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Smart Grid Ready PV Inverters with Utility Communication

Results from Field Demonstrations

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ABSTRACT

Developing, implementing, and field-testing photovoltaic (PV) inverter grid-support capabilities is needed to provide better understanding of these technologies, inform the best way to utilize these resources, and identify any challenges associated with their implementation. 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 inverters with utility communication systems. The project had five key activities: development of new advanced PV inverters (based on existing models), laboratory testing of the new inverters, computer modeling and simulations of the inverters and several distribution feeders, deployment of the inverters in the field, and testing at four demonstration sites.

The modeling and simulation phase of the project demonstrated that the benefits of advanced inverter functions designed to support the grid depended significantly on the solar load (overcast, variable, or clear), the feeder load (peak versus off-peak), and the level of PV penetration, among others. The results of the modeling and simulations, combined with the results of laboratory testing, informed the subsequent phase of the project—application in the field. Following design and development, the smart PV inverters were deployed at each of four demonstration sites along with field demonstration equipment (the results of three of the demonstrations are reported in this document). The results of this project will inform future evaluation of PV inverters with functions to support the grid as well as identify areas of improvement for more effective integration.

Keywords
Solar photovoltaics (PV)
Smart Inverter
IEEE 1547
Grid support
Distributed energy resource management system (DERMS)

EXECUTIVE SUMMARY

Project Description

Opportunities to Enhance Photovoltaic Inverters for Grid Support

When EPRI's work with solar integration began, there were no common, standards-based communication protocols to allow photovoltaic (PV) products from multiple manufacturers to be integrated in a consistent and manageable way. Additionally, there was no common suite of specific functions that these products provide—especially functions to provide grid support such as reduction of voltage variability and maintenance of unity power factor.

Although some manufacturers provided grid support, each did so in different, proprietary ways, making a system of diverse resources unmanageable. For example, every inverter maker offered some form of Var support, but in the absence of relevant standards, each provided such support in a different way. Common smart PV inverter functions were needed to enable high penetration levels of distribution-connected PV.

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. When this project began, these functions and protocols had not been implemented and tested in the field.

Developing, implementing, and field-testing key elements of PV inverter grid-support capabilities is needed to enable grid operators to better utilize their grid assets, increase the distribution system's capacity for higher penetration levels of PV, and reduce the cost of integrating PV plants into a distribution system.

Questions Confronting the EPRI Research Team

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 inverters that are ready for the smart grid and compatible with utility communication systems. The project team included EPRI, Yaskawa-Solectria Solar, Spirae, BPL Global, DTE Energy, National Grid, Pepco, EDD, and NREL. The team addressed the following questions:

- Can the standard grid-support functions of a PV inverter be implemented and work as intended?
- Will unintended side-effects occur?

- Are communication protocol mappings of smart inverters sufficient (DNP3 in this case)? Or will additional settings and information need to be exchanged?
- What is the extent to which unspecified characteristics, such as control loop/response time, need to be specified, and if so, to what levels?
- How should a utility select and utilize these functions for optimal benefit?
- How might a utility coordinate the actions of smart PV inverters with other distribution control equipment?

Project Design

The project was divided into five phases: development of new advanced PV inverters (based on existing models), laboratory testing of the new inverters, computer modeling and simulations of the inverters and several distribution feeders, deployment of the inverters in the field, and testing at four demonstration sites. The four 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 redesigning three models of Yaskawa-Solectria Solar PV inverters, which would eventually be deployed in the field. The grid-support functions selected for implementation were:

- Remote Connect/Disconnect
- Power Curtailment
- Power Factor Control
- Reactive Power Control
- Priority Setting
- Intelligent Volt-Var
- Volt-Watt
- Dynamic Reactive Current Support
- Low Voltage Ride Through/High Voltage Ride Through
- Status Reporting/Time

The project team defined the communication and functional requirements needs as appropriate for control via a “distributed energy resource management system” (DERMS) and developed a reference DERMS to be used for laboratory and field testing. During this project, there was a recognition of the need to identify standard DERMS functionality and DER group-level management. To address this need, EPRI and the DOE launched a new initiative and formed a working group that has since developed methods by which smart inverters can work alongside conventional distribution management devices.

The new inverters were tested and their functions verified at both the EPRI laboratory in Knoxville, Tennessee, and the National Renewable Energy Lab (NREL) Energy Systems Integration Facility (ESIF) in Golden, Colorado. Various models of the inverter were then deployed in Ann Arbor, Michigan, Boston, Massachusetts, and New Jersey. The team performed detailed power system simulations on each feeder to determine the impacts of PV systems and the new grid-supporting smart PV inverters on the feeder. The table below identifies five potential categories of benefits from implementing these functions.

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														✓	✓	✓

The final phase of the project was the execution of field demonstration of the inverters over an eight-month period at four sites:

Site H1

This site was a 1-MW PV plant in the Greater Boson area connected to a feeder operating at 13.2 kV and supplying mostly residential loads. The team tested:

- Baseline Data – validate functionality
- Volt-VAR control and vars precedence
- Toggled on/off volt-VAR control
- Fixed power factor
- Volt-watt function
- Remotely managed volt-VAR control

Site E1

This site was a 566-kW PV plant, also in the Greater Boston area, connected to a feeder operating at 4.8 kV and supplying mostly commercial and industrial loads. The team tested:

- Baseline Data – validate functionality

- Autonomous Volt-VAR control, continuous operation
- Autonomous Volt-VAR control, cycles on/off
- Remotely managed Volt-VAR control
- Autonomous Volt-VAR control PLUS Dynamic Reactive Current
- Dynamic Reactive Current Only (with no dead band)

Site F1

This site was a 224-kW PV plant in Ann Arbor, Michigan, connected to a feeder operating at 4.8 kV/13.2 kV and supplying both commercial and residential loads. The team tested:

- Baseline Data – validate functionality
- Remote Power Factor control to manage Power Factor at the substation
- Autonomous Volt-VAR control with maximum capacitance settings, cycled operation
- Centrally managed, with optimal settings computed daily by DMS

Site J1

This site was a 1.9-MW PV plant in New Jersey connected to a feeder operating at 12.47 kV and supplying both commercial and residential loads. Testing was not completed at this site due to equipment challnges.

Modification of Smart Inverters

Yaskawa-Solectria Solar, a member of the project team, modified its existing SGI and PVI inverters, implementing the selected advanced grid-support functions. The modification activities included:

1. Creation of a specification that identified grid-support functions and hardware improvements to include in the modified inverter series.
2. Redesign of the inverter series to meet the new specification and verification the successful functional and hardware improvements in the manufacturer's facility.
3. Further verification of the inverter functionality through laboratory testing (the PVI series at the EPRI Knoxville Laboratory and the SGI series at the NREL ESIF).

The following grid-support functions were tested:

- Power Curtailment
- Power Factor Control
- Intelligent Volt-Var
- Volt-Watt
- Low-Voltage Ride Through
- Reactive Power Control

Plant Master Controller

A plant master controller (PMC) is a control device that can be used to logically combine multiple PV inverters in a plant so that they can be managed as one, and to interface to a utility supervisory control and data acquisition (SCADA) system, distribution-management system (DMS), or DERMS. Using a PMC is intended to simplify the interface to a PV plant, reducing the communication and control complexity of plants consisting of many elements.

The field test sites in this project all involved multiple elements and it was decided to employ a PMC at each site.Two different off-the-shelf platforms were evaluated to implement the PMC functions. The following were accomplished during the PMC development phase:

- Two hardware platforms (SEL 3530 Real Time Automation Controller and Orion LX) were reviewed for the environmental specifications and successfully tested for extreme temperature conditions.
- New protocol mapping and communication interface for the smart grid inverter functions were developed and tested with the Modbus and DNP3 protocols using different physical layer communications.
- A data concentrator function with 90 DNP3 client interfaces was developed and tested.
- Plant-level supervisory functions such as coordinated control, preventive maintenance, and secondary fault protection were developed, demonstrated, and tested.
- Interfaces were developed for remote plant operation and monitoring.
- Secure authentication features were developed and tested for encrypted communication.

Improved Efficiency, Reduced Cost, and Increased Reliability

A key design focus of Yaskawa-Solectria Solar was modification of the power-converter module. The resulting overall cost reduction was estimated to be 18%, with an increase in reliability mean time between failures (MTBF) of 1%. These improvements were achieved by using the latest-technology IGBTs, reducing the number of capacitors, installing better-quality capacitors, and changing component termination methods. The designs of the phase-locked –loop (PLL) and ACrms voltage-sensing circuits were modified, and new components were selected to improve grid-sensing capabilities to match the line frequency and magnitude to achieve less than a 0.5% measurement error in the normal operation region during manufacturer testing. Also, inverter communication was upgraded to support the Advanced DNP3 profile for smart PV and storage systems. Currently, the inverters are compatible with the standard “AN2013-001 version 2013-01-14” by the DNP user group.

Laboratory Testing of the Modified Inverter

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 was configured to represent the actual installation site operating scenario as much as possible. As shown in Figure 2-1, the Nebland software tool (detailed in chapter 5) was used to emulate the SCADA input and the communication is set up with DNP3 protocol. The command was passed onto the plant master controller (PMC) and then delivered to the DUT. The PMC was not usually used when there is only one inverter in the plant so that it was not required to include it for the inverter functional test for the system level test. The PMC output was sent to the outstation inside the DUT, which updated the DUT control to configure the control mode and change settings. Below are sample test results for the SGI at NREL

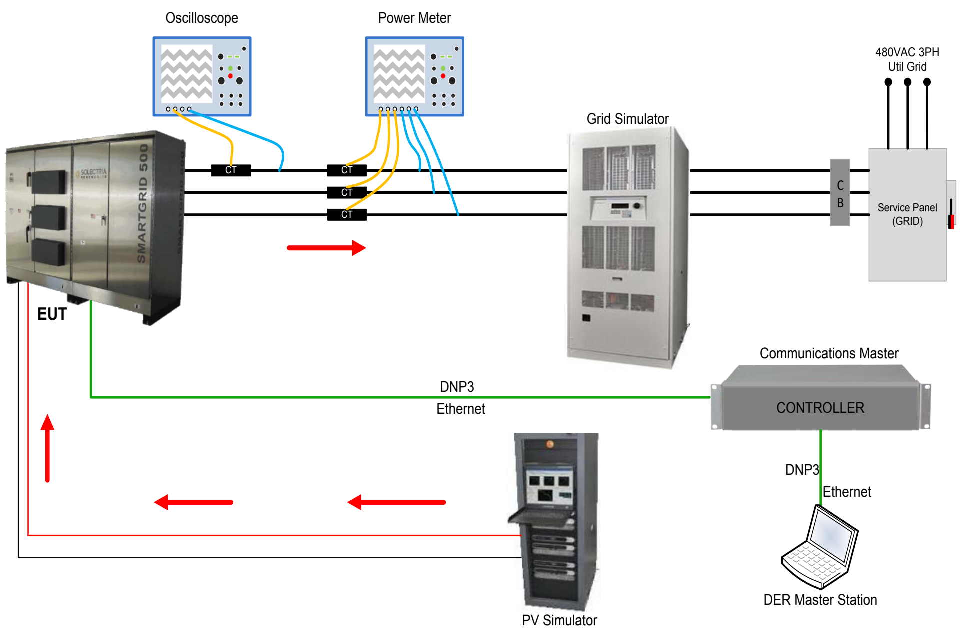


Figure 2-1 Solectria Test Setup at ESIF

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

Anti-Islanding

If a distributed generation (DG) unit energizes conductors in a circuit that has notionally been disconnected, a risk is posed to the general public and line workers. In addition, there is potential fordamage to customer or utility equipment, malfunction of protective equipment on the distribution system, poor coordination or desensitization of protective devices, and out-of-phase reclosing events, which could result in damage of synchronous motors or generators, sensitive electronic equipment, or industrial process loads.

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 ofpassive schemeswhich look for abnormalities caused by external sources.

In addition to the grid-supportive capabilities of smart inverters, the project team evaluated active anti-islanding schemes that could be integrated into an inverter without requiring full direct transfer trip (DTT) systems at each PV system. Such protection can provide the utility with direct means to establish control over generation by either signaling the units or forcing them offline.

Anti-Islanding Communication Methods

One low-frequency power-line carrier (PLC) communication system (DX3 Pulsar) and two point-to-point wireless systems (Raveon and Remote Control Technologies) were tested. At the time of this writing, there is no clear winner, and limitations will need to be weighed by the utility operator relative to cost, complexity, and overall effectiveness.

Laboratory Testing and Field Demonstration of the PLC Method

A PLC system is similar to two-way automatic communication system (TWACS), which has been used extensively in meter reading and other data-transfer applications. If the receiver observes distortions caused by the transmitter, the receiver, through an external relay contact, gives the DG unit permission to operate. Often this technique is referred to as PLC permissive (PLCP) operation. If the transmitter shuts down or if the incoming signal is blocked by an open breaker or fuse, the receiver has lost “permission,” and the DG is shut down.

For the purpose of testing the system’s connectivity, power consumption, and the resulting power quality, a Pulsar transmitter and receiver were configured at the EPRI Knoxville laboratory, which has two buildings connected by roughly 2000 feet of three-phase, medium-voltage underground cable. The DX3 transmitter was directly connected to the 480-V service of building 1. Regarding power quality, this transmitter contributed harmonics, but their overall impact on the voltage waveform was barely distinguishable from the background sample. However, the transmitter had a severe issue with immunity to voltage sags. Therefore, the transmitter would need to be more robust against short-duration disturbances that can lead to nuisance tripping of DG. Nevertheless, the testing of this system was successful in the laboratory and in the field.

Laboratory Testing and Field Demonstration of the Wireless Method

Wireless communication units from Raveon (UHF Band) and Remote Control Technologies (CB Band) were acquired and installed at the EPRI’s Knoxville laboratory. The proper functioning of both communication units were verified in the laboratory. However, inadvertent damage to the Raveon receiver prevented it from being used in field testing. The unit from Remote Control Technologies proved to provide consistent communication in the field at 1.7 miles, but communication became intermittent by 2.3 miles and failed at 2.5 miles.

Inverter and Utility Communication

An emphasis of this project was 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. Significant industry challenges include the understanding of the interactions that will be involved and the communication standards needed to support these interactions.

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’s Distributed Renewables, Generators, and Storage Domain Expert Working Group. A kickoff workshop was conducted in

Washington, DC on September 26, 2012, at which a core set of needs and priorities were identified. While there are several technology companies offering distribution management systems (DMS) products, most utilities still do not have a fully deployed or fully centralized application managing their distribution systems. Addition of advanced DER, specifically smart PV inverters, into these systems could create new motivations to centralize management of all distribution control devices.

Four levels of smart PV inverter integration are described in the following subsections.

Fixed Inverter Functionality

This kind of integration involves inverter functions with settings that are fixed within the device and cannot be altered. In terms of complexity and cost, this option is lowest. The nation of Germany provides an example of the widespread use of this approach. There has not yet been sufficient deployment and time in the field to determine the degree of success with this approach.

Onsite Reconfigurability and Monitoring

This kind of integration involves communication interfaces that are normally not connected but are locally accessible so that settings can be adjusted by physically accessing the device. Through these interfaces, the inverters' various functions can be turned on/off and reconfigured. The status and condition of the inverters can also be monitored through these interfaces. When integrated in this way, the grid-supportive functions that an inverter may provide are limited to those that are autonomous in nature.

Connected Devices, Infrequently Adjusted (Loosely Coupled)

This kind of integration involves a fixed communication network that allows the utility to remotely monitor and manage the inverter. The use of the communication system in this scenario is infrequent, such as daily, weekly, seasonally, or upon special conditions such as grid emergencies. The communication system may be viewed as an optimizing factor, but the system must perform well without it.

Connected Devices, Remotely Managed in Real Time (Tightly Coupled)

This kind of integration involves fast fixed communication networks, allowing inverters to participate in real time from a more centralized location or a control entity. The term "real-time" typically refers to a minute to several minutes but some scenarios envision faster – seconds or sub-second adjustments. The entity remotely managing an inverter—such as a DERMS—may select settings based on conditions on the transmission system, data from the feeder head at the substation, or a stressed asset that is some distance from the inverter.

DERMS

A DERMS is a logical entity that performs the direct management of DER. 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.

The field demonstration phase of this project involved both utility-managed DERMS and third-party partners. No grouping of DER was performed.

Tools for Demonstration

A reference DERMS was developed by Nebland Software. This tool allows a user to send commands to an inverter requesting smart functions per the DNP3 standard protocol and point-list for DER. The tool was expanded to include all the smart PV inverter functions. 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

Modeling and Simulation of Inverter and Feeders

The enhanced inverter and several feeders were modeled. The control settings of the advanced inverter functions to support the grid were simulated to determine their potential impacts on the feeders, such as the number of tap operations, feeder losses, feeder consumption (efficiency), maximum feeder-wide voltage, time above the ANSI maximum voltage, minimum feeder-wide voltage, difference between the minimum and maximum feeder-wide voltages (voltage variability and the flatness of the voltage profile), flicker-causing voltage fluctuations, and VI at the point of common coupling. The ultimate goal was to achieve optimal grid conditions through settings of the advanced inverter.

Atmospheric conditions—clear, variable, and overcast—and feeder loading—peak and off-peak—were also fed into the model as independent variables. The variables of the feeders affected the level of the effects that the advanced inverter controls had on the feeders. For example, inverter penetration—such as 566 kW versus 5 MW)—and the stiffness of the feeder affected the efficacy of the inverter settings.

Feeder Modeling

The three feeders shown below were modeled. Feeder J1 is located in New Jersey, and Feeders E1 and H1 are located in Massachusetts. Participating utilities provided circuit information, which was then converted into OpenDSS, which is used in the modeling program.

Feeder	Nominal Voltage (kV)	Peak Load (MW)	Voltage Regulators	Capacitors (kVA)	Feeder End Impedance	Range of X/R
J1	12	5.9	9	3900	19	1.15 ~ 9.82
E1	4	2.0	0	1050	1	1.78 ~ 15.52
H1	13	4.9	1	600	3.8	1.13 ~ 10.92

Impact of Control Settings on the Simulated Feeders

The advanced control settings of the simulated inverter did affect the three feeders. The best settings from each of the three control types—Volt-Var, Volt-Watt, and Power Factor—was determined by its ability to improve the feeder parameters of interest. Although some settings were beneficial to supporting the grid, there were also control settings that were not beneficial. Below are the summaries of the effects of control settings on each of the three feeders.

Site J1

With advanced control capability, the new inverter was endowed to improve customer efficiency, reduce line regulator tap changes, and avoid overvoltages. Advanced settings were successfully optimized to achieve minimal tap operation. All three control types—Volt-Var, Volt-Watt, and Power Factor—reduced the time that the feeder voltage exceeds the ANSI voltage limits, but no controls were capable of eliminating time above ANSI limits entirely. However, by using an oversized inverter, the advanced controls could be adjusted to eliminate all primary voltage violations.

The effect of the settings depended on the specific solar and load conditions. Solar and load measurements could be used to automatically update the inverter settings to best correlate with the current field conditions. Communication with the inverters could be used to update settings based on operator command or automatically based on SCADA measurements.

Customer efficiency was improved by adjusting all three control types. The Volt-Var and Power Factor settings reduced customer demand. The Volt-Watt settings did not provide any benefit for reducing consumption. The inclusion of PV on the feeder slightly increased consumption over the base case without PV. Lower Power Factor settings generally helped pull voltages down and thereby reduced consumption. The best settings of the three control types were those that essentially never curtailed power.

Site E1

Volt-Var and Volt-Watt settings exist that decrease the average feeder losses, prevent additional time outside of the ANSI voltage limits, and reduce voltage variability (and therefore the chance of flicker). Losses can only decrease further with the most appropriate Volt-Watt settings. Power Factor from 0.97 to 0.99 can potentially reduced losses greater than that with PV at unity power factor, but the time outside ANSI limited increases. Therefore, the best settings are that of unity power factor.

Site H1

The objectives to optimize feeder performance at this utility site were to reduce tap operations, reduce consumption, and flatten the voltage profile. All three control types affected the number of tap-changing operations. In general, setting the Volt-Var control to a low setting proved to reduce tap changing, with the optimal setting at 1.0 V pu. Volt-Watt settings must be aggressive to reduce the number of tap-changing operations, and the Volt-Watt setting affected tap-changing only on peak clear and variable days. Volt-Var settings also benefitted customer efficiency and in fact was the only setting that provided a benefit to reduce end-use consumption.

Impact of Control Settings with Higher PV Penetration

Feeders E1 and H1 had low penetrations of PV and were singled out for further modeling with a simulated PV penetration of about five to ten times the actual penetration. During modeling, the PV penetration was increased to 5 MW to study the advanced inverter impact with higher PV penetration and determine the optimal control settings.

When the penetration reaches a certain level that causes a large amount of power to flow back to the substation, the losses in the feeder can increase. The only control type to reduce these losses is the Volt-Watt control.

The voltage fluctuated more significantly with higher PV penetration. Volt-Var control, Volt-Watt control, and Power Factor control all helped reduce the voltage variability. Among them, Volt-Var control was the most effective. With low PV penetration, the most aggressive Volt-Watt control setting did not reduce the voltage variability. However, with the increased PV generation, the aggressive Volt-Watt setting did improve the voltage variability index.

In a feeder with 5 megawatts of PV penetration, the power flow through the line regulators increased, and therefore the number of tap operations substantially increased, especially in highly variable solar days. With a higher penetration, the number of tap operations was still significantly high, even with the help of these advanced inverter functions.

Both customer efficiency and flattening of the voltage profile were improved via settings of the advanced inverter functions. However, with the PV penetration set at 1 MW or 5 MW, Volt-Var was still the only control type that can flatten the feeder-wide voltage profile.

Conclusions of Modeling and Simulations

The modeling and simulation phase of the project demonstrated that the benefits of advanced inverter functions designed to support the grid depended significantly on the solar load (overcast, variable, or clear), the feeder load (peak versus off-peak), and the level of PV penetration, among others. The results of the modeling and simulations, combined with the results of laboratory testing, informed the subsequent phase of the project—application in the field.

Overall, Volt-Var control had the best ability to improve voltages and meet utility objectives. Volt-Var can operate at low active power output when feeder support is needed. Optimal settings for the Volt-Var curve depend primarily on when the inverter absorbs reactive power. Volt-Watt and Power Factor control are beneficial in several ways but not in all cases. System improvement by curtailing power with Volt-Watt settings would require more aggressive settings beginning below 1.0 V pu, which would be hard to justify implementing. Power Factor control can be beneficial; however, one annual setting is often not optimal in the majority of solar/load conditions due to increased voltage violations or conflicting impact to the optimized metric.

The best settings have been selected based on annual benefit, but better settings can occur if there is direct or remote communication to the inverter. The settings at off-peak load can be different than those at peak load. Similarly, the settings during a clear day can be different than a partly cloudy or overcast day. Periodical updates to the inverter settings can increase the overall benefit to the system.

Field Testing of Advanced Inverter Functions for Grid Support

Following design and development, the smart PV inverters were deployed at each of the four demonstration sites along with field demonstration equipment (the results of three of the demonstrations are reported in this document). In addition, each feeder/site was equipped with communication infrastructure in order to control the inverters and anti-islanding schemes. Power quality monitoring units were installed at the feeder substation, points along the feeder, and at the PV plant. They collected 1-second data and power quality events to verify operation of the smart PV inverter and the response of the feeder to changes in inverter settings. The monitors collected data on AC current, power, energy, reactive energy, voltage, frequency, plane of array irradiance, and temperature of the PV module. Also tested was the ability of the inverters to be controlled utilizing a DERMS solution selected for each site.

Hardware Upgrades

The inverters at each site were upgraded to enable advanced grid-support functions. Sites H1 and E1 had two inverters. The H1 inverters were rated at 500 kW each. The E1 inverters were rated 300 kW and 266 kW. Site F1 had a single inverter rated at 300 kW. The circuit boards of all inverters were upgraded to provide better voltage sensing, the communication boards were upgraded to support the DNP3 protocol, and an outstation was added to each inverter to translate DNP3/TCP to Modbus/RS-485.

DERMS Employed at the Test Sites

A plant master controller (PMC) was used to take DNP3 commands from a DERMS and broadcast the commands to all the inverters at the site in accordance with the DNP3 standard for smart PV inverters. The DERMS utilized for testing at sites H1 and E1 was the BPLGlobal DERMS, which controlled the inverter for all test phases, including real-time management of the inverter to maintain the power factor at the substation. Site F1 used a utility developed DRSOC as its DERMS.

The utility at site F1 also sought to demonstrate a direct transfer trip technology as part of this demonstration. It 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 Solar inverter.

Field Demonstrations

At each of the three demonstration sites, various grid-support functions were tested. The testing was done using two methods: 10 minute ON/10 minute OFF and full-day ON. Settings were based on an annual simulation.

Testing at the H1 Site

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

1. Baseline Data
2. Volt-Var control and Vars Precedence
3. Toggled ON/OFF Volt-Var control
4. Fixed Power Factor
5. Volt-Watt function
6. Remotely managed Volt-Var control

Test Phase 1: Baseline Data

Prior to testing the smart PV inverter capabilities, several weeks of baseline data were collected and analyzed.

Test Phase 2: Volt-Var ON and Vars-Precedence

The Volt-Var function operated in a Vars-Precedence mode continuously for seven days. A baseline enabled researchers to determine whether or not the inverter would be stable when operating in its various modes.

During testing, researchers noted that the voltage measurements of the advanced smart inverters were shifted from the curve assigned to the inverters. Therefore, voltage measurements may need to be improved to perform as expected. Nevertheless, the voltage was tightly regulated by the Volt-Var function during the testing. The inverters did not have access to voltages measured at the medium-voltage level. If they did, they could have better supported the grid. Active management by a DERMS can also improve inverter support of the grid. The Volt-Var control reduced the voltage variability on a feeder.

Test Phase 3: Toggling the Volt-Var Control ON and OFF

The PV load was relatively stable during transitions between Volt-Var ON and OFF. However, persistent communication problems caused the inverter to fail to respond to Volt-Var commands from the DERMS on occasion. This problem was attributed to the prototype nature of the inverters. Therefore, the researchers concluded that some functions should be autonomous to manage their own behavior in response to locally observable parameters such as voltage and temperature. Once an inverter detects a loss of communication, it should apply logical default settings.

During the toggling of the Volt-Var function, the total reactive power absorbed was approximately 220 kVars during each ON period. This is a noted advantage of smart PV inverter functions as opposed to fixed Var settings.

Test Phase 4: Fixed Power Factor

The fourth phase of testing utilized fixed Power Factor as an alternative to Volt-Var control. The Power Factor setting suggested by modeling was -0.96 (0.96 capacitive). The load and irradiance at this setting did not experience any extreme variability during the testing. When the PV plant changed from unity to 0.96 power factor, the reactive power changed from absorbing to injecting Vars.

Test Phase 5: Volt-Watt Function

During the fifth test phase, the Volt-Watt function was tested. Configured as normally expected, this function autonomously rolled off the real-power output of the PV plant as the local voltage moved higher, with the intention that the power output would be curtailed.

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. The goal was to remotely adjust the Volt-Var settings of the inverter to help the utility maintain a unity power factor at the substation by injecting reactive power when needed. The DERMS continuously adjusted the Volt-Var curves of the plant to maintain a unity power factor. However, the continuous updates exposed a flaw in the control algorithm in the inverter. Spikes in the power factor resulted from the inverter turning the Volt-Var function OFF then back ON each time a new curve-setting was sent from the DERMS.

The Volt-Var function improved the power factor at the substation from 0.985 to about unity by having the two inverters inject about 400 kVar into the feeder. During these injections, the inverter and remote-control systems remained stable.

Testing at the E1 Site

The testing at the E1 site was carried out in four phases:

1. Baseline data
2. Autonomous Volt-Var control, continuous operation
3. Autonomous Volt-Var control, cycled 10-minutes ON and OFF
4. Dynamic reactive current

Test Phase 1: Baseline Data

Prior to testing the smart PV inverter capabilities, several weeks of baseline data were collected and analyzed. Both inverters were operating in a normal unity power factor mode.

Test Phase 2: Autonomous Volt-Var Control, Continuous Operation

The Volt-Var function was on continuously over a three day test period. There was approximately a 3% offset on the voltage measurement and about a 20% error on the achieved slope. The cause of the latter is not known and is assumed to be an implementation detail of the inverters. The reactive power resulting from the Volt-Var settings that were used included both inductive and capacitive Vars, whereas at the H1 site, the Vars were always inductive.

When the Volt-Var function was turned on, the voltage profile was flatter. The inverter responded correctly to variations in the power system. The power factor was not directly regulated and was therefore variable. As was the case at the H1 site, there were no signs of instability in the behavior of the plant in Volt-Var mode. The H1 and E1 feeders are very different in nature, and to find stability at both sites with a common inverter control is an important finding for smart PV inverter use.

Test Phase 3: Autonomous Volt-Var Control, Cycled 10-Minutes ON and OFF

In the autonomous mode, the two inverters worked together to flatten the load profile. Although voltage variability was reduced during ON periods, the reactive power output was much more variable than during the OFF period. This is as expected because when the Volt-Var function is on, the inverters are reacting to the AC voltage at their output.

Test Phase 4: Dynamic Reactive Current

The purpose of this test was to understand the benefits that might be gained from a dynamic Volt-Var function rather than a static function. The goal in this test phase was to provide stabilization and reduce voltage variability, evaluating the inverter's ability to react to fast voltage variations. A day with low solar output due to overcast conditions was selected so that the PV plant real-power impact on voltage was minimized. With the Dynamic Reactive Current function on, the fast variability of voltage was reduced.

Testing at the F1 Site

The testing at the F1 site was carried out in three phases:

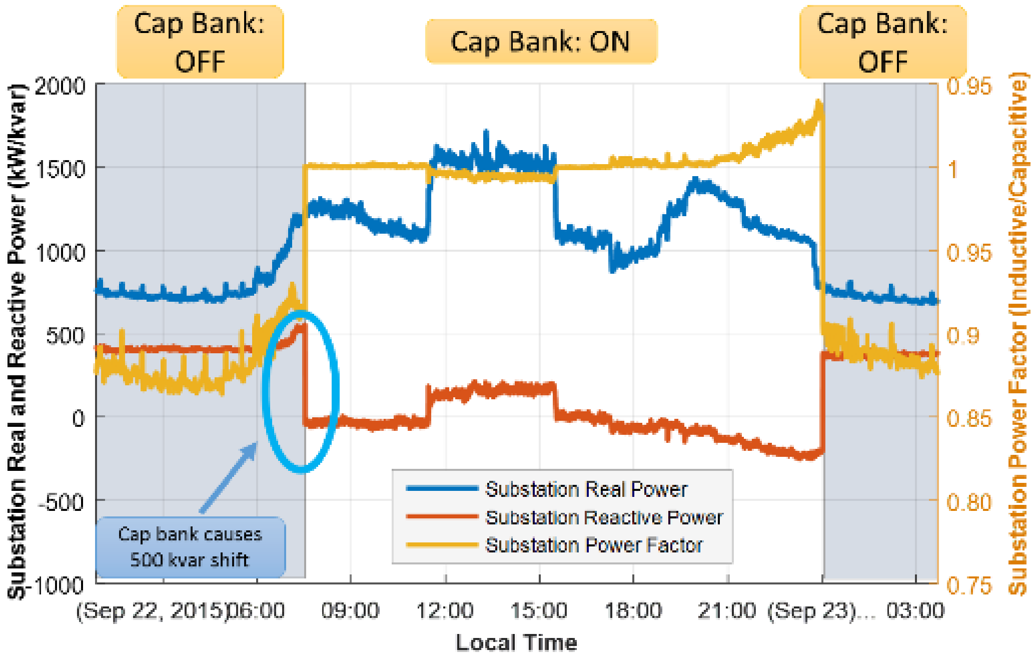
1. Baseline data
2. Remote Power Factor control to manage power factor at the substation
3. Autonomous Volt-Var control with maximum capacitance settings, cycled operation

Test Phase 1: Baseline Data

Prior to testing the smart PV inverter capabilities, several weeks of baseline data were collected and analyzed. This feeder had only one inverter, so the PV load was smaller than the PV loads at the H1 and E1 sites. The reactive power was non-zero, peaking at around 20 kVars at midday even though this is a normal/unity power factor baseline. As a result, the power factor remained above 0.98 for most of the day. This level of error is consistent with that observed at the other test sites. The cause of these step changes is not known.

Test Phase 2: Remote Power Factor Control to Manage Power Factor at the Substation

The F1 feeder had a capacitor bank that affected the performance of the inverter. As shown below, the status of the capacitor bank affected real power, reactive power, and power factor at the substation. When the capacitor bank was ON, the inverter produced inductive Vars, enabling the power factor at the substation to reach unity. Unity could not be achieved with the capacitor bank OFF. The inverter Power Factor control mode is not an effective means of managing the power factor at the substation because the reactive power output varied with solar irradiance.



Test Phase 3: Autonomous Volt-Var Control with Maximum Capacitance Settings, Cycled Operation

This phase of testing utilized the autonomous Volt-Var function. The goal of this function at this feeder was capacitive support. The cycling ON and OFF of the inverter's Volt-Var function had a notable impact on the voltage at the PV plant, resulting in an approximately 1% voltage shift. The capacitive Vars injected into the feeder raised the voltage, which was already high at the plant, fluctuating in the 1.02 p.u. to 1.04 p.u. range over the test day. This test demonstrated that the PV plant could do what capacitors could not: variably generate Vars, constraining itself so as not to push the local voltage too high. Additionally, the autonomous Volt-Var control reduced voltage variability in the feeder, including the substation.

Lessons Learned

The results of this project will inform future evaluation of PV inverters endowed with functions to support the grid. Additionally, the results contributed significantly to the IEEE 1547 revisions. Below are key takeaways from the project.

Results

- 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 IEC 61850-7-520 and 61850-7-420
- Successfully demonstrated utility control with smart inverters utilizing the 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.

- Demonstrated the ability to improve voltage regulation at a PV site utilizing the volt-VAR functionality of the inverter.
- Demonstrated the use of a separate DERMS to control the power factor at a remote point of reference
- Reliable and consistent communication, control, and response of the inverters is key to successful operation.
- Visibility into the distribution voltage level is useful to gain more benefit
- In this demonstration, the feeders were relatively stiff as was the impedance seen by the inverters resulting in limited utilization of the inverters.
- Determining settings for the smart inverter functions is critical to effective use.
- More grid impact could have been seen if the inverter had visibility into the medium voltage via a DERMS or otherwise
- Inverters are capable of responding quickly
- Utility ownership eases smart inverter experimentation and services.
- Retrofitting existing inverters may be complicated and expensive.
- If a utility is planning to remotely monitor and control a smart inverter, these objectives should be clearly defined from the start.
- 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.

Technology Gaps and Future Research

- Traditional inverter operation is not always conducive with grid support needs.
- Some functions have limited settings that impact the ability to support the grid.
- Voltage measurement accuracy of inverters needs to improve to be able to perform as expected.
- Demonstrations on higher penetration feeders are needed.
- Communication system quality and reliability will improve when manufacturers have production products and certification testing is available.
- Standards for managing groups of DER are needed
- The learnings from the project had significant contribution to the IEEE 1547 revisions
- Precision of smart inverter controls is important.
- Communication certification processes are needed.

- Functional and safety certifications are needed.
- Need more pilot projects to identify the real world challenges
- Need robust interconnection standards
- Need robust certification and performance verification process
- Need wide scale adoption of standards and communication protocols to ensure interoperability

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1
INTRODUCTION AND PROJECT OVERVIEW

Background on Smart PV inverter Functions

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 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 (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 Overview

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 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, and NREL.

The project was divided into three phases: development, deployment, and demonstration. Within each phase, the key areas included: head-end communications for 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 - 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

- Intelligent 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.

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.

Each smart PV inverter function is a tool that may be used to achieve one or more benefits on the four feeders. These benefits come in many forms and may be categorized in any number of ways. Table 1-1 identifies five potential categories of benefits from implementing these functions.

Table 1-1
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														✓	✓	✓

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.

Demonstration Sites

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 over of the feeders, PV sites, and areas of potential benefits of smart PV inverters for each.

H1

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 3-200 kVAR fixed capacitor banks near the PV site and substation LTC. Figure 1-1 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.

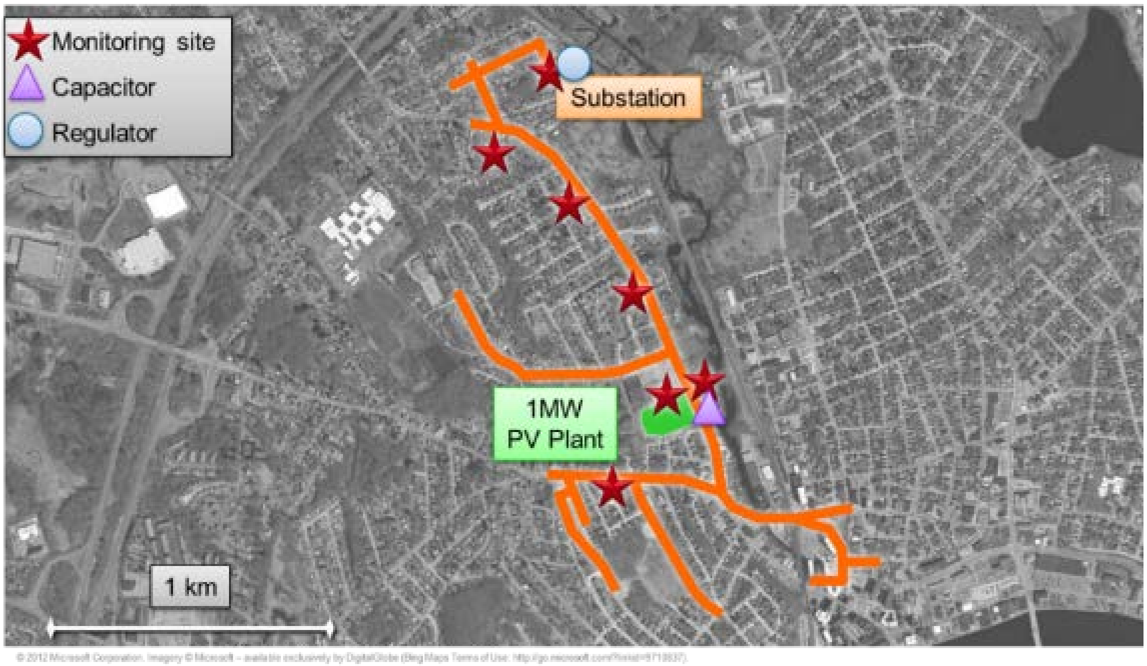


Figure 1-1
National Grid H1 Feeder – 13.2 kV residential feeder with 1 MW PV

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. Operating an inverter of this scale in a real distribution system raises several questions of stability.
- **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 Line Regulator Tap Changes –** 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 successes naturally may result in additional voltage reduction opportunity in conservation voltage reduction systems (Chapter 4).

E1

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 1-2 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.

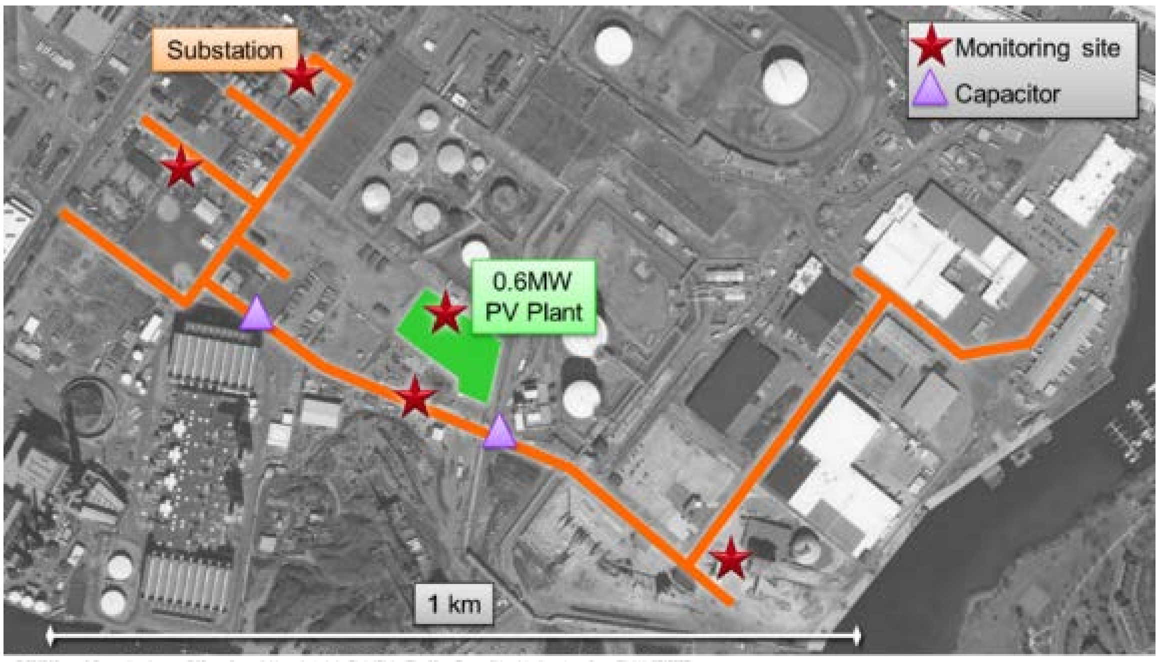


Figure 1-2
National Grid E1 Feeder – 4.2 kV commercial/industrial feeder with 600 kW PV

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.

  This control loop initially operated every few seconds, but was slowed down as testing continued due to the issue with the inverter in which the Var output was momentarily set to zero, anticipated capability is ~4 second updates.

  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. Different data will be post-analyzed in order to assess the outcome in the two benefit areas.

F1

The F1 demonstration site is a 224 kW PV plant also in Michigan. The feeder, F1, is a 4.8 kV/13.2 kV feeder with loads from the commercial and residential. 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 1-3 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.

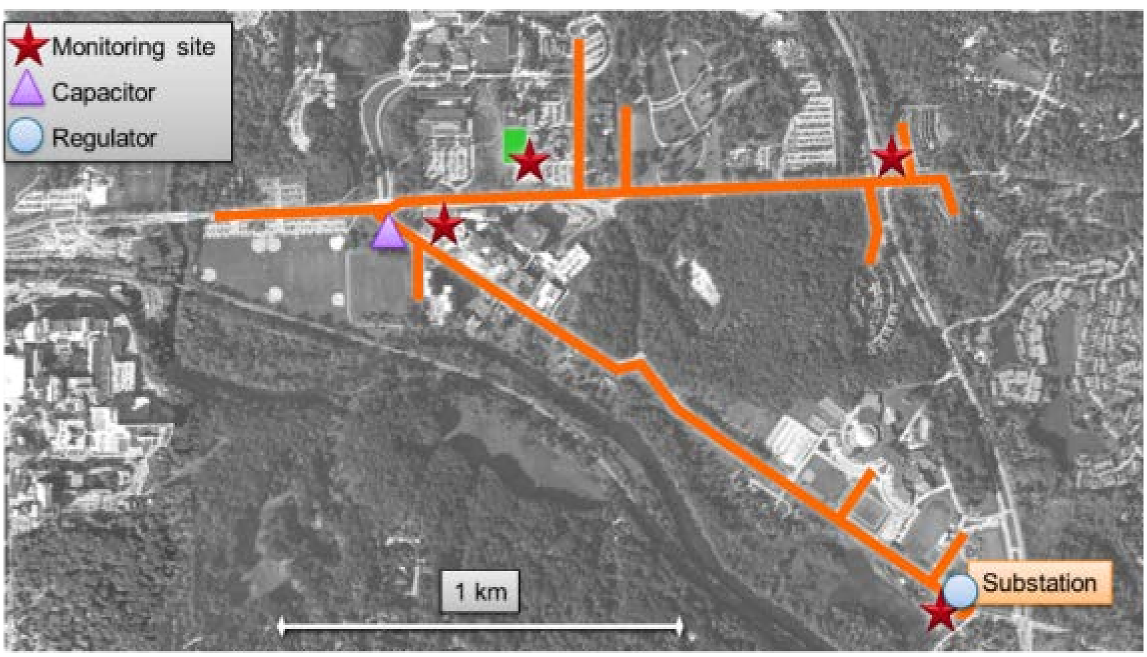


Figure 1-3
DTE Energy F1 Feeder – 4.8kV commercial overhead/underground feeder with 224 kW PV

As described previously, the DTE F1feeder, 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.
- **Deference 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.

J1

The J1 demonstration site is a 1.9 MW PV plant also 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 1-4 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 1-4
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.

Report Overview

This report will summarize the work conducted in each of the phases with particular focus on the lessons learned from field implementation. The following provides a summary of each chapter:

- *Chapter 2 Smart PV inverter Design, Development, and Verification* – provides an overview of the functions selected, inverter design, and development to implement these functions, and laboratory verification.
- *Chapter 3 Modeling & Simulation* – provides the modeling and simulation method and results to determine impact of smart PV inverters on the feeders as well as settings to be utilized in the test phases
- *Chapter 4 Utility-Controlled Islanding* – provides a closer look at the equipment investigated and tested for islanding.
- *Chapter 5 Utility Communication* – provides an overview of DERMS and the communication methods needed when utilizing smart PV inverters
- *Chapter 6 Field Deployment and Demonstration* – provides an overview of the demonstration feeders and equipment and monitoring systems installed. Additionally, this chapter summarizes the testing (both commissioning and test phases) as well as the analytics of performance.
- *Chapter 7 Lessons Learned and Conclusion* – provides a summary of the lessons learned in this project including both integration challenges as well as technical performance.

2
SMART PV INVERTER DESIGN, DEVELOPMENT, AND VERIFICATION

One of the key components of this project was to design and development of the smart PV inverters. EPRI project team partner, Yaskawa-Solectria Solar implemented the selected advanced grid support functions in its existing SGI and PVI inverter series. Standard definitions of smart PV inverter functions[1] and open communication protocol DNP3 were employed in this implementation process. Yaskawa-Solectria Solar 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 Solar 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 NREL 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 2-1 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.

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

Table 2-1
Elements of Inverter Redesign

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

Implemented Smart PV inverter Functions

This section summarizes the implemented smart grid functions and the results of tests conducted by Yaskawa-Solectria Solar. 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 was configured to represent the actual installation site operating scenario as much as possible. As shown in Figure 2-1, the Nebland software tool (detailed in chapter 5) was used to emulate the SCADA input and the communication is set up with DNP3 protocol. The command was passed onto the plant master controller (PMC) and then delivered to the DUT. The PMC was not usually used when there is only one inverter in the plant so that it was not required to include it for the inverter functional test for the system level test. The PMC output was sent to the outstation inside the DUT, which updated the DUT control to configure the control mode and change settings. Below are sample test results for the SGI at NREL

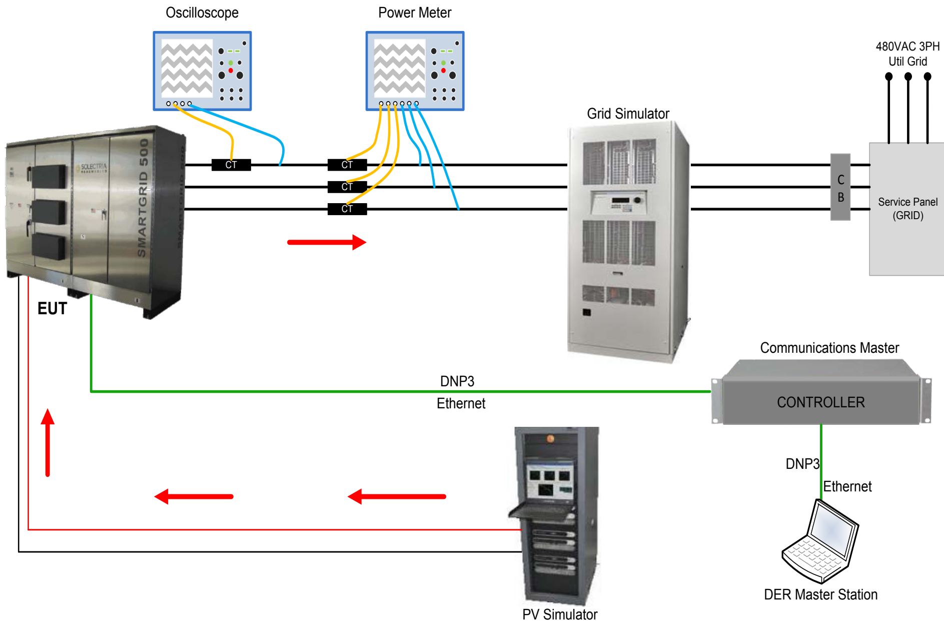


Figure 2-1
Solectria Test Setup at ESIF

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 2-2 shows and example test results for the real power curtailment function with the PVI inverter.

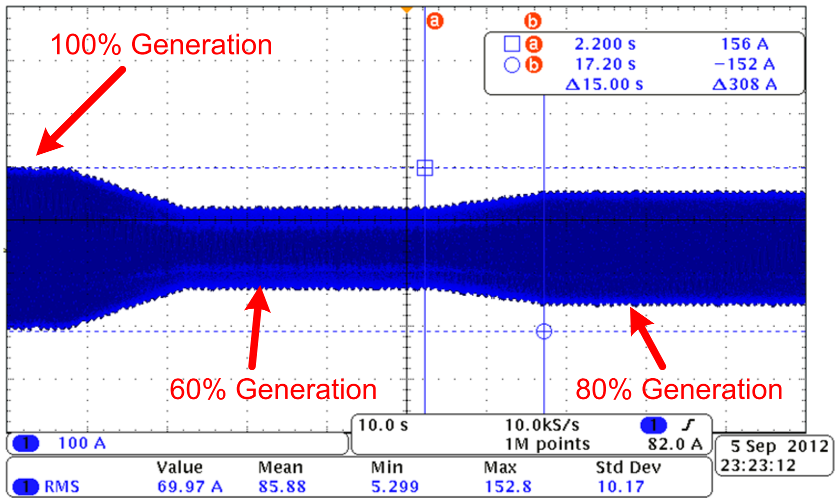


Figure 2-2
Inverter real power curtailment test

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 2-3 shows the inverter operation with different power factor commands.

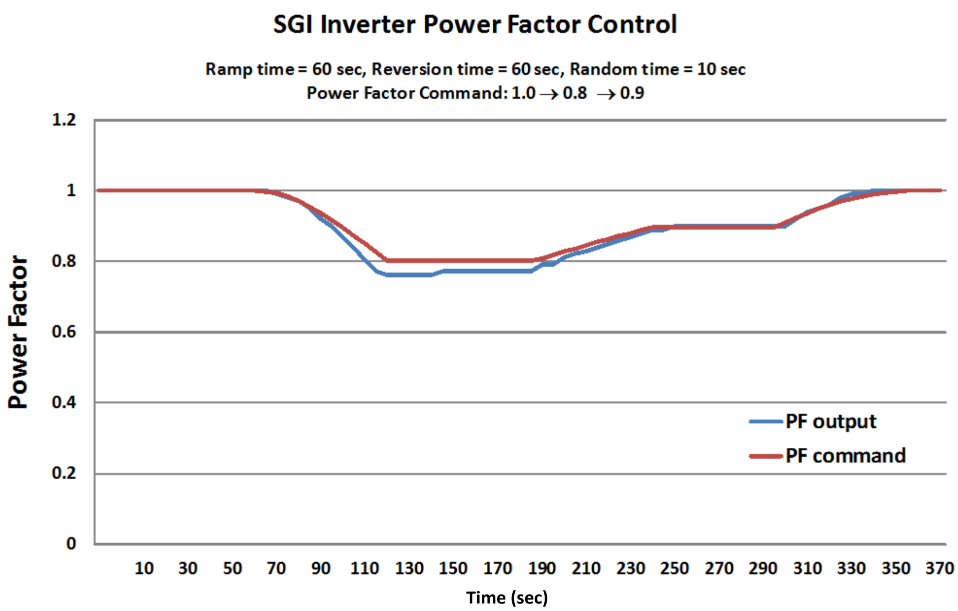


Figure 2-3
Inverter power factor control test

Volt-VAR

The intelligent volt-VAR function with deadband control was tested using the SGI 500 inverter as shown in Figure 2-4. The slew rate and the deadband for the curve can be programmed using a controller with DNP3 protocols.

