Developments in System Islanding and Synchronization Systems

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***Abstract*—Islanding detection and decoupling schemes (IDDSs) along with automatic synchronization are becoming ubiquitous in the microgrids within our power system today. The need for advanced and automatic schemes is greater than ever. This paper discusses a reliable, smart decoupling or secure islanding scheme, along with innovative autosynchronization (A25A) for microgrids using single-ended methods. A remotely located and connected microgrid with multiple generation assets required a decoupling and synchronization system for self-sustaining operational capabilities and back synchronization to the grid, as the system continued to expand and power system reliability became critical for some loads.**

System architecture, hardware, and communication requirements for both decoupling and synchronization schemes are discussed in this paper along with results of the testing of the effectiveness of the autosynchronization and decoupling system in a controlled environment using control hardware-in-the-loop (cHIL) testing methodology, as identified in IEEE Std 2030. 8-2018, *IEEE Standard for the Testing of Microgrid Controllers,* using a real-time digital simulation (RTDS) system. The paper also provides insight into model development, validation, and the process of creating this test bed along with the results from the cHIL testing. Several cases of grid and microgrid disturbances are simulated, including faults, loss of generation, loss of loads in both microgrid and utility sides, and synchronization after multiple islands are formed within the given microgrid. Some results from those cHIL tests are shared along with authors' insights into those operations. This solution is currently in service.

I. Introduction

An existing heavy industrial microgrid installed additional generation assets along with additional power system infrastructure to meet planned growth and system reliability requirements. This additional generation provided an opportunity for the microgrid to upgrade a plant-wide microgrid monitoring and control system (MMCS) and improve its ability to perform high-speed control of the electrical system to preserve frequency and voltage stability. As a part of this MMCS, advanced automatic synchronization and an island detection and decoupling system (IDDS) were implemented for safe, reliable, and economical operation of the power system and additional data monitoring and archiving opportunities. The focus of this paper is the automatic synchronization and IDDS scheme used to detect islanding or decoupling from grid disturbances and using automatic synchronization to synchronize multiple islands with the facility and later back to the utility grid. This paper presents a novel decoupling algorithm that uses the measured system frequency, voltage, and power flow across the point of common coupling (PCC) to determine the location of the disturbance and characterize it as an internal (within the microgrid) or external (outside the microgrid) event to take the necessary and improved power system stabilizing action. The effectiveness of the autosynchronization and decoupling system has been tested in a controlled environment using control hardware-in-the-loop (cHIL) testing methodology, as identified in IEEE Std 2030. 8-2018, *IEEE Standard for the Testing of Microgrid Controllers*, using a real-time digital simulation (RTDS) system [1]. Utility and microgrid disturbances are simulated using the test setup, and the solution algorithms are validated prior to deployment in the field.

The proposed advanced decoupling algorithm uses a power-supervised rate-of-change-of-frequency (ROCOF) element and measured power flow at the PCC during a disturbance. The power flow along with a ROCOF element allows differentiation between an internal and external disturbance for any disturbance observed at the PCC. Once decoupling is triggered, a high-speed load generation rebalancing scheme may act, if necessary, to preserve system integrity. Coordination between the decoupling scheme and load generation balancing scheme is also discussed in this paper. This load generation rebalancing scheme includes load shedding, generation shedding, and generation runback set point at subcycle speed to maintain frequency balance and system stability.

This paper also presents an autosynchronization (A25A) algorithm that uses an existing state-of-the-art synchronization algorithm along with some novel techniques for frequency matching to allow mismatched load generation islands to synchronize. These techniques include controlling multiple generation assets simultaneously, forcing off-nominal frequency on a given island to synchronize the island where frequency is depressed because island generation is maxed out, and controlling targeted assets based on asset availability and health. Once both the microgrid and utility grids are electrically stable, an automatic synchronization system can be used to synchronize the microgrid back to the utility grid with minimal disturbance to the critical loads.

This facility, with two ties to the utility, can split into multiple power islands for continued system operation. The MMCS has been designed to track all such possible islands and provide simultaneous (parallel) control. Fig. 1 represents the simplified microgrid power system.

II. Microgrid Electrical Network

Microgrids, by definition, are capable of islanded operation during intended or unintended loss of utility. Islanded operation requires sources which are capable of providing primary frequency and voltage regulation within the microgrid and managing the MMCS interfaces of these resources. Some examples of such assets include diesel generators, photovoltaic (PV) sources, wind sources, and fuel cells. MMCS components include islanding detection and decoupling systems, primary and backup load-shedding systems, slow-speed and high-speed generation control systems, adaptive protection systems, peak shaving, energy source optimization, and other analytical and control functions.

