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A Distributed Power System Control Architecture for Improved Distribution System Resiliency

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ABSTRACT Electric distribution systems around the world are seeing an increasing number of utility-owned and non-utility-owned (customer-owned) intelligent devices and systems being deployed. New deployments of utility-owned assets include self-healing systems, microgrids, and distribution automation. Non-utility-owned assets include solar photovoltaic generation, behind-the-meter energy storage systems, and electric vehicles. While these deployments provide potential data and control points, the existing centralized control architectures do not have the flexibility or the scalability to integrate the increasing number or variety of devices. The communication bandwidth, latency, and the scalability of a centralized control architecture limit the ability of these new devices and systems from being engaged as active resources. This paper presents a standards-based architecture for the distributed power system controls, which increases operational flexibility by coordinating centralized and distributed control systems. The system actively engages utility and non-utility assets using a distributed architecture to increase reliability during normal operations and resiliency during extreme events. Results from laboratory testing and preliminary field implementations, as well as the details of an ongoing full-scale implementation at Duke Energy, are presented.

INDEX TERMS Distributed control, microgrids, power distribution, power system protection, smart grids.

I. INTRODUCTION

The electrical infrastructures that support modern digital societies are essential for their routine operations, and failures due to extreme events can result in millions of customers without electricity, and billions of dollars of lost productivity [1]. Yet despite the criticality of electrical infrastructure, it is not cost effective to deploy enough assets to achieve high reliability. As a result, end-use customers occasionally experience outages. Customer outages can range from small events that affect only a single customer to large regional events that can impact millions of customers [2]–[6]. The single largest cause of outages is weather-related events. Extreme naturally occurring events, such as Hurricane Katrina, Hurricane Sandy, and the Tōhoku Earthquake, have an amplified impact because they span large regions and cause significant economic and societal disruptions [7]–[9]. In the past decade in North America, there have been more than 500 extreme natural events that have affected at least 50,000 customers or more each. The rate of these events is expected to increase due to a combination of aging infrastructure and climate change [1]. Typically, utilities build and operate their systems to account for normal historical conditions, and not extreme events [9]. To address the increasing occurrence of extreme events, utilities take the actions most appropriate for their specific service territories. Often, this takes the form of reinforcing traditional infrastructure; e.g., erecting stronger utility poles, under-grounding vulnerable sections of line, deploying outage management systems (OMS), and/or deploying self-healing systems.

Self-healing systems at the distribution level are becoming a more attractive option as utilities seek more flexible solutions to address reliability and resiliency challenges [10], [11]. While the deployment of self-healing technologies has the ability to significantly improve reliability, as measured by IEEE Std. 1366 metrics [12], their operation is often based on sets of assumptions and constraints, which can limit their flexibility. Common assumptions include, but are not limited to, the following: circuits normally operated in a radial configuration; no reverse power flows; static-time, inverse-overcurrent protection; and little or no non-metered power injections. While these assumptions are valid for many areas, there are many others where combinations of reconfiguration, moderate to high penetrations of distributed energy resources (DERs), and static protection set points can be the basis for preventing the deployment of self-healing technologies [13].

In North America, renewable portfolio standards and public interest are driving increased penetrations of utility and non-utility DERs, such as solar photovoltaic (PV), at the distribution level. These pressures are greatest in states with high solar resource potentials and/or regulatory incentives; examples include the states of California, Hawaii, North and South Carolina, and New Jersey [13]–[16]. The majority of distribution circuits in North America are radially operated with triplex secondaries supplying residential end-use customers [17], with the PV at the end of the secondaries. This design works well for low penetration levels of PV, but as the penetration level increases to moderate and high levels, the operational impacts of PV can interfere with centrally coordinated systems like self-healing [18].

One option to mitigate these interactions is to coordinate the operation of a limited number of DERs with a centralized self-healing system [19]. In this architecture, all the information is sent to a central location, such as the distribution operations center, data is processed, and centralized control signals are sent back to the DERs. While this approach can work for a limited number of DERs, it typically does not scale well, and the requirements for potentially long communications links and a single points-of-failure introduce challenges for resiliency during extreme events [20].

Distributed controls have been extensively examined in the literature as an alternative to centralized controls [21]. In a distributed control architecture, DERs and other field devices can communicate information and/or control signals peer-to-peer, without having to send all signals through a centralized control center. While distributed controls, and their integration with centralized controls into a hierarchical structure, provide the potential for increased resilience, the implementation of such a system has several challenges. For example, it is necessary to determine exactly how a DER, or other field devices, will connect to the distributed control system. Many commercial off-the-shelf (COTS) relays currently only support traditional point-to-point supervisory control and data acquisition (SCADA) connections and protocols. Additionally, there are cybersecurity issues associated with interfacing utility-operated industrial control systems (ICSs) and non-utility devices [22].

This paper presents a laminar control architecture for distributed power system controls that increases operational flexibility by coordinating centralized and distributed control systems. The goal of the additional flexibility is to improve the reliability and resiliency of electric distribution systems without the need for extensive additional capital deployments. The laminar control architecture uses COTS equipment, along with initial field implementation results, an expanded layered control architecture [23], and an overview of an ongoing field implementation being conducted on an operational electric distribution system. The laminar control architecture of the final system is intended to coordinate the operation of centralized and distributed utility assets, and to engage non-utility assets via a transactive energy system. The presented architecture is developed using the Open Field Message Bus (OpenFMB^{TM}) framework [25].

The rest of this paper is organized as follows. Section II provides an overview of distributed controls for electric power systems, and Section III reviews past implementations of distributed controls. Section IV provides an overview of laminar control architectures and Section V presents the system currently being implemented at Duke Energy. Section VI contains a summary and the concluding comments.