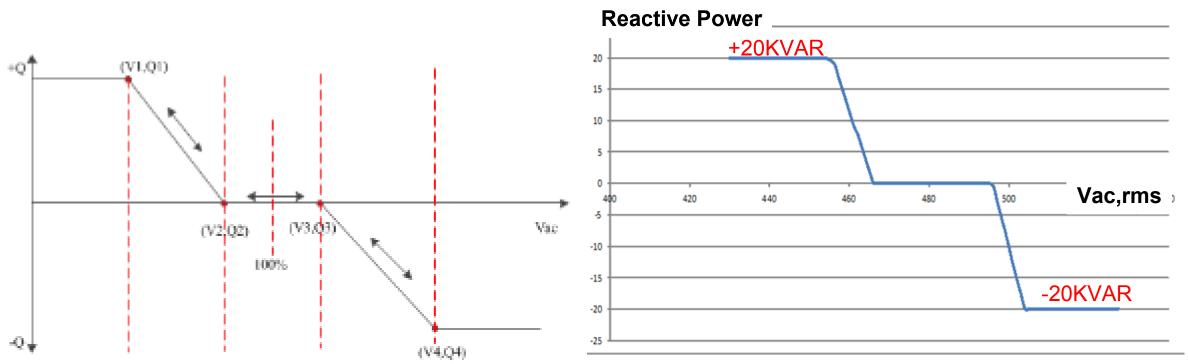


Figure 2-4
Intelligent Volt-VAR function set points and measurement

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 2-5, an example test result of the volt-watt function is shown.

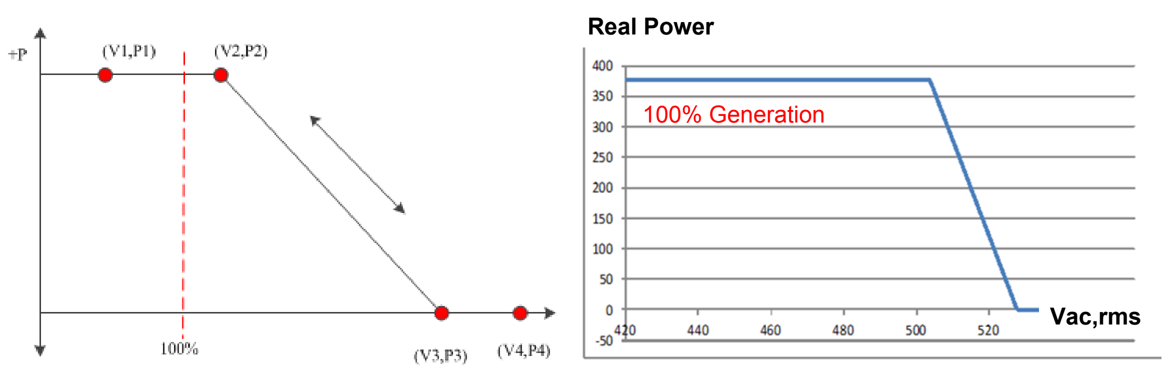


Figure 2-5
Volt-watt test results

Low Voltage Ride Through

Figure 2-6 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

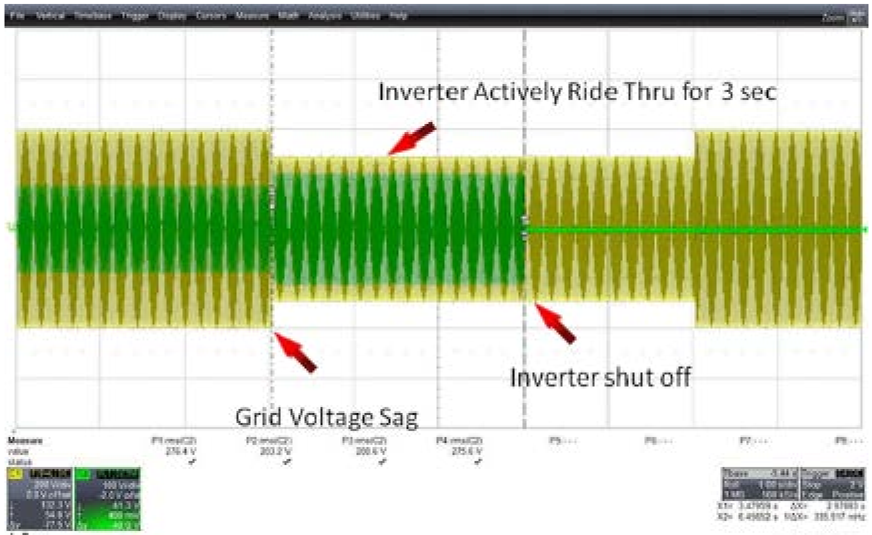


Figure 2-6
Inverter ride through and Shut-off test with 70% voltage sag

Figure 2-7 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.

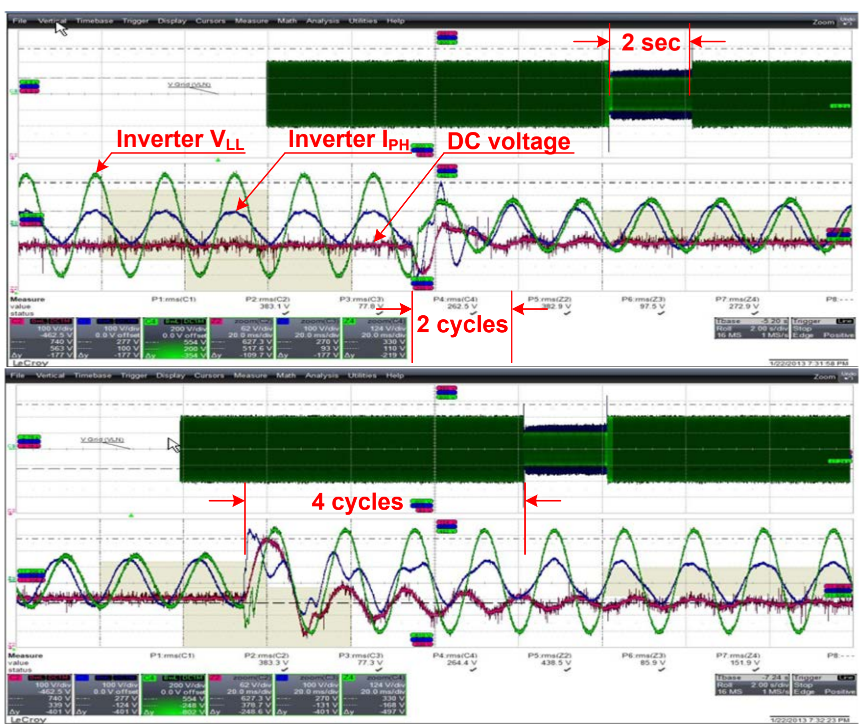


Figure 2-7
Inverter ride through operation with a temporary voltage sag

Reactive Power Control

Figure 2-8 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.

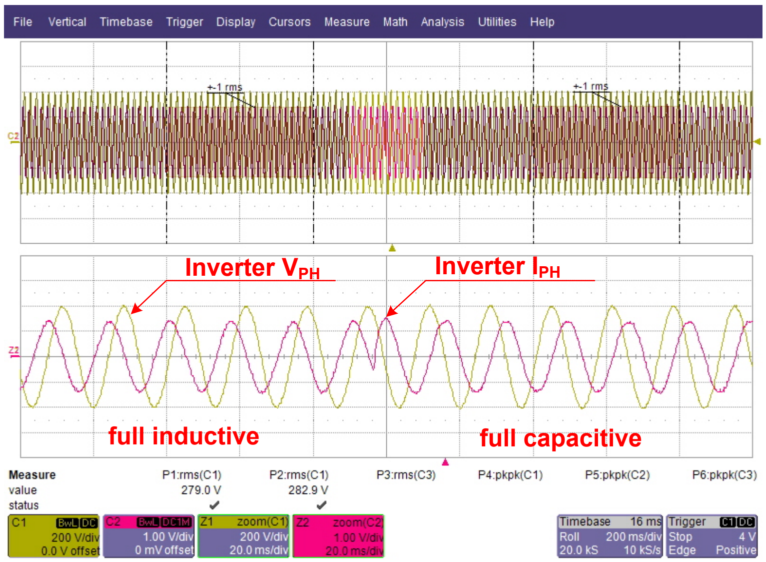


Figure 2-8
Transient response of full swing reactive power control

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 requirement

Efficiency Improvements, Cost Reduction, and Reliability Increase

With the new component technologies that have been introduced, there were several opportunities to enhance the current inverter performance. To yield the greatest cost and reliability improvements, Yaskawa-Solectria Solar focused on the modification of the power converter module

With the implementation of the new design changes to power converter stage and control circuitry, Yaskawa-Solectria Solar achieved:

- A 12% cost reduction of overall bill of materials (BOM) for the power stage (with volume production, overall cost reduction is estimated to be 18%).
- An increase in reliability by removing 114 connection points and temperature stress
- A weighted inverter conversion efficiency increase of 1%

Insulated Gate Bipolar Transistor (IGBT) Power Switches

The IGBTs in the original inverters were replaced with the latest generation IGBTs. As shown in Table 2-2, the loss characteristics were significantly enhanced enabling the inverter to run at a lower temperature. This increases the Mean Time Between Failures (MTBF) and overall system reliability.

Table 2-2
IGBT Comparison

	Old IGBT	New IGBT
Switching Loss (ON/OFF)	100%/100%	60%/75%
Built-in Die level Temperature Sensor	NO	YES
Packaging	Custom	Industry Standard
Component Cost	100%	50%

In the original design, the inverter current protection depended on a state estimator calculating the maximum allowable current to stay below the maximum junction temperature limit of the IGBT. In the new module, a built-in temperature sensor was used to get more accurate measurement of the junction temperature. This ensures that the current protection is more effective and the burden of processing the temperature estimation is reduced. The new sensor increased the reliability and dynamic operation range of the inverter. The standard package allows for multiple sourcing options, which helps with availability and lower pricing for the end user.

Capacitor

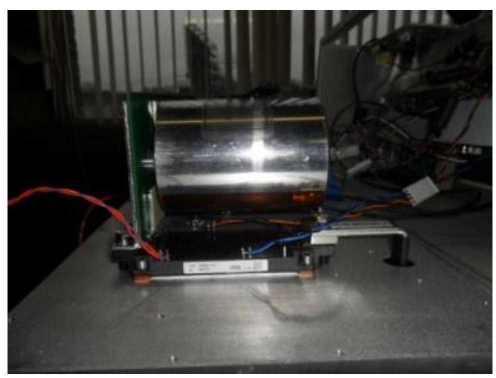
Another opportunity to improve reliability was to reduce the number of capacitors and change the termination method. The old power stage design uses many small film capacitors with solder connections. In new design, much fewer capacitors are directly connected to the bus bar structure with screws. This modification decreases the number of potential failure nodes and the stray inductances of the busbar structure ensures that transient spike voltage and current during pulse-width modulation (PWM) switching will be reduced. Table 2-3 shows the comparison between the old and new capacitor design.

Table 2-3
DC Capacitor Comparison

	Old DC-link Caps	New DC-link Caps
Number of capacitors	>20	<10
Capacitance	100%	150%
Voltage Margin	100%	180%
Cost	100%	100%
Expected Lifetime	>80,000 hours	>200,000 hours (250%)

Other aspects of the improvement are the higher capacitance and voltage rating of the new capacitors. The new capacitors provide higher capacitance without increasing the cost of the material which will reduce the ripple voltage in the DC bus. Higher voltage rating will provide less stress in the capacitor core so that higher MTBF can be expected.

Side View of DC Capacitor and IGBT (Old)



Side View of DC Capacitor and IGBT (New)

Figure 2-9
Core design changes: New design shows new capacitors and IGBTs with shorter bus bars

Grid Sensing Capabilities

PV inverters use the Point of Common Coupling (PCC) voltage to generate a synchronized current output. The phase locked loop (PLL) software routine measures the grid frequency and determines the cycle duration for the AC rms voltage calculation. The PLL dynamics and AC rms voltage sensing accuracy is directly related with the PV inverter transient performance. When PV inverters are used to operate during abnormal voltage and frequency conditions, the sensing routines need to be fast and accurate over the entire operating ranges. In order to support more extreme voltage and frequency requirement, the PLL and AC rms voltage sensing were modified.

Figure 2-10 shows the AC rms voltage sensing accuracy and linearity. As shown in the figure, the inverter has less than 0.5% measurement error in the normal operation region and relatively accurate measurement at extremely low voltage conditions.

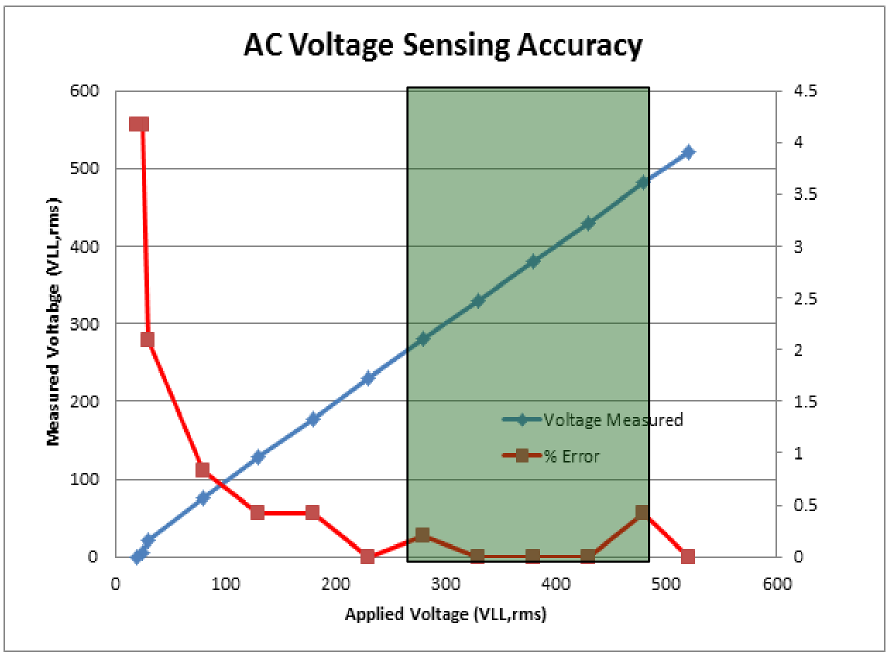


Figure 2-10
AC rms voltage sensing linearity and accuracy

A sensitivity analysis was completed to determine the benefit of signal conditioning with hardware component changes. Ultimately no hardware changes were found to be beneficial to sensing accuracy, however, new components were selected to increase the maximum sensing range to 140% of nominal voltage. This increased range provides design margin on the 120% nominal voltage requirement in the current specification while allowing room for more aggressive temporary over-voltage ranges in the future.

The dynamic response of the AC rms sensing is shown in Figure 2-11. Initially, the grid voltage (phase to ground) was set at 277V and then instantaneously dropped to 120V. Figure 2-11 shows the plot of the reported voltage from the inverter, which shows about 2.5 cycles of transient in sensing the rms accurately.

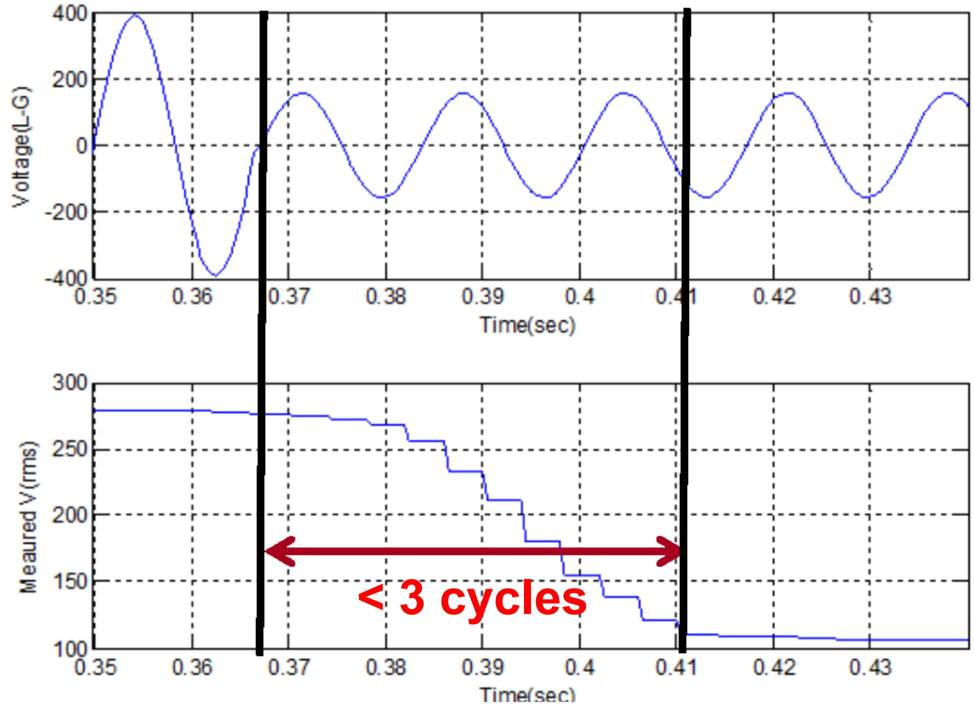


Figure 2-11
AC RMS voltage sensing dynamics

Figure 2-12 shows the dynamic response of the PLL frequency sensing. The grid frequency was changed from 60Hz to 62Hz instantaneously using a grid simulator. In order to illustrate the moment of the frequency change, the voltage magnitude was also reduced. The bottom graph shows a zoomed-in view. The PLL frequency output has a response time of approximately 3 cycles to accurately report the measured frequency.

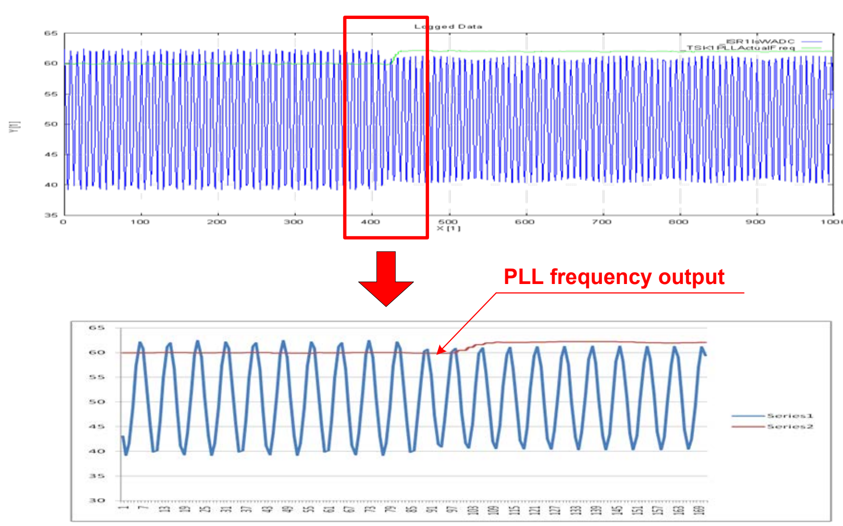


Figure 2-12
Frequency sensing transient response

Considering the worst case ride through requirement and the IEEE 1547 abnormal voltage/frequency criteria of the electrical cycles, the dynamic response of the PLL and AC rms voltage sensing is fast enough to meet the requirement.

Communication Upgrades

In order for the smart PV inverter to effectively interface with the utility, the new inverters are equipped with DNP3 communication capability. Initially, the DNP3 protocol was implemented by using “AN2011-001 version 2011-03-21” by the DNP user group and “Common Functions for Smart PV inverters (product ID: 1023059)” by EPRI. As new protocols became available, the inverters were updated to support the latest DNP3 protocol. Currently, the inverters are compatible with “AN2013-001 version 2013-01-14” by the DNP user group and the conventional MODBUS communication. About 800 analog I/O, Digital I/O and Control flag registers were added to the inverter to support the latest DNP3 standard.

3
MODELING AND SIMULATIONS

In preparation for demonstration, distribution feeder modeling was performed on each feeder to determine the impact to the system as well as settings for each of the functions to be tested based on feeder needs. The focus of this effort was on three of the four sites (J1, E1, and H1) where autonomous settings were the focus.

The detailed feeder analysis of smart PV inverter control settings consisted of modeling the utility feeders, applying various smart PV inverter functions, and analyzing the impact of different control settings. Each feeder was carefully modeled to allow accurate representation in the simulations. The methodology for applying the smart PV inverter functions was carefully designed in an automated routine for thousands of analyses. An automated routine for processing the impact/results was also designed to analyze all the monitored metrics. These three steps will be elaborated in the next three sections.

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 characteristics of the three feeders discussed in this report are given in Table 3-1.

Table 3-1
Feeder Characteristics

Feeder	Nominal Voltage (kV)	Peak Load (MW)	Voltage Regulators	Capacitors (kVA)	Feeder End Impedance	Range of X/R
J1	12	5.9	9	3900	19	1.15 ~ 9.82
E1	4	2.0	0	1050	1	1.78 ~ 15.52
H1	13	4.9	1	600	3.8	1.13 ~ 10.92

The original utility feeder model was provided in the database used by the utility. The utility provided models were then converted into the distribution system modeling environment OpenDSS. OpenDSS software is an open source power system simulation tool that allows complex analyses to be conducted in an automated and efficient manner. The software platform includes many features not available in traditional software platforms such as inverter volt-VAR control and quasi-dynamic time-series analysis. The use of these features was 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 were examined along with the short circuit characteristics of the feeder. A voltage vs. distance profile plot for one feeder is shown in Figure

3-1 that compares the Cyme voltage to OpenDSS. This match is considered acceptable and a similar match was found on the remaining feeders.

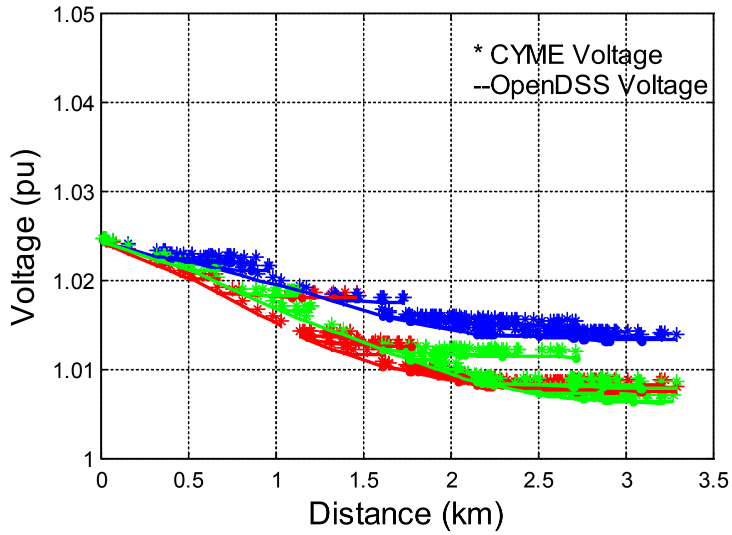


Figure 3-1
Validation of Model using Voltage Profile Plot

The steady-state validation of the feeders was also accompanied by a time-series validation. 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 feeder data was 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 was compared to measurement data for additional validation. An example of validation for the J1 feeder is shown in Figure 3-2 where simulated and measured voltage are compared at one of the solar sites over time. Figure 3-3 validates the H1 model while Figure 3-4 validates the E1 model.

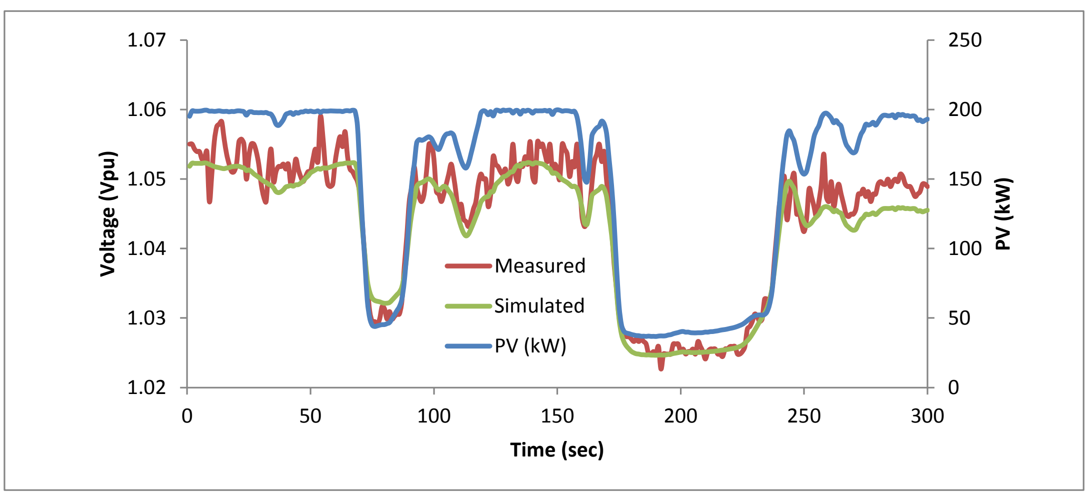


Figure 3-2
Validation of J1 Model

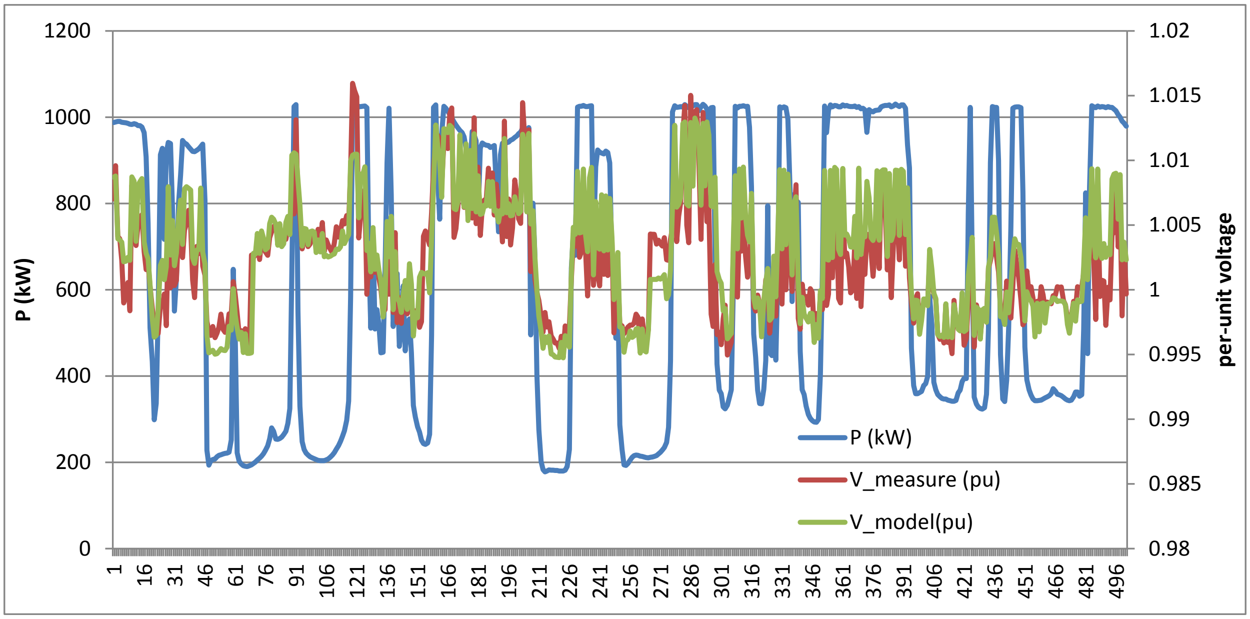


Figure 3-3
Validation of H1 Model

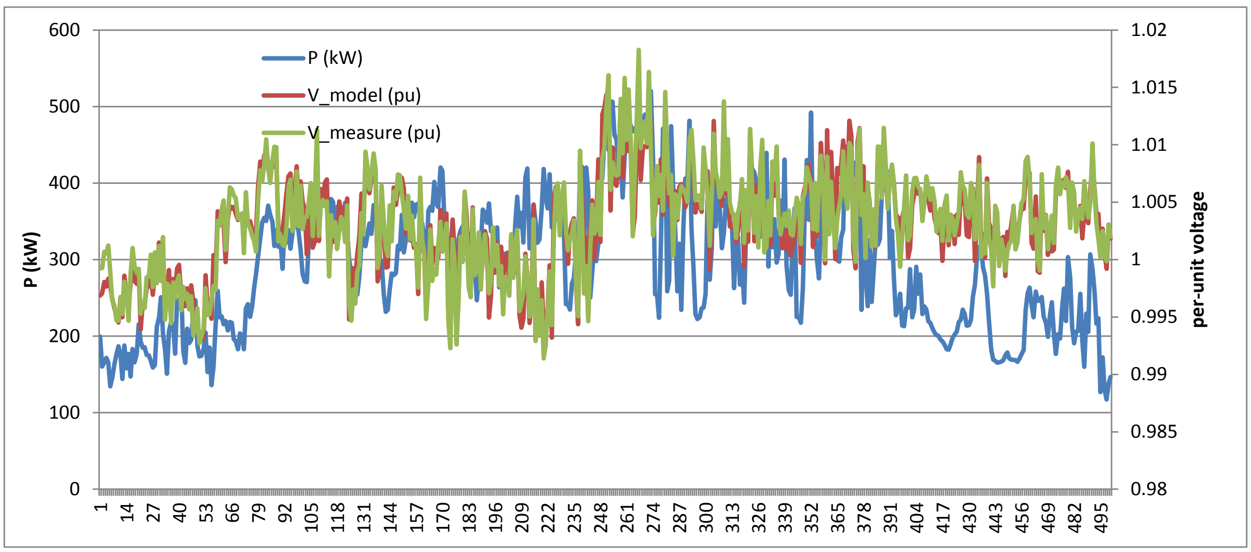


Figure 3-4
Validation of E1 Model

Details on the solar sites where the advanced inverter control will be implemented are shown in Table 3-2. The maximum PV panel AC output is approximately the rating of the inverter. This means that there will be little to no reactive power capability when the PV panel is at full output. Sizing PV systems this way has become the current trend with the cost of panels decreasing significantly compared to the cost of the inverter. This will impact the results for best inverter settings. The location of PV on the H1 feeder is stiffer compared to the location on J1 and E1.

Table 3-2
PV Site Details

Feeder	kWac (panel output)	kVA (inverter rating)	Short-circuit MVA @ POI	X/R @ POI
J1	1710	1710	30-36*	1.8-2.6
E1	566	566	38	1.8
H1	1000	1000	71	1.7

*Multiple sites on feeder

Inverter Modeling

The accuracy of the inverter model is also critical to determine the best smart PV inverter control settings. A volt-VAR response of the field tested inverter was therefore validated to the simulated response. The voltage waveform applied to the terminal of the inverter is shown in Figure 3-5. Based on the applied volt-VAR control settings in the field, the resulting measured reactive power response is shown in Figure 3-6. The figures also show the simulated test voltage waveform and reactive power response using the same control settings. The only significant difference was that the field test had a time-delay from the onset of the test until the autonomous control is activated. Otherwise, the control response was nearly identical besides some var fluctuation at unity power factor.

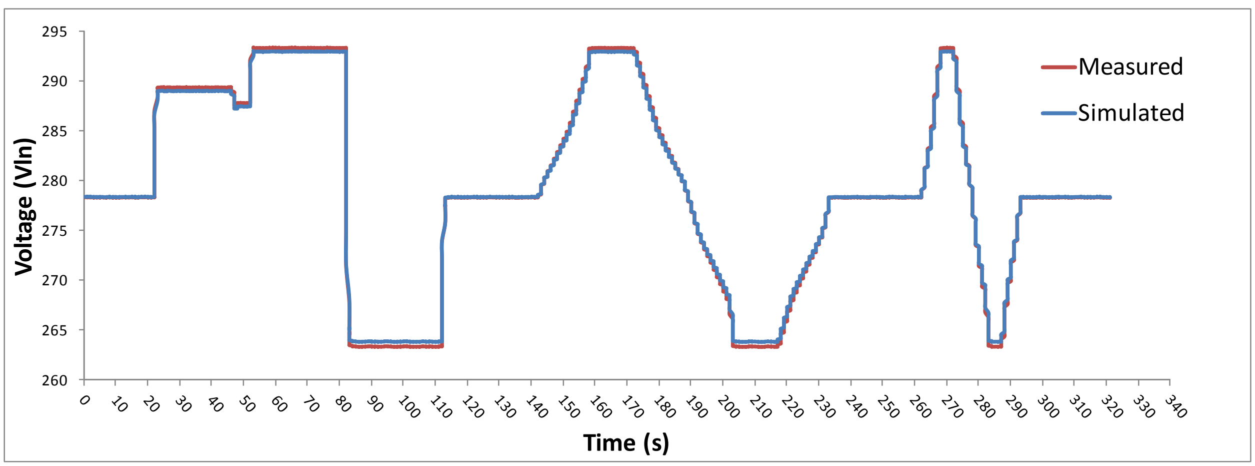


Figure 3-5
Test Voltage Waveform

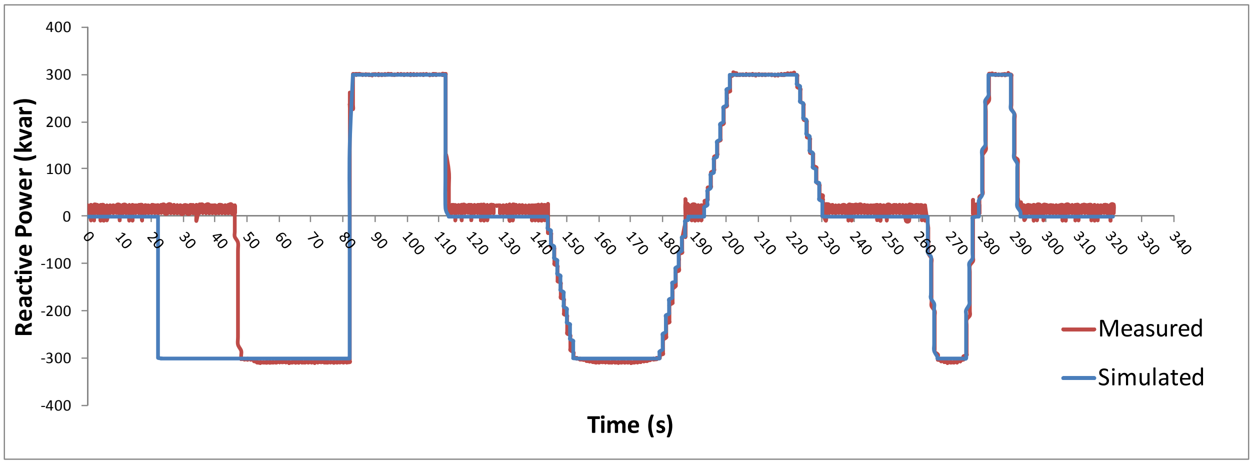


Figure 3-6
Inverter Reactive Power Response

Methodology to Determine Advanced Inverter Settings

Each utility identified the smart PV inverter functionality to be analyzed on the feeders. These functions included inductive power factor control, volt-VAR control, and volt-watt control. Since the specific feeder objective for these functions is dependent on each feeder, the methodology was designed to examine a wide range of control settings and report on a vast array of feeder impact.

Control Settings

The control settings analyzed were not all inclusive as the number of possibilities is infinite. Therefore, a range of possibilities was chosen to represent a wide spectrum of possibilities. An example set of volt-VAR control curves are shown in Figure 3-7. There are three types which include a) no dead band, b) with dead band, and c) inductive mode only. Although these are three types of curves, other possibilities could include dead bands off the y=0 axis, shifts further left/right on the x-axis, or nonlinear variation in the inductive/capacitive regions.

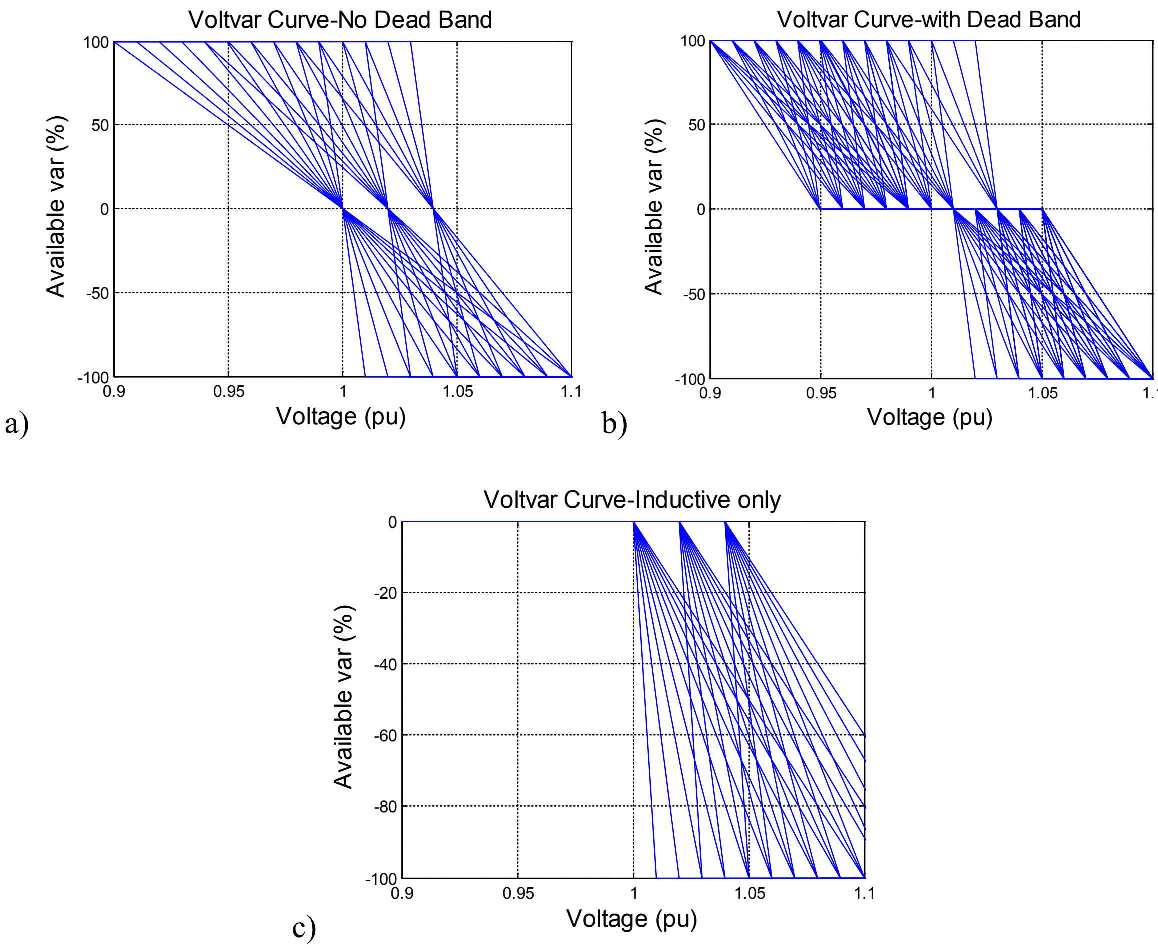


Figure 3-7
Volt-VAR Curves a) No Dead Band b) With Dead Band c) Inductive Only

Example control curves used for the volt-watt analysis are shown in Figure 3-8. These curves shown are not inclusive of all possibilities but sufficiently examine a wide range of those that are practical. Curtailment of real power is not anticipated at lower voltages while some fraction of curtailment might be expected when voltages begin to exceed the ANSI 105% voltage threshold. Power curtailment only occurs if the inverter power output is greater than the percent allowed at the specific voltage on the curve. Additional options that were not analyzed include nonlinear curves.

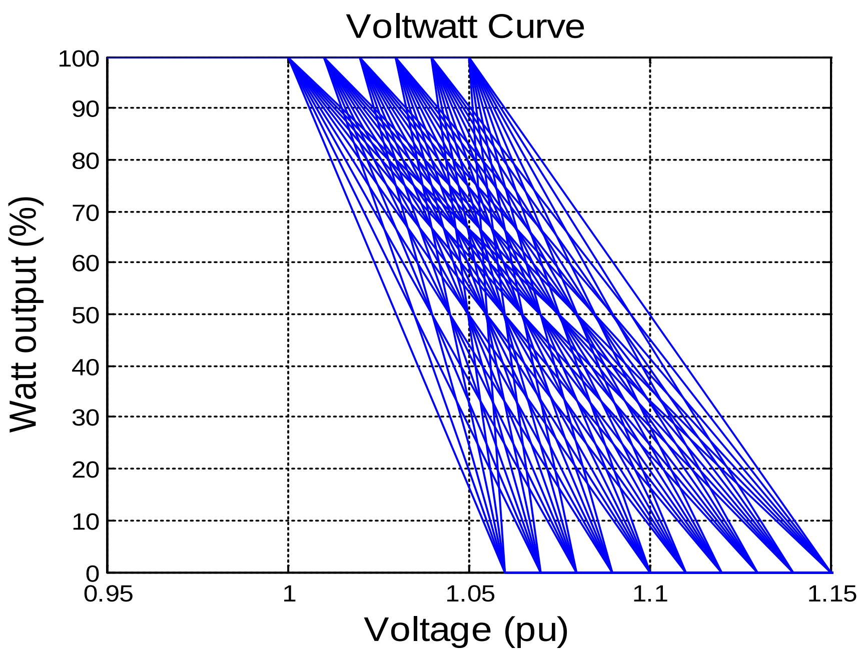


Figure 3-8
Volt-Watt Curves

The power factor control examines specific setpoints on the inverters. These inductive setpoints vary from 0.9 to 1.0 in 0.01 increments. Finer resolution could be examined but general trends are expected using these values.

Feeder Impact

The feeder impact was examined by performing a time-series simulation using each control setting, three solar profiles, and two load conditions. The solar profiles were acquired from measurement data and include one of each highly variable, clear, and overcast day. The load conditions included the peak and minimum load days. The simulation was conducted at the minute resolution for a 24 hour period in each combination of scenario. For each scenario the feeder impact was examined for 19 criteria. These include point of common coupling (PCC or POI) impact, feeder-head impact, feeder-end impact, and feeder-wide impact. A table of monitored impact is shown in Table 3-3. The impact criteria primarily used in the analysis are identified. Ideally the impact on the metrics would improve with the advanced inverter control. The metrics were used to determine feeder improvement and identify potential adverse impacts.

Table 3-3
Feeder Impact Criteria

Feeder Impact Criteria	Used in this Analysis
Minimum Feeder Head Power Factor	
Tap Operations	X
Cap Operations	
Feeder Losses (kWh)	X
Feeder Consumption (MWh)	X
Max Feeder-Wide Voltage (pu)	X
Time Above ANSI Max Voltage (sec)	X
Min Feeder-Wide Voltage (pu)	X
Time Below ANSI Min Voltage (sec)	X
Difference between Feeder-Wide Max and Min	X
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)	
Min PCC Voltage (pu)	
VI at PCC	X

Processing Feeder Impact

The feeder impact scenarios from the different smart PV inverter control settings provide an abundance of data. Figure 3-9 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.

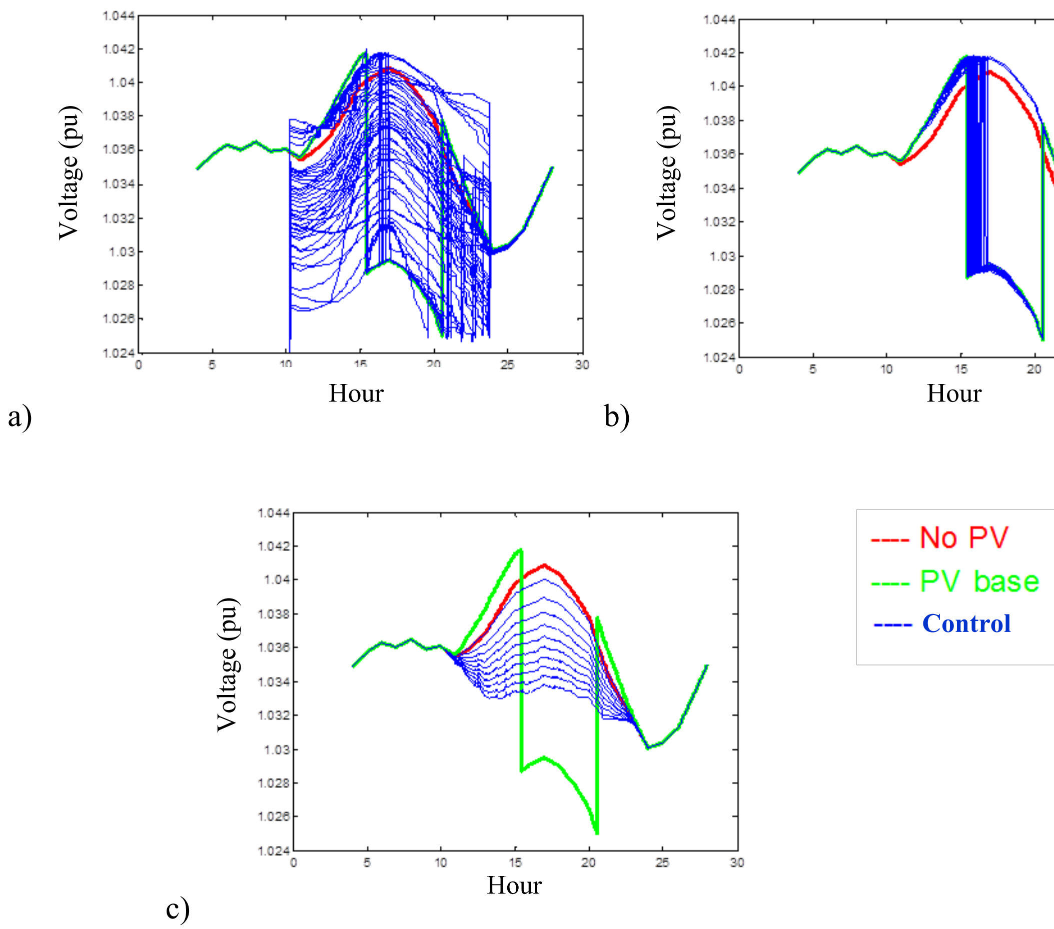


Figure 3-9
Feeder Head Voltage Response a) Volt-VAR b) Volt-Watt c) Power Factor

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 3-10. 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 10, 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.

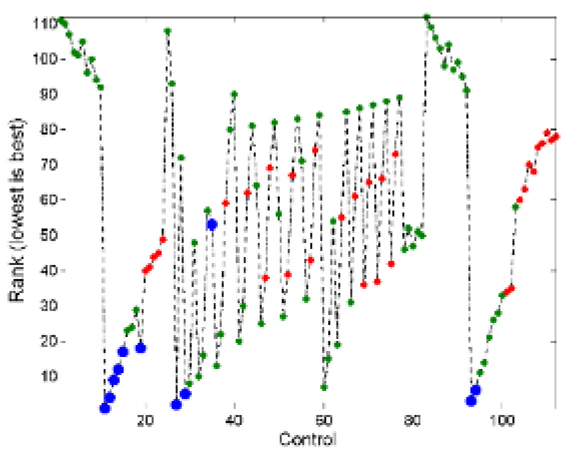


Figure 3-10
Volt-VAR Curve Ranking

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 3-11. 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.

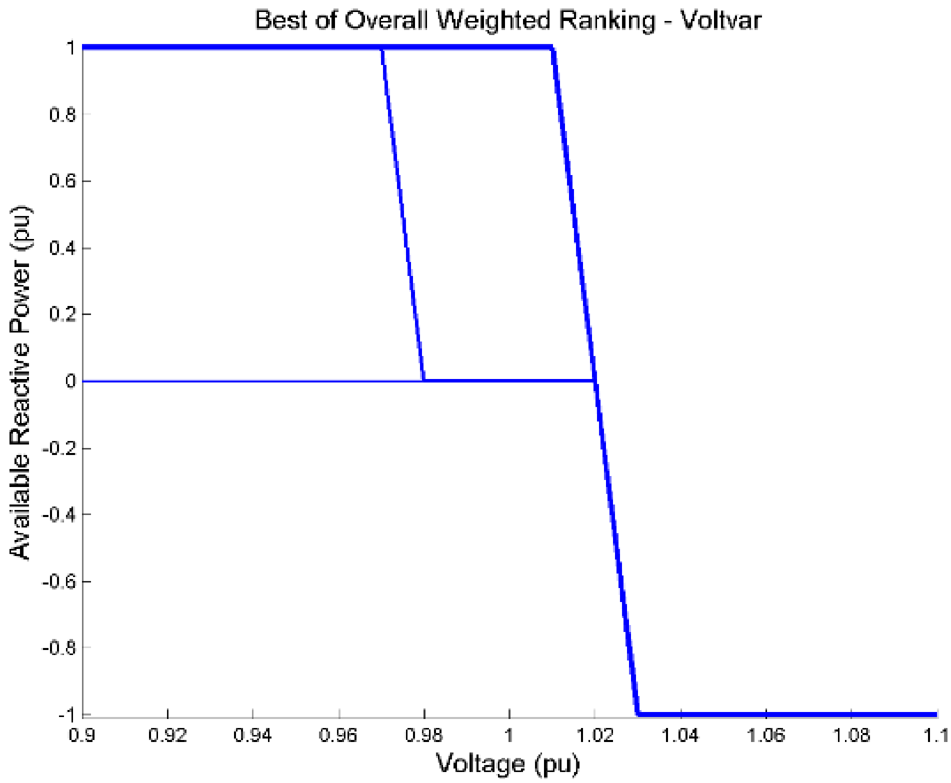


Figure 3-11
Three Highest Ranked Volt-VAR Curves (Thickest line represents the best ranked settings)

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 3-12 shows the use of proper volt-VAR settings can reduce regulator operations compared to the baseline no PV scenario.

