Final Technical Report (FTR)

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Executive Summary:

In 2011, EPRI began a four-year effort under the Department of Energy (DOE) SunShot Initiative Solar Energy Grid Integration Systems - Advanced Concepts (SEGIS-AC) to demonstrate smart grid ready inverters with utility communication. The objective of the project was to successfully implement and demonstrate effective utilization of inverters with grid support functionality to capture the full value of distributed photovoltaic (PV). The project leveraged ongoing investments and expanded PV inverter capabilities, to enable grid operators to better

utilize these grid assets. Developing and implementing key elements of PV inverter grid support capabilities will increase the distribution system's capacity for higher penetration levels of PV, while reducing the cost. The project team included EPRI, Yaskawa-Solectria Solar, Spirae, BPL Global, DTE Energy, National Grid, Pepco, EDD, NPPT and NREL.

The project was divided into three phases: development, deployment, and demonstration. Within each phase, the key areas included: head-end communications for Distributed Energy Resources (DER) at the utility operations center; methods for coordinating DER with existing distribution equipment; back-end PV plant master controller; and inverters with smart-grid functionality. Four demonstration sites were chosen in three regions of the United States with different types of utility operating systems and implementations of utility-scale PV inverters.

In the development phase of the project, work focused on designing and building the Yaskawa-Solectria Solar smart PV inverters that would be deployed in the field. The grid support functions selected for implementation were:

- Remote Connect/Disconnect - allows the inverter to disconnect and connect the inverter from the grid
- Power Curtailment - allows for control of the upper limit on real power that can be produced/delivered to the grid
- Power Factor Control - allows the power factor of DER to be set at a fixed value
- Reactive Power Control –allows for a fixed amount of reactive power to be supplied by the inverter
- Priority Setting –allows the inverter to be set for either real or reactive power priority
- Volt-VAR - allows the DER to manage its own VAR output in response to local service voltage. Watt output or VAR output priority can be set.
- Volt – Watt - allows the DER to manage power output based on voltage using power limit (configurable curve approach).
- Dynamic Reactive Current Support –allows the inverter to provide reactive current support in response to dynamic variations (changes) in voltage.
- Low Voltage Ride Through/High Voltage Ride Through –allows the inverter to stay connected in response to momentary voltage sags or swells.
- Status Reporting/Time Stamping – allows the operating mode, status, and setpoints to be available to verify operation.

In addition, the team defined the control needs via a distributed energy resource management system (DERMS) and developed a tool that could be used for lab and field testing. During this project, there was a recognition for the need to identify standard DERMS functionality and a workshop group was created. This DERMS Enterprise Integration group, mirrors the smart PV inverter working group to identify DERMS functionality with utilities and DMS/DERMS vendors. The team also evaluated potential utility-controlled anti-islanding solutions for use at the demonstration.

The deployment phase of the project focused on preparing for field demonstration of the smart PV inverters at the four demonstration sites. Given the lack of standard test procedures and certifications, the developed inverters were tested and functionality verified in both the EPRI laboratory and National Renewable Energy Lab (NREL) Energy Systems Integration Facility

(ESIF). These inverters were then deployed in Ann Arbor, MI, Boston, MA, and J1, NJ. In addition, monitoring equipment was deployed on each feeder to capture the impact of these devices in testing. Quite a bit of work was done in this phase to integrate the smart PV inverters with the DERMS solutions with active communication and control implemented. Finally, in this phase the team performed detailed power system simulations on each feeder to determine the impacts of the PV systems on the feeder as well as change in impact with a smart PV inverter. The modeling results also determined smart PV inverter settings to be used during testing based on specific identified objectives.

The final phase of the project was the field demonstration of the inverters. The project team developed site specific test plans for each location including objectives and test phases. These test plans were executed over an 8-month period and analysis was performed from the monitoring data.

Summary of Conclusions

This demonstration resulted in significant understanding grid integration challenges, how smart inverter functions operate, and grid impacts of smart inverters. Below is a summary of the major learnings:

- Supported the fundamental idea that smart inverters can provide services that are beneficial to the distribution grid.
- Successfully implemented and proved-out the standard smart inverter functions defined in International Electrotechnical Commission (IEC) 61850-7-520 and 61850-7-420
- Successfully demonstrated utility control with smart inverters utilizing the Distributed Network Protocol (DNP3) communication protocol.
- Because this project utilized standard functional definitions and the DNP3 standard communication protocol, control system and smart inverter developments were able to be carried out independently.
- Visibility into the distribution voltage level is useful to gain more benefit
- Determining settings for the smart inverter functions is critical to effective use.
- Retrofitting existing inverters may be complicated and expensive.
- Determined there is significant value in:
  - Autonomous functions – to the extent possible enabling products to manage their own behavior in response to locally-observable parameters (e.g. voltage, temperature)
  - Communication – loss detection and default values – implementing communication-connected systems in such a way that they detect communication loss as quickly as possible and apply logical default settings.
- Voltage measurement accuracy of inverters needs to improve to be able to perform as expected.
- Communication system quality and reliability will improve when manufacturers have production products and certification testing is available.
- The learnings from the project had significant contribution to the Institute of Electrical and Electronics Engineers (IEEE) 1547 revisions
- Communication certification processes and functional and safety certifications are needed.
- Need more pilot projects to identify the real world challenges

- Need robust interconnection standards, certification and performance verification process, and wide scale adoption of standards and communication protocols to ensure interoperability

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Background:

In 2009, EPRI began working with a number of utilities doing large scale Smart Grid demonstrations. These demonstrations were focused on the deployment of Distributed Energy Resources (DER) and the communication integration of these resources with the utility. Some of these projects involved the integration of inverter-based systems, such as solar PV, including diverse sizes and manufacturers.

As planning for these projects and associated vendor engagements began, two things became evident:

1. There were no common, standards-based communication protocols that would allow multiple vendors products to be integrated in a consistent and manageable way.
2. There was no common view of the specific functionality, or services, that these products would provide.

The second of these gaps was found to be far more significant. Although manufacturers all provided Smart Grid or grid-supportive functionalities, each did so in different or proprietary ways, making a system of diverse resources unmanageable. For example, every inverter maker offered some form of VAR support, but lacking any standard, each provided the support in a different way.

The potential value of proven, common smart PV inverter functions is far reaching, particularly in terms of enabling high penetration levels of distribution-connected PV. With other types of distribution equipment, utilities have been able to accommodate vendor-specific behaviors and proprietary communication protocols because they have been the owner of the devices. But distributed PV systems may be consumer owned and the inverters, which are offered by many providers, consumer selected. As a result of this diversity, manageable integration of large numbers of smart PV systems requires common functions and standard protocols.

Beginning in 2009, EPRI worked together with the Department of Energy (DOE), Sandia National Laboratories, and the Solar Electric Power Association to form a collaborative initiative to address these needs. The initiative has since defined a set of common functions and has coordinated with standards organizations so that the functions and communication protocols for their support have been codified.

This DOE smart PV inverter demonstration project that is part of DOE SunShot SEGIS-AC program carries the vision of smart PV inverter functionality to the next level through implementation and field testing. The common functions and standards have been used as a starting point for this project. It has been recognized by the project team that these functions have been developed largely on paper, without computer modeling or field testing. As a result, it remains uncertain:

- Whether the functions will work as intended, or if unintended side-effects will occur
- Whether the communication protocol mappings are sufficient (Distributed Network Protocol 3 (DNP3) in this case) or if additional settings and information need to be exchanged
- The extent to which unspecified characteristics, such as control loop/response time need to be specified, and if so, to what levels
- How to select and utilize these functions for optimal benefit
- How to coordinate the actions of smart PV inverters with other distribution control equipment

This project sought to answer these questions through implementation and evaluation in diverse field environments.

Project Objectives:

The project will develop, implement, and demonstrate smart-grid ready inverters with grid support functionality and required communication links to capture the full value of distributed photovoltaic (PV).

The scope of this project is to develop and demonstrate key elements of PV inverter grid support capabilities that will increase the distribution system's capacity for higher penetration levels of PV, while reducing the cost up to 15%. These elements are: head-end communications for Distributed Energy Resources (DER) at the utility operations center; methods for coordinating DER with existing distribution equipment; back-end PV plant master controller; and inverters with smart-grid functionality. PV inverter grid support functions will be put into practice using standard methods and communication protocols that will enable utility operators to interact with the plant for monitoring and management. Interactions may be frequent or infrequent depending on the capabilities of communication systems, with inverters performing smart autonomous behaviors in between. Demos will be carried out in three regions of the United States with different types of utility operating systems and implementations of utility-scale PV inverters.

The main goals are to leverage ongoing investments- in smart gird and related standards- and to expand PV inverter capabilities, which together will enable grid operators to better utilize these grid assets. Phase 1 of the project includes focuses on technology development and includes 6 major tasks; (1) Define functional requirements and configurability specifications, (2) Design and build smart grid functionality into PV inverters, (3) Build DER Plant Master Controller (PMC), (4) Design and develop DER Distribution Management Systems (DMS), (5) Model and study the impact of smart inverter to the distribution feeder, and (5) Develop utility-controlled active anti-island scheme. Phase 2 of the project focuses on integration testing and field demonstration and includes 5 tasks; (7) Develop Test Plan for Laboratory and Field Evaluation, (8) Evaluate Smart Inverter and DER PMC in Laboratory/Factory, (9) Deploy Hardware and Software at the Demo Sites, (10) Implement DER PMC at Demo Sites, (11) Perform Generic and Demo Site Specific Feeder Simulations with and without Smart Grid Functionality, (12) Conduct workshop on Advanced PV Inverter and Power System Simulations, (13) Design Unique Test Plans/Sequences for each Demonstration Site, (14) Test Unintentional Island Prevention at Demonstration Sites, (15) Demonstrate Grid Supportive Functionality of Inverters.

Project Results and Discussion:

Task 1 Define functional requirements and configurability specifications

EPRI and the project team defined and documented each advanced inverter function to be used in the project and detailed how each will be integrated into a DER management system. The detailed documents produced in this task will served as the design specification for the inverter implementation in Task 2 and the DER Management Software development in Task 4.

The grid support functions selected for implementation included the following.
Yaskawa-Solectria implemented these functions following the DNP3 and utilizing the specifications prepared in this task:

- Remote Connect/Disconnect - this function allows the inverter to disconnect and connect the inverter from the grid
- Power Curtailment - this function allows for control of the upper limit on real power that can be produced/delivered to the grid
- Power Factor Control - this function allows the power factor of DER to be set at a fixed value
- Reactive Power Control – this function allows for a fixed amount of reactive power to be supplied by the inverter
- Priority Setting – this function allows the inverter to be set for either real power or reactive power priority
- Volt-VAR - this function allows the DER to manage its own VAR output in response to local service voltage. Watt output or VAR output priority can be set.
- Volt – Watt - this function allows the DER to manage power output based on voltage using power limit (configurable curve approach).
- Dynamic Reactive Current Support – this function allows the inverter to provide reactive current support in response to dynamic variations (changes) in voltage.
- Low Voltage Ride Through/High Voltage Ride Through – this function allows the inverter to stay connected in response to momentary voltage sags or swells.

- Status Reporting/Time Stamping – this functions allows the operating mode, status, and setpoints to be available to verify operation.

EPRI and Yaskawa-Solectria met with each utility to understand how smart inverter grid-support functionalities would be demonstrated. In each meeting detailed conversations about the selected feeders' current conditions were discussed. Each utility described what they are hoping to accomplish by implementing the new functions.

The project deliverable whitepaper defines each smart inverter function and how distribution management system can operate them in a coordinated manner with existing circuits' components. The report is publically available via EPRI's website, Integrating Smart Distributed Energy Resources with Distribution Management Systems (PID 1024360).

The advanced grid-support functions and integration methodology developed in this task were shared with both the IEEE 1547 revision process and DNP3.

Task 2 Design and build smart grid functionality into PV inverters

One of the key components of this project was to design and develop of the smart PV inverters. EPRI project team partner, Yaskawa-Solectria implemented the selected advanced grid support functions in its existing SGI 500 kVA and PVI 60 kVA inverter series. Standard definitions of smart PV inverter functions[1] and open communication protocol DNP3 were employed in this implementation process. Yaskawa-Solectria also implemented a Plant Master Controller to communicate and control multiple smart PV inverters in a plant. In addition to adding these smart PV inverter functions, Yaskawa-Solectria also implemented several hardware improvements, including a redesign of the power stage for PVI inverter series, to improve reliability, increase efficiency, and reduce cost. In order to accomplish this, three steps were taken:

1. Create a specification identifying grid support functions to include and hardware improvements that can be made
2. Redesign inverters to meet the new specification and verify in manufacturer's facility
3. Further verify inverter functionality through lab testing – PVI at EPRI Knoxville Laboratory and SGI at National Renewable Energy Lab ESIF

The inverter redesign was broken up into six elements: (1) standard smart PV inverter functions; (2) efficiency improvements; (3) cost reduction; (4) grid sensing capabilities; (5) increase in reliability; and (6) communication upgrades. Table 1 provides a summary of these items as well as the changes made. The sections that follow provide more detail on how each item was implemented.

Table 1 Elements of Inverter Redesign

Elements	Description
Standard Smart PV inverter Functions	• Remote Connect/Disconnect • Power Curtailment • Power Factor Control • Intelligent Volt-VAR • Volt – Watt

1 Common Functions for Smart Inverters, Version 3. EPRI, Palo Alto, CA: 2013. 3002002233.

	• Dynamic Reactive Current Support • LVRT/HVRT • Reactive Power Control • Priority Setting • Status Reporting/Time Stamping
Efficiency Improvements	Weighed efficiency increase by 1%
Cost reduction	12% cost reduction in power stage of the commercial PVI inverter
Grid Sensing Capabilities	To enable the fast responding grid support functions added: • AC voltage rms sensing speed and range have been increased • PLL dynamics is increased
Reliability Increase	Reduced more than 100 connection points
Communication Upgrades	Added DNP3 communication and control protocol support

Task 3 Build DER Plant Master Controller (PMC)

The Plant Master Controller (PMC) is a control station that can be used to logically interface between multiple PV inverters in a plant and utility supervisory control and data acquisition (SCADA) system or Distribution Management System (DMS) or Distributed Energy Resources Management System (DERMS). Utilizing a PMC can reduce the communication and control burden of large plants consisting of many elements.

Two different off-the-shelf platforms were evaluated to implement the Plant Master Controller functions. The following were accomplished during the development phase:

- Two hardware platforms (SEL 3530 Real Time Automation Controller and Orion LX) were reviewed for the environmental specifications and successfully tested for the extreme temperature conditions.
- New protocol mapping and communication interface for the smart grid inverter functions were developed and tested with the Modbus and DNP3 protocol using different physical layer communications.
- Data concentrator function with ninety DNP3 client interfaces were developed and tested.
- Plant level supervisory functions such as coordinated control, preventive maintenance, and secondary fault protection functions were developed, demonstrated, and tested.
- Interfaces were developed for remote plant operation and monitoring.
- Secure authentication features were developed and tested for encrypted communication.
- Supporting multiple platform options provides flexibility in meeting different market demands and requirements

Task 4 Design and develop DER Distribution Management Systems (DERMS)

An emphasis of this project is to consider how the capabilities of smart PV inverters may be aligned-with or coordinated with the actions of other distribution control equipment such as capacitors, substation load tap changers (LTCs), line regulators and switches. At the onset of this project, it was understood that this could require looking beyond communication to smart

PV inverters in the field and could include the central office communication that may occur between software applications. Significant industry challenges have been discovered through this project, in terms of the understanding of the interactions that will be involved and the communication standards needed to support these interactions.

To help address this challenge, a collaborative industry initiative was launched from this project and aligned with the Department of Energy (DOE) SEGIS-AC program and the National Institute of Standards and Technology (NIST), through the Smart Grid Interoperability Panel (SGIP). While the industry has made progress in developing standard smart inverter functions and communication protocols for monitoring and managing PV and other DER devices in the field, standards did not yet exist to support DER group management or the enterprise integration (software-to-software) of these device capabilities in a useful and manageable way. A whitepaper was developed and published[2] in 2012 that explained the primary challenges in this area and made the case for a sustained activity to address it. A kickoff workshop was conducted in Washington, DC on September 26, 2012 at which a core set of needs and priorities were identified. The highlights of this workshop were documented in a separate EPRI report[3]. Ongoing teleconferences are being held to develop standards for DER group management and enterprise integration needs.

Based on the findings of this project, DERMS serve four primary functions:

- **Aggregate** DERMS take the services of many individual DER and present them as a smaller, more manageable, number of aggregated virtual resources.
- **Simplify** DERMS handle the granular details of DER settings and present simple grid-related services
- **Optimize** DERMS optimize the utilization of DER within various groups to get the desired outcome at minimal cost and maximum power quality.
- **Translate** Individual DER may speak different languages, depending on their type and scale. DERMS handle these diverse languages, and present to the upstream calling entity in a cohesive way.

An overall system may involve a single DERMS, or several operating in parallel, and DERMS may be utility operated applications or services provided by third parties as shown in Figure 1.

2 Integrating Smart Distributed Energy Resources with Distribution Management Systems. EPRI, Palo Alto, CA: 2012. 1024360

3 Collaborative Initiative to Advance Enterprise Integration of DER: Workshop Results. EPRI,Palo Alto, CA: 2012. 1026789

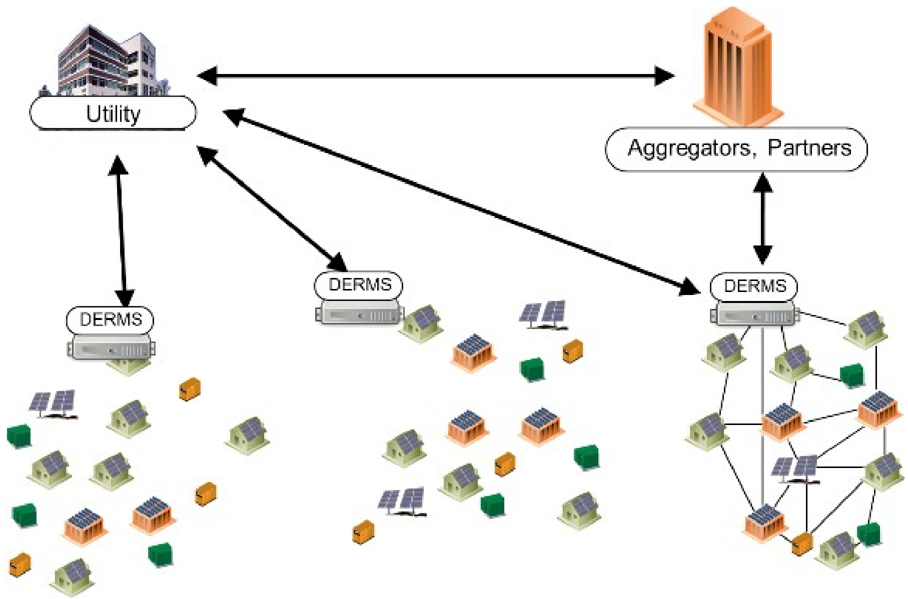

Figure 1 Multiple and Third-Party DERMS

The field demonstration phase of this project involved both utility-managed DERMS (e.g. the DTE Energy DR-SOC) and third-party partners (e.g. the BPL Global system used in the demonstrations at National Grid).

Under the project several tools were developed to assist in demonstrating these concepts during the project. A DER master station was developed by Nebland Software. This tool allows a user to send commands to an inverter requesting smart functions per DNP3 standard. Figure 2 shows the user interface that shows the functions available. During the project, the tool was expanded to include all the smart PV inverter functions. Work will continue on this tool in the next phase to allow for Common Information Model (CIM) messaging to be included.

