Adaptive Control Strategies and Communications for Utility Integration of Photovoltaic Solar Sites

Michael Mills-Price
Advanced Energy Industries, Inc.

Michael Rourke and Darrin Kite
Schweitzer Engineering Laboratories, Inc.

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Michael Mills-Price, *Advanced Energy Industries, Inc.*
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***Abstract*—The integration of photovoltaic (PV) solar sites and other distributed energy resources (DERs) into utility control systems is an increasingly important topic as the penetration levels of these resources continue to increase. The evolving regulatory and operational landscape between DER operators and regional utilities is creating opportunities for DERs to be used in grid support activities. The inherently fast-acting characteristics of inverters make them especially suited for short-duration sourcing and sinking of reactive power. This paper discusses how to address the communications integration and activation of adaptive control strategies for these DER sites. An integrated control solution needs to address methods of collecting wide-area power system state information in such a way that the feedback is available for potential control strategies. Network topology, communications protocols, time coherence, and data update rates are considered. Additionally, PV sites can operate in a number of different control modes based on grid conditions and available solar radiation. These modes can include power factor matching, power factor correction, voltage support, and net metering, among others. This paper presents an overview of the control and monitoring infrastructure necessary to support emerging PV control methodologies.**

I. Introduction

The adoption of distributed energy resources (DERs) into the electric power distribution system has increased rapidly over the past decade. This trend has accelerated greatly in the past few years, with photovoltaic (PV) power production playing an increasingly important role. The growth in DERs is expected to continue into the future, largely driven by renewable energy portfolio standards (RPSs) and concern over the adverse environmental impacts of hydrocarbon-based energy production. Utilities, especially those in states with aggressive RPS targets, need to adapt to a changing paradigm in which distribution grids are intelligent and multidirectional and contain intermittent generation.

The increased DER deployment into the distribution grid, designed for radial power flow, presents certain technical challenges for maintaining power system stability. Present regulations governing DER integration into electric power systems do not allow these resources to participate in power system support activities. In fact, DERs are mandated to disconnect from the grid during periods of instability, which in some circumstances actually exacerbates the instability. Various industry and regulatory groups have identified this as an area for improvement. The IEEE has established a working group to amend the IEEE 1547 Standard for Interconnecting Distributed Resources With Electric Power Systems to reflect an industry-wide desire for these resources to behave similar to conventional generation. California has the most aggressive RPS that targets 33 percent renewable energy resources by 2020 with a goal of 12 GW of localized electricity generation. California has also recognized the importance of revising the DER technical requirements in California Public Utilities Commission (CPUC) Rule 21 to accommodate the expected rise in DER adoption into the distribution grid [1]. The purpose for revising both IEEE 1547 and CPUC Rule 21 is to allow DERs greater flexibility in grid support activities, which will enhance the reliability of the power system.

In addition to changes in operating practices, grid operators, over time, need to modify the existing infrastructure to transition from a passive distribution model in which energy is pushed from a central location to an active model where generation is located throughout the power distribution network. Such a system requires many intelligent nodes with the dual capabilities of operating autonomously and dynamically modifying operating parameters in response to utility control signals. Power conversion devices are the base components in building this architecture. As an important first step, inverter manufacturers need to design and incorporate state-of-the-art technologies that enable these devices to provide voltage and frequency regulation at the point of common coupling (PCC).

Another important consideration is the communications network that acts as the link between the intelligent nodes located throughout the distribution system. Without adequate communications, it is impractical for automation systems to ascertain the correct system state and react appropriately to changing system dynamics. An interface capable of concentrating communications from power conversion devices and integrating with utility supervisory control and data acquisition (SCADA) systems decreases network bandwidth requirements and mitigates integration issues between different technologies. These interface devices should also be capable of processing automation logic and coordinating the sending of control signals to localized device arrays or devices located across a wide geographic area. Depending on the distribution architecture, there will likely be other components necessary to implement a reliable and dependable power delivery system.

