# Advanced Inverter Functions and Communication Protocols for Distribution Management

Adarsh Nagarajan, Bryan Palmintier, and Murali Baggu
National Renewable Energy Laboratory,
Golden, CO, USA

***Abstract*— This paper aims at identifying the advanced features required by distribution management systems (DMS) service providers to bring inverter-connected distributed energy resources into use as an intelligent grid resource. This work explores the standard functions needed in the future DMS for enterprise integration of distributed energy resources (DER). The important DMS functionalities such as DER management in aggregate groups, including the discovery of capabilities, status monitoring, and dispatch of real and reactive power are addressed in this paper. It is intended to provide the industry with a point of reference for DER integration with other utility applications and to provide guidance to research and standards development organizations.**

***Index Terms*—Advanced distribution management systems, enterprise integration, communication protocols**

## I. Introduction

The rapid rise of Distributed Energy Resources (DERs)—such as solar photovoltaics (PV), storage, smart homes, and electric vehicles—simultaneously represents a challenge and opportunity to distribution utilities. Without coordination, DERs could introduce dynamics that interact with existing utility infrastructure in difficult to manage ways. If properly coordinated such smart device have the potential to improve system operations and provide a new asset to the utility operations portfolio.

This paper considers smart inverters—PV, storage or otherwise— that are at least partially controlled by the distribution utility. It both reviews the emerging smart inverter feature set and describes potential challenges and opportunities for utility operations, with a focus on the interactions between smart inverters and Distribution Management Systems (DMSs). Utilities increasingly turn to DMS service providers to help manage increasing amounts of DER within their distribution systems, and are poised to use automation to handle the challenges and opportunities posed by DER. This work discusses the scope and requirements for DMSs to incorporate DERs with a focus on the exchange of information between DER devices and systems, which may monitor, control, maintain, audit, and generally operate the DER devices.

The operational behavior of the existing DMS systems needs a substantial shift to effectively accommodate the functionalities of smart DERs. The following issues can characterize this paradigm shift in management of power systems:

1. The number of interconnected DER systems are increasing rapidly
2. DER systems challenge traditional power system management
3. DER systems could become very powerful tools in managing the power system for reliability and efficiency
4. DER systems are becoming quite smart and can perform autonomously

In parallel, the electric power industry is preparing for higher penetrations of DERs by working collaboratively to develop smart inverter standards and field network protocols that may be used for monitoring and managing devices in the field. But standards to support the enterprise integration (software-to-software) of these device capabilities are still evolving.

There is a need for standardized formats or templates for exchanging data between different equipment and systems. Standard object models, combined with standard service models (methods for sending the data) and standard protocols (the bits and bytes actually send over the communication channel), permit different systems to interact with minimal customization. The combination of object model, service model, and protocol profiles can be termed the "information model".

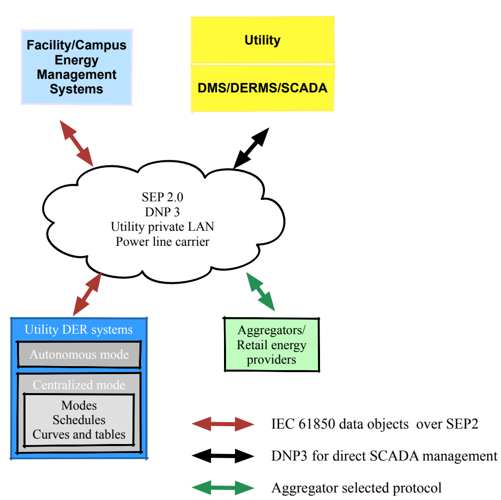


Figure 1 - Comprehensive view of functionalities for the future DMS with enterprise integration of distributed energy resources

A comprehensive view of the functionalities for the future DMS is provided in Figure 1. A DMS can assist utilities in arriving at a decision for centralized operation of distributed energy resources. In order to successfully integrate DMS with a capability to operate DERs, numerous processes



978-1-5090-2157-4/16/$31.00 ©2016 IEEE

should be standardized. Although IEEE standards, IEC standards, and numerous working groups are striving to reach a common point of agreement, there is none yet. Some of the standards in progress are IEEE 1547, IEC 61850, and SEP2 [1-10]. Figure 1 provides a demonstration of an integrated system using all of the existing standards.

