
<td>1.10 ≥ V ≥ 0.88</td>
<td>Continuous Operation</td>
<td>Infinite</td>
<td>N/A</td>
</tr>
<tr>
<td>0.88 &gt; V ≥ 0.65</td>
<td>Mandatory Operation</td>
<td>TVRT = 3 + 8.7 * (V − 0.65)</td>
<td>N/A</td>
</tr>
<tr>
<td>0.65 &gt; V ≥ 0.45</td>
<td>Permissive Operation</td>
<td>0.32</td>
<td>N/A</td>
</tr>
<tr>
<td>0.45 &gt; V ≥ 0.30</td>
<td>Permissive Operation</td>
<td>0.16</td>
<td>N/A</td>
</tr>
<tr>
<td>0.30 &gt; V</td>
<td>Cease to Energize</td>
<td>N/A</td>
<td>0.16</td>
</tr>
</tbody>
</table>
1.2.5 Islanding Requirements

- DERs must cease to energize unintentional islands within 2 seconds (extendable upto 5 seconds)
- Intentional islands must form without causing a voltage fluctuation of more than 5% of nominal.
- Classification for DERs based on the way they interact with the microgrid - Uncategorized (not designed for this operation), Isochronous capable (can regulate voltage and frequency), black-start capable (capable of energizing EPS), and intentional island capable (islanding detection capable).
- In addition, the standard also specifies criteria for droop criteria, volt-car controls, communication protocols, and defines evaluation criteria for DERs.

As can be seen, IEEE 1547 (2018) is a big step towards improving the interoperability of DERs with ADNs. It acknowledges the impact on system protection and attempts to improve system resiliency and reliability by defining requirements for formation of microgrids. In view of these changes, next section presents the overview of the research focus for this dissertation.

1.3 In this research

This research focuses on improving the resiliency and robustness of ADNs with distributed fault management schemes given the revised IEEE 1547 (2018) interconnection requirements. For a smarter grid, the three functionalities in the scope of this dissertation are i) System Protection, ii) Transitioning of Unfaulted Intentional Island to Microgrid
mode, and iii) Automated Service Restoration. This research identifies, analyzes and addresses crucial challenges and improves upon the state-of-the-art in existing adaptive protection and automated service restoration schemes for ADNs. To allow stable transitioning from grid connected to microgrid mode of operation during a fault, a fast microgrid transition (FMT) scheme is also being proposed. FMT will allow the system to quickly achieve power balance with minimum load loss, and allow the sections to form more stable microgrids. *Given the focus on resiliency and robustness, distributed and localized algorithms will be proposed to achieve the research goals.*

The novelty and improvements with the development of the proposed work will be discussed in the relevant chapters. The key novel contributions are summarized below.

### 1.3.1 Fault Detection and Isolation

- A new use-case is presented for misoperation in recloser zones due to the use of static (hard-coded) adaptive settings within the protection relay.

- Recommendations to reduce the possibilities of misoperation for the new use-case presented using existing adaptive schemes.

- Re-formulated adaptive setting estimation problem which significantly reduces the computation overhead to be implementable within the relay.

- The proposition of using moving average window load to adapt the settings to changing line load (especially between grid and microgrid modes of operations).

- Proposal for a *Dynamic Adaptive Relaying* scheme implemented locally in the relay with significantly reduced communication overhead. This allows the relays to change
its pickup as needed without dependence on external controllers and addresses the existing and upcoming use-cases for adaptive protection.

- An alternative transient based fault detection scheme using Maximum Overlap Discrete Wavelet Transform (MODWT). The scheme is able to reliably detect a fault based on local voltage measurements for cases with and without DERs.

1.3.2 Contingency Management (After Fault Isolation)

- Development of a new IIID centered multi-agent system architecture with interchangeable agent roles. The architecture depends primarily on the ability to control the IIIDs. All the other roles are preferred but not exclusive to any particular agent type.

- Proposal for a distributed Fast Microgrid Transition scheme to steer the unscheduled intentional island into a stable microgrid.

- Propose a distributed Automated Service Restoration scheme (ASR) focused on maximizing the support for more critical loads post outage as a greedy algorithm forming the largest electrically connected system(s).

In view of the problem statement and corresponding challenges, a majority of the research in these areas (especially adaptive protection) has focused on centralized solutions. There are some distributed algorithms proposed as well, which have their respective merits and demerits (will be discussed in relevant chapters). Further, given the revised IEEE 1547 (2018) - IEEE Standard for interconnecting DERs with Power System, the ride through requirements of DERs have changed drastically, which violate some of the
assumptions made in the existing research (like DERs islanding immediately after fault, the operation of system sections as microgrids).

The dissertation report is organized as follows. Chapter 2 discusses the most prominent challenges with existing adaptive protection schemes and presents relevant use-cases. The proposed dynamic adaptive scheme builds upon the primary concerns in these use-cases and presents a new algorithm which can be implemented locally within the relay. In view of the sensitivity of traditional protection schemes to system operation and configuration, Chapter 3 presents the proof-of-concept for a new transient based protection element. It is able to detect faults reliably with and without DER penetration, and can successfully distinguish between fault and non-fault transients. Next, Chapters 4 and 5 together represent the distributed contingency management as the final step for successful fault management. Chapter 4 presents a decentralized fast microgrid transition scheme (FMT) to quickly balance the system in event of unscheduled intentional islanding. Chapter 5 presents a novel automated service restoration (ASR) scheme along with a unique IIID centric architecture to integrate the FMT and ASR routines. The objective is to form the largest connected systems while optimizing the loads to be supported in the system. The performance comparison with other recently proposed schemes demonstrate the improvements offers by this research.
Chapter 2

Dynamic Adaptive Protection for Distribution Systems in Grid-Connected and Microgrid Modes

2.1 Introduction

Ensuring reliable protection is one of the primary challenges for distribution systems with increasing distributed energy resources (DERs). Paired with computational intelligence and advanced system management capabilities, these systems are also referred to as Active Distribution Networks (ADNs). ADNs have remote infeed from DERs resulting in bidirectional power flow and, variable fault current levels and voltage profiles, which may cause blinding and/or sympathetic tripping for overcurrent relays (OCRs). The utilities operate with an anti-islanding requirement to ensure that line protection is unaffected
by DERs. However, this will change with the revised IEEE 1547 (2018), which mandates minimum DER ride-through to support the faulted system unless tripped by the protection. As a result, the OCRs need to detect faults with DERs connected.

Fault pickup for OCRs is set between (usually twice) the nominal line load and (half of) the minimum fault current \( I_{f\text{min}} \) in their protection zones (2.1)/. This makes the pickup sensitive to line loading, short circuit capacity, the power flow direction, and DER remote infeed. For grid-connected systems, the difference in \( I_{f\text{min}} \) between primary and backup protection may be sufficient for relay coordination. However, with nested microgrids, this may not hold good. Traditional coordination can severely delay the response to primary zone faults. Adaptive overcurrent relaying (AOCR) schemes address this by adjusting the pickup based on the operating conditions (DER penetration, grid forming source location and others) to help maintain the selectivity and sensitivity.

\[
I_{\text{pickup}} = a * I_{\text{line load}} + b * (I_{\text{fault zone}} - a * I_{\text{load max}}) \tag{2.1}
\]

Here, ‘a’, ‘b’ are arbitrarily chosen constants such that ‘a’ \( \in [1.5, 2] \) and ‘b’ \( \in (0, 0.5] \). Constant ‘a’ provides a sufficient margin from the unfaulted line load current, and ‘b’ ensures that the relays are sensitive for faults with higher fault impedance compared to short circuit analysis values.

Most approaches in related research formulate AOCR as an optimization problem [4]–[15]. Fig. 2.1 summarizes the approaches to present the overall process. Given the computational burden, optimization based approaches cannot be solved within the overcurrent relays. Consequently, there is an inherent bias for centralized architectures using external controllers and a dependence on communicating volumes of analog data to maintain adaptivity. This can be a concern for a system with a large number of nodes/relays. To
work around this challenge, [8] limits the cases based on significant changes in topology. [9] achieves the same by using pre-defined adaptive settings in multiple relay groups, selected given the system equivalent impedance. Decentralized approaches using agents [12] have also been proposed with AOCR formulated as an optimization problem. Expectedly, as [12] notes, the process is communication intensive and time-consuming (~100s of milliseconds) which needs to be addressed to avoid misoperation in time-critical cases.

Figure 2.1: Overview: Process Flow for Estimating Adaptive Settings

Other approaches incorporate the impact of line load using the previous day load data from smart meters [7] to determine AOCR pickup. This approach is susceptible to DER output, and can negatively affect the relay’s sensitivity. But, impact of line load on the relay’s pickup needs to be considered as distribution systems move towards integration of nested microgrids. Finally, all existing AOCR schemes have a common assumption - they reprogram the new relay settings using communication or as setting groups. With
setting groups, protection engineer also needs to ensure that the new group is applicable in entirety (not just the OCR element) to the new system state. As relay manufacturers also note [16], *when reprogramming the static relay settings or changing the setting group, the relay disables itself* (all its functionalities) for a short period. Existing AOCRs are tested for the first fault detection and usually specific to either the grid or microgrid modes[13], [14] of operation. This creates a new use-case for potential misoperation in ADNs with high DER penetration which is elaborated (Section 2.3) and addressed in this research.

In view of the concerns associated with existing AOCR schemes, this chapter proposes a novel dynamic AOCR strategy. The scheme has been designed for ADNs with high DER penetration, capable of operating in both grid-connected and microgrid modes. A key advantage is being implementable within the overcurrent relays (no external controllers needed) allowing them to change the settings dynamically (fig. 2.2). To achieve these objectives, the chapter re-formulates the AOCR problem to simplify the computational burden and moves away from the optimization-based approach. The scheme is tested in Matlab/Simulink with transient domain simulations for high PV penetrations with ride-through capabilities for grid and microgrid modes of system operation. Section 2.4 describes the proposed dynamic AOCR scheme to address these concerns. The test system and corresponding DER/protection relay models are discussed in Section 2.5. Section 2.6 presents the results. Finally, section 2.7 concludes the chapter.

In an effort to resolve these challenges, alternate protection schemes are being developed. The most prominent are 1) Differential current based, 2) Adaptive overcurrent based (AOCR). Differential relays are less sensitive to system operating conditions, faster and more robust. However, they require high speed dedicated communication channels, are not flexible to changes in system topology, and still require overcurrent relays for
backup during communication failures. OCRs don’t have the concerns of differential relays and allow ADNs the flexibility to operate grid connected or as nested microgrids. As a result, AOCR schemes are being developed to adjust the pickup to maintain sensitivity even if the operating conditions change. The pickup and coordination settings are then automatically calculated given the optimization objective and constraints. The relays are then reprogrammed to maintain protection for changing system conditions. The formulation is usually an optimization problem. Therefore, recent research seems to be focused on better optimizations methods, and better problem formulation (like relay coordination, fuse-saving, load data and others). Coexistence of microgrids and problems faced in microgrid mode of operation are less researched.

### 2.2 Challenges for Existing Adaptive Approaches

The key challenges with existing AOCR schemes emerge with the upcoming DER interconnection requirements and transitioning/operating as microgrids. Addressing these will be formative for the development of more versatile AOCR schemes supporting grid/microgrid modes of operation.
2.2.1 Underreaching OCRs with multiple DER generation levels

Traditional fault analysis often considers DERs as constant current sources [17], [18]. Thus, the DER infeed is scaled proportionally to account for the fault contributions at different levels of output w.r.t. rated power. Given the existing AOCR approaches, this assumption results in multiple setting groups for the distinct levels of DER output power [8]. However, current from converter based DERs depends on the power output and PCC voltage. The voltage depends on highly variable parameters like distance from the fault, fault impedance, and fault type. DERs are constant power sources. They can feed any current only restricted by the device limits, depending on how low the PCC voltage gets and the power output. To prove this, a detailed mathematical model (fig. 2.3, 2.4) of DER infeed for system under fault is presented. Fig. 2.5 presents the fault current as a function of the fault impedance and the DER’s distance from the fault. This validates the possibility for a misoperation if the AOCR settings underestimate the DER fault current, causing the relays to underreach.

- Equivalent Circuit Analysis: Fig. 2.3(a) presents the model for a generic ADN with high DER penetration. Fig. 2.3(b) presents the sequence diagram for a three-phase fault. DER power output \( P_1 \) is assumed constant during the fault. The DER is modeled as a dependent current source. Grid side is weaker (high source impedance) and has a lower fault current capacity (typical for microgrids or remote grid-connected systems). The DER output current \( I_{D1} \) is given as (2.2).

\[
I_{D1} = \begin{cases} 
\frac{P_1}{V_{D1}} & \text{if } \frac{P_1}{V_{D1}} \leq I_{lim} \\
I_{lim} & \text{otherwise}
\end{cases}
\] (2.2)
Here, $I_{\text{lim}}$ is the upper current design limit for the DER. For this test, $I_{\text{lim}} = 1.2$ p.u.

Fig. 2.4 presents the sequence network of the system for unbalanced faults. The ‘red’, ‘blue’, and ‘green’ connections represent the sequence networks for single-line-to-ground (SLG), line-line (LL) and three-phase-to-ground (3PG) faults. The source current ($I_s$) is given as (2.3).

\[ I_s = \frac{V_{D1}}{n.Z_L + Z_f + Z_{\text{network}}} - I_{D1} = \frac{V_s - V_{D1}}{Z_s + m.Z_L} \]  

$Z_{\text{network}}$ is the additional impedance given the fault type. Solving for $V_{D1}$ using (2.2) and (2.3), we get (2.4):

\[ V_{D1} = \begin{cases} 
  \frac{V_s + \sqrt{V_s^2 + 4.P_s.Z_B(1+\frac{Z_f}{Z_A})}}{2.(1+\frac{Z_f}{Z_A})} & \text{if } \frac{P_s}{V_{D1}} \leq I_{\text{lim}} \\
  V_s + I_{\text{lim}}.Z_B & \text{otherwise}
\end{cases} \]  

Z_{\text{network}} = \begin{cases} 
  \end{cases}
Figure 2.4: Sequence Diagram: Unbalanced faults on ADNs
where,

\[ Z_A = nZ_L + Z_f + Z_{network} \]

\[ Z_B = Z_s + mZ_L \]

Using (2.2) and (2.4), the DER output current (\(I_{D1}\)) can be plotted for changes in the distance of fault from the DER (‘n’) and fault impedances (‘\(Z_f\)’). Fig. 2.5. presents the plot for DER output power of 0.2, 0.5 and 1 p.u. It can be deduced from (2.3) and (2.4) using Fig. 2.4 that \(I_{D1}\) can reach \(I_{lim}\) regardless of the power output (1 p.u to 0.2 p.u.). The schemes need to operate reliably independent of the fault type. Hence, there is a little benefit to account for different fault current contributions. It may lead to relay desensitization if the contribution from the DER is underestimated.