The protection paradigms governing modern distribution systems are also affected by increased DER penetration. While this is an important topic and deserves consideration, it is outside the scope of this paper. This paper describes in detail the component characteristics deemed essential to enable DERs to actively participate in grid support activities and to respond to control signals sent from a utility control center. Control functions deemed essential for grid support are outlined along with discussion of their implementation in power inverter technologies. Methodologies for establishing an effective communications network capable of transmitting data securely and reliably with minimum latency are discussed. Consideration is also given to the data models needed to ensure data coherency between the utility and the DER. Finally, this paper provides an overview of the integration characteristics necessary in a DER control network.

II. Inverter Control Functions

Inverters, as power electronics-based devices, have the capability to rapidly change the characteristics of their output waveforms to respond to grid transient events such as voltage and frequency sags and swells. The inverter itself can control real and reactive power (up to its nameplate kVA rating) in subcycle time frames in an attempt to counteract the grid transients as well as at a longer time scale (continually) to assist in the steady-state operation of the bulk distribution and transmission grid infrastructures. The three primary categories of inverter response are as follows:

- Static or steady-state operation.
- Dynamic operation.
- Trip envelopes and ride-through capabilities.

While these control actions are feasible with modern technology, grid and DER site operators need to remain cognizant of the regulatory environment governing the activation of these control strategies. The following discussion summarizes the most commonly employed inverter control functions.

A. Static or Steady-State Operation

The following functions belong to a class of inverter operating modes identified as static or steady state. These functions respond to an operating set point for an internal inverter parameter, such as output watts or power factor. The unit does not automatically change the operating state based on external measurements in these modes.

1) Fixed Power Factor

To achieve interconnection requirements where system voltage is a concern due to the variability of real power output from the inverter, operators use nonunity power factor operation (either sourcing or sinking VARs). Typical power factor ranges are 0.8 leading to 0.8 lagging; inverters accept this range as a direct set point.

2) Fixed VAR Output

This function provides a means for the inverter to source or sink a specified amount of reactive power, regardless of the real power operating point or power factor. As an example, local transformer and motor VARs can be offset by the inverter. In some cases, this action alleviates demand charges resulting from poor power factor at a PCC or load center.

3) Curtailment (Fixed Real Power Set Point)

In curtailment mode, inverters produce a fixed amount of real output power that is below the nameplate capacity. For no-backfeed interconnection agreements between a utility and DER operator, designers commonly activate this mode to ensure the main breaker stays connected, even under a loss-of-load event, by reducing the real output power delivery of the inverters.

4) Ramp Rate

The physical characteristics of power electronics-based devices allow rapid changes to the output waveform, which can cause harmonic injection and transient behavior at the PCC. The ramp rate setting allows the user to program a rate of change of real power from one set point to the next in an attempt to smooth out deviations in output current.

B. Dynamic Autonomous Functions

Unlike static operations, dynamic functions employ externally measured feedback to maintain an operating parameter within the power system. Either the inverter or master controller (for a fleet of inverters) calculates the error between measured values and set points to control the inverter outputs. The controller collects measurements either locally or remotely.

1) Volt/VAR

In volt/VAR mode, the inverter modifies the reactive power output (VAR) as a function of the measured system voltage. The intent of this mode is that the inverter operates as a local voltage regulator. If the measured system voltage dips below the operating thresholds, the inverter supplies VARs to boost the voltage. Similarly, if system voltage rises, the inverter sinks VARs to reduce the system voltage to within the operating threshold. Inherent to this mode is the capability to either prioritize VAR output or watt output to meet the needs of all the stakeholders. Different hysteresis bands and slopes for the volt/VAR function allow for a more flexible solution to meet local interconnection requirements.

Fig. 1 provides an example of this type of operating curve.

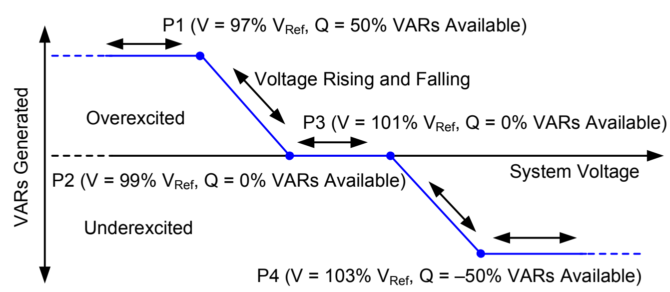

Fig. 1. Example settings of volt/VAR mode using available VARs.