Fig. 1 shows the simplified diagram of an industrial facility microgrid. A central substation bus connects all of the plants internally and is also the bus which connects to the utility at the PCC. The PCC in this industrial system has two tie lines for redundant connection; however, a single PCC connection is shown in the figure for simplicity. The tie flow across this connection is essential in islanding detection and decoupling protection, as explained further in Section IV. Plants 1, 2, and 3 are representations of subsystems within the microgrid that are capable of self-sufficient generation and load balance in emergencies and maintenance operations, thereby separating into multiple, independent islands, if required. There is no frequency-based subislanding between these plants. The internal islands are usually separated through faults on lines or manual operation. It is to be noted that the nominal frequency of this system is 50 Hz for references made here on.

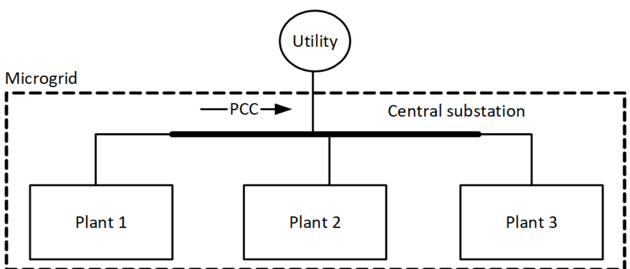

Fig. 1. One-Line Microgrid Power System

Unlike traditional sources, power from electronic-based renewable sources (found typically in microgrids) are not so predictable. Concerns such as intermittency and reduced inertia can have a large impact on power system dynamics as the installed capacity of distributed generation increases. Such concerns warrant the need for fast-acting control systems that can potentially avoid situations which could destabilize the microgrid power system. Fig. 2 shows the high-level microgrid communication and network architecture [2]. The individual microprocessor-based relays are connected to the relevant current transformers and voltage transformers (VTs). Those microprocessor-based relays and intelligent electronic devices (IEDs) communicate with the centralized controllers, for status and measurements, along with a power quality meter (PQM) and any other additional input/output (I/O) required for the MMCS functionality. The communication equipment provides a secure gateway to communicate to the external world via a security gate for system visibility and monitoring. The MMCS network also has some overall visualization from a human-machine interface (HMI) with data visualization, recording, and archiving, along with engineering tools as discussed in more detail in [3].

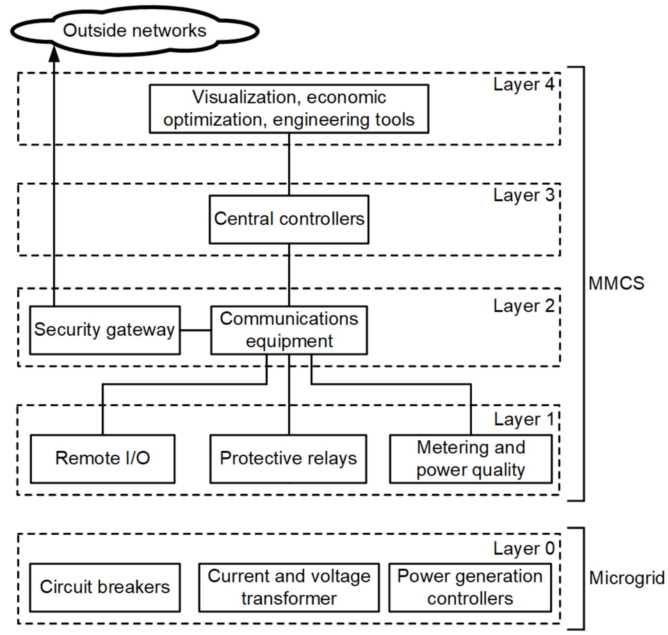

Fig. 2. High-Level Microgrid Architecture

III. Communications and Network Architecture

Modern-day electrical control systems rely significantly upon analog and digital communications. Most of the newer systems use various forms of communication media, such as radio, copper, and fiber. These media enable connections between microprocessor-based programmable logic controllers (PLCs), computers, IEDs, and several other devices that are normally found on the power grid. The application of monitoring, controlling, and managing microgrids is no different. MMCSs use a wide range of electronic devices that use industry-standard communication protocols, such as DNP3, Modbus, Inter-Control Center Communications Protocol (ICCP), IEC 61850, and IEEE C37.118. Communication protocols are mainly classified into high-speed and slow-speed protocols.