II. DISTRIBUTED POWER SYSTEM CONTROLS

Centralized controls are the current standard for distribution system operations, where they enable a more ''optimized'' level of operation [20]. However, centralized controls can require long communications links, with associated delays, and may not scale well when there are large numbers of field devices [20]. Additionally, the length of these communication links can make the distribution system vulnerable to large-scale events [2]–[6], [26]. For these reasons, distributed controls have been examined as an alternative to purely centralized controls.

A. HIERARCHICAL CONTROL WITH DISTRIBUTED AGENTS

Distributed controls have the potential to support a wide range of power system operations, with their application to

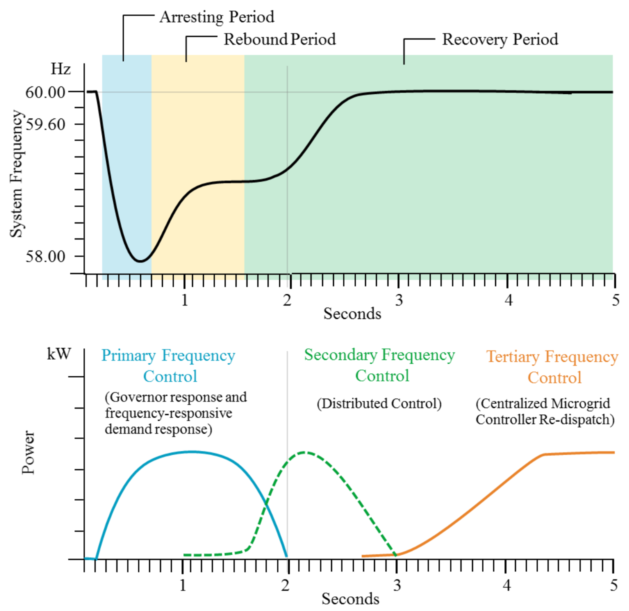

FIGURE 1. Idealized primary, secondary, and tertiary frequency response and controls following the loss of a generating unit.

microgrids having been extensively examined in the literature. Because microgrids are designed with the ability to operate independent of the bulk power system in an islanded mode, they have the ability to support critical loads during extreme events [7]–[9]. To successfully operate in an islanded mode, a microgrid should not be dependent on an extensive communications infrastructure to maintain basic operations, such as voltage and frequency regulation. This section examines frequency control for a microgrid as a use-case for the implementation of distributed controls.

In a traditional, centralized power system, when there is a large change in load or significant change in generation dispatch, frequency controls operates at three levels[27]–[29]. A three-level system can also be considered when a microgrid is operating in islanded mode at the distribution level using distributed controls [30]. The plots in Fig. 1 show the idealized operation of primary, secondary, and tertiary frequency control of a microgrid during the loss of a generating unit. The information in Fig. 1 is based on the work of Eto *et al.* [27], [28], and applied to microgrids in [30]. It should be noted that the response times seen in microgrids, as shown in [30], are on the order of seconds, while bulk systems are typically on the order of minutes [27], [28].

The idealized distributed frequency control shown in Fig. 1 can be implemented using a distributed multi-agent system (MAS) [31], [32]. The MAS shown in Fig. 2 uses three layers, similar to the centralized control of the bulk power system, but distributed for microgrid operations.

In the primary control layer, the local agents are responsible for power sharing between generators, voltage control, and frequency regulation. It is assumed that there are control agents for each active device, which can include PV, battery energy storage systems (BESSs), and loads.

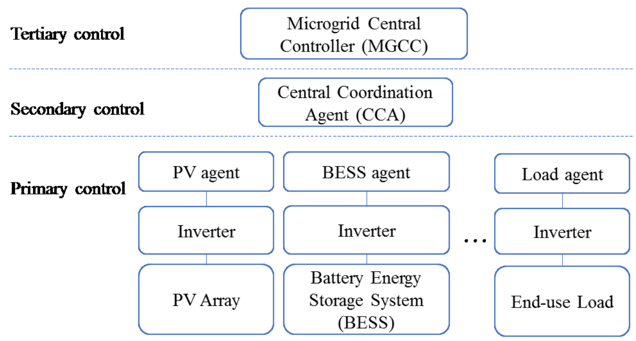

FIGURE 2. Conceptual architecture of a distributed multi-agent system for microgrid frequency control.

This is often accomplished with droop-type controllers, which operate independently on each unit [33], [34]. In extreme cases, load shedding can participate in primary frequency control. Generating units can include rotating machines and grid-forming inverters, if present; grid-following inverters do not support primary frequency control. Primary frequency control operates to arrest the initial decrease in frequency and to partially restore frequency, but does not restore it to nominal.

The secondary control layer is responsible for dispatching assets to restore frequency and voltage to nominal values after the primary control has occurred. In Fig. 2, this is shown as the central coordination agent (CCA). Secondary frequency control can occur using a secondary controller that is not associated with a single generator, such as a Woodward easYgen-3000 controller, or a dedicated microgrid controller [35].

The tertiary frequency control layer re-dispatches units, and possibly changes unit commitment, to restore the reserves that were expended during the operation of primary and secondary frequency control [27]. To achieve an optimum dispatch, tertiary frequency control typically occurs at a unit such as a microgrid central controller (MGCC).

In this type of three-layer system, control is distributed to the multiple agents throughout the system. In general, the failure of a single agent, or the loss of communications between agents, will not result in the collapse of the system. For example, the loss of communications may result in an off-nominal voltage or frequency due to the droop control actions and lack of secondary frequency control, but the frequency and voltage will be stable.

B. BENEFITS OF DISTRIBUTED CONTROL

While a centralized control architecture has the potential for a more complete level of observability and control, distributed control has several benefits [36]:

Plug and Play Capability: When a new device is connected, the control algorithms of a central controller need to be updated to reflect the addition of the new device. In contrast, distributed controls can support the interconnection of new devices without the need to modify other controllers, thus providing greater interoperability and scalability.