2) Watt-Frequency

Similar to the volt/VAR function, the inverter can modify its real power output in response to measured frequency events and perform droop control to assist the bulk power system in regulating system frequency. This function can be either an open or closed loop and benefits from a programmable droop characteristic that provides flexibility in meeting interconnection requirements.

3) Dynamic Reactive Current

In addition to volt/VAR, the dynamic reactive current function operates on the measured voltage rate of change rather than the actual quantity. This control action helps to stabilize rapidly increasing or decreasing system voltages.

C. Trip Envelopes and Ride-Through Capabilities

Present regulations require inverters to rapidly disconnect from the power system during system events. The disconnection time period is based on the voltage per-unit deviation. The existing IEEE 1547 low- and high-voltage ride-through limits along with the new proposed limits are illustrated in Fig. 2. The black voltage-time curve represents the existing IEEE 1547 limits. The green and red curves are the limits proposed in IEEE 1547a. The green curve represents the must-stay-connected range, while the red represents the must-disconnect limits.

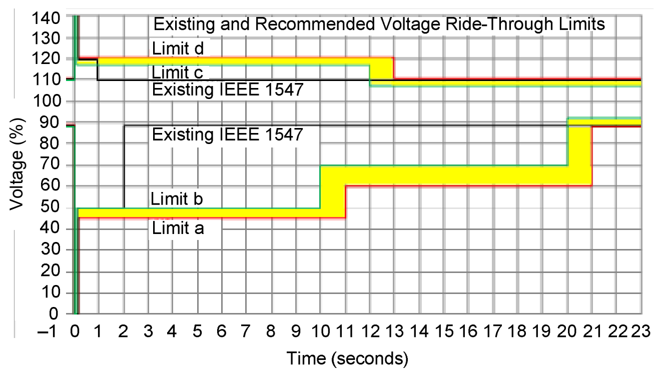

Fig. 2. Existing and proposed voltage ride-through limits.

Similar to the new proposed voltage ride-through limits, the limits proposed by IEEE 1547a for frequency ride through provide greater flexibility in inverter operating conditions. This is becoming increasingly important in low-inertia distribution systems (especially those created by islanded systems) because the frequency tends to drift over a wider range with respect to load. Fig. 3 shows the default frequency-time curve along with underfrequency (UF) and overfrequency (OF) primary and secondary limits, which can be activated by the master controller in coordination with the power system operator.

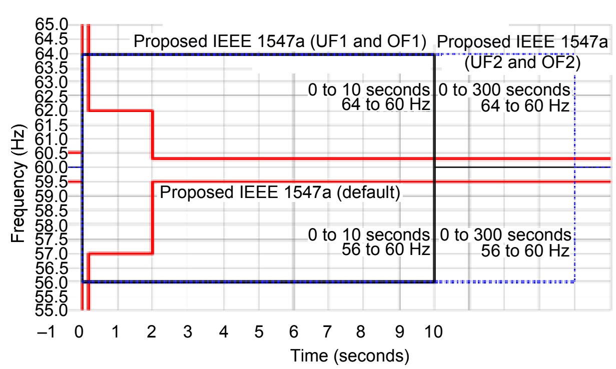

Fig. 3. Proposed frequency parameters in IEEE 1547a.

The changes proposed in CPUC Rule 21 and IEEE 1547a stipulate a large role for DER generation to assist in grid support during events. Industry groups, along with regulatory authorities, are working to harmonize the proposed operating standard to limit the adverse effects of DER installations during power system events. The ability for DER operators to configure trip envelopes allows for a wider variance in inverter operating bounds while preserving the need to coordinate with local system protection.

III. Communication

Under normal operating conditions, advanced functionality in inverters enables these devices to operate autonomously in regulating voltage, frequency, and power factor at the PCC. However, under certain grid conditions, the potential exists for autonomous inverter action to exasperate grid instability [2]. Using communications-assisted control actions to modify operating parameters and send permissive and blocking signals from SCADA gives operators and asset owners the flexibility to respond to changing conditions.