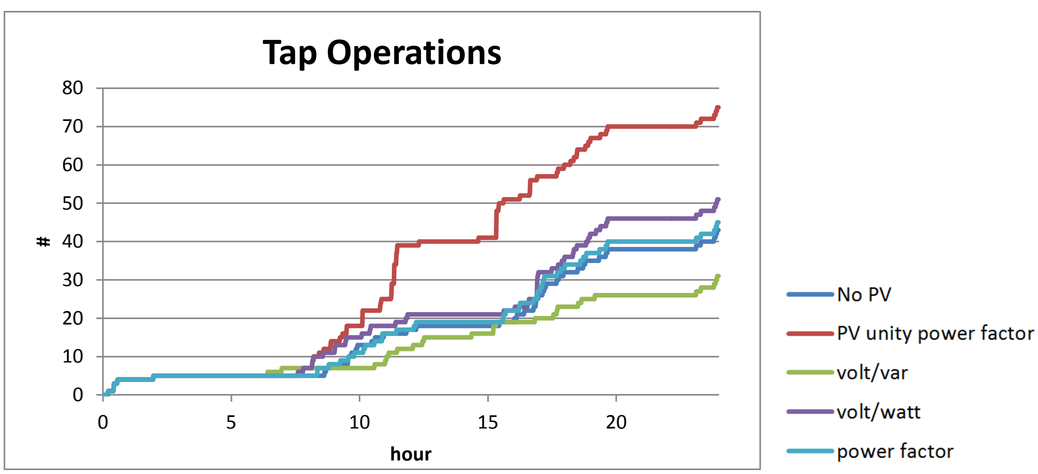


Figure 3-12
Regulator Tap Response from Best Settings

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 3-13. This figure shows two potential settings for volt-VAR control. One provides benefit to the system while the other causes adverse impact. Figure 3-14 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 3-15 shown in green.

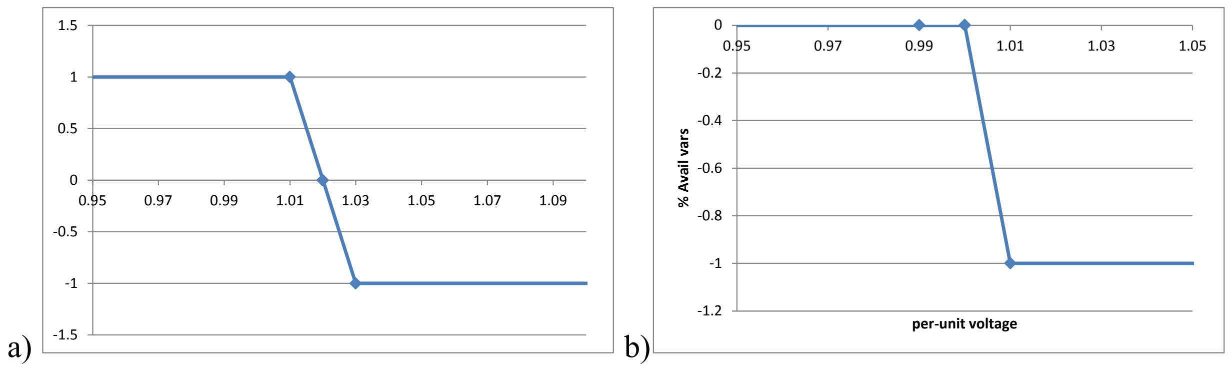


Figure 3-13
Volt-VAR Control a) Best Setting b) Worst Setting

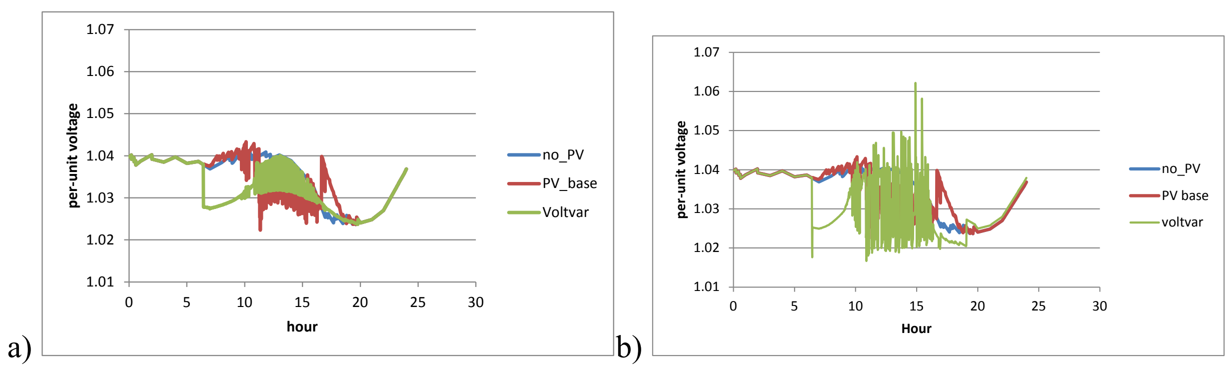


Figure 3-14
Voltage Response a) Best Setting b) Worst Setting

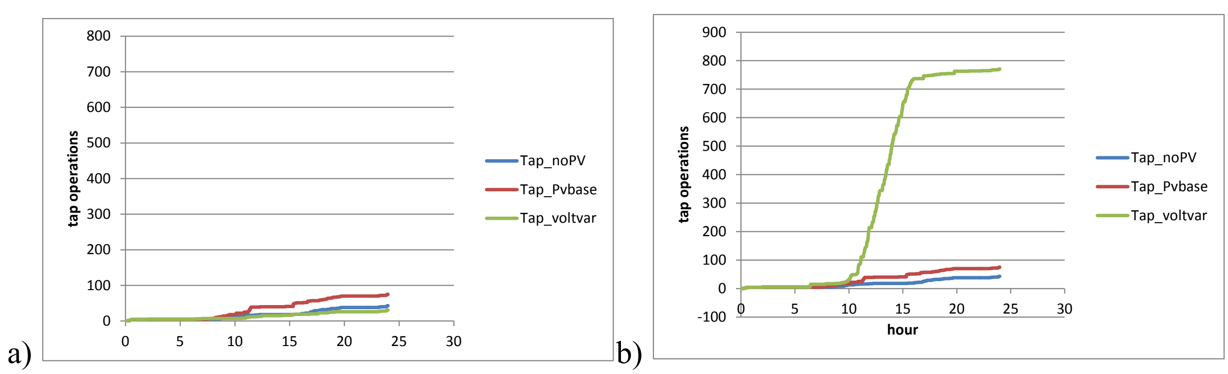


Figure 3-15
Regulator Tap Response a) Best Setting b) Worst Setting

Advanced Inverter Settings

The three feeders with large PV systems were analyzed to determine the most appropriate advanced inverter settings. Each feeder had several objectives identified for which the inverter's settings would be determined.

Pepco Holdings – J1

The Pepco Holdings – J1 feeder was analyzed with all 18 - 95 kVA rated inverters having advanced control capability. There were five goals identified with the use of added inverter functionality. Only two are optimized in this analysis to determined best control settings. The optimized objectives will 1) improve customer efficiency and 2) reduce line regulator tap changes. Improving customer efficiency is analyzed by the metric of end-use consumption during the day. The optimal control setting will reduce the consumption the most. To determine the optimal setting for tap operations, the total number of operations is examined while the best control setting occurs for the case with the least operations.

The remaining three goals were analyzed outside of the optimization. These goals included 1) avoiding overvoltages, 2) improving hosting capacity, and 3) deferring the need for additional capacitors. Overvoltages are flagged in each optimization to identify problematic settings. The feeder PV hosting capacity will increase with the improvement in metric, but determining the magnitude was outside of the scope for this analysis. The need for additional capacitors was reduced when voltages are improved thus it will be assumed that the optimal control settings will defer new capacitor additions.

One year of SCADA measurement data at the feeder head identified that the midday feeder load is near the analyzed peak load level 11 % of the time whereas near the analyzed offpeak load level 89 % of the time. This fraction was used to weight the benefit of control settings to represent a full year. One year of solar measurement data showed the variable day is likely to occur 54 % of the year while the overcast and clear days occur 13 and 33 %, respectively. The probability of scenario occurrence is shown in Table 3-4.

Table 3-4
Solar/Load Probability (%)

Variable Solar, peak load	5.94
Variable Solar, offpeak load	48.06
Overcast Solar, peak load	1.43
Overcast Solar, offpeak load	11.57
Clear Solar, peak load	3.63
Clear Solar, offpeak load	29.37

Voltage Control Tap Operations

The best inverter settings determined through the analysis were dependent on how the six analyzed days represent the entire year. The best settings with this taken into consideration are shown in Table 3-5 for the tap operation metric. The average daily values for several metrics based on the annual representation are shown in Table 3-6. These values only represent the average during daylight hours for

- MeanPCCv – average PV interconnect voltage
- Voltage Variability Index – Voltage variability index at the inverter terminal
- Tap Operations – Line regulator and LTC tap operations
- Consumption – End-use consumption in kWh
- Losses – Total feeder losses in kWh
- Time Above – Seconds that any point on the feeder is above 105% nominal
- Time Below – Seconds that any point on the feeder is below 95% nominal
- Max V – Maximum voltage at any point on the feeder
- Min V – Minimum voltage at any point on the feeder

The best settings were optimized for tap operation reduction but many of the additional metrics show there is benefit as well. All three control types can reduce the time outside ANSI voltage limits, but no controls are capable of eliminating time above ANSI limits entirely.

Table 3-5
Best Annual Inverter Settings

Volt-VAR	Y1=1 X1=0.5	Y2=1 X2=0.98	Y3=0 X3=1.03	Y4=0 X4=1.04	Y5=0 X5=1.05	Y6=-1 X6=1.10	Y7=-1 X7=1.5
Volt-Watt	Y1=1 X1=0.5	Y2=1 X2=1	Y3=0 X3=1.06	Y4=0 X4=1.5			
Power Factor	0.94						

Table 3-6
Daily Metrics Based on Annual Average for Best Inverter Settings

Time Below	0	0	0	0	0
MaxV	0	1.0483	1.0531	1.0521	1.0498
MinV	0	0.9684	0.9684	0.9684	0.9684

Volt-VAR

OffPeak Load and Clear Solar Day

The best settings and characteristics shown in Figure 3-16 were calculated based on offpeak load and clear solar conditions. These were best settings specific to this solar/load condition. The middle setpoint depicts the center (X4 setting) of the seven point volt-VAR curve. This occurs on the volt-VAR X axis midway between the capacitive and inductive regions. The absorbing var setpoint shows when the inverter will begin absorbing reactive power (X5 setting). This occurs on the volt-VAR x axis when the y value begins to go negative. Although the controls are cycling through different characteristics, the overall best ranking occurred for controls that have a 1.02 Vpu absorbing var setpoint. Higher setpoints potentially increase voltage violations. The benefit with the 1.02 Vpu absorbing var setpoint increases as the slope of the inductive mode becomes more negative (steeper) as shown by the volt-VAR slope characteristic ((Y6-Y5)/(X6-X5)), but the most aggressive slope is not the most optimal. The dead band is the characteristic of how long the reactive power is zero (X5-X3). Curves that are inductive only have a dead band characteristic of 0.

Based on the three best curves, the best settings all had similar absorbing reactive power settings. These results illustrated that there are best settings dependent on the specific solar and load condition. Solar and load measurements could be used to automatically update the inverter settings to best correlate with the current field conditions.

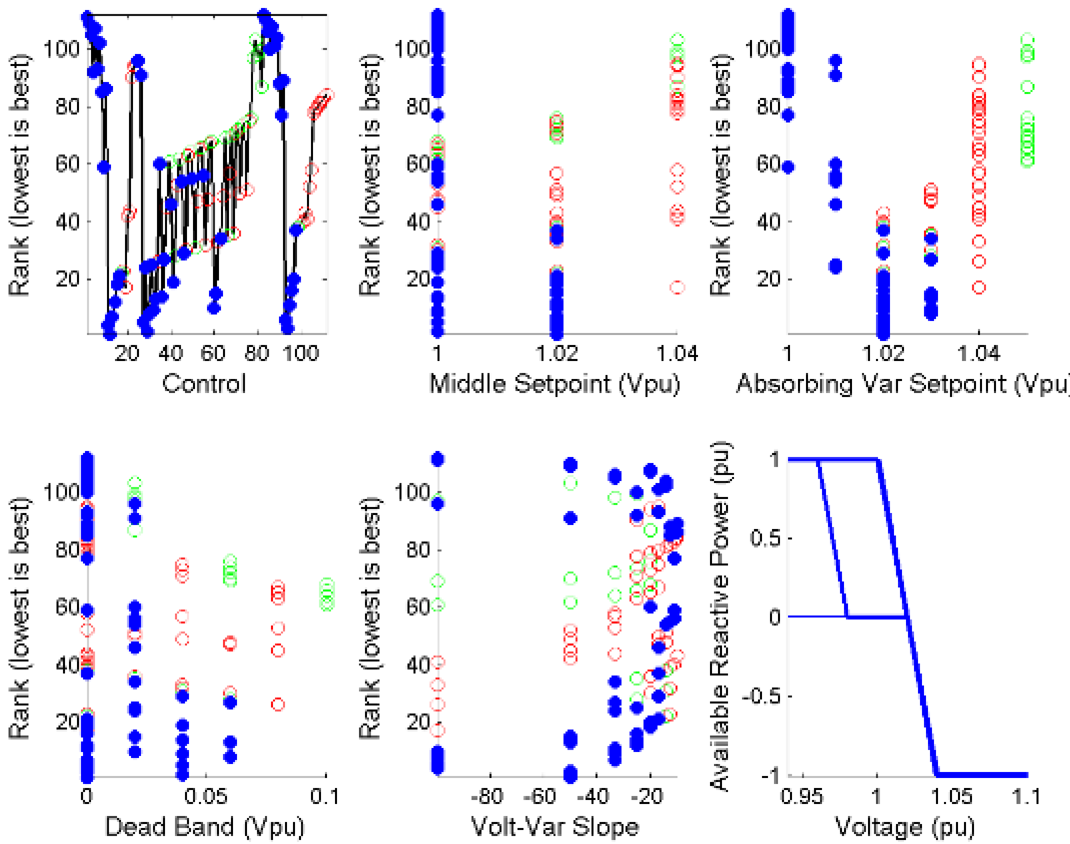


Figure 3-16
Best Volt-VAR Settings and Characteristics

Peak Load Day

The best settings and characteristics shown in Figure 3-17 are based on peak load and all solar conditions. Settings were calculated based on peak load and weighted by probability of solar condition occurrence. In this situation, the best settings apply to all solar conditions but are specific to peak load. During peak load, the three best settings had an absorbing var setpoint of 1.04 Vpu but various slopes. The most aggressive slope was the best.

These results illustrate that optimal settings are dependent on the representative scenarios used in the analysis. The load level can impact the feeder and affect the inverter settings that provide the best benefit. Communication with the inverters can be used to update settings based on operator command or automatically based on SCADA measurements.

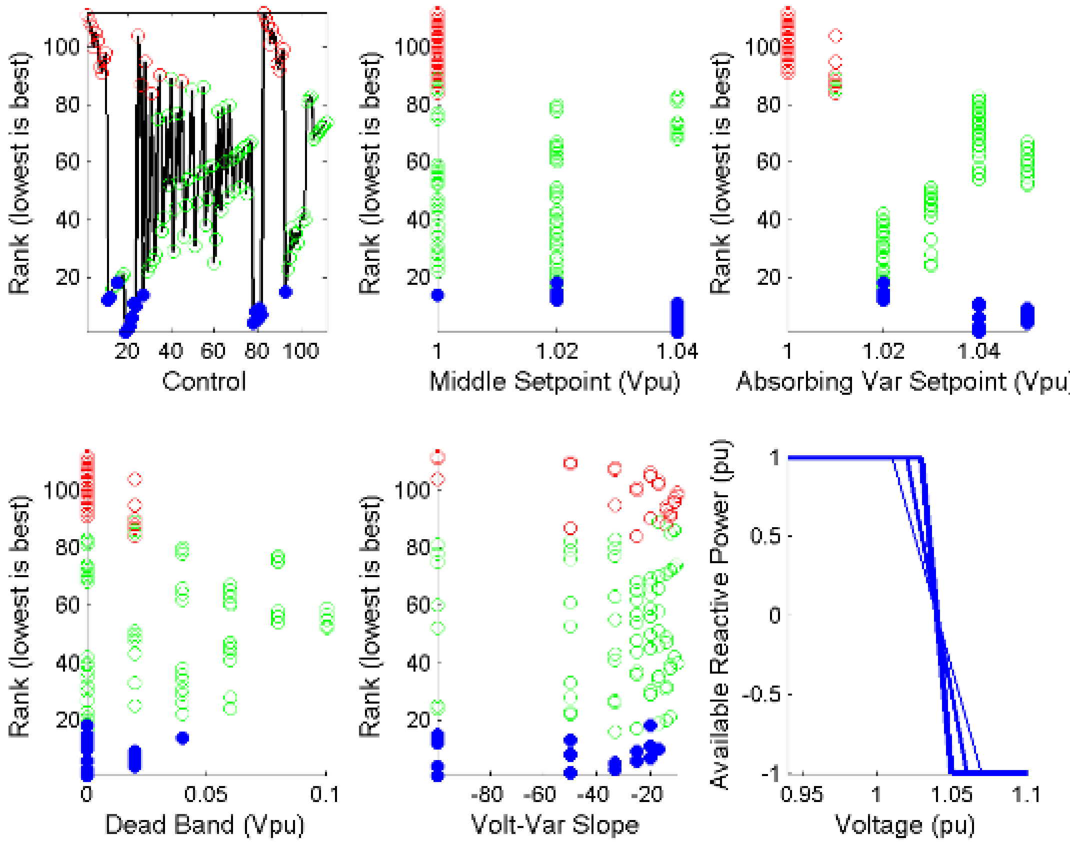


Figure 3-17
Best Volt-VAR Settings and Characteristics

Variable Solar Day

The best settings and characteristics shown in Figure 3-18 are based on variable solar conditions. Settings were calculated based on variable solar and weighted by the probability of load condition occurrence. In this situation, the best settings apply to all load conditions but were specific to variable solar.

During variable solar, the three best settings had an absorbing var setpoint of 1.04 Vpu but various slopes. The results illustrated that the inverter control is incapable of eliminating time outside ANSI limits, but the better settings could reduce time outside ANSI compared to the unity power factor case. Many settings increased the time outside ANSI limits which is due to the inverters inability to provide reactive power at full active power output. On a variable solar day, the solar active power output may be low while the reactive power demand is high. As the PV active power output increases, the reactive capacity of the inverter decreases although the inverter needs to increase reactive power demand to counter the rise in voltage. This ends up causing a more significant change in voltage than if the inverter had remained set at unity power factor where voltages are varying purely on active power output.

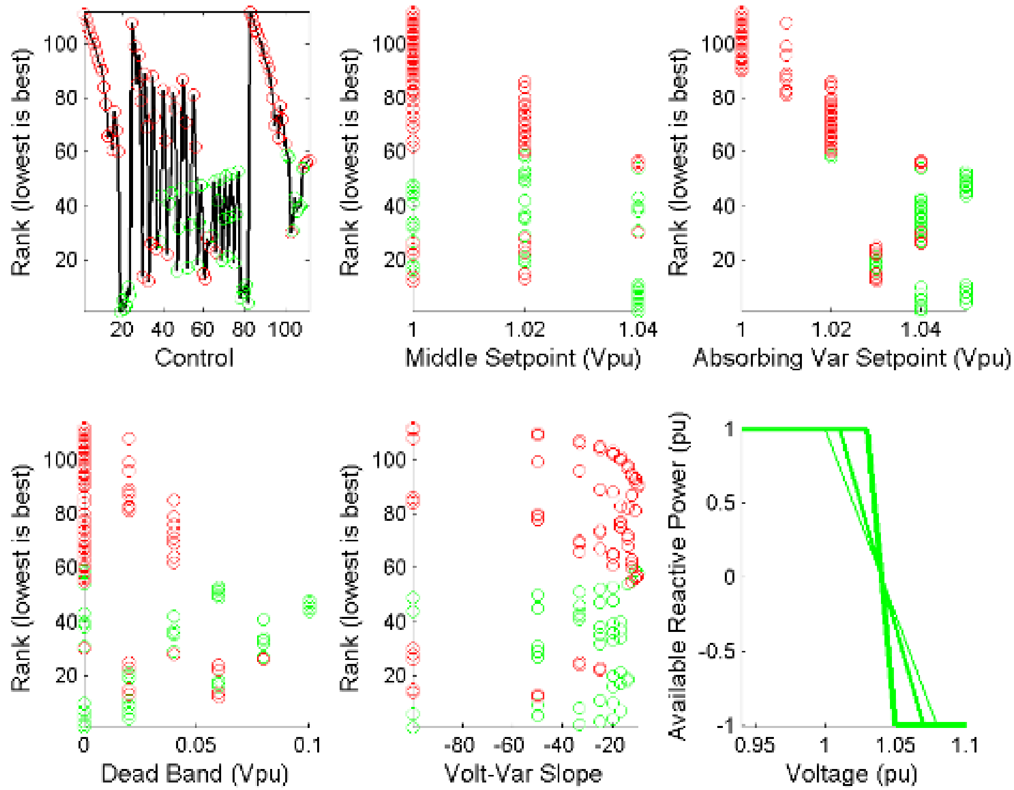


Figure 3-18
Best Volt-VAR Settings and Characteristics

Overall Best Settings

The overall best settings apply for all load/solar possibilities. The simulated daily impact was weighted based on annual measured occurrence of each condition. Only one setting can be used if there is no communication to update settings based on real-time load/solar conditions in the field.

The settings in Table 3-7 show the best control for each individual type of day. Note that there is little repetition of the best control on the individual days. The variable solar conditions have the same best curves as well as the peak /clear and peak/overcast conditions.

Table 3-7
Best Individual Day Inverter Volt-VAR Settings

	Y1=1 X1	Y2=1 X2	Y3=0 X3	Y4=0 X4	Y5=0 X5	Y6=-1 X6	Y7=-1 X7
Variable Solar, peak load	0.5	1.03	1.04	1.04	1.04	1.05	1.5
Variable Solar, offpeak load	0.5	1.03	1.04	1.04	1.04	1.05	1.5
Overcast Solar, peak load	0.5	1.02	1.04	1.04	1.04	1.06	1.5
Overcast Solar, offpeak load	0.5	1.01	1.02	1.02	1.02	1.03	1.5
Clear Solar, peak load	0.5	1.02	1.04	1.04	1.04	1.06	1.5
Clear Solar, offpeak load	0.5	1.00	1.02	1.02	1.02	1.04	1.5

Figure 3-19 shows the ranking of the overall best volt-VAR control settings and the characteristics of those settings. Since the majority of the year is similar to offpeak load, the best annual settings should be primarily dependent on the three offpeak settings. However, due to voltage violations that occured during the variable solar conditions, many settings are unacceptable.

If the inverter had been 1.1x the size of the PV system, there would have been more consistency in the best annual inverter settings. Figure 3-20 shows the best settings and characteristics assuming oversized inverters. With slightly larger inverters, the settings also have the ability to eliminate the primary voltage violations. The best settings are also capable of reducing the tap operations to less than that occurring prior to the installation of PV.

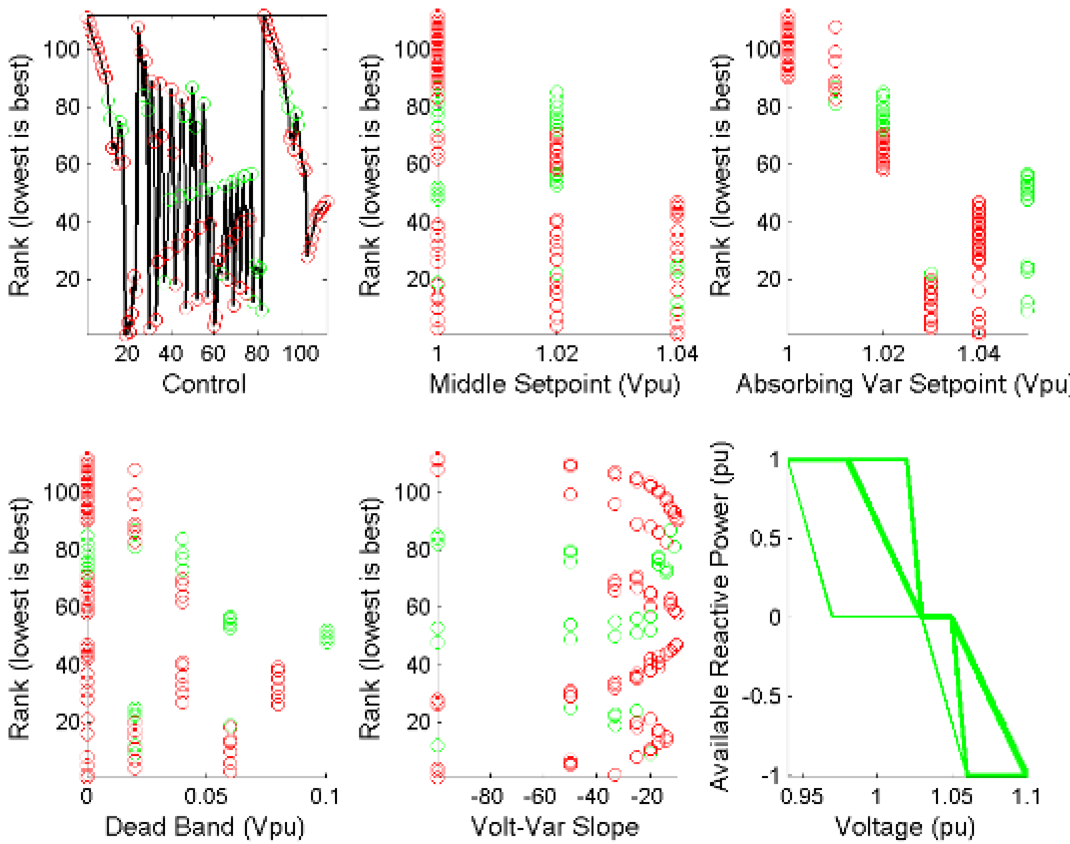


Figure 3-19
Best Volt-VAR Settings and Characteristics

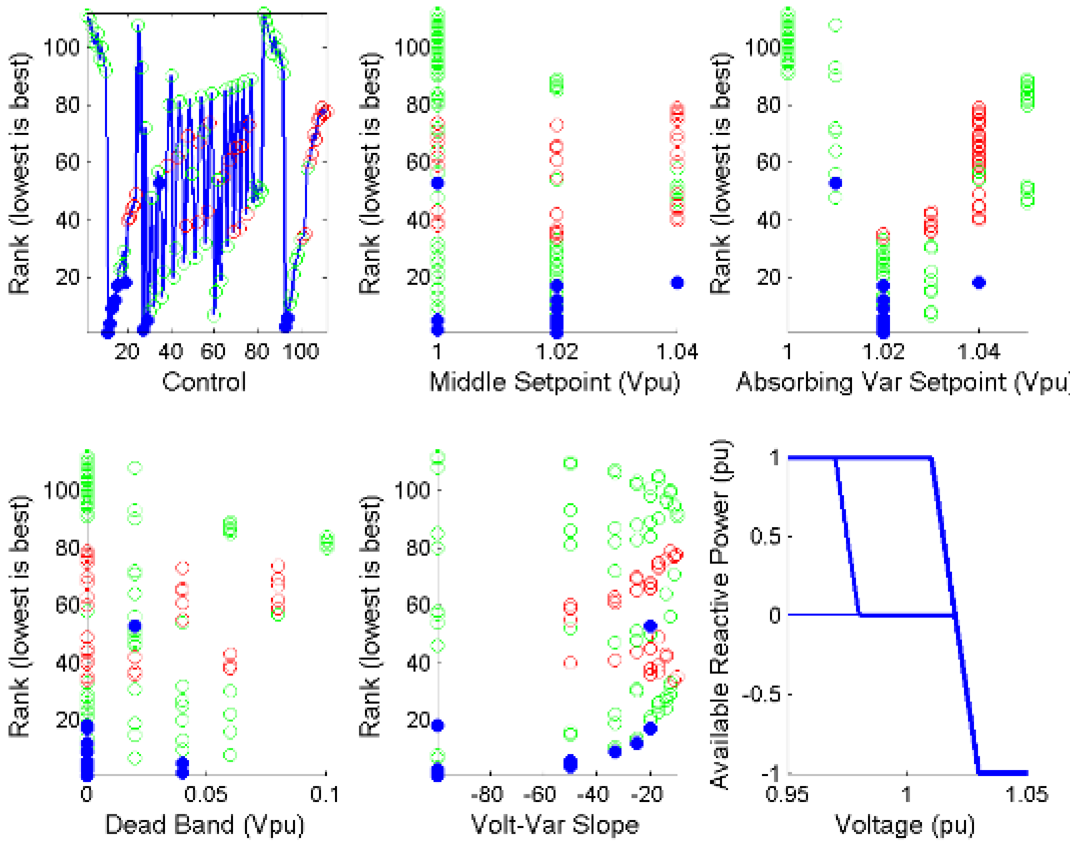


Figure 3-20
Best Volt-VAR Settings and Characteristics if Inverters are Oversized Relative to PV

Volt-Watt

As shown in Figure 3-21, the best volt-watt settings were unable to eliminate the time outside ANSI limits but the time was the same or reduced with many settings. The best settings begin to curtail power (X2 setpoint) as soon as the PCC voltage exceeds 1.0 Vpu. This curtailment of power may be seen negatively by the PV owner but prior to PV installed on the feeder, the simulation shows very little time outside ANSI limits. The better settings have steep volt-watt slopes ((Y3-Y2)/(X3-X2)). The settings with the highest setpoint essentially never curtail power, thus the feeder response is the same as if the PV had no control.

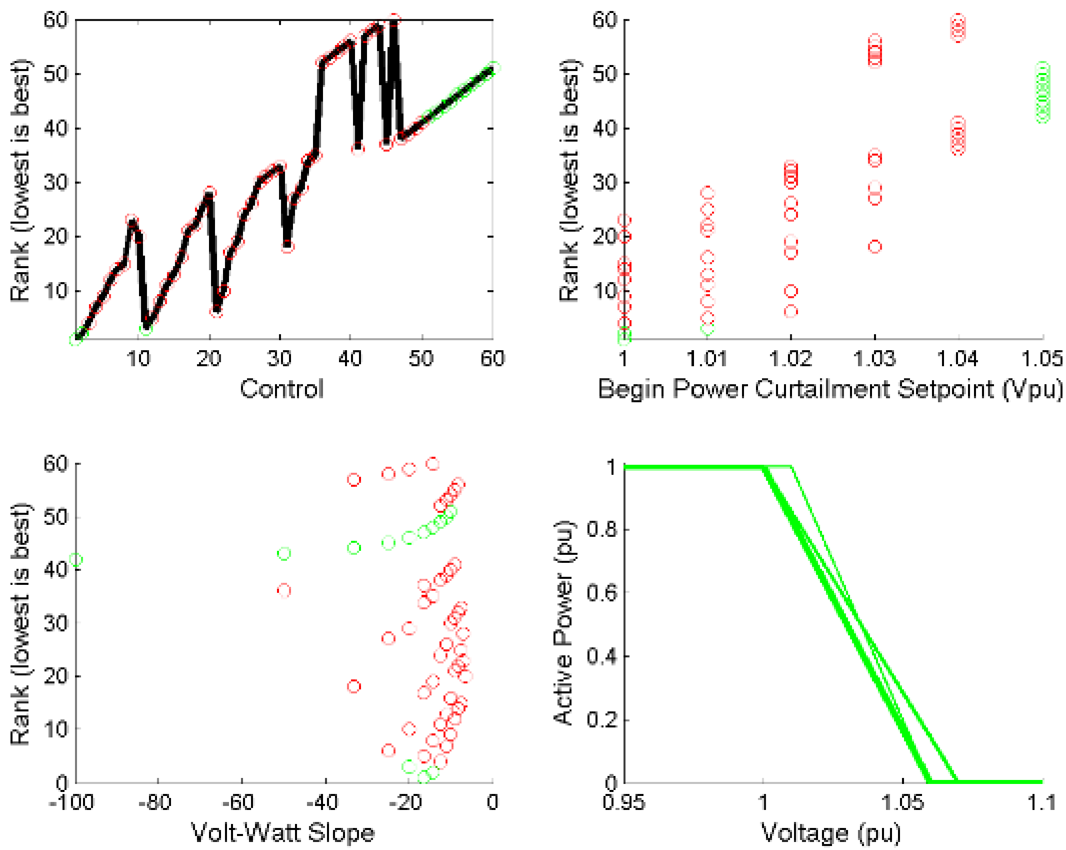


Figure 3-21
Best Volt-Watt Settings and Characteristics

Power Factor

The best overall power factor setting to reduce tap operations was 0.94. The best settings for the individual scenarios are shown in Table 3-8 and Figure 3-22. The offpeak/variable day caused an increase in time above ANSI voltage limits thus the best individual setting for that day is unity. The increase in violations was due to limited and more variable reactive power. The reduction in time in violation on the other days, however, allows the off-nominal power factor settings to be the overall best.

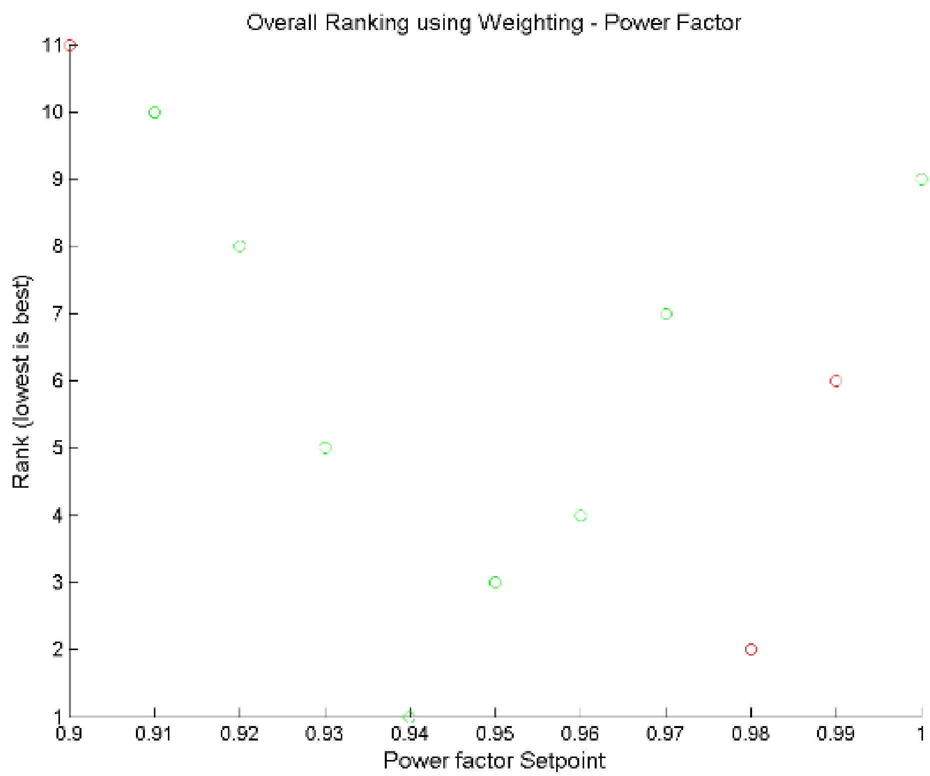


Figure 3-22
Best Power Factor Settings and Characteristics

Table 3-8
Best Individual Day Inverter Power Factor Settings

Variable Solar, peak load	0.95
Variable Solar, offpeak load	1.00
Overcast Solar, peak load	0.99
Overcast Solar, offpeak load	0.99
Clear Solar, peak load	0.91
Clear Solar, offpeak load	0.94

Customer Efficiency

Customer efficiency can be improved the best over the year with the settings shown in Table 3-9. The volt-VAR and power factor settings reduced customer demand but do not eliminate voltages outside ANSI limits as shown in Table 3-10. The volt-watt settings do not provide any benefit by reducing consumption. The use of reactive power for improving consumption also decreases average losses but increases tapping.

Table 3-9
Best Annual Inverter Settings

Volt-VAR	Y1=1 X1=0.5	Y2=1 X2=1.01	Y3=0 X3=1.02	Y4=0 X4=1.02	Y5=0 X5=1.02	Y6=-1 X6=1.03	Y7=-1 X7=1.5
Volt-Watt	Y1=1 X1=0.5	Y2=1 X2=1.05	Y3=0 X3=1.06	Y4=0 X4=1.5			
Power Factor	0.91						

Table 3-10
Daily Metrics Based on Annual Average for Best Inverter Settings

Time Below	0	0	0	0	0	0
MaxV	0	1.0483	1.0531	1.0518	1.0531	1.0518
MinV	0	0.9684	0.9684	0.9684	0.9684	0.9684

There are volt-VAR settings that could provide further improvement to customer efficiency as shown in Figure 3-23, but those settings cause additional time outside of ANSI voltage limits. When ignoring voltage violations, the trends show that the settings improve for lower absorbing var setpoints, steeper slopes, and no dead band. The three best settings all had similar absorbing reactive power settings.

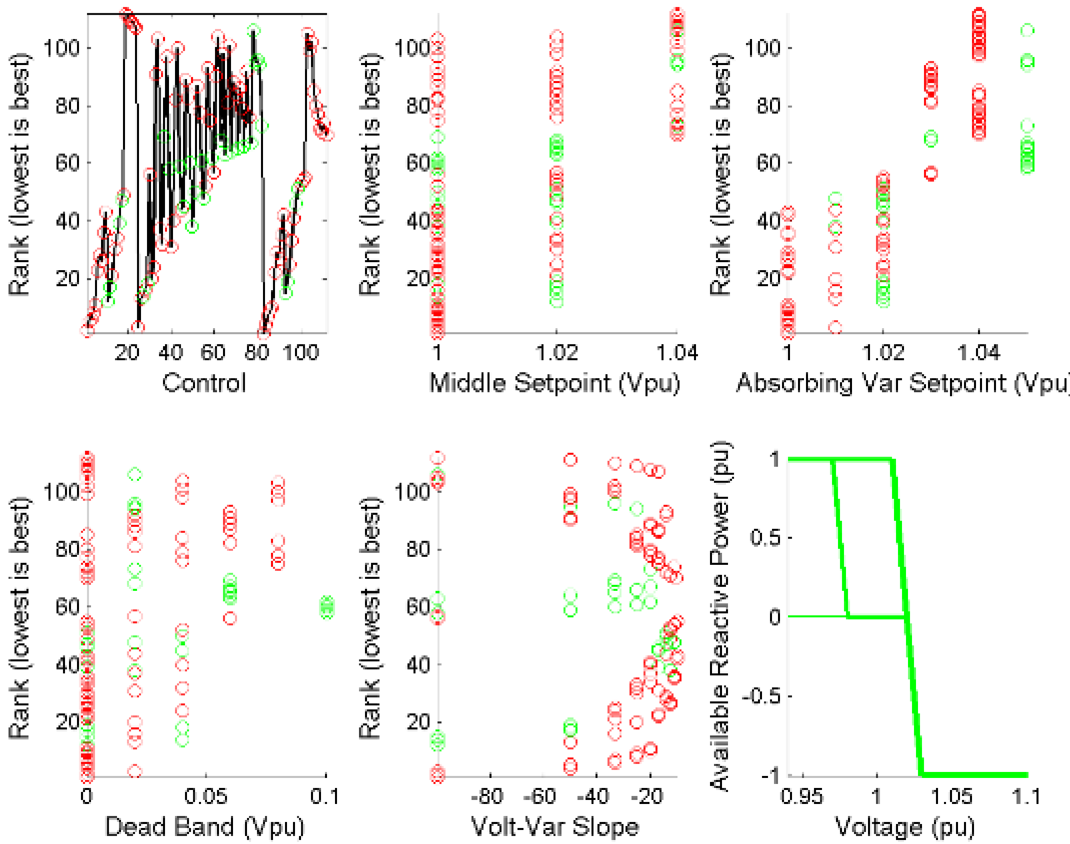


Figure 3-23
Best Volt-VAR Settings and Characteristics

The inclusion of PV on the feeder slightly increased consumption over the base case without PV. Reducing the PV active power output with volt-watt control would conceptually decrease consumption, but because these settings altered the feeder regulator tapping and capacitor switching, many increase the time outside ANSI limits. Therefore, the best settings were those that essentially never curtail power as shown in Figure 3-24.

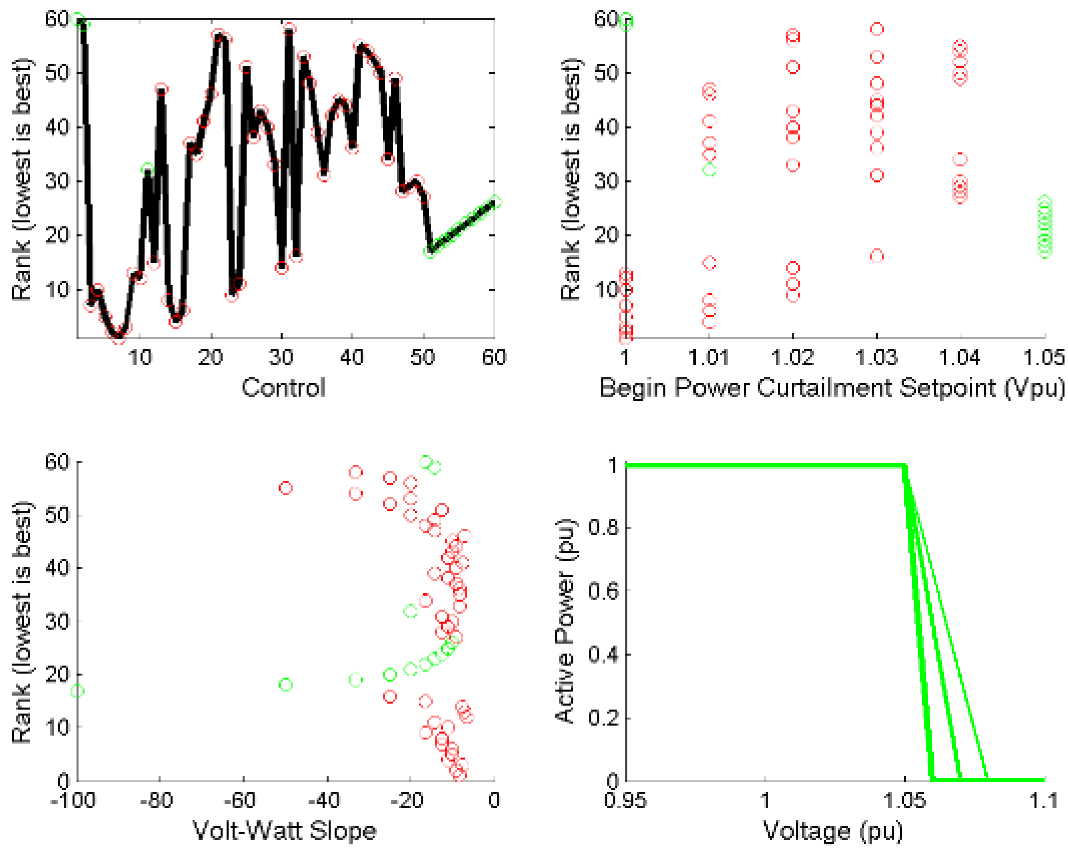


Figure 3-24
Best Volt-Watt Settings and Characteristics

The trend of best power factor setting generally increased toward lower settings as shown in Figure 3-25. Lower settings generally helped pull voltages down and reduce consumption and time outside ANSI limits.

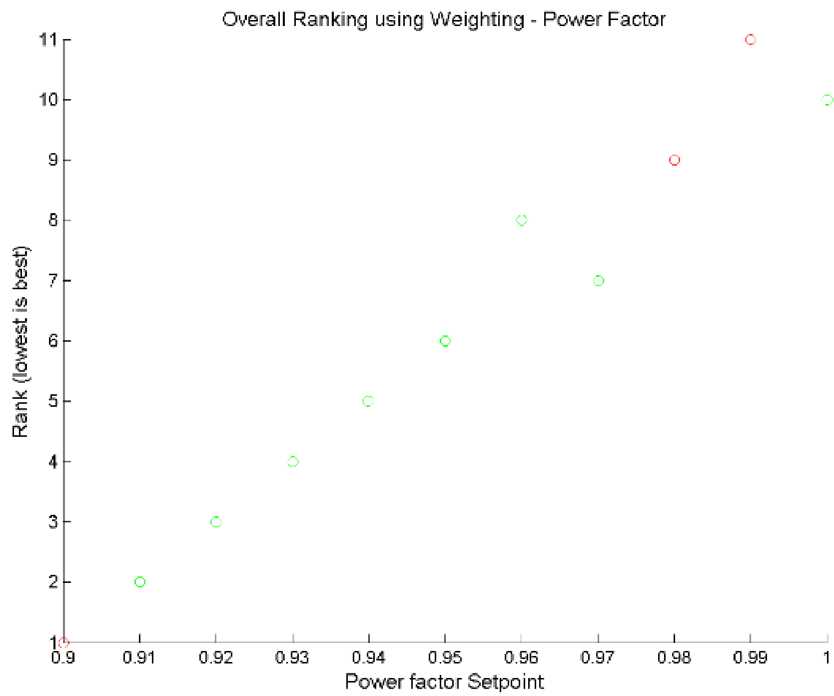


Figure 3-25
Best Power Factor Settings and Characteristics

National Grid – E1

The National Grid – E1 feeder was analyzed with both large inverters (rated 266 and 300 kVA) with advanced control capability. There were four goals identified with the use of added inverter functionality. Only two are optimized in this analysis to determined best control settings. The optimized objectives will 1) reduce flicker and 2) reduce losses. Reducing the potential for flicker is analyzed by the voltage variability index. This index calculates the change in voltage during each time-step of the simulation. Less variable voltage will result in a reduced chance of flicker. Losses were examined by summing the total kWh losses for all feeder elements during daylight hours.

The remaining two goals were analyzed outside of the optimization. These goals included 1) reducing capacitor switching and 2) deferring capacitor additions. Reducing capacitor switching was not analyzed explicitly in the simulation because the new voltage-based control has not been determined. These capacitors are currently on time-based control. Capacitor additions were assumed to be deferred since the optimization improves voltages and selects settings that reduce time outside ANSI limits.

The year of SCADA measurement data used for E1 was based on H1 data because no load measurement data is available. The analyzed peak load level was similar to the measurement data 4 % of the time whereas the measurement data was near the analyzed offpeak load level 96 % of the time. One year of E1 solar measurement data shows the variable day is likely to occur

55 % of the year while the overcast and clear days occur 14 and 31 %, respectively. The probability of scenario occurrence is shown in Table 3-11.

Table 3-11
Solar/Load Probability (%)

Variable Solar, peak load	2.2
Variable Solar, offpeak load	52.8
Overcast Solar, peak load	0.56
Overcast Solar, offpeak load	13.44
Clear Solar, peak load	1.24
Clear Solar, offpeak load	29.76

Losses

Table 3-12 shows the best inverter settings for the objective of reducing losses. Volt-VAR and volt-watt settings exist that decrease the average losses as shown in Table 3-13 and prevent additional time outside of the ANSI voltage limits. The best power factor control was unity because other settings increase time outside ANSI.

Table 3-12
Best Annual Inverter Settings

Volt-VAR	Y1=1 X1=0.5	Y2=1 X2=0.97	Y3=0 X3=1.0	Y4=0 X4=1.0	Y5=0 X5=1.0	Y6=-1 X6=1.03	Y7=-1 X7=1.5
Volt-Watt	Y1=1 X1=0.5	Y2=1 X2=1.0	Y3=0 X3=1.06	Y4=0 X4=1.5			
Power Factor	1.0						

Table 3-13
Daily Metrics Based on Annual Average for Best Inverter Settings

Time Below	0	0	0	0	0	0
MaxV	0	1.0106	1.0138	1.0128	1.0141	1.0138
MinV	0	0.9655	0.9655	0.9673	0.9655	0.9655

The better volt-VAR settings had an absorbing var setpoint of 1.0 Vpu as shown in Figure 3-26. Lower setpoints cause additional time outside ANSI limits while higher setpoints had significantly higher ranking. No bandwidth was preferred while the best three curves have moderate slopes. The steepest slopes did not have the highest ranking.

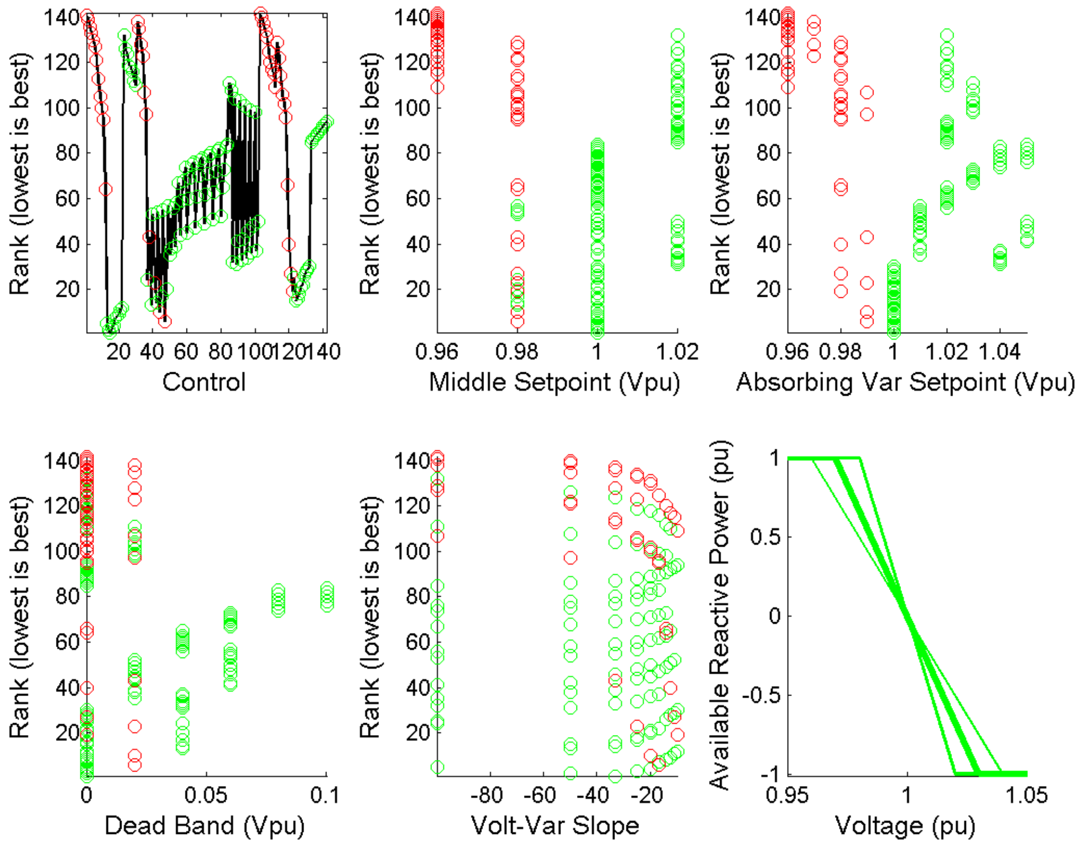


Figure 3-26
Best Volt-VAR Settings and Characteristics

Compared to the base case, losses reduce due to the PV. Losses can only decrease further with the most appropriate volt-watt settings. The best settings had low setpoints and steeper slopes as shown in Figure 3-27. This shows that the settings must be very aggressive to provide any benefit. Only on the offpeak clear and variable solar days do voltages and power output at the PV system exceed the most aggressive settings. Less aggressive settings such as higher setpoints don't curtail power.