Real-Time Functions: It is complex and expensive for centralized controls to perform all real-time functions, due to the high communication burden. In contrast, distributed controls can reduce the data communication requirement and spread the computation burden across the distributed platform(s).

Data Communication Accessibility: Centralized control uses extensive wide area networks (WAN), and needs to accommodate a significant number of messages or packets from all of the devices, which can require significant bandwidth. In contrast, distributed controls use local and asynchronous communication structures, which only require a local area network (LAN) and data exchange.

Cost: Although centralized controls can have lower cost for basic system functions, it can be expensive to expand and include advanced functions after initial deployment. The initial capital cost of distributed controls can be higher, but they can be lower for future changes due to the increased interoperability and scalability.

C. DISTRIBUTED CONTROL PERFORMANCE IN RESILIENCY-BASED MICROGRID APPLICATIONS

Resilience is considered an essential characteristic of next-generation distribution systems. When using distributed controls, the network is less vulnerable to disasters since the decisions are made locally, reducing the dependency on communication with a centralized controller. Additionally, local operation enables fast response during system disturbances. Resiliency applications, such as seamless islanding, fast load restoration, and fast resynchronization, are investigated and their performances discussed below [37]–[40].

Seamless Islanding: In this application, the objective is to seamlessly transition to islanded operation with minimal fluctuations in frequency or voltage. As soon as the circuit breaker at the point of common coupling (PCC) is opened, the DER outputs, as well as emergency demand response, must operate to ensure rotor angle, frequency, and voltage stability, as defined in [41]. In a distributed scheme, the individual droop controls operate to maintain frequency and voltage without communications, and secondary frequency control will restore the frequency and voltage to nominal if a communications infrastructure is available, but it is not required for stable operations. Similarly, tertiary control will restore the operating reserves if a communications infrastructure is available, but it is not required for stable operation.

Fast Load Restoration: In this application, the objective is to re-energize any load that was lost during the islanding process, either as part of the primary frequency response or due to transient conditions. Once the transients from the islanding operation have subsided, the distributed controls facilitate this application by sequentially energizing end-use loads. While some loads may be able to be restored with the distributed controls, limited on-line generation assets may prevent the re-energization of all loads without the operation of secondary and tertiary frequency controls.

Fast Resynchronization: In this application, the objective is to reconnect the islanded microgrid to the distribution system with minimal transients. In a distributed implementation, some level of communications between local agents is necessary to meet the voltage and frequency synchronization requirements across the circuit breaker at the PCC. Once the circuit breaker at the PCC is closed and the microgrid is connected to the utility distribution system, the local agents will operate to achieve the desired function(s) for grid-connected operations.

III. EARLY-STAGE FIELD IMPLEMENTION OF DISTRIBUTED CONTROLS

While there have been many distributed control architectures proposed in [42], few have progressed past the stage of simulation or laboratory-level evaluation. This section examines how OpenFMB has been used to implement distributed controls in laboratory and preliminary field tests by Duke Energy. This work forms the basis for the ongoing full-scale field implementation, which is discussed in Section V.

For many utilities, including Duke Energy, coordinating the operations of DERs is one of the most pressing near-term opportunities for distributed controls [43]. In distribution systems with high penetrations of DERs, the use of a centralized decision-making authority can lead to greater communication infrastructure requirements and time delays in decision making. Additionally, existing central control systems cannot handle the large number of connections that would be necessary to support medium and high penetration levels of DERs [20].

OpenFMB is a framework and reference architecture which enables the coordination of grid edge devices through interoperability and distributed controls [25]. The framework reduces the need for a centralized intelligence or control, and allows management of distribution systems at the circuit level. OpenFMB adapters enable communication between such varied protocols as: distributed network protocol 3 (DNP-3), Modbus, American National Standards Institute (ANSI) C12, Message Queuing Telemetry Transport (MQTT), Data Distributed Service (DDS), IEC 61850 Generic Object Oriented Substation Event (GOOSE) messages, Advanced Message Queuing Protocol (AMQP), and NATS. The OpenFMB adapters have been developed, tested, and placed in the open-source [25]. The following example shows how distributed controls using OpenFMB have been implemented at 12.47 kV primary distribution voltage levels.

Duke Energy operates in regions with rapidly increasing penetrations of non-utility solar PV [44]. As a result, there is significant interest in distributed controls that can coordinate BESS operations to mitigate transients associated with the variability of PV operations. The first field implementation of OpenFMB to coordinate DERs and BESS occurred at the Marshall Test Site [45]. The goal of the implementation was to validate the use of OpenFMB to enable high-speed distributed coordination between PV and a BESS, without the need for a central controller [45]. The following sections examine the coordination of BESS with PV for both a

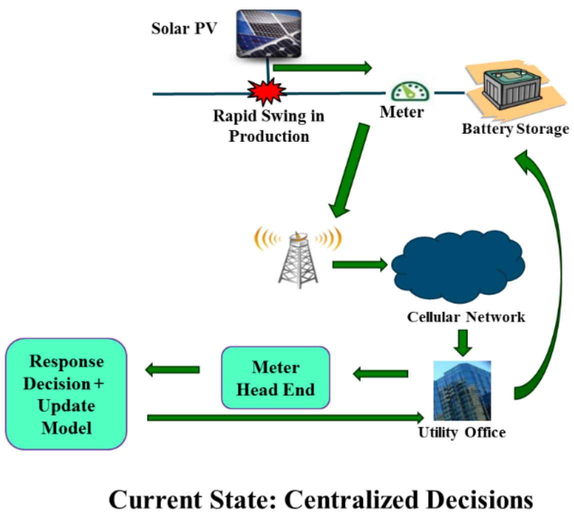

FIGURE 3. Communications path for coordinating BES operations to mitigate solar transients when centralized communications are used.