High-speed protocols are often used in situations where speed matters. For example, applying IEC 61850 Generic Object-Oriented Substation Event (GOOSE) messaging for high-speed breaker tripping can be commonly found in load-shedding applications. On the contrary, slow-speed protocols work great for interfacing with microgrid assets, moving data between HMI and storage systems, etc.

Depending on the application criticality, it is essential to identify and segregate communication networks to guarantee dedicated bandwidth and network latency. A good design stage activity is to identify all the I/O signals required for monitoring and control functions. Using the I/O list, network calculations should be performed to calculate the required bandwidth for the types of communications.

Fig. 2 shows the Ethernet network connections between the various equipment for the microgrid. However, the local relays for the automatic synchronization and IDDS can operate independently in local mode.

IV. Automatic Synchronization System Design

This section discusses the design and functionality of the automatic synchronization system which is a part of the MMCS. This system can work in conjunction with an existing generation control system whereby it temporarily takes control from that system to perform the synchronization process and then relinquishes control after the synchronizing breaker closes. The system (shown in Fig. 3) has two major components interfacing with the power system infrastructure of the microgrids: the MMCS controller that tracks the topology of the power system and routes the raise and lower commands to the generation assets, and the relays that track breaker status and information from the potential transformers (PTs) and perform synchronism checks, including sending close commands to the breaker. The autosynchronization relay, or IED, is used to synchronize all the breakers at the central substation bus in Fig. 1. Each relay is wired with PT connections from both sides of the breakers and has the breaker status and control wired. When the synchronization scenario is selected, the respective IED wired to the breaker monitors the system status to verify the permissive mode to close the breaker. The three permissive modes are defined as:

1. Synchronizing close (slip is detected and matching is required).
2. Parallel permissive close (both buses are live, but no slip is detected).
3. Dead-bus permissive close (one or both buses are dead).

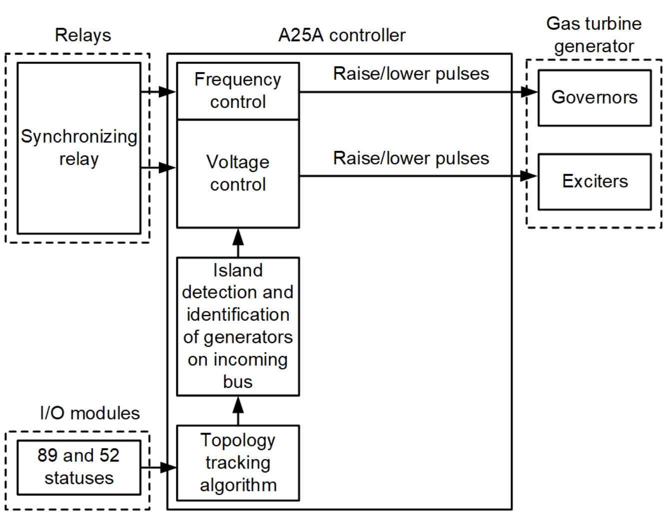

Fig. 3. Autosynchronization Control System

The controller monitors the power system topology and identifies the generation assets connected to any given island. The controller, in the case of synchronization close where slip and voltage difference is present, will route the raise and lower commands to the generation assets on each side of the islands to match the voltage and frequency.

During this process, the IED continues to monitor the slip frequency, voltage difference, and angle, and issues a slip-compensated advanced angle close using (1) [4].

$$\text{ADVANG}° = \left(\frac{(\text{SLIP})\text{cyc}}{\text{s}}\right)\left(\frac{\text{s}}{60\ \text{cyc}}\right)\left(\frac{360°}{\text{cyc}}\right)\left((\text{TCLS})\text{cyc}\right) \quad (1)$$

where:

ADVANG is the advanced close angle.

TCLS is the circuit breaker close mechanism delay.

Once the slip, voltage difference, and advanced angle are within the acceptance criteria, a close command is initiated by the autosynchronizing IED. Table I provides the supervision settings for the autosynchronizing IED for synchronizing close. In the case when the breaker stays open after a close command is issued, which is a **CLOSE FAIL**, an LED will illuminate, indicating an issue with the closing circuit or the breaker. In the case when the breaker closes after the close command is initiated but reopens within a user-settable period, then a **CLOSE LOCKOUT** is issued by the relay.