In the existing regulations and current effort to revise the regulations governing DER interconnection, CPUC and IEEE have recognized that communications capability in DERs is an essential functionality [1] [3]. Two key considerations, interoperability and extensibility, should govern the design for the interface between the DER local-area network (LAN) and the wide-area network (WAN) that is responsible for transmitting information to utility SCADA systems and other stakeholder energy management systems (EMSs).

Interoperability is the ability of one or more devices to exchange information without special effort. This is achieved when system designers and integrators use standard data objects, protocols, and methods for transmitting data. Extensibility refers to the ability of a system to accommodate future technological advancements. This is an important characteristic because the capability of devices in the network continues to evolve at a rapid pace and is usually upgradable via software patches. Equipment owners need to incorporate both of these considerations early in the project decision-making process, reducing the likelihood of expensive system upgrades or redesigns in the future.

DER installations are located based on available resources, proximity to existing utility infrastructure, and local financial incentives, among many other factors. When considering future installations, time should be spent evaluating the existing physical constraints—such as the distance to the nearest substation, the legacy communications infrastructure, and the project budget constraints—in order to help select the best communications method for the DER installation. In this context, the chosen method must also fulfill the performance criteria for the given application.

A. Performance Metrics

This subsection describes the performance metrics that should be considered when specifying the communications technology used at the DER site. Note that each performance criterion discussed is not mutually exclusive and each interacts with one another. The asset owners and the interconnected utility must determine the appropriate balance.

1) Throughput

Throughput is the amount of information that is successfully transmitted through a network, usually expressed in bits per second (bps). This parameter contains protocol overhead and message retransmissions due to errors encountered in the network. A more useful performance metric is goodput, which is the amount of useful data or application-level data that reaches the destination application. Carefully consider which communications protocols exhibit the lowest overhead, especially when network throughput is limited, in order to maximize network goodput.

2) Latency

Latency represents the time that elapses between when a message is generated until it is processed in the destination device. The network throughput, message size, and processing required in intervening equipment contribute to message latency. Communicating only the information necessary for the application and reducing the number of intervening nodes reduce message latency.

3) Reliability

Reliability as defined in IEEE 1547.3 includes "reliability, availability, and maintainability of the communication system" [4]. The parameter accounts for software and hardware malfunctions, downtime due to maintenance, and network reconfiguration times. Reliability represents the likelihood of a sent message reaching its intended destination within permitted time constraints.

4) Security

Security describes the ability of a network to protect against unauthorized intrusions. Intrusions manifest as attempts to collect application and user data and/or attempts to disrupt normal communications and system operation. Physical security is achieved by limiting access to physical communications infrastructure such as multiplexers and switches. Cybersecurity is generally a more complex topic that requires careful choices in technologies employed throughout the communications network. Examples of cybersecurity technologies are encryption algorithms, firewalls, password management, and antivirus. There are several protocols that operate at different layers within the Open Systems Interconnection (OSI) communications model that provide mechanisms for securing data transmission. Internet Protocol Security (IPsec), Transport Layer Security (TLS), and Secure Shell (SSH) are examples of popular security protocols for Ethernet networks.

B. Network Technologies

There are many network technologies used in modern communications networks. This subsection is a brief discussion of the technologies that utilities and DER owners are likely to use in WANs and LANs. Understanding the existing technologies deployed in communications networks provides insight into how performance metrics affect DER applications.

1) Wide-Area Networks

a) Synchronous Networks

Time-division multiplexing (TDM) is a long-established method for WAN communication. TDM technology provides the deterministic and high-availability performance required for mission-critical information transfer. Synchronous optical networks (SONETs) and synchronous digital hierarchy (SDH) are examples of modern TDM standards widely used on dedicated fiber-optic networks. These technologies provide a point-to-point communications link that provisions dedicated bandwidth for each application. There are existing technologies that promise 5-millisecond network failover times if the network is configured in a ring topology, as shown in Fig. 4. This provides a redundant path and significantly increases communications reliability.