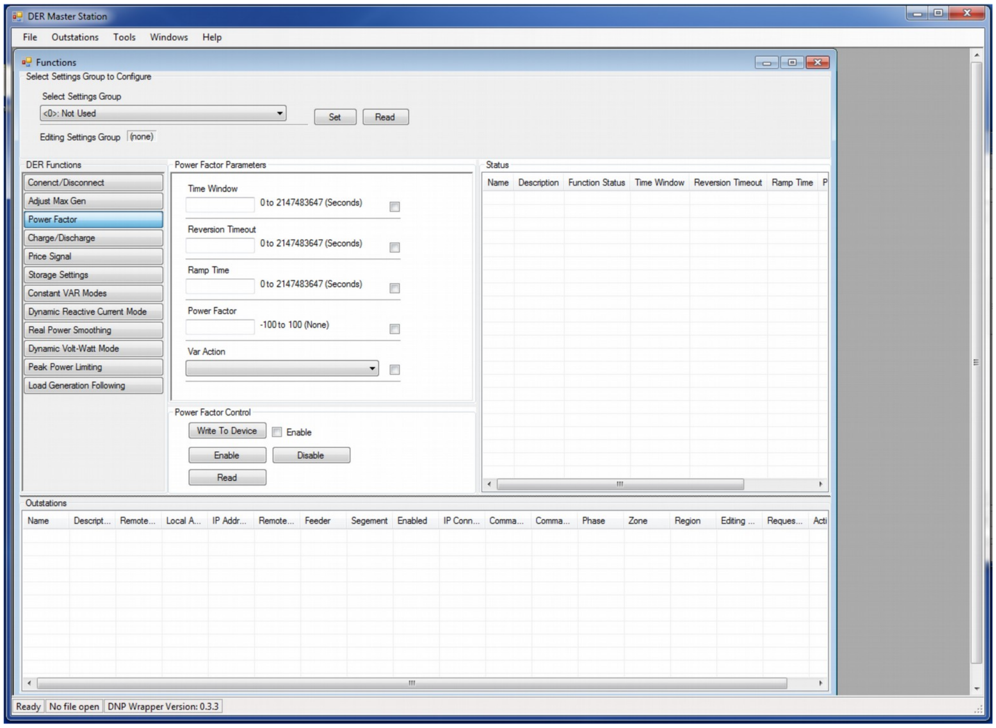

Figure 2 DER Master Station Tool

In addition, Spirae, Inc detailed four use cases as an initial step in mapping the standard smart PV inverter functions to enterprise integration standards. These included:

- Coordinated volt-VAR control
- Reactive power dispatch
- Real power dispatch
- DER discovery

These use cases have been expanded upon as part of the DER Group Management working and are included in the [Common Functions for DER Group Management, Second Edition.]

Task 5 Model and study the impact of smart inverter to the distribution feeder

Detroit Edison performed preliminary modeling with selected smart inverter functions in order to understand the impact of the new PV system and smart inverter on the feeder and the protection necessary. For this analysis, DTE Energy used the Electrical Distribution Design (EDD) DEW distribution analysis tool that can support power flow, time series, and steady state or quasi-steady state analysis. These applications were used to quantify the impact of adding the PV inverter as well as to determine mitigation measures for those impacts.

The modeling methods analyzed the impacts of the smart inverter interconnection in terms of:

- Voltage regulation along the feeder
- Current capacity constraints
- Expected impacts due to fault current contributions from the interconnected PV
- The impacts of implemented anti-islanding functions of the PV inverters

- The increase in the number of line regulator/switched capacitor bank operations caused by the interconnection of PV

An initial baseline review was performed of the feeder to observe the changes to the voltage profile with and without the PV system.

DEW's automated DER Assessment Application was used to determine the impacts of adding DER to the system. The focus for this analysis included:

- Fault Analysis - determines fault current levels with and without PV for protection and coordination. This phase can also be used for the analysis of ride through settings. The results of this analysis are below.
- Step Change Review- determines the potential impact of sudden changes in PV output verse study criteria violations. The results of this analysis are below data.

Fault protection is provided from the breaker at F1 Substation which is equipped with two sets of electromechanical relays. The 13.2 kV portions of the circuit are protected by fuses at the isolation transformers. Line reclosers and overhead sectionalizing fuses have not been used.

Automatic reclosing is used to provide automatic restoration for temporary faults. Two sets of relays are used to provide a fast operation when the fault is cleared the first time. The high speed tripping is intended to also clear temporary faults downstream of fuses. This avoids a permanent outage for customers downstream of the fuse. The clearing time for the second and subsequent operations is determined by a relay with a slower characteristic. This permits downstream fuses to operate and clear faults downstream of the fuse selectively, thus avoiding an additional breaker operation.

Step change violations/problems were observed in this phase of the analysis but easily mitigated using power factor (PF) control.

The application performs a series of power flow analysis runs associated with loss and restoration of user selected PV generation and corresponding load conditions. There were four scenarios for the step change analysis shown in Table 2 with both a description and results. The voltage violation threshold chosen for this analysis was a 0.7 per unit (pu) rise or fall at the PV Point of Interconnection (POI).

Table 2 Step Change Analysis Scenarios

Scenario	Description	Results
Scenario 1	Considers PV system at 100% rated output and operating at unity PF to lose 100% of output and then return with all regulation equipment locked and released at the appropriate time.	The step change in voltage for the sudden loss and return of PV at unity PF produces the highest voltage change.
Scenario 2	Repeats Scenario 1 with an 80% loss of output at unity PF.	A modest improvement in step change from Scenario 1.
Scenario 3	Repeats Scenario 1 with the PF set to 0.9 absorbing VArs.	Smart inverter can be used to negate the impact of the PV.
Scenario 4	Repeats Scenario 2 with the PF set to 0.9 absorbing VArs.	Smart inverter can be used to negate the impact of the PV.

After establishing the impact of the PV system with a standard inverter and an inverter with changes to the power factor, smart inverter controls were developed and implemented in the model with input from Yaskawa-Solectria. The following functions were included:

- Priority Setting
- PV Setting Modification
- Power Factor Adjustment
- Volt-Watt Control
- Dynamic Reactive Current Support

Task 6 Develop utility-controlled active anti-island scheme.

In the electric power system, islanding occurs when a portion of the system (the island) becomes disconnected from the grid and continues to operate. Unintentional islanding (often referred to as simply islanding) is not planned and is undesirable because line worker practices, protective equipment, and grid control systems are not designed for those conditions.

Currently, there are two prevailing approaches to prevent individual distributed generation from creating unintended islanding. The primary approach utilizes onboard anti-islanding protection at each DG system. In certain situations, feeder-level protection may be used to directly trip individual DG in coordination with utility operations.

For larger DG systems, the interface commonly found on rotating generators usually involves a combination of a multi-function relaying package at the generator, additional feeder protection systems at the substation, and a direct-transfer-trip (DTT) scheme designed to disconnect the DG unit if an upstream breaker is opened[4]. These technologies have a long history of use and are considered effective where they have been installed. They can be relatively expensive[5], particularly for smaller DG where relaying can exceed the cost of the generator. Beyond the cost issue is the added complexity of communication, because most DTT schemes are point-to-point and require a separate transmitter dedicated to each DG installation.

For smaller DG systems, which are mostly inverter-based, onboard anti-islanding detection schemes are much less expensive to implement than DTT. These approaches all revolve around searching for certain abnormalities in local voltage or frequency that would indicate an unintentional island at their location[6]. According to the prevailing standards, if a DG unit can successfully detect an island in under two seconds from when it is separated from the grid, it is deemed compliant. In order to pass the islanding test, inverters typically require a combination of a passive scheme, which looks for abnormalities caused by external sources, and an active anti-islanding behavior. Active schemes modulate the inverter’s output at regular intervals and

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4 M. Davis, *Distributed Resources Task Force Interconnection Study.* Edison Electric Institute (EEI). 2000.

5 J. A. Gonzalez, A. Dysko, et al., *The Impact of Renewable Energy Sources and Distributed Generation on Substation Protection and Automation: Working Group B5.34.* CIGRE, 2010.

6 W. El-Khattam, T. S. Sidhu, and R. Seethapathy, “Evaluation of Two Anti-Islanding Schemes for a Radial Distribution System Equipped With Self-Excited Induction Generator Wind Turbines,” *IEEE Transactions on Energy Conversion*, vol. 25, no. 1, pp. 107–117, 2010.

attempt to create a voltage or frequency disturbance. If the inverter is still connected to the larger grid, these disturbances will have little or no measureable effect on power quality. If the installation has been islanded over a small enough portion of the system, these techniques will cause a detectable change in local voltage or frequency[7].

There are several technical solutions that could help mitigate the risk imposed by islanding, without requiring full DTT systems at each residential PV system. They each provide the utility with direct means to establish control by either signaling the units or forcing them offline. Depending on the circuit, the DG, the existing utility equipment and practices, as well as the individual vendor solutions, each technique has its own complexity, cost, and effectiveness[8].

During the course of this project, EPRI conducted an evaluation of several communication-based anti-islanding technologies. These fell into two categories: power-line carrier (PLC) and wireless communication. Some of the units considered are summarized in Table 3.

Table 3 Technologies Considered for Anti-Islanding Use

Technology	Type	Notes
DX3 Pulsar	Low-Frequency PLC	Tested in laboratory and at National Grid New York site
ABB	High-Frequency PLC	Not tested; impractical to implement on distribution systems
GridEdge Networks	High-Frequency PLC	Not tested; coupling unit (13kV) required for installation
Raveon	Point-to-Point Wireless	Laboratory tested
Landis + Gyr	Wireless Mesh	Not tested; requires multiple units installed for field evaluation
GE Digital	Point-to-Point Wireless	Considered, but not tested
Remote Control Technologies	Point-to-Point Wireless	Tested in laboratory and field

PLC-Based Anti-Islanding

For the purpose of testing the system's connectivity, power consumption, and the resulting power quality, a Pulsar transmitter and receiver were configured at EPRI's Knoxville facility. As shown in Figure 3, EPRI has two labs connected by roughly 2000ft of three-phase, medium voltage underground cable. The DX3 transmitter was directly connected to Building 1's 480-V service, which is provided through a 300kVA step-down transformer.

7 W. Bower and M. Ropp, *Evaluation of Islanding Detection Methods for Utility-Interactive Inverters in Photovoltaic Systems,* Sandia National Laboratory. 2002.

8 "IEEE Draft Recommended Practice for Establishing Methods and Procedures that Provide Supplemental Support for Implementation Strategies for Expanded Use of IEEE Standard 1547," IEEE P1547.8/D8, July 2014

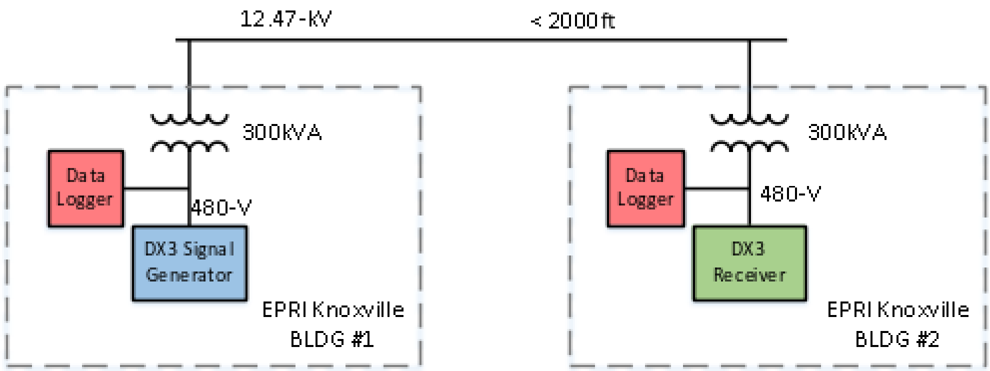


Figure 3 Testing arrangement for DX3 Pulsar in EPRI's Knoxville labs

As discussed previously, the amount of distortion (or signal strength) from the transmitter may be adjusted by the firing angle of the thyristors. A larger firing angle results in a larger time window during which the thyristor is conducting, and the voltage is prematurely reduced to zero. Even though the distance between the two EPRI labs was very short, a large (20 degree) firing angle was required to establish connectivity with the receiver because of the relatively large impedance of the lab's medium voltage transformer (about 3.17% at 300kVA). However, an increase in firing angle also brings about an increase in power consumption (see Figure 4). Though the peak stress on the thyristors was quite high (as much as 600A for a 25 degree firing angle), the average power consumption was much less.

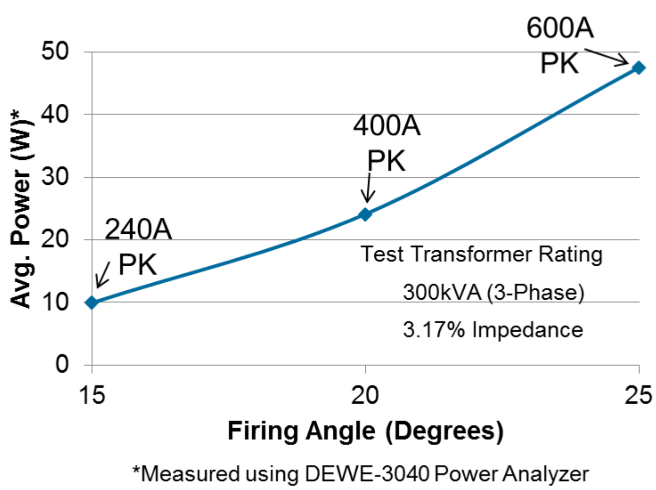


Figure 4 Power consumption and peak thyristor current at different firing angles

Any PLC signal method immediately raises questions of negatively impacting power quality. Though the distortion at the transmitter is immediately recognizable, the attenuation due to two transformers and a line segment reduced the harmonic contribution significantly. Figure 5 shows a comparison between the background voltage distortion (with the transmitter off) and the voltage distortion at the same location with the transmitter operating. The transmitter contributes both even harmonics (because the distortion doesn't occur every cycle) as well as 15Hz sidebands on the other harmonics. Though these frequencies are visible under FFT, their overall impact on the voltage waveform is barely distinguishable from the background sample, and the total harmonic distortion (THD) is relatively unchanged.

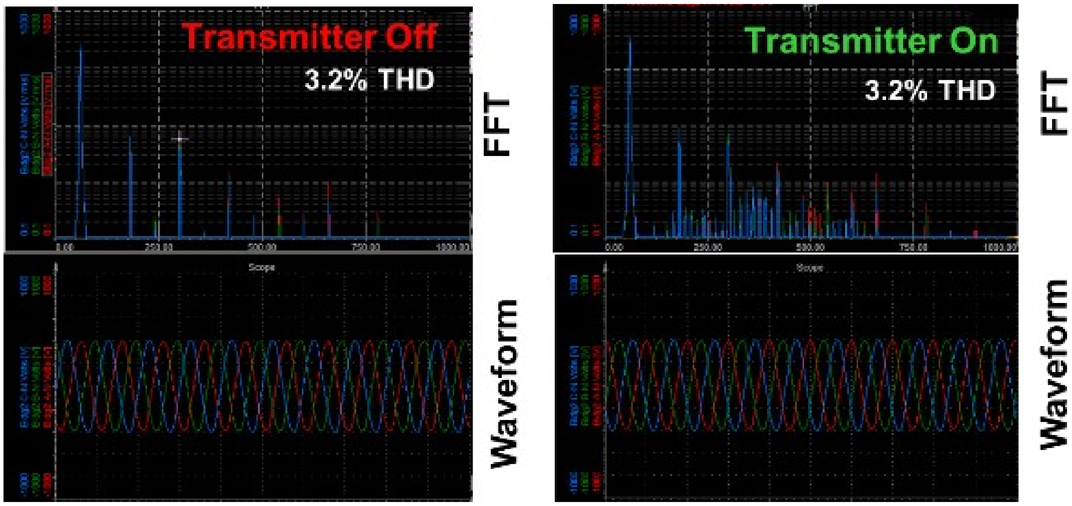


Figure 5 Background FFT with the transmitter off (left), FFT of building 2 voltage with transmitter on (right)

The transmitter, however, had a severe issue with immunity to voltage sags. For any three-phase sag that resulted in retained voltage less than 70% of nominal, the transmitter tripped almost immediately, as shown in Figure 6. For even smaller sags, the transmitter would go off-line within a half-second (or 30 cycles). After a trip event from a three-phase sag, it consistently took the transmitter approximately 4 seconds to recover. When exposed to only a single-phase voltage sage, the transmitter's response was much less severe, as demonstrated in Figure 7. In lab tests the unit showed ride-through capabilities of up to 20 cycles at a retained voltage approximately 10% of nominal. The recovery time was less than the three-phase case, lasting approximately 1.6 seconds in all cases tested.

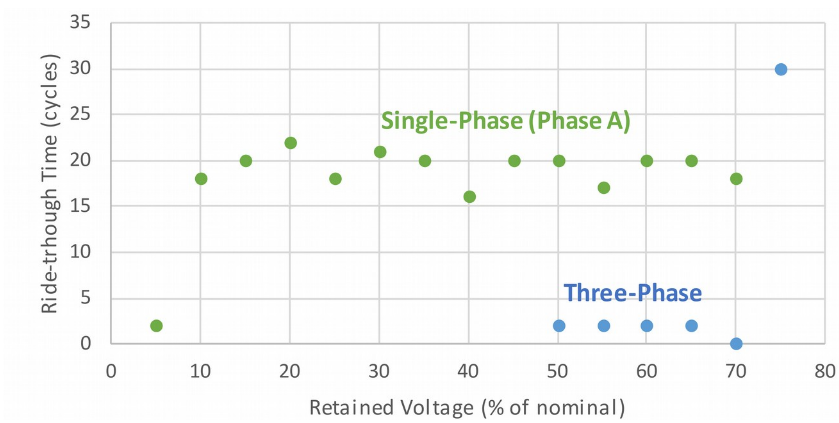


Figure 6 DX3 transmitter ride-through for single- and three-phase voltage sags

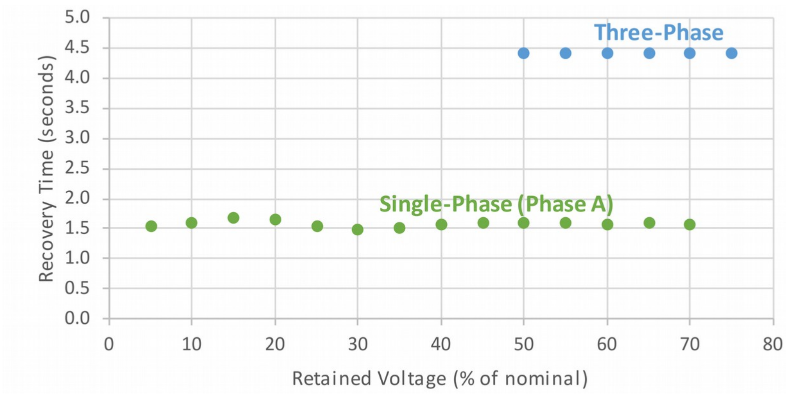


Figure 7 Recovery time after single- and three-phase sags

The likely root cause of the ride-through issue was the power supply for the transmitter's control power. The power supply lacked sufficient operating range or holdup time for the application. In the lab environment, when an external supply was used to power the transmitter's control circuitry, no dropouts were recorded. In conclusions, addressing this shortcoming would make the transmitter more robust against short-duration disturbances that lead to nuisance tripping of PV and other DER systems.

Wireless Based Anti-Islanding

Rather than use the power line as a communications medium, it's also possible to wirelessly connect to remote DER for islanding prevention. Some examples of technologies reviewed for this purpose are shown in Table 4.

Table 4 Wireless Technologies Reviewed for Anti-Islanding Applications

Vendor	Product	Band	Architecture
Raveon	RV-M7-U	UHF (300MHz-1GHz)	Bidirectional
Landis & Gyr	RF Mesh UtiliNet	ISM (900MHz)	Mesh
GE Digital	DGT	ISM (900MHz)	Bidirectional
Remote Control Tech	92408-LRWSS	ISM (27MHz)	Unidirectional

Some physical characteristics to consider when selecting wireless communications for anti-islanding:

Logic Type – With the PLCP system, the receiver was continuously monitoring for a heartbeat signal, such that if the signal was lost, the unit was to trip without delay. In wireless communications this technique implies that a continuous stream of data would be required for the DG to remain operational. This leads to higher stress and throughput (and perhaps cost) required from the communications system. In these solutions, a loss of signal would likely result in a nuisance trip of the DG unit. Alternatively, a "report by exception" strategy would result in transmissions only in the event of a protective device operation. This requires less data transfer, but also runs the risk that a loss of signal would effectively defeat the anti-islanding mechanism.

Frequency Range – The carrier frequency, used to transmit the anti-islanding signal, also plays a large role in system design. Low frequency (<100MHz) carriers often have a longer range for the same transmitter power level, however they are less likely to pass through obstacles (like buildings) if the transmitter & receiver are not within line-of-sight. They also require a large antenna for maximum signal transfer, which may be impractical is many distribution applications. High-frequency systems, on the other hand, have shorter range for the same signal power, yet the antenna height is typically much more manageable.