This paper reviews advanced inverter features and identifies the need for DER integration with utility operations with a focus on DMS. The purpose of this paper is to discuss the scope and requirements of DMS for the exchange of information between DER devices and any systems which monitor, control, maintain, audit and generally operate the DER devices.

The content is divided under five sections. Challenges and opportunities for integrating DER with utility operations will be discussed in Section II. An exhaustive list of advanced inverter functionalities is presented in Section III. In order to leverage the advanced inverter functionalities information communication technologies are required, which will be discussed in Section IV. The existing state of communication protocols is discussed in Section V. Finally Section VI mentions the emerging standards to accommodate increased DER on the feeders.

## II. CHALLENGES AND OPPORTUNITIES OF INTEGRATING DER WITH UTILITY OPERATIONS

Installing DER devices presents DER owners and utilities with multiple challenges. The main challenge is the interconnection of the DER system to distribution systems that were not designed for two-way real and reactive power flows. As a result DERs can cause over/under voltage challenges, protection difficulties, increased equipment wear, and other issues. These technical challenges are complicated by mixed DER ownership—customer vs. utility vs. third-party—and resulting split incentives. There are three key considerations for utilities and other organizations to utilize DER effectively:

1. DERs that are not connected to communication infrastructure should be captured by utility DMS and related tools along with some indication of known static information such as PV location and output capacity. DMS and related tools should also be prepared for DER powerflow impacts that may complicate load allocation and other estimation techniques.
2. Communication connected DERs require timely and efficient exchange of critical and relevant information. For instance, some information may be collected once a month, such as meter reads of DER usage, and maybe perfectly adequate.
3. Communication connected DERs need to be intelligently integrated into existing control schemes along side current utility control equipment such as capacitor banks and tap changing transformers. New approaches to conservation voltage reduction (CVR) and integrated volt-var control (IVVC) schemes may be needed to optimally use the unique features of DERs.

For efficient operation of communication connected DERs, multiple stakeholders must work in agreement. Responsibilities and the necessary communications between stakeholders are provided in Figure 2. The list of DER stakeholders includes:

1. DER owners
2. Marketers or energy service providers
3. Distribution system operators
4. DER operators
5. DER system
6. Telecommunications maintenance

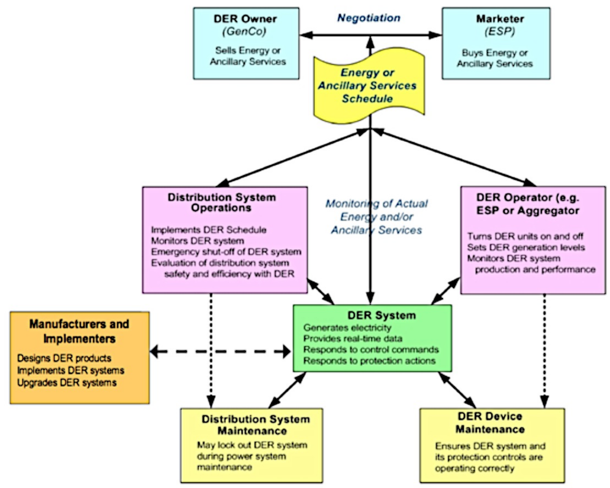


Figure 2 - Responsibilities of DER stakeholders

## III. ADVANCED INVERTER CAPABILITIES

Inverter-based DER functions range from simple (turn on/off, limit maximum output) to quite sophisticated (volt-VAR control, frequency/watt control, and low-voltage ride-through). They also can utilize varying degrees of autonomous capabilities to help cope with the sophistication [11]. Some of the available/expected functionalities in advanced inverters include:

- Maximum generation limit
- Fixed power factor
- Intelligent volt-VAR
- Volt-watt
- Frequency-watt
- Watt-powerfactor
- Price or temperature driven
- Low/high voltage ride through
- High penetration circumstances
- Systems with poor power quality
- Low/high frequency ride through
- Dynamic reactive current
- Real power smoothing
- Dynamic volt-watt
- Peak power limiting
- Load and generation following

978-1-5090-2157-4/16/$31.00 ©2016 IEEE

The fixed power factor mode provides a simple mechanism to absorb/provide reactive power to offset potential voltage rise/drop from real power injection/absorption. Although more intelligent Volt-VAR functionality is preferred looking forward, inclusion of this function was viewed as a necessity for the present. Intelligent voltvar mode is intended to provide a mechanism through which a DER may be configured to manage VAR output to directly support the local service voltage. Typically, volt-VAR mode is designed in a way that Watts take precedence over VARs. Alternatively, VAR-priority can provide reactive power support for local operations by slightly backing off on watts as voltage rises, enabling more VAR capability to be available.

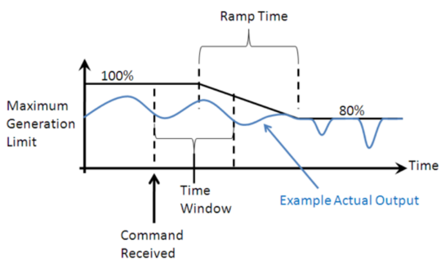


Figure 3 - Depiction of maximum generation limit functionality

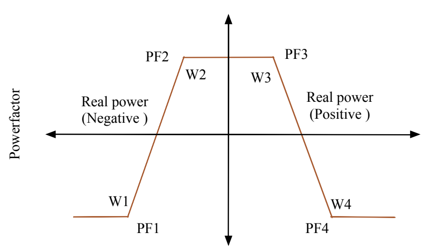


Figure 4 - Depiction of watt-powerfactor functionality

## IV. Information and Communication Architectures

DER systems are capable of providing many functions that support power system operations. Many of these inverter-based functions are described in the *Advanced Functions for DER Systems Modeled in IEC 61850-90-7* [11]. Most DER systems can or must operate autonomously in order to meet power system safety, reliability, and efficiency criteria, but communications can provide additional functionality. The five types of architectures envisioned are as follows:

### *A. Autonomous DER response to local conditions*

In this architecture, DERs operate autonomously using pre-set parameters and/or schedules without any remote communications. Autonomous DER systems respond "instantaneously" to locally sensed conditions such as voltage, frequency, and/or temperature. These pre-settings may be updated as needed (not in real-time), possibly through the Internet or through other communication methods. Autonomous DER systems can also be scheduled for different actions at different times of the day or week, potentially including randomized responses to diversify timing. This would prevent sudden shifts by multiple DER systems to changing conditions. Both "ride-through" and anti-islanding tripping are always autonomous emergency actions.

### *B. DMS direct interactions with DERs*

Here the DMS directly sends control settings to DERs similar to signals sent to existing utility control devices. For large numbers of DERs a dedicated DER management system (DERMS) takes on the actual role of DER communication to provide better scaling, support logical grouping of DERs, and simplify the use of non-SCADA protocols. The DMS may either update the autonomous settings for each DER system or issue direct commands. On start-up, DERs may adopt a default set of autonomous settings that are modified over time by the DMS/DERMS in response to utility needs or potentially pricing signals.

### *C. Utility broadcast/multicast*

Similar to direct DMS-DER interactions, a one-way broadcast of setting can be used to control DERs. These notifications could be direct settings requests or more likely mode changes, emergency commands, or price signals. Generally, no direct communication response would be received from individual DER systems. A key issue with broadcast architectures is uncertainty. Since actions are requested without necessarily knowing which DER systems can or will respond, the response will best be modeled as stochastic. Instead system-level changes are expected (e.g. reduced generation), would be monitored at the substation or other metering points. Financial settlements would likewise occur separately using existing meters.