### 2.2.2 Delayed trip time for a fault in the primary protection zone

Microgrids can have significantly lower fault currents compared to grid-connected systems. This negatively affects the OCR sensitivity in primary/secondary zones. In the microgrid mode, traditional time-based coordination can cause a significant delay in a relay’s trip time for primary zone faults. Existing AOCR approaches do not discuss this problem.

### 2.2.3 Current direction reversal due to the mode switching

Current direction reversal is possible for i) the grid-connected system given the DER output states, or ii) microgrids depending on the location of the grid forming DER (Fig. 2.19, 2.20). Existing AOCR approaches seldom discuss the directional aspects of
Fault Current approaching limit

Figure 2.5: DER Fault Current vs. Fault Location (p.u.) vs. Fault Impedance (p.u.)
protection. However, adapting directional supervision when available is important to ensure selectivity towards internal vs external faults. *Without accounting for directional supervision, it is difficult to create a robust scheme for the coexistence of grid-connected and microgrid modes.*

These observations show that the existing AOCRs lack applicability to ADNs with both grid and microgrid modes, are vulnerable to under-reaching and changing fault current, and can be too complex to implement in traditional distribution relays. The next section elaborates a new emerging vulnerability difficult to address with current practices to programming the relay.

2.3 Use-case: Misoperation in Recloser Zones

IEEE 1547 (2018) requires the DERs to disconnect for any fault in their zone when initiated by the protection relay. This paired with the current AOCR ideology of using static (programmed) settings presents a new use-case for relay misoperation. This can be a significant concern but has not been discussed in the literature or considered by the existing AOCRs. Therefore, this section elaborates on the mechanism and sequence of events leading to the misoperation and presents two ways to address this challenge.

2.3.1 System Setup

Assume a distribution system with a recloser for the downstream load with high DER penetration (Fig. 2.6a). As per IEEE 1547 (2018), DERs need a minimum ride-through programmed (≥ 0.16 ms) unless tripped by the local protection. The relay protecting the zone uses existing AOCR schemes and will (ideally) detect the first fault and trip the reclosers and the DERs in its protection zone.
2.3.2 Sequence of Events

Fig. 2.6 shows the sequence of events for this case.

Figure 2.6: Use-Case for Relay Misoperation: a) Unfaulted system with Adaptive settings, b) Relay sees reduced fault current, c) Relay trips the breaker, and both DERs in fault zone as per IEEE 1547 [3], d) Relay attempts a reclose, but mistakes line current for fault current, e) Misoperation - Recloser Lock-out

- A temporary fault strikes (fig. 2.6a) when the system has a high DER infeed. The resulting fault current seen by the relay is very low.

- The relay detects the fault with existing AOCR settings (Fig. 2.6b) and trips the recloser. DER1, DER2 (Fig. 2.6c) are deenergized to prevent feeding the fault.

- The relay starts a timer to reclose for a potential temporary fault. Note, the relay’s pickup settings are still set based on the pre-fault DER penetration.

- The temporary fault clears before the recloser wait timer expires. Then, the relay
tries to re-close the breaker (Fig. 2.6d). However, now the entire load current is seen by the relay. This will be higher than prefault for high DER penetration cases. The relay can misinterpret the nominal load as a fault, and lead to recloser lockout (Fig. 2.6e).

2.3.3 Concerns

This is a critical concern because the relay can’t change settings (or groups) and switch to NO DER settings - the relay will get blinded in wake of a fault. Even with the knowledge of this potential misoperation, existing schemes cannot eliminate the risk of recloser misoperation.

2.3.4 Solutions

The chapter presents two potential ways to address this risk of misoperation as under:

Conservative Settings with existing AOCR strategies

For a given test system, by comparing each relay’s pickup settings for different operating modes and DER penetration levels, critical relays most prone to recloser misoperation can be identified. Note, this can not eliminate the risk of misoperation, only reduce it by sacrificing sensitivity. Fig. 2.7 and 2.8 show the nominal short circuit fault currents and load currents as seen by the corresponding relays (‘8’ in total) in a test ADN (Section 2.5). Fig. 2.9 presents the corresponding OCR pickup settings for the relays. The difference in the pickup between grid and microgrid modes can be significant due to reduced fault current capacity, or change in line load based on the location of MG forming source. From fig. 2.9, location ‘4’ sees the largest difference in the pickup with and without
DERs in microgrid mode. This helps identify when the corresponding relay is prone to misoperation during reclosing.

To improve security with existing AOCRs, the lower limit on the pickup for location ‘4’ should be limited to maintain a safe margin from peak nominal load current (2.1), to avoid misoperations. A backup voltage-based protection can help compensate for losing sensitivity. Alternatively, differential protection may be better suited. The recommendations to address the existing and upcoming challenges are summarized in a table (Table 2.1).

![Minimum Fault Current as seen by the protection relays across the test system for all operating modes](image)

**Figure 2.7**: Minimum Fault Current as seen by the protection relays across the test system for all operating modes
Figure 2.8: Nominal Load Current as seen by the protection relays across the test system for all operating modes.

Figure 2.9: Pickup across the respective ‘8’ relays for the 15-bus test system in all operating modes (Section 2.5.1)
Table 2.1: Recommendations: Reducing the risk of misoperations with existing adaptive protection schemes

<table>
<thead>
<tr>
<th>Sl.</th>
<th>Test Steps</th>
<th>Recommendation</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Communication vs.</td>
<td><strong>Using Short circuit and Nominal Load</strong></td>
</tr>
<tr>
<td></td>
<td>Conventional</td>
<td>For any relay:</td>
</tr>
<tr>
<td></td>
<td>Coordination</td>
<td>Are fault currents in primary and backup zones comparable for any relay?</td>
</tr>
<tr>
<td>2</td>
<td>Relay sensitivity to</td>
<td><strong>Using Short circuit and Nominal Load</strong></td>
</tr>
<tr>
<td></td>
<td>DER presence</td>
<td>For any relay:</td>
</tr>
<tr>
<td></td>
<td></td>
<td>$I_{\text{fault, min}} \approx 2I_{\text{load,nom}}$</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Differential zone or Voltage based backup protection</td>
</tr>
<tr>
<td>3</td>
<td>Recloser Zone Misoperation</td>
<td><strong>Using Pickup Current Values</strong></td>
</tr>
<tr>
<td></td>
<td>For any relay:</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Sharp changes in relay pickup for different number of DERs operational</td>
<td>a) Using lower limits on the pickup values</td>
</tr>
<tr>
<td></td>
<td></td>
<td>have a margin from highest nominal load current</td>
</tr>
<tr>
<td></td>
<td></td>
<td>b) Backup Undervoltage protection</td>
</tr>
<tr>
<td></td>
<td></td>
<td>c) Use differential zones instead</td>
</tr>
</tbody>
</table>

31
Use of Dynamic Settings

Even with the knowledge of offline DERs, relays cannot change the settings because of getting disabled temporarily when updating. Therefore, if the relays can automatically adapt their pickup based on DER status, that will resolve the issue. The primary challenge here is the computational complexity of optimization based schemes, preventing the implementation within the relay. This is a key motivation towards developing the dynamic AOCR proposed in the next section.

2.4 Proposed Dynamic AOCR Scheme

With the motivations established in Sections 2.1-2.3, a dynamic AOCR scheme is now proposed. It addresses the existing and upcoming challenges for ADNs with nested microgrids. The focus is on implementing the adaptivity within the relay with minimal dependence on external controllers. Therefore, the AOCR problem needs to be re-formulated for the relay while ensuring reliable performance for changing line load and fault current capacity. These parameters depend on the time of the day, mode (grid-connected/microgrid) and DERs status (on/off) in the protection zone. The scheme also needs to ensure coordination with backup protection. Fig. 2.10 summarizes the process flow for the overall scheme.

2.4.1 Re-Formulation: The Adaptive Relaying Problem

AOCR is being re-formulated to reduce the complexity of the problem to be solvable by a simple distribution protection relay. With the help of these steps, the need for an optimization based solution is eliminated.
Figure 2.10: Overview - Proposed Dynamic AOCR Scheme
Using DER status (ON/OFF) instead of multiple DER output levels

Section 2.2.1 validates that adjusting the relay settings based on DER output increases the risk of misoperation. Therefore, dynamic AOCR accounts only for DER status when estimating relay pickup. If a DER is online, its maximum fault current contribution is considered. When offline, no contribution from DER is considered. This ensures that settings do not under-reach, and further helps with faster trips for faults when DERs contribute less than their limits (more current at the feeder relay). If there be \( P \) DERs in the system feeding the fault, offline short circuit values can be programmed during initial analysis (not in real time) only for \( 2^P \) cases for both modes (grid/microgrid). The respective minimum fault current values are saved in the relay’s database as shown in Table 2.2 (assuming \( P = 3 \) DERs). The columns ‘State’ and ‘Minimum Fault Current’

<table>
<thead>
<tr>
<th>DER1</th>
<th>DER2</th>
<th>DER3</th>
<th>State</th>
<th>Minimum Fault Current</th>
</tr>
</thead>
<tbody>
<tr>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>Corresponding</td>
</tr>
<tr>
<td>0</td>
<td>0</td>
<td>1</td>
<td>1</td>
<td>Minimum Fault</td>
</tr>
<tr>
<td>0</td>
<td>1</td>
<td>0</td>
<td>2</td>
<td>Current Values</td>
</tr>
<tr>
<td>1</td>
<td>0</td>
<td>0</td>
<td>3</td>
<td>programmed for</td>
</tr>
<tr>
<td>1</td>
<td>0</td>
<td>1</td>
<td>4</td>
<td>each state</td>
</tr>
<tr>
<td>1</td>
<td>1</td>
<td>0</td>
<td>5</td>
<td></td>
</tr>
<tr>
<td>1</td>
<td>1</td>
<td>1</td>
<td>6</td>
<td></td>
</tr>
</tbody>
</table>

are programmed in the relay. ‘State’ is the decimal representation based on the status of the respective DERs. This is a practical method that can be implemented even in simple modern relays. Fig. 2.10 (top-right) shows the implementation in the relay.
Communication-based Relay Coordination

As discussed in Section 2.2, delayed trip time of OCRs is a growing concern for microgrids and systems with weak sources. The fault current capacity of primary and secondary zones can be similar, which negatively impacts the speed of primary protection response. Therefore, multiple projects [19],[20] are using communication-based coordination 2.11 with conventional time-based coordination as the backup. Therefore, communication-based coordination (Fig. 2.10 (bottom-left)) will be used for the proposed dynamic AOCR. Under this scheme, downstream relays send a block signal to their upstream relays (given the direction of current flow at the time) when a fault is detected. Similar to time-based coordination, the relays will wait for a coordination time interval before tripping the local breaker. Unlike time-based coordination, this delay is fixed (~600ms). If the fault is not cleared with this time, the backup protection will trip its corresponding local breakers. Because ADNs use inverse time-delayed OCR, the trip time $\epsilon$ [100ms, few seconds]. This time is enough to block the upstream relay and ensure coordination. Other communication delays are not relevant because the trip decision is made locally.

2.4.2 Adaptive Line Load

The general equation to calculate OCR pickup ($I_{pickup}$) based on the line load ($I_{line load}$) and minimum zonal fault current ($I_{fault min zone}$) is presented in (2.5).

$$I_{pickup} = a \ast I_{line load} + b \ast (I_{fault min zone} - a \ast I_{load max})$$  \hspace{1cm} (2.5)
Here, $a$, $b$ are arbitrarily chosen constants such that $a \in [1.5, 2]$ and $b \in (0, 0.5]$. $a$ provides a margin from the unfaulted line load, and $b$ helps the relays maintain sensitivity. The line load changes between the grid-connected and microgrid modes, and throughout the day. Therefore, the dynamic AOCR scheme adjusts the relay sensitivity using a 10-second moving average window filter (MAWF) of locally measured line load (Fig. 2.10 (center)) to adapt the pickup to the operating conditions. First, a 1-second MAWF line load, $I_{1secAv}$ is calculated as (2.6).

$$I_{1secAv} = \frac{1}{f_s} \cdot \sum_{j=1}^{f_s} I_{line_j}$$  \hspace{1cm} (2.6)

Here, $I_{line_j}$ is the RMS line current seen by the relay every cycle. $I_{1secAv}$ is the 1-average of this current over $f_s$ cycles (=60). The 10-second average ($I_{mov10s}$) averages ten consecutive 1-second averages ($I_{1secAv}$) as given in (2.7). The calculation is done piecewise for memory considerations.

$$I_{mov10s} = \frac{1}{10} \cdot \sum_{i=1}^{10} I_{1secAv_i}$$  \hspace{1cm} (2.7)
2.4.3 Dynamic AOCR Scheme

Given the proposed re-evaluations and MAWF line-load, the relay knows the DER operating states, system operation mode (grid/microgrid), corresponding minimum fault currents \((I_{\text{fault}_{\text{minzone}}})\), and the 10-second MAWF line load \((I_{\text{mov}_{10s}})\). Using this information, a dynamic AOCR scheme (Fig. 2.12) is proposed. The original pickup calculation (2.5) can be restated as (2.8) and programmed as a custom time-OCR element. Practical implementation for simulations (Fig. 2.10 (center-right)) is presented using the process flow diagram. It shows the instantaneous (50P1), time-delayed (51P1) and directional (67P1) OCR logic integrated to the dynamic adaptivity. Implementation of an OCR element in a typical distribution relay is presented in [16].

\[
I_{\text{pickup}} = a \ast I_{\text{mov}_{10s}} + b \ast (I_{\text{fault}_{\text{minzone}}} - a \ast I_{\text{mov}_{10s}})
\]  

(2.8)

![Figure 2.12: Proposed Logic - Dynamic AOCR Scheme](image-url)
2.5 Test Setup

This section presents the Matlab/Simulink models for the test 15-bus ADN, protection relays and DERs used.

2.5.1 Power System Model

In the absence of existing standard models, a 15-bus ADN with high DER penetration has been developed in Simulink. It can operate in both grid-connected and microgrid modes. The system is rated at 12.47kV with a net load of 4.5MW, 2MW of PV, and is about 6.7 circuit miles. Fig. 2.13 shows the topology of the system along with ‘eight’ protection relays. Microgrids ‘MG1’ and ‘MG2’ can be formed and operated independently or together isolated from the grid.

![Figure 2.13: The 15-bus Test Active Distribution Network](image)

2.5.2 DER Model

The DERs used in this system are averaged PV plant models adapted from [21], [22] with low voltage ride-through as per IEEE 1547(2018). Fig. 2.14 presents a high-level diagram. DERs stay connected to the system under fault for 15 cycles if the PCC voltage
falls below 0.5 p.u., unless tripped by a local relay. The reconnection time is 10 seconds.

![Diagram of Photovoltaic Model for EMT-type Simulations](image)

**Figure 2.14**: Overview: Photovoltaic Model for EMT-type Simulations [22].

### 2.5.3 Relay Model

A directional OCR logic based on SEL 651 [23] is developed in Simulink (Fig. 2.10 (center-left)). The line voltages/currents (sampled at 480Hz) are used for phasor calculation, directional supervision, and fault detection using the proposed dynamic AOCR. Table 2.3 presents the relay locations and the respective primary and secondary zones.