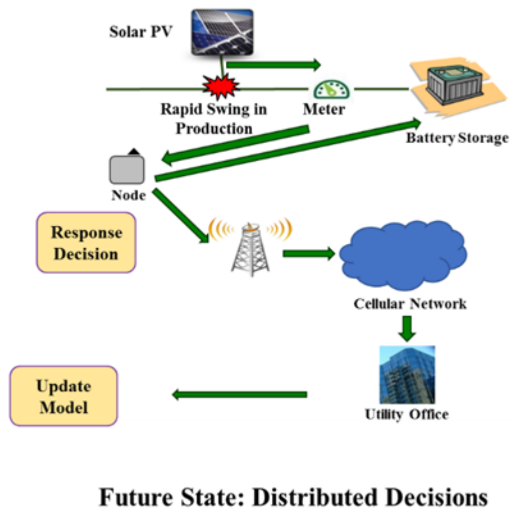

FIGURE 4. Communications path for coordinating BES operations to mitigate solar transients when distributed communications are used.

centralized and decentralized scheme, and examines the impact a decentralized system has on cybersecurity.

A. CENTRALIZED IMPLEMENTATION OF COORDINATING SOLAR AND BESS

Using traditional SCADA systems, the coordination of solar PV and BESS can be accomplished through a centralized control, as shown in Fig. 3. When there is a rapid swing in PV production, this information is communicated to the utility's central control center. The data is analyzed there, and then a response signal is sent to the BESS to mitigate the rapid swing in PV production.

While modern communications systems have the potential to support a small number of solar PV and BESS units in a centralized scheme, the approach of centralized control does not scale well when there are thousands, or tens of thousands, of solar PV units which must coordinate with tens, or hundreds, of BESS units [20]. Additionally, the communications links between the solar PV, BESS, and the control center can span a large geographic distance and rely on multiple communications nodes. Even with the redundancy inherent in modern communications networks, the long distances make the controls susceptible to interruption during extreme events.

B. DECENTRALIZED IMPLEMENTATION OF COORDINATING SOLAR AND BESS

To address the issues of scalability and resiliency, the demonstration at the Marshall Test site implemented a decentralized OpenFMB-based system that allows for the solar PV and BESS to communicate peer-to-peer using a publish-subscribe (pub/sub) messaging pattern, as shown in Fig. 4. This system of Fig. 4 was implemented with Raspberry Pi^{TM}and ODROID-U3 controllers.

The canonical model of the OpenFMB Unified Modeling Language (UML) reference implementation uses data structure classes and hierarchy based on the Common Information Model (CIM), while it leverages artifacts based on the 61850 logical nodes for its semantic vocabulary and attributes. As such, specific values within the OpenFMB UML model for a device can be selected for publishing. Similarly, any device can subscribe to specific OpenFMB UML model entries for any other device. For example, one or more PV arrays can publish their active power output, and these values can be subscribed to by a BESS. This allows the BESS to operate based on the output of a single PV, or a collection of units.

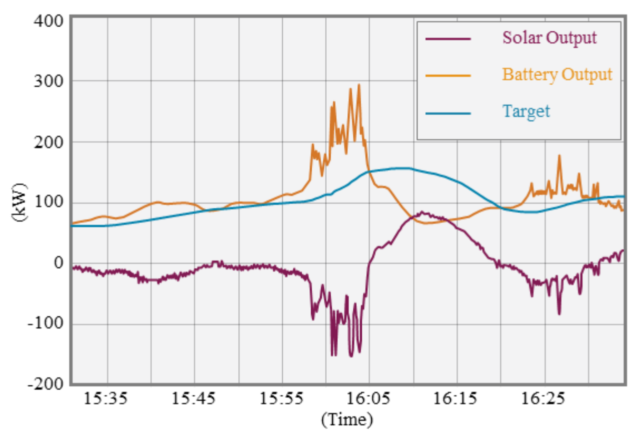

FIGURE 5. BESS Inverter interface for control of active power flow to the distribution circuit.

In this configuration, the rapid fluctuations in the solar PV are published and the BESS, and potentially other devices, subscribe to this information. Using this direct pub/sub messaging pattern, the BESS can quickly take action; there is no need for the information to be sent to the central control center.