### *D. Aggregator-based interactions*

Common scenarios include a campus DMS coordinating many DER systems on different buildings or an energy service provider managing disparate DER systems within a community. Optionally, some DMS could aggregate DER information for use by utilities, including current and forecast energy and ancillary services capabilities. Critical DMS that manage the larger DER power plants (including virtual power plants (VPP)) and substation DER systems would interact more directly with utility operations.

### *E. Distributed control approaches*

In addition to these fairly traditional, centralized controls architectures, there is considerable active research [12] into approaches where DERs communicating peer-to-peer without centralized control to achieve comparable or improved system performance relative to more traditional central or hierarchical architectures.

## V. Communication protocols for DERs

As the level of distributed generation increases on the electric power system, the distributed generation sources may be called upon to perform additional functions that are not defined in the current version of the IEEE 1547 standard. It is expected that future grid codes will contain allowances for an expanded set of DER functions, and some of these additional functions may be implemented and controlled through communications (from a utility or grid/micro-grid controller or from a facility control system or customer input) and/or from firmware installed in DER device(s).

The International Electrotechnical Commission (IEC) published a Technical Report [4] (IEC TR 61850-90-7) largely based on this on-going effort, and has become the basis for possible enhancements to the IEC61850-7-420 standard. This work is also supported by US National Institute of Standards and Technology (NIST) as part of the Smart Grid Interoperability Panel (SGIP) Priority Action Plan 7. This effort is also of interest to the commercial communications protocols community. For example, a DNP3 Application Note (DNP 2010) was written for several advanced functions [1].

### A. *Early Grid Communication protocols*

Westronic Incorporated developed DNP3 between 1992 and 1994, intending it to be the first open protocol standard in the utility industry. The designers of DNP3 did not find any of the existing efforts suitable. At the time when Westronic was considering DNP3, there were two main candidates available for an open protocol: Electrical Power Research Institute (EPRI) had released the Utility Communications Architecture (UCA) version 1.0 and International Electrotechnical Commission (IEC) had developed the first few documents in the IEC 60870-5 series of specifications

### B. *EPRI Enterprise Integration*

EPRI conducted a workshop and published the report *Collaborative Initiative to Advance Enterprise Integration of DER: Workshop Results* (1026789) and made publically available [10]. The participants identified a range of useful functions for enterprise integration of DER and prioritized these functions in terms of value to the industry and achievability.

### C. *IEC_61850 for DER object models*

IEC TC-57, WG-17 is developing the communication architecture for integrating DER into the IEC 61850 body of communication standards. IEC 61850, the first standard to be produced by WG-17, provides standards for object models for exchanging information with DER devices. Accordingly, no assumption was made as to DER ownership. Ownership could reside with a utility or an alternative party. No limitations were placed on type of distribution system (networked or radial) or on where in the distribution system the DER might be located. The object models provide the structured, standard identification and naming of the attributes that need to be included in the information exchange with the DER. These object models will become a part of the IEC 61850 body of communication standards for electric power systems. The goal is to achieve interoperability of DER with the power system. Interoperability of all intelligent electronic devices (IEDs) in the system is desired, and DER is one such IED type.

### D. *IEEE 1547 for interconnection*

IEEE 1547a [4] is the update to the base IEEE 1547 of 2003. Its main purpose is to permit the DER system to actively regulate voltage at the PCC, so long as the area ESP (energy service provider) operator approves and this active voltage regulation does not compromise the unintentional islanding detection and disconnect function. It also permits the high and low frequency limits of both voltage and frequency to be extended for specific time periods so that voltage and frequency ride-through by DER systems can occur. Currently 1547 is under going a comprehensive overhaul that will further refine the set of required interconnection features for inverters and other DERs.