Spectrum Licensing – Typically operation of a wireless communications system requires some form of licensing from the FCC. However, there are a number of bands where “unlicensed” operation is allowed. These include both 900MHz (where many AMI systems operate) as well as 2.4GHz(which is common for Wi-Fi). Licensed spectrum at other frequencies comes at a cost, and is subject to availability, but may be less prone to legitimate interference.

Unidirectional/Bidirectional Operation – As with the PLCP scheme, a unidirectional technique only allows the signal to be transmitted in one direction. This doesn’t allow for any confirmation of the DG’s status to be provided upstream. Bidirectional communication is possible if all DG units have transceivers, yet this is a much more complex (and potentially costly) solution.

Radial/Mesh Architectures – Some wireless networks allow the signal to propagate through a mesh of transceivers rather than directly from the head-end to the end point. This allows the range of communication to be extended without using repeaters, since every node in the mesh is a repeater itself. However, this makes the nodes more complex than a simple receiver, and it could be much slower connecting to devices at the end of the mesh (away from the substation, for instance), rather than those near the origin of the trip signal.

Existing Infrastructure – Wireless communication based solutions may be possible through existing infrastructure, such as AMI networks. However, the high-speed (less than 2 second response time) required needs to be weighed against the capabilities of these systems, as well as the available throughput after the channel has provided for its primary responsibilities.

In addition, DTE installed a remote transfer trip scheme on the F1 feeder as part of the demonstration. Because the inverter under test no longer met current UL 1741 requirements, DTE Energy required relay protection at the inverter site, and a transfer trip scheme, which shuts down the inverter if the utility substation breaker opens.

DTE Energy installed a SEL-351-7 relay at the inverter site. This relay provided protection for Over/Under Voltage and Over/Under Frequency conditions. The output of the relay was connected to the remote shutdown terminals on the Yaskawa-Solectria inverter.

The transfer trip scheme utilized two Acromag 983EN-4012 devices employing the i2o Peer-to-Peer technology. This technology allows inputs on one unit to automatically actuate an output on the other unit over an Ethernet link. The Ethernet link was provided via a private mesh wireless network (Tropos) owned and maintained by DTE. Figure 8 shows the main components for this scheme.

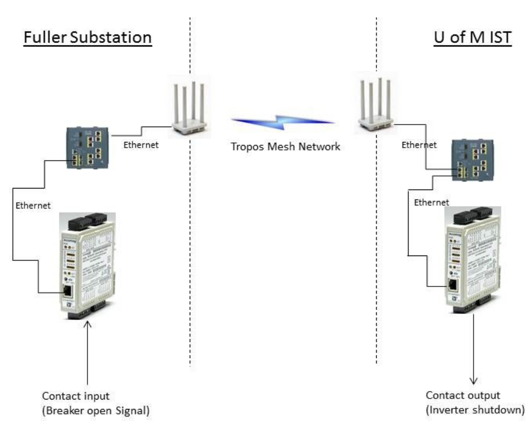


Figure 8 Components of Transfer Trip Scheme

The 983EN modules include a watchdog timer feature. This was used to provide alarming should communication between the two modules be interrupted for any reason. The substation module was configured to communicate with the IST module every two seconds under “no change” conditions. It was also configured to immediately relay a change in the status input. The watchdog time on the 983EN at the inverter location was configured to provide an alarm if it did not receive data from the substation module within ten seconds.

After completion of the installation, no alarms have been generated by the watchdog timer.

DTE Energy also tested the use of a private AT&T cellular APN to provide the communication path between the two 983EN modules. While this did allow the modules to communicate successfully, the latency was deemed unacceptable. For security reasons, this APN network does not allow peer-to-peer communication. Therefore, data would be required to route through the DTE DR-SOC network. Latency checks were performed from the DR-SOC network to the two locations. Ping tests showed a time delay of approximately 400 milliseconds to the solar site, and about 200 milliseconds to the substation. Figure 9 show the results of these tests.

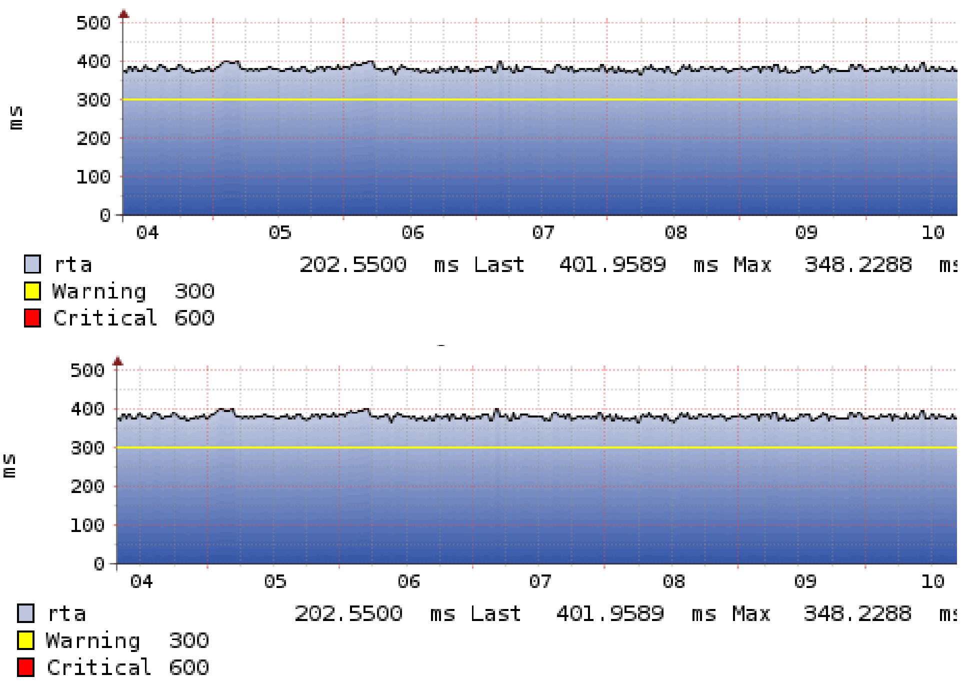


Figure 9 Results of Latency Checks

It is evident that supplemental anti-islanding protections will become necessary as distribution-connected DER levels rise and as these DER increasingly provide grid-supportive services that act to stabilize and resist anomalies. There are several communication technologies that are commonly available and are candidates for serving in these supplemental anti-islanding protection systems. However, none of these systems is presently a clear choice or perfect solution. Each has advantages and disadvantages and ultimately some combination or new technology may be needed. Key factors include:

- Whether the communication strategy involves transmitting a signal to trip the DER (normally inactive) or halting the transmission of a signal to trip the DER (normally active)

- The up-time of the communication technology – how often, and for what duration does the communication path go offline?
- Average and peak latency. How fast can the communication technology inform one or many DER, and what is the worst case?
- Carryover. How long does the communication system stay online after widespread outages, and how quickly does it come back online after power is restored.
- Data throughput and charges – particularly as it relates to normally active scenarios.
- Cost, particularly of the component of the system that exists at each DER site.

At the time or this evaluation, there was no clear choice. More research is needed and in the meantime the factors listed above will need to be weighed by the utility operator. The operator's preferred approach may depend on the expected DER deployment (scales and quantities), the local distribution scenario (load/generation balance), degree of measurement and automation available, and individual utility objective or preferences for trip time and assurance.

Supplemental anti-islanding is not a complete cure for the risk of unintended islanding and utility safety practices will necessarily have to change as it becomes increasingly impractical to securely lock-out/tag-out all sources of distribution circuit energization. Future research in anti-islanding needs to be accompanied with looking for better options and ideas on coordination of substation protection, relaying, and line worker safety practices. The main takeaways from this project point to a need for a replicable solution that is easily plug and play. As with the main interfaces for DER communication and control, a modular standard interface for anti-islanding (e.g. possibly as simple as a defined dry contact I/O interface) may be of value so that DER can be designed in such a way that they are compatible with any type of supplemental anti-islanding technology and this technology can be replaced/upgraded over the life of the DER system. Currently, such a modular interface standard does not exist.

Phase I CRITICAL MILESTONES

1. Publish the white paper on smart-grid functionality requirements and configurability specifications - ***Integrating Smart Distributed Energy Resources with Distribution Management Systems (PID 1024360)***
2. Technical report based on the initial factory test results from the newly developed smart-grid ready inverter and DER plant master controller (PMC) – ***As described in Phase 1 Continuation Report***
3. Successful development of DER distribution management system (DERMS) – ***As described in Task 4***
4. Successful development of utility-controlled active anti-island detection scheme. – ***As described in Task 6***
5. PV system impact analysis on the host distribution feeder in Detroit – ***As described in Task 5***
6. End of Phase 1 presentation and Go/No-Go decision point – ***February 7-8, 2013 in Boston, Massachusetts***

Task 7 Develop Test Plan for Laboratory and Field Evaluation

EPRI and the project team developed test plans for each site field evaluation. Each smart PV inverter function is a tool that may be used to achieve one or more benefits on the four feeders. Table 5 identifies five potential categories of benefits from implementing these functions. These are: improvements in efficiency, power quality, asset life, reliability, and the deferral of capital spending on system upgrades.

Table 5 Demonstration Plans for Host Feeders

Benefits / Inverter Function	Efficiency		Power Quality				Asset Life			Deference of Capital Spending				Reliability		Enabling
	Reduced distribution line losses	Improve customer efficiency CVR	Flatter voltage profile	Improved harmonics	Voltage flicker	Overvoltage	Reduce LTC tap changes	Reduce line regulator tap changes	Reduce switch cap changes	Defer capacitor additions	Defer line regulators	Defer reconductoring	Defer substation upgrades	Support during momentary	Support during automation	Higher Penetration of PV
Intelligent Volt-Var Control	✓	✓	✓			✓	✓	✓	✓	✓	✓					✓
Power Factor	✓		✓			✓				✓						✓
Dynamic Reactive Current					✓	✓								✓	✓	✓
Remote Connect/Disconnect															✓	✓
Power Curtailment						✓	✓	✓			✓	✓	✓			✓
Intelligent Volt-Watt Control		✓				✓										✓
L/H Voltage Ride-Through														✓	✓	✓

This project focused on four demonstration sites in three regions of the country. Two sites are located in Great Boston Area of Massachusetts (H1 and E1), one site is located in Michigan (F1), and one site is located in New Jersey (J1). Below is an overview of each of the feeders, PV sites, and areas of potential benefits of smart PV inverters for each.

The H1 demonstration site is a 1 MW PV plant in the Greater Boson area. The feeder, H1, is a 13.2 kV feeder with mostly residential loads. The summer and winter peak are 5.3 and 3.5 MVA respectively. The feeder has one 3-200 kVAR fixed capacitor banks near the PV site and substation LTC. Figure 10 below provides a one line of the feeder, the location of the substation and PV plant, as well as the monitoring points along the feeder utilized during demonstration.

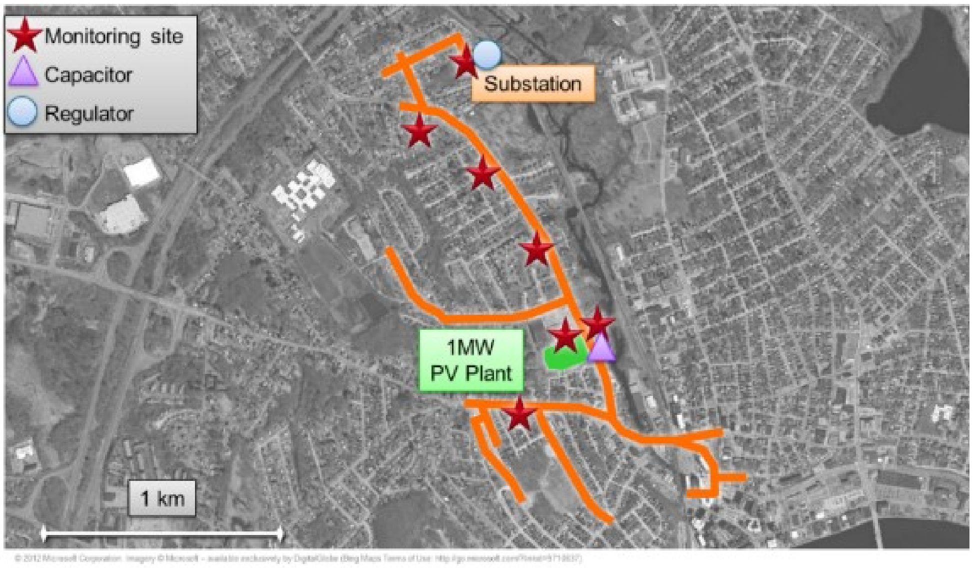


Figure 10 National Grid H1 Feeder – 13.2 kV residential feeder with 1 MW PV

The H1 feeder, with its equipment and PV system near residential loads, presents an opportunity to evaluate several potential smart PV inverter impacts and benefits:

- **Smart PV Inverter Stability –** The inverter's reactive power capabilities will be utilized during the H1 testing, operating in a number of control modes. Operation stability is of primary focus with an inverter of this scale in a real distribution system.
- **Flatter Voltage Profile –** The reactive power capability of smart PV inverters may be able to flatten the voltage profile along feeders. To the extent that this is effective, several benefits could be derived:
    - **a)** Consumers could be provided with improved power quality, supporting proper operation and reliability of equipment.
    - **b)** Distribution circuits could be enabled to host more PV.
    - **c)** The need for distribution control devices could be reduced or eliminated.
- **Reduced Equipment Operations –** Wear and tear on distribution control equipment could be reduced. Most notably, the on/off operation cycles of capacitors and the up/down tap changing of voltage regulators could be reduced, potentially extending service life and reducing costs.
- **Improve Customer Efficiency via Improved CVR -** voltage-flattening offers additional voltage reduction opportunity for conservation voltage reduction

The E1 demonstration site is a 566 kW PV plant also in the Greater Boston area. The feeder, E1, is a 4.8 kV feeder with mostly commercial and industrial loads. The summer and winter peak are 2 and 1.8 MVA respectively. The feeder has two 3-150 kVAR switched capacitor banks upstream and downstream of the PV site. Figure 11 below provides a one line of the feeder, the location of the substation and PV plant, as well as the monitoring points along the feeder utilized during demonstration.

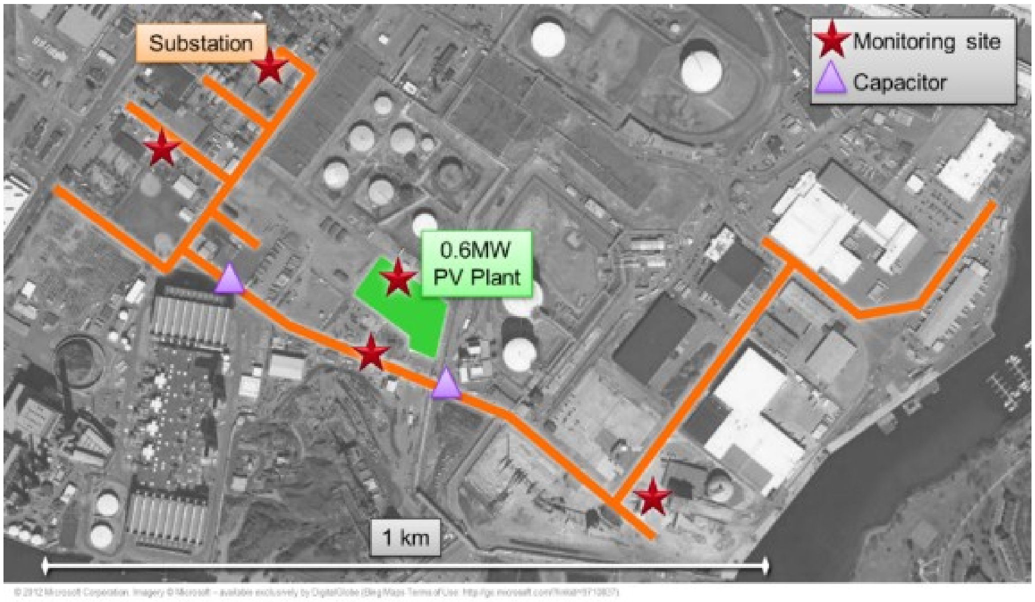


Figure 11 National Grid E1 Feeder – 4.2 kV commercial/industrial feeder with 600 kW PV

The E1 feeder provides opportunity to observe the inverters operating in this unique environment with the following specific interests:

- **Voltage Variability Reduction** - Assess how the dynamic reactive power capabilities of smart PV inverters can be used to reduce fast voltage variations on the feeder. This demonstration will require the installation of fast sampling power quality meters on the distribution feeder and post-processing to determine the frequency of occurrence of voltage variations with a range of time constants. This function is for the reduction of variability from any source, including that caused by variability in the PV itself, loads, or control equipment, such as the switching of bulk capacitors or tap changes.
- **Reduced Capacitor Switching Operations** - Assess the autonomous volt-VAR function of the inverter in regard to its potential to reduce the average number of capacitor switching operations by improving voltage. This will require instrumentation to detect and log the switching of the capacitor bank, with and without the volt-VAR functionality enabled.
- **Feeder Losses Reduction** - In the same fashion as conducted at the H1 site, assess the volt-VAR function of the inverter, modifying the settings in real-time, in order to hold the feeder power-factor measured at the substation at unity. This demonstration required metering at the feeder head, near real-time processing by the BPL Global DERMS and communication of updated settings to the inverter.

The testing for both goals (reduced tap changes and deferred capacitor additions) will be carried out simultaneously, with different settings being used in successive test phases. Test data will be post-analyzed in order to assess the outcome in the two benefit areas.

The F1 demonstration site is a 224 kW PV plant in Michigan. The feeder, F1, is a 4.8 kV/13.2 kV feeder with commercial and residential load. The summer and winter peak are 3.1 and 1.7 MVA respectively. The feeder has one 600 kVAR capacitor bank, with an autonomous fixed schedule. In addition, the substation has a 750 kVAR line regulator. Figure 12 below provides a one line of the feeder, the location of the substation and PV plant, as well as the monitoring points along the feeder utilized during demonstration.

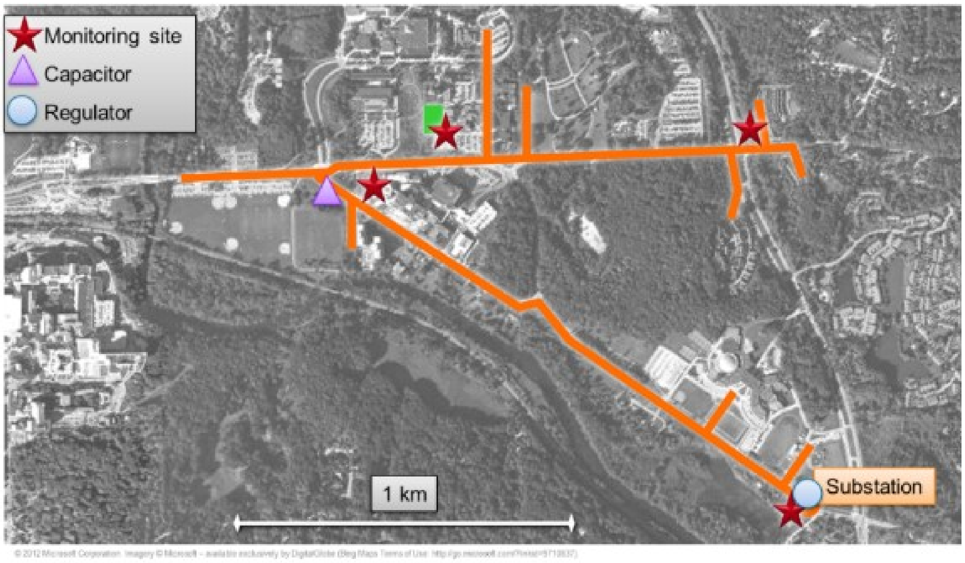


Figure 12 DTE Energy F1 Feeder – 4.8kV commercial overhead/underground feeder with 224 kW PV

As described previously, the F1 feeder, with its controls and ratio of peak solar generation relative to peak load, presents an opportunity to evaluate many potential smart PV inverter benefits:

- **Bus Regulator Tap Changes -** Utilize the autonomous Volt-VAR function of the inverter to reduce the average number of LTC tap changes. To achieve this would require more or larger inverters and to directly measure it would require the deployment of sensing and logging equipment that can monitor or infer state changes by the regulators. The regulators are located at the substation and control the bus voltage. This bus is normally connected to only the one feeder involved in this test.
- **Deferral of Capacitor Additions -** Using the reactive power capabilities of smart PV inverters in-lieu of capacitor banks (to avoid the need for additions) and in-coordination with existing cap banks to reduce the need for additions. The test data collected in this project will enable further computer analysis because this feeder does not presently need capacitor additions.