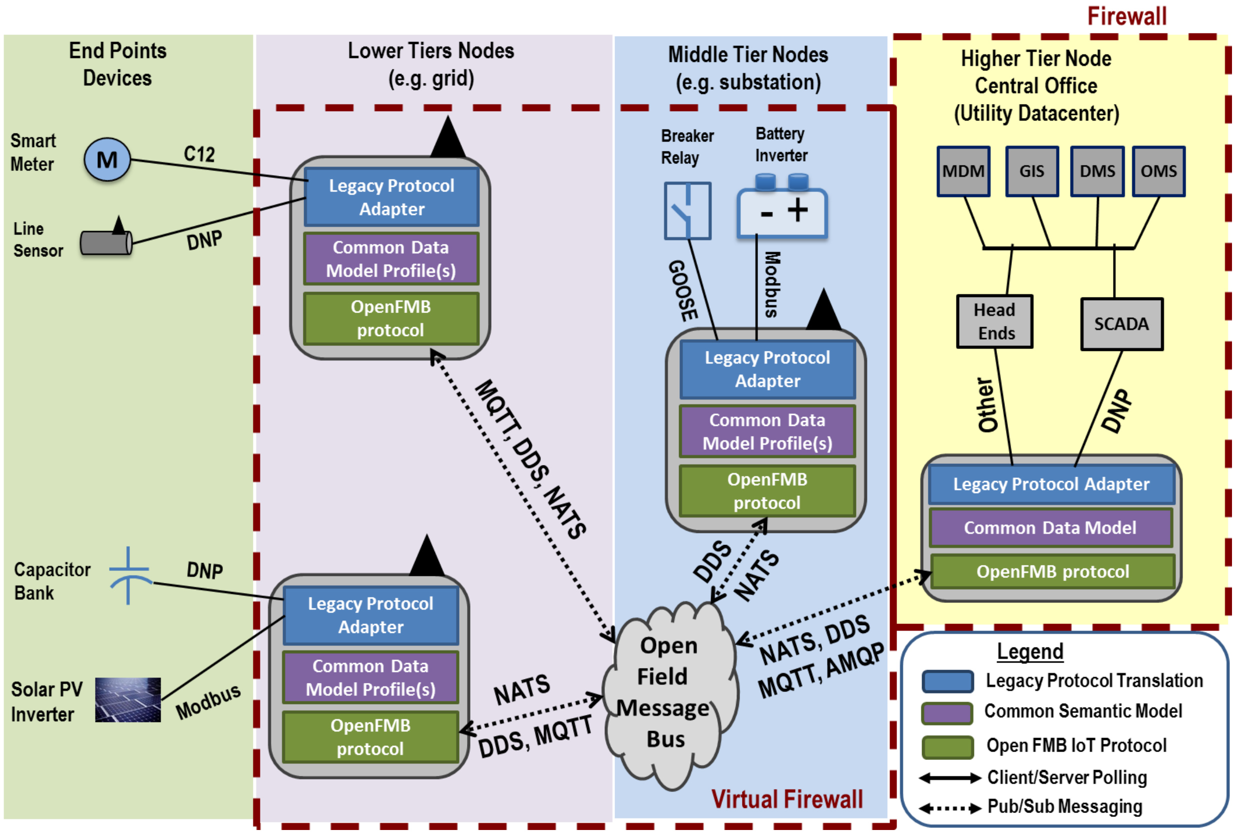

FIGURE 6. Layered architecture of OpenFMB control system.

The fluctuations in the solar PV and the response of the BESS can be recorded in the control center if it is subscribing to the PV and BESS (in particular, if the control center is subscribed to the active power output of the PV and the BESS). Using the pub/sub messaging pattern, it is possible for a wide range of values to be shared between devices, and the pattern to change over time, without the need for dedicated control lines. The ability of the distributed system to coordinate the operation of the BESS to mitigate the variations in solar PV output is shown in Fig. 5.

From the field data shown in Fig. 5, it can be seen that the active power output of the BESS is effectively coordinated to offset the variations in solar PV, maintaining a new target output active power. The target active power output shown in Fig. 5 is an arbitrary time-varying value intended to show the flexibility of the distributed control system; the value could also be kept at a constant value for peak reduction, or other similar functions.

From Fig. 6, it can be seen that the OpenFMB framework allows the simultaneous use of multiple protocols. This is essential in distributed control systems since multiple protocols are often used. For example, distribution utilities in North America use DNP-3 for end-point devices, such as line sensors and shunt capacitors. However, the majority of PV and BESS controllers use Modbus, and smart meters use ANSI C12. As a result, the interoperability challenges associated with coordinating these devices can be significant [20]. This early implementation of OpenFMB-based distributed controls provided a number of lessons learned [46]:

- Open-source, lightweight message bus protocols are not difficult to implement on static embedded telemetry and have the following advantages:
  - Portability, reusability, and modularity
  - Significant reduction in time and effort to deploy
  - Greater interoperability between different vendors
- A pub/sub messaging pattern enables interoperability between different protocols, disparate legacy assets, and information technology (IT) enterprise systems, and has multiple advantages:
  - Agnostic of programming language, operating system (OS), and protocol(s)
  - Agnostic of physical communications medium: Wi-Fi, Cellular (LTE/GSM/EVDO), or PLC
  - Decoupling of physical, network, and logic layers

C. CYBERSECURITY CONSIDERATIONS OF OpenFMB AND DISTRIBUTED CONTROL

As the number of distributed devices increases, so does the level of exposure to cyber-events. The level of exposure is further increased by the fact that the majority of these devices are physically located outside of secure locations, and in

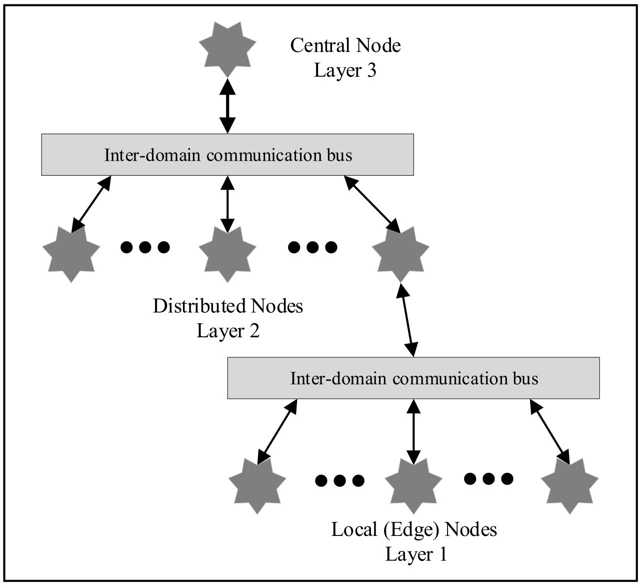

FIGURE 7. Laminar architecture concept.

many cases are not utility owned. To address this, the pub/sub messaging pattern allows for the implementation of device whitelisting and the use of encryption at various layers of the open system interconnection (OSI) model. Additionally, the devices shown in Fig. 6 are implemented with trusted platform module (TPM) 2.0 modules, using X.509 certificates. With these features as part of the implemented system, it was determined to be more secure than the existing centralized SCADA systems.