#### Table 2.3: Relay Location, and Respective Primary, Secondary Reach

<table>
<thead>
<tr>
<th>Sl.</th>
<th>Line</th>
<th>Near Bus</th>
<th>Primary Zone</th>
<th>Secondary Zones</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>1-2</td>
<td>1</td>
<td>{1,2,15}</td>
<td>{3,4}</td>
</tr>
<tr>
<td>2</td>
<td>2-3</td>
<td>2</td>
<td>{2,3,4}</td>
<td>{4,5},{4,6,7}</td>
</tr>
<tr>
<td>3</td>
<td>4-5</td>
<td>4</td>
<td>{4,5}</td>
<td>-</td>
</tr>
<tr>
<td>4</td>
<td>4-6</td>
<td>4</td>
<td>{4,6,7}</td>
<td>{6,8,9}</td>
</tr>
<tr>
<td>5</td>
<td>6-8</td>
<td>6</td>
<td>{6,8,9}</td>
<td>{9,10},{9,11,12},{9,13,14}</td>
</tr>
<tr>
<td>6</td>
<td>9-10</td>
<td>9</td>
<td>{9,10}</td>
<td>-</td>
</tr>
<tr>
<td>7</td>
<td>9-11</td>
<td>9</td>
<td>{9,11,12}</td>
<td>-</td>
</tr>
<tr>
<td>8</td>
<td>9-13</td>
<td>9</td>
<td>{9,13,14}</td>
<td>-</td>
</tr>
</tbody>
</table>
**Directional Supervision**

The directional element uses the logic developed in [24]. The ‘positive’ ($T_{32P}$) and ‘negative’ ($T_{32Q}$) sequence directional torques are calculated as (2.9), (2.10) using the respective voltage and current phasors.

\[
T_{32P} = |3V_1|.|3I_1|.cos[\angle 3V_1 - (\angle 3I_1 + \angle Z_{L1})]
\]

(2.9)

\[
T_{32Q} = |3V_2|.|3I_2|.cos[\angle -3V_2 - (\angle 3I_2 + \angle Z_{L1})]
\]

(2.10)

Here, $V_1$, $V_2$ and $I_1$, $I_2$ are the respective positive, negative sequence voltage and current phasors. $Z_{L1}$ is the positive sequence line impedance. The net directional element $T_{32PQ}$ is the weighted sum of $T_{32P}$ and $T_{32Q}$ given as (2.11).

\[
T_{32PQ} = T_{32Q} + k.T_{32P}
\]

(2.11)

Here, $k$ is a constant such that $k < 1$. For the model used in this study, $k = 0.3$. The value of $k$ is arbitrary and depends on the system’s positive and negative sequence unbalances.

**Trip Logic**

When picked up, the overcurrent element (50P) starts the timer to trip. It issues a trip if the timer expires. Downstream relays will send ‘Block’ to their upstream backup relays when they see a fault. When receiving a block from a downstream relay, the given relay will wait for 600ms (programmed coordination time). If the fault persists when the timer expires, it will trip the local breaker. If the fault direction doesn’t match the relay settings, directional supervision ($T_{32PQ}$) can block the relay trip.
2.6 Results and Discussion

This section analyzes the performance of the proposed dynamic AOCR scheme for the use cases from Section 2.2 and compared to traditional OCRs.

2.6.1 DER Model Validation: Fault infeed from a DER for generation at and below rated capacity

This use-case validates the discussion in Section 2.2.1 using simulation results. For the test, a three-phase fault is simulated on Bus 4 with a fault impedance of ‘0’, ‘0.4’, ‘1’ and ‘2’ ohms, respectively. The resulting PCC Voltage and output current plots (fig. 2.16) for DER1 are observed. DER1 has a rated capacity of 1MW [full load amps = 44A, $I_{\text{limit}} (2.I_{\text{nominal}}) = 88A$]. For bolted faults (low PCC voltage), $I_{\text{out}}$ for DER1 is close to $I_{\text{limit}}$ (88A). The duration of infeed depends on the ride through. For this case, DER1 trips 0.24 seconds after the voltage falls below 0.5 p.u.. As the fault impedance increases, the PCC voltage improves, resulting in lower DER infeed. This validates that MPPT and PCC voltages are quintessential to determining the current output from DER. However, estimating adaptive settings for different levels of pre-fault DER generation can cause under-reaching of the relays and should be avoided.
Figure 2.16: Case 1: PCC Voltage and DER Current for faults at 10% output
2.6.2 Case 1: Demonstration of the dynamic AOCR using a simple system over 24 hours

Dynamic AOCR adjusts relay’s sensitivity to faults given the variable load and changing short circuit current to adapt between grid-connected or microgrid modes. Case 1 demonstrates this functionality using a simpler ‘three’ bus distribution system (Fig. 2.17a) with 60% DER penetration. The system can operate in both grid-connected and microgrid modes. The equivalent grid/microgrid forming sources are connected at Bus 1. Fig. 2.17b) shows the comparative performance of the dynamic vs traditional adaptive schemes over 24-hour period. As the load profile ([25]) varies during the day, the system transitions from grid connected to microgrid mode at Hour ‘12’. This results in a drastic change in the minimum available short circuit current at Bus B3. Note that, dynamic settings adapt and maintain sensitivity to faults unlike existing adaptive practices even for low fault current capacity. For simplicity, the impact of having DERs disconnected (Section 2.3) is not considered in this case. Case 2 will present the benefit of the dynamic adaptivity for faults in recloser zones.

2.6.3 Case 2: Temporary fault in Recloser Zone

This use case demonstrates the vulnerability discussed in Section 2.3. The results show a scenario where the existing AOCR schemes can misoperate and how the dynamic adaptivity helps the relay avoid misoperation. Here, the test system is in microgrid mode resulting in low fault current capacity (fig. 2.7) and is struck by a temporary 3-phase bolted fault on Bus 4. Fig. 2.18 presents the PCC voltage and line current seen by the relay. ‘A’, ‘B’, ‘C’, ‘D’ and ‘E’ are the points of interest. The temporary fault strikes at ‘A’ (t = 2 sec). OCR detects the fault and the DERs trip at ‘B’ (t = 2.246 sec) as per
Figure 2.17: Test Case 1: (a) 3-Bus System, (b) 24-hour Protection with Dynamic Adaptive Settings
the IEEE 1547(2018) [3]. Right after the DERs go offline, the dynamic AOCR readjusts its pickup (Point B). The settings from traditional AOCR will stay the same as before (static). At ‘C’ (t = 2.75 sec), the fault clears. When the relay attempts a reclose without DERs online [Point ‘D’ - (t = 2.8 sec)], the line current is high enough to be mistaken for a fault by traditional AOCR (fig. 2.18). The dynamic AOCR based relay added security based on DER status at Point ‘B’ making the system immune to changing operating conditions.

![Graph](image)

**Figure 2.18:** Case 2: Recloser Zone Performance: Existing AOCR vs. proposed dynamic AOCR Schemes
2.6.4 Case 3: Current direction reversal due to a mode change

Custom relay OCR logic affords the ability to integrate directionality. Therefore, the proposed dynamic AOCR adjusts the relay’s direction given the grid forming source. ‘Eight’ relays are distributed across the system at the positions marked with a circuit breaker. Figures 2.19 and 2.20 present the current direction reversal (marked in red) when system transitions from the grid-connected to microgrid mode. For this system, the microgrid forming source is at Bus 7. As a result, the current in the lines between buses 1, 2, 3, 4, 6, and 7 will be reversed. As seen in table 2.4, the relay operated expectedly for both microgrid and grid-connected modes. This substantiates the value of directionality in adaptive methodologies.

Figure 2.19: Case 3: 15-Bus ADN in Grid-Connected Mode

Figure 2.20: Case 3: 15-Bus ADN in Microgrid Mode
2.6.5 Case 4: Performance of proposed dynamic AOCR for multiple fault locations and types

This test ensures that the reformulated AOCR can perform as reliably as (or better than) the traditional AOCR settings. Using the test 15-bus ADN (Section 2.5), all combinations (1440) of the following fault cases were simulated in the transient domain using Simulink.

- Three fault types (Single Line to Ground, Line to Line, Three Phase to Ground)
- 15 fault locations across the system (Each bus - represents the end of the line fault)
- Fault impedance (ohms): 0 (bolted), 20 (low), 50 (medium) and 100 (high)
- Two system types: Grid-connected, Islanded
- DERs Active: None; DER1 only; DER2 only; DER1, 2

Fig. 2.21 presents a box plot of the trip times using traditional adaptive schemes (solid green) vs the proposed dynamic scheme (dashed red) in grid-connected mode. Smaller trip times (faster) are better. The spread and median trip time for the proposed scheme is lesser than traditional schemes, demonstrating better performance. The difference in trip times increase noticeably for microgrid mode (Box plot in fig. 2.22) due to lower fault current capacity. In this mode, dynamic AOCR detects the faults much faster (up to 20 cycles - Location 3, 4) compared to conventional settings. Table 2.4 summarizes the relative trip times for the proposed dynamic AOCR schemes w.r.t. fixed relay settings (conventional scenario). A trip time greater than 0.6 seconds is considered being ”No Trip”. These results confirm that the proposed dynamic AOCR performs reliably for all the combinations of fault scenarios in the test system and the additional use-cases (Sections 2.2, 2.3). For most cases, relays didn’t detect high impedance faults (HIF) =
Figure 2.21: Relay Operating Times (cycles): All 15 locations for Grid-connected Test System with DER1, DER2 Online

Figure 2.22: Relay Operating Times (cycles): All 15 locations for Islanded Test System with DER1, DER2 Online
100 ohms. Therefore, those results are not presented here. HIF cases will need dedicated elements.

Table 2.4: Summary - Trip Times for the Proposed Dynamic AOCR Scheme w.r.t. The Conventional Settings

<table>
<thead>
<tr>
<th>Location Bus</th>
<th>Grid '0'ohms</th>
<th>Connected '20'ohm</th>
<th>(DER1,2 ON) '50'ohm</th>
<th>Micro '0'ohms</th>
<th>Grid '20'ohm</th>
<th>DER1,2 ON '50'ohm</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>-0.106</td>
<td>-0.58</td>
<td>No Trip</td>
<td>-0.24</td>
<td>-2.4</td>
<td>-4.134</td>
</tr>
<tr>
<td>2</td>
<td>-0.226</td>
<td>-0.835</td>
<td>No Trip</td>
<td>-0.21</td>
<td>-2.04</td>
<td>-4.122</td>
</tr>
<tr>
<td>3</td>
<td>-0.376</td>
<td>-1.172</td>
<td>No Trip</td>
<td>-0.81</td>
<td>-1.661</td>
<td>-12.485</td>
</tr>
<tr>
<td>4</td>
<td>-0.389</td>
<td>-1.206</td>
<td>No Trip</td>
<td>-0.775</td>
<td>-1.647</td>
<td>-12.398</td>
</tr>
<tr>
<td>5</td>
<td>0</td>
<td>0</td>
<td>No Trip</td>
<td>0</td>
<td>0</td>
<td>No Trip</td>
</tr>
<tr>
<td>6</td>
<td>-0.209</td>
<td>-0.616</td>
<td>No Trip</td>
<td>-2.088</td>
<td>-4.791</td>
<td>-223.175</td>
</tr>
<tr>
<td>7</td>
<td>-0.216</td>
<td>-0.636</td>
<td>No Trip</td>
<td>Location of Microgrid Forming DER</td>
<td></td>
<td></td>
</tr>
<tr>
<td>8</td>
<td>-0.329</td>
<td>-0.758</td>
<td>-18.703</td>
<td>-0.838</td>
<td>-1.826</td>
<td>-10.578</td>
</tr>
<tr>
<td>9</td>
<td>-0.331</td>
<td>-0.762</td>
<td>-18.781</td>
<td>-0.841</td>
<td>-1.831</td>
<td>-10.608</td>
</tr>
<tr>
<td>10</td>
<td>0</td>
<td>0</td>
<td>No Trip</td>
<td>0</td>
<td>0</td>
<td>No Trip</td>
</tr>
<tr>
<td>11</td>
<td>0.023</td>
<td>0.065</td>
<td>No Trip</td>
<td>0.097</td>
<td>0.212</td>
<td>1.255</td>
</tr>
<tr>
<td>12</td>
<td>0.024</td>
<td>0.065</td>
<td>No Trip</td>
<td>0.101</td>
<td>0.212</td>
<td>1.256</td>
</tr>
<tr>
<td>13</td>
<td>0.017</td>
<td>0.041</td>
<td>0.485</td>
<td>0.082</td>
<td>0.177</td>
<td>0.573</td>
</tr>
<tr>
<td>14</td>
<td>0.024</td>
<td>0.054</td>
<td>0.575</td>
<td>0.097</td>
<td>0.209</td>
<td>0.632</td>
</tr>
<tr>
<td>15</td>
<td>-0.238</td>
<td>-0.863</td>
<td>No Trip</td>
<td>-0.252</td>
<td>-2.58</td>
<td>-3.924</td>
</tr>
</tbody>
</table>

2.7 Conclusion

This chapter presents a dynamic adaptive overcurrent relaying (AOCR) scheme to improve the distribution system protection for grid-connected and microgrid modes. Besides the vulnerability of existing AOCRs to system mode (grid/microgrid), DER fault contribution, and others, this chapter presented a new use-case for recloser misoperation. This use-case emerges given the long DER ride-through requirements paired with low
fault current and static relay setting ideology of existing AOCRs. The proposed dynamic AOCR strategy addresses these challenges with a scheme that can be locally implemented within the relay. With a moving average line load estimate, and knowledge of DER status, the relay can adapt its pickup to the system operating conditions. To be implementable with the relay, the adaptive protection problem is re-formulated for less computational complexity. Communication is used to ensure relay coordination for low fault current (microgrid) modes. The tests are based on transient simulations in Simulink cover all fault types/impedances and operating modes of a 15-bus distribution system with 55% DER penetration. The results show that the proposed scheme performs as reliably as existing schemes in addition to addressing the emerging use-cases of misoperation.
Chapter 3

Fault Identification in Distribution Systems using Maximum Overlap Wavelet Decomposition

3.1 Introduction

Overcurrent based relays are widely used as the primary means of the protection for distribution systems. In transmission systems, these popularly serve as the primary backup protection. However, current based schemes are more sensitive to the line loading, direction of power flow and connected generation sites. Therefore, it can be challenging to detect the faults reliably, while ensuring security during non-fault disturbances. System voltage is less sensitive to these phenomena, but may not offer as much sensitivity from the change in magnitude. Initial transients (at the point of disturbance) and system harmonic content can, however, provide useful insights into the nature of disturbances. A more reliable protection solution can be achieved through a combination of existing and
emerging techniques for fault identification.