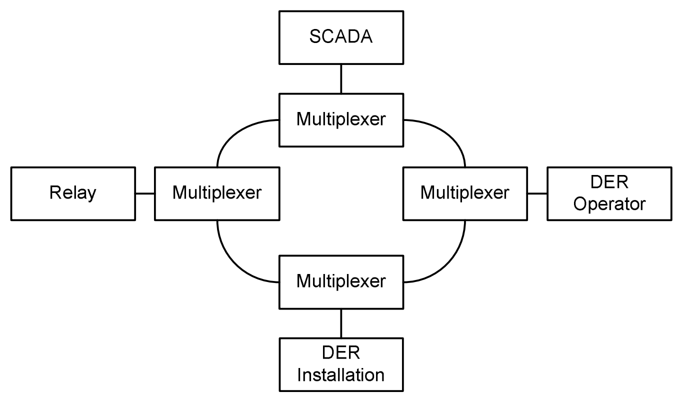

Fig. 4. A SONET ring architecture with multiple access points.

b) Asynchronous Networks

Asynchronous communication in modern WANs is dominated by a group of communications technologies generally referred to as Ethernet. These technologies are widely used in private and proprietary networks and have gained increased acceptance in the electric power industry. Developments in information technology (IT) and the deployment of these technologies into Internet infrastructure have put downward pressure on equipment and installation costs, which has contributed significantly to the rising popularity of Ethernet across a wide spectrum of industries. Many utilities lease communications resources from local service providers that employ Ethernet technologies.

In Ethernet networks, LAN and WAN infrastructure devices (such as managed switches) route data packets through a wide variety of network topologies, depicted commonly as clouds (see Fig. 5). By design, the path a message takes to a destination can be varied and is not known by the end user. Packet rerouting and network reconfiguration are commonplace, and as such, the communication is not deterministic. This makes it difficult for designers to estimate latency and reliability metrics, especially when the network is not owned by the utility. There are several technologies that seek to address the nondeterministic nature of Ethernet, and careful examination of these technologies is required when applications require fast and reliable information exchange.

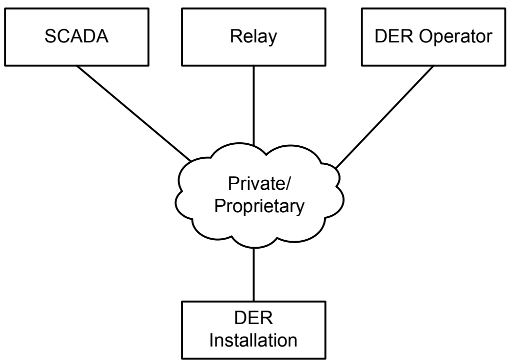

Fig. 5. An Ethernet architecture.

2) *Local-Area Network*

The LAN that links the intelligent electronic devices (IEDs) throughout a DER installation is an asynchronous network that incorporates either serial (EIA-232, EIA-485, EIA-422) or Ethernet communication, or a combination of both. The installation of Ethernet communication in power system architectures has accelerated in the last couple of years. This is driven by reduced cabling requirements, the perceived plug-and-play nature of the technology, and adoption of the IEC 61850 communications standard. Ethernet networks are usually characterized by routable protocols, high bandwidth, and interfaces capable of supporting multiple protocol sessions simultaneously. Additional infrastructure (i.e., switches and routers) supports the interconnection of devices within the communications topology. In many cases, Ethernet network designs require segmentation of traffic from devices into virtual LANs (VLANs) to reduce the processing burden at the network interface controller and improve reliability. Although Ethernet has been the main topic for discussion recently, serial communication still provides many benefits, such as point-to-point topologies, accessibility to serial protocols, and proven troubleshooting methodologies.

3) *LAN-to-WAN Interface*

As mentioned previously, the link connecting LANs to WANs is largely determined by the physical constraints of the DER installation. Fiber-optic cables offer fast data rates and immunity to electromagnetic interference and ground potential rise. The cost to install fiber may be prohibitive for DER installations far from utility interconnections. Point-to-point or point-to-multipoint wireless radios offer a good alternative to fiber, and 38.4 kbps data rates are available in existing technologies.

It is important to engage the IT and operational groups of both the utility and DER operators to determine the procedures for accessing and exchanging data with the DER LAN. Information exchange agreements should define standard security practices, protocol support, available data sets, and procedures for activating control strategies.