## VI. Inverter Communication

### A. *Elements of successful communication*

Numerous working groups seek to identify standard protocols for utility communications. At a high level the requirements for communications include the following:

- Communications capability: DER systems with smart inverters shall be capable of communications although the implementation of those communication capabilities is a deployment decision and/or an upgrade decision.
- Utility data monitoring and control requirements: The utilities must determine the required data. SunSpec Alliance assists in determining what data exchanges are supported by most smart inverter-based DER systems.
- IEC 61850 abstract information model: The IEC 61850 abstract information model must be selected as providing the basis for the communications. Specifically IEC 61850-7-420 provides abstract information models for general data exchanges with DER systems, while IEC 61850-90-7 provides specific object models. [4]
- Utility protocol: A common communication protocol must be agreed by DMS, and by aggregators of DER systems in order to communicate with the utility in support of smart inverter-defined functionality. Figure 5 illustrates a model using IEEE 2030.5 (SEP 2).
- Internet protocols: The Internet protocols TCP/IP will be used.
- Communications media: No restrictions or constraints are expected to be placed on the communications media so long as they can meet the utility performance and security requirements. Expected media types include cellphone channels, AMI networks, private utility networks, and the Internet. Telecommunications providers may also supply communication channels, which are combinations of different media.
- Cyber security requirements: Utilities are expected to identify cyber security requirements based in part on IEEE 2030.5 cyber security specifications and in part on utility security policies and procedures. These cyber security requirements are expected to include appropriately configured firewalls, authentication and integrity of all messages, monitoring, time synchronization across all systems, security monitoring, and audit logs of all significant alarms and events

978-1-5090-2157-4/16/$31.00 ©2016 IEEE

All these building blocks are required to successfully communicate with smart inverters. As described in the following subsection, there are numerous efforts to standardize portions of these interactions.

### B. *Emerging standards*

*1) SEP 2.0:* The smart energy profile (SEP) 2.0 application protocol represents an important recent initiative towards standardizing the communication layer for DERs [2]. SEP2 provides the high-level application layer while leveraging the ubiquitous TCP/IP standards for internetwork routing. It was built from a collaboration of the ZigBee, WiFi, and HomePlug (powerline carrier) Alliances and hence is designed to run on a wide range of physical layers [13]. *Figure 5* provides a conceptual implementation of SEP 2 protocol. SEP2 has been identified as a "standard for implementation" in NIST's Framework and Roadmap for Smart Grid Interoperability Standards [NIST 1108] and, California's Smart Inverter Working Group (SIWG) is encouraging SEP2 as the standard for future communications [5] and is assisting working to integrate it into the multi-phase updates to the Rule 21 interconnection standard.

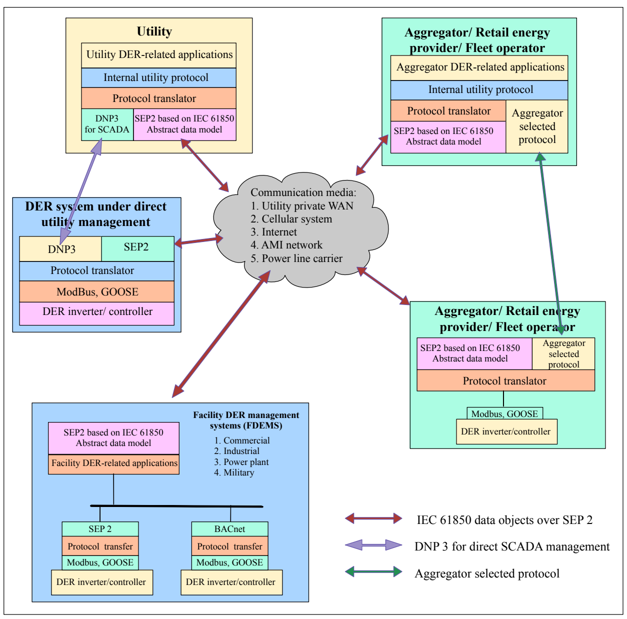


Figure 5 - Conceptual implementation of IEEE 2030.5 (SEP2) communications with DER