Researchers have actively looked into both transient and harmonic based techniques for differentiating faults from disturbances and improving the speed of protection. Fourier (FT) and wavelet transform (WT) based methods are most commonly used. FT decomposes the signal into periodic sinusoids to detect harmonic based events. But, in general, transients are localized and non-periodic or have an unknown harmonic signature. Non-fault disturbance transients are short-lived and less severe [26] compared to fault-induced transients. Also, time information is lost, which makes it less useful for high-speed protection methods. Variations like Short-Time-Fourier-Transform (STFT) provide a little more localized information. However, their application for transient analysis is very limited due to insufficient resolution. Alternatively, WT based techniques have been utilized in a broad spectrum of engineering applications concerned with feature detection. WT is based on decomposing the input waveform into multiple levels of outputs based on their relative frequencies (fig. 3.1). Therefore, WT based techniques are regarded to be more effective in detecting singular points and sudden changes, compared to FT based methods like STFT [27]. WT can easily detect positions of sudden and slow transitions. Discrete Wavelet Transform (DWT) and Maximum Overlap DWT (MODWT) are the most common techniques.

But the occurrence of transients is not a conclusive indicator of faults. A non-fault phenomenon like capacitor bank switching, load switching, and others also induce transients. To resolve this, the characteristic behavior of the transients needs to be taken into consideration. The current state of research in this area is presented in the next section (Section 3.2). The major shortcomings identified were 1) Performance in wake of non-fault disturbance was not evaluated, 2) Schemes were designed for transmission systems or high impedance faults (HIFs) only, or 3) Residual voltage/current components
Figure 3.1: Overview: Wavelet Transform

were used for the analysis, which limits the application.

In this chapter, the limitations highlighted above are addressed, and a novel fault detection scheme is proposed using MODWT. Supervisory checks are proposed which allow security during non-fault disturbances and thus more reliable fault detection. Section 3.3 introduces the basic equations for MODWT coefficient calculation. Section 3.4 presents the proposed protection scheme. Section 3.5 presents the test case which was used to generate the simulated fault cases. The algorithm is evaluated using with test cases from simulation model in Matlab/Simulink and field events of non-fault disturbances [28], [29], and the results are presented in Section 3.6. Section 3.7 concludes the paper.

3.2 Related Research - Fault Identification using Wavelet Transform

The potential of using wavelets for detection and location of faults and other disturbances was noted early in [30] and [31]. Reference [30] introduced the use of DWT based disturbance analysis. The ability of WT to focus on short time intervals for high-frequency
components and long intervals for low-frequency components is demonstrated for application in fault analysis. Authors note the striking resemblance between the phase voltages for capacitor switching and single phase to ground fault events. However, capacitor switching is shown to primarily invoke the high-frequency modes, while faults result in a broader band of frequencies is affected. This proposition holds in the results from [32] where an ANN-based power disturbance classifier using WT is presented. Based on the results shown for various power quality disturbances in [32], [33] (viz. flickers, capacitor switching, and harmonic distortion), same conclusion can be drawn. [31] demonstrates a fault location technique using WT. This characteristic of wavelet coefficients for fault and unfaulted events forms the underlying principle for the algorithm proposed in this chapter.

In [34], DWT is used to locate and isolate faulted sections in distribution systems with DGs. The polarities of wavelet coefficients of high-frequency components of current measurements from different zones are compared to determine the fault types and differentiate between internal and external faults. The response to non-fault disturbances has not been evaluated. Reference [35] uses absolute values of level one coefficients from DWT over a cycle to detect faults. The fault is asserted when the absolute sum (calculated previously) exceeds a set threshold continuously for a specified time. One of the major shortcomings of this approach is using higher frequency components only, which are also prevalent in non-fault disturbances. Lower frequency components should also have been taken into account.

In [36], residual voltage and current is passed through DWT to extract transient for fault detection. A basic directional element is implemented using the sum of instantaneous transient power summed over two power cycles. [37] also uses angle displacement between wavelet coefficients of residual voltages and currents for detecting high impedance faults.
An artificial neural network (ANN) was also trained to present an alternative implementation. The primary drawback of these approaches is the use of only residual quantities, which depend on the magnitude of the residue and may/may not always be available. Further, this limits the application of this method in distribution systems, which can have a natural residue on the circuit.

Wavelet energy estimation [38] is another popular way to analyze the wavelet coefficients. References [26], [39], [40] and [41] use wavelet energy for fault identification, but are restricted to HIFs or transmission systems only.

To summarize, the majority of the research so far has largely been focused on high impedance faults. When considering local fault disturbances, higher frequency components or residual voltage/currents are considered. This makes the application limited, and performance uncertain in face of non-fault disturbances. The proposed algorithm attempts to address these issues. Now, the wavelet transform is introduced (Section 3.3) to elaborate on the steps and information required for the proposed fault detection algorithm.

### 3.3 Wavelet Coefficient Calculation

This section briefly introduces the calculation of MODWT coefficients which will be analyzed by the proposed algorithm for fault identification. For wavelet analysis, first a wavelet transform technique, and a mother wavelet is to be selected. Mother wavelet is like the filter, which splits the input into higher and lower frequency (relative) levels. The choice of mother wavelet depends on the application. Second, the wavelet coefficients are calculated and analyzed.
3.3.1 Step 1: Choice of Wavelet Transform method and Mother Wavelet

MODWT over DWT:

Both DWT and MODWT have been utilized for reliable detection of faults. However, there are a few features which make MODWT more desirable for the analysis, especially in cases of real-time implementations. In [42], it is shown that DWT is very sensitive to the initial starting point because it requires down-sampling of the outputs and scaling the filters at each stage. MODWT does not result in a phase shift as seen in DWT and helps in the better interpretation of the output. It is also said to be able to detect the transients faster compared to DWT [26]. Further, MODWT can handle input data of any length, which makes it more applicable for real-time applications. Further, it is less sensitive to the choice of initial wavelets.

Daubechies ’db4’ as the Mother Wavelet

In general, Daubechies family of wavelets are regarded most suitable for fault localization and detection ([35], [36]). Generally, ‘db4’ (4 level) is desirable in terms of the computational effort and details of information needed for the power system analysis applications.

For this reason, MODWT has been used for wavelet analysis with a choice of ‘Daubechies Wavelet 4 (db4)’.
3.3.2 Step 2: Wavelet Coefficients using MODWT

For a given sample size N, the jth level MODWT wavelet coefficients are defined as [38]:

\[ \tilde{W}_{j,t} = \sum_{l=0}^{L_j-1} \tilde{h}_{j,l} X_{t-l \mod N} \]

\[ L_j = (2^j - 1)(L - 1) + 1 \]

Here, \( t = 0, \cdots, N - 1 \), and \( \{ \tilde{h}_{j,l} : l = 0, \cdots, L_j - 1 \} \) is the jth level MODWT wavelet filter, defined in terms of jth level wavelet filter \( h_{j,l} \) as \( \tilde{h}_{j,l} \equiv h_{j,l}/2^{j/2} \).

Next (Section 3.4), the proposed algorithm is discussed.

3.4 Proposed Protection Algorithm

The primary contribution of this research is formulating a method to utilize the individual and relative content of different wavelet-coefficient-level magnitudes to detect faults and ensure that the algorithm does not misidentify non-fault disturbances. Fig.3.2 summarizes the algorithm in a logic diagram. Here, we describe the algorithm for the proposed protection element. The first step is to calculate the ‘four’ level wavelet coefficients using ‘MODWT’ technique using equations as in Section 3.3 and the ‘db4’ mother wavelet.

3.4.1 Underlying Principle for Differentiating from Non-fault Disturbances

As discussed earlier, the wavelet transform decomposes the input signal into its high and low-frequency components while preserving the time information. Therefore, the research proposes that the severity (magnitude of the individual ‘four’ coefficient levels)
and composition (relative magnitude of the ‘four’ coefficient levels) information from the transient can be combined to differentiate between the fault and non-fault events. Use of the prominence of lower frequency coefficient components during faults (Section 3.2) is also being proposed to add additional security for extreme events.

![Figure 3.2: Logic Diagram - Proposed Algorithm](image)

3.4.2 Fault Identification Algorithm

**Wavelet Decomposition** - Calculate the MODWT wavelet coefficients

The incoming signal is decomposed to ‘4’ levels of wavelet coefficients using MODWT and ‘db4’ (Daubechies) wavelet with a sliding 5ms window. The number of samples will change depending on the sampling frequency. Since ‘db4’ requires a minimum of 16 samples, the corresponding minimum sampling frequency is 3.2kHz. Given the 60Hz fundamental, 5ms window allowed reasonable separation between minimum sampling frequency and fundamental for the reliable content of higher and lower frequency coefficients.

**Severity Check** - Analyzing the Severity of the transient

The decomposed coefficients at all levels should at least be equal to the setting threshold of the minimum value of the coefficient. When this occurs, the transient is considered to
be severe. The individual coefficient content at all levels must be equal to about 1% of
the primary per-phase RMS voltage at any given time. When the condition is satisfied
for all ‘four’ levels, ‘Severity’ is asserted. This is similar to the severity check used in
relay protection-logic on individual current/voltage magnitudes to avoid misoperation.

Compoision Check - Analyzing the composition of wavelet coefficients

- For all levels, the peaks are detected continuously using a moving 3 sample window.
The maximum value persists for the next 3ms (at least 10 samples) unless a higher
peak is subsequently detected.

- For all coefficient-levels, their respective peaks are compared to get the maximum
prevalent peak at any given instant in the processing window (5ms).

- If all the peaks are at least 30% of the maximum peak, it is assumed that the
wavelet coefficients have a reasonable mix strongly indicative of a fault. This setting
is dependent on the system type and may need to be adjusted if the system also
sees a significant coefficient mix during the non-disturbance cycles.

Security Check - Analyzing the prevalence of higher level coefficients

Switching events can cause severe transients but decay quickly. Since the above two crite-
ria are magnitude based, severe transients can cause the above two criteria to misinterpret
a switching event. Therefore, additional security is introduced by checking for the preva-
ience of higher level (lower frequency) components. This is done by a moving integration
of the coefficients over a quarter cycle. This quantity is dependent on the prevalence of a
given coefficient level over a period, and not the instantaneous magnitude. At the time of
the fault, these should be the highest among the wavelet coefficient levels. The prevalence
should meet a threshold of at least 10 percent of RMS voltage value.

**Persistence Check: Checking if the fault persists**

When all three of the above criteria (Severity, Composition, and Security) are met, the disturbance is classified as a potential fault. Now, an event counter declares a fault condition if the potential fault conditions are continuously asserted for 1ms (20 samples for a time-step of 50us). Otherwise, the counter is reset.

Please note, as with any protection element, the settings of pickup and event count for the protection algorithm presented here should be treated as default values. The settings can be influenced if there is a significant unfaulted wavelet content for different coefficient-levels. Given this chapter, these settings have successfully worked for all but one field events which were evaluated. ‘One’ of the field events had a high level of initial ‘second’ and ‘fourth’ level coefficients without any disturbances. Increasing the severity check threshold allowed preventing false positive for a non-fault transient event.

### 3.5 Test system

A simplified radial distribution system model with a 2MW PV plant at Bus 1 (Fig.3.3) is used for simulating different faults in the system (Case 1, 3). For Case 1 (No DER penetration), the PV plant is offline, and the measurements are made at bus B1. For case 3 (with 80% DER penetration), the PV plant is online, and the measurements are recorded at Bus 'SS'.
3.5.1 Case 1: Fault on the distribution line without DER penetration

For this case, no DER penetration is considered. Total of ‘four’ fault types are simulated, namely: A-G fault (Fig.3.4), A-B-G fault (Fig.3.5), A-B-C-G fault (Fig.3.6) and B-C fault (Fig.3.7). The faults are simulated with low (1e-4 ohm) and high (20 ohm) fault impedance. The proposed algorithm is able to detect all fault types correctly for both low and high fault impedances. For brevity, only the high impedance case waveforms are shown.

3.5.2 Case 2: Non-fault Transient events

Two types of scenarios were tested.

- \textit{Capacitor switching in the Simulink Model (Fig.3.8)}

- \textit{Field data obtained from [28]}: Figures 3.9, 3.10, and 3.11 present the voltage waveforms for the respective cases. Fig.3.12 presents a field event with recurring power quality disturbances. Details of the event type are not available in the log. Three cases represent different levels of transient severity to test the performance of the algorithm. Fault was not detected in any of the cases.
Figure 3.4: Transient Event - Simulation Result - A-G Fault

Figure 3.5: Transient Event - Simulation Result - A-B-G Fault
Figure 3.6: Transient Event - Simulation Result - A-B-C-G Fault

Figure 3.7: Transient Event - Simulation Result - L-L Fault
Figure 3.8: Non-Fault Transient Event - Simulation Result - Capacitor Switching

Figure 3.9: Non-fault Transient Event 1 (Normal) - Field Event [28]
Figure 3.10: Non-fault Transient Event 2 (Medium) - Field Event [28]

Figure 3.11: Non-fault Transient Event 3 (Severe) - Field Event [28]
shows a waveform with recurring non-fault transients. Details were not available in the data log.

![Waveform with recurring non-fault transients](image.png)

Figure 3.12: Non-fault Transient Event 4 (Periodic) - Field Event [28]

3.5.3 Case 3: Fault on the distribution line with DER penetration

This test case evaluates the performance of the proposed scheme in presence for high DER penetration for all fault types similar to Case 1. For brevity, only the A-G fault case with 10 ohm fault impedance is shown.
Figure 3.13: Transient Event - Simulation Result - A-G Fault with High DER Penetration

3.6 Simulation Results

This section presents the results of analyzing the algorithm with different fault and non-fault transient events from simulation and field respectively. The results have been compiled in Table 3.1. It assimilates the response of the different parts of the protection algorithm being proposed (severity, composition, security, and persistence) at the time of disturbance. It can be seen that, given a transient, severity check always asserted (as expected). There are cases when one or more of these aspects can assert for a non-fault transient event. However, the fault assertion was always blocked by other checks which the wavelets did not pass.