TABLE I
SUPERVISION SETTINGS FOR AUTOMATIC SYNCHRONIZING FOR SYNCHRONIZED CLOSE

	IEEE C50.12 and IEEE C50.13	**A25A acceptance criteria**
Angle	±10°	Target 0°
Voltage	+5%	±5%
Breaker close time	NA	3 cycles
Slip	±0.067 Hz	±0.04 Hz

If the synchronizing scenario is a parallel permissive close, then the synchronizing relay issues a close command to close the breaker and, if the synchronizing scenario is a dead-bus close, the relay verifies the VT health for any erroneous dead-bus measurements and issues a close, unless the dead bus is the utility for the two utility incomers. This process can be initiated from the relay front panel in the local mode and from the remote HMI for safe, unattended synchronization.

A. IDDS

An MMCS should be programmed to track the internal islands of the system when disconnected from the utility. This is also true when some islands are formed when the system overall is connected to the utility. For example, Plant 1 can be an island while Plants 2 and 3 are connected to the utility. This allows for simultaneous voltage and frequency control of islands with available generation capacity, as done by the controller mentioned.

Island detection and decoupling are technically two separate schemes. An island-detection scheme detects an islanding condition where a microgrid has been separated from the utility. Sometimes this disconnection may happen upstream of the PCC breaker. A decoupling scheme detects an abnormal condition in the utility or a grid disturbance which is outside the tolerance region of the given microgrid, and it intentionally opens the PCC breaker to prevent complete load and generation loss in a given microgrid. Utmost care has to be taken when selecting those set points such that the settings can ride through a nonsevere grid disturbance while intentionally disconnecting for a severe disturbance to prevent any nuisance tripping. For this case study, multiple schemes working in parallel were selected and tested in the testing environment and settings were adjusted prior to field commissioning. Typically, there are three types of decoupling schemes: direct transfer trip (DTT), local-area-based, and wide-area-based. Due to lack of communication with the remote devices, a wide-area-based scheme was not implemented for this project. More analysis on the IDDS schemes and examples are in [5] for further reading.

1) DTT

A DTT-based IDDS scheme deploys a communication or hardwired-based tripping scheme and is widely used in many protection applications. For this project, the remote breaker status for the PCC was monitored by the local relay, and in the case of opening the remote breaker and having a healthy communication channel, the local breaker also trips, initiating an islanding condition. Fig. 4 shows the scheme implemented.

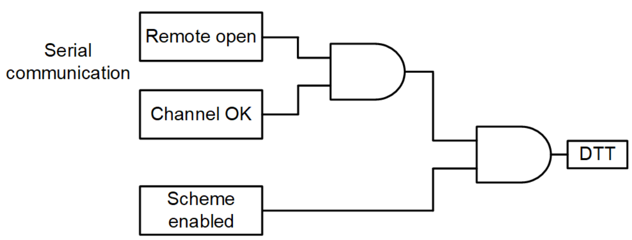

Fig. 4. DTT Scheme Logic

2) Local-Area-Based Detection

The local-area-based detection is applied at the two utility incomers for this microgrid. This type of scheme utilizes local-based measurements, such as voltage, frequency, ROCOF, power, and rate-of-change of power. This scheme is a passive detection scheme which can be implemented in most IEDs, as is the case for this microgrid.

a) Underfrequency/Overfrequency (UF/OF)

This type of decoupling or protection scheme has been around for a while. It utilizes local voltage and frequency measurements compared against a user-settable threshold pickup and an associated timer, which allows for detecting grid disturbances. These set points were carefully coordinated with the existing protection systems to avoid false tripping during fault conditions. Fig. 5 shows the frequency-based decoupling set points. Fault-blocking elements are also programmed for the frequency elements, which would block frequency elements from operating in a depressed voltage condition due to unreliable frequency measurements from the VT.