IV. INFRASTRUCTURE

In order to enable flexible DER control strategies between utility operators and DER sites, the infrastructure of IEDs in the network needs to exhibit some minimum integration functionality. Advanced consideration of device capabilities during installation or upgrades by system designers minimizes rework or field upgrades at a later time.

A. Data Concentrators

PV inverters have almost exclusively used Modbus® for the small amount of integration previously available. The referenced CPUC report includes a detailed discussion about gaining greater integration of PV sites into wide-area SCADA systems by designing standard interfaces and protocols into PV systems [1]. The report authors express concern that without standard interfaces, new DER installations will begin operating with a wide variety of communications methods, none the same, creating a bottleneck and potential need for many equipment upgrades in order to make the wide-area system work harmoniously. The proposal is to create one standard integration method and encourage all equipment manufacturers and users to take that approach. Due to growing use and an active organizing body, IEC 61850 is the desired approach, and IEC 61850 logical nodes have been created as a model for the DER installations. Additionally, the DNP Users Group published an application note describing a custom profile for using DNP3 as part of PV integration projects [5]. The application note specifically uses IEEE 1815.1 naming so that protocol converters can be used to efficiently map DNP3 data from DER systems into IEC 61850 networks.

As discussed previously, inverters are not the only IEDs required for many control strategies. Microprocessor-based protective relays, revenue meters, and equipment monitors work together in order to perform the necessary feedback, control, and supervisory functions. Even though standards organizations suggest common integration methods, it is not always possible for designers to enlist a common communications mechanism between all of the IEDs in the network.

Data concentrators solve this problem by providing a means for all of these disparate devices to communicate amongst themselves while simultaneously providing a common point of DER connection to SCADA or other master systems.

As shown in Fig. 6, data concentrators support multiple communications interfaces over a variety of protocols. For simplicity, the diagram does not include Ethernet or TDM infrastructure elements. Some equipment manufacturers also provide data concentrators that not only support the protocol mapping functions but also integrate the advanced control capabilities that this paper discusses [6].

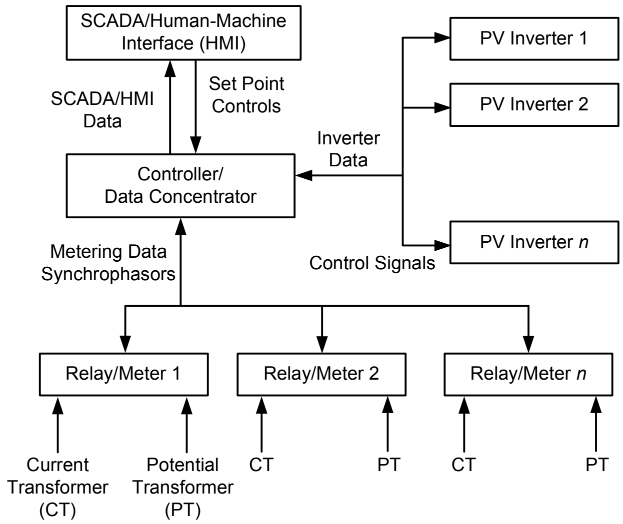

Fig. 6. DER LAN network architecture.

B. Inverters

In order to achieve more than autonomous operation, PV inverters need to be capable of integrated operation via communications protocols and networks. Inverter manufacturers have commonly implemented this service via Modbus protocol for the past few generations of devices. Contemporary models of inverters exist that include Ethernet for integration and configuration. As utility-scale PV integration becomes more prevalent, protocol and media options will likely grow.

C. Protective Relays

Even though their main function is equipment and personnel protection, modern relays are quite valuable as multifunction system monitors and controllers. Based on market feedback, relay manufacturers have deployed advanced communication, user logic, and security into many contemporary devices. Because they reside throughout the network, including at the PCC, relays can be powerful (and almost free) additions to the instrumentation network.

D. Meters and Equipment Monitors

Similar to protective relays, revenue meters and distributed equipment monitors natively include many communications and control mechanisms. Meters additionally provide a detailed feedback mechanism for many types of power system parameters and power quality. To the extent these devices exist at relevant nodes in the power system, they are ready-made for use in future PV control strategies.