For example, for the low transient field event, security check asserted because the magnitude of the lower frequency was prevalent. However, the composition of the different levels confirmed that the event is not a fault. Similarly, for another non-fault field event with severe transients, composition check was asserted initially when magnitudes of the
wavelet coefficients were low. At this time, security check failed. Later in the same event, as the coefficients grew (progression of transients), the composition check failed. However, given the magnitude of the coefficients, security check has asserted. To elaborate on the

<table>
<thead>
<tr>
<th>Event Type</th>
<th>Source</th>
<th>Severity asserted</th>
<th>Composition asserted</th>
<th>Security asserted</th>
<th>Persistence asserted</th>
<th>Fault Asserted</th>
</tr>
</thead>
<tbody>
<tr>
<td>A-G fault (No DER)</td>
<td>Simulation</td>
<td>Yes</td>
<td>Yes</td>
<td>Yes</td>
<td>Yes</td>
<td>Yes</td>
</tr>
<tr>
<td>B-C fault (No DER)</td>
<td>Simulation</td>
<td>Yes</td>
<td>Yes</td>
<td>Yes</td>
<td>Yes</td>
<td>Yes</td>
</tr>
<tr>
<td>ABC-G Fault (No DER)</td>
<td>Simulation</td>
<td>Yes</td>
<td>Yes</td>
<td>Yes</td>
<td>Yes</td>
<td>Yes</td>
</tr>
<tr>
<td>A-G fault (80% DER)</td>
<td>Simulation</td>
<td>Yes</td>
<td>Yes</td>
<td>Yes</td>
<td>Yes</td>
<td>Yes</td>
</tr>
<tr>
<td>Capacitor Switching</td>
<td>Simulation</td>
<td>Yes</td>
<td>No</td>
<td>No</td>
<td>No</td>
<td>No</td>
</tr>
<tr>
<td>Non-fault - 1</td>
<td>Field</td>
<td>Yes</td>
<td>No</td>
<td>Yes</td>
<td>No</td>
<td>No</td>
</tr>
<tr>
<td>Non-fault - 2</td>
<td>Field</td>
<td>Yes</td>
<td>No</td>
<td>No</td>
<td>No</td>
<td>No</td>
</tr>
<tr>
<td>Non-fault - 3</td>
<td>Field</td>
<td>Yes</td>
<td>Yes</td>
<td>No</td>
<td>No</td>
<td>No</td>
</tr>
<tr>
<td>Non-fault - 4</td>
<td>Field</td>
<td>Yes</td>
<td>No</td>
<td>Yes</td>
<td>No</td>
<td>No</td>
</tr>
</tbody>
</table>

performance of the algorithm in view of the actual wavelet data, two of the events (A-G fault from simulation and low-transient-non-fault field event) are being presented, split into their wavelet levels and the assertion of algorithm coefficients at different levels.
3.6.1 Analysis: Simulation - A-G fault without DERs

The three-phase voltages for the event are shown in Fig.3.4. Fig.3.14 presents the protection response for the simulated A-G fault event with respect to voltage in phase A. At about 3500ms, the fault strikes. The wavelet coefficients (Subplots (b)-(e)) see a sharp change for a short time at the point of fault. Subplot (f) shows that the prevalence of all the coefficients increases due to the transient. However, the lower level (Level 3, 4) components are the highest which satisfied the security checks, as seen in subplot (g). Similarly, severity and composition checks are also asserted because all the coefficients exceeded the threshold and lower level components have a significant content. When the fault was continuously asserted for 1ms, as in the proposed algorithm, the fault is finally asserted.

3.6.2 Analysis: Non-fault Transient event

The three-phase (transients) - Field event voltages for the non-fault field event is shown in Fig.3.10. Fig.3.15 presents the protection response for the corresponding non-transient event. The ‘four’ level wavelet-coefficients are presented in Subplots (b)-(e). As in the fault case, coefficient content increased when the disturbance was incident. Subplot (f) shows that the prevalence of all the coefficients increase. However, notice that the lower level (Level 3, 4) components increase less significantly compared to the higher levels. Therefore, the composition check blocks the fault assertion (Subplot (g)), even though severity check asserted at t = 25ms. There are times when composition check has asserted momentarily (t = 28ms). However, At this time, security checks blocked the fault assertion.

Unlike the fault, the coefficients have a relatively higher value without disturbance
Figure 3.14: Analysis: A-G fault a) Voltage in Phase ‘A’, b-e) Level 1-4 MODWT Coefficients respectively f) Quarter Cycle integration (Prevalence) of the ‘four’ wavelet coefficients, g) Protection Response
(subplot (b)-(e)). Since the system corresponding to the event is unknown, the reason for this can not be identified. However, it is seen that power quality does affect the unfaulted wavelet-coefficients of the voltages sometimes. For this case, the algorithm worked expectedly with the default settings. However, nevertheless, if the unfaulted content is too high, the settings may need to be tuned in other cases.

Figure 3.15: Analysis: Non-Transient a Voltage (Fault) - Field Event in Phase ‘B’, b-e) Level 1-4 MODWT Coefficients respectively f) Quarter Cycle integration (Prevalence) of the ‘four’ wavelet coefficients, g) Protection Response
3.6.3 Analysis: Fault on the distribution line with DER penetration

Fig. 3.16 presents the simulation results for Case 3 (high DER penetration) for A-G fault with 10ohm fault impedance. For comparison, the performance of an overcurrent element is also shown in fig. 3.16b. In this case, the remote infeed is sufficiently high for the overcurrent to not detect the fault. However, the transient based scheme detected the faults reliably, similar to case 1.

3.7 Conclusions

The wavelet transform analysis is a powerful scheme to gain additional information from the transients occurring during power system operation. The primary requirement is that the algorithm needs a high sampling rate (more than 3.2kHz for the given settings). For lower sampling rates, only the higher level wavelet coefficients (corresponding to lower frequencies) will be realistic, and may not operate reliably at all times. With the aid of the proposed fault detection scheme using MODWT, all fault types were reliably identified. Similarly, the non-fault disturbances were reliably screened for both simulation and field event reports. This proves the potential of wavelet transforms in fault detection. Considerable research still needs to be done in improving the selectivity of the protection element, to allow it in protection schemes. However, given the success of the fault detection, when overcurrent elements fail to recognize the fault, it is expected that the proposed method element will aid in improving the system protection in combination with other elements.
Figure 3.16: Simulation Result - A-G Fault with 80% DER Penetration - (a) Three phase voltage, (b) Adaptive Overcurrent Response, (c) Proposed MODWT based Fault Detection Response
Chapter 4

Fast Microgrid Transition Scheme for Active Distribution Systems with Nested Microgrids

4.1 Introduction

The increasing DER penetration and improving capabilities of ADNs allow implementation of advanced functionalities towards system resiliency and reliability. Ability to operate as a microgrid is one such feature. As defined in Chapter 1, a microgrid is a localized grid which can operate autonomously or when connected to the grid and help mitigate grid disturbances to improve resiliency. Like any other stable system, to form a stable microgrid, it has to be ensured that the available generation in the microgrid meets or exceeds the demand. When this is not possible, load shedding schemes may need to be used to achieve power balance. Even if the DERs in the microgrid to be formed can increase generation, it may or may not be fast enough (within 1-2 seconds). Therefore,
balancing the system load and generation boils down to shedding sufficient non-critical load in the system (or loads with lesser priority to support) to form a stable microgrid. ‘Fast Microgrid Transition’ is referred to as an advanced microgrid functionality which uses proactive load shedding and minimizes the transition time of the circuit section from grid connected to microgrid mode of operation.

4.2 Related Research

Load shedding for balancing the system has been more closely looked for systems operating in microgrids in operation. [43] proposes an optimized method for balancing microgrid and considers load shedding. [44] presents a similar case study for an oil refinery focused on load management for operating microgrids. However, it is important to understand that the transitioning from grid connected to microgrid is not trivial, and includes a lot of operational procedures and protocols [45]. [46] reviews research on different microgrid architectures and classifies the system balancing as the functionality of the primary control. It notes that a majority of the ongoing research with primary controllers is aimed at improving DER controller schemes to allow a smoother transition to microgrid mode, and for good reasons. [47] presents droop based strategies to allow DERs to seamlessly transition from grid connected to microgrid mode, and vice versa. [48] reviews two kinds of transition strategies namely mode adaptive and uniform control. It notes that more research is needed in developing methods to reduce the voltage and current transients during mode transition, which is a function of unbalance. When simulating the process of reducing the system unbalance during the transition, often the microgrid load is classified as ‘critical’ and ‘non-critical’. Accordingly, during microgrid formation, it is a common assumption to lose all the non-critical load to reduce system load right away [49]. How-
ever, this may result in excessive load shedding. Besides, shedding the non-critical load doesn’t guarantee system balance. In addition, the time of withstanding unbalance is also critical for stable microgrid formation. [45] studies use-cases for the transition of circuit section from grid connected to islanded modes for scheduled and unscheduled intentional islanding. It is shown that due to longer periods of overloading, or the clearing time for faults can be a key factor towards the formation of a stable microgrid thereafter. The possibility of a microgrid collapsing due to overload is shown. These cases justify the need for a reliable load shedding scheme, and the need to quickly achieving power balance.

As a result, this research focuses on reducing the time to achieve power balance while optimizing the amount of load needed to be shed. Accordingly, relevant use-cases are discussed next.

4.3 Possible Use-Cases

Section 1.1 defines the different types of islanding. This section reiterates the key points from there and defines the primary use-cases relevant to FMT. Islanding can be intentional or unintentional. In essence, unintentional islanding is not desirable and the DERs are expected to immediately ‘cease to energize’ on detecting an unintentional island. However, when intentional islands are formed, there are two possible cases namely i) Scheduled Intentional Islanding, and ii) Unscheduled Intentional Islanding. These use-cases are described below.

4.3.1 Unscheduled Intentional Islanding

Unscheduled intentional islanding is defined as the islanding scenario where the microgrid isn’t expecting to be isolated from the grid. This is usually a result of a fault on the grid...
side or microgrid side, resulting in the tripping of the PCC breaker. In this case, the microgrid which was islanded needs to balance the system after islanding from the grid.

- **Positive unbalance (load > generation):** The voltage and frequency will already start declining. Therefore, localized load shedding schemes are programmed to trip the respective loads when the rate of change of frequency (ROCOF) increases a certain threshold or the bus voltage falls below the given threshold. This case is usually the biggest challenge in the formation of a stable microgrid and thus can benefit the most from the FMT. As noted previously, even when it is possible to increase the local generation, this may not be fast enough (within 1-2 seconds) depending on the unbalance at the time of islanding. The objective of FMT is, therefore, to shed as least amount of load needed as soon as possible to get to a system with a stable frequency and voltage within the permissible operating limits.

- **Negative unbalance (load < generation):** The frequency (and sometimes voltage) will already start increasing. This is not as critical situation from a transition point of view. The controllers of the DERs can quickly limit the generation to ensure that the frequency and voltage stay within the upper operating limits. This case is not of concern for microgrid formation.

### 4.3.2 Scheduled Intentional Islanding

Scheduled intentional islanding is defined as the islanding scenario where the microgrid is expecting to be isolated from the grid. This is usually a result of a request from the grid side or due to microgrid’s own optimization routines. In this case, the microgrid will first ensure that the net power exchange at its PCC with the grid is negligible (the system is balanced) before the breaker at PCC is opened. FMT will help quickly balancing the
system and thus forming the microgrid. However, from a stability point, FMT doesn’t have a key role in this use-case.

As can be seen, unscheduled intentional islanding with a positive unbalance is the primary use-case for FMT. This would also be the most probable scenario, during a fault, or a system contingency. Scheduled intentional islanding is a secondary use-case. Next, the proposed FMT algorithm is discussed.

4.4 Problem: Load Dispatch Identification

This section describes the Load_Estimation_component formulation. It is a component used by both the proposed FMT and ASR schemes to see if the resulting system configuration will be steady-state stable. FMT uses the results from LDI to find the set of loads which have to be shed. ASR will use it for its zone aggregation problem, and estimate which combination of loads and/or tie-lines provide the most stable operational configuration. The test system is assumed to have the DERs with hierarchical control to stable and optimal operation for the constituent [nested] microgrids. As a result, the generators are capable of successfully transitioning the microgrids between grid-connected and intentional islanded modes. Therefore, the LDI uses the standard formulation [50]–[56] as a Mixed Integer Linear Programming (MILP) to identify the loads that can be supported by the given power system section. It prioritizes the loads based on their criticality without violating the system’s operational constraints.

4.4.1 Objective Function - Maximizing the priority load (4.1)

\[ C_{\text{island}} = \sum_{i=1}^{n} P_i \cdot w_i \cdot s_i \] (4.1)
Here, $C_{island}$ represents the weighted sum of the loads connected (total $n$) and is the cost function which should be maximized. Load status is given by $s_i(0/1)$, and active power demand and priority by $P_i$ and $w_i$ respectively.

Using priority based objective function represents the overall benefit (combination of monetary/social/technical) which is to be maximized. The weights of the individual loads represent the respective valuation (monetary/social/technical) for a utility when operating under limited generation and/or contingency. This allows the critical loads like hospitals (social) and commercial customers (monetary) to be prioritized for service (higher weight). Similarly, the loads on the distant feeders (technical) may be prioritized for demand-side management due to higher losses/voltage drops by assigning lower weight. By assigning very high weights, the scheme can ensure that a particular load is always the first priority.

4.4.2 Constraints

Power Balance (4.2)

$$\sum_{i=1}^{n_{der}} S_{available,i} = \sum_{j=1}^{n_{load}} S_{load,j} + \sum_{k=1}^{n_{br}} S_{losses,k} \tag{4.2}$$

Here, $S$ is the respective active/reactive component of the available generation, demand, and line losses for the potential island of interest. $n_{der}$, $n_{load}$, and $n_{br}$ represents the number of DERs, loads, and branches respectively in the given microgrid.
Inequality Constraints:

- Voltage magnitude \(v_{m}^{i}\) and angle \(\theta_{i}\) (4.3, 4.4) for the buses must be within the respective limits. \(n_{mg}\) is the number of buses in the given system.

\[
v_{m}^{i,min} \leq v_{m}^{i} \leq v_{m}^{i,max}, \quad i \in 1...n_{mg}
\] (4.3)

\[
\theta_{i,min}^{i} \leq \theta_{i} \leq \theta_{i,max}^{i}, \quad i \in 1...n_{mg}
\] (4.4)

- For Generator ‘i’, active \((P_{g}^{i})\) and reactive \((Q_{g}^{i})\) generation must be within the respective limits (4.5),(4.6).

\[
P_{g}^{i} \in [P_{g}^{i,min}, P_{g}^{i,max}], \quad i \in 1...n_{der}
\] (4.5)

\[
Q_{g}^{i} \in [Q_{g}^{i,min}, Q_{g}^{i,max}], \quad i \in 1...n_{der}
\] (4.6)

- Branch Loading Limits (4.7)

\[
I_{s,r} \leq I_{s,r}^{limit}
\] (4.7)

Here, \(I_{s,r}\) is the current flowing from node \(r\) to node \(s\), and \(I_{s,r}^{limit}\) is the maximum current limit.

The system thus identified based on the load subset subject to the above constraints is evaluated for a stable power flow. When the power flow is stable and within operational constraints, the resulting load subset represents the system which can be supported.

Next section describes the FMT routine to identify the loads to be shed for unscheduled intentional islands.
4.5 Proposed FMT Algorithm

FMT is an advanced microgrid functionality which precomputes the sheddable load and balances the island quickly to aid in the transition to the islanded mode. Unscheduled intentional islanding is time critical. Therefore, discrete load shedding is the primary means for achieving power balance. Renewable based generation (PV, Wind) cannot be dispatched. The conventional DERs (e.g. diesel generators) respond very slowly (in order of seconds) which may not prevent the collapse of the given island. The only dispatchable resource will be a storage unit in the system. For a generic case, the available generation is therefore assumed to be constant, given the short time frame (up to 100s of milliseconds) from the perspective of FMT. Given the hierarchical control, any real time mismatches in the power balance of the operating intentional island will be addressed by droop (the primary control).