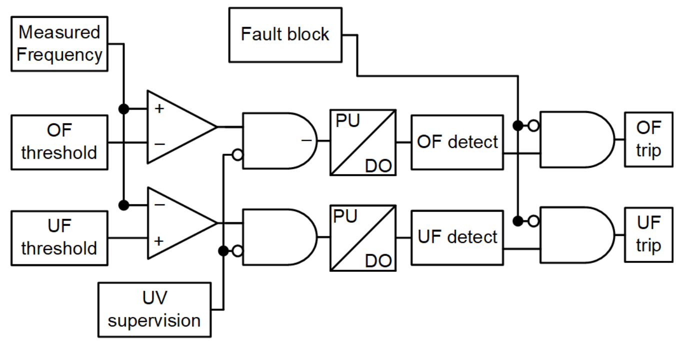

Fig. 5. 81U/O Protection Scheme

b) Fast ROCOF (81RF) Element

The 81RF element provides a faster response compared to standard frequency-based elements (81O and 81U) or just ROCOF (81R) elements, as this scheme combines the benefits of both elements into one element that looks not just at the deviation from the nominal but also at the rate of change of that deviation prior to making a decision. Fig. 6 shows the 81RF scheme where DF is the frequency deviation from nominal and DFDT is the ROCOF deviation. During steady state when system frequency is at nominal, the operating point is going to be at the origin. If the system frequency increases, it will move to Trip Region 1 when the system is accelerating. If the system frequency decreases, the operating point will move towards Trip Region 2, meaning the power system frequency is decelerating. If the operating point is within the Trip Region 1 or Trip Region 2 and a user-settable timer expires, then a trip action can be initiated.

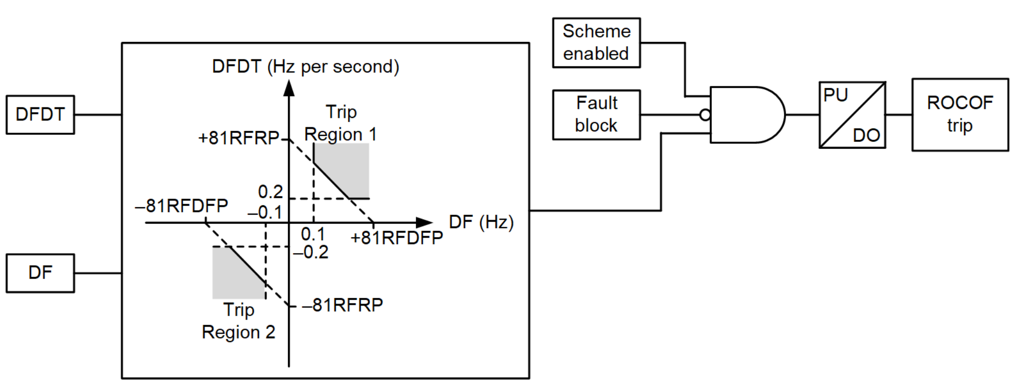

Fig. 6. Frequency-Based Decoupling Logic with 81RF Characteristics

3) Power-Based 81RF Element

The power-based decoupling scheme is an extension of the 81RF element, where the power flow at the PCC is further utilized to determine if the event is internal or external. For example, in an external UF event, the frequency falls and the tie flow power increases in terms of export to the utility. Whereas in an internal UF event, the plant imports power from the utility. This protection element works in conjunction with the MMCS to decide if 81RF decouples the system or waits for other protections to act, thereby limiting loss of load or generation in the plant.

An external event (on the utility side) can be detrimental to the plant; therefore, 81RF is allowed to operate normally and decouple the plant instantaneously. In an internal event, the decoupling scheme checks if the plant has sufficient incremental reserve margin (IRM) or decremental reserve margin (DRM) to decouple without having the MMCS act by shedding load or generation. The 81RF is blocked from operating for an internal event if the tie power flow does not meet the IRM or DRM capacity of the plant. In this case, the plant holds on longer hoping for a recovery, thereby saving its assets from going offline due to controller action. Fig. 7 illustrates an example of power-based decoupling for a UF event (in the negative region of 81RF characteristics).

B. HMI

The automatic synchronization and decoupling system installed at the microgrid is also equipped with a remote HMI. This internal interface mimics the relay front panel for the autosynchronization and decoupling IEDs, making the user interface the same for the users standing in front of the relay during local mode of operation or users standing in front of the HMI during the remote mode of operation. The remote HMI is integrated with the overall MMCS HMI, so it provides additional information rather than just individual relay measurements. Fig. 8 shows a typical autosynchronization screen.