IV. LAMINAR ARCHITECTURE

The previous section reviewed how distributed controls have been implemented to coordinate the operations of a single PV array and a single BESS. As the number of distributed devices and systems increases, it is necessary to develop an architecture that can scale. This section discusses how laminar control architectures can be used when there are numerous distributed devices and systems [23], [24].

Laminar architectures are a form of hierarchical architecture, but with the addition of specific constraints on the interactions between layers. The constraints on the interactions between layers are meant to facilitate interoperability and scalability. The constraints on interactions between layers take two forms: the layering of controls, and the decomposition of objectives into sub-objectives, or sub-problems, with constraints coupled between layers [23], [24]. By implementing these two concepts, laminar control systems enable the coordination of centralized and distributed controls, while ensuring that control roles are well defined, and message traffic is properly structured and minimized. Additionally, coordinating the constraints and information exchanges between layers, instead of sharing all information, ensures interoperability when there are large numbers of devices connected, and when there are mixed ownership models [23]. Laminar coordination may be thought of as an architectural formalization of the structure and connectivity associated with optimization and control techniques, such as primal and dual decomposition [23].

In addition to traditional controls systems, a laminar coordination framework can be extended to include transactive energy concepts. An example of an architecture which coordinates the operation of centralized, decentralized, and transactive systems into three laminar layers of controls is shown in Fig. 7, with each layer operating to achieve its own layer level goal(s), and managing the constraints and data exchange between layers.

While the laminar architecture uses the same physical peer-to-peer communications and message bus shown in Fig. 6, layers exist at the functional level as well as the physical level, and constraints are coupled (exchanged) between layers. The three layers used for the laminar architecture, along with their objectives, are discussed in the following sections.

A. LAYER 1: LOCAL (EDGE) DEVICE OPERATIONS

Layer 1 represents the range of operations that occur at the local or edge-devices. Operations at this layer are based on local measurements and pre-programmed device set points. These operations can include, but are not limited to, voltage regulator tap operations, recloser operations, PV maximum power point tracking, local microgrid operations, changes in inverter output, and changes in electric vehicle charging. For example, a recloser would sense local current and operate based on the current protection settings to allow momentary faults to clear and/or to isolate permanent faults.

B. LAYER 2: DISTRIBUTED DEVICE COORDINATION

The second layer of the laminar coordination is the distributed coordination of aggregated individual devices which are associated with a group. Operations at this layer can be achieved with peer-to-peer communications, so that there is no need for communications to go through a central location. By coordinating the operations of individual devices with a distributed layer, the system can maintain a greater level of functionality if the communications link(s) to the centralized system is lost. For example, reclosers could adaptively change their protection group settings based on the status (OPEN/CLOSED) of other local reclosers. Layer 2 operations are coordinated to ensure harmonization with Layer 1 operations.

C. LAYER 3: CENTRALIZED OPTIMIZATION

While the distributed coordination of Layer 2 provides significant benefits, one of the single greatest advantages to centralized control is the ability to use all available data and the computing capabilities commonly found at the control center to achieve a greater level of optimization [20]. Central optimization can include, but is not limited to, coordinated Volt/VAR Optimization (VVO), short term load forecasting, optimal dispatch of DERs, coordination of DERs for ancillary services, and optimal reconfiguration. The objective at Layer 3 is to provide computationally- and data-intensive optimized solutions to system-level objectives which are not time critical, with operations taking over one-minute. For example, the optimal status of reclosers can be determined as part of a centralized self-healing system. Layer 3 operations are coordinated to ensure harmonization with Layer 1 and Layer 2 operations.

D. COORDINATION BETWEEN LAYERS

The coordination of information between layers can be divided into data and control signals that move between each layer. The goal is to define the minimum amount of information that must be transferred to achieve the optimization objective. One of the key features of OpenFMB is that it is specifically designed to synchronize and validate data [25]. Therefore, OpenFMB is able to achieve operational objectives at each layer, and to exchange the minimum necessary set of data to coordinate operational objectives across layers. As such, OpenFMB is a well-suited framework for implementing a laminar control architecture, as will be shown in the following section.

V. CONCEPT OF OPERATIONS FOR RESILIENCY-BASED FIELD IMPLEMENTATION

Building on the past field implementations discussed in Section III, and utilizing the laminar architecture discussed in Section IV, this section presents an architecture that is currently being implemented to address existing operational challenges at Duke Energy. The operational challenge is the interactions between moderate to high penetrations of solar PV and their potential interactions with centralized controls. Specifically, a system is being implemented by Duke Energy to enable a centralized self-healing system to be deployed in regions with moderate to high penetration of solar PV, which can include one or more microgrids. For this project, a moderate penetration of PV is defined as nameplate capacity of PV being 25%–49% of the circuit peak load, and high penetration as PV nameplate capacity exceeding 50% of the circuit peak load.

The presented architecture is being implemented to operate four 12.47 kV distribution circuits, which are supplied from two substations. The four circuits are part of a centralized self-healing scheme that can control 4 circuit breakers and 12 reclosers; overhead switches are also present but require manual operation by line crews. In addition to the switching devices, there is an inverter based utility microgrid and non-utility rooftop solar at two locations. The utility microgrid is designed to supply a local civic center during major storm disruptions, while the non-utility rooftop solar is designed to support their commercial owners. The civic center is considered a critical load because it acts as an emergency staging area for the region during extreme events. A reduced order one-line diagram of the electric distribution system is shown in Fig. 8.

The locations of reclosers in Fig. 8 were selected by Duke Energy planning engineers to follow a "4-3-2" rule of thumb. Specifically, each segment, defined as the circuit length between reclosers, will have no more than 400 customers, 3 miles of overhead conductors, or 2 MW of end-use load. The 4-3-2 rule of thumb was developed by Duke Energy as a general design guideline which is intended to limit the amount of the system which will be impacted by a single fault.