Should a fault occur, the relay will send the trip signal to a given IIID which takes 50-60ms to trip. Meanwhile, the same relay will also send the trip signals to the sheddable loads. As a result, by the time the section is actually islanded, the load sheds are already in process, which compensates for the communication delay. This novel scheme is also unique in presenting a distributed solution to balanced unscheduled microgrids with optimum load shedding. Unlike other schemes focused on load shedding for grid-connected systems or microgrids only, this scheme supports transition during the loss of grid. Further, it adapts to the topology changes and integrates with existing ASR schemes. The steps (fig. 4.1) are presented below.

1. **Defining the Microgrid Forming Nodes**: As per IEEE 1547 [3], ADNs can have nested microgrids connected to each other using IIIDs. These IIIDs are associated with respective agents SA_{IIIDk}. The FMT functionality resides here and monitors
Start

Initialize the kth IIID

Update Microgrid Topology

BFS

LAk, DAk

LAk

MG

Topology Load Dispatch Identification

Poll LAi, DAj

System Agents

Pdi, Qdi, Pgj, Qgj

Status

Identify Loads to Shed

IIIDk Tripped?

No

Yes

Topology Changed?

Trip Signals

Yes

No

Confirmk

LAk

Figure 4.1: Flowchart: Proposed Fast Transition Scheme
the section downstream as a potential intentional island. Respective DAs and LAs report the available generation and demand to the given IIDIs. For nested microgrids, it is possible that a DA/LA reports to more than one IID.

2. Potential Intentional Island Estimation: Each IID agent SA_{IID_k} estimates the potential intentional island which will be formed if it opens by searching the system topology using breadth-first search (BFS). This estimate is revised every time the system topology changes. The topology of the system is available to all SA_{IID_k}(s) including the information about any out-of-service sections/components. From the potential intentional island topology, the SA_{IID_k} identifies the corresponding DAs and LAs connected.

3. Identifying the dispatchable load: For the potential intentional island, SA_{IID_k} polls the member DAs and LAs periodically to update the load \((P_{di},Q_{di})\), generation \((P_{gj},Q_{gj})\) and resulting unbalance state of the system. After that, it runs the LDI routine described in section 4.4 to identify the dispatchable load subset. As expected, the routine will prioritize the weighted load within the operational constraints.

4. Fast Microgrid Transition: In event of an unscheduled intentional island, the given SA_{IID_k} sends the request to shed the load IDs in the dispatchable load subset. This ensures that the power balance is achieved as soon as possible. Meanwhile, it is assumed that other functionalities which allow the DERs to change mode and select the grid forming or grid supporting DERs also run desirably. For scheduled intentional islands, the SA_{IID_k} will execute the request to island faster.

The intentional island thus formed will have an optimum load generation balance.
After FMT, the faulted system will settle into a new post-fault steady state with sections operating in islanded or grid-connected modes. There will also be (un)faulted sections facing a blackout.

4.6 Test Setup

The effectiveness for any contingency management scheme can be gauged by 1) Flexibility: Adapting its response given the disturbance and system operating conditions, 2) Scalability: Performing consistently for systems of practical complexity, and 3) Resulting Topology: The final system topology resulting from the restorative actions (relevant to ASR). Therefore, this section presents ‘two’ (out of three) distribution system topologies to demonstrate the performance of the proposed FMT routine. The algorithm’s flexibility is described using the smaller 33-bus system (System 1) with cases I-III. These represent the operating scenarios with and without DERs (fig. 4.2). Case IV demonstrates the scalability of the algorithm with a larger 136-bus Distribution system (system ‘2’).

4.6.1 System 1: Modified 33-bus system with DER installations by Wu, Lee [57], [58]

For ASR, the high loss lines in the original system [57] results in high voltage drops. Therefore, here the resistance is adjusted to preserve ‘X/R = 5’ for all lines. The system is radial with multiple tie-lines to offer interesting ASR possibilities. For DER penetration cases (case I, II), ‘four’ DERs (Table 4.1) are introduced in [58]. The DER power ratings are scaled up by a factor of ‘4’ and ‘2’ for cases ‘I’,‘II’ respectively for the medium and high DER penetration scenarios.
Table 4.1: Modified 33-Bus Distribution Test System - DER Ratings

<table>
<thead>
<tr>
<th>Location (Bus)</th>
<th>Rating (MW) - Case I</th>
<th>Rating (MW) - Case II</th>
</tr>
</thead>
<tbody>
<tr>
<td>4</td>
<td>0.2</td>
<td>0.1</td>
</tr>
<tr>
<td>7</td>
<td>0.4</td>
<td>0.2</td>
</tr>
<tr>
<td>25</td>
<td>0.8</td>
<td>0.4</td>
</tr>
<tr>
<td>30</td>
<td>0.4</td>
<td>0.2</td>
</tr>
</tbody>
</table>

Figure 4.2: One-Line Diagram - 33-Bus Distribution System with DERs
Case I [System 1 with high DER penetration]: This case presents FMT for a fault on Bus 3 is shown for a high DER penetration scenario. The fault causes the corresponding IIIDs (2-3, 3-4, and 3-23) to trip and form ‘one’ grid-connected, ‘two’ unfaulted sections (can be microgrids), and ‘one’ faulted section (blackout). FMT is responsible for transitioning the unfaulted sections with local DERs to be operated as microgrids.

Cases II and III represent the medium and no DER penetration case for System 1. Only cases I, II (with DERs) are relevant to FMT.

4.6.2 System 2: The LaPSEE 136-Bus Distribution System [59]

This is a 136-bus medium city real distribution system [59] rated at 12.47kV and 14.85MW load for reconfiguration studies. There are ‘19’ tie-lines, ‘16’ IIIDs ([nested] island forming sections) and ‘18’ DERs in the system (Table 4.2). Fig. 4.3 presents the one-line diagram. For clarity, only the buses associated with a tie-line or IID are marked to aid the discussion of results.

<table>
<thead>
<tr>
<th>Type</th>
<th>Details</th>
</tr>
</thead>
<tbody>
<tr>
<td>Tie</td>
<td>[7,6], [137,10], [51,57], [106,155], [141,59], [53,62], [38,43],</td>
</tr>
<tr>
<td>Switch</td>
<td>[156,223], [146,131], [138,20], [150,141], [147,139], [151,141],</td>
</tr>
<tr>
<td>From,To</td>
<td>[148,138], [145,125], [144,78], [90,137], [96,144], [126,211]</td>
</tr>
<tr>
<td>IID</td>
<td>[100,1], [100,48], [100,133], [100,24], [100,121], [33,34],</td>
</tr>
<tr>
<td>From,To</td>
<td>[100,207], [100,75], [100,148], [123,124], [153,154], [33,61],</td>
</tr>
<tr>
<td></td>
<td>[153,138], [142,143], [142,146], [80,81], [219,220], [54,55], [6,9]</td>
</tr>
<tr>
<td>DERs</td>
<td>[28,0.6], [45,0.5], [129,1.2], [135,0.6], [82,0.5], [18,0.4],</td>
</tr>
<tr>
<td>Bus,MW</td>
<td>[7,0.3], [218,0.9], [222,0.5], [152,0.4], [204,0.5], [201,0.6],</td>
</tr>
<tr>
<td></td>
<td>[205,0.6], [143,0.4], [146,0.7], [53,0.8], [58,0.6], [163,0.5],</td>
</tr>
</tbody>
</table>

Case IV [System 2 with high DER penetration]: This case pertains to the 136-bus
Figure 4.3: The LaPSEE 136-Bus Distribution System
system and shows a permanent fault on line 148-149. This results in tripping of IIIDs 100-148, 153-138 and 153-154 to isolate the faulted zone. Therefore, the system is split into ‘one’ grid-connected, ‘two’ unfaulted sections (can operate as microgrids) and ‘one’ fault zones. Similar to Case I, FMT will be concerned with transitioning the two unfaulted sections into operating as microgrids.

4.7 Simulation Results - Fast Microgrid Transition

The response of the proposed FMT routine for the test cases in Section 4.6 is presented in this section. Table 4.3 summarizes the actions.

FMT worked reliably and shed the optimal amount of load quickly to balance the microgrids. Cases I (33-Bus system with high DER) and IV (136-bus system with high DER) are discussed. As per the FMT algorithm, the actions (loads to shed given an IID trips when the system is online) are computed in advance and the results are stored with the respective IIIDs.

4.7.1 Case I: Bus Fault at Bus 3

Here, three IIIDs (2-3,3-4,3-23) trip after the fault. Each IID needs a different set of loads to be tripped. As soon as the IIIDs are about to trip, they will send the request to shed the respective loads. The loads implement the command and trip. The result is one grid-connected and two balanced microgrids with a heavy load shedding. These are evaluated for ASR.
4.7.2 Case IV: Fault on Line 148-149 causing isolation of one section

Here, a permanent line fault on Line 148-149 causes the IIIDs 100-148, 153-138, and 153-154 to trip to isolate the fault from the grid and all the DERs in the system. As a result, two potential microgrids can be formed when IIIDs 153-138, and 153-154 operate. Given the high DER penetration in these sections, FMT determined that only Load at Bus 155 needs to be shed. The result is a grid-connected and two balanced microgrids. Similar to system 1, these are then evaluated for ASR.
### Table 4.3: Result Summary - Sequence of Events using Distributed FMT Routine

<table>
<thead>
<tr>
<th>System</th>
<th>Case</th>
<th>Potential Microgrids</th>
<th>Loads to be Shed</th>
<th>Steps</th>
</tr>
</thead>
<tbody>
<tr>
<td>33-Bus System</td>
<td>High DER Penetration</td>
<td></td>
<td></td>
<td>1) IIIDs B3, 4, 23, 2, 3 broadcast change of status</td>
</tr>
<tr>
<td></td>
<td>1) Bus Fault:B3→ Test Case I</td>
<td>8</td>
<td>5, 6, 9, 11, 14-18, 24, 26, 28-30, 32; B3, 23: {24}; B2, 3: {5, 11, 16, 17, 24, 29, 32}</td>
<td>2) FMT Response: Request to Shed</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>3) Shedding the Loads: {5, 6, 9, 11, 14-18, 24, 26, 28-30, 32}</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>4) System settled to post-fault steady state</td>
</tr>
<tr>
<td>33-Bus System</td>
<td>IIIDs tripped: 3-4, 2-3, 3-23</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Net Load: 3.72MW</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>LaPSEE 136-bus With DERs</td>
<td>High DER Penetration</td>
<td>18</td>
<td>155</td>
<td>1) IIIDs B100, 148, 153, 138, 153, 154 broadcast change of status</td>
</tr>
<tr>
<td></td>
<td>2) Line Fault:148-149→ Test Case IV</td>
<td></td>
<td></td>
<td>2) Shed Load: 155 by IID at B153, 154</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>3) Shedding Load: 155</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>4) System settled to post-fault steady state</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>IIIDs tripped: 100-148, 153-138, 153-154</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Net Load: 14.852MW</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
4.8 Conclusion

This chapter presents the proposed algorithm for the ‘fast microgrid transition’ routine as a part of the overall DCMS strategy. The proposed FMT routine allows a grid connected potential microgrid to quickly achieve power balance after unscheduled intentional islanding while dispatching optimum amount of least priority load. The functionality resides within the IIIDs which connect the circuit sections to the grid side, and can adapt to change in topology. This is because the proposed algorithm re-evaluates the downstream island which will be formed due to the operation of the corresponding IIID. The algorithm proposed here is a part of the distributed contingency management scheme. The automated service restoration part of DCMS is presented in the next chapter.
Chapter 5

Multi-Agent Distributed Service Restoration Scheme for Distribution Systems with Embedded Microgrids

5.1 Introduction

Fault Location, Isolation, and Service Restoration (FLISR) is of primary importance in improving the resiliency and reliability for utilities. However, with increasing distributed energy resource (DER) penetration, and distributed intelligence and measurements across the system, sections of the power system can be operated as microgrids using intentional island interconnection devices (IIIDs). This allows the evolving active distribution networks (ADNs) to achieve more complex system level goals like demand-side response (DSR), resiliency, reliability, and robustness. This chapter introduces the automated service restoration as part of the proposed Distributed Contingency Management Scheme (DCMS).
For this research, ASR is defined as the ability of a system to change its topology post outage for restoring service to unfaulted sections operating as grid connected or independent microgrids. Following the results from Fast Microgrid Transition (FMT) as presented in Chapter 4, the systems have settled into a post-fault steady state and need service restoration. The ASR challenge is well formulated as a multi-objective optimization problem and solved using both centralized and distributed schemes. The distributed schemes are primarily multi-agent systems (MAS) based ([50]–[56], [60]). The primary aim is to maximize the more critical load online with secondary objectives like least switching operations. Early research didn’t consider DERs ([50], [51], [60]) which limits their application. While the optimization functions for ASR has changed little, the assumptions and agent architecture can negatively impact the robustness and applicability. For e.g., the architecture limits the functionality of [52]–[56] even with consideration for DER penetration. References [52]–[55] assume a rigid agent architecture with the system divided into regions with pre-defined roles assigned to the regional agents (RAs). This is undesirable because 1) Failure of RAs can be the single point of failure, and 2) Scheme Non-scalability. Interchangeable agent roles improve the system robustness and reliability [56]. Further, the ASR schemes (except for [53]) don’t consider formation of the largest electrically connected system. This helps in reducing the impact of variability in generation and demand. It is critical for microgrids for improving system inertia and overall stability.

In view of these drawbacks, this chapter presents a novel ASR scheme. After the system settles into a post-fault steady state, the proposed distributed ASR assesses the system state and reconfigures the system. This is done using available tie-lines and IIIDs to form the largest balanced electrically connected microgrid(s) and grid-connected sections. The proposed ASR improves upon the previous work [61] by forming the systems
with the best voltage profiles by choosing among the multiple tie-lines in the section. It is a greedy algorithm (distributed implementation of Prim’s algorithm [62]) which forms the largest possible electrically connected stable sections.

Rest of the chapter is organized as follows: The system and agent architectures are described in Sections 5.2 and 5.3 respectively. Then, the distributed ASR scheme is presented in Section 5.4. The performance is tested on a 33-bus, 69-bus and a 136-bus distribution system (introduced in Section 5.5) for different levels of DER penetration. Section 5.6 shows the performance of the proposed ASR scheme for the test systems and the resulting system topologies. Finally, Section 5.7 concludes the chapter.