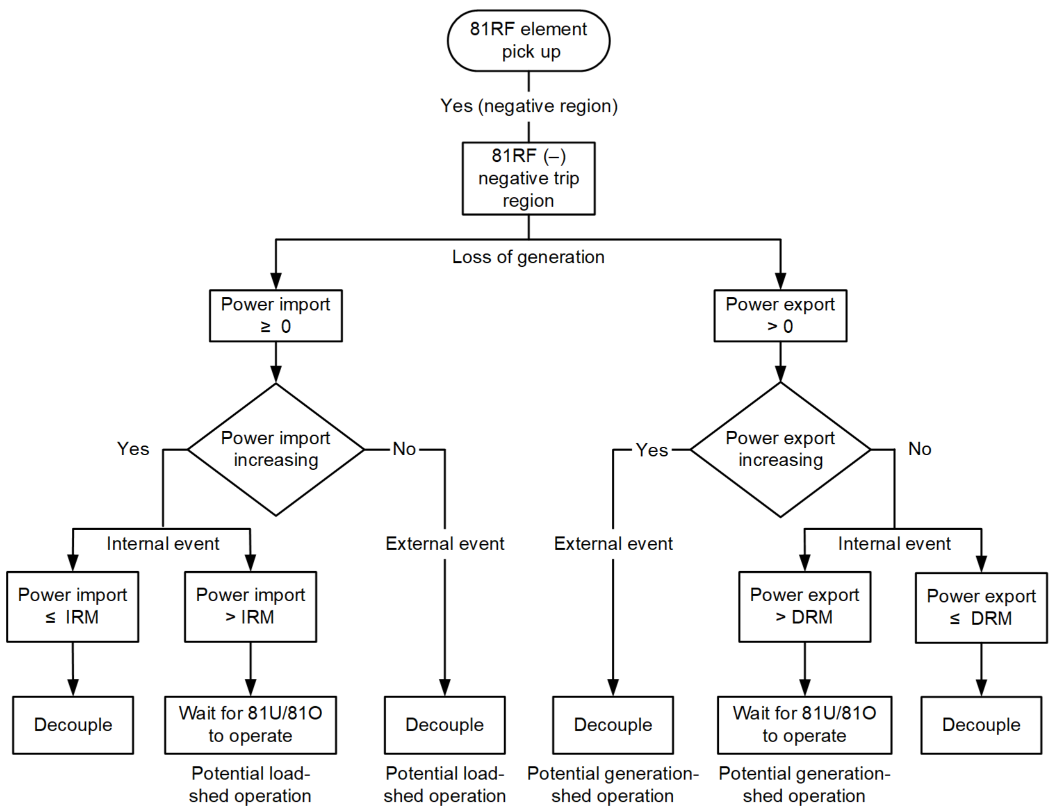

Fig. 7. Power-Based 81RF Algorithm

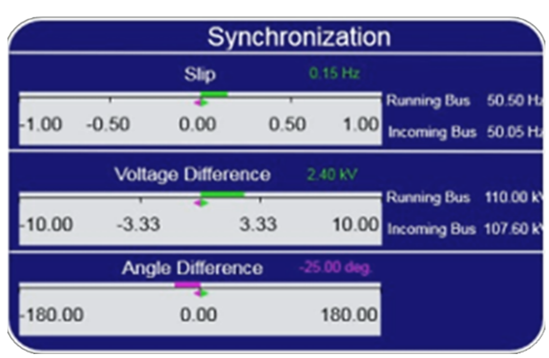

Fig. 8. Autosynchronization Display Screen

V. Dynamic Testing and Analysis

This section describes the real-time simulation setup for cHIL testing for the scheme. The simulation environment used for this cHIL testing is a hardware-based Electromagnetic Transients Program (EMTP) which is capable of continuous real-time simulation; it provides real-time data to the connected control devices, accepts control commands, and reflects them in the power system simulation. The time step used for this simulation was 50 microseconds, so the relays accept the current, voltage, and inputs statuses that mimic the field setup. This model utilizes the full power system model, including generation assets, transformers, governor and excitation systems, inertia of the loads, lower-voltage network, and nonlinear mechanical characteristics of both generation and loads. This level of modeling provides accurate dynamic response characteristics required for this testing and was validated prior to performing any testing.

Prior to installation of the autosynchronization and decoupling system, a complete factory acceptance test (FAT) was performed in a controlled simulation environment using real-time HIL testing for the control system component. This cHIL setup allows the team to validate the functionality of the resynchronization and decoupling scheme prior to field deployment. Fig. 9 shows the cHIL testing setup.