The J1 demonstration site is a 1.9 MW PV plant in New Jersey. The feeder, J1, is a 12.47 kV feeder with loads from commercial and residential customers. The summer is 6 MVA. The feeder has one 900 kVAR capacitor bank (voltage controlled), one 1200 kVAR capacitor bank (voltage controlled), and three 600 kVAR capacitor banks (2 manual and 1 voltage controlled) with an autonomous fixed schedule. In addition, the feeder has three line regulators controlled by the local voltage. Figure 13 below provides a one line of the feeder, the location of the substation and PV plant, as well as the monitoring points along the feeder utilized during demonstration.

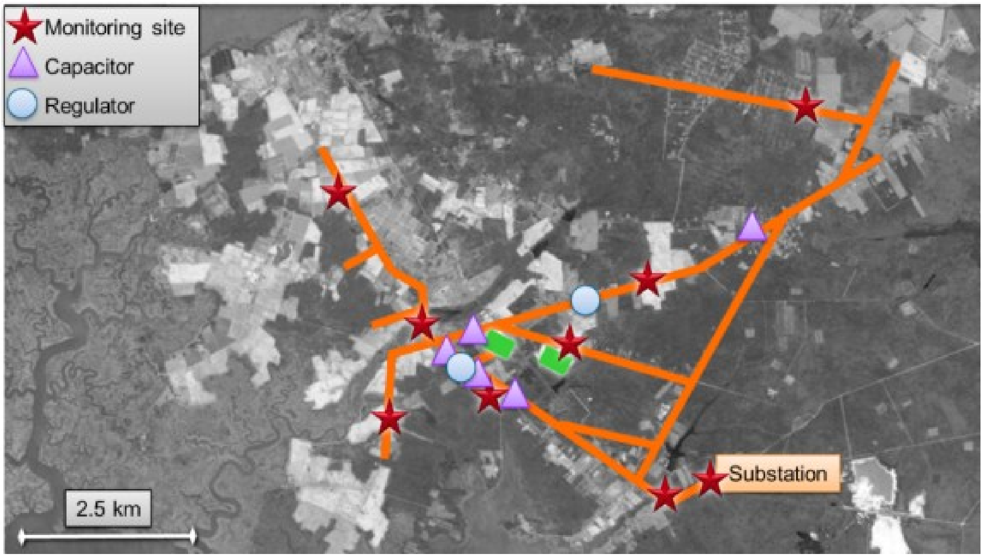


Figure 13 Pepco Holdings J1 Feeder – 12.4 kV rural feeder with 1.9 MW PV

The J1 feeder, with its controls and existing PV on the feeders, presents an opportunity to evaluate many potential smart invert benefits:

- **Avoidance of Overvoltage Conditions -** This demonstration will show how the autonomous volt-watt function of the smart PV inverter can help to avoid overvoltage conditions caused by PV plant output. This demonstration will require monitoring of overvoltage events over a long period of time, with volt-watt functionality in active and inactive states.
- **Reduced Line Regulator Tap Changes -** This demonstration will utilize the autonomous Volt-VAR function of the inverter in order to reduce the average number of LTC tap changes. This will require the deployment of sensing and logging equipment that can monitor or infer state changes by the regulators. The regulators are located at the substation and control the bus voltage. This bus is normally connected to only the one feeder involved in this test.

Because of equipment issues, the demonstration was not possible at this site, but the feeder was modeled to show the potential impact.

Task 8 Evaluate Smart Inverter and DER PMC in Laboratory/Factory

Testing of the SGI and PVI inverters was carried out between October 2013 and March 2014. The SGI inverter was tested at the NREL ESIF facility, while the PVI was tested at the EPRI Lab in Knoxville. The ESIF test facility was selected for the SGI because the inverter could be test at full power. The ESIF facility provides 1.5MW of emulated PV source and 1.2MVA of grid simulator which can represent most realistic installation condition for the utility scale inverter test.

The test is configured to represent the actual installation site operating scenario as much as possible. As shown in Figure 14, the Nebland software tool is used to emulate the SCADA input and the communication is set up with DNP3 protocol. The command is passed onto the plant master controller (PMC) and then delivered to the DUT. The PMC is not usually used when there is only one inverter in the plant so that it is not required to include it for the inverter functional test for the system level test. The PMC output is sent to the outstation inside the DUT, which will update the DUT control to configure the control mode and change settings. Below are sample test results for the SGI at NREL.

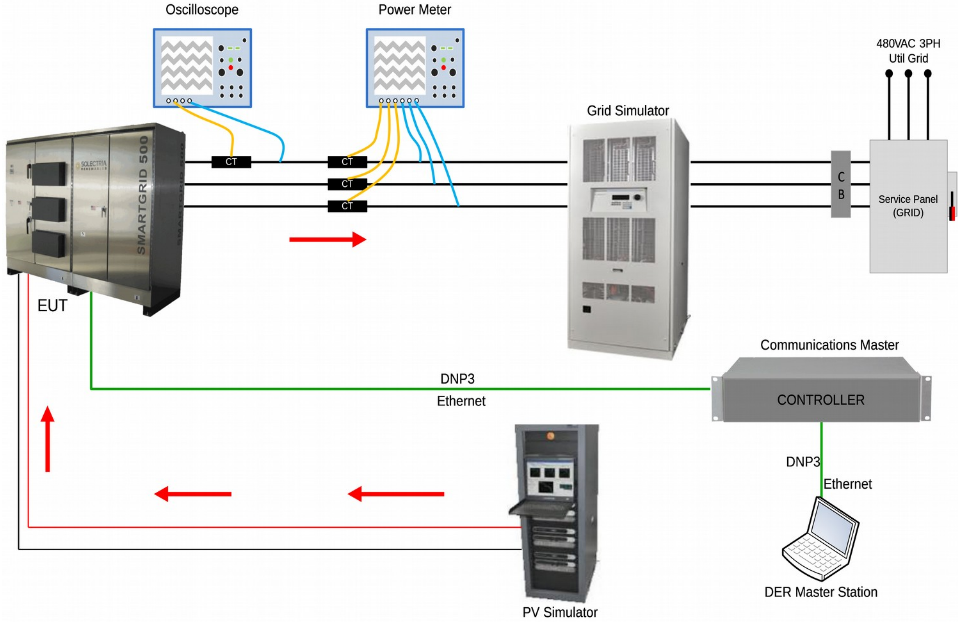


Figure 14 Solectria Test Setup at ESIF

The functions include: power curtailment, power factor control, intelligent volt-VAR, volt-watt, low voltage ride through, and reactive power control.

Power Curtailment

The power curtailment function requires the inverter to limit its ac output current to keep the real power output below the maximum generation limit. In this test scenario, a utility controller sends out several power curtailment commands using the DNP3 protocol with a given ramp rate (e.g. 15 seconds), randomization time window (e.g. 5 seconds) and reversion time (e.g. 0 seconds) as defined in the DNP3 protocol. These time settings represent the optimal time duration to control the startup transient of the function or define the time to disable the inverter operation, and can be programmed as required using DNP3 communication. Figure 15 shows and example test results for the real power curtailment function with the PVI inverter.

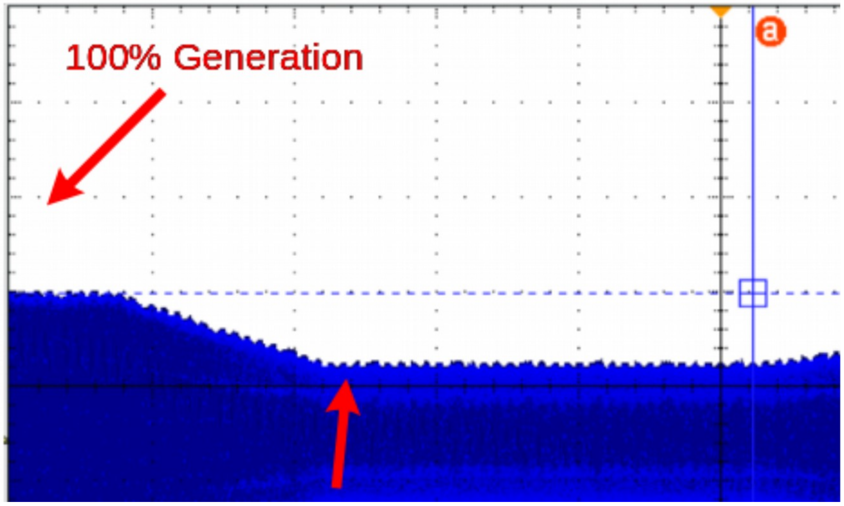


Figure 15 Inverter real power curtailment test

Power Factor Control

In order to test the power factor control, the real power output level was held constant and reactive power output was changed to respond to different power factor commands. Figure 16 shows the inverter operation with different power factor commands.

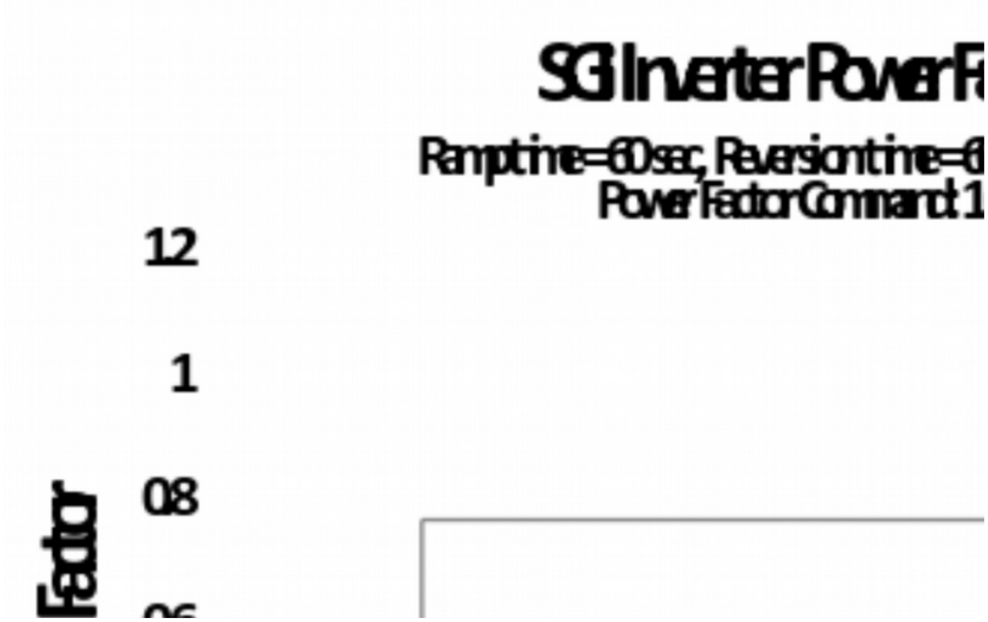


Figure 16 Inverter power factor control test

Volt-VAR

The intelligent volt-VAR function with deadband control was tested using the SGI 500 inverter as shown in Figure 17. The slew rate and the deadband for the curve can be programmed using a controller with DNP3 protocols.

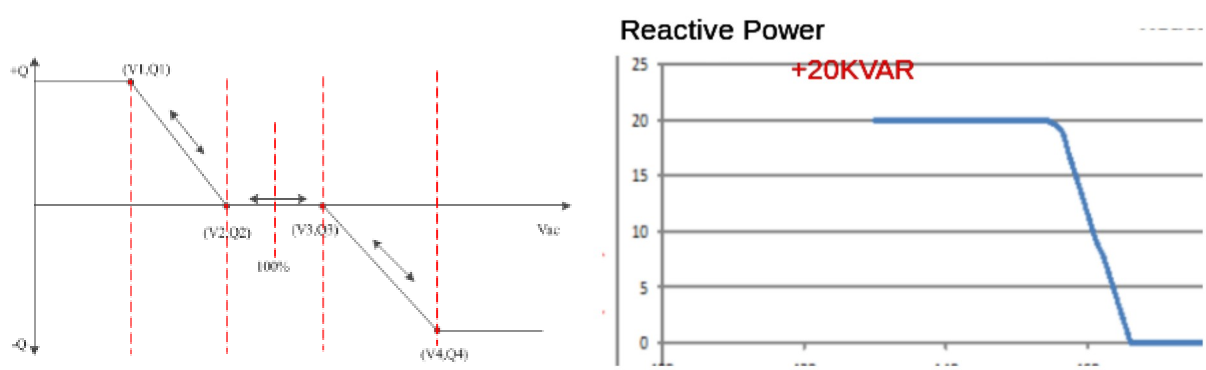


Figure 17 Intelligent Volt-VAR function set points and measurement

Volt-Watt

The volt-watt function decreases the real power generation when the inverter's terminal voltage exceeds a threshold configured by the operator. Rate of change in real power in response to voltage increase is defined by a characteristics curve. In Figure 18, an example test result of the volt-watt function is shown.

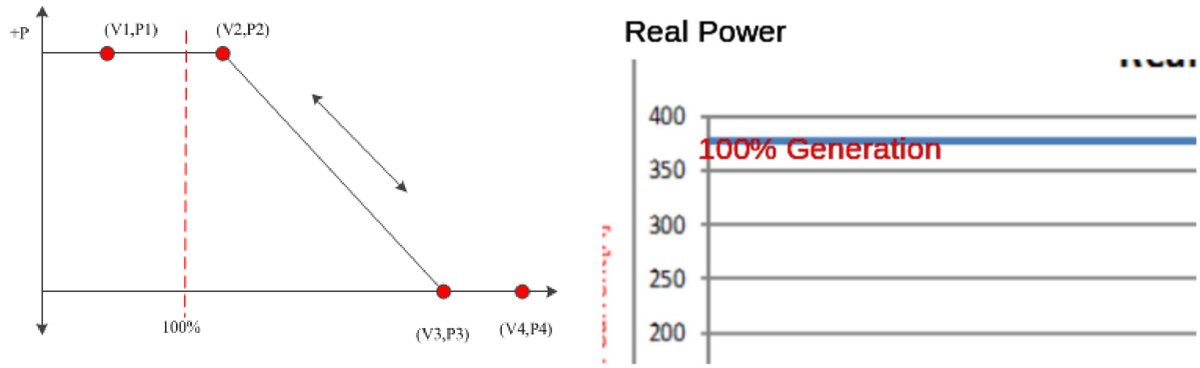


Figure 18 Volt-watt test results

Low Voltage Ride Through

Figure 19 shows the inverter operation during a 70% voltage sag (70% remaining voltage during sag). The wave shapes in yellow shows the AC voltage and in light green shows the inverter output current. The inverter was designed to ride through up to 30% voltage sag for 3 seconds and then shut down if the sag lasts longer. During the first 3 seconds, the inverter generated extra (reactive) current to support the sagged voltage as is shown in the green current trace. This operation is called ‘active ride through’ which is a required function in this project

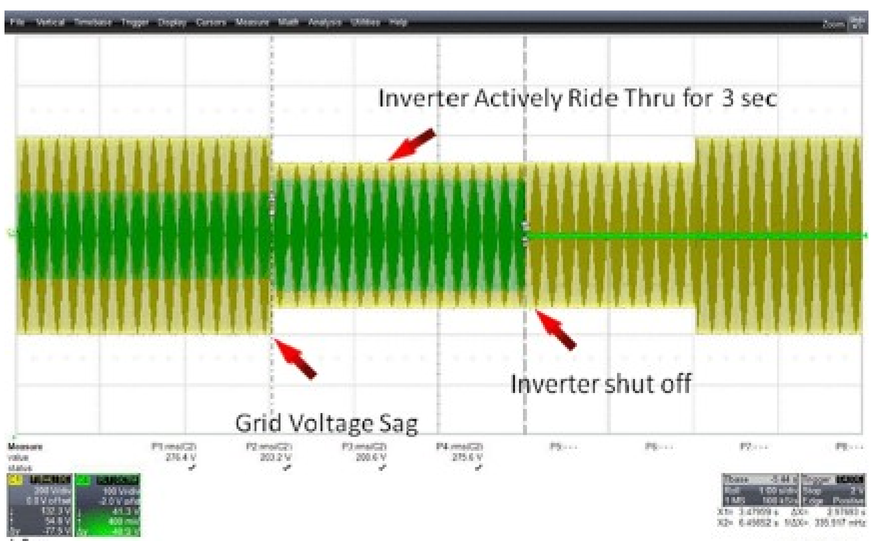


Figure 19 Inverter ride through and Shut-off test with 70% voltage sag

Figure 20 shows the transients when the inverter is going into and getting out of the sag condition with 55% voltage sag. The zoomed in transient waveforms show only a few cycle of settling time (less than 5 cycles) with the current waveform, which should be fast enough to respond to the grid transient. The voltage sag is severe, but ride through time lasts 2 seconds and the inverter continues to operate normally during and after the sag condition. Initially, the inverter was generating 55kW. During the sag, the real power is reduced to lower level and 20kVar reactive power was provided to support the grid voltage.

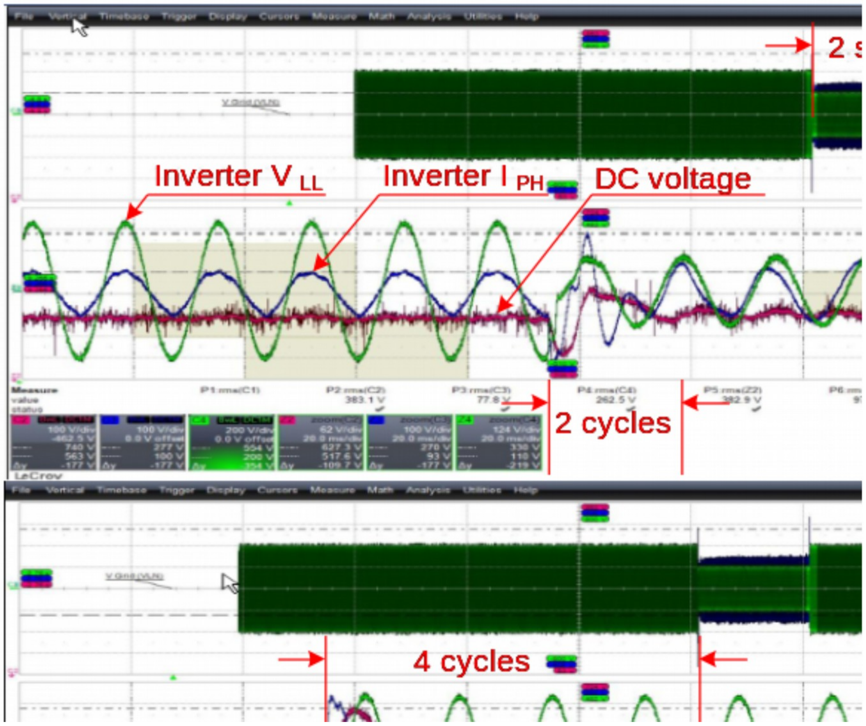


Figure 20 Inverter ride through operation with a temporary voltage sag

Reactive Power Control

Figure 21 shows the fast dynamics of the reactive power control during testing. When commanding an instantaneous reactive power, the inverter current stays within in the appropriate range.