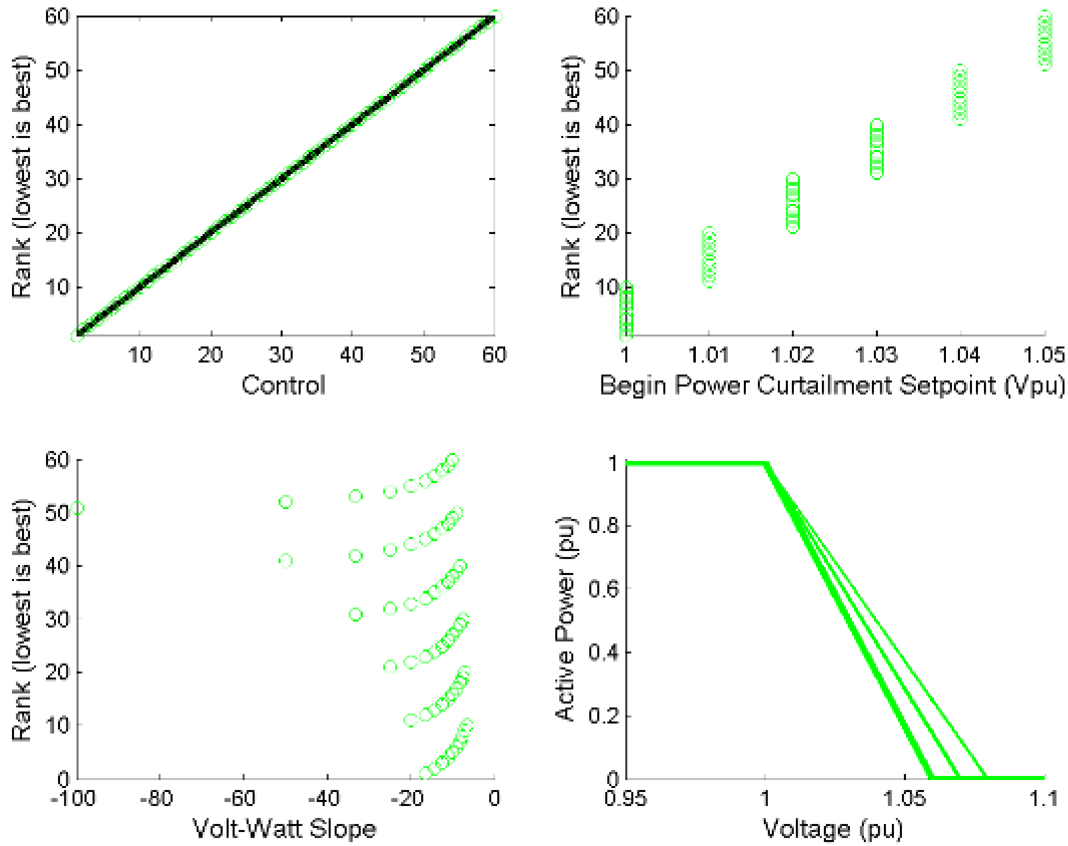


Figure 3-27
Best Volt-Watt Settings and Characteristics

Demanding reactive power at a set off-nominal power factor generally increases losses as the power factor decreases as shown in Figure 3-28. Power factor from 0.97-0.99 can potentially reduce losses greater than that with PV at unity power factor, but the time outside ANSI increases. Therefore, the best settings were that of unity power factor.

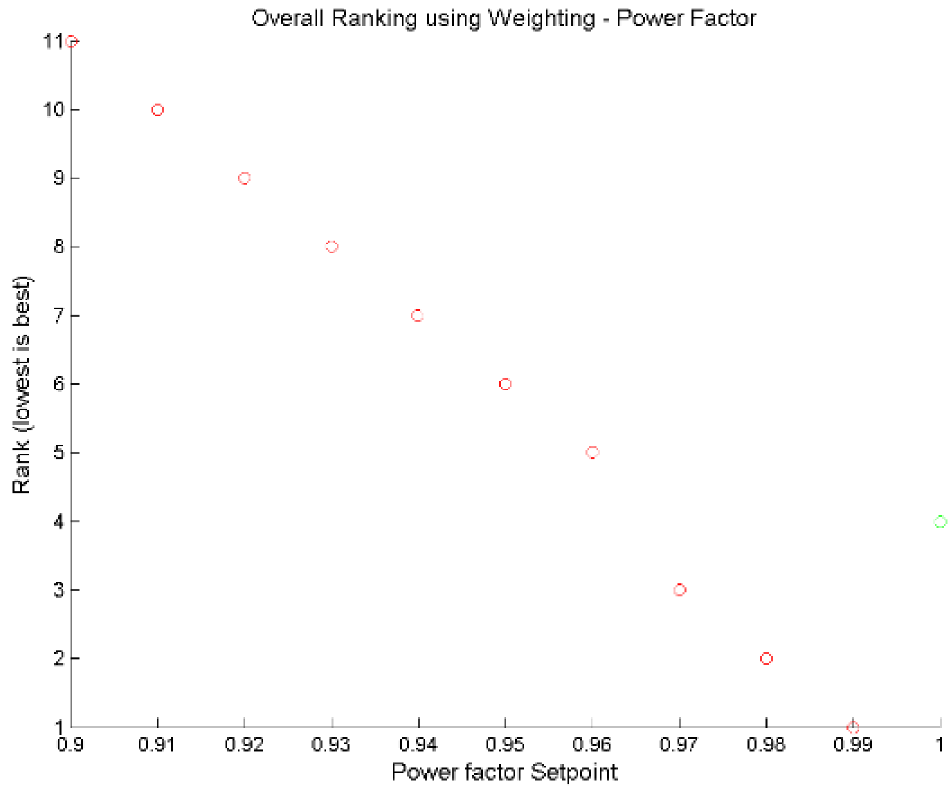


Figure 3-28
Best Power Factor Settings and Characteristics

Voltage Variability Index

The voltage variability index is a measure of how much the voltage changes during the course of the day. The best overall control settings are shown in Table 15. The volt-VAR control had the best ability to minimize the voltage variability index compared to the volt-watt and power factor control as shown in Table 16.

Table 3-14
Best Annual Inverter Settings

Volt-VAR	Y1=1 X1=0.5	Y2=1 X2=1.01	Y3=0 X3=1.02	Y4=0 X4=1.02	Y5=0 X5=1.02	Y6=-1 X6=1.03	Y7=-1 X7=1.5
Volt-Watt	Y1=1 X1=0.5	Y2=1 X2=1.0	Y3=0 X3=1.06	Y4=0 X4=1.5			
Power Factor	1.0						

Table 3-15
Daily Metrics Based on Annual Average for Best Inverter Settings

Time Below	0	0	0	0	0	0
MaxV	0	1.0106	1.0138	1.0198	1.0141	1.0138
MinV	0	0.9655	0.9655	0,9278	0.9655	0.9655

The volt-VAR control settings had a trend such that the optimal absorbing var setpoint is 1.02 Vpu with the steepest slope. The next two best settings had the same setpoints with slightly reduced slopes as shown in Figure 3-29.

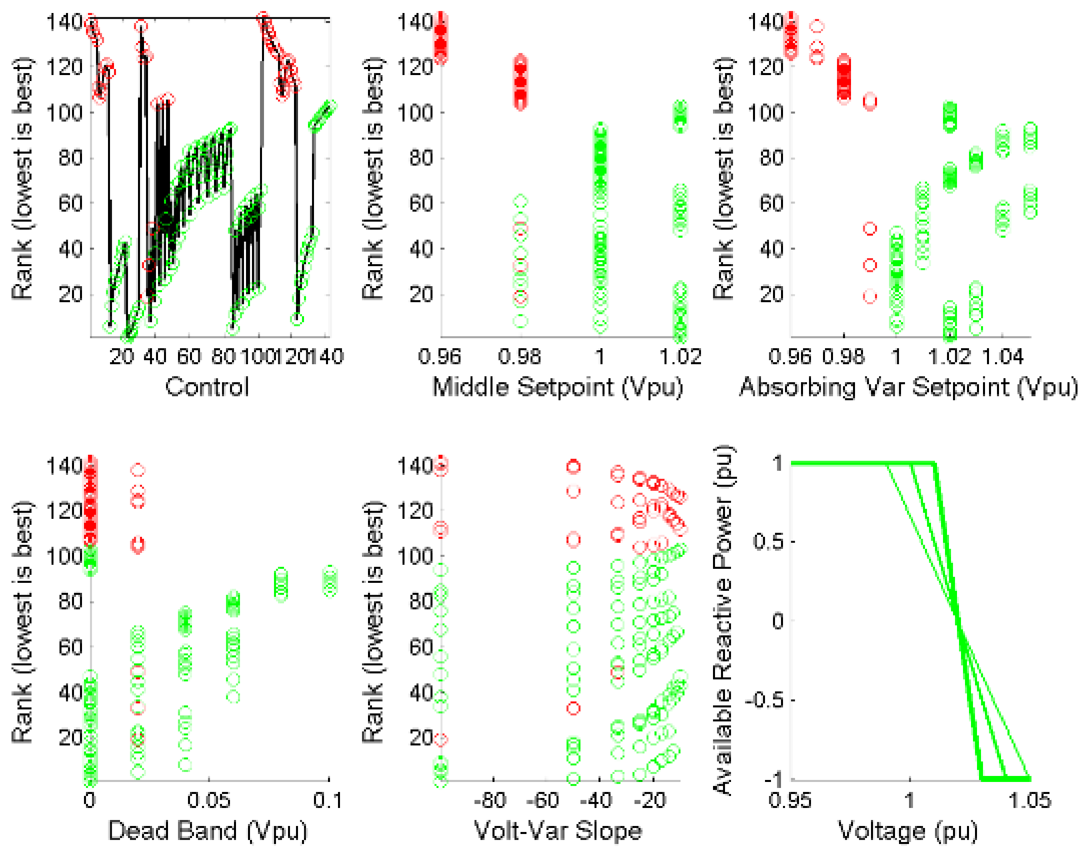


Figure 3-29
Best Volt-VAR Settings and Characteristics

Volt-watt control was seldom applied since voltages and PV output only enter that control region in two of the six analyzed days. The best curves shown in Figure 3-30 are the most aggressive.

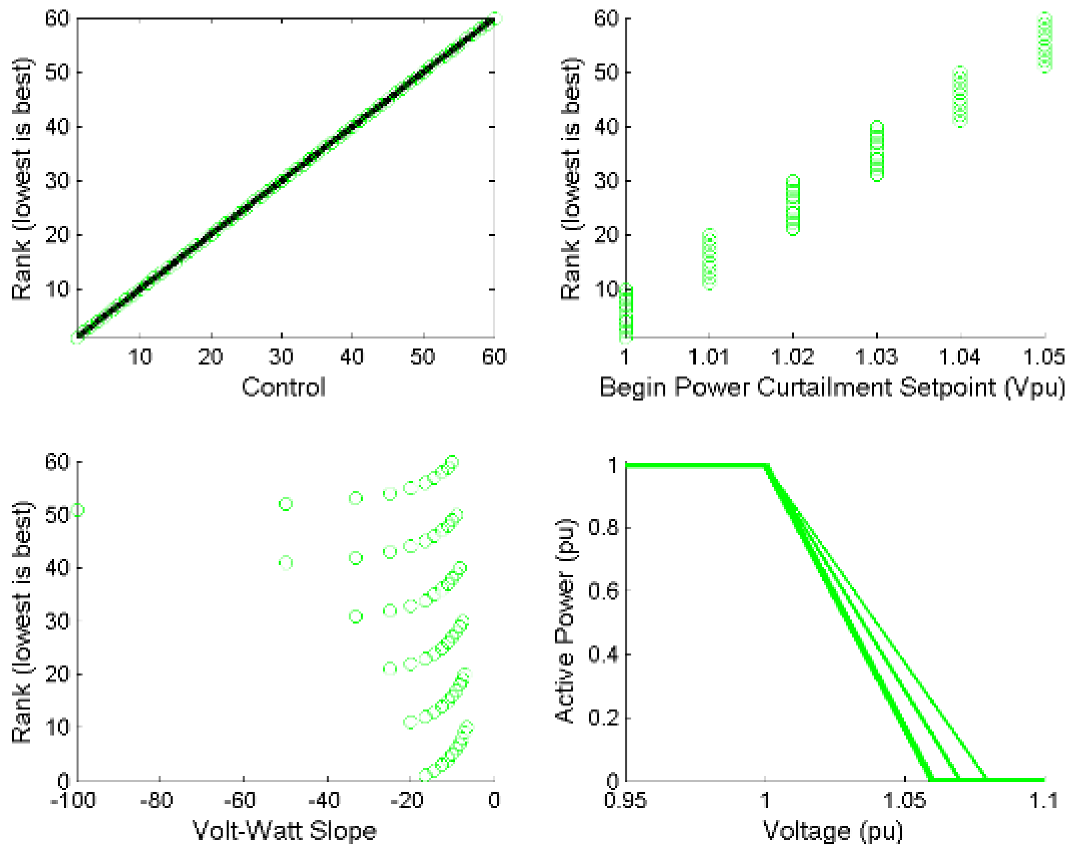


Figure 3-30
Best Volt-Watt Settings and Characteristics

The most optimal power factor control had a power factor setpoint of 0.92 but increases the time outside of ANSI, thus the most optimal settings is unity as shown in Figure 3-31.

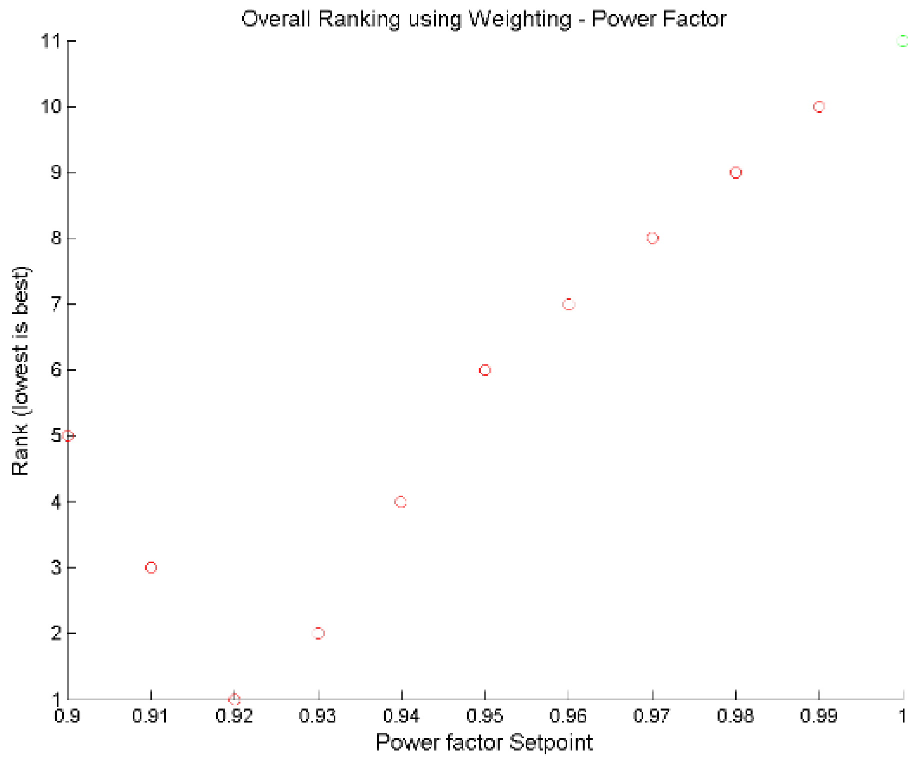


Figure 3-31
Best Power Factor Settings and Characteristics

National Grid – H1

The National Grid – H1 feeder was analyzed with both inverters (each rated 500 kVA) having advanced control capability. There were three goals identified with the use of added inverter functionality. All three are optimized in this analysis to determined best control settings. The optimized objectives will 1) reduce tap operations, 2) reduce consumption, and 3) flatten the voltage profile. To determine the optimal setting for tap operations, the total number of operations was examined while the best control setting occurs for the case with the least operations. Improving customer efficiency was analyzed by the metric of total end-use consumption. The optimal control settings for flattening the voltage profile were determined by reducing the difference between the maximum and minimum feeder voltage during the day.

One year of SCADA measurement data at the feeder head identified that the midday feeder load was near the analyzed peak load level 4 % of the time whereas near the analyzed offpeak load level 96 % of the time. This fraction was used to weight the benefit of control settings to represent a full year. One year of solar measurement data shows the variable day was likely to occur 51 % of the year while the overcast and clear days occur 15.5 and 33.5 %, respectively. The probability of scenario occurrence is shown in Table 3-16.

Table 3-16
Solar/Load Probability (%)

Variable Solar, peak load	2.2
Variable Solar, offpeak load	52.8
Overcast Solar, peak load	0.56
Overcast Solar, offpeak load	13.44
Clear Solar, peak load	1.24
Clear Solar, offpeak load	29.76

Voltage Control Tap Operations

The best settings to reduce tap operations are shown in Table 3-17. The volt-VAR settings and the off-nominal power factor settings show that the use of reactive power can reduce tapping as shown in Table 3-18. Volt-watt control can also reduce tapping.

Table 3-17
Best Annual Inverter Settings

Volt-VAR	Y1=1 X1=0.5	Y2=1 X2=0.99	Y3=0 X3=1.00	Y4=0 X4=1.00	Y5=0 X5=1.00	Y6=-1 X6=1.01	Y7=-1 X7=1.5
Volt-Watt	Y1=1 X1=0.5	Y2=1 X2=1.0	Y3=0 X3=1.06	Y4=0 X4=1.5			
Power Factor	0.96						

Table 3-18
Daily Metrics Based on Annual Average for Best Inverter Settings

Time Below	**0**	**0**	**0**	**0**	**0**	**0**
MaxV	0	1.0496	1.0496	1.0478	1.0496	1.0496
MinV	0	0.9620	0.9620	0.9620	0.9620	0.9620
Vcliff	0	0.0877	0.0877	0.0858	0.0877	0.0877

The three best volt-VAR settings to reduce tap operations had the same characteristics in the inductive region as shown in Figure 3-32. This was the same outcome as found for the J1 feeder. In general, lower absorbing var setpoints are better with the most optimal at 1.0 Vpu.

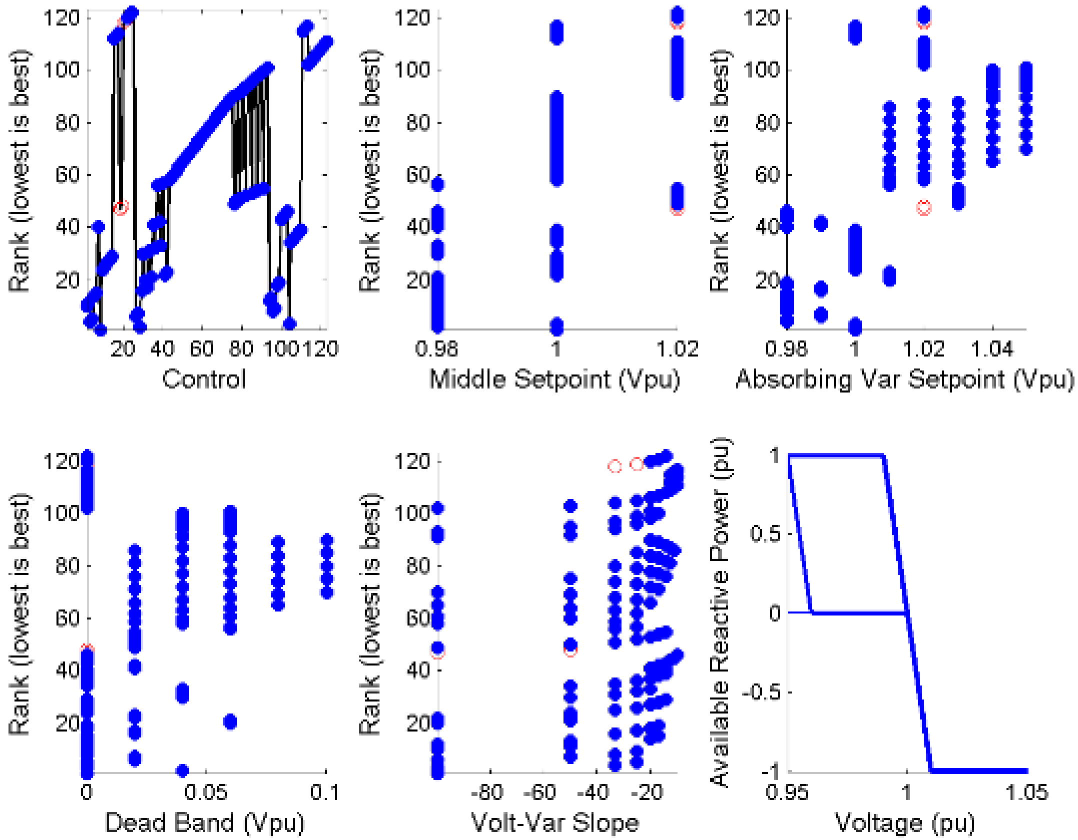


Figure 3-32
Best Volt-VAR Settings and Characteristics

Volt-watt settings must be aggressive to provide benefit by reducing tap operations as shown in Figure 3-33. Any controls with power curtailment setting 1.01 Vpu or higher did not impact the feeder. On the overcast days the control never enters the active curtailment region. Only on the offpeak clear and variable days were the taps impacted by volt-watt control. The volt-watt control also operated on the peak clear and variable days, but the tap operations did not change.

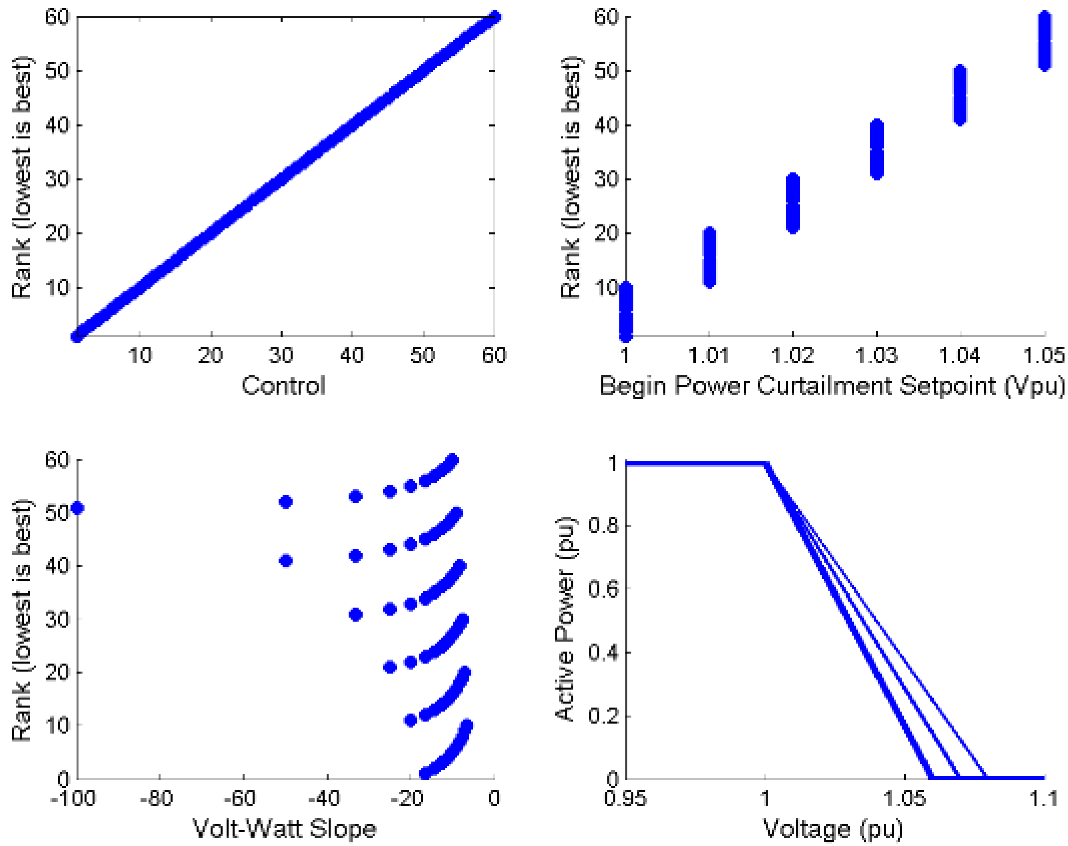


Figure 3-33
Best Volt-Watt Settings and Characteristics

The power factor trend in Figure 3-34 shows that 0.96 power factor was the most optimal to reduce tapping. Lower power factors did not provide additional benefit while higher power factors up to unity are less beneficial.

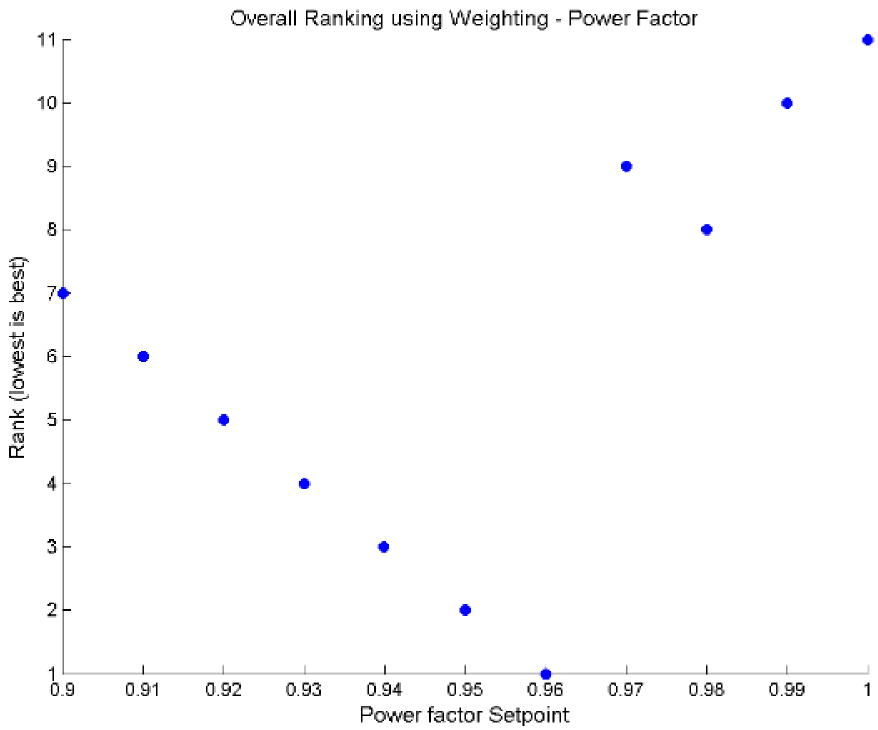


Figure 3-34
Best Power Factor Settings and Characteristics

Customer Efficiency

The volt-VAR settings that provide benefit to reduce end-use consumption are shown in Table 3-19. The best volt-watt curve essentially did not impact the feeder and was not active in any scenario because the reduction in PV output will increase consumption closer to that in the base case. The single best annual power factor setting was to maintain unity. The average kWh improvement during daylight hours for the best settings was minimal as shown in Table 3-20 .

Table 3-19
Best Annual Inverter Settings

Volt-VAR	Y1=1 X1=0.5	Y2=1 X2=0.97	Y3=0 X3=0.98	Y4=0 X4=0.98	Y5=0 X5=0.98	Y6=-1 X6=0.99	Y7=-1 X7=1.5
Volt-Watt	Y1=1 X1=0.5	Y2=1 X2=1.02	Y3=0 X3=1.09	Y4=0 X4=1.5			
Power Factor	1.0						

Table 3-20
Daily Metrics Based on Annual Average for Best Inverter Settings

MaxV	0	1.0496	1.0496	1.0477	1.0496	1.0496
MinV	0	0.9620	0.9620	0.9620	0.9620	0.9620
Vcliff	0	0.0877	0.0877	0.0857	0.0877	0.0877

The best volt-VAR settings shown in Figure 3-35 have a low absorbing var setpoint. The better settings also did not have a dead band. The slope of the curve was better when it is steep but can still have high rank as slope decreases.

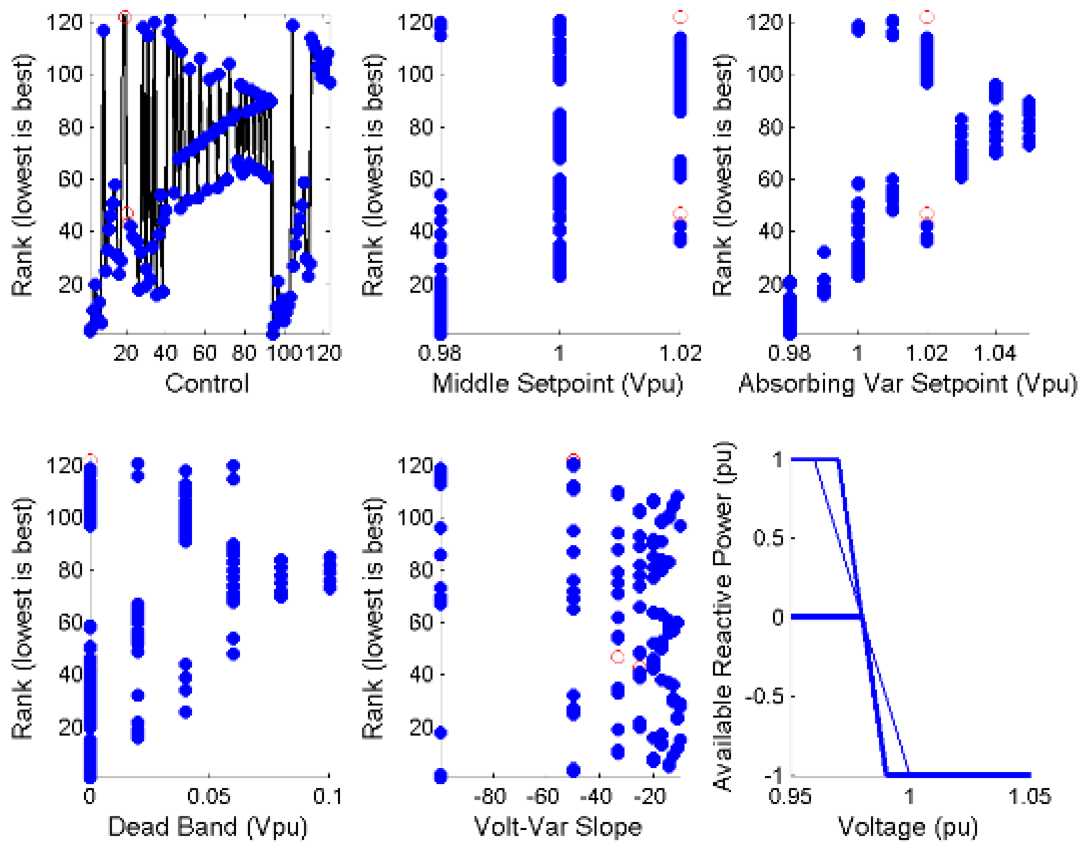


Figure 3-35
Best Volt-VAR Settings and Characteristics

The best volt-watt settings had a setpoint of 1.02 Vpu as shown in Figure 3-36. Rank decreases with higher and lower setpoints. Lower setpoints had higher rank because PV was being curtailed. This causes the feeder to operate with less PV generation which mimics a case similar to the basecase without PV. Without PV the consumption increases. Voltages also did not go above 1.02 Vpu in the analysis. Therefore, all settings with a 1.02 Vpu setpoint or higher had no impact on the feeder. That is why the rank vs. control linearly increases for these settings.

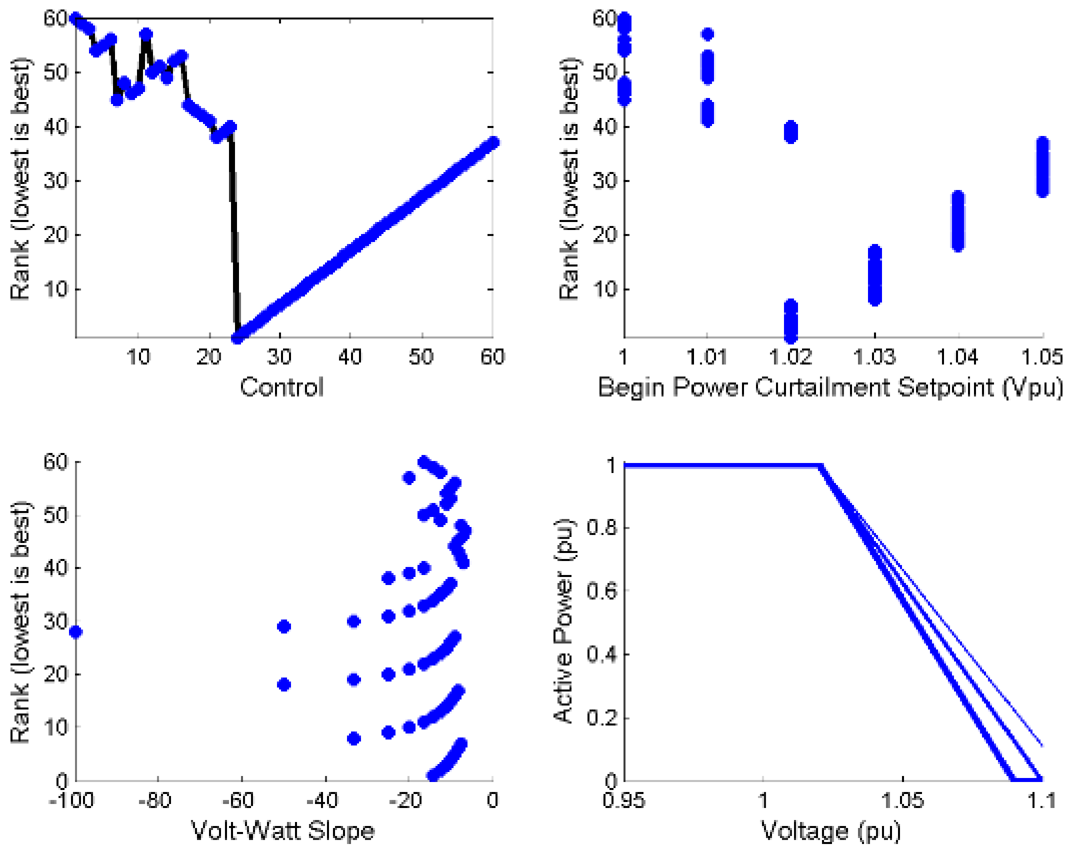


Figure 3-36
Best Volt-Watt Settings and Characteristics

Overall consumption increases with all off-nominal power factor controls as shown in Figure 3-37. One might expect that demanding more reactive power will drive down feeder voltages and reduce consumption, but this is not the case. The tap control operations change which causes increased consumption.

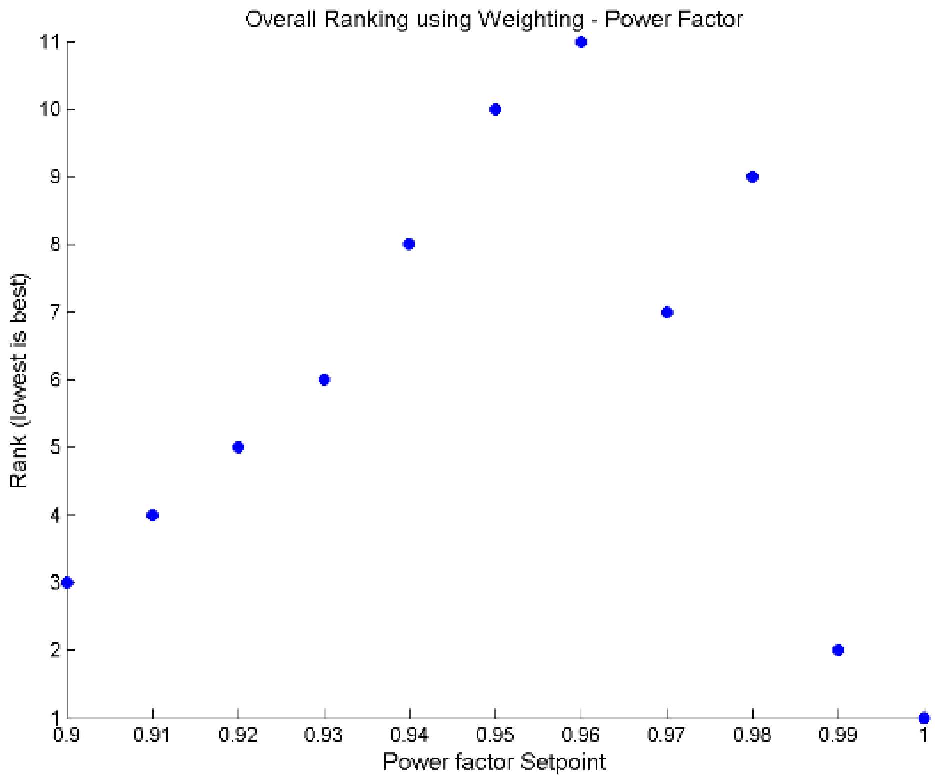


Figure 3-37
Best Power Factor Settings and Characteristics

Flattened Voltage Profile

Volt-VAR was the only control type that can flatten the feeder-wide voltage profile. The best settings are shown in Table 3-21. The minimum and maximum feeder voltages occur when the volt-watt and off-nominal power factor control provide insignificant benefit. Table 3-22 shows that the optimal volt-watt and power factor controls did not improve the optimized metric.

Table 3-21
Best Annual Inverter Settings

Volt-VAR	Y1=1 X1=0.5	Y2=1 X2=0.97	Y3=0 X3=0.98	Y4=0 X4=0.98	Y5=0 X5=0.98	Y6=-1 X6=0.99	Y7=-1 X7=1.5
Volt-Watt	Y1=1 X1=0.5	Y2=1 X2=1.0	Y3=0 X3=1.06	Y4=0 X4=1.5			
Power Factor	1.0						

Table 3-22
Daily Metrics Based on Annual Average for Best Inverter Settings

Time Below	0	0	0	0	0	0
MaxV	0	1.0496	1.0496	1.0477	1.0496	1.0496
MinV	0	0.9620	0.9620	0.9620	0.9620	0.9620
Vcliff	100	0.0877	0.0877	0.0857	0.0877	0.0877

The better volt-VAR controls had a low absorbing var setpoint as shown in Figure 3-38. Slope had a slight impact to rank as well.

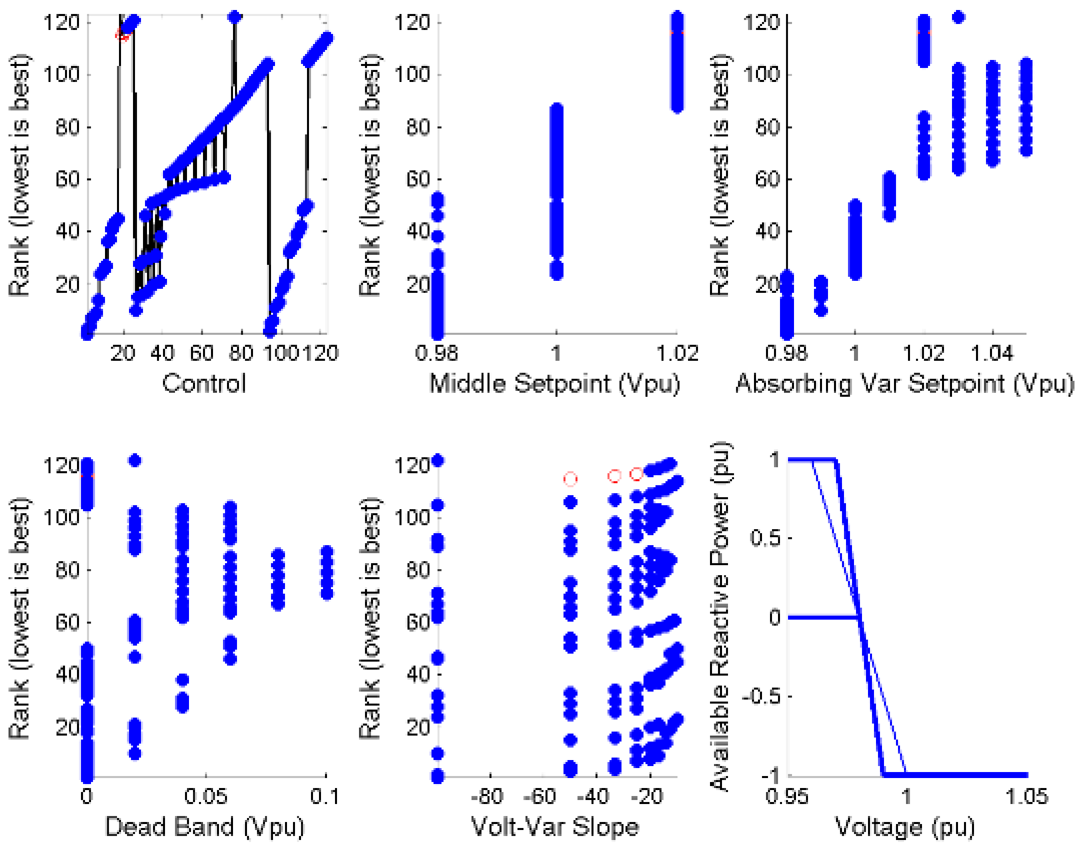


Figure 3-38
Best Volt-VAR Settings and Characteristics

The control did not help improve the range in voltage since the minimum and maximum voltages occur outside of the time when the control region was satisfied. The order of rank linearly increased with the order that the controls are analyzed as shown in Figure 3-39.

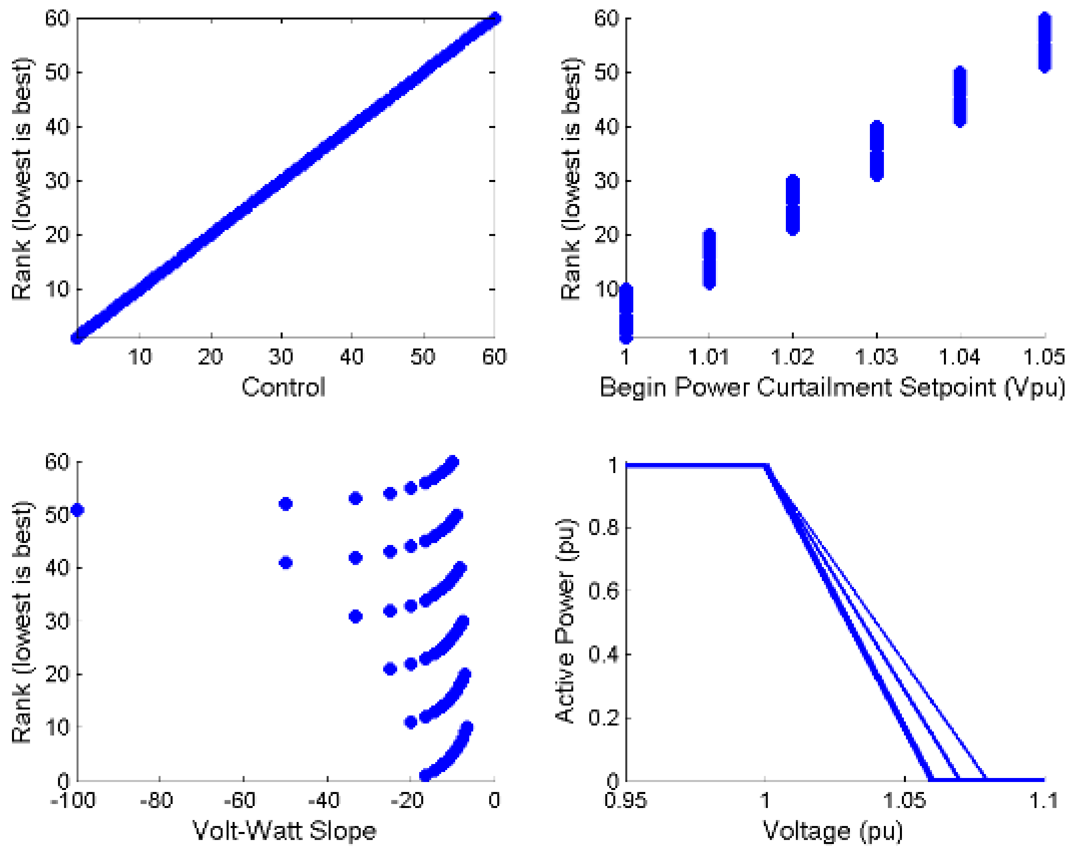


Figure 3-39
Best Volt-Watt Settings and Characteristics

The order of rank followed that of the order of analyzed control settings as shown in Figure 3-40. The minimum and maximum voltages used to calculate the feeder-wide voltage range was not impacted by off-nominal power factor control when those voltages occur.

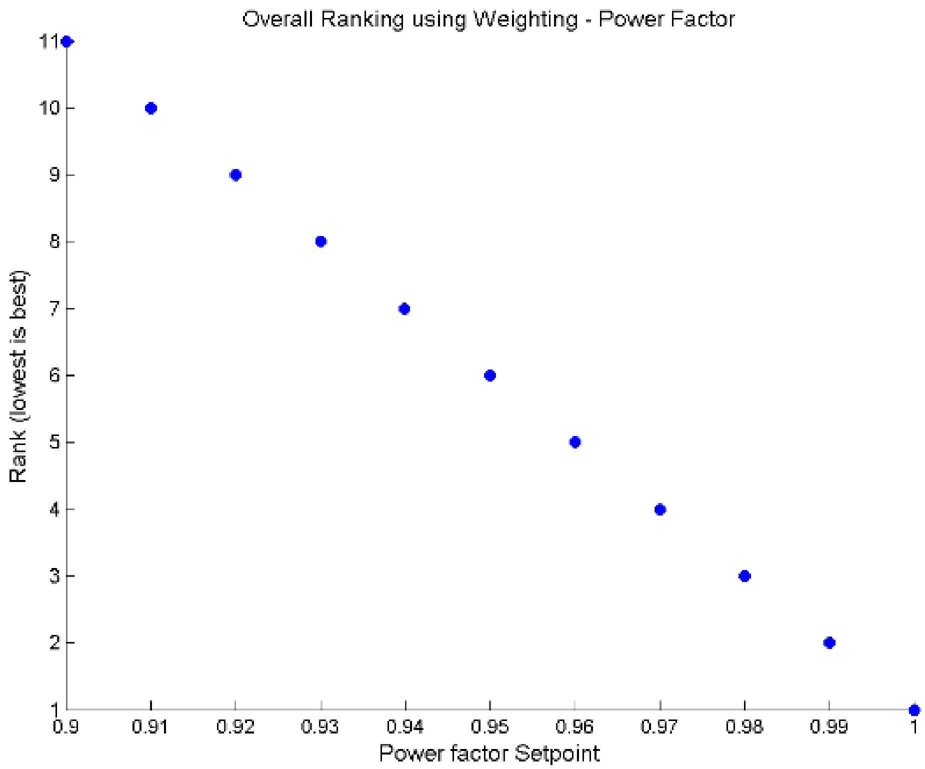


Figure 3-40
Best Power Factor Settings and Characteristics

Advanced Inverter Impact with Higher PV Penetration

The PV penetration on the two National Grid feeders are low and do not cause significant impact to the feeders. In this chapter the PV system on each feeder are increased to 5 MW to study the advanced inverter impact with higher PV penetration and determine the optimal control settings.

National Grid – E1

Losses

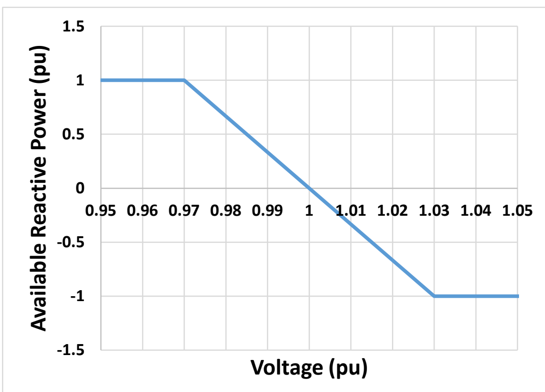
The low penetration distributed PV can reduce feeder losses, however, when the penetration reaches a certain level that causes a large amount of power to flow back to the substation, the losses can increase. As shown in Table 3-23, The 5 MW PV system cause back flow and increase feeder losses. Table 3-23 also shows the only control type to reduce losses is volt-watt control. Volt-VAR control and power factor control do not prevent the increase in losses.

The optimal volt-VAR control setting for 566 kW PV penetration and 5 MW PV penetration is shown in Figure 3-41 respectively. Compared to the setting for the 566 kW PV system, the volt-VAR setting for the 5 MW PV system is more benign which has a wide dead band and less steep slope to generate less reactive power since reactive power flow causes additional feeder losses.

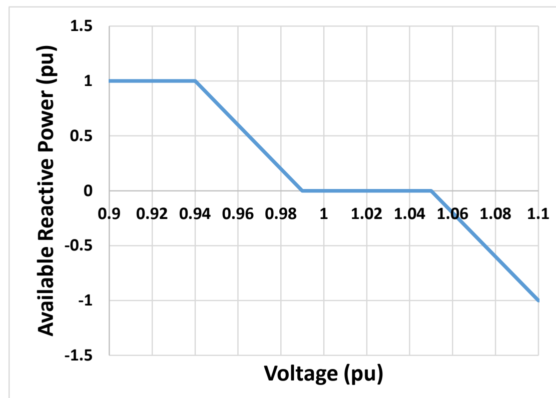
The volt-VAR settings for both penetrations barely change losses. For the same reason the optimal power factor setting is unity power factor for the 5 MW system, the same as the setting for the 566 kW system. The volt-watt control setting for the 5 MW PV system is the same as that for the 566 kW system, which is the most aggressive setting to reduce the backflow and thus the feeder losses.

Table 3-23
Daily Losses Based on Annual Average for Best Inverter Settings - Comparison of 566 kW Penetration and 5 MW Penetration (kW)

	Base case	PV	VV	VW	PF
566 kW PV	228.1	212.6	211.5	211.7	212.6
5 MW PV	228.1	900.1	901.0	466.9	900.1



a) 566 kW PV



b) 5 MW PV

Figure 3-41
Best Volt-VAR Settings for a) 566 kW PV b) 5 MW PV

Voltage Variability Index

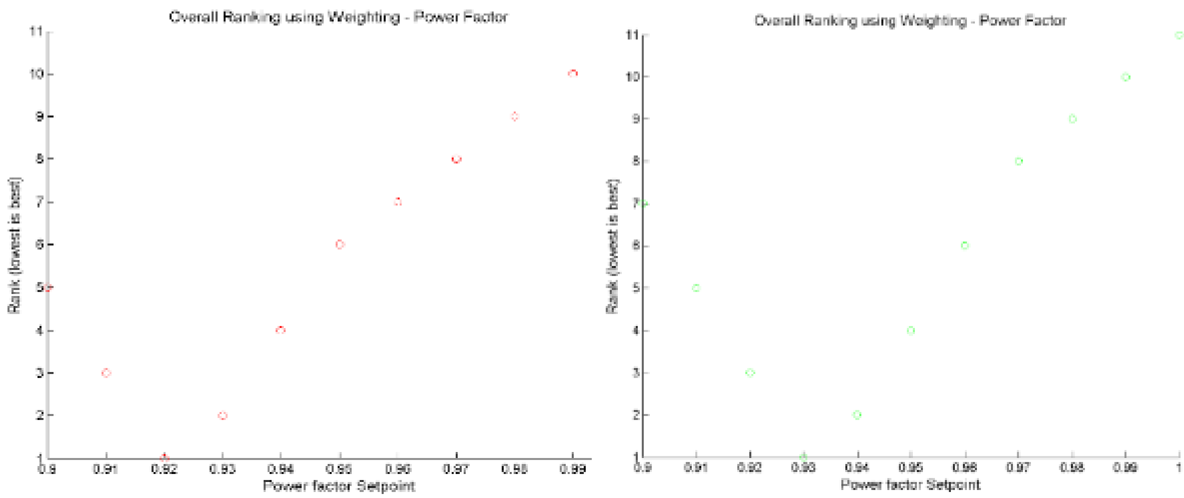
The voltage fluctuates more significantly with high PV penetration indicated by the high voltage variability index in Table 3-24. Volt-VAR control, volt-watt control and power factor control all help reduce the variability. Among them, volt-VAR control is the most effective.