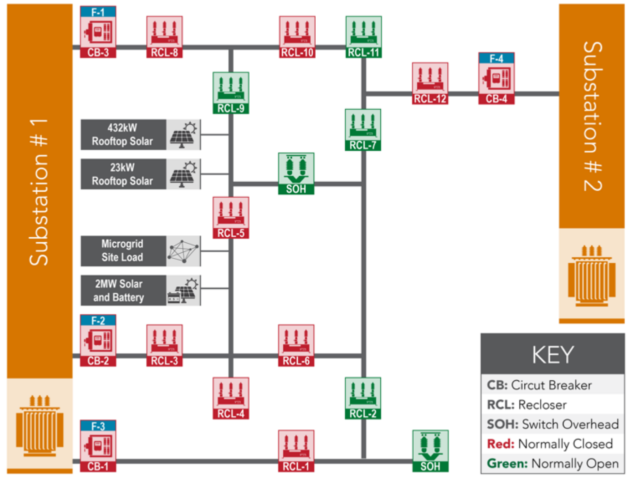

FIGURE 8. Reduced order one-line diagram of Duke Energy circuits.

The challenge with the system shown in Fig. 8 is that while the 4-3-2 rule of thumb provides manageable segments for reconfiguration, there are a large number of DERs that are operating in conjunction with a self-healing system, a utility-owned microgrid, and non-utility solar PV. Therefore, it is necessary to implement a control system that can properly coordinate the operations of the various distributed and centralized systems. In particular, it is necessary to be able to quickly isolate faults, ensure proper protection coordination is reestablished after switching operations, and to be able to optimally reconfigure the system. Additionally, it is desired for the system to use transactive energy signals to incentivize non-utility assets to support switching operations for reliability and resiliency. These functions correspond directly to the three layers of laminar architecture discussed in Section IV, and shown in Fig. 7.

A. OpenFMB HARNESS

To implement the laminar architecture described in Section IV, the work presented in this section uses OpenFMB, implemented into a control structure referred to as the OpenFMB Harness. The function of the OpenFMB Harness in the Duke Energy implementation is to act as a communications message bus, as shown in Fig. 9. In this implementation, it is referred to as a harness because there are numerous devices that can be connected, and it is more than a single message bus. For the system shown in Fig. 8, a leased wireless Long-Term Evolution (LTE) communications infrastructure is used, with over 100 cellular nodes covering the area served by the distribution circuits. Unlike the demonstration discussed in Section III, utility devices are integrated with COTS Remote Terminal Units (RTUs), instead of the Raspberry

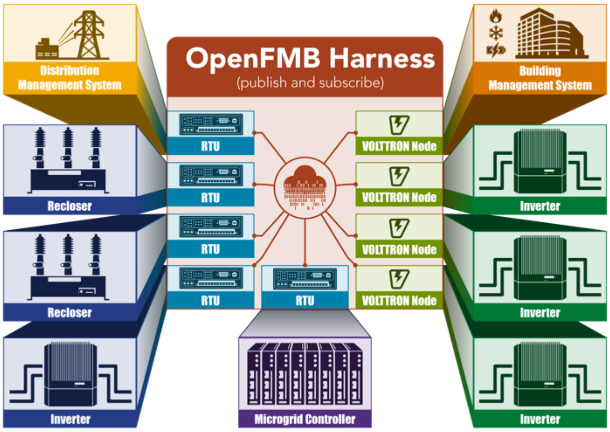

FIGURE 9. **Structural view of the OpenFMB Harness being deployed on the system shown in Fig. 8.**

Pi™ and ODROID-U3 controllers. Non-utility devices can be connected to the OpenFMB Harness using COTS equipment, but they do not require a full RTU. For this implementation, COTS controllers running VOLTTRON nodes are used for non-utility devices [47].

The use of COTS equipment for utility devices is essential for the end goal of improved reliability and resiliency, since these devices are hardened for ICS applications. The OpenFMB adaptors are run on each COTS controller using open-source software as a containerized application. The COTS controllers, and their containerized software, communicate peer-to-peer via the LTE network. In this way, it is possible for various devices and systems to communicate directly peer-to-peer, as part of the laminar architecture. The use of open-source software running as a containerized application on COTS controllers also increases the portability of the architecture. Specifically, the use of open-source software and COTS controllers make it practical for most utilities to implement a system with similar capabilities.

While not shown in Fig. 9, it is possible for numerous other device types to connect to an OpenFMB Harness. These could include, but are not limited to, shunt capacitors, voltage regulators, remote sensors, and phasor measurement units (PMUs). These devices are not included in Fig. 9 because they are not part of the control system being deployed to operate the distribution system of Fig. 8. The next section provides an example operational case from the concept of operations (CONOPS) for the system in Fig. 8

B. EXAMPLE CONOPS FOR LINE-TO-GROUND FAULT

While the full CONOPS contains numerous operational use-cases, this section provides a generic description of operations for a line-to-ground fault that results in the operation of protection devices, reestablishment of protection coordination, and subsequent reconfiguration by the self-healing system after engaging a transactive energy signal. These operations correspond to the three layers of laminar control discussed in Section IV.

The primary protection scheme for the circuits shown in Fig. 8 is based on overcurrent detection, with reclosers acting as the primary protection and sectionalizing devices on the three-phase primary [47]. In this case, fuses which protect single-phase laterals are not considered part of the laminar control system since they do not have any communications or control capabilities. Only protection devices on the three-phase ''backbone'' of the circuits are part of the active control system; i.e., substation circuit breakers and reclosers.

Traditionally, overcurrent protection works well on radially-operated systems with substantial fault current. However, overcurrent schemes face challenges with the presence of DER, automated restoration schemes, and the potential for portions of the system to operate as islanded microgrids [48]. In a highly-dynamic system such as this, the fault current magnitude and direction can vary depending on system configuration, status of the microgrid, and DER output.