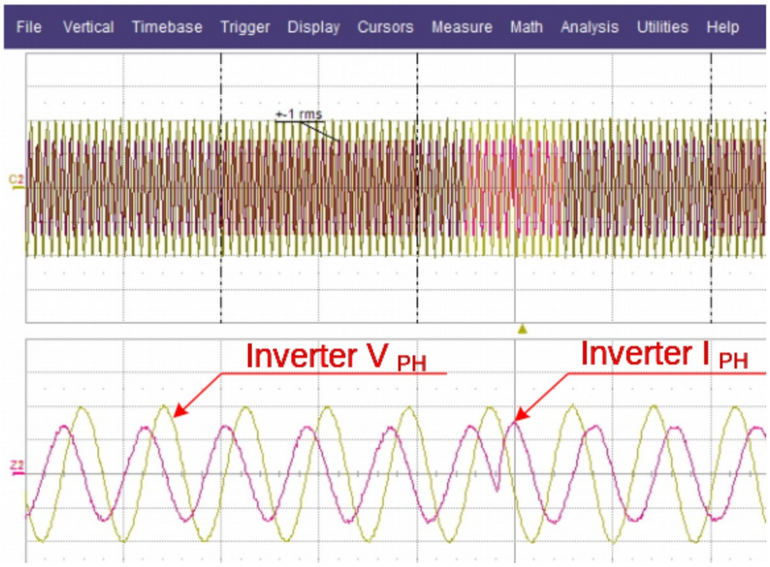


Figure 21 Transient response of full swing reactive power control

Task 9 & 10 Deploy Hardware and Software at the Demo Sites, Implement DER PMC

For each utility demonstration site, equipment and software upgrades were identified. Table 6 provides a summary for each feeder.

Table 6 Hardware and Software Deployment Plan

Site	Inverter + PMC	DERMS	Anti-Islanding	PQ Monitoring
National Grid H1	2 SGI + 1 PMC	BPL Global	none	Site + 5 along feeder
National Grid E1	2 SGI + 1 PMC	BPL Global	none	Site + 4 along feeder
DTE Energy F1	1 SGI + 1 PMC	DRSOC	Direct transfer trip (radio)	Site + 2 along feeder
Pepco J1	6 PVI + 1 PMC	Nebland Software	none	Site + 7 along feeder

Task 11 Perform Generic and Demo Site Specific Feeder Simulations with and without Smart Grid Functionality

There are two key parts of the modeling task a) quasi steady-state time-series (QSTS) simulations in OpenDSS to compare feeder performance with and without smart inverters and b) time-domain analysis in Matlab to investigate possible inverter interaction. The initial work on the time-domain analysis has been completed. Using a simplified utility feeder model, PV with volt-VAR control was added and the interactions between two PV units were evaluated under different function parameters. The findings indicated that interactions can exist between two inverters with smart functions implements. In general, the modeling showed that (1) High ratios may cause oscillations, (2) Smaller adjustments at each step as a result of smaller control parameters reduces oscillations, and (3) Longer voltage averaging window increases magnitude of oscillations, although dampening does occur.

The QSTS simulation based feeder analysis of smart inverter functions is also well underway. The detailed feeder analysis consists of modeling the utility feeders involved in the project, application of various smart inverter functions, and analysis the impact. These three steps will be elaborated in the next three sections.

Detailed Feeder Modeling

The accuracy of the model used in the simulation has a direct impact on how accurate the simulated results will be to the field response when the control is implemented in the field. Therefore, much care is given to modeling each feeder and then validating the model to utility data and field measurements.

The original utility feeder model has been provided to EPRI in the database used by the utility. Because each utility is using a different software platform (Cyme, DEW, Synergi), the utility provided models are converted into the open-source modeling environment OpenDSS. This software is maintained by EPRI and allows complex analyses to be conducted in an efficient manner. The software platform includes many features not available in traditional software platforms such as inverter volt-VAR control and QSTS analysis. The use of these features is pertinent to the success of the simulation and will be discussed in the next section.

The converted feeder model must match the models behavior in the utility environment. To check this, voltage profiles across the feeder are examined along with the short circuit characteristics of the feeder. The voltage profile plot of the H1 feeder is shown in Figure 22.

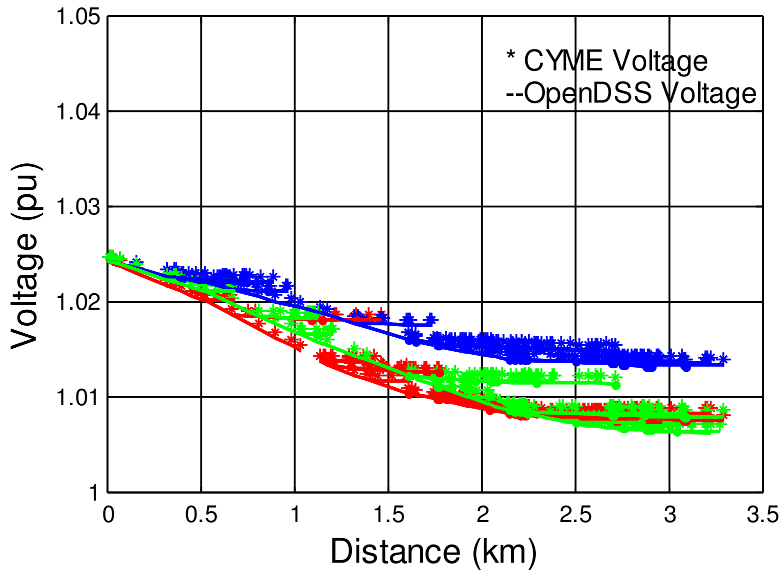


Figure 22 Validation of Model using Voltage Profile Plot

The steady-state response of the feeder is accompanied by a time-series validation of the feeder model. In the time-series model, all control modes must be implemented such as capacitor control modes setpoints, and delays. The model also incorporates voltage regulation control such as substation load tap changers, line drop compensation, and line regulators. These controls involve voltage setpoints, transformer ratios, bandwidths, and delays. The majority of data is provided in the utility model; however, additional data must be acquired and incorporated for the analysis performed in this study. The time-series response of the model is compared to measurement data for additional validation. An example of validation for the Pepco feeder is shown in Figure 23 where simulated and measured voltages are compared at one of the solar sites.

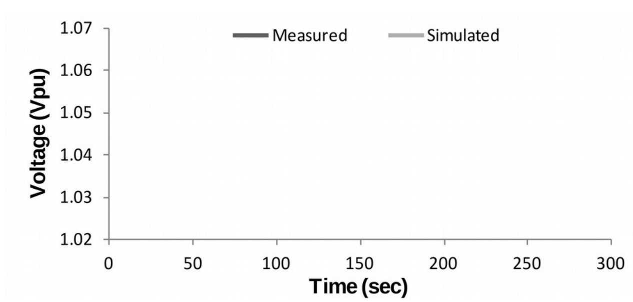


Figure 23 Validation of Model using Time-Series Voltage

Methodology for Smart Inverter Application

Each utility identified the smart inverter functionality to be analyzed on the feeder. These functions include power factor control, volt-VAR control, and volt-watt control. The specific feeder objective for these functions is dependent on the feeder so the methodology has been designed to examine a wide range of control settings and report on a vast array of feeder impact.

The control settings used are not all inclusive as the number of possibilities is infinite. Therefore, a representative range of possibilities has been chosen in the analysis. A total of 112 volt-VAR control curves are shown in Figure 24. There are three types: a) no deadband, b) with deadband, and c) inductive mode only. Although these are three main types of curves, other possibilities could include deadbands off the y=0 axis, shifts further left/right on the x-axis, or nonlinear variation in the inductive/capacitive regions.

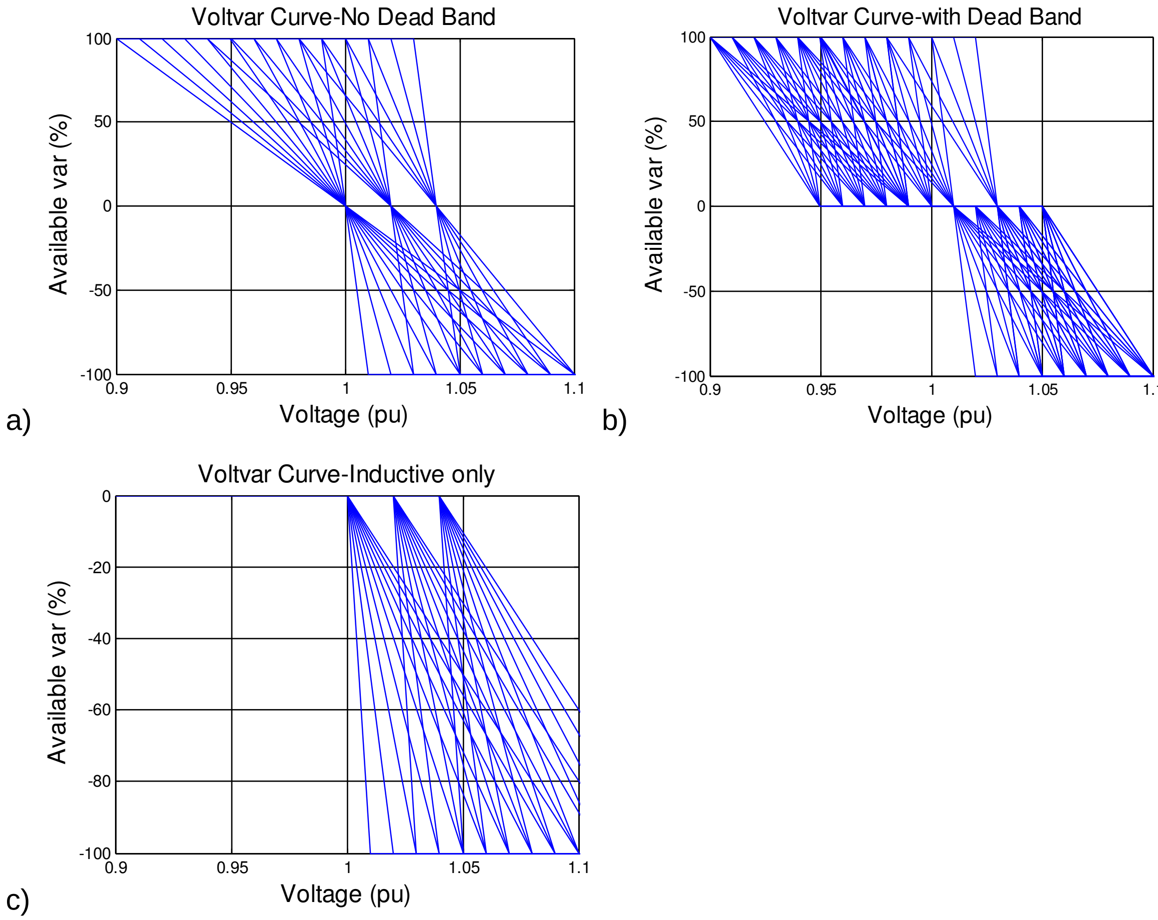


Figure 24 Volt-VAR Curves Analyzed a) No Deadband b) With Deadband c) Inductive Only

The control curves used for the volt-watt analysis are shown in Figure 25. These 60 curves are again not inclusive of all possibilities but sufficiently examine a wide range of those that are practical. Curtailment of real power is not expected at lower voltages while curtailment might be expected when voltages begin to exceed the ANSI 105% limit. Additional options that are not analyzed include nonlinear curves.

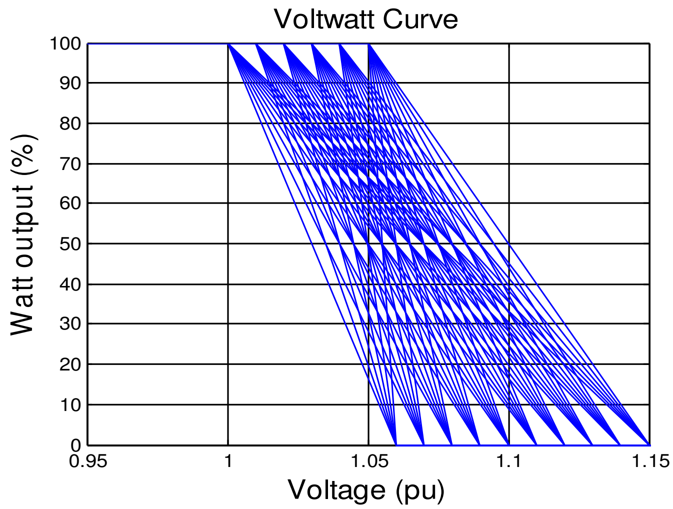


Figure 25 Volt-Watt Curves Analyzed

The power factor control examines specific setpoints on the inverters. These inductive setpoints vary from 0.9 to 0.99 in 0.01 increments. Finer resolution could be examined but general trends are expected using these values.

The feeder impact is examined by performing a time-series simulation using each control setting, three solar profiles, and two load conditions. The solar profiles are acquired from measurement data and include one of each highly variable, clear, and overcast day. The load conditions include the peak and minimum load days. The simulation is conducted at the 1-minute resolution for a 24 hour period in each combination of control setting, solar profile, ad load condition. For each scenario the feeder impact is examined for 19 criteria. These include point of common coupling impact, feeder-head impact, feeder-end impact, and feeder-wide impact. A table of monitored impact is shown in Table 7.

The four primary impact criteria are identified. These are: 1) the tap operation criterion is used to determine the benefit of reducing wear and tear on those devices. 2) the feeder consumption criterion is used to judge the overall benefit to customer efficiency. 3) mean point of common coupling (PCC) voltage is used to gauge the impact on customer efficiency as well as voltage profile. 4) the voltage variability index (VI) at the PCC determines the voltage smoothing potential of the inverter control. Ideally the values for all four criteria should reduce under the smart inverter control strategy.

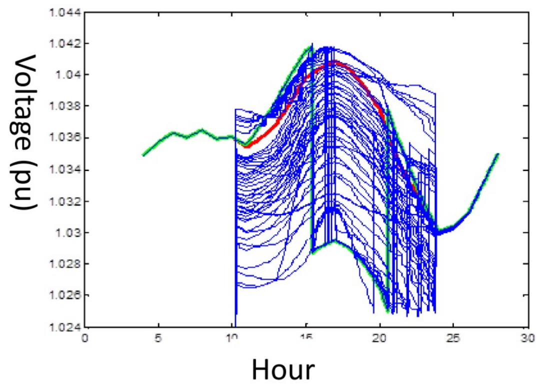
Table 7 Feeder Impact Criteria

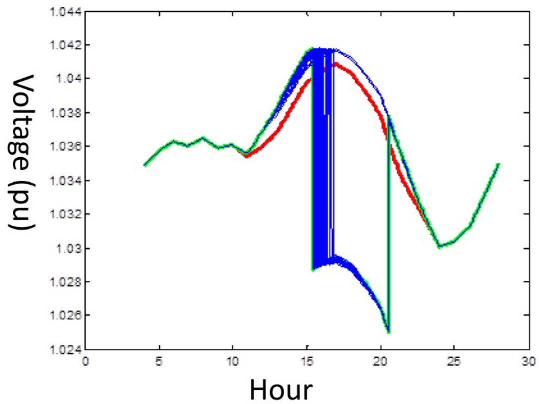
Feeder Impact Criteria	High Priority Impact
Minimum Feeder Head Power Factor	
Tap Operations	X
Cap Operations	
Feeder Losses (kWh)	
Feeder Consumption (MWh)	X
Max Feeder-Wide Voltage (pu)	
Time Above ANSI Max Voltage (sec)	
Min Feeder-Wide Voltage (pu)	
Time Below ANSI Min Voltage (sec)	
Max Feeder Head Voltage (pu)	
Mean Feeder Head Voltage (pu)	
Min Feeder Head Voltage (pu)	
Max Feeder End Voltage (pu)	
Mean Feeder End Voltage (pu)	
Min Feeder End Voltage (pu)	
Max PCC Voltage (pu)	
Mean PCC Voltage (pu)	X
Min PCC Voltage (pu)	
VI at PCC	X

Methodology for Analysis of Feeder Impact

The feeder impact scenarios from the different smart PV inverter control settings provide an abundance of data. Figure 26 shows the voltage response at the feeder head for the various settings of the three control types. One noticeable aspect of this example was that volt-VAR control is capable of significantly altering the feeder as soon as the inverter comes online for the day. These inverters were only capable of reactive power support when the inverter is online during active power generation, and the reactive capacity is greatest during low active power output. This occurs because the inverters operate in the watt precedence mode for the simulation. The volt-watt and power factor control are dependent on the active power output from the inverter which typically increases midday.

a) b)





c)

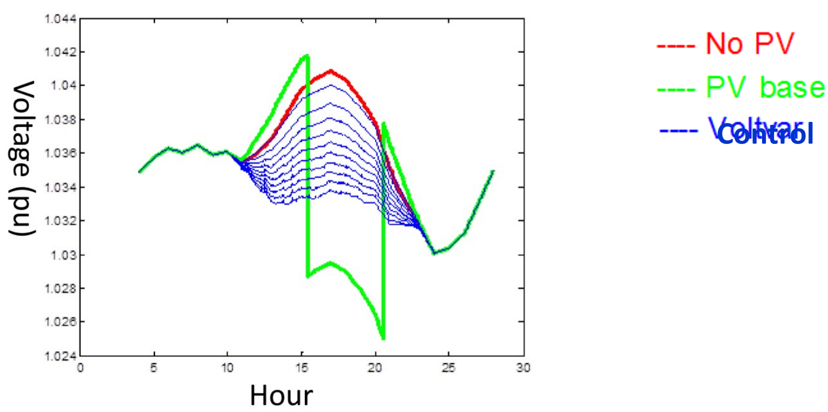


Figure 26 Feeder Head Voltage Response a) Volt-VAR b) Volt-Watt c) Power Factor

The selection of best settings was done by ranking the control setting based on the performance metrics and then down-selecting based on voltage limits. An example of the volt-VAR control ranking is illustrated in Figure 27. The ranking labels the most optimal control settings to the least optimal control settings. The ranking was weighted based on the feeder impact criteria metric and also the solar/load condition. Weighting based on feeder impact was applied because multiple feeder impact metrics can be examined simultaneously yet some criteria can be more important to the overall objective. Weighting was also adjusted based on solar/load condition to determine the overall impact over a longer time horizon where some conditions are more likely to occur than others.

The control with the lowest overall rank identifies the control that consistently provides a better benefit with respect to the optimized metric/s. The magnitude of rank was dependent on the total number of control settings analyzed and will be dependent on whether volt-VAR, volt-watt, or power factor is analyzed. In Figure 27, a total of 110 different volt-VAR control settings are considered. The solid blue circles identify control settings that did not cause a primary node voltage violation (outside ANSI min/max). Green circles identify control that caused primary node voltage violation but for a length of time less than or equal to the baseline PV at unity power factor scenario. Red circles identify settings that caused primary node voltage violations for a length of time greater than the baseline PV scenario.

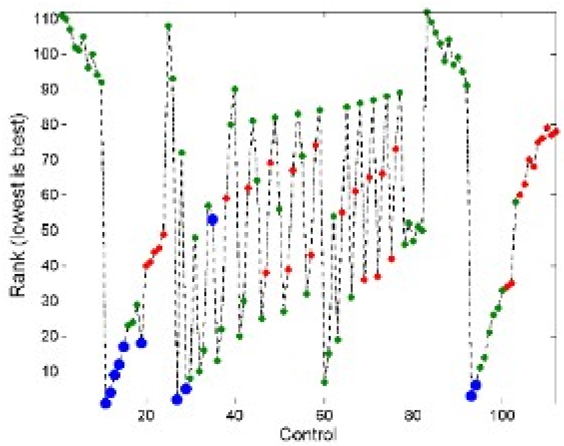


Figure 27 Volt-VAR Curve Ranking

Trends can be seen in the ranking based on control setting analyzed, as shown by the dashed black line. These trends occur because the control settings utilized sample through different characteristics involving setpoints, bandwidths, and slopes that are somewhat similar.

An illustration of the three best volt-VAR curves is illustrated in Figure 28. All three curves have identical shape in the lower half of the figure. Fortunately, in this example, the best control settings (lowest magnitude rank) do not cause any violations. Throughout the analysis, however, there were situations that the lowest ranked control settings only reduce, or potentially increase, voltage violations. In these conditions, the recommended best settings would be based on lowest rank as well as whether a reduction or elimination of voltage violations is required.