E. Synchrophasor Controllers

As previously noted, DER installations are mandated to accurately identify system instability and quickly take appropriate corrective actions. In some cases, the proper response is for the inverter to disconnect; in other cases, the DER facility may be able to actively counteract the power system disturbance (i.e., watt-frequency mode or dynamic reactive current mode). Before any response initiates, the DER master controller needs to measure the dynamic power system state, categorize any disturbances, and determine the needed response.

Previous works on smart island detection describe synchrophasor-based anti-islanding schemes for synchronous generators and PV sites [7] [8]. Controllers for these types of installations need to be able to simultaneously receive synchronized phasor messages from multiple IEDs, communicate with one or more local inverters, and evaluate the smart islanding algorithm. For simplicity and cost-effectiveness, system designers gain the most benefit if the controller also performs the data concentration and protocol conversion functions previously discussed.

In order to understand the significant operational advantages inherent to smart islanding control, we need to briefly summarize the detection algorithm as presented in detail elsewhere [7]. As shown in Fig. 7, the controller receives synchrophasor messages from local and remote relays in the power system. Even though the figure only shows two for purposes of illustration, more IEDs (measuring nodes within the operating area of the DER) may be present, depending on the system topology and performance requirements. For each node of interest, the controller uses the synchronized vector messages to calculate the vector angle between the local (closest node to the inverter) and remote nodes.

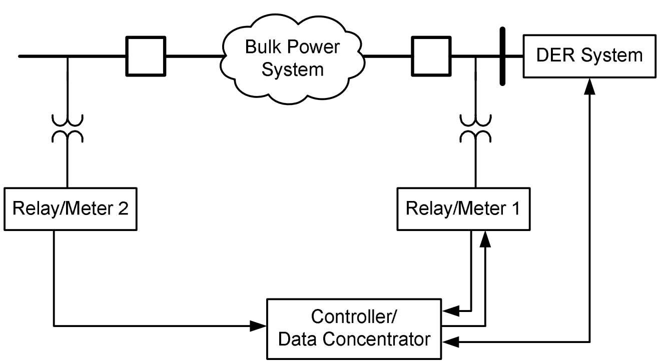

Fig. 7. Master controller connection summary.

The controller tracks the rate of change of that angle, which is labeled slip frequency. If the DER is properly synchronized with the power system, the slip frequency should be very low, with an average of zero over time. The controller also calculates slip acceleration as the rate of change of slip frequency. From the slip and acceleration calculation, the algorithm operates in two ways. First, the slip frequency is compared to the threshold. If the slip exceeds the threshold for longer than a predetermined time, then the algorithm determines that an island exists.

The second method uses both the slip and acceleration in a relationship, as shown in Fig. 8, and identifies an island more quickly than if only using slip as a detection method.

These wide-area island detection methods provide important advantages for quickly distinguishing between events that require DER separation versus transients that could be eliminated using the control mechanisms discussed previously. Synchrophasor-based algorithms also are faster and more selective than the local voltage and frequency-based methods commonly employed at modern PV sites.

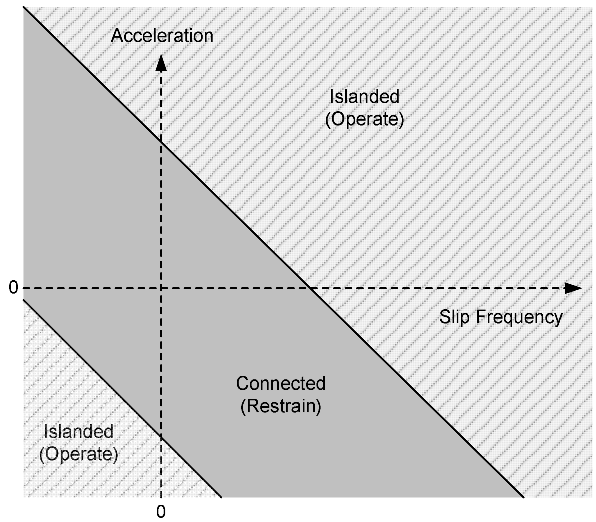

Fig. 8. Islanding detection characteristics [7].