The 566 kW PV system and the 5 MW PV system share the same optimal volt-VAR control setting, which has most aggressive slope and no dead band to reduce the high voltage variability. The optimal volt-watt setting for the 5 MW PV system is also the same as that for the 566 kW PV system, which is the most aggressive. In low penetration, the most aggressive volt-watt control setting did not reduce the voltage variability due to the low PV penetration. However, with the increased PV generation, the aggressive volt-watt setting does improve the voltage variability index.

The overall ranking of the power factor settings for each penetration is shown in Figure 3-42. The optimal power factor setting is 0.93 for the 5 MW PV system, which is very close to the calculated optimal setting of 0.92 for the 566 kW PV system. The calculated power factor setting to mitigate voltage deviation is determined approximately by the X/R ratio of the POI and therefore the power factor setting for low PV penetration and high PV penetration should be similar. At the higher penetration, the power factor control does reduce some voltage violations but not all (indicated by the green circles).

Table 3-24
Daily Voltage Variability Index Based on Annual Average for Best Inverter Settings - Comparison of 566 kW Penetration and 5 MW Penetration

	Base case	PV	VV	VW	PF
566 kW PV	1	1.8	1.3	1.7	1.8
5 MW PV	1	8.6	2.6	4.4	3.1



a) 566 kW PV **b) 5 MW PV**

Figure 3-42
Best Power Factor Settings and Characteristics a) 566 kW PV b) 5 MW PV

National Grid – H1

Voltage Control Tap Operations

The H1 feeder has line regulators with line drop compensation (LDC) at the feeder head. The 5 MW PV system significantly impacts the power flow through the line regulators and therefore substantially increases the tap operations, especially in highly variable solar days. As shown in Table 3-25, the daily average tap operations increase to 74. The volt-VAR control, volt-watt control and power factor control respectively reduce the tap operations to approximately half of the unity power factor PV condition (labeled PV in the table). However, the tap operations are still significantly high even with the help of these advanced inverter functions. The results indicate that LDC control strategy in the high PV penetration scenario, even with advanced inverter control, could not function appropriately. In many cases, line drop compensation should be removed when distributed variable generation exists on the feeder.

The best volt-VAR control setting for each penetration is shown in Figure 3-43. Compared with that for the 1 MW PV system, the optimal volt-VAR control setting for the 5 MW system has a lower setpoint when the system begins to absorb reactive power (0.99 Vpu) and a wider dead band (0.97 Vpu to 0.99 Vpu). This helps to control the feeder voltage within the ANSI limit but allows the voltage to fluctuate some without reactive power response. This reduces the current magnitude change in the LDC. The slopes are the same for both penetrations. A dead band implies that any additional reactive power flow causes more current variability in the LDC and does not further reduce the tap operations.

The volt-watt setting is the same for both the low and high PV penetration scenarios. Only aggressive volt-watt settings can reduce tap operations. Any volt-watt settings with power curtailment set point 1.01 Vpu or higher do no impact taps operations.

The optimal power factor setting is 0.98, slightly different from 0.96 for the 1 MW PV system. The optimal settings for both penetrations suggest that a lower power factor setting is not necessarily beneficial to reduce tap operations since more reactive power will impact the current flow through the current sensor of the LDC.

Table 3-25
Daily Tap Operations Based on Annual Average for Best Inverter Settings - Comparison of 1 MW Penetration and 5 MW Penetration

	Base case	PV	VV	VW	PF
1 MW PV	3	4	3	3	3
5 MW PV	3	74	36	31	36

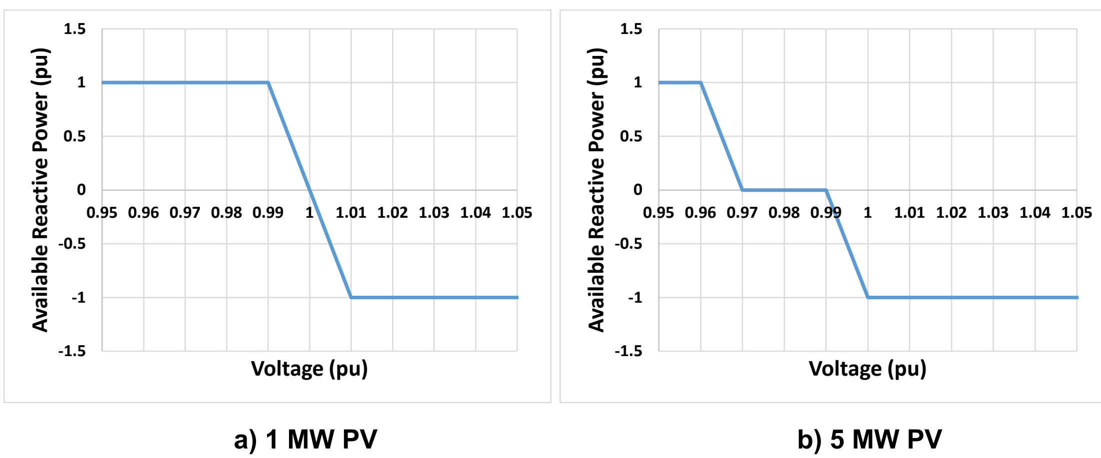


Figure 3-43
Best Volt-VAR Settings for a) 1 MW PV b) 5 MW PV

Customer Efficiency

As shown in Table 3-26, the end-use consumption reduces more with the 5 MW PV penetration operating at unity power factor (PV) over the 1 MW PV penetration. This is the result of LDC tap position that reduces the voltage and thus consumption. The further reduction obtained by the use of volt-VAR control or power factor control is slight but larger than that in the low PV penetration scenario. Volt-watt control does not provide additional consumption reduction. The calculated optimal settings vary slightly for all three control functions due to the impact on LDC tap position, but the benefit from all three functions remains negligible.

Table 3-26
Daily Consumptions Based on Annual Average for Best Inverter Settings - Comparison of 1 MW Penetration and 5 MW Penetration (MWh)

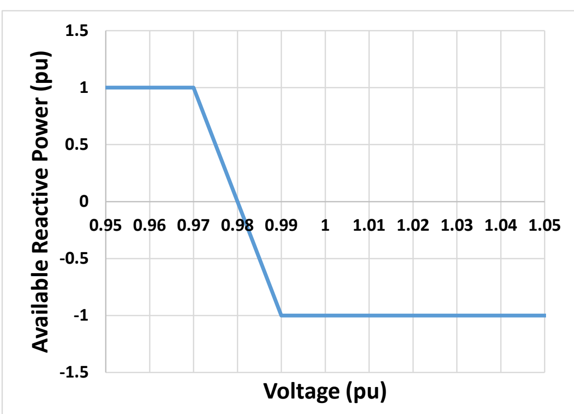
	Base case	PV	VV	VW	PF
1 MW PV	39434	39418	39379	39418	39418
5 MW PV	39434	39182	39141	39182	39158

Flattened Voltage Profile

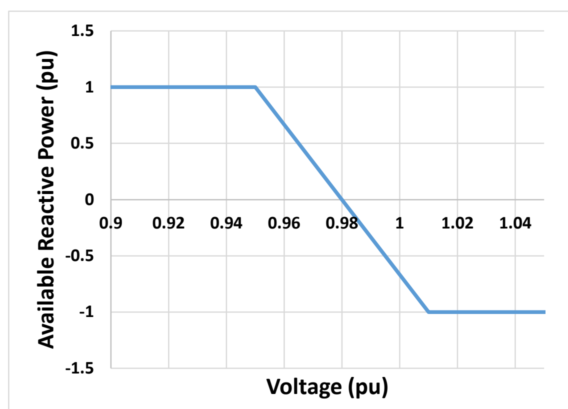
In both 1 MW penetration and 5 MW penetration, volt-VAR is still the only control type that can flatten the feeder-wide voltage profile as shown in Table 3-27. The optimal volt-VAR setting for each penetration is shown in Figure 3-44. The setting for the 5 MW PV system has a less aggressive slope but the same setpoint and dead band as that for the 1 MW PV system. The slope is lower but the available reactive power with the 5 MW system inverter is greater.

Table 3-27
Daily Voltage Difference Based on Annual Average for Best Inverter Settings - Comparison of 1 MW Penetration and 5 MW Penetration (pu)

	Base case	PV	VV	VW	PF
1 MW PV	0.088	0.088	0.086	0.088	0.088
5 MW PV	0.088	0.088	0.087	0.088	0.088



a) 1 MW PV



b) 5 MW PV

Figure 3-44
Best Volt-VAR Settings for a) 1 MW PV b) 5 MW PV

Conclusion

The goal of this task is to determine the best advanced inverter settings for each inverter based on specific utility objectives. The best settings are determined by analyzing a significant number of settings necessary for volt-VAR, volt-watt, and off-nominal power factor control. The results of this task will help select the settings to apply in the field.

There is a unique feeder impact for each of the different control types and settings. Between every feeder there is also be a unique response to similar settings. The best settings are dependent on the feeder operating conditions as well as the feeder response objectives.

Overall, volt-VAR control has the best ability to improve voltages and meet utility objectives. Volt-VAR can operate at low active power output when feeder support is needed. Optimal settings for the volt-VAR curve are primarily dependent on when the inverter changes from providing to absorbing reactive power. Dead bands are not often found in the best settings. Steep slopes are beneficial in many cases but more benign slopes generally will be good for a wider variety of feeder response objectives.

Volt-watt and power factor control are beneficial in several but not all cases. System improvement by curtailing power with volt-watt settings would require more aggressive settings beginning below 1.0 Vpu which would be hard to justify implementing. Power factor control can be beneficial; however, one annual setting is often not optimal in the majority of solar/load conditions due to increased violations or conflicting impact to the optimized metric.

The best settings have been selected based on annual benefit, but better settings can occur if there is direct or remote communication to the inverter. The settings at off-peak load can be different than those at peak load. Similarly, the settings during a clear day can be different than a partly cloudy or overcast day. Periodical updates to the inverter settings can increase the overall benefit to the system.

Optimal inverter settings can change due to the size of the PV. Volt-VAR control and power factor control remain the most influential since reactive power can have a significant impact on the system. The volt-watt control still tends to provide limited improvement to the performance metrics analyzed.

DTE F1 Modeling

In addition to the methods described above, DTE worked with EDD to model the F1 feeder and determine appropriate settings. Additionally, EDD provided settings for DRSOC based day ahead feeder simulations using load and weather forecasts.

EDD provided software development and engineering consulting support for the implementation of real-time Forecast/Schedule/Monitor/Adjust (FSMA) – DMS analysis, for use with the Fuller circuit. A model of the Fuller circuit was developed and validated against real time measurement data. The basis of the FSMA module was to generate a control plan for the circuit on a rolling 24-hour timeframe.

Study Base Description

Existing Fuller substation is a two transformer Class E substation built in 1956 in the Ann Arbor Area of Michigan. Each of the substation's two 41.57/4.8 kV 4MVA(Y – Δ) transformers are tapped off a looped 41.57kV Tie line that has two independent sources. Each transformer feeds two circuits via a single breaker, one load carrying and one throw over circuit to be used for cable failures. The section breaker is utilized to provide automatic throw over for loss of a single transformer or 41.57 kV source. The circuit to be used in this study, DC 379, is a 4.8 kV ungrounded delta distribution circuit

Existing Fuller DC 379 circuit is a 4.8 kV Delta distribution circuit approximately 5 miles in length with a Peak Load of 3100 kW. It has 580 customers consisting of 557 Residential, 23 Commercial, and no Industrial. There is one 750kVA 4.8/13.2 kV ISO Up transformer that provides underground 13.2kV service to several transformers.

Existing Circuit Regulation - The circuit's voltage is regulated to 123 $\pm$ 1.5 meter volts by a 750kVA step regulator and is gang operated which monitors a single phase voltage. In addition, one 600 kVAr capacitor bank controlled by a radio activated time clock with an on time at 7:30AM and an off time at 24:00PM on a daily cycle is on the 3-phase overhead trunk one mile from the substation.

Existing Protection for Fuller DC 379: Phase-to-phase faults on D.C. 379 are detected by electromechanical phase relays which trip the respective substation breaker. The phase relays at the substation trip the substation breaker for faults on 100% of this circuit. No reclosers, sectionalizers, or sectionalizing fuses are utilized.

During normal unattended operation, automatic reclosing is used. After opening for a line fault, the breaker is reclosed automatically a preset number of times before locking out and remaining open.

Phase-to-ground faults are detected by equipment at the substation. The circuit is not automatically interrupted for ground faults. An alarm is provided to the central office to dispatch crews to isolate the ground fault and make repairs.

Outdoor overhead fuses provide fault protection for the various overhead transformers. Cable poles are similarly fused to provide fault protection for the associated cable and underground fed transformers.

Summary of the DEW circuit model

Model Build

DTE has extracted the base model from its ESRI system and built a DEW circuit model. Load was attached from the CSB and MV90 system for use in validating the time varying model with measurements at the start of circuit. This included using the newly installed AMI metering.

Load attachment

There are 44 distribution transformers on this circuit. There were 593 meters representing 4 different customer rate classes attached to 30 of the 44 distribution transformers on the model. This meant that 14 of the distribution transformer did not have customer meters and therefore had no consumption associated with them (no load attached). In the model, these 14 transformers' load was represented by a spot load based on a percent of connected capacity that would equal the peak load for the year. For the 30 distribution transformers with customers attached, the annual kilowatt sales for each meter were aggregated per transformer and parsed into even monthly consumptions. It is also noteworthy that there were 5 account numbers without a full year's data.

The loading validation was further refined by using the newly installed AMI metering as well as walking down the entire circuit to validate meter attachments and phasing.

Validation of the Model

This task established an accurate baseline prior to the installation of the PV and Smart Inverter system on Fuller DC 379.

In the model, the spot load on the 14 transformers without consumption was deleted. This provided a check on matching start-of-circuit measurements by using just the consumption data for the 30 distribution transformers with customers attached. By sampling some of the noon hour time points it appears that the load was within 20% or less, thus indicating that the consumption measurements formed a complete set for the circuit and it is just the transformer to meter relationships that should be fixed.

DEW's measurement matching capability can be used to force a matching of SCADA measurements and load measurements.

Recognizing that 14 of the 44 distribution transformers on the circuit do not have customer loads attached to them, it would be best to validate some of the customer meters to transformer relationships before running a circuit base line. This necessitated a field visit to those transformer sites. In this way, measurement matching scaling factors would be more uniform.

The loading validation was further refined by using the newly installed AMI metering as well as walking down the entire circuit to validate meter attachments and phasing.

These circuit loads were compared to available start of circuit measurements and a load shaving factor of approximately 10% was used match both high and low load conditions.

FSMA - Forecast Schedule Monitor and Adjust

EDD provided software development and engineering consulting support for implementation of real-time Forecast/Schedule/Monitor/Adjust (FSMA) – Distribution Management System (DMS) analysis, for use with the Fuller circuit.

The FSMA is a Configurable, Hierarchical, Model-based, Scheduling Control (CHMSC) of automated utility control devices and photovoltaic (PV) generators. In the FSMA application, a DEW algorithm recommends operating points for all the system active devices that have automated control. This could include substation regulators, circuit regulators, capacitor banks, and generator controllers.

The FSMA Application will monitor and forecast the following:

1. Customer level voltage,
2. Feeder efficiency,
3. Autonomous control device operation, and
4. Coordinated device control operation using rolling time-series plots which is only relevant to display, not to the algorithm/calculations

The FSMA algorithm, which exists in hierarchical control architecture is failure tolerant, strives to maintain the voltage level that existed before introducing the PV into the circuit while minimizing the circuit loss and reducing the motion of the automated control devices.

EDD had access to required measurement data and the validated Fuller circuit model. The project deployed FSMA functionality together with the circuit model to the DR SOC. The basis of the FSMA module was to generate a control plan for the circuit on a rolling 24-hour timeframe and to deliver those recommendations to the DR SOC for implementation.

In the particular case of the Fuller circuit, FSMA is recommending control set points for the capacitor and the PV inverter.

The application uses forecast solar generation and load using historical data and incoming measurements. These were used by the FSMA module to generate an objective function based control plan for the DR SOC to implement. The FSMA module will continue to update the control plan at user specified intervals, in this case every 15 Minutes, as new measurements and system operation states change. The control plan provides inverter, capacitor and regulator set points on the Fuller circuit that will enable operators to control the circuit within operating limits and to support generator output. For this phase of the project, the FSMA will not deliver control commands to field devices. The FSMA will monitor field conditions, calculate a State Estimation, and present operators with warnings and alarms. The FSMA also generate reports and stores historical results.

FSMA CVR Algorithm Description:

The algorithm used by FSMA/CVR uses a tabu search to determine the optimal control positions for capacitors, voltage regulating transformers, and solar panel supplying inverters (power factor set points) with user-configurable weighting factors for the following objectives:

1. Voltage violation reduction (volts outside of target range for all service locations with voltage violations)
2. Loss reduction (kW)
3. Load reduction (kW, based on reduction in real power of voltage-dependent loads when voltage is reduced)
4. Solar Output “Flicker” (volts)

The weighted improvements are compared against the user-configurable “costs” of the following:

1. Switching a capacitor (“cost” to switch on or off)
2. Stepping a voltage regulating transformer (“cost” per step moved per phase)
3. Curtailing inverter output (“cost” per kW curtailed)

The user may set up any of these weighting factors and costs and may also select which capacitors, voltage regulating transformers, and/or inverters are allowed to be controlled by the central FSMA/CVR algorithm. Devices not centrally controlled will be controlled to their local set points (e.g. capacitors may switch based on time of day or based on line voltage if they are not participating in the central control algorithm). Figure 3-45 shows how the user may make all of these setup/configuration changes:

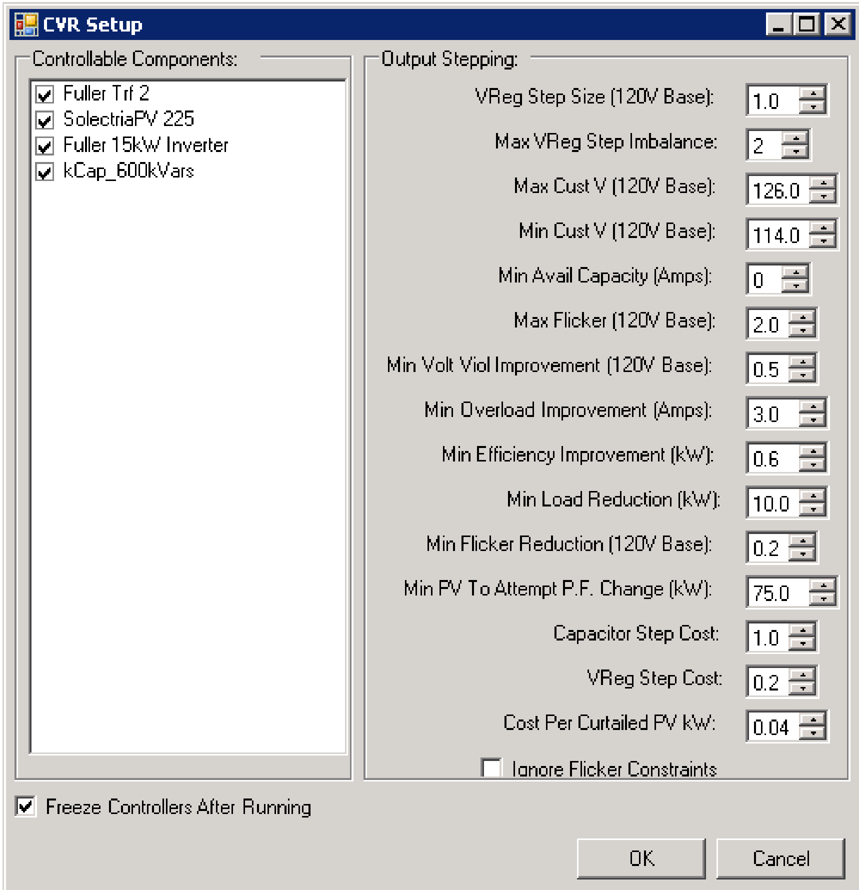


Figure 3-45
FSMA Setup Dialog

The user sets up the weighting factors to achieve the desired sensitivity.

The application then listens for the updates for input KW and KVAR measurements from the Transformer and PV inverter from the loadwatch server. At this point the algorithm calculates new positions for the capacitor bank and PV inverter settings to achieve an improved circuit operating point.

DEW and DR-SOC interface

The FSMA Application can be run as a service or as a user accessible application within DEW.

The FSMA Application has a configurable display as can be seen in Figure 3-46 below.

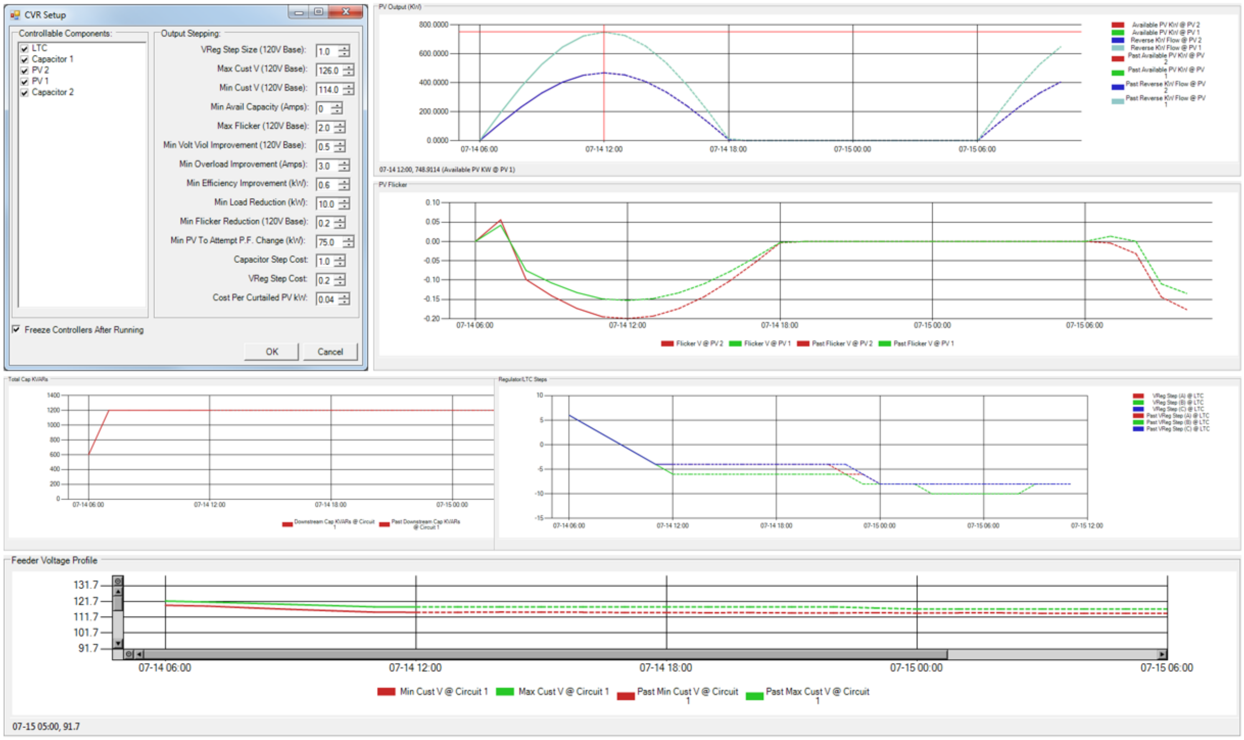


Figure 3-46
FSMA Application Display

4
UTILITY-CONTROLLED ISLANDING

Evaluating Communications-Based Techniques for Anti-Islanding

In the electric power system, islanding occurs when a portion of the system (the island) becomes disconnected from the grid and continues to operate. Generally, an island includes one or more generators and loads, along with the wires, transformers, and protective devices necessary to connect them together. IEEE defines both *intentional* and *unintentional* islanding. Intentional islanding may be desirable in some cases, such as in a microgrid designed to run independently during a weather event or unforeseen outage. Unintentional islanding (often referred to as simply *islanding*) is not planned and is considered undesirable because line worker practices, protective equipment, and grid control systems are not designed for those conditions.

Why be concerned about unintentional islanding?

The primary risks most often cited and considered include:

Danger to line workers and the public – An unintended island may result in a portion of a distribution circuit being energized unexpectedly, affecting maintenance practices and increasing the risk of accidental contact with live equipment during maintenance and repair operations. If a DG unit energizes downed conductors, this could potentially pose a risk to the general public as well.

Damage to customer or utility equipment – Unintended islands are not guaranteed to properly regulate voltage and frequency, to maintain effective grounding, and to limit harmonic distortion, any or all of which may upset or damage equipment.

Misoperation of protective equipment – An unintended island could result in poor coordination or desensitization of protective devices, as well as the potential for an out-of-phase reclosing event. Either condition could result in damage of synchronous motors or generators, sensitive electronic equipment, or industrial process loads.

Depending on the specific conditions, these concerns may be more or less warranted or severe. The duration of the island is also an important factor. For instance, the safety of a line worker is by far the most important concern, but it may take several seconds or minutes after an island is formed before a worker would be in danger. Conversely, the effect of out-of-phase reclosing may be limited to only a few synchronous machines or filter banks, though the consequences are potentially severe. Prevention by anti-islanding alone requires a faster response than the utility's reclosing times, which may be as short as 30 cycles[2].

[2] D. Williston and D. Finney, "Consequences of Out-of-Phase Reclosing on Feeders With Distributed Generators," Whitepaper. Williston & Associates Inc, 2010.

Existing practices to prevent unintentional islanding

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[3]. According to a recent EPRI survey, islanding concerns were the stimulus for greater than 90% of the installations of DTT[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. This becomes more complex when feeders are reconfigured to accommodate change load or to restore service after an outage.

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 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].

The search for more advanced islanding protection

There is not a clear answer to the question of whether onboard anti-islanding methods alone will be sufficient to protect the distribution system and ensure appropriate safety. Case-by-case analysis will yield different probabilities and risks. These have to be weighed, often on a circuit-

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

[4] *Protecting the Modern Distribution Grid: EPRI Survey on Distribution Protection with Emphasis on Distributed Generation Integration Practices*. EPRI, Palo Alto, CA: 2013. 3002001277.

[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.

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

by-circuit as well as generator installation-to-installation basis. If the risk of having only onboard anti-islanding protection becomes sufficient enough, it could limit the amount or type of DG that could be installed on a feeder.

There are several technical solutions, however, 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 over generation 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 will have its own complexity, cost, and effectiveness[8].

During the course of this project, EPRI conducted an evaluation of several communications systems that could act as a supplement to onboard anti-islanding. These fell into two categories: power-line carrier (PLC) and wireless communication. Some of the units considered are summarized in Table 4-1.

Table 4-1
Technologies Considered for Anti-Islanding Use

Technology	Type	Notes
DX3 Pulsar	Low-Frequency PLC	Tested in laboratory and at National Grid
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

For the units that were laboratory and field tested, the results are discussed in the following sections.

Considerations for PLC-based Anti-Islanding

For this project, one of the technologies reviewed most extensively was a low frequency power line carrier (PLC) from DX3 Limited of Canada, called the “Pulsar”. The carrier is a subharmonic tone that occurs once every four cycles, for a bandwidth of 15Hz (or one bit every four cycles.) More specifically, the tone is a “notch” in the line voltage that is created by the transmitter “shorting out” near the zero crossing of the voltage waveform. The transmitter voltage and current, Shown in Figure 4-1, are similar to Two-Way Automatic Communications

[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

System (TWACS) that has been used extensively in meter reading and other data transfer applications[9].

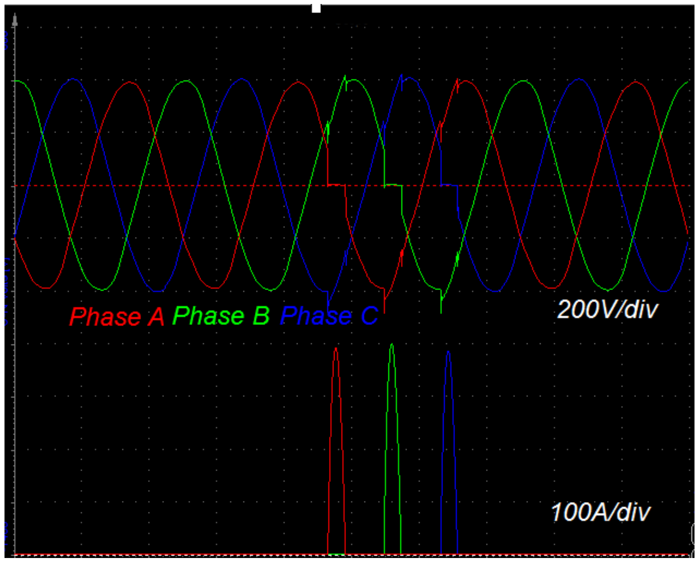


Figure 4-1
Voltage and Current Waveforms in DX3 Transmitter

For anti-islanding applications, the requirement is straightforward[10]. A receiver, placed near DG units downstream of the transmitter watches for distorted voltage caused by the transmitter. If the receiver observes distortions caused by the transmitter, the receiver, through an external relay contact, gives the DG unit permission to operate. Often this technique is referred to as power line carrier permissive (PLCP) operation. If the transmitter shuts down, or if the incoming signal is blocked by an open breaker or fuse, the receiver has lost "permission" and the DG is shut down. From the receiver's perspective a "lost" signal is actually a clean ac waveform, lacking the signature waveform distortion. Figure 4-2 shows an example case where the transmitter's signal would be blocked by an open breaker on one of the branches. This would force the DG on that branch to shut down, thereby preventing an unintentional island. The DG on the other branch, which has an uninterrupted path to the transmitter, would continue operating. In order to avoid nuisance tripping of the DG, the receiver will typically wait up to 8 signal periods (32 cycles) of lost signal before declaring the upstream path to be open.

[9] *TWACS - From the Beginning,* Aclara Technologies, LLC. Available: http://www.aclaratech.org/NewsLetter/TWACS_FromTheBeginning.pdf.

[10] W. Xu, G. Zhang, et al., "A Power Line Signaling Based Technique for Anti-Islanding Protection of Distributed Generators—Part I: Scheme and Analysis," *IEEE Transactions on Power Delivery*, vol. 22, no. 3, pp. 1758–1766, 2007.

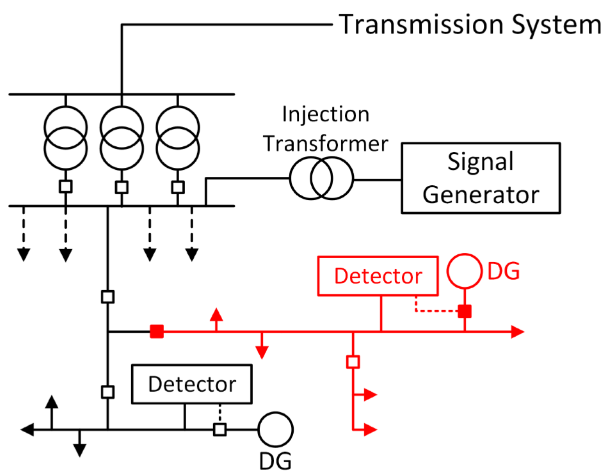


Figure 4-2
One-line diagram showing an open breaker blocking the signal path

One of the benefits of this method is that the receiver can be made low-cost. Unlike communications-based methods, or even high-frequency PLC, the receiver only requires the ability to sense voltage (through a step-down transformer), process the signal, and actuate a small contactor. External to the receiver, the DG or other protective equipment must be able to read a dry contact input. Unlike many HF techniques, the receiver (and transmitter) may be magnetically coupled to the line, rather than requiring an expensive capacitive coupling. Also, because the low-frequency signal is much less prone to reflections or excessive attenuation from changes in line impedance, this technique doesn't require line traps or other external filtering[11,12].

The transmitter, however, is a significantly higher cost. The "notch" in the voltage waveform is created by a single thyristor (per phase) that "fires" (or conducts) near the zero-crossing of the voltage waveform. This creates a period where the utility voltage reaches zero slightly ahead of the natural zero crossing, one type of voltage distortion. The thyristors in the DX3 Pulsar are designed to operate at 480-V and require a low-impedance (large) step-up transformer for the signal to propagate to downstream devices, though the average power consumption of the Pulsar (and the thermal stress on the transformer) is very low. A photograph of the transmitter is shown in Figure 4-3.

[11] "IEEE Guide for Power-Line Carrier Applications," *IEEE Std 643 2004*, pp. 1–134, 2005.

[12] M. P. Sanders, J. Appleyard, et al., "Special Considerations in Applying Power Line Carrier for Protective Relaying," in *Protective Relay Engineers, 57th Annual Conference for*, 2004, pp. 247–281.

Figure 4-3
Internal photo of the DX3 Pulsar transmitter

While the interface transformer must be low-impedance, the upstream HV-MV transformer (at the substation) must be small enough that the available fault current at the transmitter does not overwhelm the transmitter's thyristors. Substations with higher fault capacity will require the DX3 to consume more power to produce the same signal strength, and therefore will require larger thyristors be installed.

For maximum coverage, and depending on the availability of land in the areas surrounding the chosen substation, the DX3 Pulsar may require construction either inside or near the substation. This may be a barrier to some installations and may add significant cost in others. However, once the design and setup are completed, the technique itself is fairly robust with the power line being a reasonably robust communications medium. However, some attenuation of signal has been reported due to lines with high shunt capacitance[13]. In any installation, the design tradeoff is that of transmitter power consumption and signal strength (or reach.)

Laboratory Testing

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 4-4, 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.

[13] M. Ropp, D. Joshi, et al., "New Results for Power Line Carrier-Based Islanding Detection and an Updated Strengths and Weaknesses Discussion," in *37th IEEE Photovoltaic Specialists Conference (PVSC)*, 2011, pp. 2584–2587.

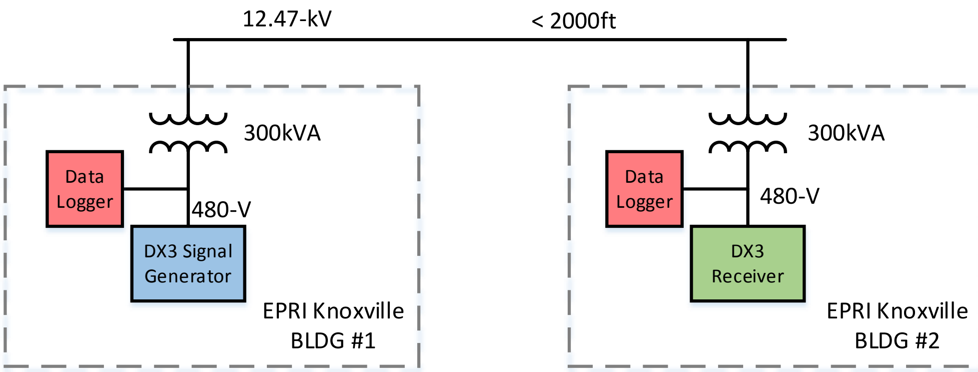


Figure 4-4
Testing arrangement for DX3 Pulsar in EPRI's Knoxville labs

Though the receiver is also intended to be a low-cost item, implementation required additional components for the demonstration. For one, the receiver's inputs are only rated for 24Vac, thus they required external potential transformers (PTs) to step down the voltage from 277V. Because the receiver's inputs have a high impedance, only small burden (25VA) PTs were necessary. Though PTs could also be used to power the unit, a separate power supply provided more reliable operation in practice. The combined equipment could be accommodated in a moderately-sized NEMA enclosure (as shown in Figure 4-5.)

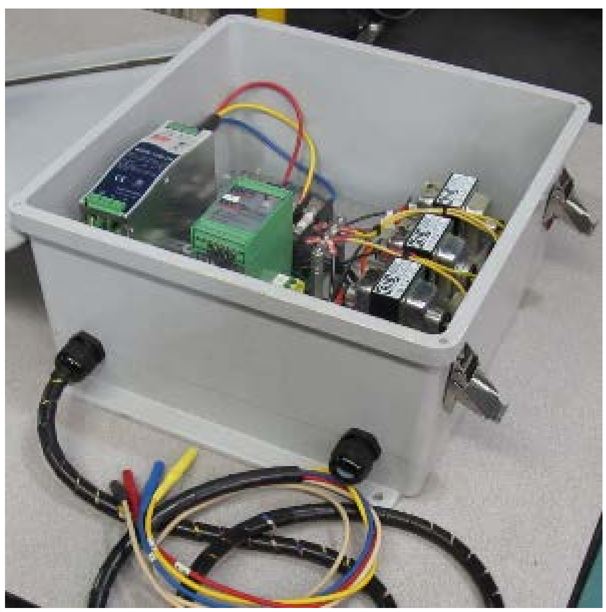


Figure 4-5
DX3 receiver, PTs, and power supply in a NEMA 4X enclosure

Signal Strength and Power Consumption

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 4-6). 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.

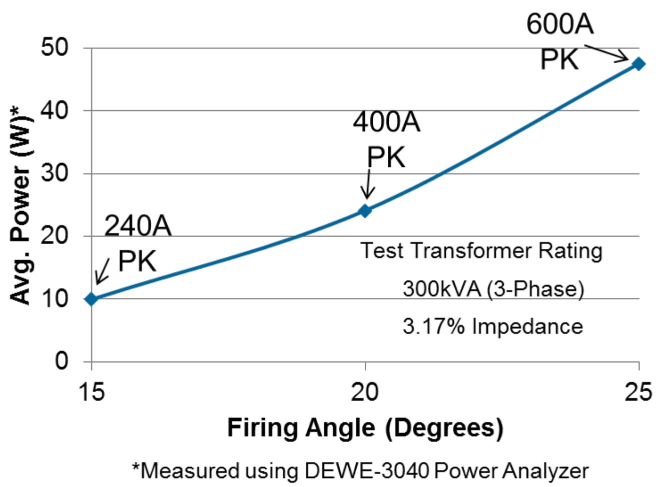


Figure 4-6
Power consumption and peak thyristor current at different firing angles

Power Quality

Any PLC signal method immediately raises questions of negatively impacting power quality. Though the distortion immediately at the transmitter is immediately recognizable, the attenuation due to two transformers and a line segment reduced the harmonic contribution significantly. Figure 4-7 and Figure 4-8 show 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.

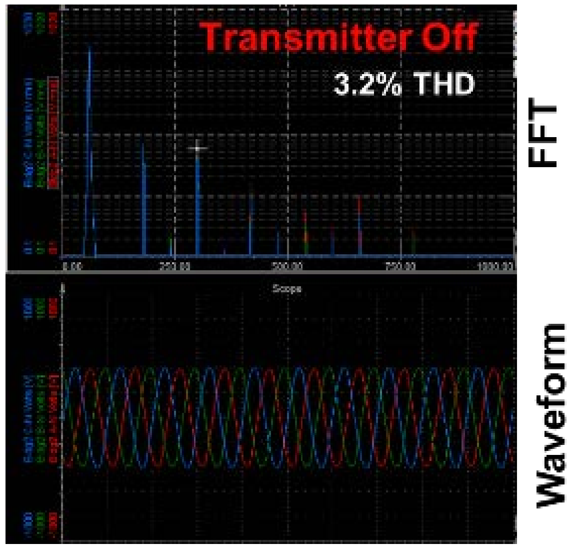


Figure 4-7
Background FFT with the transmitter off

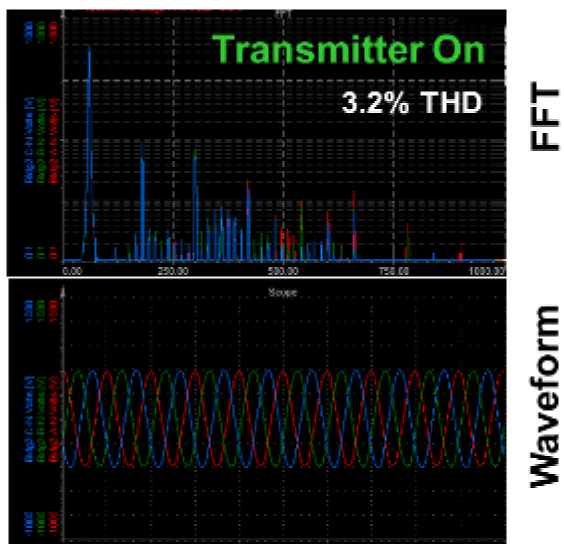


Figure 4-8
FFT of building 2 voltage with transmitter on

Sag Immunity

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 4-9. 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 4-10. 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.

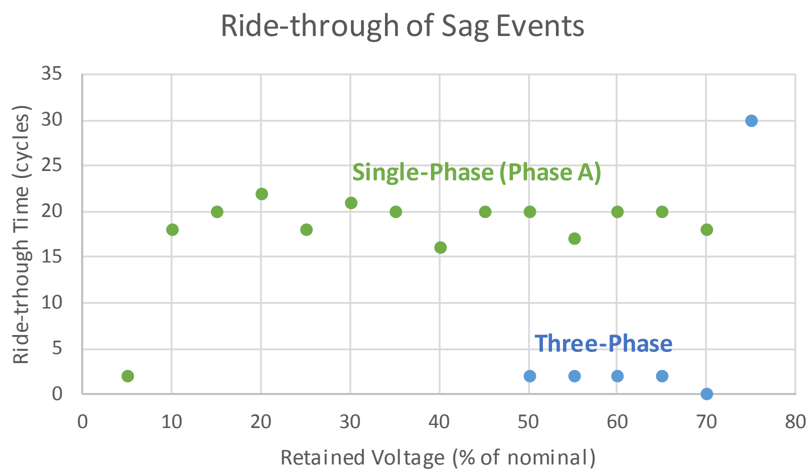


Figure 4-9
DX3 transmitter ride-through for single- and three-phase voltage sags

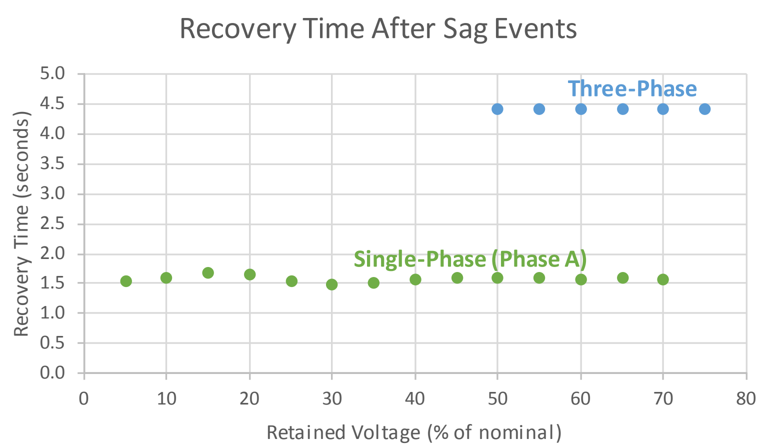


Figure 4-10
Recovery time after single- and three-phase sags

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. Addressing this shortcoming would make the transmitter more robust against short-duration disturbances that lead to nuisance tripping of DG.

Field Demonstration

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 4-11. As part of the project, National Grid allowed EPRI to monitor installation during both normal and fault conditions.

Figure 4-11
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 4-12, 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.

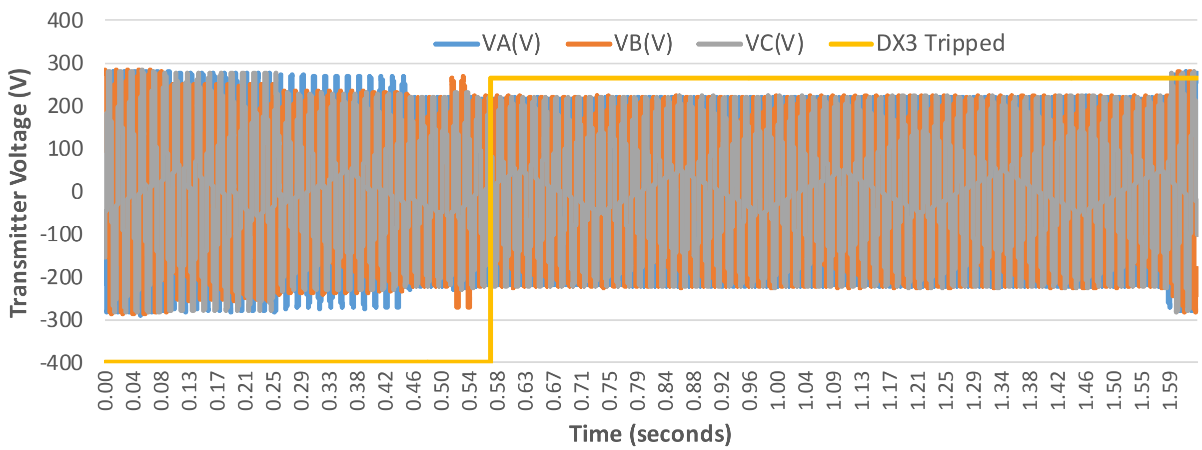


Figure 4-12
Recorded event of transmitter tripping off-line during field testing

Wireless Communication-based Methods

Rather than use the power line as a communications medium, it's also possible to wirelessly connect to remote DER for islanding prevention. Unlike PLC, where the physical characteristics often restrict communication options, variations in wireless communication means were numerous. Some examples of technologies reviewed for this purpose are shown in Table 4-2

Table 4-2
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.

Laboratory & 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 4-13 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 4-13
Summary of Field Tests with Remote Control Technologies 27MHz system

DTE Remote Transfer Trip Scheme

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 4-14 shows the main components for this scheme.

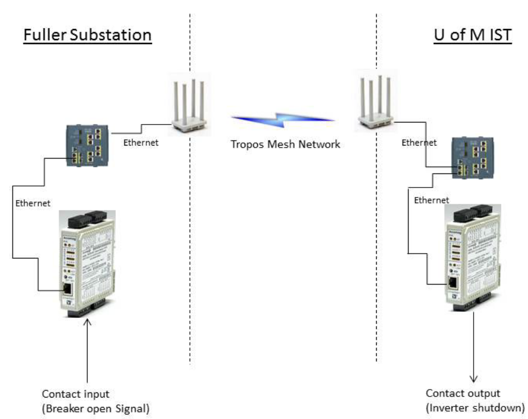


Figure 4-14
Components of Transfer Trip Scheme

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.

Alternatives for Ethernet communication

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 4-15 show the results of these tests.

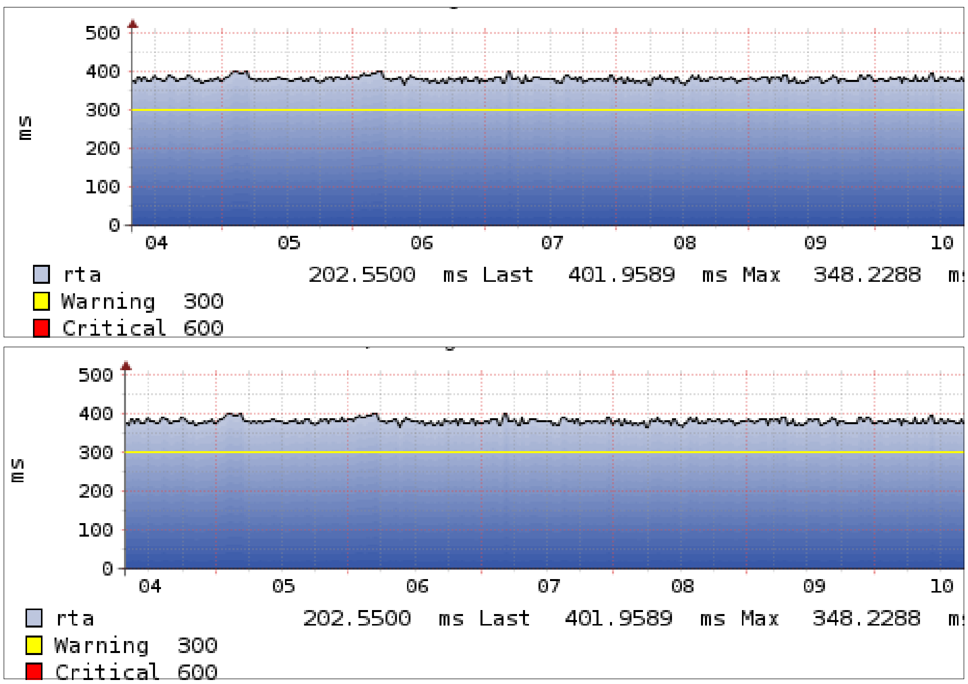


Figure 4-15
Results of Latency Checks

Summary

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.

5 UTILITY COMMUNICATION

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 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's Distributed Renewables, Generators, and Storage Domain Expert Working Group. This initiative builds upon a prior smart PV inverter communication initiative to advance industry efforts to bring inverter-connected distributed energy storage and generation into use as a grid resource. While the electric power industry has taken these prior steps to prepare for higher penetration of distributed energy resources (DER) by developing smart PV inverter standards and communication protocols that may be used for monitoring and managing 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[14] 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[15]. Ongoing teleconferences are being held to develop standards for DER group management and enterprise integration needs.

Recognizing the need for additional methods and standards for DER group management is one of the key benefits of this project and will result in a valuable contribution to the goals of DER integration worldwide.

A key observation of this project regards the present industry status for Distribution Management Systems (DMS). While there are several technology companies offering DMS products, most utilities still do not have a fully deployed, or fully centralized application managing their distribution systems. Each of the utilities involved in demonstrating advanced inverters for this

[14] *Integrating Smart Distributed Energy Resources with Distribution Management Systems*. EPRI, Palo Alto, CA: 2012. 1024360

[15] *Collaborative Initiative to Advance Enterprise Integration of DER: Workshop Results*. EPRI, Palo Alto, CA: 2012. 1026789

project has a distribution management process or approach, but this approach generally involves fixed or autonomously managed control devices, configured according to a predetermined strategy so that the various components work together in a harmonized way.

It may be argued that shifting management of these devices to a central point of control, to a DMS, would allow for more optimized management, but such integration also involves cost and complexity and, generally speaking, utilities use simpler more straight-forward approaches as long as they work in a satisfactory way.

Addition of advanced DER, specifically smart PV inverters, into these systems could create new motivations to centralize management of all distribution control devices. But it is also possible that smart PV inverters can be setup to act autonomously, thoughtfully configured, so that they interact with the existing distribution controls in an acceptable way. Although perhaps not the most optimal from a technical perspective, such approaches might be optimal from a cost perspective, at least until penetration levels necessitate a more advanced approach. Several levels of smart PV inverter integration have been identified, with general categories as described in the following subsections.