*2) Open FMB:* A utility-oriented alternative to SEP2 that intends to provide flexible communication architectures for utility controlled devices. OpenFMB [14] provides peer-to-peer communication across vendors architecture that will increase intelligence and operational efficiencies while allowing for secure and reliable communication and fast decision-making in the field. [14]

*3) SunSpec:* SunSpec [9] complements the utility to DER pathways provided by SEP2, OpenFMB, DNP-3, etc. by standardizing the interface to the inverters themselves. It provides a common register map and standard set of control modes to simplify connecting heterogeneous inverter types.

## CONCLUSIONS

Advanced inverters offer both a challenge and opportunity for distribution management by providing a wide range of grid support functions with the possibility for remote control. As DERs increase, it will become critical to capture their autonomous capabilities with DMSs, potentially as new equipment class and likely requiring updated approaches to load allocation to support increased customer-side real and reactive generation. With the addition of communications, advanced inverter enabled DERs can participate directly in DMS management schemes, initially through simple power factor, reactive power, and curtailment modes. Optimizing these communication pathways will likely involve moving beyond existing SCADA/DNP-3 paradigms to include SEP2/IEEE P2030.5, OpenFMB, broadcast, and potentially distributed control approaches. Now is the time to get involved and help shape these emerging developments.

## REFERENCES


[1] IEEE Standard for Electric Power Systems Communications -- Distributed Network Protocol (DNP3), IEEE Std. 1815-2010, Jul. 2010.

[2] IEEE Adoption of Smart Energy Profile 2.0 Application Protocol Standard," IEEE Std 2030.5-2013, Nov. 2013

[3] IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems, IEEE Std 1547.2-2008, April 2009

[4] IEEE Standard Conformance Test Procedures for Equipment Interconnecting Distributed Resources with Electric Power Systems - amendment 1," IEEE Std 1547.1a-2015, May 1 2015

[5] IEC Technical Report IEC 61850-90-7, "Communication networks and systems for power utility automation–Part 90-7: Object models for power converters in distributed energy resources (DER) systems," Edition 1.0, Feb 2013. Available: http://webstore.iec.ch/webstore/webstore.nsf/Artnum_PK/47564

[6] California Public Utilities Commission, "Recommendations for Updating the Technical Requirements for Inverters in Distributed Energy Resources, Smart Inverter Working Group Recommendations," Jan 2014, Smart inverter working group (SIWG), Technical reference materials, http://www.energy.ca.gov/electricity_analysis/rule21/

[7] Consortium for SEP 2 Interoperability (http://www.csep.org)

[8] NIST framework and roadmap for Smart Grid Interoperability Standards, Release 1.0.

[9] SunSpec Alliance Inverter Control Model, work in progress. (http://www.sunspec.org/specifications/).

[10] J. Johnson S. Gonzalez, M.E. Ralph, A. Ellis, and R. Broderick, "Test Protocols for Advanced Inverter Interoperability Functions – Main Document," Sandia Technical Report SAND2013- 9880, Nov 2013.

[11] Electric Power Research Institute, "Enterprise Integration Functions for Distributed Energy Resources – Phase 1 Common Functions for Smart Inverters. EPRI, Palo Alto, CA: 2011. Product ID Number 1023059

[12] D. Emiliano, H. Zhu, and G. Giannakis. "Distributed optimal power flow for smart microgrids." Smart Grid, IEEE Transactions on 4.3 (2013): 1464-1475.

[13] Smart Energy Profile Technical Requirements Document (09-5449). http://www.zigbee.org/Standards/ZigBeeSmartEnergy/20TechnicalRequirementsDoc.aspx

[14] Smart Grid Interoperability Panel (SGIP) for OpenFMB, Available online : http://www.sgip.org/022015-Release-OpenFMB