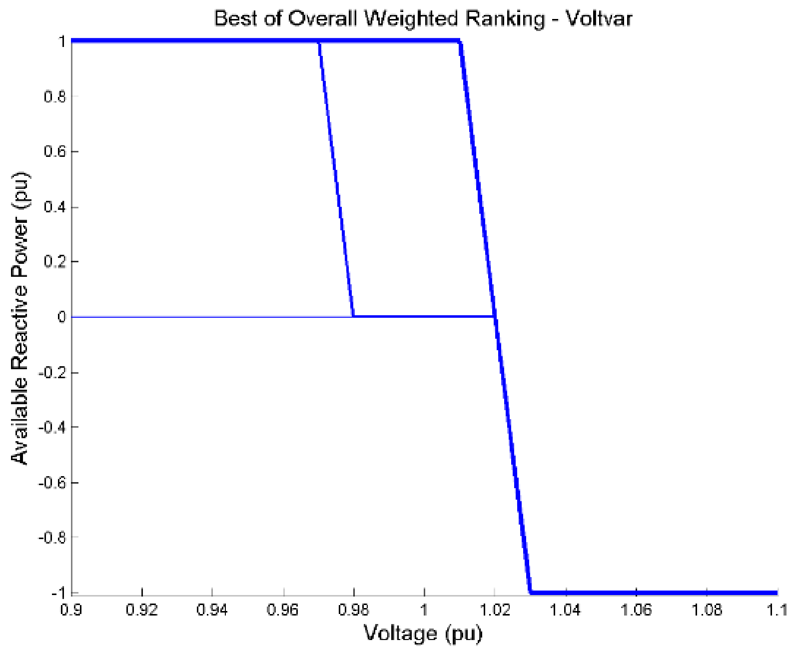


Figure 28 Three Highest Ranked Volt-VAR Curves (Thickest line represents the best ranked settings)

The best settings from each of the three control types has the ability to improve the feeder response similar to that prior to adding PV to the feeder and potentially better in some cases. Figure 29 shows the use of proper volt-VAR settings can reduce regulator operations compared to the baseline no PV scenario.

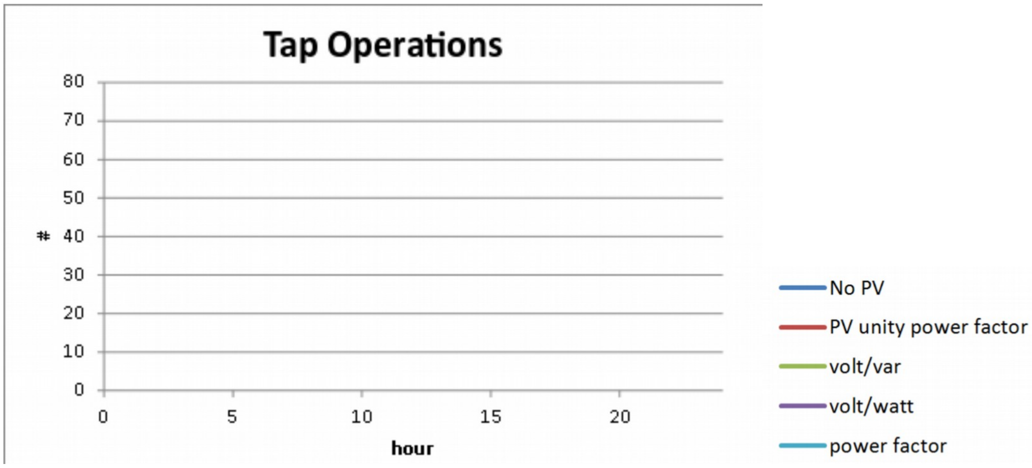


Figure 29 Regulator Tap Response from Best Settings

The analysis was aimed at determining the best control settings, but to give perspective, there are also control settings that would not be preferred. An example of the best and worst volt-VAR settings are shown in Figure 30. This figure shows two potential settings for volt-VAR control. One provides benefit to the system while the other causes adverse impact. Figure 31 shows the feeder voltage response from the two volt-VAR settings. The variations in voltage from the worst setting also translate to the significant increase in voltage regulator tap operations shown in Figure 32 shown in green.

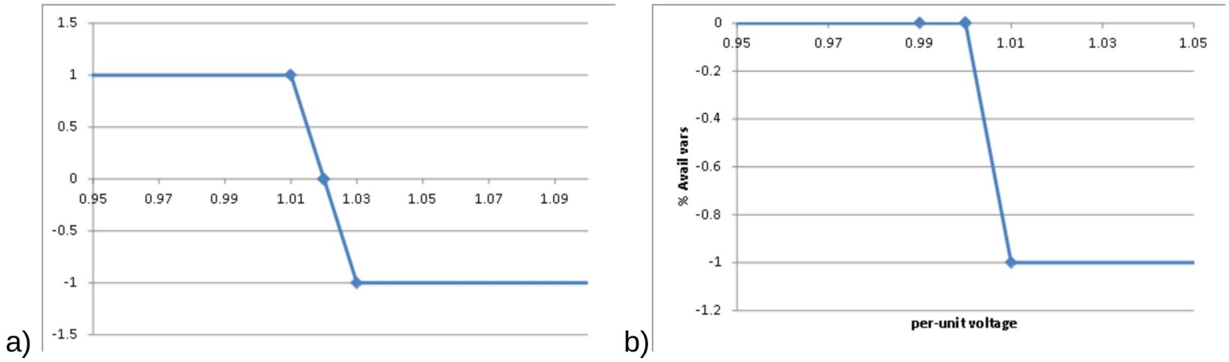


Figure 30 Volt-VAR Control a) Best Setting b) Worst Setting

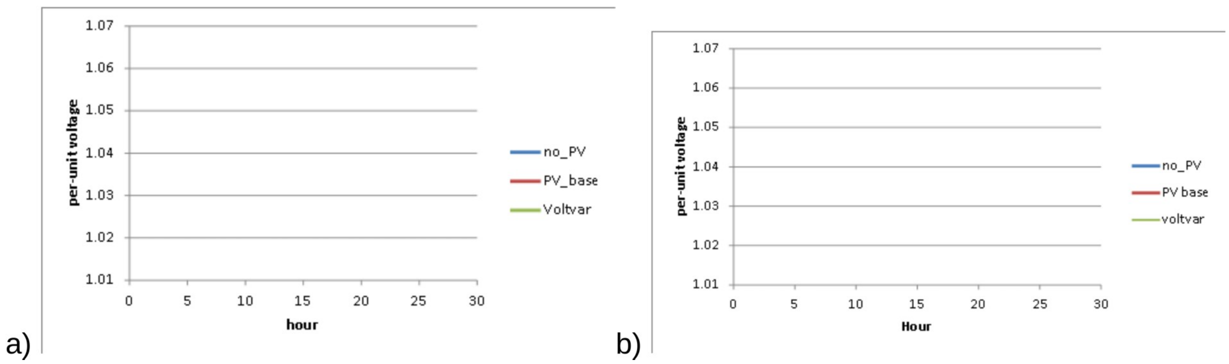


Figure 31 Voltage Response a) Best Setting b) Worst Setting

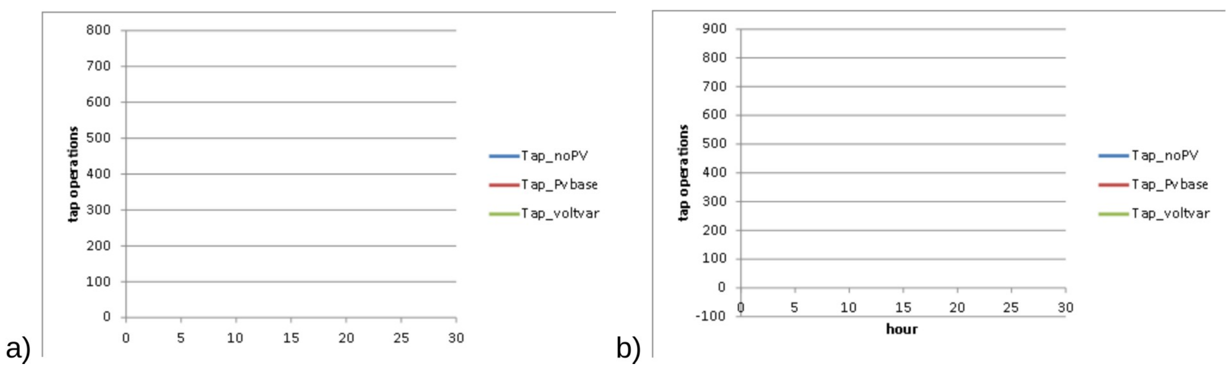


Figure 32 Regulator Tap Response a) Best Setting b) Worst Setting

Task 12 Conduct workshop on Advanced PV Inverter and Power System Simulations

The workshop was held on Wednesday May 7, 2014 in conjunction with the EPRI-Sandia PV Symposium in Santa Clara California. The topics covered in the one-day session included:

- DOE SunShot Initiative overview
- Project Background
- Smart Inverter Standards
- Prevention of Unintentional Islanding
- Modeling Smart Inverters on the Distribution System
- DTE Modeling for Day-Ahead Forecasting

- PVI & SGI Testing
- Enterprise Integration and Standard Methods for DERMS
- DERMS at National Grid
- Utility Demonstration Plans

Phase II – Yr 1 CRITICAL MILESTONEs

1. Complete the development of generic and demonstration site specific feeder models for simulations of impact of the smart-grid functionality – ***As described in Task 11***
2. Successfully complete the functionalities and performance of the PV inverters and DER PMC in the laboratory and the factory site to verify they meet the design objectives – ***As described in Task 8***
3. Successfully conduct the workshop on advanced PV inverters and power system simulation. – ***As described in Task 12 on May 7, 2014***
4. Go/No-Go decision point – ***Review held in Washington DC May 1, 2014***

Task 13 Design Unique Test Plans/Sequences for each Demonstration Site

Initial field demonstration was carried out over a 4-month period specifically aimed at commissioning the smart PV inverter functionality of each inverter. At each of the three sites, five functions were tested to validate the function operated properly as well as determine the accuracy of its operation.

The following 4 months of field demonstration were performed by executing the test phases selected out based in the utility feeders, equipment deployed, and modeling performed. The testing was done using two methods: 10 minute on/10 minute off testing and full day on. The later consisted of turning on a function to operate for a full day or week. This allowed the team to capture data on the stability of the function as well as its response over the course of the day. These on days can then be compared to similar off days (in regards to solar resource and load) to understand impact. Due to the shorter test window, the 10 minute on/10 minute off testing was done to see impact of particular functions during many different conditions throughout the day. Assuming that weather and feeder state will not change dramatically in a 10-minute window, this testing allowed us to compare the state of the feeder with and without the function operating.

The testing at the National Grid H1 site was carried out in six phases:

1. Baseline Data – no smart inverter functionality turned on
2. Volt-VAR control and vars precedence
3. Cycled on/off volt-VAR control
4. Fixed power factor
5. Volt-watt function
6. Remotely managed volt-VAR control

The testing at the National Grid E1 site was carried out in six phases:

1. Baseline Data
2. Autonomous volt-VAR control, Continuous Operation
3. Autonomous volt-VAR control, Cycled On/Off
4. Remotely Managed volt-VAR control
5. Autonomous volt-VAR control PLUS Dynamic Reactive Current

6. Dynamic Reactive Current Only (with no dead band)

The testing at the DTE Energy F1 site was carried out in four phases:

1. Baseline Data
2. Remote PF Control to Manage PF at the Substation
3. Autonomous Volt-VAR Control with Maximum Capacitance Settings, Cycled Operation
4. Centrally managed, with optimal settings computed daily by DMS

Task 14 Test Unintentional Island Prevention at Demonstration Sites

The original intent of the field demonstration was to install the lab-evaluated DX3 transmitter at National Grid's H1 substation that was being utilized for other phases of the current project. However, because of construction requirements and difficulty procuring a suitable location near the substation, installation at H1 was deemed unacceptable. The transmitter was sized, however, for the low fault current level at the H1 substation. Therefore, it was also not suitable for installation at several backup sites around EPRI's Knoxville facility due to much higher fault currents in those substations. Thus, installation in Knoxville was also ruled out.

Though the unit evaluated in the lab never made it to the field, the lab experience lent support to another field demonstration of the DX3 Pulsar at a National Grid substation in Potsdam, NY. A photograph of the installation is shown in Figure 33. As part of the project, National Grid allowed EPRI to monitor installation during both normal and fault conditions.

Figure 33 Photo of DX3 Pulsar installation in Potsdam, NY (Source: National Grid)

During normal system conditions, the units operated nearly seamlessly, with the transmitter reaching 3 downstream rotating DG. However, the sag immunity problem observed during laboratory testing caused significant issues with false trips. In Figure 34, the transmitter saw a sag to 80% retained voltage and tripped within 30 cycles (0.5 seconds), consistent with laboratory experiments. This event also required a 4 second recovery time before the transmitter returned to operation.

As a modification in the field, National Grid added delays to their receiver units such that a 4 second recovery period wouldn't cause the DG to trip. While this is a less than ideal solution (given that the expectation for anti-islanding performance under IEEE1547 is 2 seconds), it satisfied National Grid's criterion for demonstration.

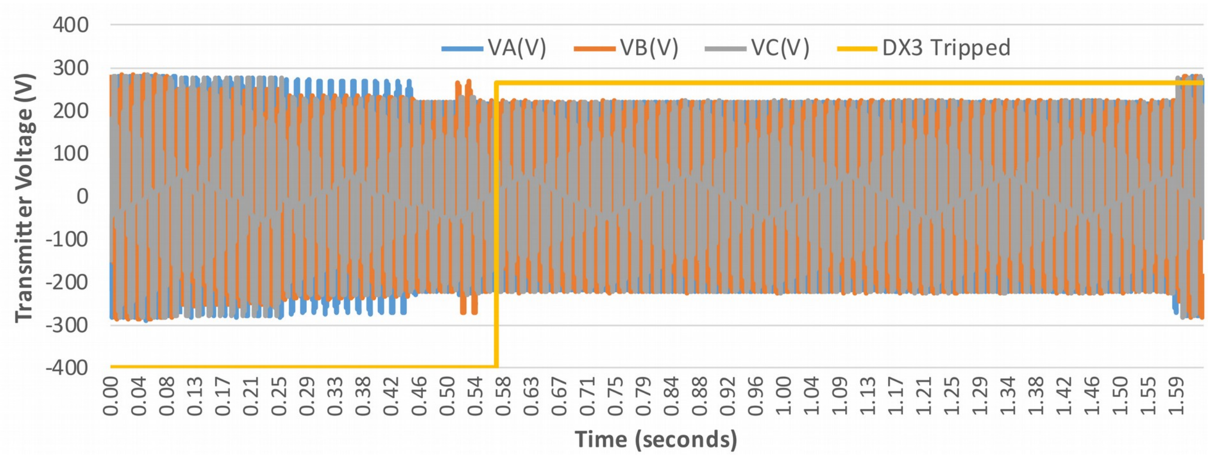


Figure 34 Recorded event of transmitter tripping off-line during field testing

As part of the project, wireless communications units from Raveon (UHF Band) and Remote Control Technologies (CB Band) were acquired and installed at EPRI's lab in Knoxville, TN. Both units were purchased with "stock" omnidirectional antennas, and mounted on a short mast near the facility. While both units passed a laboratory-scale demonstration, inadvertent damage to the Raveon receiver prevented it from being used in field testing.

With the transmitter installed at EPRI's facility, the Remote Control Technologies receiver was transported to locations with a varying distance from the transmitter. Figure 35 summarizes the findings that consistent communication was possible at 1.7 miles, and became intermittent by 2.3 miles, and failed at 2.5 miles. Upon further discussions with the manufacturer, the recommended antenna to achieve the quoted 5-mile range was one with an 18-foot vertical, with radials pointing down at 45 degree angles. A half-wave element of that size was deemed necessary because of the long wavelength of the 27MHz frequency, and the low transmitter power limits of 5 watts in that band.

Figure 35 Summary of Field Tests with Remote Control Technologies 27MHz system

Task 15 Demonstrate Grid Supportive Functionality of Inverters

The testing was performed using the settings as determined from the feeder modeling and as defined in Task 13. These settings were based on the six PV and load scenarios and were selected as the best setting on an annual basis. When testing, it was determined that in the 4 months we were testing the recommended settings for each site would likely not show much of an impact because they are ideal for the current period. This resulted in a shift to the test plan to set the volt-VAR curve in such a way that the inverters were operating "on the slope" and not in an optimal annual state. By doing this, the analytics were able to better show the ability of the inverter to impact the system and the stability of the functions themselves.

The analytics that follow focus on validating smart PV inverter functionality as well we capturing the voltage impacts of these smart PV inverters on the demonstration feeders. For each of the three sites demoed, a summary of key findings are included.

This phase of testing involved the Volt-VAR function operating in a Vars-precedence mode continuously for 7 days.

The initial research question, and perhaps the most important, is whether or not the inverter is stable when operating in its various modes. Computer modeling is effective in determining the grid impact of smart PV inverter functions at high solar-penetration levels, but such modeling and simulation generally assumes that the inverter function is stable.

Field testing is required to determine whether or not the actual control loop of the inverter is stable in real world environments. This is particularly important for functions such as Volt-VAR control that create a natural feedback loop as illustrated in Figure 36.

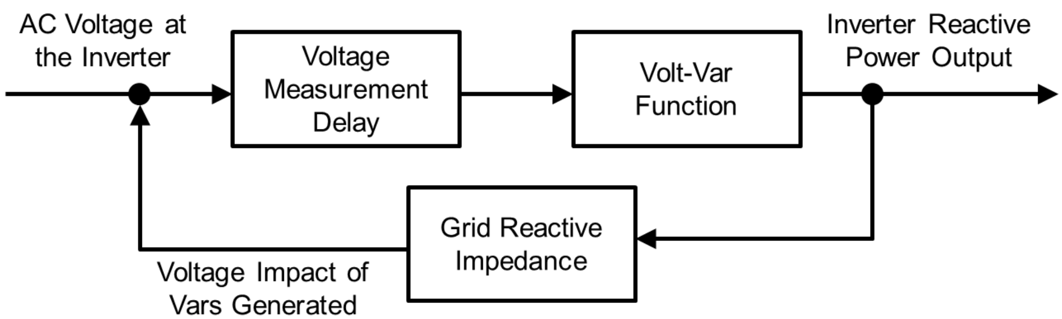


Figure 36 Example Potential Feedback Loop

This test could also be considered as a scenario where the inverter functionality is fixed at install time and not adjusted (or rarely adjusted) thereafter. The Volt-VAR curve in Table 8 was used for this test. This curve was determined based on measurements at the inverter (normally around 0.98pu) with the goal of operating on the sloping portion of the volt-VAR curve where the loop-gain of the feedback loop shown in Figure 36 is the greatest. The modeling and simulation also showed that a steep Volt-VAR curve as used here was best overall.

Table 8 Volt-VAR Curve for Test Phase 2

Volt-VAR	Y1=1	Y2=1	Y3=0	Y6=-1	Y7=-1
	X1=0.5	X2=0.97	X3=0.98	X6=0.99	X7=1.5

Figure 37 is a scatter-plot of the measured voltages and reactive power levels produced by the plant over the course of the testing. Each blue dot in this plot represents the one-second measured results during the “On” test periods over the three-day Phase 2 test.

The voltage measurement accuracy of the inverter can be seen in this plot, with a 0.3% shift in the trend line followed from the assigned curve. A take-away of this is that voltage measurement accuracy of inverters may need to be improved to perform as expected. As noted by the scatter of blue points, the voltage was tightly regulated by the Volt-VAR function during the testing.

There were no voltages lower than 0.978 p.u. or higher than 0.987 p.u. at the AC output of the plant.

Voltage observations elsewhere on the feeder, reflective of the medium voltage, were not as tightly regulated. It was noted that the plant only swung through 1/3 of its potential Var range of control. A take-away of this is that a plant of this size could have done more to positively impact the grid if it had visibility to the medium voltage or were actively managed by a DERMS with such visibility.