Fixed or Self-Managed Inverter Functionality

This use case involves the deployment of inverters with grid-supportive functionality that is fixed within the device. In this case, devices are designed by manufacturers to provide these functions, and to do so in a predetermined way throughout their service lives. The functionality is fixed out of the box, and cannot be altered.

In terms of communication system complexity and cost, this option is lowest. From the utility perspective, it does not require the deployment of a communication system or the specification of a communication protocol. From the inverter manufacturer's perspective, no utility-specific communication technology or protocol need be incorporated into the device. The deployment and commissioning of devices is straightforward because no communication connection needs to be established and no inverter configuration is required at the point of install.

Fixed, out of the box functionality is not limited to simple or static behavior. "Curve" type functions such as volt-VAR control or any function based on parameters known to the inverter (temperature, voltage, frequency) could be selected and fixed out of the box. Dynamic functions could also be fixed, such as dynamic reactive current injection and other functions that are based on time rate of changes (e.g. dV/dt or df/dt).

The challenge of the fixed functionality use case lies in the upfront selection of functions to be included and the specific settings for these functions. For example, if a volt-VAR curve function were to be built-in and not reconfigurable, what settings would it have? What would be the volt-VAR curve shape?

The nation of Germany provides an example of the widespread use of this approach. Both the medium voltage and low voltage German grid codes identify a wide range of smart PV inverter functions that are required for all inverters, including specific settings. Standard communication protocols, and communication connections to enable the updating of these functions are not required and have not been used, other than a power-line carrier based "ripple control receiver" that allows for a 2-bit control for maximum generation level – 100%, 66%, 33% or 0%.

Many other countries and grid-operators are unsure how the German settings for these codes were determined, and there has not yet been sufficient deployment and time in the field to determine the degree of success with this approach.

Onsite Reconfigurability and Monitoring

This use case involves the deployment of inverters that have built-in communication interfaces that are normally not used, but are locally accessible. Through these interfaces, the inverters' various functional behaviors can be turned on/off and reconfigured. The status and condition of the inverters can also be monitored through these interfaces.

Because this use case assumes that there is not normally any communication connection to the inverter, the range of grid-supportive functions that that the inverter may provide is limited to those that are autonomous in nature. As international efforts have been made to define common, standard functions for smart PV inverters, much attention has been placed on the need for effective autonomous functions. "Autonomous" in this context refers to functions that work effectively in situations where there is no communication connection to the inverter, or a communication connection that has limited bandwidth, high latency, or poor reliability such that it cannot be depended upon for remote management of the inverter. As with the functions described in the "Fixed Inverter Functionality" use case, these autonomous functions include a wide range of relatively advanced, curve-based functions that allow the inverter to vary a controlled parameter, such as Vars in response to a locally observed parameter such as temperature, voltage, or frequency.

The defining difference between this use case and the "Fixed Functionality" use case is that in this case the inverter behaviors could be modified by physically accessing the device, and plugging into it with some software reconfiguration tool or using a manufacturer's built-in reprogramming interface.

The practicality and affordability of this approach depends primarily on two factors:

- The number of units requiring reconfiguration. For very high volume products such as small-scale residential or light-commercial systems, onsite reconfiguration is likely not practical, even if infrequent. For larger commercial or utility-scale systems that appear in lower numbers, onsite reconfiguration may be more practical, but these larger systems are also more likely to be integrated using a communication system.
- The frequency with which reconfiguration is required. Reconfiguration that is anticipated with regularity, such as seasonal, is not lot likely to be practical for this use case. Rare reconfiguration, used on an as-needed basis to solve unexpected problems, may be useful.

Onsite reconfigurability could be supported with either vendor-proprietary or open standard communication protocols. In the event that personnel set out to make changes in this way, there is a degree of benefit in having open standards for the local reconfiguration, in that a common tool (e.g. handheld reprogramming device) could be used to support all device types and brands. Dealing with separate vendor tools and instructions for use would require significant training of personnel and could make the reconfiguration process difficult.

More importantly, the use of vendor-proprietary protocols for this use case would tend to preclude the deployment of fixed communication equipment and integration at a future time. In other words, smart PV inverters must support an open standard communication protocol if they are to ever become added into a fixed monitoring and management network.

Connected Devices, Infrequently Adjusted

This use case involves the deployment of inverters along with a communication network that allows the utility to remotely monitor and manage the inverter. In this use case, the use of the communication system is assumed to be infrequent, such as daily, weekly, seasonally, or upon special conditions such as grid emergencies.

The rationale for employment of this kind of arrangement is twofold. First, the communication system may be performance (data throughput) limited such that it is not possible to communicate with all inverters in the system more frequently. Second, it may be undesirable to depend on the communication system due to reliability concerns and a desire for higher grid resiliency. In other words, the communication system may be viewed as an optimizing factor, but the system must perform well without it.

The end result is that the inverters must support a wide range of functions with a high degree of autonomy, much as with the previous use cases.

Connected Devices, Remotely Real-time Managed

This use case involves the deployment of smart PV inverters along with communication networks that are capable of supporting the inverter's real-time management. This means that the data throughput, latency, and reliability of the communication network allow the utility to manage the settings of the inverters frequently, from a more centralized location or control entity.

The exact meaning of "real-time" will likely differ from utility-to-utility and from case to case. In general, however, real-time does not mean anything as low as cycles or seconds. Fast inverter responses to line transients, voltage or frequency excursions, or other fast conditions must be managed locally by the inverter. In addition, it is advisable that static curve functions, such as volt-VAR curves and watt-frequency curves are always managed locally by the inverter.

In the context of distribution management systems, the term "real-time" tends to refer to a minute to several minutes. DMS typically reevaluate the system state, possibly recomputed power flow, and resolve volt-VAR optimization algorithms on these minutes timeframes. When the grid-supportive capabilities of inverters become thought-of as additional distribution management tools, it is natural to consider their "real-time" management on similar timeframes, in the order of minutes between updates.

In addition to the frequency of updates, a primary distinction between the real-time use case and the "infrequently adjusted" use case is that in a real-time managed scenario, the entity that is controlling the inverter's settings throughout the day has visibility to system conditions across the wide-area. Whereas an infrequently reconfigured inverter operates regularly based only on the locally-observable parameters (time, temperature, voltage, frequency), the entity remotely managing an inverter (e.g. DMS) may select settings based on conditions on the transmission system, data from the feeder head at the substation, or a stressed asset that is some distance from the inverter.

Defining DERMS

The latter two of the four cases described in the preceding sections involve a fixed communication system through which DER are managed either frequently or infrequently. The logical entity that performs the direct management of DER is referred to as a DER Management System, or DERMS. 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 5-1.

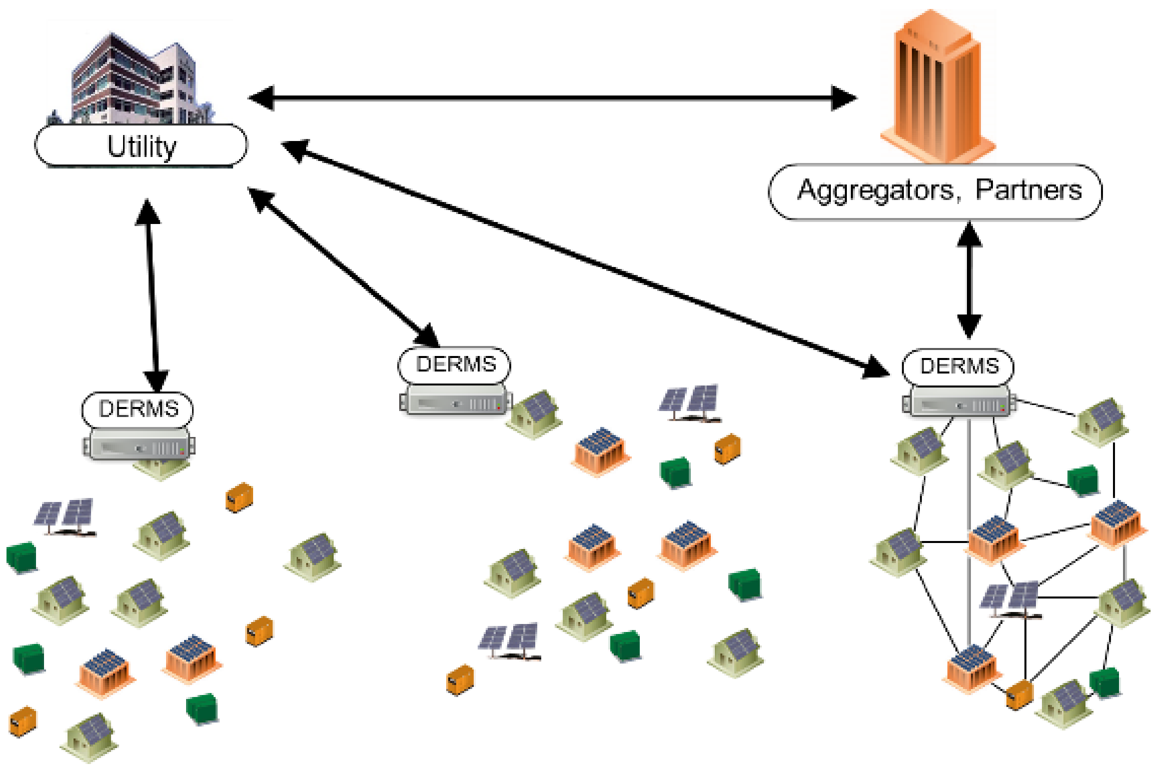


Figure 5-1
Multiple and Third-Party DERMS

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).

This project involved large scale inverters, and only one PV plant was connected on each feeder. As a result, no grouping of DER was performed, but the basic principles were first recognized here – that larger groups of smaller DER can be aggregated and presented as single virtual resources and that the services presented by these groups could be independent of the specifics of the DER types that makeup the groups. Addressing these aggregation needs in a standardized way became the focus of the DER Group Management / Enterprise Integration initiative.

The project also identified that grouping of DER should be possible at any level (residential, facility, microgrid, substation, etc. and that nested levels of aggregation (groups of groups) should be possible as illustrated in Figure 5-2. In this way, a high-level DERMS might be managing a number of smaller downstream DERMS, any of which might be utility-managed, third-party, or customer-owned systems.

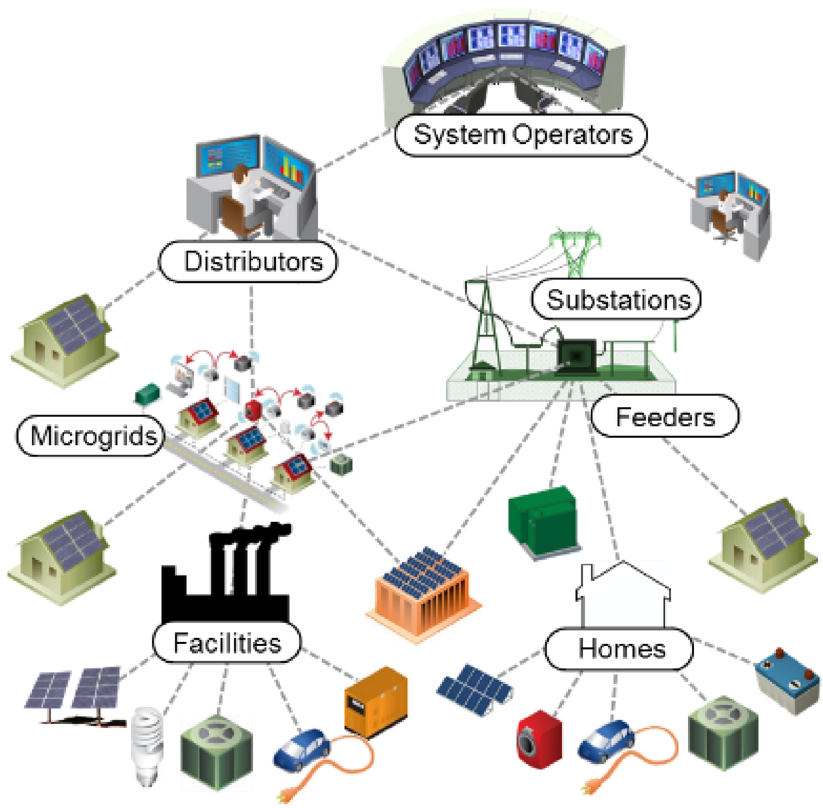


Figure 5-2
Multiple/Nested Grouping of DER

Standard Functions for Managing DER Groups

The DER group management initiative is operating in successive phases, each identifying and developing additional capabilities. At the time of this publication, the initiative is completing its second phase, and the results to this point are published in EPRI reports[16,17]. The standard DER group management functions are described in detail in these reports and mappings into specific communication protocols such as the IEC Common Information Model and NRECA MultiSpeak have also been produced. These functions are summarized in Table 5-1.

Table 5-1
DERMS Group Management Functions

DER Group Management Function	Description
Individual DER Representation in the System Model	This enables general representation in the system model and sharing of individual DER existence and capabilities among software applications and businesses. This kind of representation is a foundational need for intelligent group creation and management.
DER Group Creation	This function allows a software entity to define a logical group of DER and to exchange the definition of this group with other applications or businesses. The purpose of grouping is subsequent monitoring and management at the group level.
DER Group Member Query	This function allows one entity to inquire from another to learn the current members of a DER Group.
DER Group Maintenance	This set of functions provides the ability to add, update, or delete members from a group.
Status Monitoring of DER Groups	This function allows the exchange of real-time status information for DER groups. This function addresses dynamic data, including present value and the present range of adjustability (i.e. the min/max dispatchable range of manageable parameters).
Nameplate Capability of DER Groups	This function allows the exchange of information indicative of the installed (nameplate) capability of DER groups. This data is generally static, changing only as equipment changes are made.
Real Power Dispatch of DER Groups	This function allows the dispatch of real power from DER groups.
Reactive Power Dispatch of DER Groups	This function allows the dispatch of reactive power from DER groups.
DER Group Forecast	This function allows the exchange of forecast information regarding the availability of real and reactive power from DER groups. Note: This function does not relate to how forecasts are determined (e.g. weather data, sky-viewing cameras, etc.) but only to how such information might be exchanged between entities.

[16] *Enterprise Integration Functions for Distributed Energy Resources: Phase 1*. EPRI, Palo Alto, CA: 2013. 3002001249

[17] *Common Functions for DER Group Management, Second Edition*. EPRI, Palo Alto, CA: 2015. 3002005789

Table 5-1 (continued)
DERMS Group Management Functions

DER Group Management Function	Description
DER Group Mode Change	This function notifies groups of DER of changes to circuit configuration and other conditions that may merit a change in inverter modes.
DER Group Curve Settings	This function manages curve functions (e.g. volt-VAR control, watt-frequency control) for DER groups.
DER Group Maximum Real Power Limiting	This function sets limits on the aggregate power generated and/or absorbed by DER groups.
Schedules for DER Services	As an alternative to real-time requests, this function allows the exchange of schedules for DER group services, such as the Real Power Dispatch function.
Ride-Through Service	This function allows event ride-through characteristics to be changed for a group of DER.
Energy Price-Based Management	This function enables DER groups to be provided with energy price information and to be configured to provide services based on price.
Service Cost-Based Management and Bidding	This function (or data-exchange addition to other functions) enables queries regarding the availability of DER services on a cost-basis and also the offer/provision of services based on a cost.
Voltage Regulation Settings	This function allows for adjustment of a target voltage regulating setting of a group of DER. This could be used, for example, in coordination with a conservation voltage reduction system.
DER Group Historical Meter Data	This function allows for exchange of interval meter data that is indicative of the aggregate production of a group of DER.
Connect/Disconnect Control	This function allows for remotely turning groups of systems on or off. Potential uses include maintenance, disabling of malfunctioning equipment, and anti-islanding.
Provide Fast Up-Down Regulation Services	This function allows groups of DER to be rapidly dispatched (e.g. 4 seconds update rate) both up and down in real power in order to help regulate the system.
Provide Dynamic System Voltage Stabilization Services	This function allows groups of DER to provide real and/or reactive power in response to the rate of change (dV/dt) of the service voltage amplitude at each DER. The behaviors would be designed to resist voltage fluctuations.
Select Bellwether Meters	This function requests that a given list of electricity meters provide additional, or more timely data for system control purposes.

Tools for Demonstration

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. Figure 5-3 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 CIM messaging to be included.

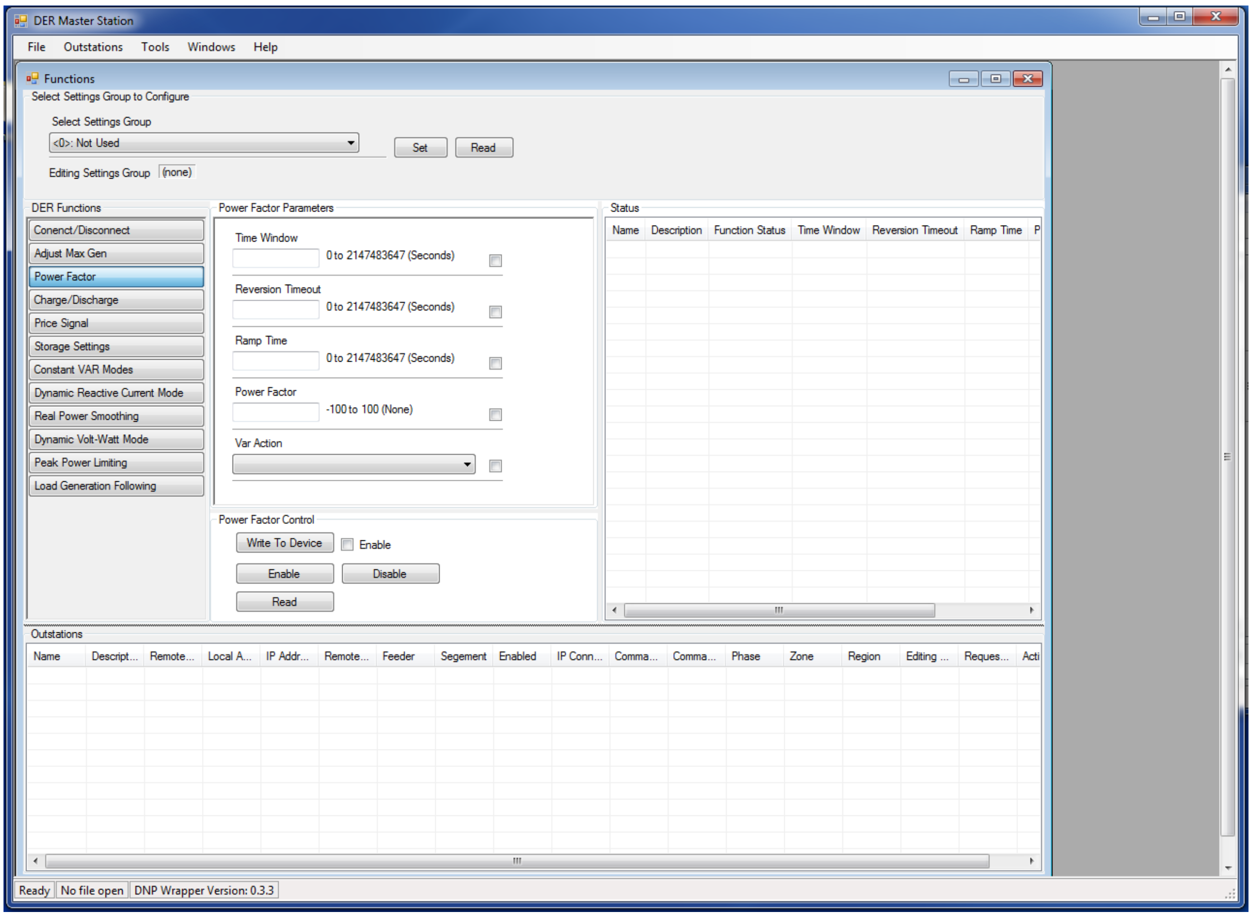


Figure 5-3
DER Master Station Tool

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 were used as a foundation for the working group and demonstrating a DERMS like system.

Finally, for the demonstration phase of this project two additional tools were used for the DERMS implementation. At the DTE site, their DRSOC was used to communicate and control the smart inverter. At the National Grid sites, BPLGlobal's Connected Energy DER Management tool was used. In both cases, the tools were enhanced to be able to communicate with the inverters over DNP3 for the functions selected. In the case of DTE, the DRSOC was updated working with EDD to include a day ahead forecast of smart inverter settings based on weather and load conditions. In the case of National Grid, BPLGlobal determined a control algorithm that could be used to change the inverter settings in order to maintain the power factor at the substation. This closed loop control is discussed in more detail in the demonstration results.

6
FIELD DEPLOYMENT AND DEMONSTRATION

Following design and development, the smart PV inverters were deployed at each of the four demonstration sites along with field demonstration equipment. In addition, each feeder/site was equipped with communication infrastructure in order to control the inverters and utility needed anti-islanding schemes. Monitoring equipment was also installed at the sites and across the feeders to capture field performance. This chapter provides an overview of the field deployment and field demonstration at each site.

Field Deployment

In order to capture the performance and behavior of the smart PV inverters, monitoring systems were deployed. There are two types of monitoring utilized in this project (1) high-resolution feeder monitoring and (2) high-resolution power quality monitoring. Power quality monitoring units were installed at both the feeder substation as well as the PV plant collecting 1 second data as well as power quality events. At various points along the feeder, high-resolution monitoring units were also installed to capture the changes based on smart PV inverter functionality and load. Table X provides a summary of the number of units installed on each feeder. The goal of the monitoring is to give an accurate picture of not only verification of operation of the smart PV inverter, but an indication of the response of the feeder to this change in operation. The monitoring units deployed capture 1-second AC Current, Power, Energy, Reactive Energy, Voltage, Frequency, Plane of Array Irradiance, and PV module temperature. Figure 6-1 shows monitoring points along each feeder.

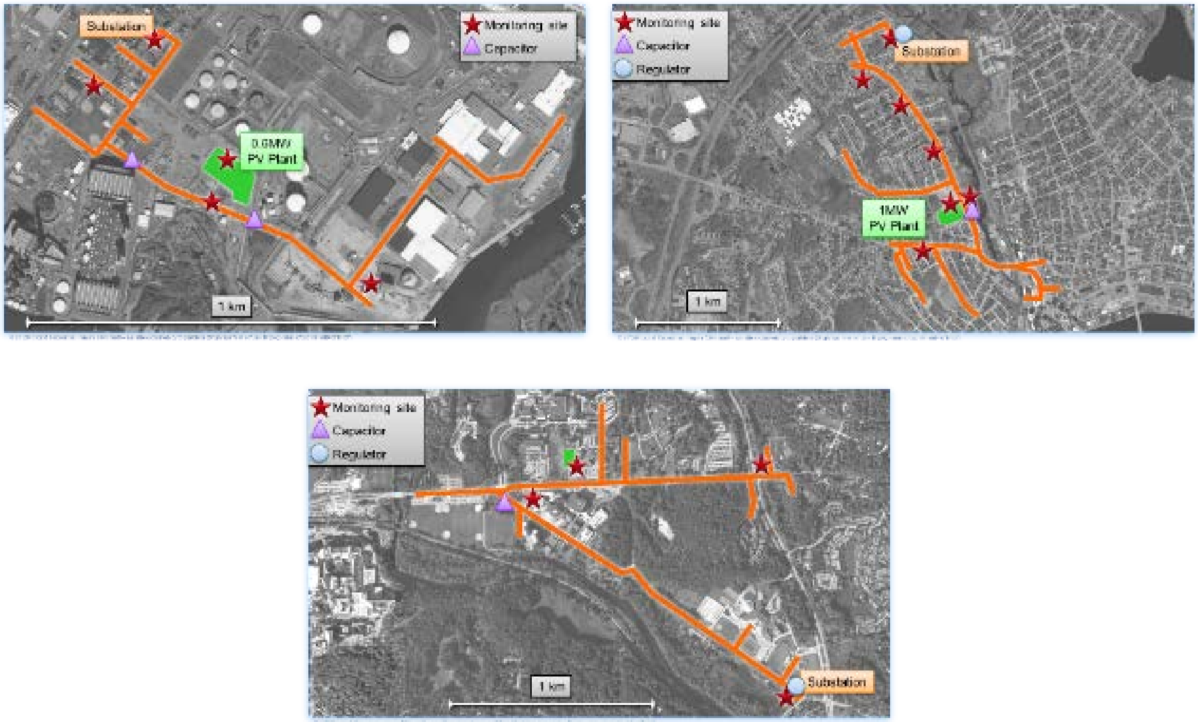


Figure 6-1
Feeder Maps Showing Monitoring Points along Feeder

In addition to monitoring equipment at the site and across the feeder, field deployment also involved installation of the smart PV inverters, PMCs, and communication hardware to allow the inverters to be controlled utilizing the site-selected DERMS solution. The following sections detail the equipment installed by site.

H1 Hardware Upgrades

On the H1 site, there were two 500 kW inverters that were upgraded for demonstration. Table 6-1 provides an overview of the changes at this site.

Table 6-1
Inverter Upgrades at H1

Specification	H1 Inverter 1	H1 Inverter 2
Size	500kVA	500kVA
kW rating	500kW	500kW
kvar rating	300kvar	300kvar
PMC	One shared for the whole site	
Voltage sensing board/full power stage	Power Stages (costly but more efficient). For Yaskawa-Solectria Solar to support voltage and frequency ride through, the team had to work on enhancing the voltage and frequency capabilities of the voltage sensing board from its standard capabilities to one that meets the requirements of the project. The new voltage sensing board firmware supports a wide range of voltages and frequencies that are able to support all new local and international ride through standards. Yaskawa-Solectria Solar uses a module approach when it comes to generating power; each module is 167kW on the SGI 500kW inverter. Circuit boards such as the voltage sensing board are placed inside these modules. This approach allows for quick swap out, which results in lower downtime.	Only PCB upgrades (time constraint). The voltage sensing needed to be upgraded for the inverter to support Voltage and Frequency ride through. However, for this inverter only upgraded the PCB that is responsible for the voltage and frequency setting.
Control Circuit	AC feed (contactor couldn't be replaced, modified Inverter). The additional challenge to ride through events more than 50% voltage brings is the need to find an alternative way to feed the control power that is normally feed off of AC voltage during an event. The teams suggested approach was to feed the controls directly off of the DC array. To support this, a 24Vdc power supply was added that feeds directly off the array in addition the coil of the AC contact need to change form an AC coil to a DC coil, however for this inverter that was not possible due to limitations at the site. This inverter remained feed off AC controls.	For this Inverter, used the 24V power supply that supports the controls and it was feed off of the PV array. The contactor coil was also replaced with a coil that is feed off of DC voltage instead of AC voltage.
Firmware	Required upgrade to support DNP3 protocol	Required upgrade to support DNP3 protocol
Communications	Added Outstation to translate DNP3/TCP to Modbus/RS-485	Added Outstation to translate DNP3/TCP to Modbus/RS-485

In addition, a Plant Master Controller (PMC) was used to take DNP3 commands from a DERMS and broadcast the commands to all the inverters at the site in accordance with the DNP3 standard for smart PV inverters. The PMC synchronizes its time by connecting to an IRIG-B clock. It also collects crucial power and energy readings for the total site and individual inverters from the SEL-735 PQ meter.

In order for communication and control to be utilized in testing, communication and metering connections were made at the site and the substation. Figure 6-2 provides a diagram of the infrastructure deployed.

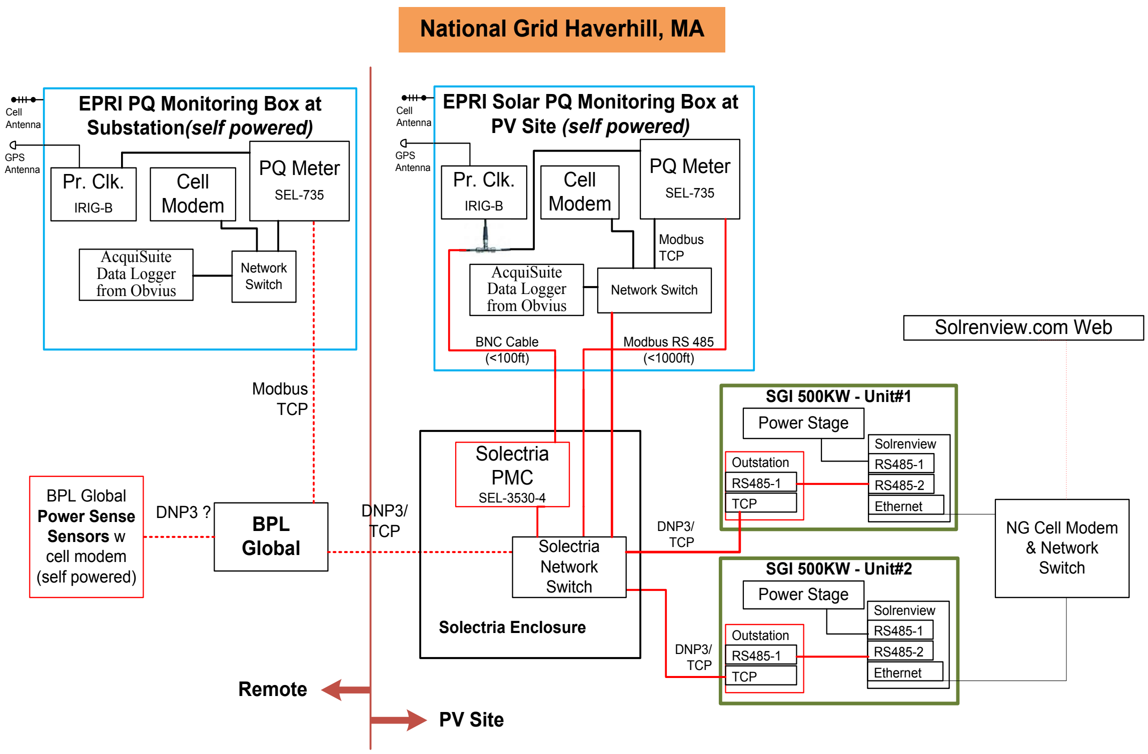


Figure 6-2
H1 Communication Infrastructure

The DERMS utilized for testing was the BPLGlobal DERMS. This software provided control of the inverter for all test phases including real-time management of the inverter to maintain the power factor at the substation.

E1 Hardware Upgrades

On the E1 site, there were two inverters – 300kW and 266 kW – upgraded. Table 6-2 provides an overview of the changes at this site. Similar to the H1, at E1 a PMC was added to broadcast the DNP3 commands from the DERMS to all the inverters at site

Table 6-2
Inverter Upgrades at E1

Specification	E1 Inverter 1	E1 Inverter 2
Size	300kVA	266kVA
kW rating	300kW	266kW
kvar rating	180kvar	160kvar
PMC	One shared for the whole site	
Voltage sensing board/full power stage	Power Stages (costly but more efficient)	Power Stages (costly but more efficient)
Control Circuit	AC feed (contactor couldn't be replaced)	AC feed (contactor couldn't be replaced)
Firmware	Required upgrade to support DNP3 protocol	Required upgrade to support DNP3 protocol
Communications	Added Outstation to translate DNP3 to Modbus	Added Outstation to translate DNP3 to Modbus

In order for communication and control to be utilized in testing, communication and metering connections were made at the site and the substation. Figure 6-3 provides a diagram of the infrastructure deployed.

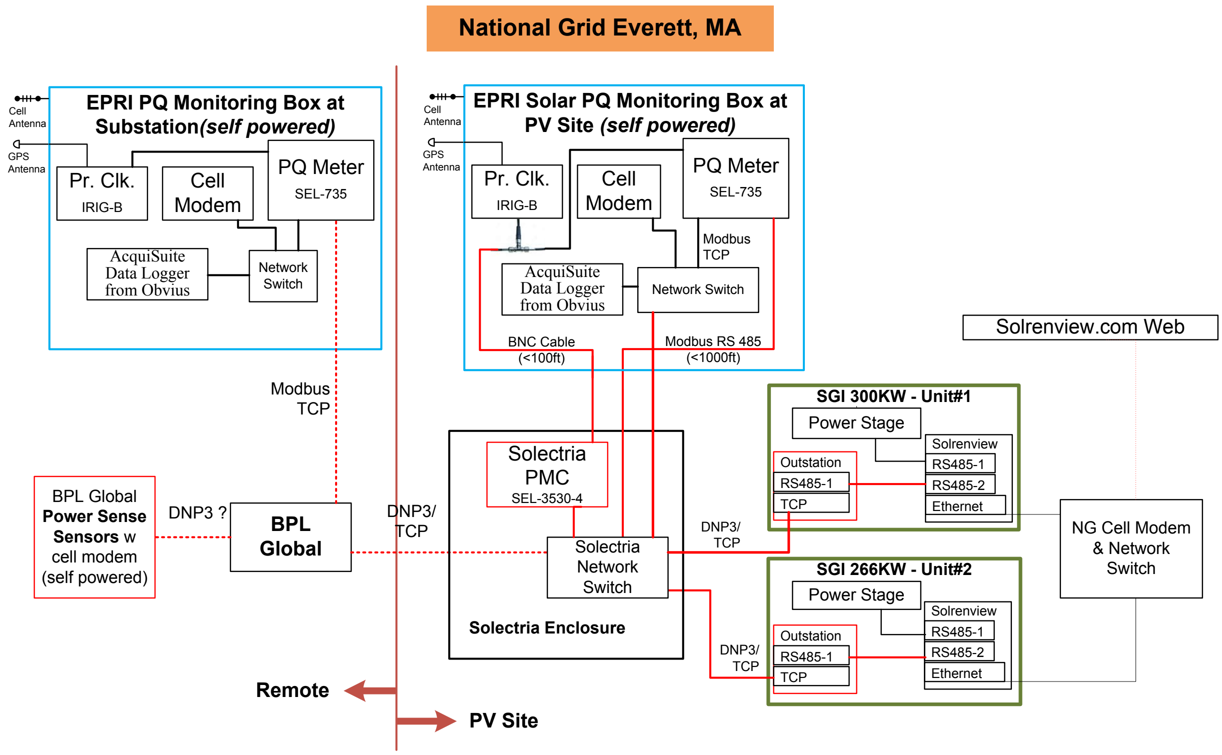


Figure 6-3
Communication Infrastructure at E1

In this demonstration, the DERMS utilized was also the BPLGlobal DERMS. This software provided control of the inverter for all test phases.

F1 Hardware Upgrades

On the F1 site, the 300 kW inverter was upgraded. Table 6-3 provides an overview of the changes at this site. Similar to the other sites, F1 site also had a PMC was added to broadcast the DNP3 commands from the DERMS to the inverter at site.

Table 6-3
Inverter Upgrades at F1

Specification	F1 Inverter 1
Size	300kVA
kW rating	300kW
kvar rating	180kvar
PMC	One dedicated for the inverter
Voltage sensing board/full power stage	Power Stages (costly but more efficient)
Control Circuit	AC and DC feed (DC feed was not sufficient)
Firmware	Required Upgrade to support DNP3 protocol
Communications	Added Outstation to translate DNP3 to Modbus

In order for communication and control to be utilized in testing, communication and metering connections were made at the site and the substation. Figure 6-4 provides a diagram of the infrastructure deployed.

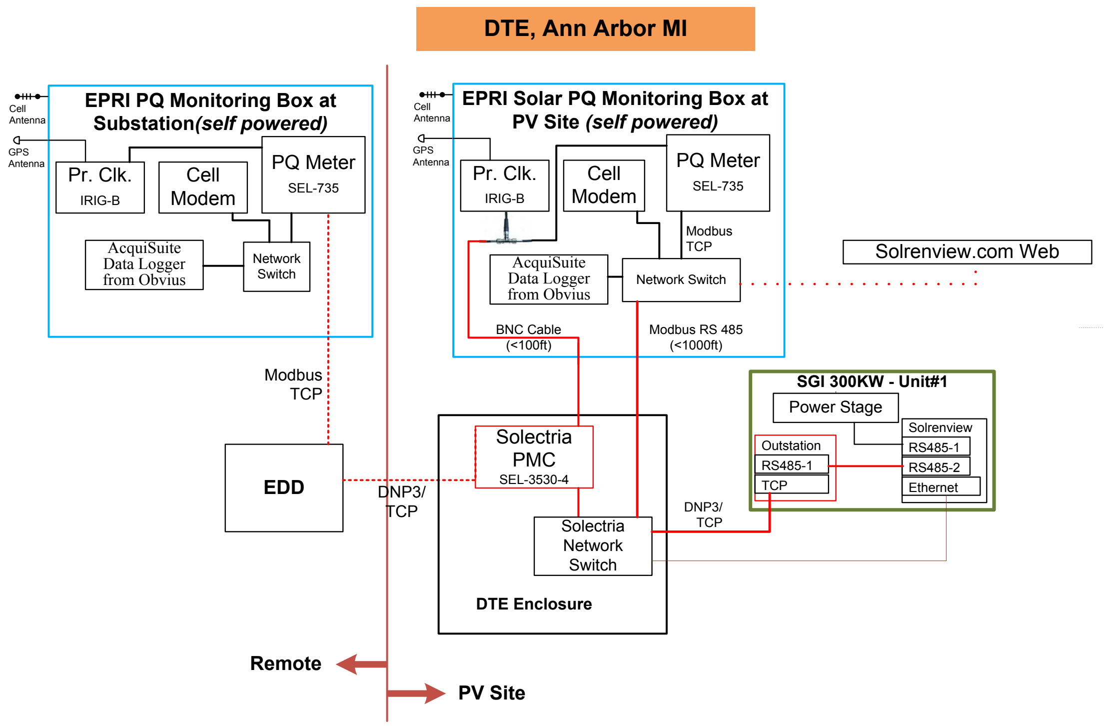


Figure 6-4
Communication Infrastructure at F1

In the case of the F1 feeder, DTE's DRSOC tool was utilized as the DERMS to communicate with a control the inverter during the test phases.

DTE also sought to demonstrate a direct transfer trip technology as part of this demonstration. DTE Energy installed a SEL-351-7 relay at the inverter site. This relay provides protection for Over/Under Voltage and Over/Under Frequency conditions. The output of the relay is connected to the remote shutdown terminals on the Yaskawa-Solectria Solar inverter.

The transfer trip scheme utilizes 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 is provided via a private mesh wireless network (Tropos) owned and maintained by DTE.

Field Demonstration

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 four 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 was performed using the settings as determined from the feeder modeling. These settings were based on an annual simulation. When testing, it was determined that in the 4 months we were testing the recommended settings for each site would like 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, the test phases will be introduced and then results from field demonstration shown.

National Grid H1 Testing

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

1. Baseline Data
2. Volt-VAR control and vars precedence
3. Toggled on/off volt-VAR control
4. Fixed power factor
5. Volt-watt function
6. Remotely managed volt-VAR control

What follows is an explanation of each test phase and the results from the field.

Test Phase 1 – Baseline Data

Prior to testing the smart PV inverter capabilities, several weeks of baseline data was collected and analyzed. The baseline included data from all the points of measurement on the H1 feeder identified in the map above. As indicated in the analysis that follows, this data aided in the impact analysis.

Figure 6-5 shows the response of the H1 PV site on a clear day in July, 2015. All smart PV inverter functions were turned off during this period, and the power factor was set to unity. In spite of these settings, the measured power factor was not exactly unity, although it remained above 0.98 (inductive) for most of the day and was near 0.99 at midday. According to the manufacturer, this error is caused in part by the fact that the inverter was pre-existing and updated in the field for the project. This update included a field calibration process that was not as accurate as factory calibration.

As a result of this imprecision, the inverters absorbed 135kVars (inductive Vars) at midday when the plant output peaked at 875kW.

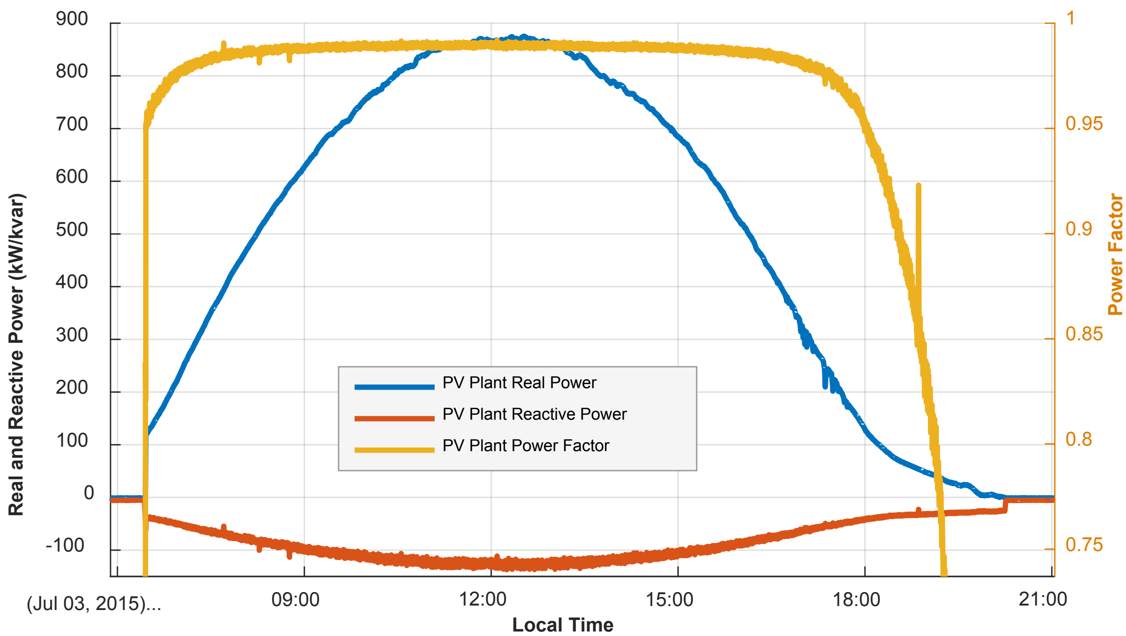


Figure 6-5
Example Baseline Day for the H1 Plant

It is important to note this characteristic because it has a significant influence on the evaluation of smart PV inverter functions during on/off cycled testing.

Test Phase 2 – Volt-VAR Control on, and Vars--Precedence

The second 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 6-6.

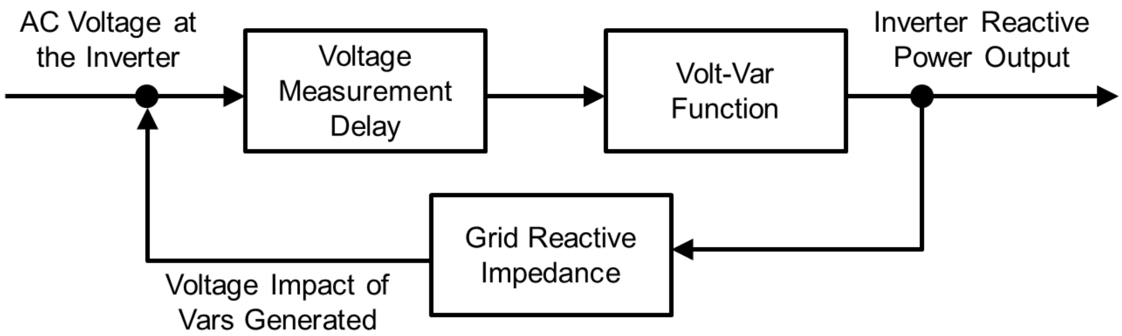


Figure 6-6
Example Potential Feedback Loop

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 6-4 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 6-6 is the greatest. The modeling and simulation also showed that a steep Volt-VAR curve as used here was best overall.

Table 6-4
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 6-7 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.

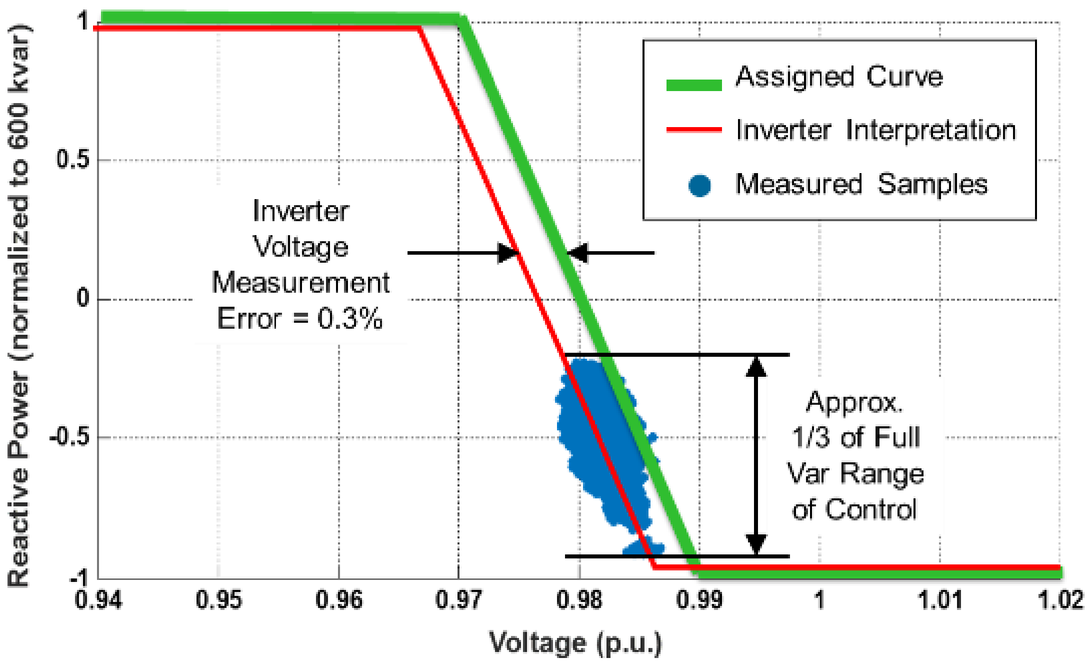


Figure 6-7
Volt-VAR Curve Settings and Data from the H1 Test Site

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. The solar variability index is a metric created by Sandia National Laboratories which quantifies the variability of solar resource, normalized to a theoretical clear sky day. This metric can be thought of as a ratio of the length of the measured irradiance to the length of the clear-sky irradiance[18]. A similar metric is proposed for quantifying the variability of voltage, where the GHI and CSI vectors are replaced with measured data from a smart-functionality case and a unity case respectively.

Solar Variability Index

$$SVI = \frac{\sum_{k=2}^{n}\sqrt{(GHI_k - GHI_{k-1})^2 + \Delta t^2}}{\sum_{k=2}^{n}\sqrt{(CSI_k - CSI_{k-1})^2 + \Delta t^2}}$$

Voltage Variability Index

$$VVI = \frac{\sum_{k=2}^{n}\sqrt{\left(V_{smart\ k} - V_{smart\ k-1}\right)^2 + \Delta t^2}}{\sum_{k=2}^{n}\sqrt{\left(V_{unity\ k} - V_{unity\ k-1}\right)^2 + \Delta t^2}}$$

Although not evident in the charts previously presented, the Volt-VAR control also reduces voltage variability. Figure 6-8 shows an example of the reduction in voltage variability due to the Volt-VAR curve being enabled. The blue curve is the voltage at the PV plant throughout a single test day when the Volt-VAR curve was enabled, and red curve is the voltage at the PV plant on a similar day at unity power factor operation. As shown, the voltage was lowered (pulled toward

[18] J. Stein, et al, The Variability Index: A New and Novel Metric for Quantifying Irradiance and PV Output Variability (ASES 2012 VI, SAND2012-208)

the middle of the Volt-VAR curve that was used) and variability was significantly reduced when the Volt-VAR function was enabled.

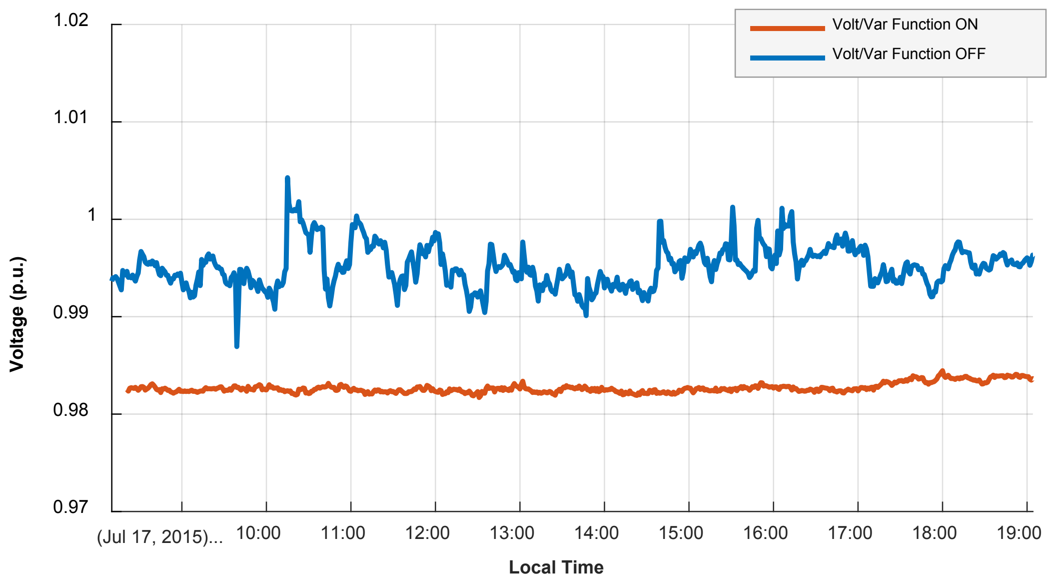


Figure 6-8
Daily Voltage at the H1 PV Plant with and without Volt-VAR Control

Figure 6-9 shows a time series plot of the voltage at the substation for the same two days shown in Figure 6-8. The voltage during the day where the volt-VAR function was on is less variable than the day where the volt-VAR function was off.

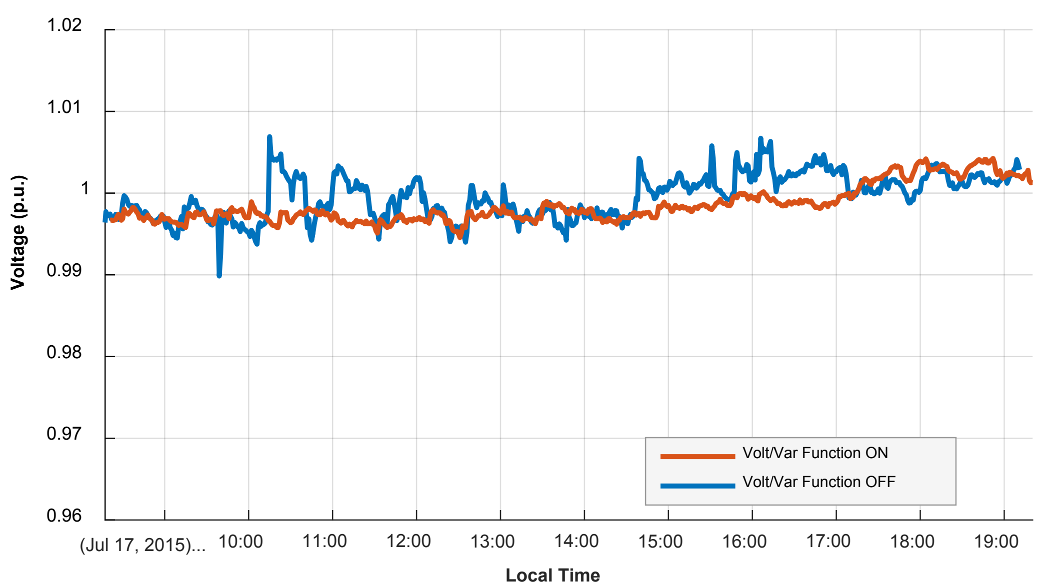


Figure 6-9
Time series plot of substation voltage for a day with the volt/var function enabled, and a similar day operating at unity power factor

Figure 6-10 provides an alternate view of the impact on variability. 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.