5.2 System Architecture and Assumptions

This section describes the corresponding agents, nomenclature, and advantages offered by the proposed MAS architecture. The system architecture is the key enabler for the DCMS with both balancing the intentional island (FMT) and automated restoration (ASR) aspects integrated. As per IEEE 1547[3], IIIDs define the sections which can be operated as intentional islands. Therefore, the proposed architecture is only critical of the availability of IIIDs for any action involving contingency management. This dependency ensures a simpler, more efficient and scalable architecture. Agents (distributed nodes with proposed DCMS and other supporting applications) are spread across the system at different power system components (generation, load, protection). They implement optimization schemes, state estimation, and other distributed automation algorithms. This is a big improvement on the previous work [61] focused only on ASR aspects of contingency management.
5.2.1 Agent Types

Three types of agents: Switch Agent (SA), DER agent (DA) and Load agent (LA) are present. DAs and LAs are scattered across the system. They can run state estimation to update the SAs and implement load/generation dispatch requests. SA is associated with any available switch (SA_{switch} [can only control the local switch]) or IIID (including tie-switches) as SA_{IIID} [can control the local switch and participate in the proposed DCMS].

5.2.2 Nomenclature

- **Potential Intentional Island** is referred to as the (nested) intentional island which will be formed if given SA_{IIID} trips.

- **Load Dispatch Identification (LDI)** is the problem of identifying which of the loads for the system under study can be supported given the available generation (Section 4.4). Less critical loads are shed first.

- **Dispatchable Load Subset** is the output of the LDI routine for each potential intentional island possible and is calculated by the respective SA_{IIID}.

- **Zone** is an electrically connected section of the power system. Within the zone, power can flow without interruption. Open SA_{switch} and SA_{IIID} define the zone boundaries. Throughout the chapter, the zones will be referred based on the buses separating them from the rest of the system. For eg. in System 1 (fig. 5.7), zone 1 is formed by opening IIID between Buses 2, 3. Hence, it is referred to as Z1:{B2}.
  - **Online Zone**: Zone with at least one active generator.
  - **Offline Zone**: Zone with no active generation source. When there are no offline
zones available for reconnection, an online zone can behave as an offline zone to aggregate online zones.

- **Zone Aggregation** problem assesses if the given set of zones can be combined into a bigger zone. It uses the LDI routine with a different final objective.

- **Connection Request (CR)** is sent by an offline zone to its online neighbors and contains the topology, load, and generation (online zone behaves as offline) information.

- **Negotiator** is a SA which participate in ASR for its zone. For offline zones, they send CRs to available online neighbors. For online zones, they test the received CRs using LDI (Section 4.4) to identify the loads which can be supported. The available zonal SA with most computational resources acts as the negotiator.

- **Proposal** is the response sent by an online zone for each received CR from the respective offline zone. This lists the loads of the offline zone which can be supported.

### 5.2.3 Advantages

The resulting architecture is scalable and offers a unique advantage of combining both FMT and ASR routines. Due to the absence of any regional agents, the MAS isn’t affected by the unavailability of some agents [55], which improves system robustness. It is only critical of the availability of SAs (which need to be available anyways for restoration). Other agent roles are interchangeable which improves the system robustness. DAs and LAs may estimate the system state locally using an approach similar to [63]. Fig. 5.1 presents a location of agents in a generic power system section with the flow of information
for the proposed DCMS. This results in a more flexible and economic implementation to work efficiently for larger systems alike.

![Figure 5.1: Generic - Agents Assignments in a Zone](image)

### 5.2.4 Assumptions

1. Zones of the system are capable of stable operation in both grid-connected and islanded mode, and transitioning between the two.

2. The system has settled to a new steady operating state (few seconds after the outage). Therefore, ASR algorithm is expected to run with a timescale of a few seconds or more, as it operates post outage.

3. DAs and LAs run local state estimation routines and report the demand/supply to their corresponding switch agents as applicable.

4. DSR schemes, if any, have been implemented to form stable microgrids.

5. Protection is assumed to operate desirably. Associated concerns are not in the scope for this research.
5.2.5 Messages Exchanged (relevant to ASR)

- **BS-\{Status, SwitchID, SAID\}**: When a status of ‘SwitchID’ changes, the agent ‘SAID’ broadcasts the following message packet to all the agents.

- **CR-\{A,B\}**: Connection request from offline zone ‘A’ to online zone ‘B’

- **CF-\{B,A\}**: Confirmation from online zone ‘B’ to offline zone ‘A’ to acknowledge CR-\{A,B\}

- **PR-\{B,A\}**: Proposal from online zone ‘B’ to offline zone ‘A’ in response to CR-\{A,B\}

- **RE-\{A,B,Decision\}**: ‘Decision’ (Accept:1,Decline:0) from the offline zone ‘A’ to online zone ‘B’ in response to PR-\{B,A\}

- **CH-\{B,SwitchID,SAID,NewStatus\}**: Request from online zone ‘B’ to agent ‘SAID’ to change the status of the switch ‘SwitchID’ to ‘NewStatus’.

5.3 Agent Structure of IIID

An IIID is a SA which can form an intentional island if needed. IIID Agents are quintessential to the proposed DCMS because of their ability to reconfigure the system topology based on the proposed actions by DCMS. IIID agents process the information from the agents in a given zone based on its (zone’s) state to make decisions. Understanding their architecture will provide insight into the distributed information flow. This section describes the constituents and the structure of an IIID agent.
5.3.1 Definitions:

- **Component** is a function which produces an output given the input. Eg: Summation.

- **Actor** is an entity comprising one or more components. Its output is based on (sometimes iterative) interaction with other actors. Eg: FMT and ASR actors.

- **Agent** is an independent device comprising one/more actors (fig. 5.2). It collaborates with other agents to achieve system objectives. No agent controls the entire system.

![Figure 5.2: Structure: Generic Agent with Actors and Components](image)

5.3.2 IIID Agent Structure

Agent structure refers to the constituents which make the agent. Here, the constituents of an IIID agent (fig. 5.3 - participating components and actors) are presented.
Figure 5.3: Structure: IIID Agent with Actors, Components, and Data Exchanges

Components

- **Load_Estimation_component**: This component implements the problem formulation defined in section 4.4.

- **Clustering_component**: This component uses the system topology to update the information about the connected system (zone) and identify neighbors.

Actors

- **Zone_Actor**: Contains the information about the zone, the given agent is associated with. For FMT, this is the potential intentional island formed if an IIID trips. For ASR, this provides information about the zonal buses, generators and transmissions lines.

- **Database_Actor**: Stores the high-level information about the aggregated system health (healthy branches), tie-lines, and local system load aliases.
• **Communication.Actor**: Handles communication requests with other agents on the behalf of the given agent using relevant communication protocols/media.

• **Online.Negotiator.Actor**: Participates in the ASR when the given IID is a part of an online zone as the negotiator. It contains information about the ‘received requests’ and ‘response to proposals’ (from/to the communication_actor).

• **Offline.Negotiator.Actor**: Takes part in the ASR when the given IID is a part of an offline zone as the negotiator. It contains the information about the ‘CR to be sent’ and ‘received proposals’ (to/from the communication_actor).

• **FMT.Actor**: Implements the proposed FMT scheme. It has local copies of ‘load estimation’ and ‘clustering’ components to proactively determine the loads to shed if the given IID trips to form an island. This actor communicates the load shed commands to the communication_actor to be forwarded as necessary.

• **ASR.Actor**: Implements the proposed ASR scheme. It has a ‘load estimation’ component to solve zone aggregation for online zones. For offline zones, it processes the received requests to choose the most preferred one.

### 5.4 Proposed ASR Algorithm

ASR is implemented to reroute the power in the system as needed to restore power to the faulted sections. With the availability of microgrids, the proposed algorithm expands the objective to include both grid connected and intentionally islanded sections. The novelty of the proposed ASR is that it is a greedy algorithm which ensures the formation of the largest electrically connected section(s) possible. The proposed ASR algorithm
allows multiple nodes (zones) to expand simultaneously to improve the load support locally as they join to form larger zones. This is an improvement upon ([50]–[52], [54]–[56], [60]) because the proposed algorithm ensures the formation of largest connected online zones. This helps with a more stable and resilient operation of sub-section(s) given the uncertainty in operating conditions like load/demand. Compared to [53], the architecture is much more robust because the system is not divided into pre-defined zones. This improves the algorithm scalability without losing resiliency/flexibility. The algorithm uses the formulation in Section 4.4 to ensure that the resulting system will perform within the operational constraints. The formulation expands the previous work [61] by optimizing the choice of tie-lines (for multiple options to connect two zones) based on the voltage profile. The formulation is presented below.

5.4.1 Optimization Sub-Objective

For zones ‘m’ and ‘n’, if there are ‘j’ switches ‘TL\_j’ in between to connect them, the problem is given as (5.1).

\[ V_j = LDI(Zone_m \cup Zone_n) \]  

(5.1)

Here, \( V_j \) is the bus voltage array when connecting zones ‘m’ and ‘n’ using \( TL_j \) based on ‘LDI’ (section 4.4). The best IIID is chosen to minimize the absolute sum of the deviation of the individual bus voltage from the desired nominal bus voltage (1 p.u.) using (5.2).

\[ TL_{\text{chosen}} = \text{argmin} \left( \sum_i \text{abs}(V_{i,j} - 1) \right) \]  

(5.2)

Here, \( V_{i,j} \) is the p.u. voltage at the \( i^{th} \) bus, given that zones ‘m’ and ‘n’ are connected by \( TL_j \).
5.4.2 Steps for ASR

After the system settles into a new state following the FMT algorithm, the agents execute ASR to optimize the load supported while operating within operational constraints. The steps are presented as under:

1. *Alert the system about the change of state:* Changes in switch state (fault/otherwise) is broadcasted by corresponding SA using message $BS\{\text{Status,Switch_ID,SA_ID}\}$. All the system agents update their local topology and mark the faulted lines ‘out-of service’. Pre-fault topology is available to all SAs.

2. *Choosing Negotiators:* The SAs estimate their zonal boundaries and classify their zones as online/offline. Zonal SAs consense on negotiators for their zone from among themselves and update all the agents in the zone. DAs and LAs send the regional generation/demand updates to the zonal negotiators.

3. *Sending Connection Requests:* Offline zone negotiators send the CRs ($CR\{A,B\}$) to the negotiators for their online neighbors. Online zones acknowledge with CF-$\{B,A\}$. When no offline zones have an online neighbor, negotiators for the remaining online zones consense on an online zone to act as offline (for ASR only). The criteria are that the online zone should not be connected to the grid, have the least number of buses, and net load (in that order).

4. *Online Zones evaluate the received CRs:* Negotiators for online zones evaluate the zone aggregation problem for the fictitious system formed by combining on its own zone along with the CRs received (Section 4.4). Online zones can curtail less critical online loads for more critical offline loads. Based on the results, a proposal ($PR\{B,A\}$) is sent to the offline zones in response to the respective CRs. It ($PR\{B,A\}$)
contains the load IDs which can be supported.

5. **Offline Zones choose from available offers:** From all the proposals \(PR\{-B,A\}\) received, the negotiator chooses the one which maximizes its online load. When multiple proposals meet these criteria, the zone with the highest net generation or lowest demand is accepted in that order. An acceptance/decline \(RE\{-A,B,Decision\}\) is sent to the respective online zones.

6. **Online Zones update their topology based on acceptances/declines:** Based on the received response \(RE\{-A,B,Decision\}\) to the proposals, the online zones reevaluate zonal aggregation and identify the best tie-switch (Section 5.4.1) and the switching operations for merging the zones. Messages \(CH\{-B,SwitchID,SAID,NewStatus\}\) are sent to implement the changes. This process iterates until the largest online sections are formed.

As can be seen, the proposed ASR routine is a greedy algorithm. The implementation resembles a distributed version of the Prim’s algorithm [62]. Prim’s algorithm is an algorithm to find the minimum spanning tree for a weighted undirected graph. It begins by selecting an arbitrary vertex, which then visits its unvisited neighbor vertex with the lowest edge weight. This is repeated until the entire tree is traversed. With distributed implementation, the proposed algorithm begins at multiple offline zones across the given system (acting as the vertices). These zones connect to their neighboring online zones with the objective to minimize their own outage.

This concludes the discussion of the proposed DCMS. Next, the test cases and simulation results would be presented to demonstrate the performance for small and large ADNs.
5.5 Test Setup

The effectiveness for any contingency management scheme can be gauged by 1) Flexibility: Adapting its response given the disturbance and system operating conditions, 2) Scalability: Performing consistently for systems of practical complexity, and 3) Resulting Topology: The final system topology resulting from the restorative actions. Therefore, this section will present ‘three’ distribution system topologies to validate the respective criterion for the proposed ASR scheme. The algorithm’s flexibility is described using the smaller 33-bus system (System 1) with cases I-III. These represent the operating scenarios with and without DERs (fig. 5.4). Case IV demonstrates the scalability of the algorithm with a larger 136-bus Distribution system (system ‘2’). Case V compares the performance of the proposed DCMS with the results from [64].

5.5.1 System 1: Modified 33-bus system with DER installations

by Wu, Lee [57], [58]

The 33-bus system has been introduced in Chapter 4.6.

Cases I, II, III [System 1 with different DER penetration levels]: These cases present ASR for a fault on Bus 3 is shown for high, medium and no DER penetration respectively. The fault causes the corresponding IIIDs (2-3, 3-4, and 3-23) to trip and form ‘one’ grid-connected, ‘two’ unfaulted sections (can be microgrids), and ‘one’ faulted section (blackout). When DERs are connected (Case I,II) more than one online zones will be seen.
5.5.2 System 2: The LaPSEE 136-Bus Distribution System [59]

The 136-bus system has been introduced in Chapter 4.6. Case IV [System 2 with high DER penetration]: This case pertains to the response of ASR for the 136-bus system given a permanent fault on line 148-149. Only the events after FMT will be discussed.

5.5.3 System 3: PG&E 69bus 22kV System [65]

The PG&E system [65] is used to compare the performance of the ASR routine with another recently proposed scheme [64]. Identical system models are used as per [64]. Case V compares the performance for System 3 with and without DER penetration.
Figure 5.5: The LaPSEE 136-Bus Distribution System

Figure 5.6: The PG&E 69-Bus System \cite{64}, \cite{65}
5.6 Simulation Results

The results for the test cases for ASR in Section 5.5 are summarized in tables 5.1, and 5.2.