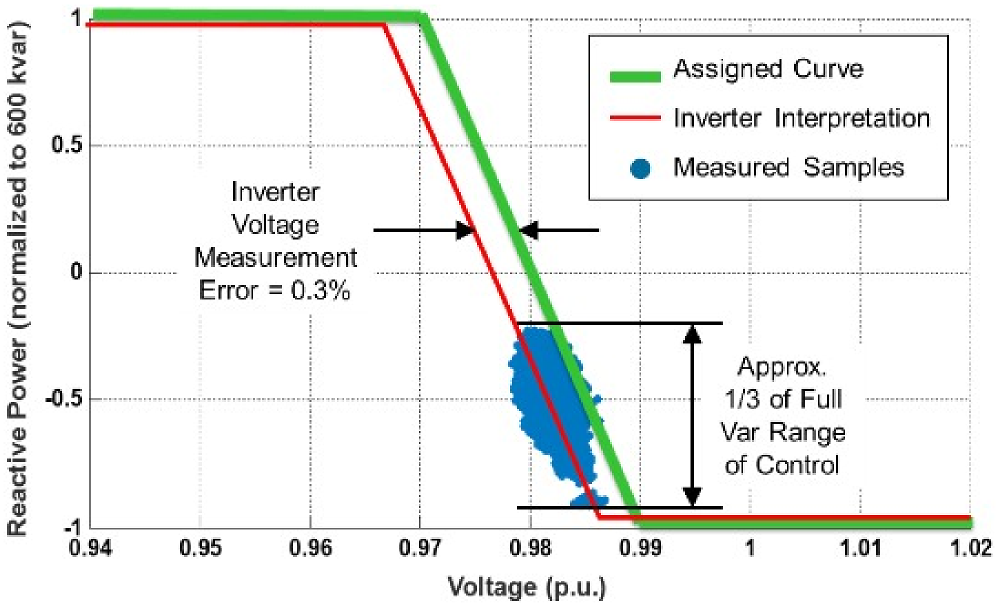


Figure 37 Volt-VAR Curve Settings and Data from the H1 Test Site

In this same test phase, voltage variability was also evaluated at both the PV plant, across the feeder, and at the substation. In order to quantify this variability, methods for calculating solar variability were used. Figure 38 provides a view of the impact on variability over the course of a day. This chart is a histogram of occurrences of 1-second voltages with the Volt-VAR function “On” (red histogram) and “Off” (blue histogram). Each has the appearance of a normal distribution. With Volt-VAR control “On”, 99.7% of occurrences fall within an approximately 0.3% range. With Volt-VAR control “Off”, the distribution is at a higher voltage and 99.7% of occurrences is approximately 0.9%, or 3 times greater.

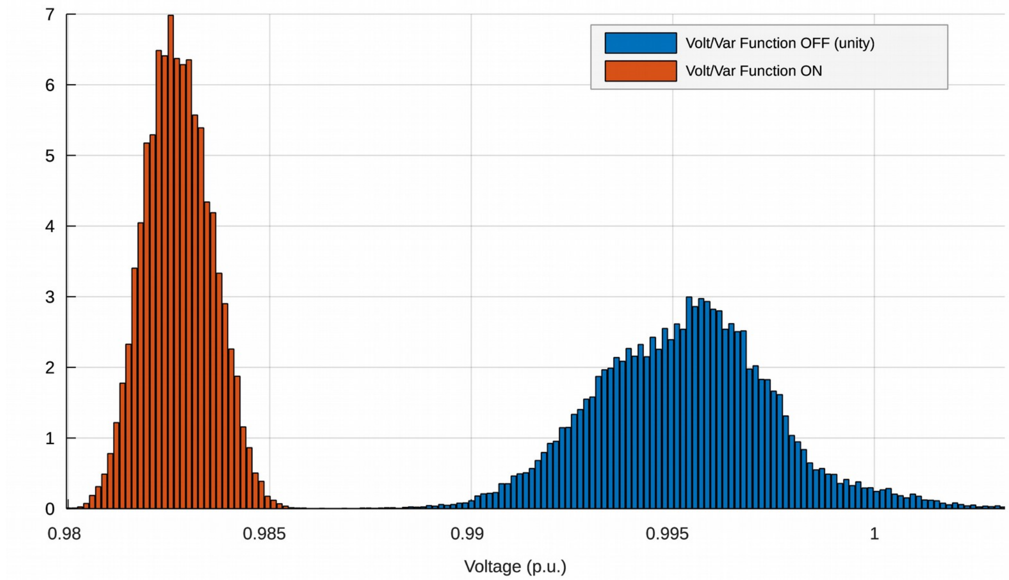


Figure 38 Histogram of Voltage at the H1 PV Plant

Figure 39 is a box and whiskers plot comparing the measured voltage from two similar days. The two similar days are chosen based on their variability index, clearness index, and the daytime energy consumption of the feeder. In the box and whiskers plot, the boundaries of the blue box represent the inner-quartile range, the red line represents the median value, and the whiskers represent the minimum and maximum values found excluding outliers. Outliers are determined as values which are more than 1.5 times outside of the inner quartile range.

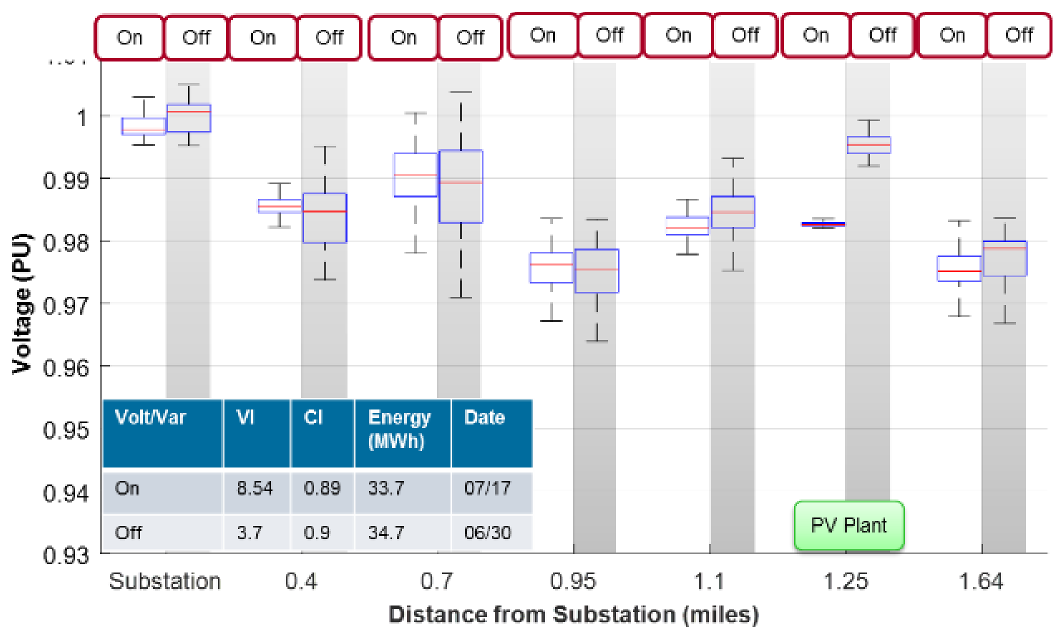


Figure 39 Box and whiskers plot of days with the volt-VAR function enabled and disabled for multiple points along the feeder

Voltage duration curves for all the points of measurement on the H1 feeder are provided in Figure 40, both with Volt-VAR control (top) and without (bottom). On these curves, the vertical axis represents the percentage of time that the voltage remained at a given level and show the overall picture for the Volt-VAR control impact on the feeder during the Phase 2 test.

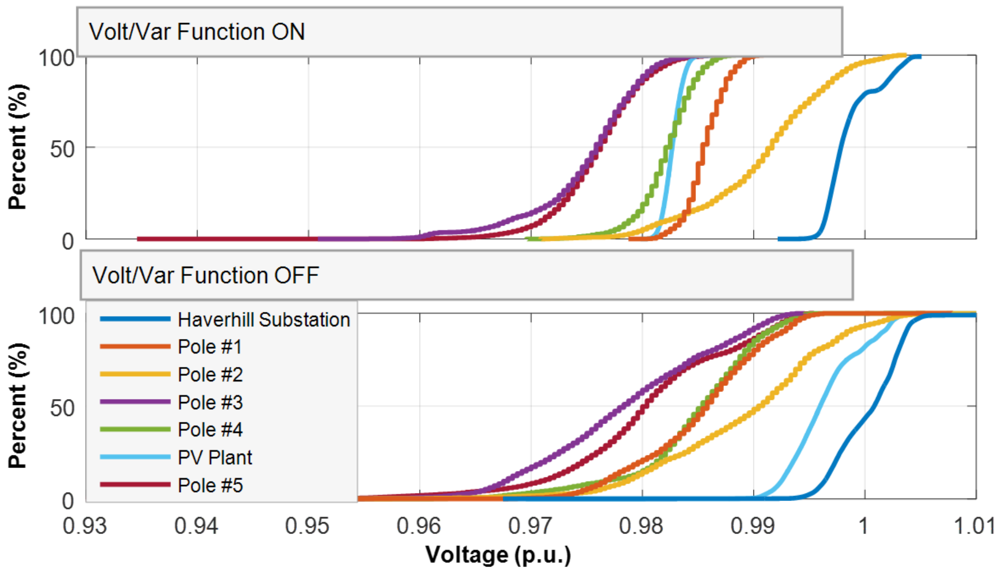


Figure 40 Typical Duration Curve of Voltages at H1

Note that the configuration used (see Figure 37) was centered at 0.98 (p.u.). This plot format shows both the shift of curves left-and-right (indicating a voltage regulating impact) and the steepening of curves (indicating a reduction in variability). The light blue curve from the PV plant is naturally the most effected in both regards. But it is notable that all the duration curves became steeper, and the entire grouping became tighter, indicating a successful flattening of the voltage profile along the feeder, even using only 1/3 of the plant's reactive power potential as previously noted.

Figure 41 illustrates a period of 10 minute on/off testing during which communication problems existed. Communication issues of this type persisted through much of the testing. In this case, it is clear that the DNP3 communication from the offsite control system to the plant was successful, but the in-plant translation of the received commands and dissemination to the two inverters was not reliable.

Figure 41 shows 11 successive 10 minute test periods during which it attempted to cycle the Volt-VAR control on/off. During the first two "On" periods, inverter 2 (red line) turned on but inverter 1 (blue line) did not. During the fourth and fifth "On" periods, the opposite happened, with inverter 1 turning on and inverter 2 staying off.

Ultimately these communication problems were traced to design implementation issues that related to the newness / prototype nature of the products being tested. However, for the project team, the experience called attention to the value of two things:

1. Autonomous functions – to the extent possible enabling products to manage their own behavior in response to locally-observable parameters (e.g. voltage, temperature)
2. Communication-loss detection and default values – implementing communication-connected systems in such a way that they detect communication loss as quickly as possible and apply logical default settings.

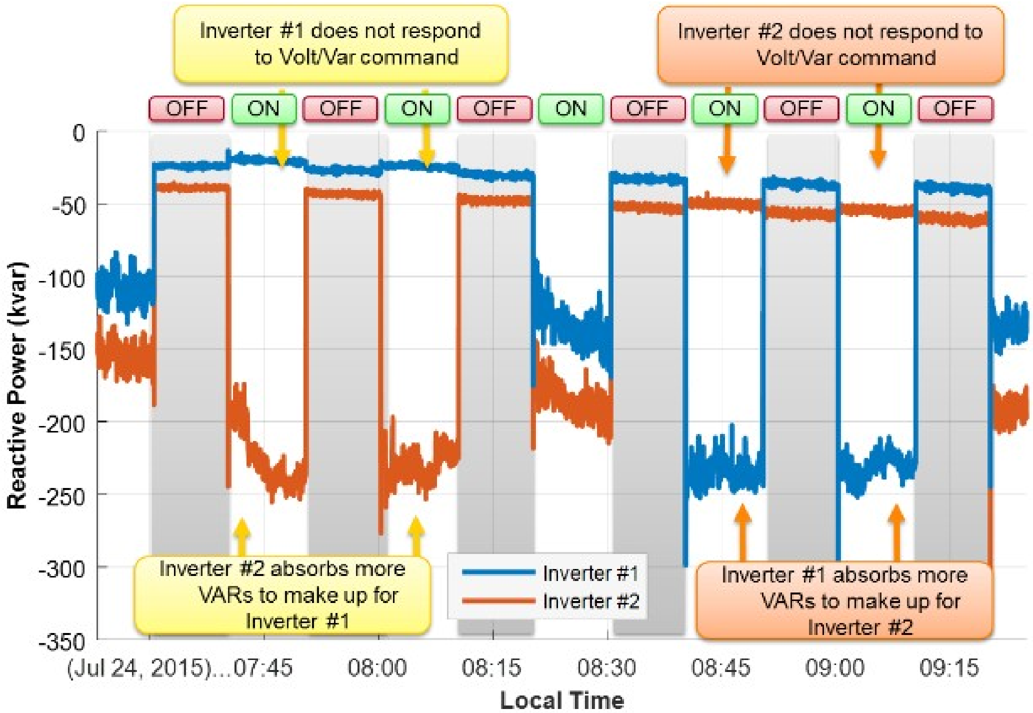


Figure 41 Reactive power response to 10 minute on/off volt-VAR testing

Also observable in Figure 41 is the fact that when the Volt-VAR function is activated in only one inverter, that inverter generates more Vars than when both are operating (compare the blue line from the third “On” period to the fourth). This is because the voltage at the PV plant is significantly impacted by the reactive power, and when only one inverter is operating the system stabilizes at a different point on the Volt-VAR curve.

In spite of the communication problems described here, the total reactive power absorbed was approximately 220kVars during each “On” period. This is a noted advantage of smart PV inverter functions as opposed to fixed Var settings. In this case, the inverter that did respond compensated for the one that did not.

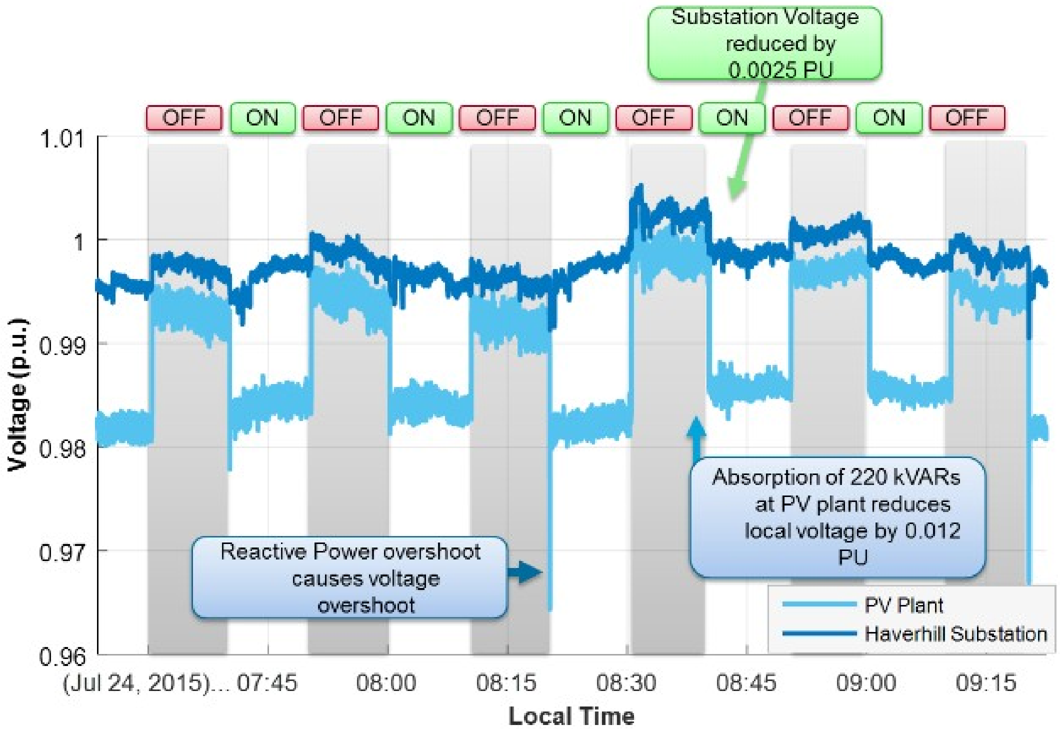


Figure 42 Voltage response to 10 minute on/off volt/var testing

The PV plant experienced an average voltage drop of 1.1% each time the Volt-VAR function was enabled. This equates to an effective local reactance (as seen by the inverter), which agrees with the expectations and value calculated from the system model. This level of voltage impact is significant, and this PV plant is capable of nearly three times as many Vars - up to 600kVars, which corresponds to the voltage compensation of about 3%.

Just as significant in this data set is that the substation experienced an average voltage shift of 0.27% for the same time period each time the function was enabled. This is evidence that the reactive power capability of even a modest quantity of PV can have voltage impacts throughout the feeder, improving power quality and potentially reducing the need for other equipment.

Also noted in Figure 42 is an undesired overshoot in the voltage waveforms. The combined overshoot in Var absorption of inverters 1 and 2 can be seen in Figure 41 and caused a voltage overshoot when the Volt-VAR function was successfully activated on both inverters at 8:20 am. This overshoot was related to the inverter's handling of the Volt-VAR function when activated without ramp-time limits. The time duration of this overshoot was very short, and was only captured by EPRI's datalogger for a single 1-second datapoint. It did not cause any issues to the feeder.

During the next test phase, the Volt-Watt function was tested. Configured as normally expected, this function autonomously rolls-off the real-power output of the PV plant as the local voltage moves higher. The result is the creation of more "available Var" headroom in addition to reduced Watt output. The settings identified by EPRI modeling were used, with the intention that Watt output will be curtailed at the highest voltage levels reached at the H1 site.

The actual voltage at the H1 site was never high, so the curve shown in Figure 43 was used to verify the function. During the period of testing This function was activated for 10 minutes at a time, with comparisons made to a baseline from an average of the before and after data. At least 10 events were tested, at select times and dates over a one-week testing period.

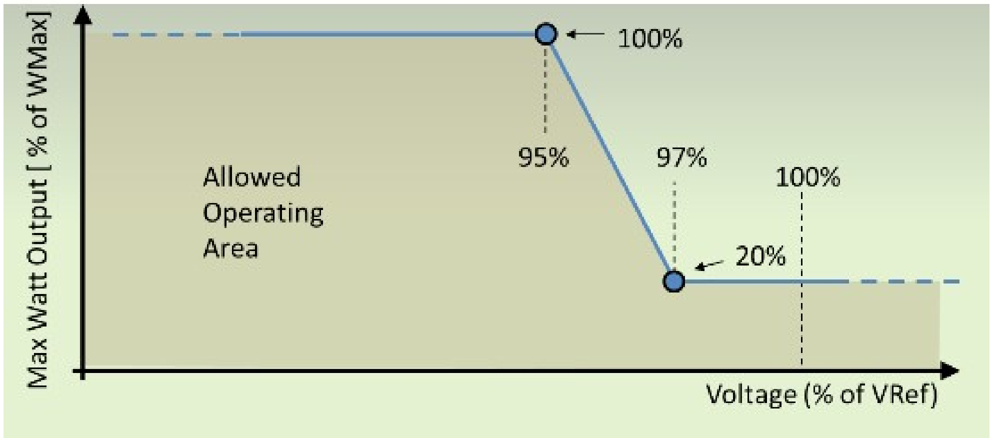


Figure 43 Volt-Watt Settings Used for H1 Test

Test Phase 6 – Remotely Managed Volt-VAR Control

This test was conducted in the same way and for the same duration as the first two tests, but in this test the volt-VAR curve settings were modified by a remote managing entity (the BPL Global DERMS) in near real-time. At a fast update rate (a few seconds) the BPL Global software read the power factor of the feeder at the substation meter, and computed a change in the volt-VAR curve setting at the inverter in order to bring the power factor as close as possible to unity.

The curve settings were all of the same shape, with a straight sloping line, but shifted left and right by the BPL Global DERMS in order to achieve the desired reactive power level. The intended benefit of using the volt-VAR function for this use case is that the substation power factor can be managed while retaining the benefits of fast local response to changes in voltage at the PV plant.

As described previously, this test phase employs a remote DERMS and communication system to manage the PV site based on remote measurements and feeder-level goals not achievable by the local inverter. Specifically, this test mode used BPL Global's remote DER management system to continuously adjust the Volt-VAR curves of the plant in an effort to maintain (as close as possible) unity power factor at the substation.

Figure 44 provides an improved view of the remote volt-VAR control test. In this view, the data is removed at each moment of communication (when the inverter inadvertently turned the Volt-VAR function off). This is done to make the remaining test result more visible. In addition, the view in Figure 44 shows the substation power factor line both above and below unity to indicate whether it was capacitive or inductive.