In addition to islanded conditions, DER installations need to properly identify and mitigate negative consequences during unbalanced conditions. Either during single-line-to-ground faults or single-pole tripping on longer transmission lines, standard power control strategies for inverters introduce unacceptable overcurrent and VAR oscillations to the power system [9]. The synchrophasor-based controller that provides smart islanding supervision also has the needed phasor information to calculate symmetrical components and identify an unbalanced condition. Depending on the regional operating standards and capabilities of the inverters in operation, the controller can automatically respond during an unbalanced condition.

F. Additional Control Functions

In addition to detection for island and unbalanced conditions, DER controllers need to support a number of other supervisory and custom logic functions.

1) Priority Control Modes

As discussed in previous sections, there are multiple control strategies available for the operation of DER installations, depending on power system conditions and the standards of the DER owner and local utility. In some cases, more than one control function can be active that would simultaneously impact the same inverter parameter, such as output watts. In those cases, the master controller needs to arbitrate which control functions can remain active and which reference signals take priority. Industry groups have published guidelines for this operation that assist in implementing a common strategy between manufacturers, but the local controller device needs to be capable of processing the control mode commands and determining the appropriate configuration [5]. For example, a command for frequency-watt control takes precedence over dynamic volt-watt operation.

2) Set Point and Control Mode Management

In the simplest form, a DER unit may consist of one controller and a local inverter, but the most flexible and useful configuration is to have one master controller that can actively supervise multiple PV locations over a geographic area. In this way, all of the DER installations can operate in concert with a single command channel to the local utility and SCADA. Additionally, some control functions, such as real power smoothing, depend on a reference power measurement from a remote meter or other IED. The combined controller and data concentrator simplifies all wide-area modes.

3) Logic Engine

While many common mathematical functions and communications protocols reside in controllers and data concentrators, device manufacturers cannot predict or preconfigure the wide array of installations and operating characteristics that may be in use. Therefore, the controller device needs a simple and efficient means for users to employ their own logic and business rules. A controller that includes an IEC 61131-3 logic engine is a popular choice due to the wide variety of programmable logic controllers (PLCs) and general system controllers that use such a standard logic engine. IEC 61131 includes standard programming languages that are widely used throughout utility and industrial automation applications. Users report decreased training costs and improved development times because logic designers do not need to learn new programming languages and techniques for each device in a system.

V. Conclusion

Utilities and system operators are confronted with a new paradigm in how the electric power grid is configured and managed. The presence of variable generation in the distribution grid is a new reality, and entities operating in locations with significant DER generation (more than 15 percent) need to prepare strategies for incorporating this new set of generation in a way that increases reliability, security, and flexibility. The presented architecture comprises several technologies that cross organizational and operational boundaries. The intent of this paper is to present a holistic view of incorporating the various technologies in order to improve system performance and take advantage of emerging regulatory standards. While PV inverters are central to the control architecture, many other IEDs need to work in concert with the inverter in order to successfully implement dynamic control strategies. Additionally, the communications infrastructure needs to exhibit the necessary bandwidth, availability, and security to support the reporting and control functions.

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VII. BIOGRAPHIES

Michael Mills-Price is the technology development lead for the solar energy business unit at Advanced Energy Industries, Inc. Michael is the principal designer responsible for bringing new technologies to market and continues to lead teams toward advanced systems control to broaden the scope and lessen the impacts associated with widespread photovoltaic adoption. Michael received his Bachelor of Science and Masters of Science in Electrical Engineering from Oregon State University (OSU), is a registered professional engineer, and is an active member of IEEE. Michael is also an adjunct professor at OSU, teaching senior level energy storage and energy distribution systems courses.

Michael Rourke received his Bachelor of Science in Electrical Engineering and Masters of Engineering in Electrical Engineering from the University of Idaho. Michael spent ten years working on research and development of control systems for steel and aluminum facilities; he is a member of the Association of Iron and Steel Technology. He joined Schweitzer Engineering Laboratories, Inc., in 2000. Michael works on product development for automation and integration applications.

Darrin Kite received his Bachelor of Science in Renewable Energy Engineering from the Oregon Institute of Technology in 2012. Before joining Schweitzer Engineering Laboratories, Inc. (SEL) in 2012, he worked as an engineering intern at Bonneville Power Administration. He is presently working as an associate automation engineer in SEL research and development.

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