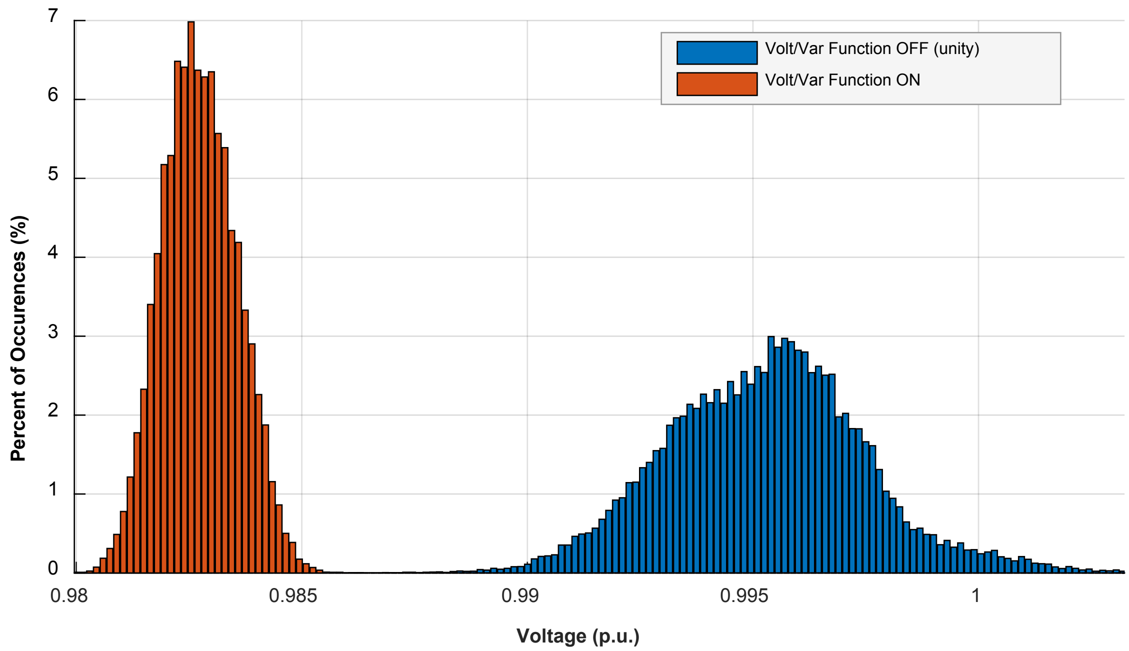


Figure 6-10
Histogram of Voltage at the H1 PV Plant

Even at the substation, some impact of voltage variability is seen (Figure 6-11) although here the voltage regulator of the substation held the mean voltage fairly constant. It is also noted that the voltage measurements at the substation, both with and without Volt-VAR control have split distribution. This is due to the action of the substation voltage regulator, with the separation between the two distributions equating to approximately one step or 5/8%.

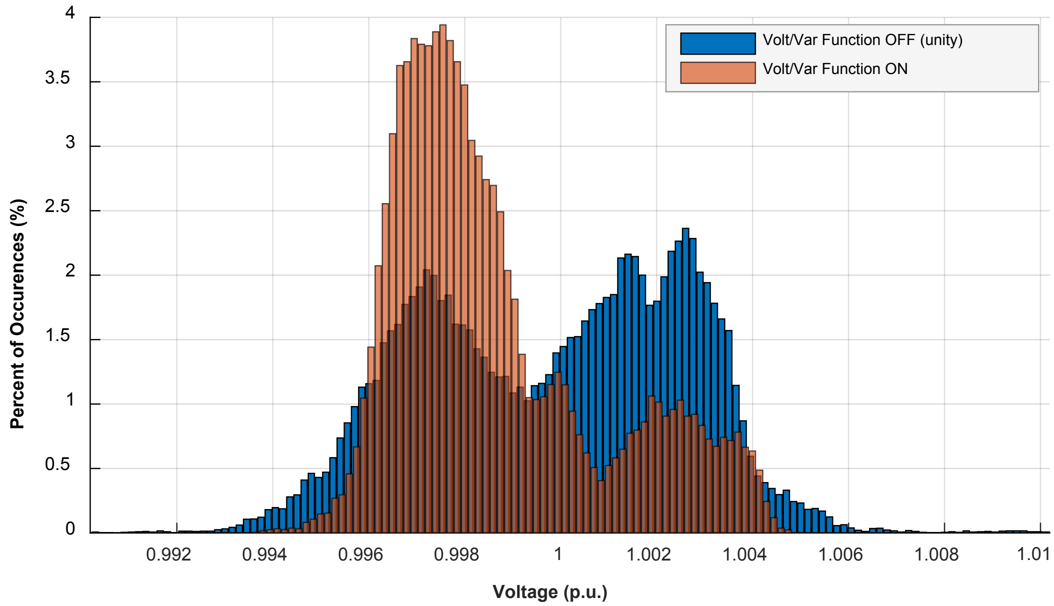


Figure 6-11
Histogram of Voltage at H1 Substation

Figure 6-12 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.

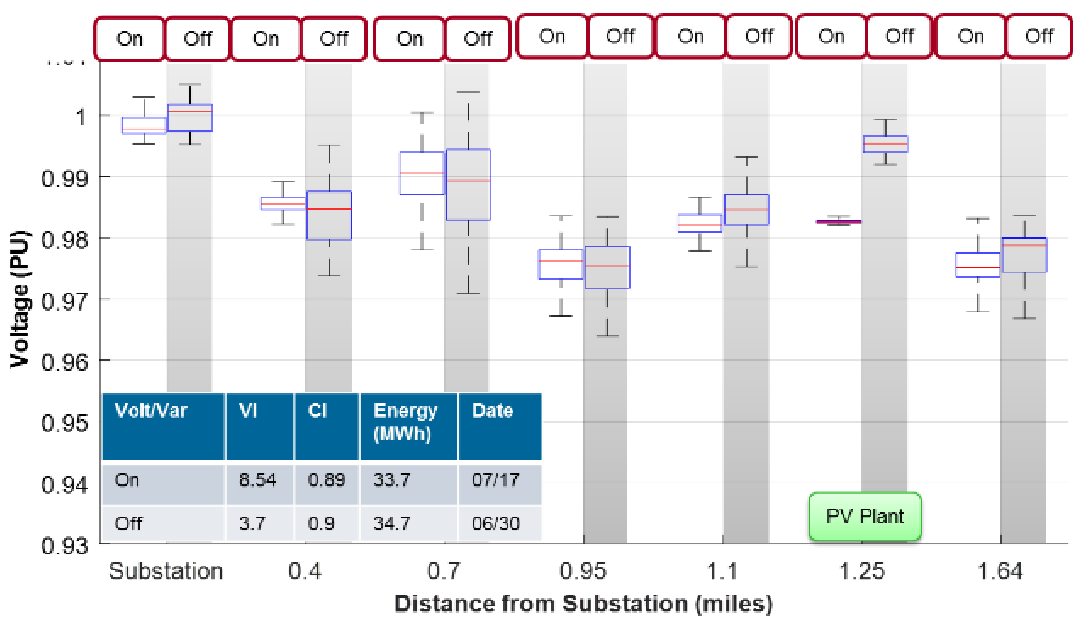


Figure 6-12
Box and whiskers plot of days with the volt-VAR function enabled and disabled for multiple points along the feeder

Table 6-5 shows the voltage variability indices as described previously. Across the feeder, the voltage variability index is less than one for this day. This means that the voltage while the volt-VAR function was enabled was less variable than the voltage during unity power factor operation. At the substation, the voltage was about 40% as variable when the volt-VAR condition was enabled than the unity case. At the last measurement position on the feeder the voltage was about 90% as variable when the volt-VAR function was enabled.

Table 6-5
Voltage variability indices for locations along the feeder

Distance from Substation (miles)	0 (Sub)	0.4	0.7	0.95	1.1	1.25 (PV Plant)	1.64
Voltage Variability Index	0.41	0.54	0.70	0.52	0.93	0.41	0.93

Voltage duration curves for all the points of measurement on the H1 feeder are provided in Figure 6-13, 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.

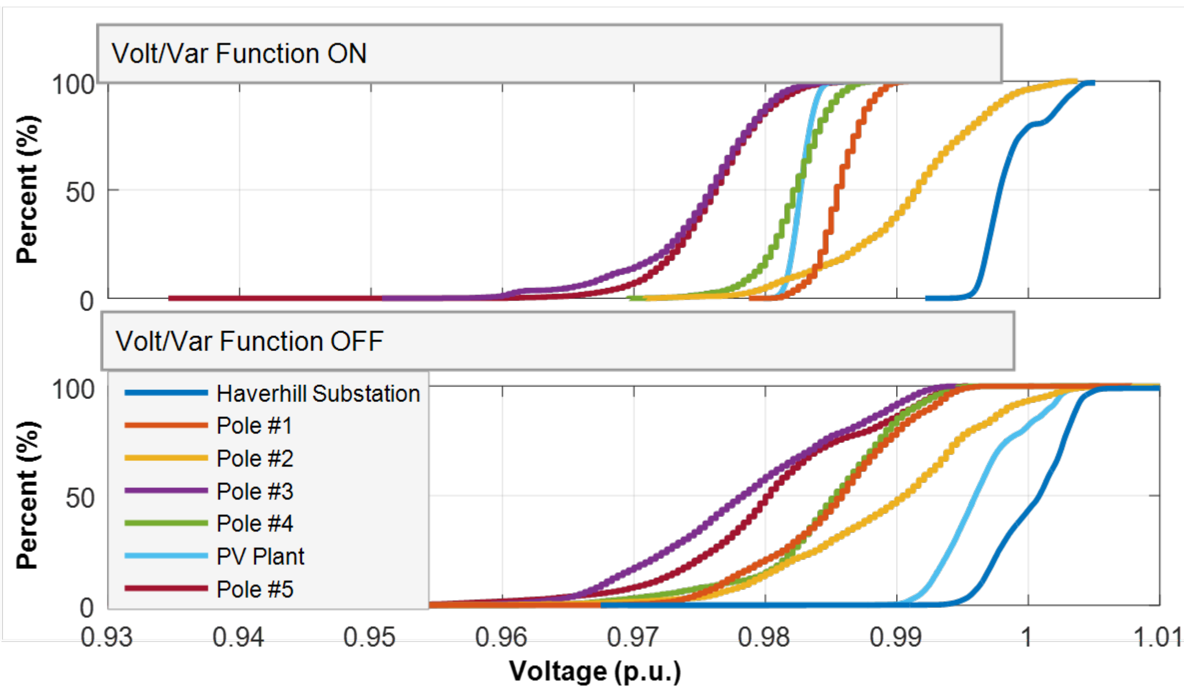


Figure 6-13
Typical Duration Curve of Voltages at H1

Note that the configuration used (see Figure 6-7) 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.

Test Phase 3 – Toggled On/Off Volt-VAR Control

This test phase operated for three days, 10 minutes on, 10 minutes off, in order to provide increased insight into the difference made by the volt-VAR function. In addition, each on/off cycle provides insight into the transient stability of the inverter as the function is enabled and disabled under various operating conditions.

Figure 6-14 shows the load and irradiance during one of the selected time periods when the ten minute on/off test results were closely analyzed. The purpose of this plot is to show that the load was relatively stable (note the right-hand scale) during the period, and the irradiance, although constantly rising, did not have significant variability.

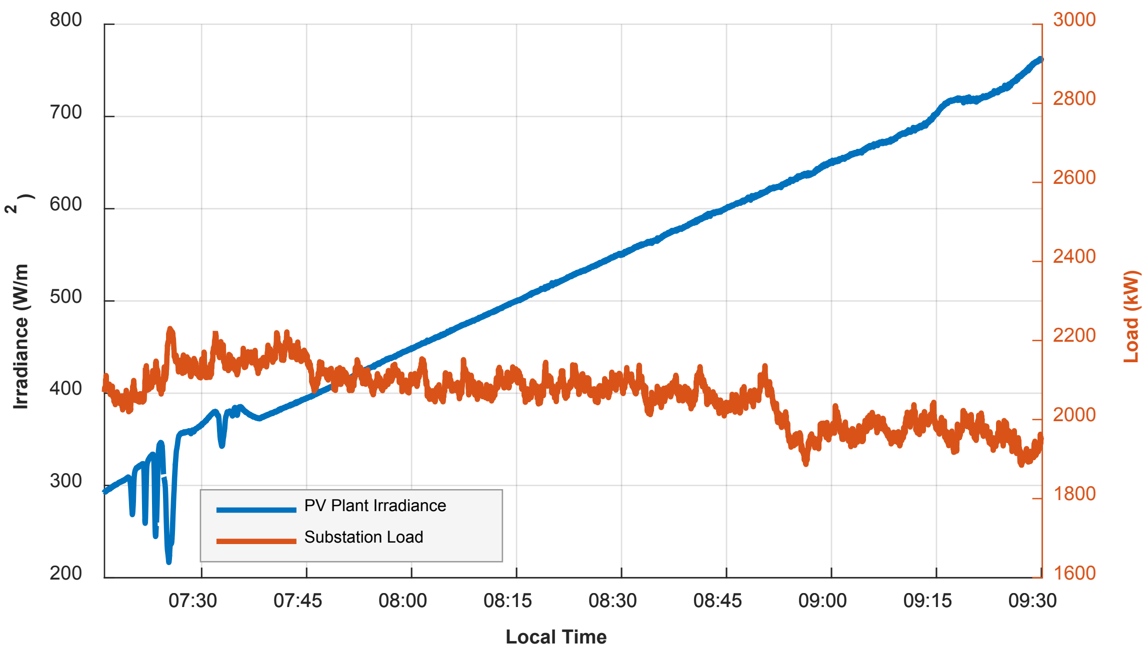


Figure 6-14
Time series plot showing the load and irradiance from 7:15 am to 9:45 am

Figure 6-15 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 6-15 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.

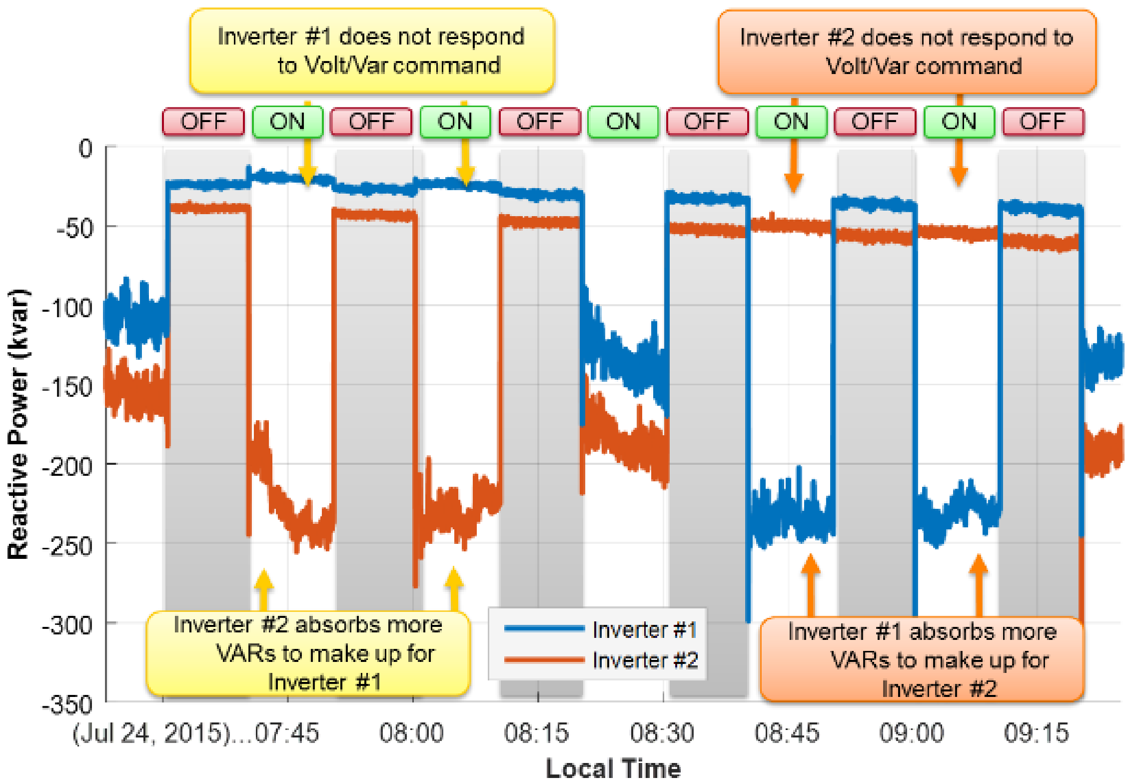


Figure 6-15
Reactive power response to 10 minute on/off volt-VAR testing

Also observable in Figure 6-15 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.

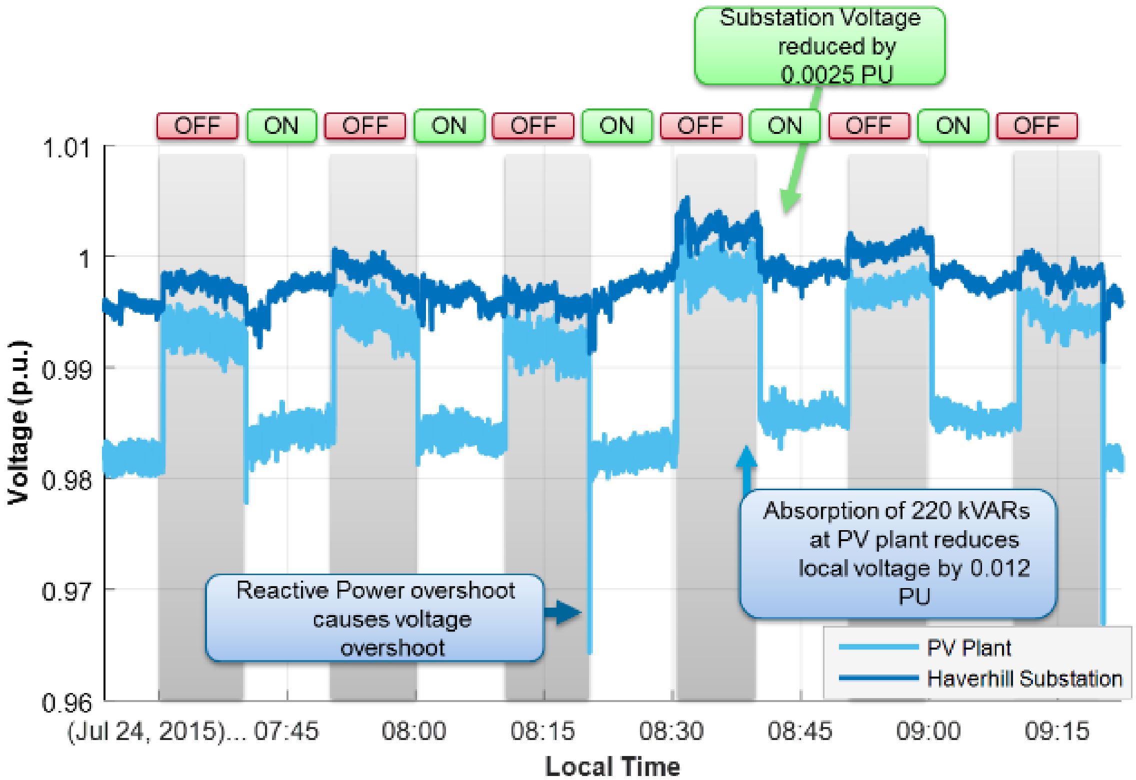


Figure 6-16
Voltage response to 10 minute on/off volt/var testing

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 6-16 is an undesired overshoot in the voltage waveforms. The combined overshoot in Var absorption of inverters 1 and 2 can be seen in Figure 6-15 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.

Figure 6-17 shows the effect of the Volt-VAR curve on several pole monitoring locations along the feeder for the same time period. At most transition periods, when the inverter moves from unity to smart functionality, there is a noticeable impact at each of the pole locations.

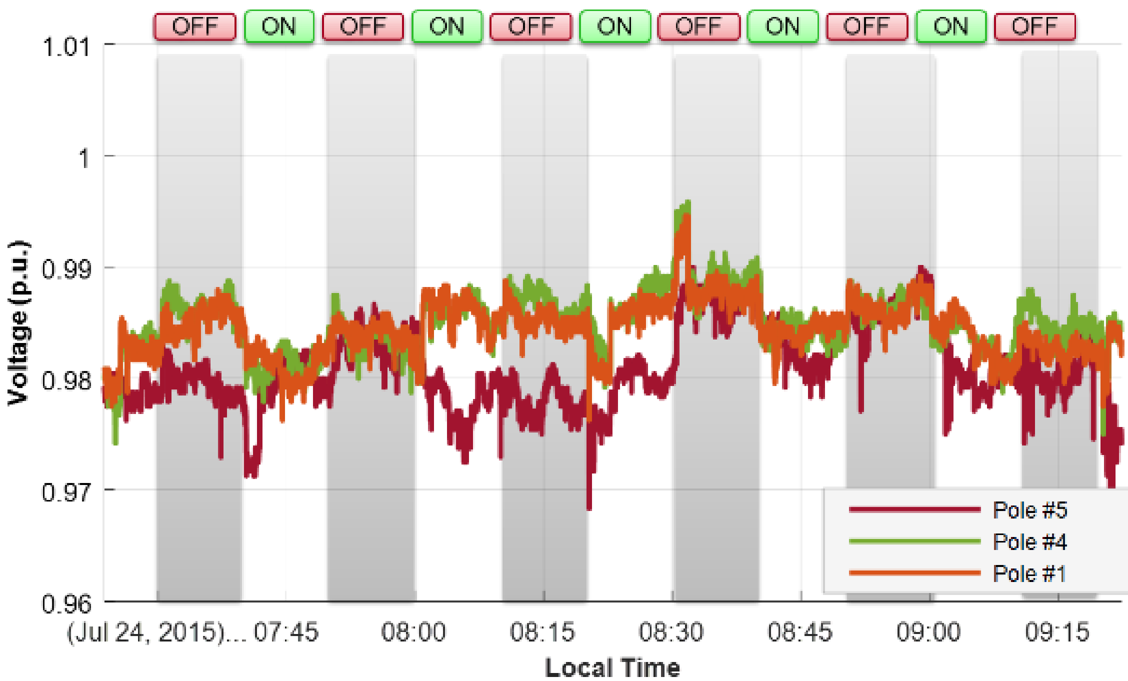


Figure 6-17
Effect of 10 min on/off volt/var curve testing on pole voltages along the feeder

In Figure 6-18 the effect of the volt-VAR curve is much more evident here, where all 3 pole locations above experience an increase of about 0.004 p.u. when the function is disabled.

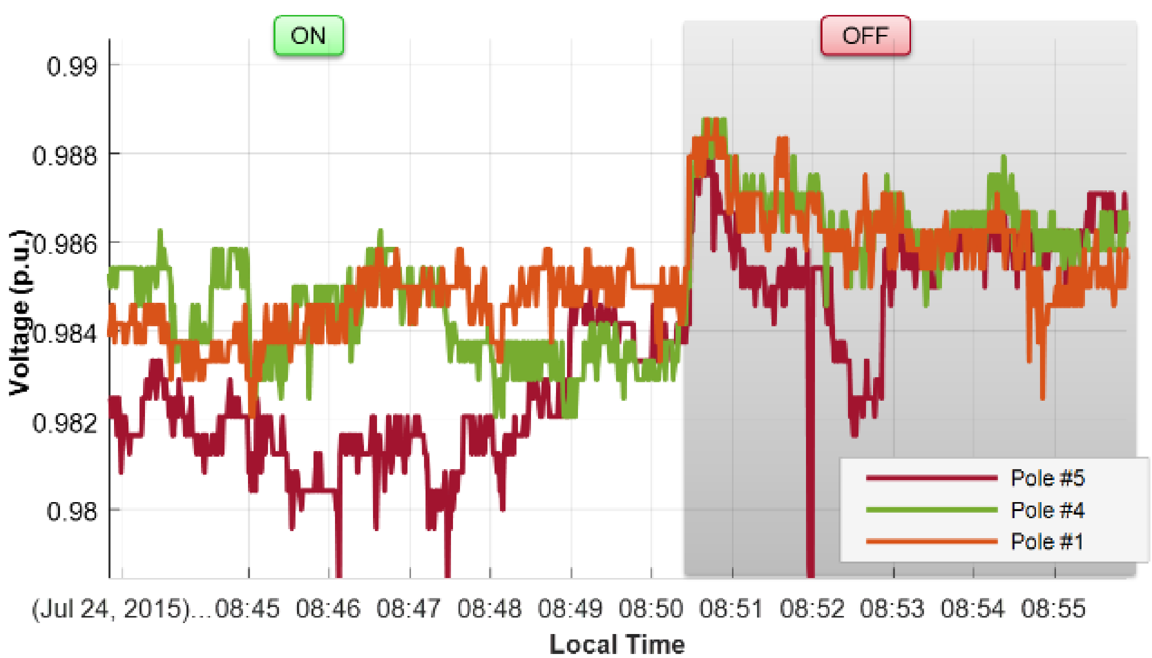


Figure 6-18
Zoomed in effect of volt/var functions on pole locations along the feeder.

Test Phase 4 – Fixed Power Factor

The fourth phase of testing utilized fixed power factor as an alternative to volt-VAR control. A fixed power factor makes the var output proportional to the real-time Watt output of the PV plant. This mode of operation may be preferred in cases where the PV plant output (Watts) is the primary cause of voltage problems on the feeder and the Var requirements are thereby more related to the Watt output than to the local voltage level.

The PF setting used was calculated by EPRI modeling – 0.96 for voltage control operations. This test was conducted for three days, 10 minutes-on, 10 minutes off. Figure 6-19 demonstrates that the load and irradiance did not experience any extreme variability during the time period shown in Figure 6-20.

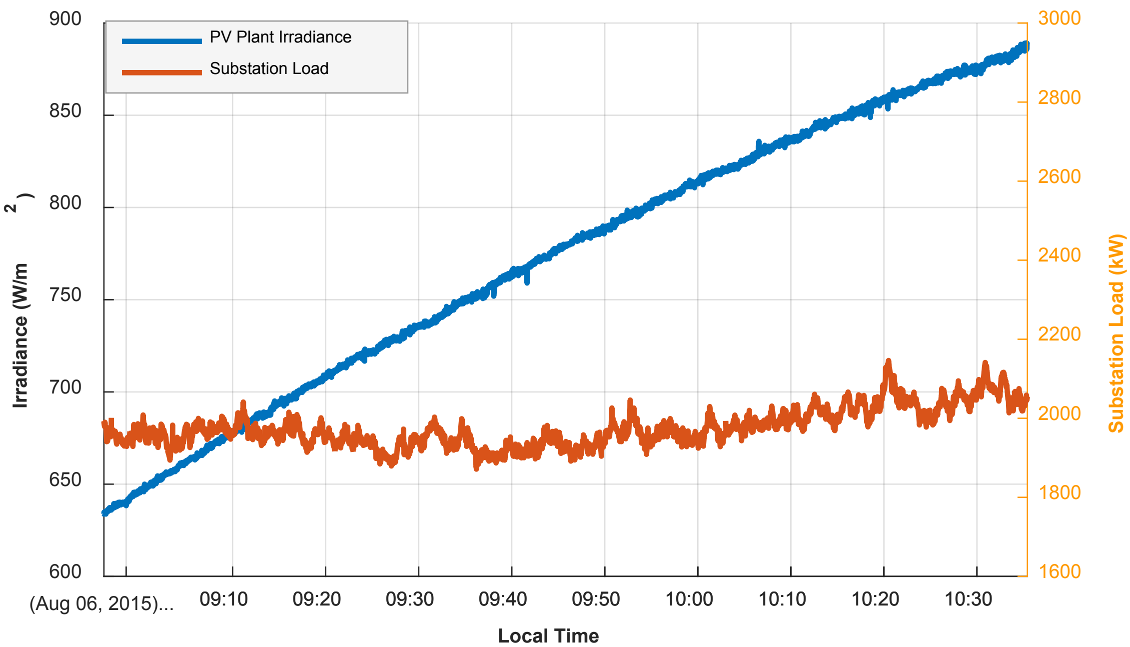


Figure 6-19
Irradiance and substation load during 10 minute on/off constant power factor tests

Figure 6-20 shows the power factor of both the PV Plant and the substation, as well as the reactive power from the PV plant during a representative window of the three-day 10 minute on/off power factor tests. In this case, the power factor setting during the on period was 0.96 capacitive as selected by the modeling and simulation. Recall that as shown in Figure 6-5, the reactive power of this inverter was offset when it is set to unity power factor.

When the PV Plant changes from unity to 0.96 power factor, the reactive power changes from absorbing to injecting vars. This moves the PV plant power factor from 0.99 inductive to 0.98 capacitive. As a result of the constant power factor setting, the power factor at the substation is increased from 0.98 to 0.99.

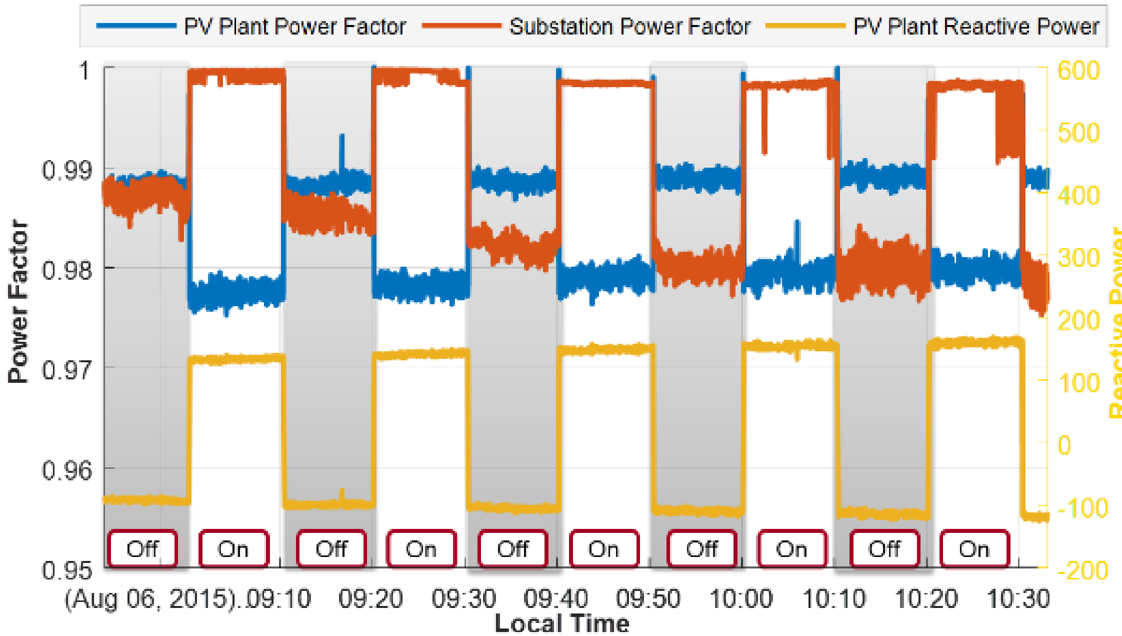


Figure 6-20
Constant Power Factor Mode, Cycled 10 minute On/Off

Test Phase 5 –Volt-Watt Function

During the fifth 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.

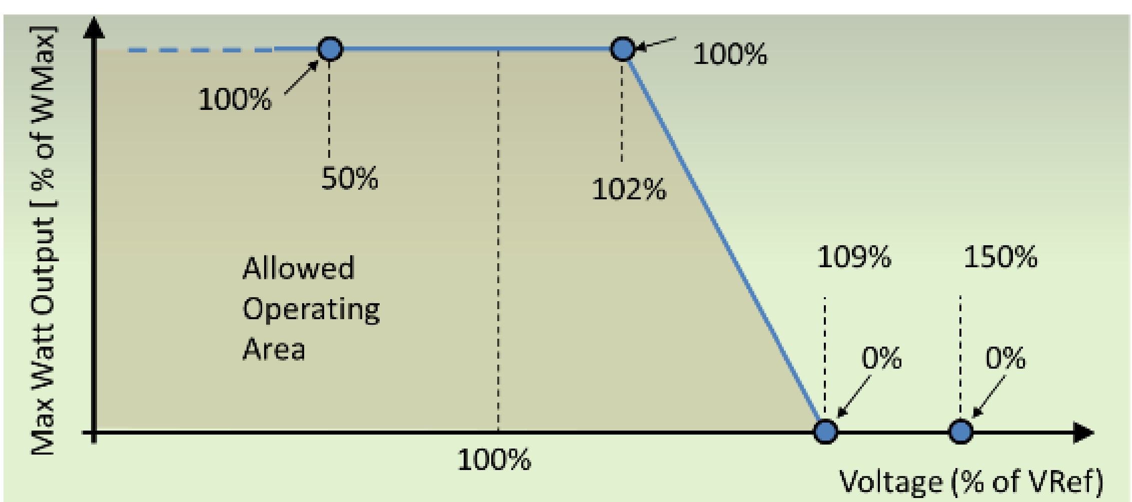


Figure 6-21
Volt-Watt Function Example Settings

The actual voltage at the H1 site was never high, so the curve shown in Figure 6-22 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.

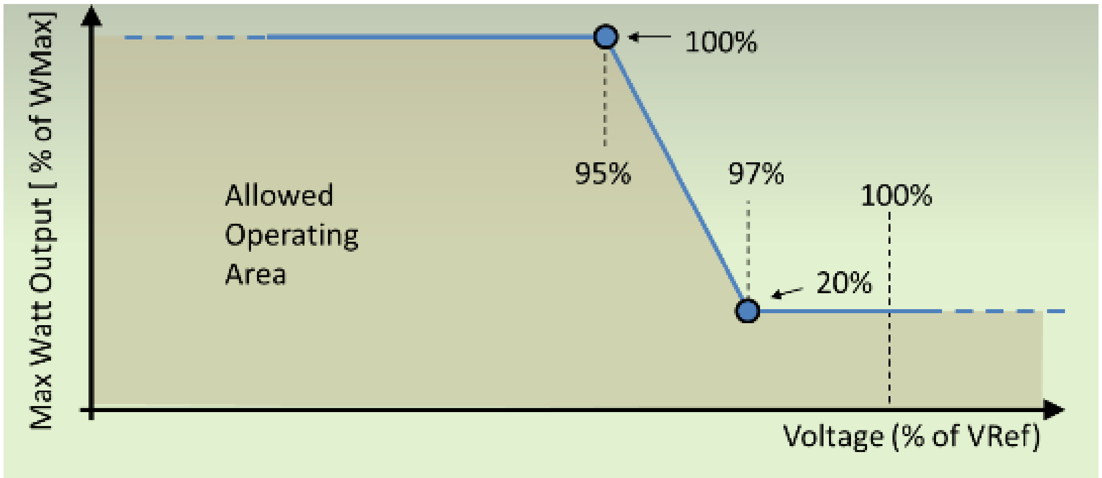


Figure 6-22
Volt-Watt Settings Used for H1 Test

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 6-23 shows a representative three-hour period of testing in this mode of operation. During this window of time, the substation power factor was particularly low, requiring all the Var capability of the PV plant in order to bring it to unity. In other time periods, less Vars were required from the PV plant in order to attain unity at the substation.

The top chart shows the resulting substation power factor over time and the bottom chart shows the reactive power generated by each inverter during the same time period. Note that when they are operating, each inverter is generating near 300kVars, the design limit for these inverters.

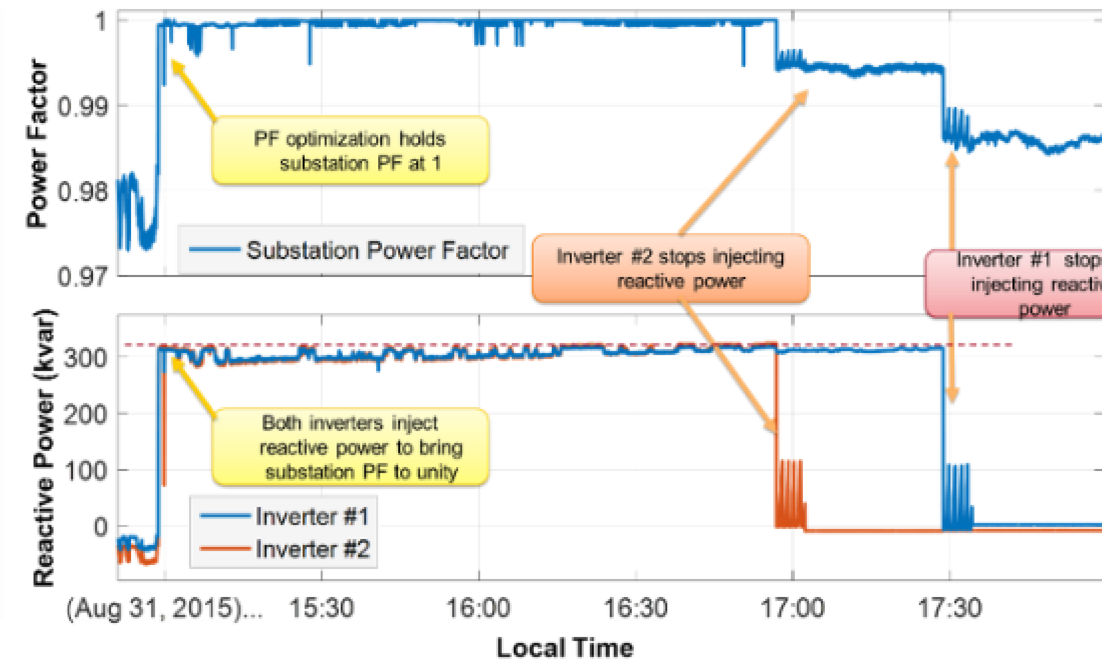


Figure 6-23
Power Factor optimization testing

At the left side of Figure 6-24, the Volt-VAR function is off. The inverter outputs are absorbing about 50kVars each due to their characteristic behavior as noted previously. At this time, the power factor at the substation is around 0.975 and the real and reactive powers are 3.5 MW and 800 kvar respectively. Just before 15:00 hours, the BPL Global control system was activated and both inverters were sent calculated Volt-VAR curves that resulted in near full Var output and bringing the power factor at the substation to near unity. For the next two hours, the control system recomputed the optimal Volt-VAR curves, but didn't need to readjust the inverter configurations. Just before 17:00 hours, one of the two inverters was stopped and 30 minutes later the other.

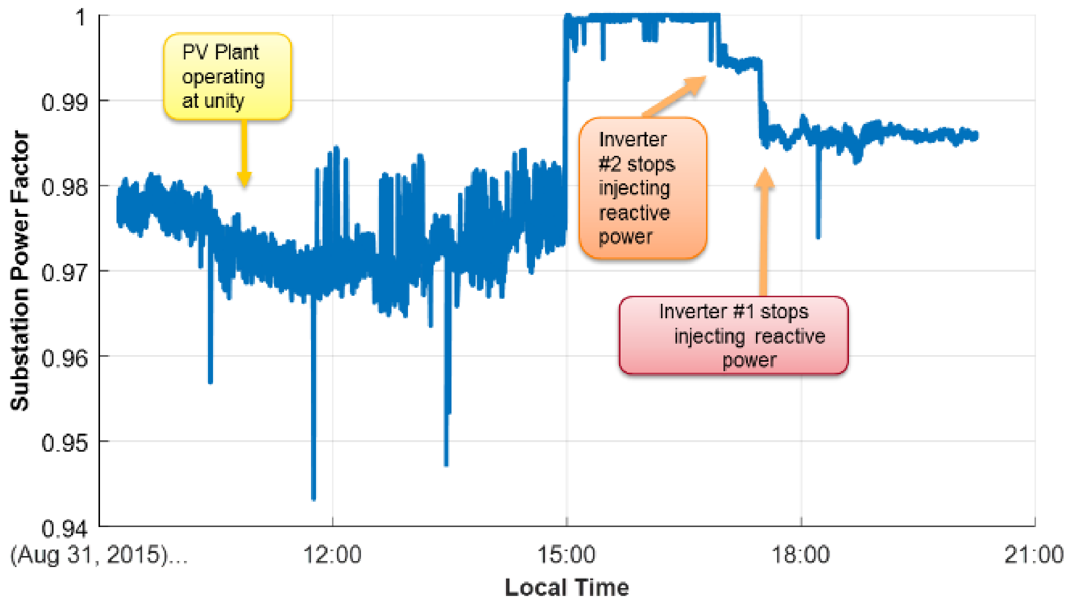


Figure 6-24
Closer view of substation PF during remote volt-VAR control

Figure 6-25 shows the same control scheme operating during a different time period. In this case, the PV plant had ample Var capacity to bring the PF at the substation to unity. As a result, the BPL Global control system re-assessed the Volt-VAR curve settings throughout the test period.

The continuous updates exposed a flaw in the control algorithm in the inverter. Most of the spikes shown in Figure 6-25 are the result of the inverter turning the Volt-VAR function off then back on each time a new curve-setting is sent. Because of this undesirable characteristic, the update rate of the control algorithm was limited to about one minute.

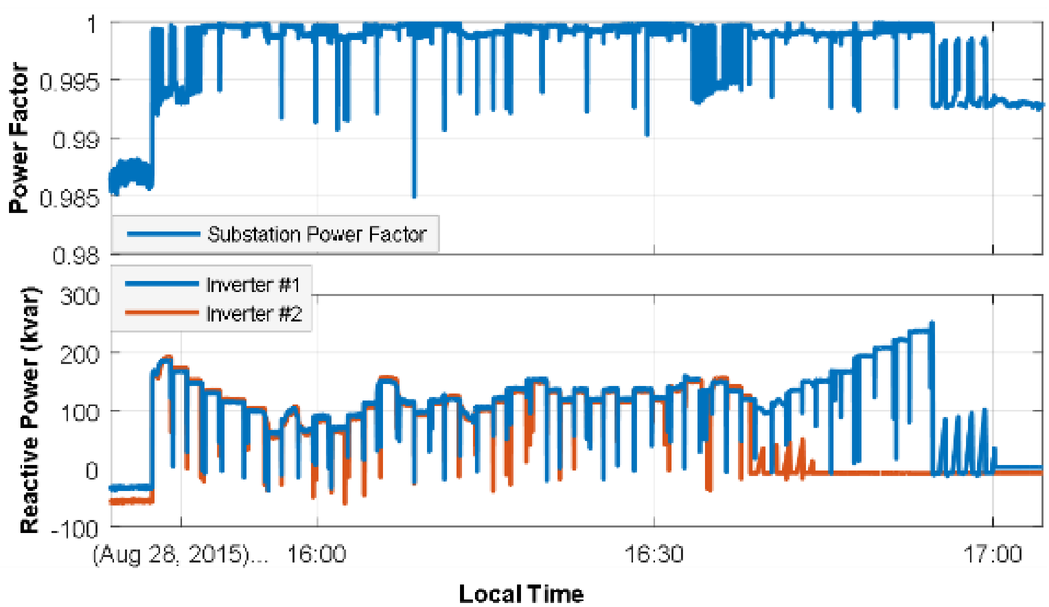


Figure 6-25
Remote Volt-VAR Control, Unconstrained Case

Figure 6-26 provides an improved view of the remote volt-VAR control test of Figure 6-25. 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 6-26 shows the substation power factor line both above and below unity to indicate when it was capacitive or inductive.

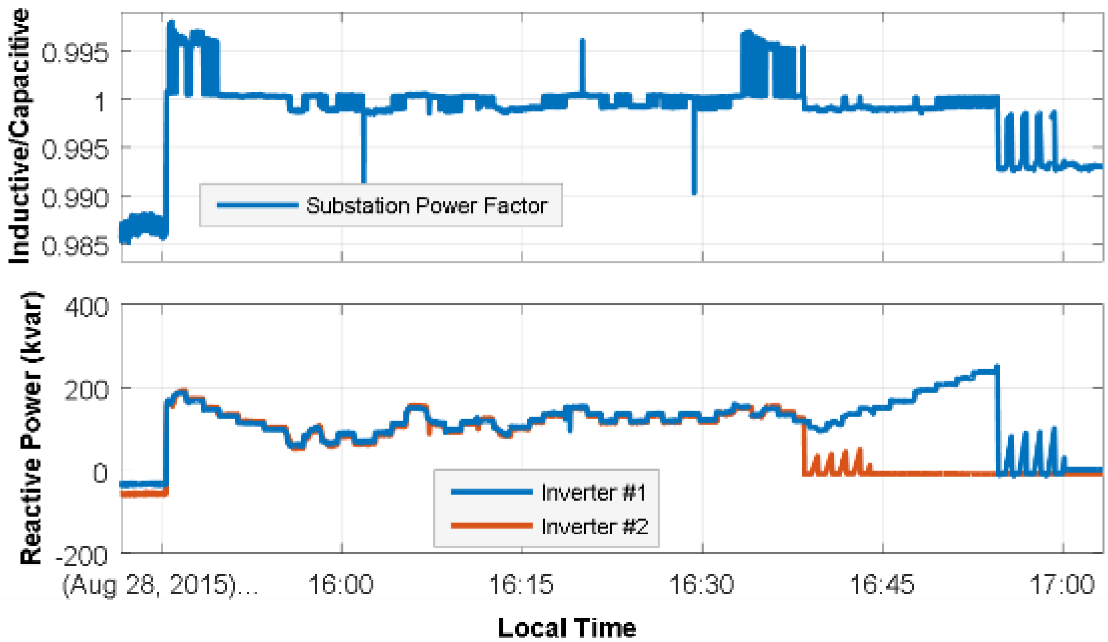


Figure 6-26
Remote Volt-VAR Control, Unconstrained Case with Communication-Caused Glitches Removed

The following observations are made from these results:

1. Prior to enabling the remote Volt-VAR control mode, the power factor at the substation was around 0.985.
2. Once the remote Volt-VAR control mode was activated, the reactive power of each inverter rose to around 200[kVar], or 400[kVar] total.
3. The Var output from the PV plant was, generally speaking, sufficient to bring the PF at the substation to unity, and at no time in this dataset was the PV plant called upon to produce its maximum capability of 600[KVar].
4. Twice during this dataset, something on the feeder (not the PV plant) added additional momentary inductive Vars, causing spikes in the power factor at the substation. This can be seen just after the Volt-VAR function turned on at t=15:45 and again at t = 16:35. These two events had similar amplitude and duration of about 5 minutes. The reactive power measurements at the substation and PV plant were studied during these periods to verify that the PV plant was not the source of these spikes.
5. The inverter and remote control system responded stably to these disturbances. During each period, the reactive power level of the PV plant can be seen stepping lower in response to the average PF error.

6. The remote Volt-VAR control algorithm can be seen incrementing and decrementing the reactive power level form the inverters as it shifts the Volt-VAR settings both left and right during the control period.
7. At t=16:40, when only one of the two inverters is responding, the PF drops below unity and the control algorithm iteratively shifts the Volt-VAR curve setting of the remaining inverter so as to compensate for the one that is not performing.

National Grid E1 Testing

This test plan was designed to span a four month period, including the following test phases:

- Baseline Data
- Autonomous Volt-VAR control, Continuous Operation
- Autonomous Volt-VAR control, Cycled On/Off
- Remotely Managed Volt-VAR control
- Autonomous Volt-VAR control PLUS Dynamic Reactive Current
- Dynamic Reactive Current Only (with no dead band)

These test phases are intended to provide insight into not only smart PV inverter benefits, but the incremental benefits that might be achievable through simultaneous operation of two functions.

Test Phase 1 – Baseline Data

Prior to starting smart function testing, the inverters at the E1 site were configured to operate at unity power factor and data collected for several weeks. Figure 6-27 shows an example day at the E1 PV plant when the inverters were operating in a normal unity power factor mode. In this day example, it is noted that one of the inverters started up several minutes before the other, causing a two-stepped start.

In addition, it is noted that the total reactive power from the plant is much closer to zero throughout the day that was the caser at the H1 site (compare the red curve to that in Figure 6-5). The reason for this, as shown in the next section, is that the errors of the two inverters at this site tended to cancel out one another.

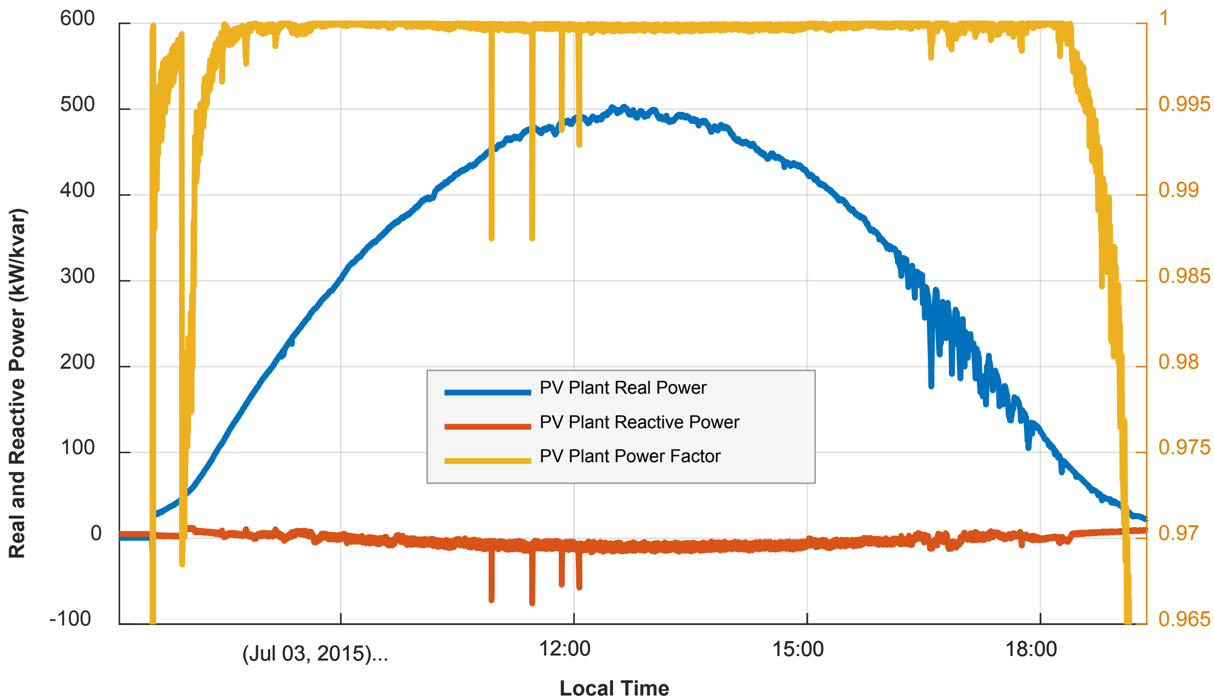


Figure 6-27
Example Baseline Day for the E1 Plant

Test Phase 2 - Autonomous Volt-VAR Control, Continuous Operation

The second phase of testing modeled a scenario where the inverter is providing continuous advanced functionality that is adjusted to the site conditions at install time but not adjusted (or rarely adjusted) thereafter. In this scenario, the Volt-VAR configuration illustrated in Figure 6-28 was used. The test sequence involved 4 days of operation with the Volt-VAR function continuously active.