To account for the highly-dynamic system conditions, adaptive relay ''setting groups'' are implemented in the circuit breakers and reclosers to allow the protection system to be flexible enough to handle different system configurations. Setting groups allow a protective device to change its protective settings based an external input. Protective settings stored in each setting group are pre-calculated by Duke Energy protection engineers based on expected configurations of the system and ranges of DER performance. The group settings are programed locally at the RTU or transmitted via SCADA. Once set, the individual reclosers can change between settings groups based on local information from current transformers (CTs) and potential transformers (PTs), external inputs such as breaker or microgrid status, or based on commands from the central distribution management system (DMS). The communications infrastructure supports determining the currently-appropriate setting group, but its operation is not necessary during the fault clearing process.

Traditionally, the command to change to a different setting group is either based on local information, or from a signal dispatched from a central control system, such as a DMS. A centrally-dispatched command requires a robust communication channel back to the central system for both command and monitoring. Even with a robust communication channel, communication delay and a delay switching between setting groups can impact protection system performance under rapidly changing conditions, such as those expected during extreme events.

As previously discussed, OpenFMB enables peer-to-peer communication between protective devices and other system devices, as part of Layer 2, lowering communication delays, reducing the dependency on a centralized system, and allowing for greater flexibility. Rather than waiting for a command to change settings groups from a centrally dispatched system, protective devices may subscribe to relevant data from neighboring devices, such as recloser status, and change their setting group based on this information. This is done using the pub/sub message pattern implemented in the OpenFMB

Harness. For the system being deployed, all reclosers publish their current status information (OPEN/CLOSED) and each recloser subscribes to the other reclosers and circuit breakers. Additionally, reclosers subscribe to various values for the microgrid and other DERs, to determine the range of available fault currents. This ensures that each protective devices knows the current topology of the system, as well as the available fault current, and can select the appropriate set point group based on this information.

As a result, whether the topology change is due to a command from the DMS, automated reconfigurations, or unforeseen events, the protective devices can quickly and reliably adjust the setting group to ensure proper protection coordination as the system conditions change. Additionally, as protection devices are updated, any relevant information available via OpenFMB may be utilized by these protective devices, without the need for significant architectural changes or updates to utility communication, information technology, or SCADA systems. All that would be required is a change of values to the semantic model within the device.

An example using the system shown in Fig. 8 follows. A permanent three-phase line-to-ground fault is located within the segment bounded by RCL-8, 9, and 10, and is initially isolated by the operation of RCL-8. This includes three operations of the recloser in an attempt to clear temporary faults, with the unit going into a "locked out" state on the third operation. This is an example of a Layer 1 action in the laminar architecture as depicted in Fig. 7.

As soon as RCL-8 opens in the locked-out state, it publishes its new position on the OpenFMB Harness. All devices subscribing to the status of RCL-8 register the change in state and evaluate whether they need to change their setting group to maintain proper protection coordination. The distributed sharing of information to ensure proper protection coordination is an example of a Layer 2 action. If for some reason there is a failure in the communications infrastructure supporting the pub/sub exchange of information, protection coordination would not be updated. However, the Layer 1 device actions would still occur based on the most recent information, and the fault(s) would be isolated. The worst case scenario is that the miss-coordination results in additional end-use customers being unnecessarily isolated.

Once the central control system, the self-healing application within the DMS, registers the change in status of RCL-8, it will begin an optimization to determine if the system should be reconfigured to achieve the objectives of the optimization. While the specific algorithms of the optimization are proprietary, the high-level goal is to restore power to the greatest number of end-use customers while maintaining operational constraints; e.g., voltage magnitudes and line flows. The centralized optimization can take up to a few minutes and is example of a Layer 3 action. If the centralized optimization determines an acceptable reconfiguration sequence, then the appropriate OPEN/CLOSE commands are issued to the associated reclosers via a DNP-3 signal over SCADA. As the position of each recloser changes, protection coordination is maintained via subsequent Layer 2 operations.

If the centralized self-healing system determines that the reconfiguration options currently available are not acceptable, due to limited switching options, it can engage the non-utility DERs, via transactive energy controls, in an attempt to provide more switching options. There are two primary reasons why the centralized self-healing system could determine that a recloser cannot be operated. First, it may not be able to close a recloser because there is an excessive phase angle and/or voltage difference across the unit. Second, a switching operation could lead to a series of segments, or a microgrid, supplying a level of load that is not desirable. An undesirable load level could either be a violation of a thermal limit, or a microgrid needing to supply power at a level that cannot be supported for the required period of time. While the transactive energy signal is not discussed in detail, it functions to incentivize the non-utility assets to operate in a way that increases the number of switching options available to the centralized self-healing system.

The device operations to isolate a fault, restore coordination, and to optimally reconfigure the system engage all three layers of the laminar architecture. Faults are isolated at Layer 1 via high-speed local device operations. Protection coordination is reestablished using the peer-to-peer communications scheme of OpenFMB at Layer 2. Central optimization for reconfiguration, and the possible engagement of transactive control, is implemented at Layer 3. These operations are consistent with the generalized laminar architecture show in in Fig. 7.

VI. SUMMARY

This paper has presented an architecture for distributed power system controls that increases operational flexibility by coordinating centralized and distributed control systems. The presented architecture is based on laboratory experiments, field implementations, and an ongoing deployment. Using COTS equipment and containerized open-source software, the system is able to provide additional operational flexibility to improve the reliability and resiliency of electric distribution systems. The presented implementation enables the coordinated operations of utility and non-utility assets in the form of self-healing systems, microgrids, and distributed PV, but it is extensible to a wide range of centralized and distributed systems. The combination of open-source software, a standards-based approach, and its extensibility to a wide range of centralized and distributed technologies makes the presented work applicable to utilities around the world.

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