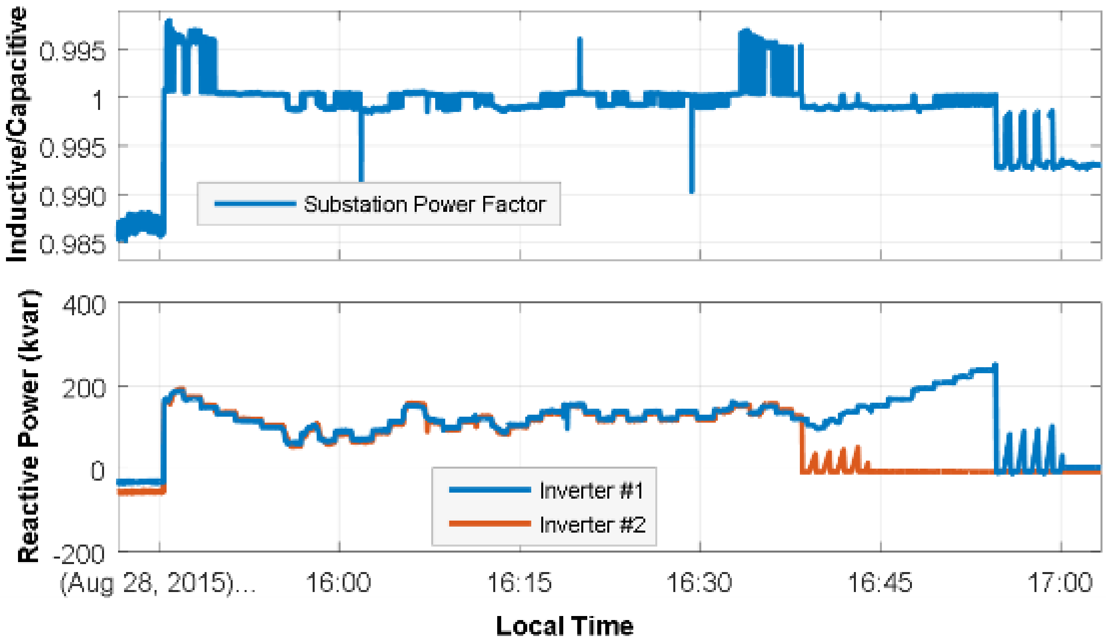


Figure 44 Remote Volt-VAR Control, Unconstrained Case with Communication-Caused Glitches Removed

At the DTE F1 site, there was a case where the ride through curve was utilized. Figure 45 shows a voltage sag event recorded by the PQ meter installed at the F1 PV site. During the event, two phase voltages were at around 73% of V_N for approximately thirty-three cycles. The other phase voltage during this event stayed at 85% of V_N. The inverter successfully rode through the voltage sag event without disconnecting from the grid.

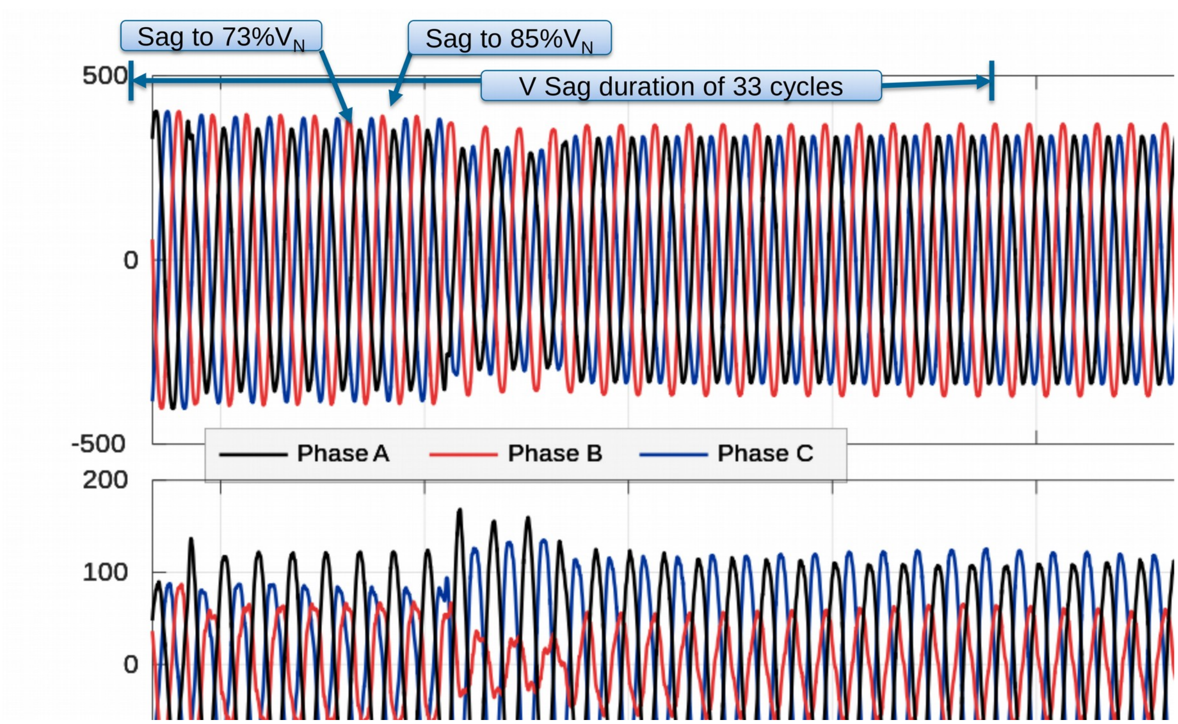


Figure 45 Smart Inverter Response to a Voltage Sag Event at F1 Site

Major Accomplishments and Conclusions:

- **Supported the fundamental idea that smart inverters can provide services that are beneficial to the distribution grid.**
  This project provided the first complete (design-to-field) smart inverter demonstration. It took concepts that had been largely developed as paper exercises and carried them to real-world implementation. Multiple test sites were involved, and the scale of the PV plants was enough in each case to make observable impacts on the feeders.

  A key success of this project was the simple fact that smart inverter functions were activated and worked as intended - nothing was damaged, nothing bad happened. Multiple smart inverter functions were exercised, providing a range of services. The scale of the smart inverters was such that harmful or negative impacts could have occurred in the event of unstable or oscillatory control loop. This fact required the manufacturer and project team to perform extensive testing and modeling.
- **Successfully implemented and proved-out the standard smart inverter functions defined in IEC 61850-7-520 and 61850-7-420**
  These standards provide thorough smart inverter function descriptions and an information model that is the foundation for associated communication protocols. The IEC standard identifies a specific way for each grid-supportive service to be implemented.

  Prior to this project, the smart inverter functions as defined in the standard had not been implemented or tested. Some manufacturers had grid-supportive capabilities but each in their own proprietary way, so cohesive integration of multiple systems was not possible. Each function that was implemented in this project exactly followed the IEC 61850 standard functions. In this way, several of the standard functions were directly validated.
- **Successfully demonstrated utility control with smart inverters utilizing the DNP3 communication protocol.**
  Prior to this project, communication with and control of smart inverters was only done using vendor proprietary methods. A DNP3 communication protocol mapping (DNP3 AN 2013-001) was developed just prior to this project, but had not been implemented. In this project, the DNP3 standard was used exclusively. This provided a direct assessment of the clarity and sufficiency of this new protocol mapping. The use was ultimately successful, but because there was not yet a certification process, the process included the identification of some gaps and ambiguities. These were documented to be corrected in the next version of the DNP3 standard.
- **Because this project utilized standard functional definitions and the DNP3 standard communication protocol, control system and smart inverter developments were able to be conducted in parallel.**
  This project included a smart inverter manufacturer and three different DERMS tools (BPL Global, DTE Energy DR-SOC, and EPRI / Nebland Software). Through the use of functional and communication standards, the project participants were able to carry out their developments in parallel. In addition, the integration of these components was more seamless, with go-to references to help resolve issues of interpretation.
- **Demonstrated the ability to improve voltage regulation at a PV site utilizing the volt-VAR functionality of the inverter.**
  One of the most commonly discussed opportunities/expectations for smart inverters is the service of reactive power production with the goal of supporting or regulating the voltage at the PV plant and elsewhere. The Volt-VAR function is one of the most complex methods of doing this, but also offers some of the greatest opportunities in

terms of autonomy and self-adjustment. In this demonstration, at the H1, E1, and F1 sites, the volt-VAR curve function was able to operate successfully in three different inverter sizes/models and to regulate the voltage at the site itself.

- **Demonstrated the use of a separate DERMS to control the power factor at a remote point of reference**
  In this project, the BPLGlobal control system was used to maintain power factor at the H1 substation by controlling the smart inverter's operation. To achieve this, the volt-VAR function was used. The DERMS monitored a power-quality meter at the substation every few seconds, computed a volt-VAR curve to achieve the desired power factor at the substation, and communicated the settings to the inverter. The specific algorithm implemented by BPL Global included an iterative aspect for stability. By using the volt-VAR function, the PV plant retained instantaneous responsiveness to local conditions while the larger control loop operated on a slower timeframe.
- **Reliable and consistent communication, control, and response of the inverters is key to successful operation.**
  In this project, the need and value of seamless communication was demonstrated. In some cases, it was seen that the commands sent to the inverters via DERMS were not received by the inverters themselves. In other cases, the command was received by the inverter, but the inverter did not respond. This exposed several points: (1) being able to monitor and validate operation is critical is smart inverters will be relied on for support and (2) integration in the field can be a challenge even with open standards and lab testing. In the case of this project, some of the observed issues had to do with the conversion from DNP3 to vendor proprietary protocols – translation from outstation to inverter operation.
- **Visibility into the distribution voltage level is useful to gain more benefit**
  There were many circumstances noted during the field testing in which the inverter had more capability to offer (e.g. more reactive Vars available) but failed to produce more because the conditions at the local ECP (terminals of the inverter) were satisfied. At the same times, the conditions at the medium voltage were sub-optimal and would have benefitted from the additional capabilities of the inverter. There is a cost associated with metering/monitoring at the medium voltage, but additional benefits possible if such metering is provided.

  Lack of monitoring at the distribution voltage level was a challenge in this project to completely capturing the grid impacts. The varying load conditions during the day cause changes that can be hard to quantify. In order to get this visibility, there is a significant amount of utility support and resource needed to do this effectively.
- **In this demonstration, the feeders were relatively stiff as was the impedance seen by the inverters resulting in limited utilization of the inverters.**
  The demonstration focused on 3 utility owned PV sites that happened to be sited on well-regulated feeders with relatively little issue from the PV plants. Therefore, the response of the inverters to grid changes was evident, but broad impact was minimal. The inverters had substantial opportunity to provide more reactive power as noted previously
- **Determining settings for the smart inverter functions is critical to effective use.**
  In this project, extensive work was done to develop methods for determining the appropriate smart inverters settings at each site on each feeder. The appropriate settings can vary based on objective and need. In some cases, it was observed that some settings may work sometimes, but may also cause an adverse impact at other times. When deploying inverters with this functionality, it is critical that the settings be

determined through study of the particular site/feeder or utilizing settings that are less aggressive.

- **More grid impact could have been seen if the inverter had visibility into the medium voltage via a DERMS or otherwise**
  In this project it was seen that if the smart inverter has visibility to the distribution voltage on other locations of the feeder beyond the point of connection, it can provide more value.
- **Inverters are capable of responding quickly**
  In all of the testing in this project, it was evident that the inverters were able to respond very quickly to changing grid conditions or to commands sent to the inverter to change operation. This was true even with large inverters on utility scale PV plants responding to very fast voltage variability evens. More research is needed to determine the limits of such functionality and optimal settings as this capability is considered in operations.
- **Utility ownership eases smart inverter experimentation and services.**
- **Retrofitting existing inverters may be complicated and expensive.**
  In this project, existing inverters already installed in the field were retrofitted to include grid support. It was found that in order to incorporate all of the functionality desired both hardware and firmware changes were required. This can result in additional cost and complications when trying to use grid support. If smart inverters functions are desired, it is recommended that advanced planning and consideration for cost of adding this functionality be considered. This is also true when it comes to interoperability.
- **If a utility is planning to remotely monitor and control a smart inverter, these objectives should be clearly defined from the start.**
  While the inverter implemented the DNP3 functions as defined, some DNP3 points were not implemented in such a way that they could be read or changed remotely. Examples identified in this project included voltage offset, constant VAR set point, L-L and L-N, restarting the inverter, ramp time to original setting is default. This limits the ability to manage the inverter based on grid conditions.
- Determined there is significant value in:
  - **Autonomous functions** – to the extent possible enabling products to manage their own behavior in response to locally-observable parameters (e.g. voltage, temperature)
  - **Communication** – loss detection and default values – implementing communication-connected systems in such a way that they detect communication loss as quickly as possible and apply logical default settings.

Inventions, Patents, Publications, and Other Results:

YEAR	EPRI Product Link and Ref. Number	Document TITLE
2015	3002005789	Common Functions for Der Group Management, Second Edition
2015	3002003291	Are Current Unintentional Islanding Prevention Practices Sufficient for Future Needs?
2015	3002006203	Recommended Settings for Voltage and Frequency Ride-Through of Distributed Energy Resources
2014	3002003035	DER Enterprise Integration: CIM Interoperability Test Report

		and Workshop Results
2014	3002004681	Enterprise Integration Functions Test Plan for Distributed Energy Resources, Phase 1
2014	3002003291	Unintentional Islanding Protection for DG
2014	3002002233	Common Functions for Smart Inverters, Version 3
2013	3002001250	Test Protocol for Smart Inverter Grid Support Functions, V1
2013	3002001249	Enterprise Integration Functions for Distributed Energy Resources, Phase 1
2013	3002002271	Modeling High-Penetration PV for Distribution Interconnection Studies: OpenDSS, Rev 2.0
2012	1024360	Integrating Smart DER with Distribution Management Systems
2012	1026789	Collaborative Initiative to Advance Enterprise Integration of DER
2012	1026809	Common Functions for Smart Inverters, v.2

Conference Publications

- Huque, Aminul. Smart Inverter Grid Support Functionalities: Demonstration of Grid Benefits. SEPA Utility Solar Conference, San Diego, CA. April 28 2015
- Huque, Aminul. Smart Inverter Grid Support Functionalities: Demonstration of Grid Benefits. Distributech. San Diego, CA. Feb 5, 2015
- Key, Tom. ISGT. Washington DC Feb 11
- Huque, Aminul, "SMART-GRID READY PHOTOVOLTAIC INVERTERS WITH UTILITY COMMUNICATION – LESSONS LEARNED FROM FIELD DEMONSTRATIONS, Solar Power International, Las Vegas, NV, Oct 21-23, 2014
- Arafa, Samer, "Smart PV Plant Benefits for the Utility Grid", PVAmerica, Boston, June 24, 2014.
- Huque, Aminul, "Smart Inverter Grid Support Functionality: Time to be Proactive", 3043 in The Role of Smart-Inverters for Distribution Grid Support at Solar Power International, Chicago, October 23, 2013.
- Huque, Aminul. IEEE PES Meeting, July 22-25 2013
- DOE SunShot Workshop April 1-4, Albany, NY. Key, Tom
- Huque, Aminul. Solar Power International. Orlando, FL
- Key, Tom. SEPA Utility Solar Conference. Tucson, AZ. April 17, 2012
- Huque, Aminul. EPRI PQ & SD Conference. San Antonio, TX. June 6, 2012
- SunShot Grand Challenge Summit and Technology Forum. Denver, CO. June 13-14

Path Forward: In the future, more research is needed on the integration and use of smart inverters in the field. Main areas of emphasis include:

- **Traditional inverter operation is not always conducive with grid support needs**. In this project, there was a need for reactive power after the sun went down. This was not able to be achieved using the inverter because the inverter shuts down at night. Additionally, the inverter reset every morning to factory settings (not previous day setting) highlighting the importance of autonomous settings.

- Currently in the DNP3, no all status/alarm points are mapped. One learning of this project was the **need to include all status points and alarm points** to help diagnose issues seen in the field.
- **Some functions have limited settings that impact the ability to support the grid**. For example, the curve functions and DRC voltage settings are limited to 100% of Vref. It is recommended that the standard support higher values.
- **Voltage measurement accuracy** of inverters needs to improve to be able to perform as expected. As utilities look to these devices to provide grid support, the accuracy of response based on local conditions will be critical. This requires the voltage measurement role in inverters to shift from informational to critical control-variable.
- **Demonstrations on higher penetration feeders are needed.** Many of the impacts and potential benefits of smart inverters are not apparent until the PV level is substantially high. In this project, the feeders selected did not have high penetration scenarios. Using power system modeling, we were able to show the benefit that could be seen using smart inverters. However, more field demonstrations should be done to understand the difference in operation.
- **Communication system quality and reliability will improve when manufacturers have production products and certification testing is available.** When standard communication protocols become the normal/native language of the inverters and plant controllers, the one-off translators from open standard networks to proprietary inverter interfaces will be eliminated. These translators were problematic in this project. In addition, certification was not yet available at the time this project was carried out, leaving the project team to perform their own compliance testing.
- **Standards for managing groups of DER are needed**
  This project identified the limitations and insufficiency of existing smart inverter functions and protocols in relation to DER group-level management. As a result, EPRI, the DOE, and other stakeholders launched a parallel initiative in 2013 that continues to the present time. This parallel initiative is filling the gap, developing consensus methods and communication protocol mappings (e.g. IEC CIM and MultiSpeak) that support DER groups at multiple levels.
- **The learnings from the project had significant contribution to the IEEE 1547 revisions**
  Experience gathered in this project contributed in the IEEE 1547a-2014 and IEEE 1547.1a-2015 amendments to IEEE 1547-2003 and IEEE 1547.1-2005 DER interconnection standards. Advanced grid support functions included in the amendment were implemented and tested in this project. Successful laboratory testing and field demonstration provided the necessary confidence to include them in the standards. Several of the EPRI project team members are also very active in the ongoing IEEE P1547 full revision process and facilitating the subgroups which are tasked with developing the voltage regulation and response to abnormal voltage and frequency conditions. The voltage regulation subgroup is developing the requirements related DER required reactive power capability and advanced grid support functions including volt-var and volt-watt for distribution voltage support. The response to abnormal voltage and frequency conditions subgroup is developing the voltage and frequency ride through requirements and defining the expected DER behavior during the fault conditions.
- **Precision of smart inverter controls is important.**
  In order to inverters to be used to support the grid precision of the controls themselves is critical. In some cases, var offsets were seen that caused inverter response to be different than expected. Additionally, when controlling more than one inverter at the site,

each inverter may provide different amounts of reactive power support or compensate for reduced amounts from the other inverters.

- **Communication certification processes are needed**.

  In this project, the EPRI OpenDERMS implementation of the DNP3 protocol became the interpreting authority to achieve interoperability between the inverter and the various control systems. A standard certification process is needed for communication interfaces similar to what was done for functional testing historically.

  This project involved three different communication and control systems provided by three different business entities. It was noted that the key point of interface (the many-to-many interface) is at the DER plant where the control systems meet the plants. Communications inside the plant were known only to the plant. For example, the internal plant communications used a vendor-proprietary Modbus protocol and this was not a problem in the project because it was not a point at which interoperability with other systems was needed. Likewise, the communication protocols internal to the communication and control systems were not an issue and could be tailored to minimize data charges or maximize network throughput. But at the edge of the DER plant, the point where many (any) communication systems interface to many (any) plants, communication certification is needed.
- **Functional and safety certifications are needed.**

  In addition to communication certification, in order to achieve expected behavior and interoperability, functional certifications are needed. For example, during the field testing it was noted that the inverter momentarily returned to defaults (e.g. no Vars) when being adjusted from one power factor to another. Going forward, smart inverter listing processes such as those defined by Underwriter Laboratories' UL1741 test standards and performed by United States Occupational Safety and Health Administration (OSHA) designated Nationally Recognized Testing Laboratories (NRTL). These tests ensure that products exhibit proper power responses and execute control commands as intended. This project provided evidence that without such tests and listings, it is not possible to achieve cohesive grid support from diverse sets of makes, models, brands and types of DER.
- **Need more pilot projects to identify the real world challenges** which are not always visible in modeling and simulation – communication issues, inverter reliability, communication reliability, availability of utility infrastructure and data
- **Need robust interconnection standards** – IEEE 1547 requirements need to be robust enough to create common approach and expectation across industry
- **Need robust certification and performance verification process** – existing IEEE 1547.1 interconnection certification is not sufficient to verify performance of smart PV inverter functionality
- **Need wide scale adoption of standards and communication protocols to ensure interoperability**

References:

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8. “IEEE Draft Recommended Practice for Establishing Methods and Procedures that Provide Supplemental Support for Implementation Strategies for Expanded Use of IEEE Standard 1547," IEEE P1547.8/D8, July 2014