Following the FMT after a fault, the IIIDs which trip will quickly shed excess load and form stable microgrids. Now, the SAs in the system will run the ASR part of the routine to finish the DCMS as proposed. Table 5.1 summarizes the sequence of events for Cases I-IV. Table 5.2 compares the performance for Case V.
Table 5.1: Result Summary - Sequence of Events using Distributed ASR Routine

<table>
<thead>
<tr>
<th>Case</th>
<th>Event</th>
<th>Iter</th>
<th>Zones formed</th>
<th>Actions Taken</th>
<th>Load Steps</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td>Online</td>
<td>Offline</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Lines charged</td>
<td>Loads Tripped</td>
<td>(MW)</td>
</tr>
<tr>
<td>0</td>
<td>Z1:{B2}</td>
<td>Z2:{B3}</td>
<td>-</td>
<td>5-6,9,11, 1.94</td>
<td>-</td>
</tr>
<tr>
<td></td>
<td>Z3:{B4}</td>
<td>14-18,24,26,</td>
<td>Switches B3_4,3,23,2,3 &amp; loads</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Z4:{B23}</td>
<td>28-30,32</td>
<td>5-6,9,11,14-18,24,26,28-30,32</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>With DERs 1</td>
<td>{Z1},{Z3},{Z4}</td>
<td>{Z2}</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>I 33-Bus System 2</td>
<td>25-29</td>
<td>24,25</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Bus Fault: B3</td>
<td>charging 25-29 and tripping Load[24,25]</td>
<td></td>
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<td></td>
<td></td>
<td></td>
<td>IIDIs tripped: 3</td>
<td>{Z1},{Z3,4}</td>
<td>{Z2}</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>3-4,2-3,3-23</td>
<td>No offline zone: Z3_4 moves to offline</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Net Load: 4</td>
<td>{Z1}</td>
<td>{Z2},{Z3,4}</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>3.72MW</td>
<td>charging switch 12-22 and Load[24,25]</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>5</td>
<td>{Z1,3,4}</td>
</tr>
</tbody>
</table>

0 | Z1:{B2} | Z2:{B3} | - | 4-6,8,9, 1.035 | - | Change of status broadcasted for: |
|      | Z3:{B4} | 14-18,26, | Switches B3_4,3,23,2,3 & loads |
|      | Z4:{B23} | 28-33 | 4-6,8,9,14-18,24-26,28-33 |
|      |    With DERs 1 |    {Z1},{Z3},{Z4} | {Z2} | - | - | 1.035 | - No offline zone: Z4 moves to offline |
|      |      |      |    II 33-Bus System 2 | 25-29 | 23,11 | 2.65 | - Neighbors Z4 and Z3 merge by |
|      |      |      | Bus Fault: B3 | charging 25-29 and tripping Load{11,23} |

Continued on next page
Continued from previous page

<table>
<thead>
<tr>
<th>Case</th>
<th>Event</th>
<th>Iter</th>
<th>Online</th>
<th>Offline</th>
<th>Actions Taken</th>
<th>Online</th>
<th>Steps</th>
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<tr>
<td></td>
<td></td>
<td></td>
<td></td>
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<td>Zones formed</td>
<td></td>
<td></td>
</tr>
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<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>Actions Taken</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
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<td></td>
<td>Online</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Zones formed</td>
<td>Actions Taken</td>
<td>Online</td>
<td></td>
<td></td>
<td></td>
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<td></td>
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<td>Case</td>
<td>Event</td>
<td>Iter</td>
<td>Online</td>
<td>Offline</td>
<td>Lines</td>
<td>Loads</td>
<td>Load</td>
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<td>-------</td>
<td>-------</td>
<td>------</td>
<td>--------</td>
<td>---------</td>
<td>-------</td>
<td>-------</td>
<td>------</td>
</tr>
<tr>
<td>IIDDs tripped:</td>
<td>3</td>
<td>{Z1},{Z3,4}</td>
<td>{Z2}</td>
<td>-</td>
<td>-</td>
<td>2.65</td>
<td>- Loads charged:5,6,9,14-18,26,28-33</td>
</tr>
<tr>
<td>3-4,2-3,3-23</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Net Load:</td>
<td>4</td>
<td>{Z1}</td>
<td>{Z2},{Z3,4}</td>
<td>8-21</td>
<td>-</td>
<td>3.625</td>
<td>- Neighbors Z{3,4} and Z1 merge by</td>
</tr>
<tr>
<td>3.72MW</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>5</td>
<td>{Z1,3,4}</td>
<td>{Z2}</td>
<td>-</td>
<td>-</td>
<td>3.625</td>
<td>- ASR complete (No more zones available)</td>
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</table>

Without DERs

<table>
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<th>Event</th>
<th>Iter</th>
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<th>Offline</th>
<th>Actions Taken</th>
<th>Online</th>
<th>Steps</th>
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<td>33-Bus System</td>
<td>0</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>0.46</td>
<td>Similar sequence flow</td>
<td></td>
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<tr>
<td>III</td>
<td>Bus fault: B3</td>
<td>1</td>
<td>{Z1}</td>
<td>{Z2},{Z3},{Z4}</td>
<td>8-22</td>
<td>-</td>
<td>2.70</td>
</tr>
<tr>
<td>IIDDs tripped:</td>
<td>2</td>
<td>{Z1,3}</td>
<td>{Z2},{Z3}</td>
<td>25-29</td>
<td>Load:30</td>
<td>3.05</td>
<td>for Cases I, II</td>
</tr>
<tr>
<td>3-4,2-3,3-23</td>
<td>3</td>
<td>{Z1,3,4}</td>
<td>{Z2},{Load:30}</td>
<td>-</td>
<td>-</td>
<td>3.05</td>
<td></td>
</tr>
</tbody>
</table>

With DERs

<table>
<thead>
<tr>
<th>Case</th>
<th>Event</th>
<th>Iter</th>
<th>Online</th>
<th>Offline</th>
<th>Actions Taken</th>
<th>Online</th>
<th>Steps</th>
</tr>
</thead>
<tbody>
<tr>
<td>LaPSEE 136-bus</td>
<td>Z2:{B138},</td>
<td>Z4:{B148,B153}</td>
<td>-</td>
<td>155</td>
<td>13.63</td>
<td>- Change of status broadcasted for:</td>
<td></td>
</tr>
<tr>
<td>Test Case IV</td>
<td>Z3:{B154}</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>Switches G,148,153,138,</td>
<td></td>
</tr>
<tr>
<td>IIDDs tripped:</td>
<td>1</td>
<td>{Z1},{Z2},{Z3}</td>
<td>{Z4}</td>
<td>-</td>
<td>-</td>
<td>13.63</td>
<td>- No offline zone: Z3 moves to offline</td>
</tr>
<tr>
<td>IV</td>
<td>100-148,</td>
<td>2</td>
<td>{Z1},{Z2}</td>
<td>{Z3},{Z4}</td>
<td>-</td>
<td>-</td>
<td>13.63</td>
</tr>
<tr>
<td>153-138,</td>
<td>153-154</td>
<td>3</td>
<td>{Z1,3},{Z2}</td>
<td>{Z4}</td>
<td>155-156</td>
<td>14.55</td>
<td>- No offline zone: Z2 moves to offline</td>
</tr>
<tr>
<td>14.852MW</td>
<td>5</td>
<td>{Z1,2,3}</td>
<td>{Z4}</td>
<td>62-63</td>
<td>-</td>
<td>14.55</td>
<td>- ASR complete (No more zones available)</td>
</tr>
</tbody>
</table>
Case I, II

When the fault isolated, the system splits into four parts (Table 5.1, fig. 5.7). The status change (tripping) of the respective IIIDs (100-148, 153-138, 153-154) is broadcasted. As a result, sections {1,2,19-22}(Zone 1), {4-18,26-33}(Zone 3) and {23-25}(Zone 4) are online and Bus 3 (Zone 2) is isolated and offline. Since none of the offline zones have an available online neighbor, Zone 4 will act as offline given the criteria in section 5.4 to form the largest connected system. Zone 4 sends a CR to neighbor Zone 3. In response, Zone 3 sends a proposal which is accepted by Zone 4 as it was the best (only) proposal. Zone 4 sends an acceptance to Zone 3. Zones 3 and 4 merge by closing tie-line 25-29. This results in multiple offline loads being picked up. Similarly, for next iteration, Zone 3+4 merges with Zone 1 (grid-connected) by closing tie-switch 12-22, and picking up remaining loads. There were two possibilities: Switches 8-21 and 12-22, and the algorithm selects 12-22 for better voltage profile. Case II will have a similar sequence of events, except that load shedding is more severe due to less DER generation.

Case III

When DERs are absent, Zone 1 (grid-connected) will be online. Other sections (zones 2, 3, 4) will be offline. Using the ASR routine, section {4-18,26-33} (Zone 3) merges with {1,2,19-22} (Zone 1) first by closing tie-switch 12-22. The voltage drop prevents the system from supporting the load at bus 30 for more critical loads. Next, section {23-25} is brought online by closing tie-switch 25-29. Given the voltage drop, loads at buses 17, 24, and 26 are shed in favor of more important load at Bus 30 (shed previously).
Figure 5.7: Sequence for Events: Case II
Case IV

Given the fault, IIID G-148 trips and sends a permissive trip resulting in isolating microgrids formed by IIIDs 153-138 and 153-154. The FMT scheme is implemented as discussed previously, resulting in ‘one’ grid-connected section, ‘two’ microgrids, and ‘no’ unfaulted offline zones (fig. 5.8). Table 5.1 summarizes the sequence of events. Here, since both the microgrids are online, they connect to different branches of the grid-connected section by choosing from among the available tie-lines. To test the complexity of the system for larger systems, the loads are placed on their individual buses. This results in a system of 240 nodes. Even then, the FMT and ASR routines performed well and completed in about 40 seconds (including calculations for both FMT and ASR schemes).

Figure 5.8: Case IV: LaPSEE 136-Bus System: Post-Fault Steady State Before ASR (Only Participants Shown)
Case V

The approach used in [64] is implemented on balanced intentional islands by finding the shortest path to connect all the DGs. The algorithm uses heuristics to find the most suited tie-switch to connect the sections of power system, and pickup any DERs. Then, Harmony Search Algorithm (HSA) is used to solve the reconfiguration problem to improve the system voltage. As a result of this multi-stage process, the number of switching stages are increased. In comparison, the proposed scheme in this dissertation is focused on aggregating the zones based on the available tie-switches. Therefore, the number of switching operations is less.

As table demonstrates, for no DER penetration, proposed scheme ends up with more load picked up along with fewer switching actions. The voltage profiles of the resulting systems from [64] and the proposed DCMS are very similar (Fig. 5.9a) given the voltage limit of +/- 7% ([0.93,1.07] p.u.) from [64]. The slightly better voltages on a few buses for the system with no DERs (Fig. 5.9a) is attributed to the loads not picked up by the resulting topology using [64].

For high DER penetration, the proposed scheme picked up the same amount of loads as [64] but with fewer switching operations. Similar to the no DER scenario, both the system configurations ([64] vs. proposed) have a stable power flow and comparable voltage profiles (Fig. 5.9b).

5.7 Conclusion

This chapter proposes the ASR part of the proposed distributed contingency management scheme (DCMS) for active distribution networks (ADNs), which can operate as both grid-connected and independent microgrid(s). The novel architecture presented as
Figure 5.9: Voltage Profile Comparison - [64] vs. Proposed for PG&E System in Case V (a) Without DERs, (b) With DERs
Table 5.2: Case V: Performance Comparison - Proposed ASR vs Existing Strategies [64]

<table>
<thead>
<tr>
<th>Event</th>
<th>ASR Strategy</th>
<th>Lines Tripped</th>
<th>Lines Charged</th>
<th>Additional Load Shed</th>
</tr>
</thead>
<tbody>
<tr>
<td>No DERs 69-Bus System</td>
<td>Proposed</td>
<td>7-8</td>
<td>11-43</td>
<td>-</td>
</tr>
<tr>
<td>Line Fault: 7-8</td>
<td>Results in [64]</td>
<td>7-8,12-13, 11-43, 21,24,26, 57-58,64-65</td>
<td>27,64,46</td>
<td></td>
</tr>
<tr>
<td>With DERs 69-Bus System</td>
<td>Proposed</td>
<td>7-8,28-29</td>
<td>11-43</td>
<td>-</td>
</tr>
</tbody>
</table>

a part of the scheme makes it immune to agent failures and is critical only of the island interconnection devices. Agent architecture is presented to show the distributed information flow. After the proposed ‘fast microgrid transition’ algorithm steers the unscheduled intentional islands into balanced operating microgrids, the proposed ‘automated service restoration (ASR)’ reconfigured the resulting system sections to maximize the support of more critical loads. It is a greedy algorithm which formed the largest possible electrically connected operable system(s). Further, when two sections can be interconnected by multiple switches, the proposed DCMS chose the switch best suited for system’s voltage profile. The test results demonstrated the flexibility and scalability of the proposed DCMS with the small 33-bus and the larger 136-bus systems. The 69-bus system is used to present the improvement with other recently proposed algorithms. It adapted the sequence of actions to the level of DER penetration, and the faulted sections/buses.
Chapter 6

Conclusions and Future Work

This dissertation presents a distributed fault management strategy for active distribution networks with high penetration of distributed energy resources (DERs). The preceding chapters presented the individual schemes, and the validation results. This chapter presents conclusions based on the overall research, and potential venues for future work in this region.

6.1 Conclusions

With increasing DER penetration and evolving DER interconnection requirements, system operation and protection are becoming increasing interdependent. Use and advancement of local and global (across the system) intelligence is critical for developing coherent solution towards a more resilient and reliable grid. Therefore, this dissertation presents a distributed fault management strategy offering 1) Improved fault detection and isolation schemes, and 2) A distributed management scheme for the contingent system formed after fault isolation.
Fault detection is a time-constrained challenge with response time within 600ms. The dissertation offers two alternatives - 1) A dynamic setting strategy for improved adaptive overcurrent, and 2) A transient based fault detection scheme. The proposed dynamic strategy

6.2 Future Work

This section identifies the interesting venues to expand the work in this dissertation, and move closer to a scheme that can be demonstrated for effectiveness in real-time applications.

6.2.1 Fault Detection and Isolation

Dynamic Adaptive Protection

- Optimizing the number of DERs influencing relay’s adaptivity: With increasing number of DERs in a distribution system (more plausible for residential networks), it might be difficult or even impractical to account for the status of each downstream DER affecting the relay’s fault current. Therefore, approaches to concentrate this information, or forming a more selective set of DERs which have the most influence on relay’s sensitivity can greatly improve the performance of overcurrent protection even with large number of DERs.

- Non-communication based approaches for sensing DER status: The ability to communicate with another asset offers multiple opportunities which might otherwise be infeasible or difficult to realize. However, failure in communication channel itself might compromise the performance of the protection scheme in discussion. There-
fore, non-communication based approaches to sense the status of DERs connected in the system will add another layer of robustness to the performance of the proposed dynamic adaptive protection scheme.

**Transient based Fault Detection**

- *Supervisory elements for fault detection*: Further analysis in developing supervisory elements is quintessential in converting the said scheme into a versatile protection element.

### 6.2.2 Distributed Contingency Management

**Fast Microgrid Transition**

- *Real time validation*: Study the impact of transients on system operation using Microgrid transition for practical use-cases will help in identifying any challenges with real time implementation. Developing a transient-model based real-time test-bench with microgrid forming capabilities is an important next step in implementing the scheme in real systems.

**Automated Service Restoration**

- *Implementation in real-time HIL system*: Similar to FMT, implementing the proposed algorithm using HIL platforms is a vital next step.

- *Bad data filtering*: Given the distributed implementation, the ability of the agents to identify and filter bad data will help in improving the robustness of the scheme by addressing the cybersecurity related aspects of the problem.
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