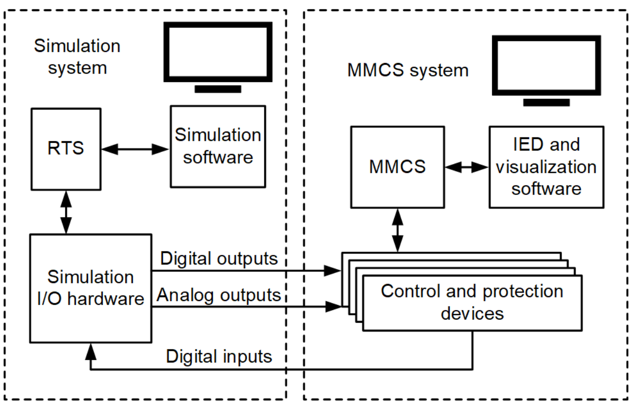

Fig. 9. System Simulation Setup

Multiple studies were performed using the model that provided insight into system operation, vulnerabilities, and response to contingency events, such as external grid disturbance and internal events. This model was validated prior to cHIL testing.

A. Case 1: System Decoupling During External Disturbance

A loss of generation on the utility side causes the frequency of the system to drop rapidly from the nominal. This is a UF event which can be picked up by the 81RF element in the negative region. The decoupling relay declares this an external event since the export to the utility increases rapidly while the frequency is declining. There are no additional blocks or checks for the relay, so it issues a trip signal at the PCC for islanding. Since the microgrid does not have a deficit in generation, there is no need for the MMCS to take action by shedding any load within the plant.

Fig. 10 shows a simulated comparison of an external fault event with and without fast decoupling. The frequency plot shows the speed at which frequency returns close to nominal with fast decoupling, compared to the dotted red line, which stays lower, close to 81U levels, and takes longer to recover. The important information to notice is the wide change in the power through the tie lines (PCC) during this event. The power exchange not only could exceed PCC limitations for the long term, but also oscillations in the power are observed over a long period of time, which can be detrimental to sensitive processes in such field events. A similar explanation and examples are illustrated in [6].

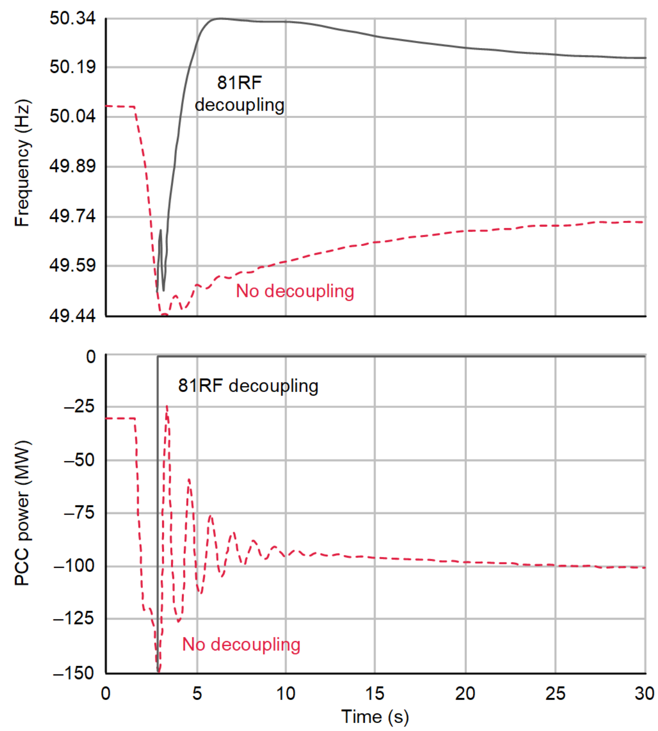

Fig. 10. 81RF Decoupling Comparison for External UF Event

B. Case 2: System Decoupling During Internal Disturbance

Like the previous event, a loss of generation within the microgrid creates a deficit in generation, causing the frequency to drop. However, since this is an internal event, it is helpful to use the utility's inertia to prevent a decoupling event. The decoupling relay verifies the power direction and blocks the 81RF element if it detects that the tie flow is in an increasing import condition. This is true if the IRM available within the system is not satisfied by the generation. If the available IRM is greater than the power import at the time 81RF is detected, the decoupling relay issues the trip, so the generation within the plant can pick up the step change in load without interruption.

C. Case 3: Synchronization Between Islands Internally

In the case of island-to-island synchronization, after a system disturbance multiple islands were formed, with each plant (1, 2, and 3) operating as an individual island, with an open breaker connected to each of the islands from the central substation (Bus 1). The synchronization was performed utilizing the relays at Bus 1. A breaker at the central substation connecting Plant 1 was selected to energize, as Bus 1 is islanded on its own without any generation—a dead bus. Once the synchronization breaker was selected, the relay LED indicated that the system was ready to initiate; synchronization was initiated by selecting **OK to INIT Auto SYNC/CLOSE**. As soon as the pushbutton was pressed, since it was in a dead-bus permissive mode as utility breakers were open, the IED initiated close. Once Bus 1 was energized, operators can synchronize Plants 2 and 3 on the island to form a single island within the microgrid. Each of the breakers on Bus 1 connecting Plants 2 and 3 were selected sequentially, and an automatic synchronization system was able to synchronize those islands back into a singular island within the microgrid. One important point to highlight here is that, rather than typing to control the generation assets to the nominal frequency and voltage, the autosynchronization system dispatches the generation on the side with negative slip to move up, and the generation on the side with positive slip to move down. In the case of Island 3, where system frequency was 49.5 Hz, the entire system frequency on the other side of the island was adjusted to 49.45 Hz until the slip was within acceptable limits ($< \pm 0.05$ Hz). In the case of frequency swings outside of 1 Hz or voltage swings outside of the acceptable percentage of nominal voltage, the synchronization process is aborted and the MMCS controls the frequency back to the nominal frequency of those islands. This also allows for faster synchronization, as both sides of the islands are moving towards the target.

D. Case 4: Synchronization Back to the Utility

Once all three plants are synchronized back as one island, the synchronizing breaker at the PCC is used to synchronize the island back to the utility. During this process, all the generation within the islands that are inside the capability curve (regulation limits) are dispatched to move towards the utility voltage and frequency, simultaneously. Any generation assets that are in local mode or offline are excluded during this dispatch process. While the controller reduces the slip and voltage difference, the autosynchronization relays continuously monitor the process and provide the operator with real-time feedback using the front-panel display and the remote HMI. Once the relay detects that those synchronizing criteria are satisfied, the autosynchronization relay sends a breaker close command to close the synchronizing breaker and generate an event report. The relay continues to monitor the breaker status for successful closure, **CLOSE FAIL** (failure to close), or **CLOSE LOCKOUT**. The synchronizing breaker closes within a user-settable timer condition and reports it using the relay Sequential Events Recorder (SER) and event report to gather the necessary information.

VI. Conclusion

Today's microgrid requires an advanced autosynchronization scheme that can reconnect multiple islands within the microgrid and back to the utility when the grid is available and requires a fast, reliable IDDS scheme that can detect the utility disturbance and decouple to initiate local, high-speed load generation rebalancing actions based on the power flow. This paper presents the need, functionality, design, testing, and validation of an advanced automatic synchronization system and innovative decoupling system. State-of-the-art schemes were used and modified to fit the need for the given power system and discussed in detail. The real-time digital simulation of the model power system and cHIL testing of the schemes provides qualitative analysis of the speed and reliability of the IDDS scheme and functionality verification of the automatic synchronization system. The cHIL testing provided the highest fidelity for the test cases, which would have simply not been available in the field, providing additional functional validation. The system is in service and has been operating successfully since 2019. Some of the key points to take away from this paper include:

1. Innovative techniques, such as forcing an off-nominal frequency, can be adapted to allow for synchronization between islands when generation is maxed out in any given island.
2. Advanced techniques can be adapted to allow us to determine event types to make more educated decisions.
3. The local-area-based 81RF element reliably detects utility disturbances.
4. A backup scheme is always better than a single-element scheme for IDDS to support system reliability.
5. Automatic synchronization and IDDS schemes can be safely and economically implemented in any microgrid using standard relays and communications.

VII. Acknowledgement

The authors gratefully acknowledge Tim George Paul for developing the controls and Nathan Bridges of Schweitzer Engineering Laboratories, Inc., for providing support during testing.

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IX. Biographies

Ashish Upreti PE is a staff engineer at Google. He received his bachelor's and master's degrees in electrical engineering from the University of Idaho. He is a registered professional engineer in the state of Washington and a senior member of the IEEE. He previously worked at Schweitzer Engineering Laboratories, Inc. (SEL) and has more than ten years of experience in the field of power system protection and automation, including power management schemes for large-scale industrial power plants, remedial action schemes, and microgrid solutions.

Asad Mohammad received his BE in electrical engineering from Andhra University, India, in 2011, and an MS in electrical engineering in 2017. He previously worked as a substation design engineer, and he currently works as a power system studies engineer at Schweitzer Engineering Laboratories, Inc. (SEL) since 2017. He has been a member of IEEE since 2015.

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