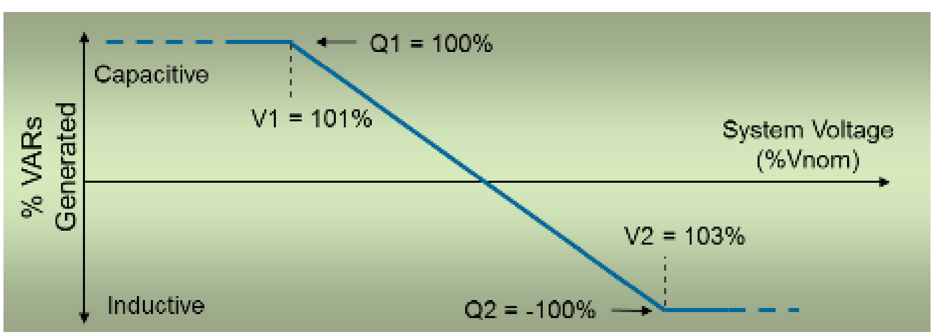


Figure 6-28
Phase 2 Volt-VAR Settings, Tailored to Site Voltage Conditions

These settings (the example shown) shift the midpoint of the volt-VAR curve off Vnom to provide a Var behavior that is optimal for the site. With the autonomous Volt-VAR function, only the voltage that can be observed at the local ECP is effective.

Figure 6-29 shows (in green) the curve setting used for all Volt-VAR testing at the E1 site. This curve was selected based on computer modeling of the E1 feeder and actual baseline data taken from the site. This curve is different from the H1 settings in that it is centered at 1.02 p.u. rather than 0.98 p.u. but the two are similar in that they slope from max capacitive Vars to max inductive Vars linearly over a 2% voltage range.

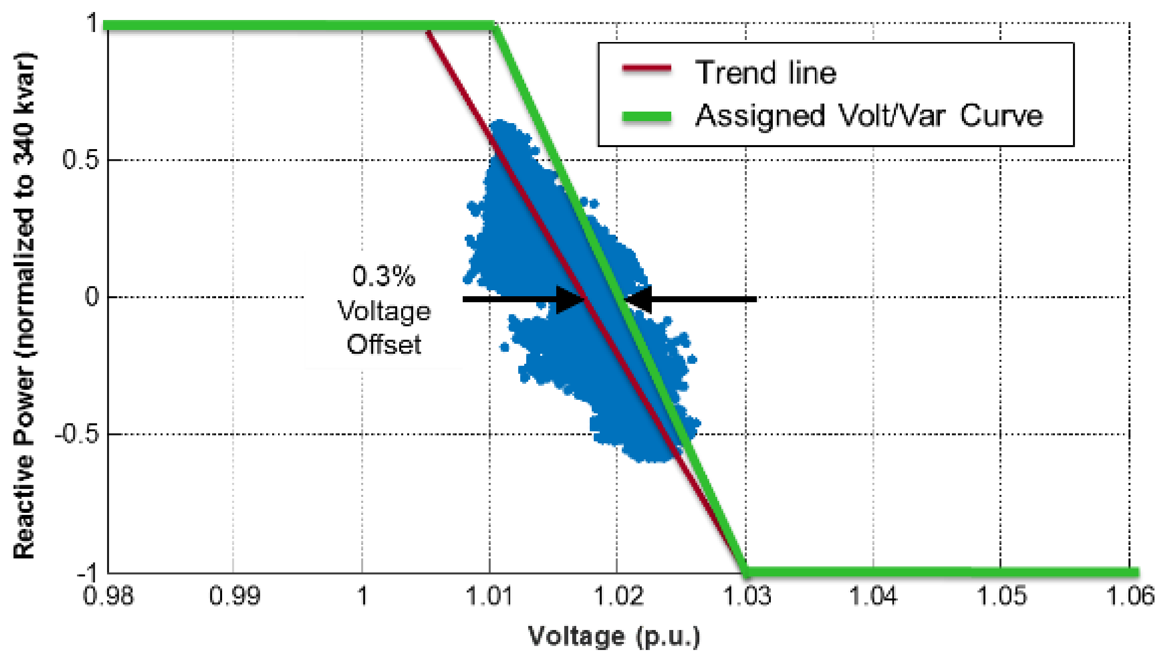


Figure 6-29
Volt-VAR Curve Settings and Data from the E1 Test Site

Each blue dot in this scatter plot represents one second over a three day test period in which the Volt-VAR function was on continuously. The red trend line is the least-squares line of best fit through these points. This shows that there is approximately 3% offset on the voltage measurement (same as the H1 site) and about a 20% error on the achieved slope. The cause of the latter is not known and is assumed to be an implementation detail of the inverters.

An interesting aspect of the testing at the E1 test site was that the reactive power resulting from the Volt-VAR settings that were used included both inductive and capacitive Vars whereas at the H1 site the Vars were always inductive. This is evident from comparing the two scatterplots (Figure 6-7 and Figure 6-29).

Figure 6-30 shows an example day in which the Volt-VAR function was continuously active. As noted from the blue curve (real power), this day was mostly clear, with scattered clouds after noon. During this day, the voltage at the plant was generally above the center of the Volt-VAR curve and reactive power was absorbed. In this mode of operation, the power factor is not directly regulated and is therefore variable (note the scale difference between Figure 6-27 and Figure 6-30).

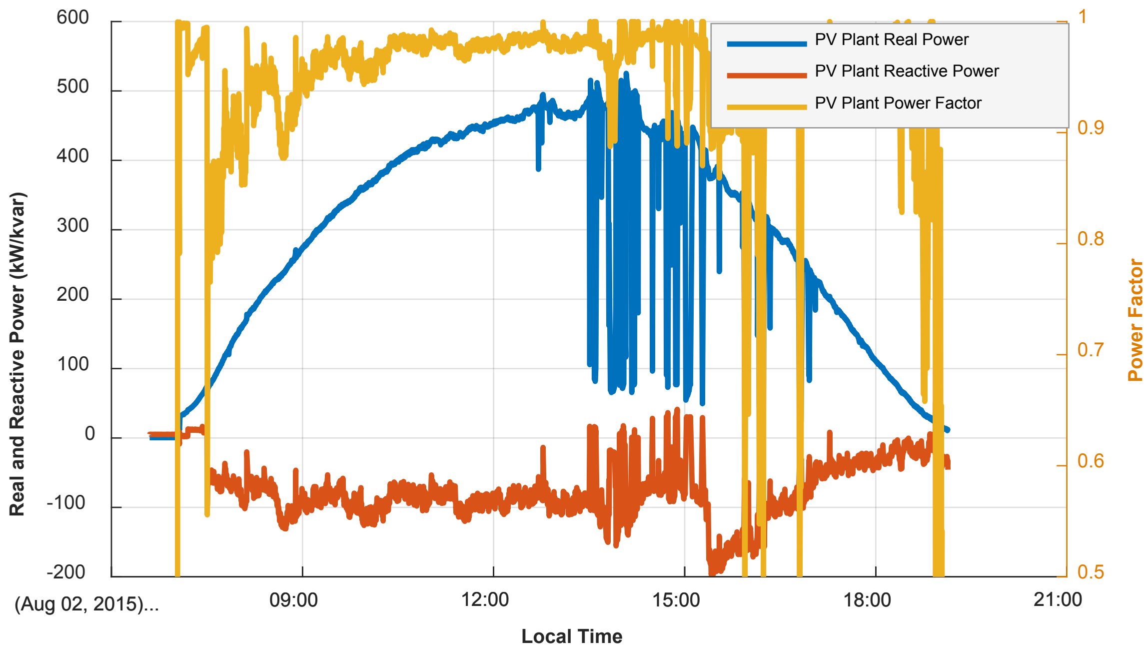


Figure 6-30
Example Volt-VAR Day for the E1 Plant

As was the case at the H1 site, there were no signs of instability in the behavior of the plant in Volt-VAR mode. This is a significant success and important take-away of this project. At the E1 site, the grid impedance at the point of connection was different and the nature of loads and associated variability on the feeder was higher. The H1 and E1 feeders are very different in nature and to find stability at both sites with a common inverter control implementation is important for smart PV inverter utilization.

Figure 6-31 provides a time plot of the voltage at the E1 PV plant for one day of normal operation (unity power factor, blue) and a similar day with the Volt-VAR function active (red). Each line in this figure is a 1 minute average of the three-phase average voltage.

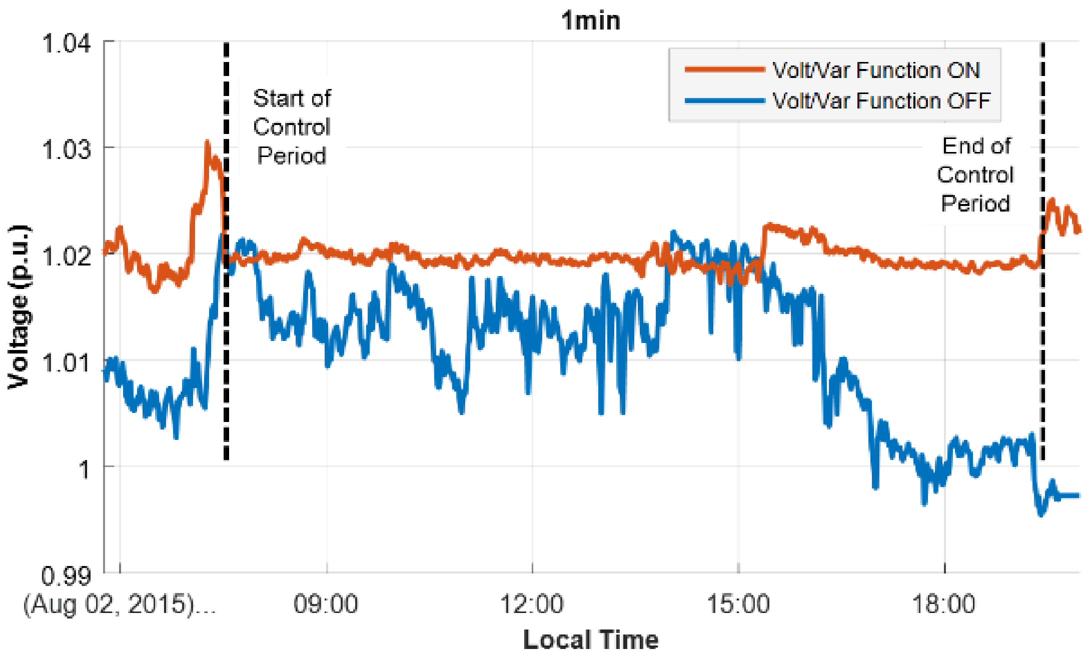


Figure 6-31
Daily Voltage at the E1 PV Plant with and without Volt-VAR Control

This view shows the significant impact of the Volt-VAR function at the inverter site in terms of smoothing and flattening the voltage throughout the day. The only notable voltage change is a step increase around T = 15:30. Because the red line is from the same day that is represented in Figure 6-30 above, it is possible to better assess what happened at time 15:30. Figure 6-30 shows that inductive Vars were being generated by the inverter approaching the time in question, acting to pull the voltage at the site lower. At about 15:30, the voltage at the PV plant stepped higher and the inverter reacted by generating more inductive Vars, acting to resist the voltage increase (not to cause it).

This evidence indicates that the voltage shift occurred due to some other event on the power system, and not as a result of any undesirable action of the inverter. The voltage change of 1.2V/280 = .43% observed in Figure 6-31 and the reactive power shift of ~75kVar observed in Figure 6-30 indicate a Volt-VAR curve slope of around 174kVars per %V which matches the slope of the configured Volt-VAR curve of the inverter (60%*580/2%). In short, the inverter responded correctly.

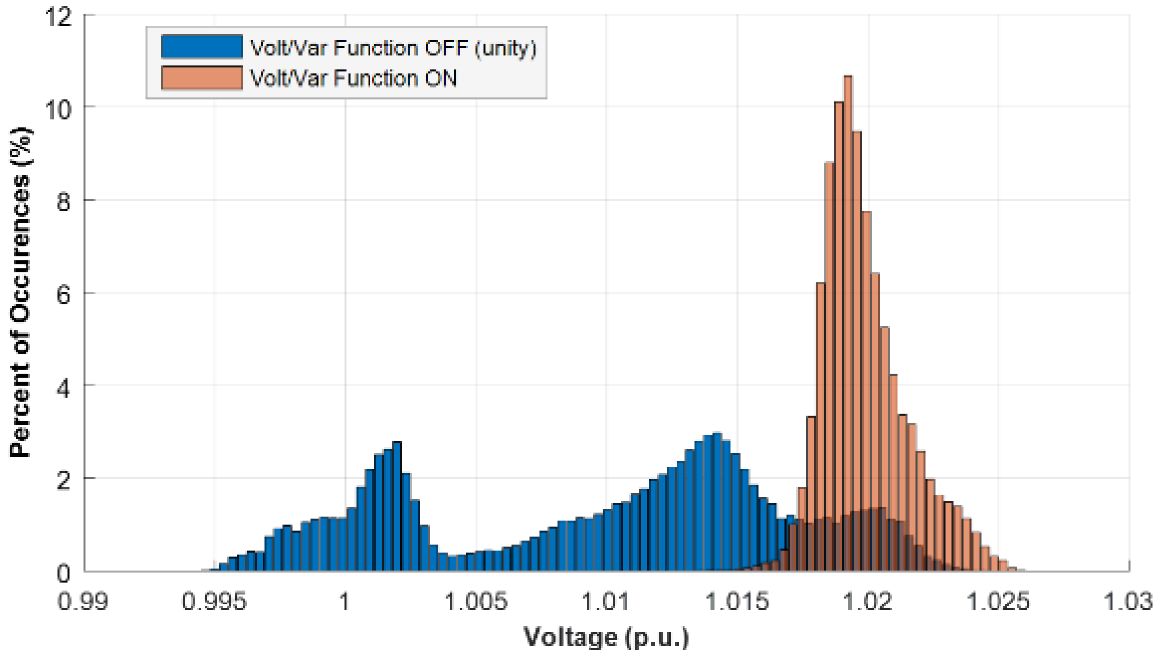


Figure 6-32
Typical Histogram of Voltage at the E1 PV Plant

Test Phase 3 – Autonomous Volt-VAR Control, Cycled 10 minutes On/Off

This test phase used the same Volt-VAR settings as Phase 2, but with the function toggled on for 10 minutes then off for 10 minutes throughout a three day test period.

Figure 6-33 shows the reactive power output of each inverter cycling between normal unity power factor mode and Volt-VAR mode, 10 minutes on, 10 minutes off. Here, it can be seen that during the “Off” periods, the offset Var levels of the two inverters have opposite polarity, causing the total for the plant to be close to zero as noted previously.

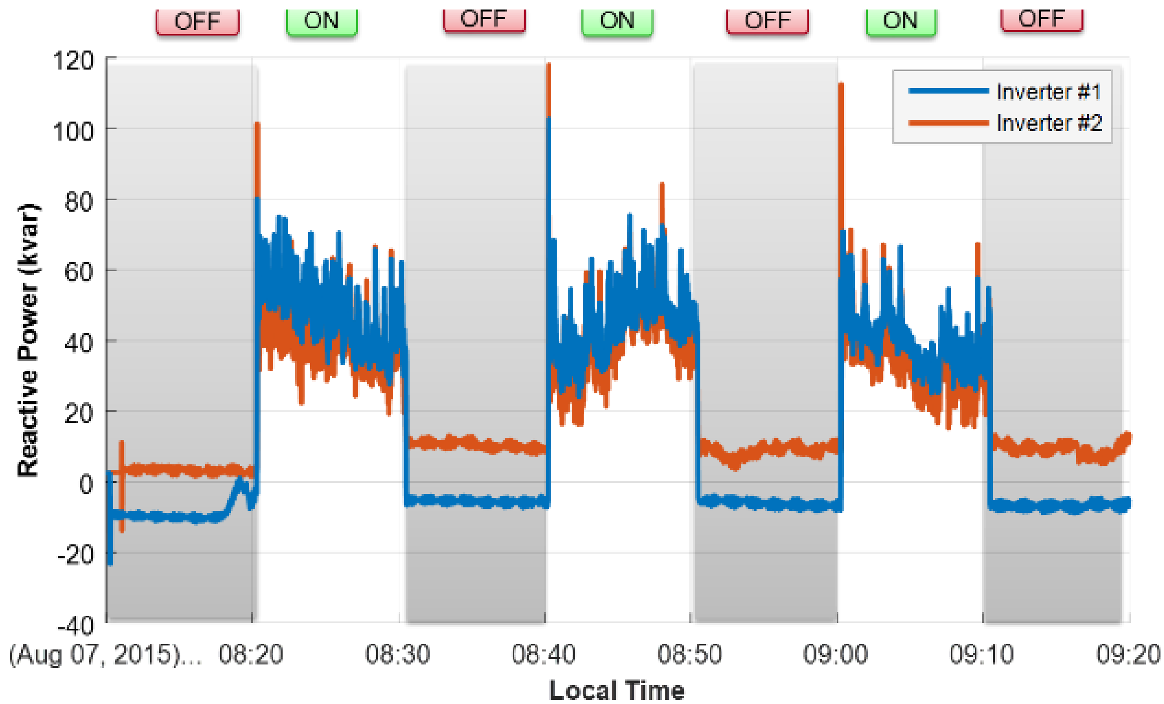


Figure 6-33
Volt-VAR Control Mode, 10 minutes Cycling On/Off

During the "On" periods, the reactive power output is much more variable than during the "Off" period. This is as expected because when the Volt-VAR function is on, the inverters are reacting to the AC voltage at their output.

Also visible in Figure 6-33 is that the inverter exhibited an overshoot in Var output when the function was first activated. This was also observed at the H1 test site and can be seen in the On/Off graphs in the previous section. Figure 6-34 shows the turn-on characteristic in more detail. During these tests, the ramp-time setting was set to 1-second, minimized so as to simplify the data analysis so that there is a full 10 minutes in the on state and a full 10 minutes in the off state. As a result of this aggressive setting, the inverter response pulls back after the voltage responds to provided Vars. In practice, it is suggested that function ramp-times would be significantly longer than the voltage measurement settling times and such overshoots would not occur.

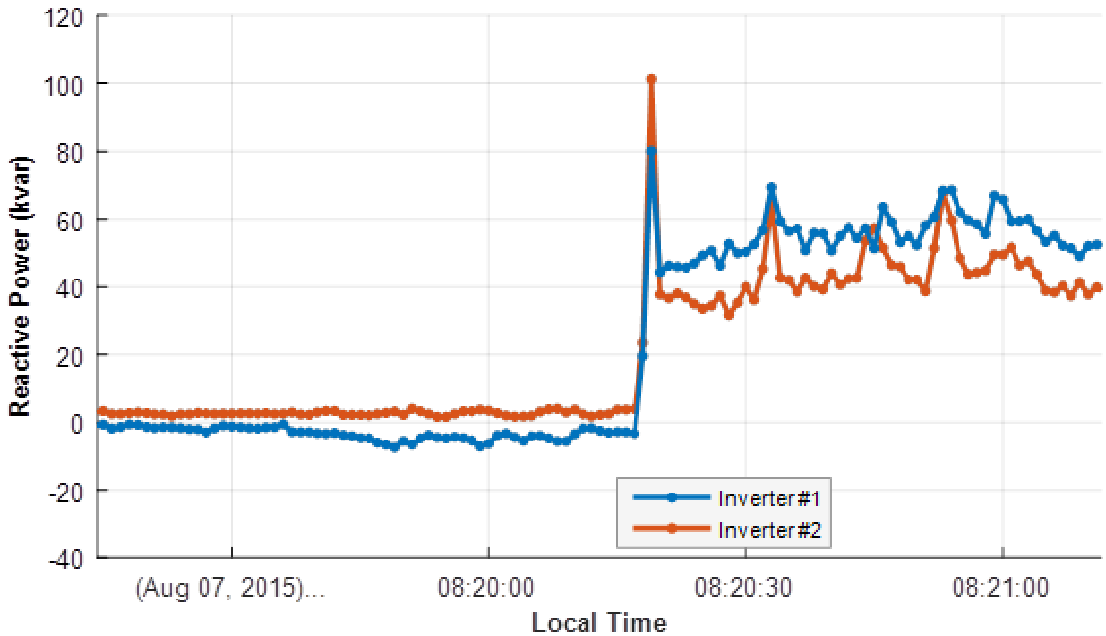


Figure 6-34
Volt-VAR Function Turn-On Characteristic

Figure 6-35 shows the impact of the Volt-VAR function on the voltage at the PV plant. The time window here is the same as that shown in Figure 6-33. Here, it can be seen that the Volt-VAR function actually reduced the voltage variability whereas in Figure 6-33 it might (incorrectly) appear that voltage variability is made worse. During the period shown here, the voltage level at the PV plant increased by about 0.5 to 1.0% when the Volt-VAR function was on.

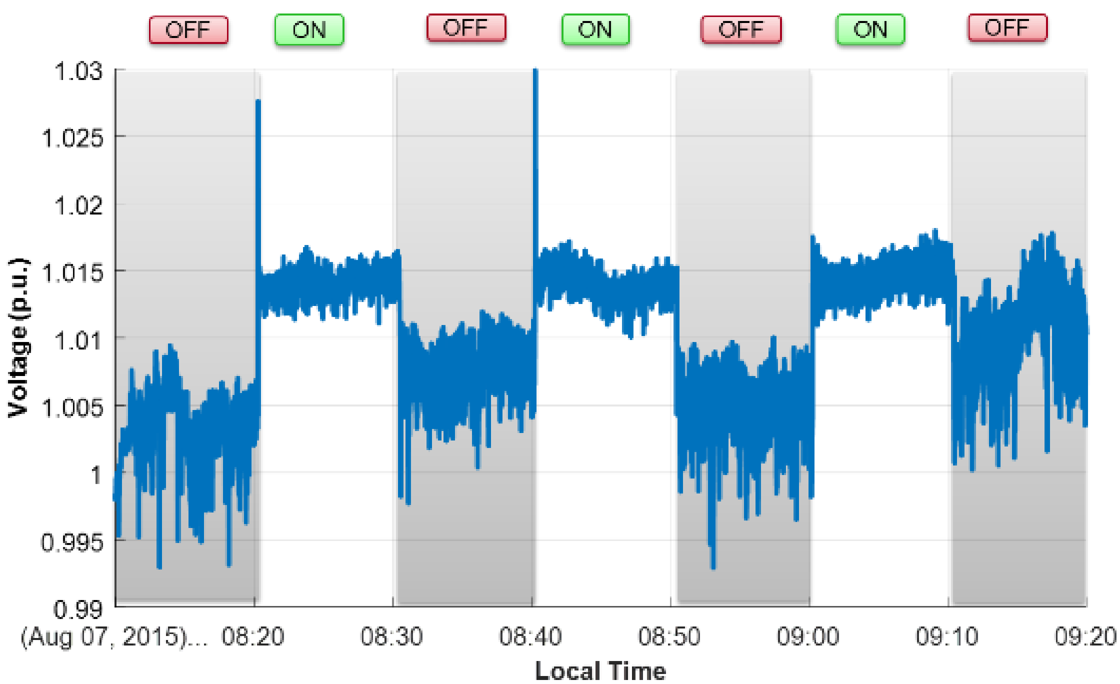


Figure 6-35
Impact of Volt-VAR Mode on Voltage at the E1 PV Plant

Figure 6-36 provides a view of the voltage impact at other points on the E1 feeder. This chart compares 1-minute average (of the three-phase average) voltage measurements at each monitoring point. The horizontal axis identifies the distance from the substation of each monitoring station. The vertical axis and box-and-whiskers plots identify the range of 1-minute average voltages at each site.

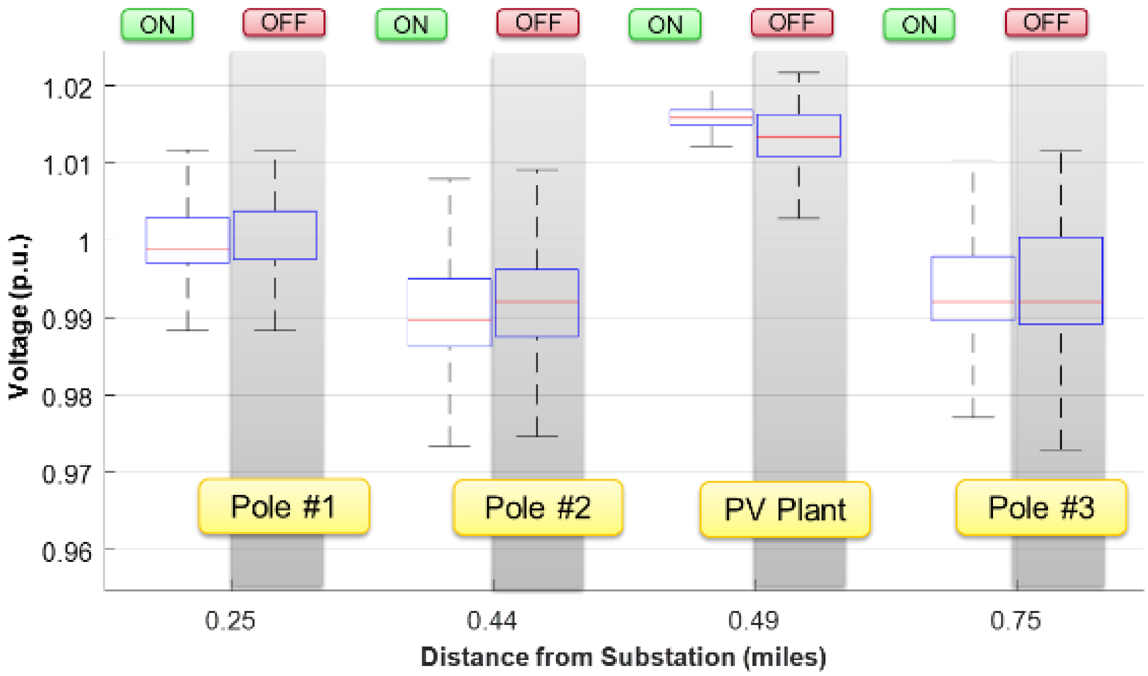


Figure 6-36
Volt-VAR Impacts at Monitoring Points on the E1 Feeder

This data for the E1 site is taken from the same day with 10-minute On/Off cycling of the Volt-VAR function.

Figure 6-37 provides a cumulative duration curve of the voltages at each monitoring point on the E1 feeder. Plotted in this way, the steepness of a given curve is related to how narrow the distribution of voltages at that monitoring point and how tightly the set of curves is grouped (left to right) is related to the flatness of the voltage profile along the feeder.

On this feeder, the yellow curve (PV plant) is most impacted, shifting toward the right (toward the center of the Volt-VAR curve at 1.02% and becoming steeper when the function is on.

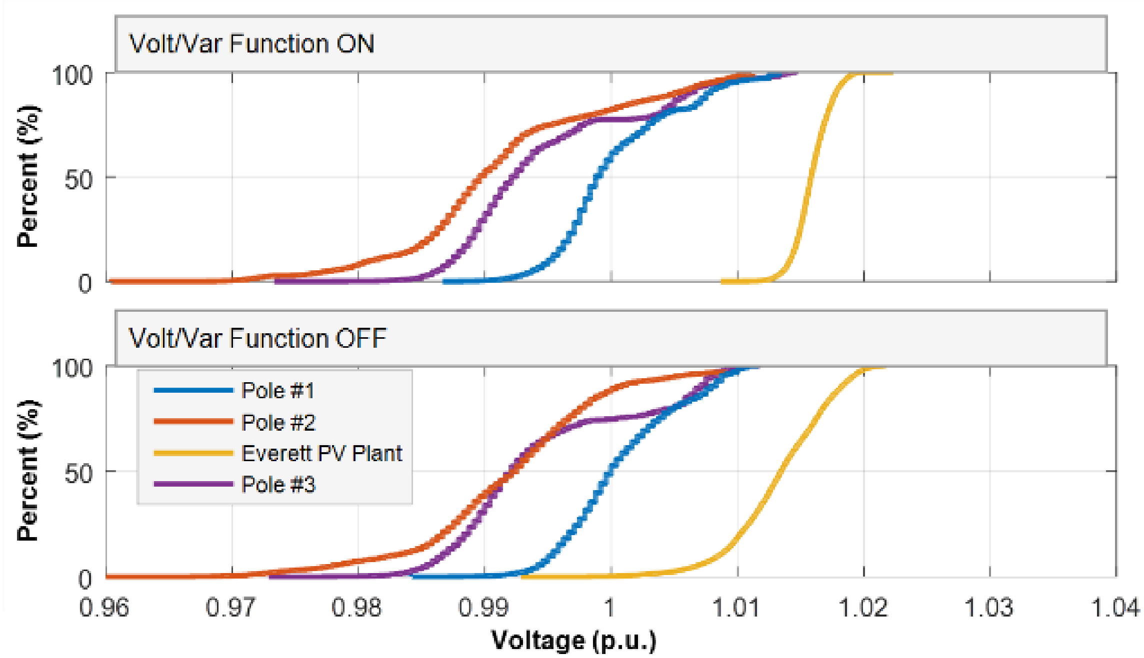


Figure 6-37
Typical Duration Curve of Voltages at E1

Test Phase 4 – Remotely Managed Volt-VAR Control

The original project plan for the E1 test site included the remotely-managed volt-VAR control scenario that was carried out at the H1 site and described previously. This scenario operated the PV plant to achieve higher-level goals, specifically holding the power factor at unity at the substation. This demonstration requires metering of real and reactive power at the substation.

Unfortunately, this test was not carried through at the E1 site because the substation metering could not be deployed. A challenge of all projects of this kind is that they move beyond research and development groups and ask for action from operations whose first priority is meeting customer needs. In this particular case, access to the substation was limited due to a number of operational policies and access restrictions. As noted, monitoring systems were successfully installed at several locations along the feeder, but not at the substation.

Test Phase 5- Dynamic Reactive Current

During this phase of testing, the Dynamic Reactive Current (DRC) function was utilized with the slope settings indicated in Figure 6-38. The horizontal axis in this figure is not related to the absolute voltage value, but to the recent change in voltage, as defined by “Delta Voltage” in Figure 6-39. A voltage averaging time (FilterTms) of 300 seconds (5 minutes) was used. The purpose of this test was to understand the benefits that might be gained from a dynamic function versus rather than a static volt-VAR function. The goal in this test phase was to provide stabilization and reduce voltage variability.

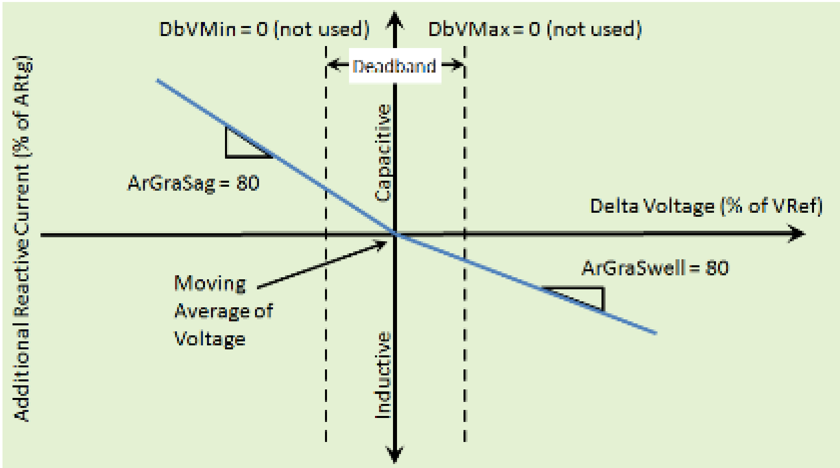


Figure 6-38
Dynamic Reactive Current Settings

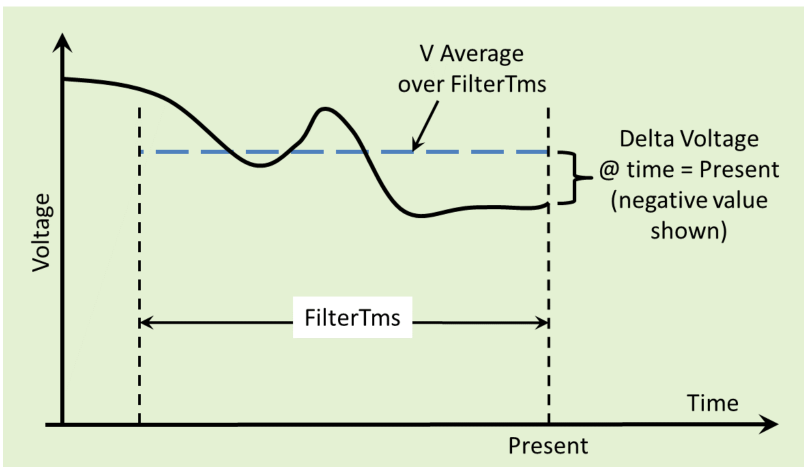


Figure 6-39
Definition of "Delta Voltage"

With an averaging time of 5 minutes, this function acts to resist voltage changes that are faster than 5 minutes, but does nothing to resist gradual rise and fall in voltage that is slower than 5 minutes. The E1 test site, being heavily industrial, was deemed a good location for evaluating the inverter's ability to react-to fast voltage variations.

The project schedule only allowed for one day of DRC testing. This was performed on December 1st, 2015, a Tuesday, from 10AM till 2:30PM. This test day was selected with low solar output due to overcast conditions so that the PV plant real-power impact on voltage was reduced/minimized. A like-day was observed on November 12th, a Thursday.

Figure 6-40 provides a comparison of the voltage measured at the PV plant on the two days, during the same time periods. Both traces are 1-second average voltage. It is evident that with the DRC function on, the fast variability of voltage is reduced (orange trace). Also notable is that as expected the slower rise and fall of voltage throughout the day is of comparable scale.

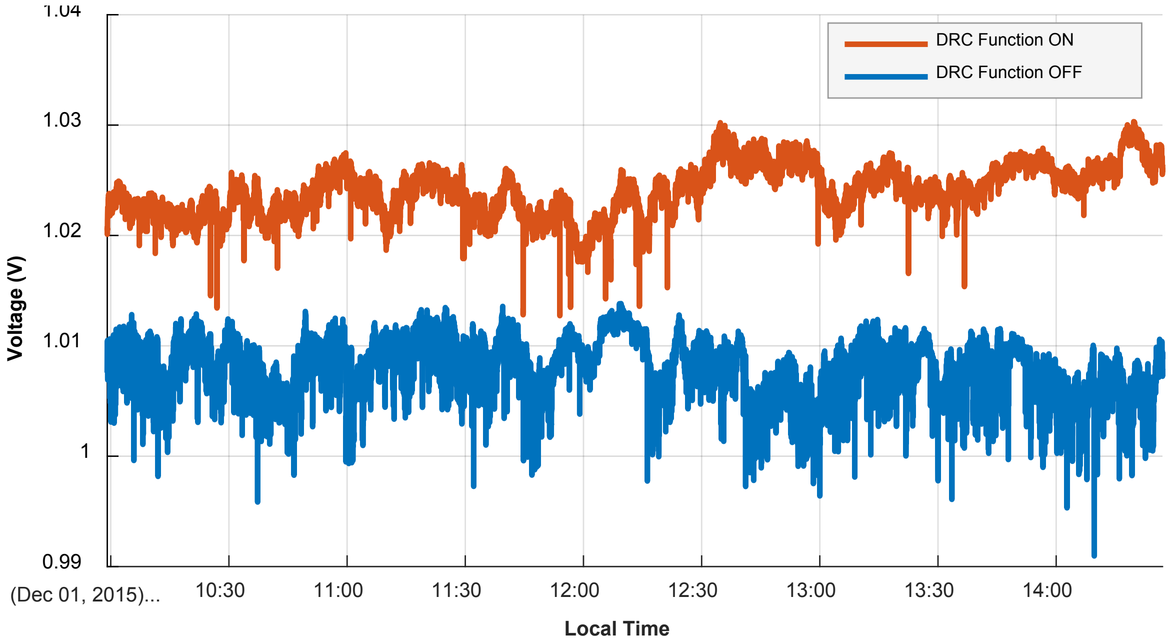


Figure 6-40
Dynamic Reactive Current Impact on Voltage

Fast Fourier transforms were calculated for the two voltage waveforms in Figure 6-40 and the results are provided in Figure 6-41. These charts show the frequency range from .003Hz (5 minute period) to 0.5Hz (2 second period). According to the DRC settings selected, the function is not intended to be effective below .003Hz. Below this frequency, the voltage variations are slow and the present voltage does not differ from the trailing 5 minute average very significantly.

The DRC function is theoretically not bounded on the right hand side, and the speed with which the dynamic Vars respond to voltage variations is limited only by the inverters' voltage measurement speed and reactive power control loop. The test data, however, was limited to 1 second intervals and so could not represent any improvements that might have occurred above 0.5Hz).

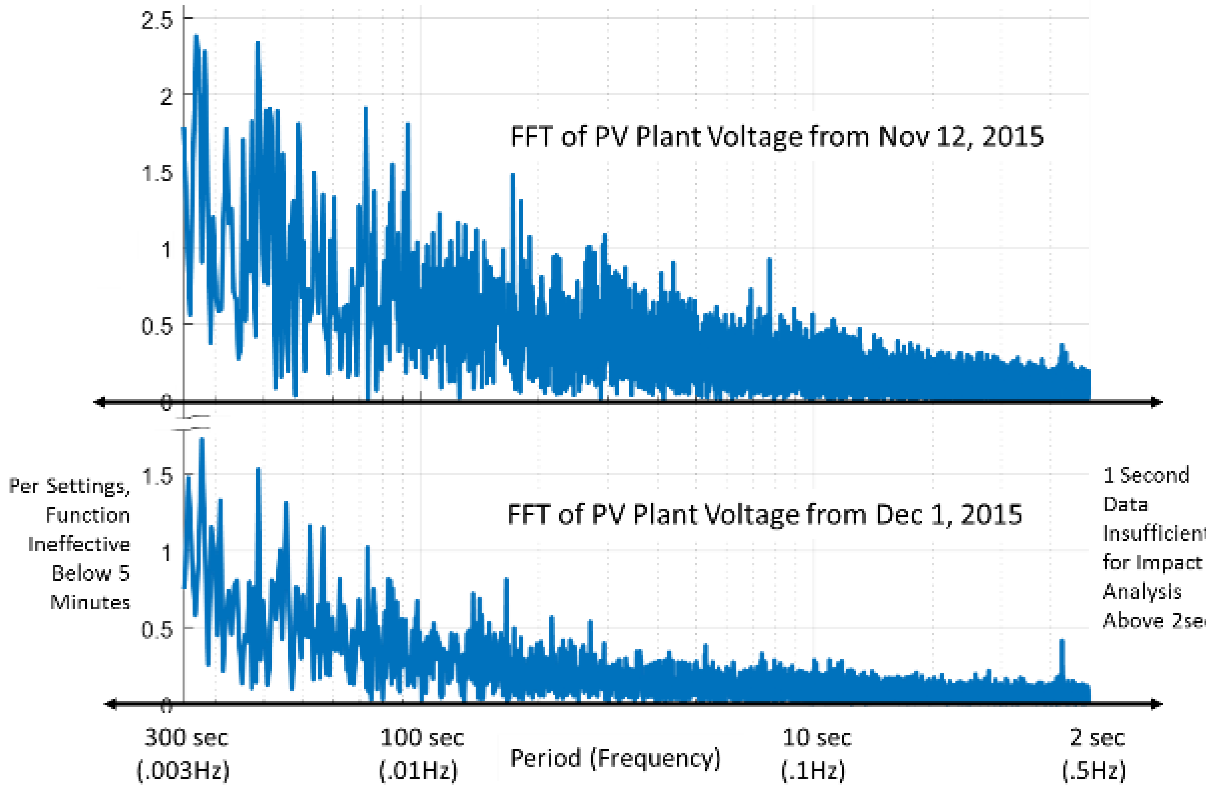


Figure 6-41
FFT of Voltage with and without DRC

FFTs were also calculated for the plant reactive power during the same two periods and is provided in Figure 6-42.

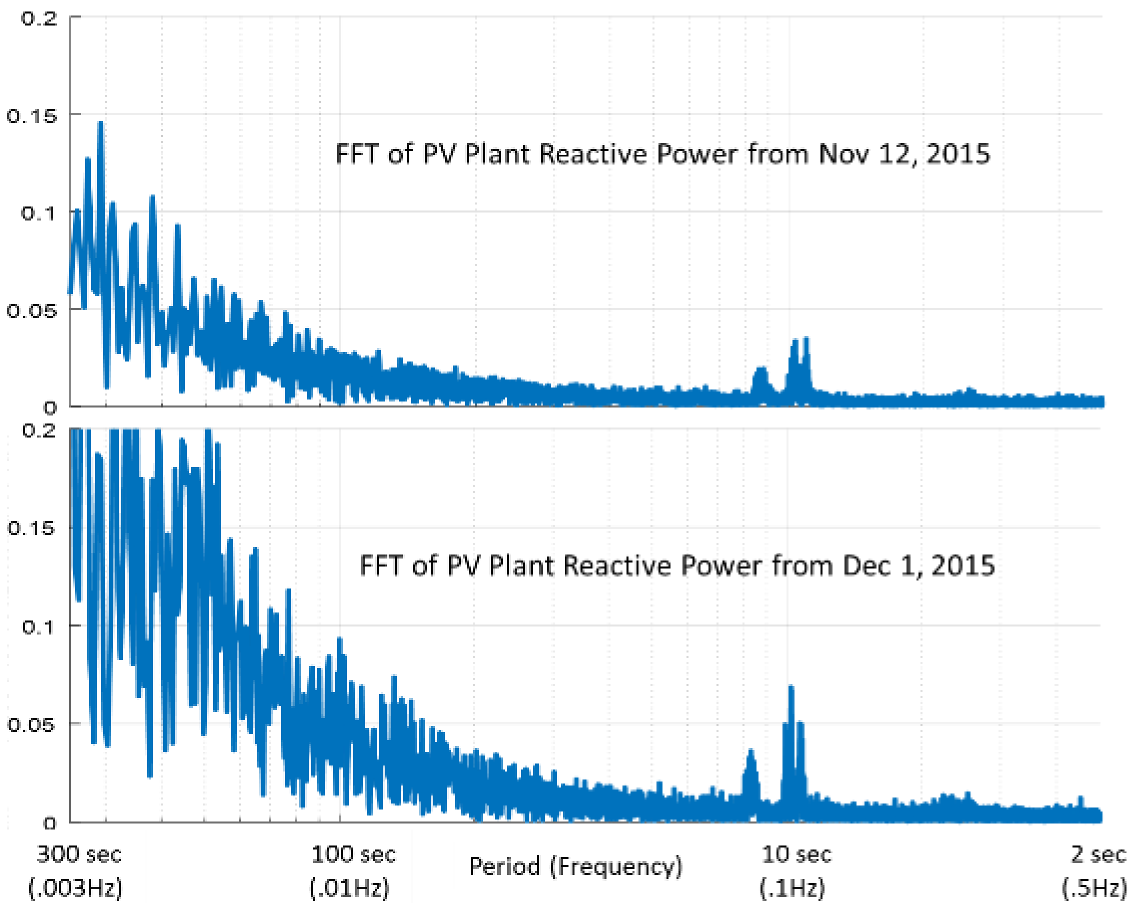


Figure 6-42
FFT of Reactive Power with and without DRC

The Fourier transform provides a spectral look at the action of the DRC function, allowing assessment of its impact on voltage variability at any given frequency in the effective spectrum of the function. This view, and the primary motive for this analysis, also allows one to look for any oscillatory tendencies that might exist at a given frequency. No such tendencies were evident in the collected data set. It can be seen in the reactive power spectrums that there were peaks around periods of 10 and 25 seconds for which there is no notable voltage cause. This, however, is present both with and without the DRC function active, so is not created by this function. The cause is unknown and could be related to periodic industrial loads on the feeder, a characteristic behavior of the inverter, or other causes. As will all the functions evaluated in this project, more testing is prudent for additional sites, other inverter designs, and various DRC settings, including filter different times and different curve lopes.

To quantify the impact of the particular DRC settings used in this test, the voltage waveforms of Figure 6-40 were used to calculate variability. For this calculation, and to focus on the DRC function, the one second data was used, but variations with periods longer than 300 seconds were removed. In other words, an ideal high-pass filter was applied to the two voltage waveforms so as to retain the fast (<300sec periods) voltage variations but remove the slow rise and fall in voltage that can be seen throughout the test periods.

The variability was calculated as: Sum|(V_n – V_{n-1}| for each of the two series. The result with DRC on was 56% of that with DRC off.

It is notable that EPRI computer modeling has shown that this function adds significant benefits when used in conjunction with the Volt-VAR function. This combination was not evaluated in this project.

DTE F1Testing

This test plan was designed to span a four month period, including the following test phases:

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

Test Phase 1 - Baseline Data

As with other test sites, prior to beginning the smart PV inverter testing, baseline data was collected over many days from the sensors on the F1 feeder and PV plant. Figure 6-43 provides an example clear day of output by the F1 PV plant operating in normal, unity power factor mode. This plant is smaller scale than those tested at the H1 and E1 sites, with a 300kVA inverter and 224kW of panels. As can be seen in the figure, real power output peaked at 180kW on this test day.

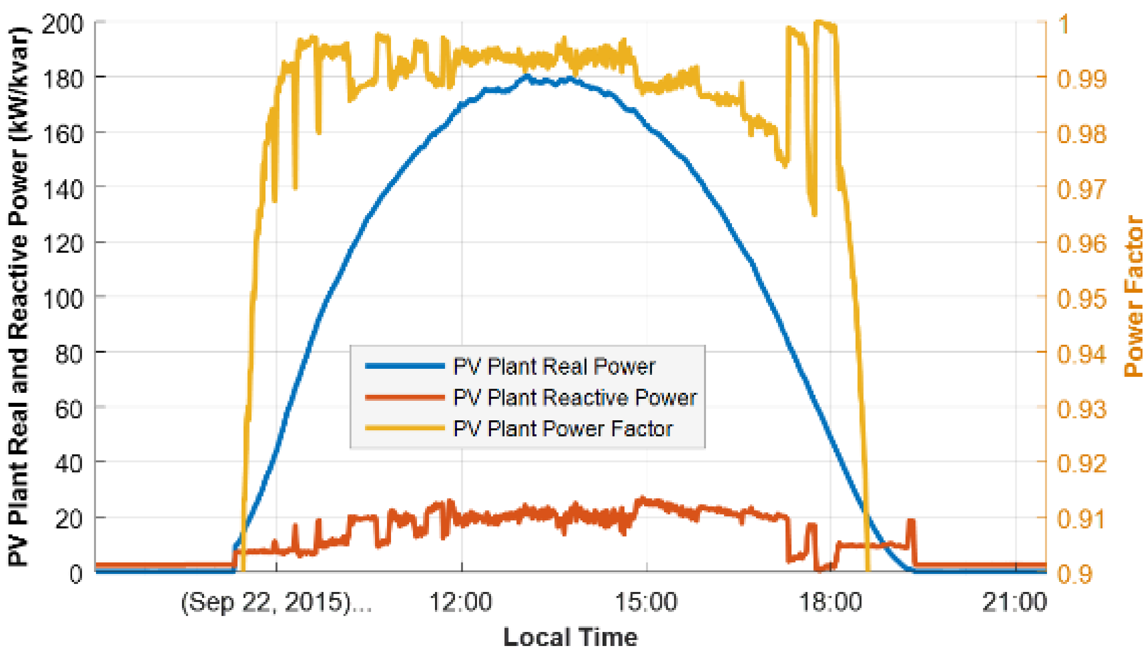


Figure 6-43
Example Baseline Day for the F1 PV Plant

It is observed that the reactive power is non-zero, peaking around 20kVars at midday even though this is a normal/unity power factor baseline. As a result, the power factor remains above 0.98 for most of the day. This % level of error is consistent with that observed at the other test sites and can be seen in the remainder of the test data from the F1 site. The unintentional Vars at the F1 site exhibit notable step changes that were not seen at other sites. The cause of these step changes is not known.

Figure 6-44 shows data from the same day as Figure 6-43, but measured at the substation. A notable characteristic of this feeder and day is that it has a 600kVar capacitor bank that is switched on in the morning and off in the evening. This can be seen most directly in the red line which is the total reactive power measurement. At around 7:30AM, a step down of 600kVars can be seen and at around midnight a step back up of the same amount. The impact is also seen in the power factor plot shown in the yellow line. At around 11AM, there is a notable increase in load on the feeder (~500kW), lasting until around 3:30PM.

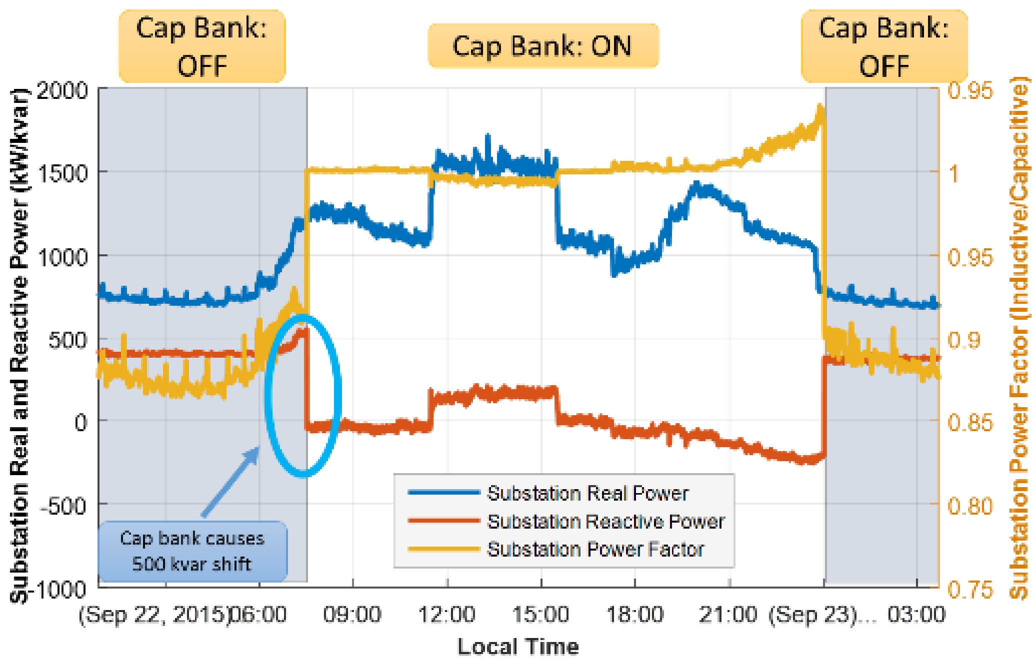


Figure 6-44
Example Baseline Day for the F1 Feeder

Test Phase 2 – Remote PF Control to Manage PF at the Substation

During this test, the inverter's power factor was remotely managed so as to help manage the power factor at the substation. As indicated in Figure 6-45, this test was conducted on two consecutive business days, the first with the capacitor bank on and the second with the capacitor bank off. As is evident in the figure, the first of these days experienced variable cloudiness and the second was clear.

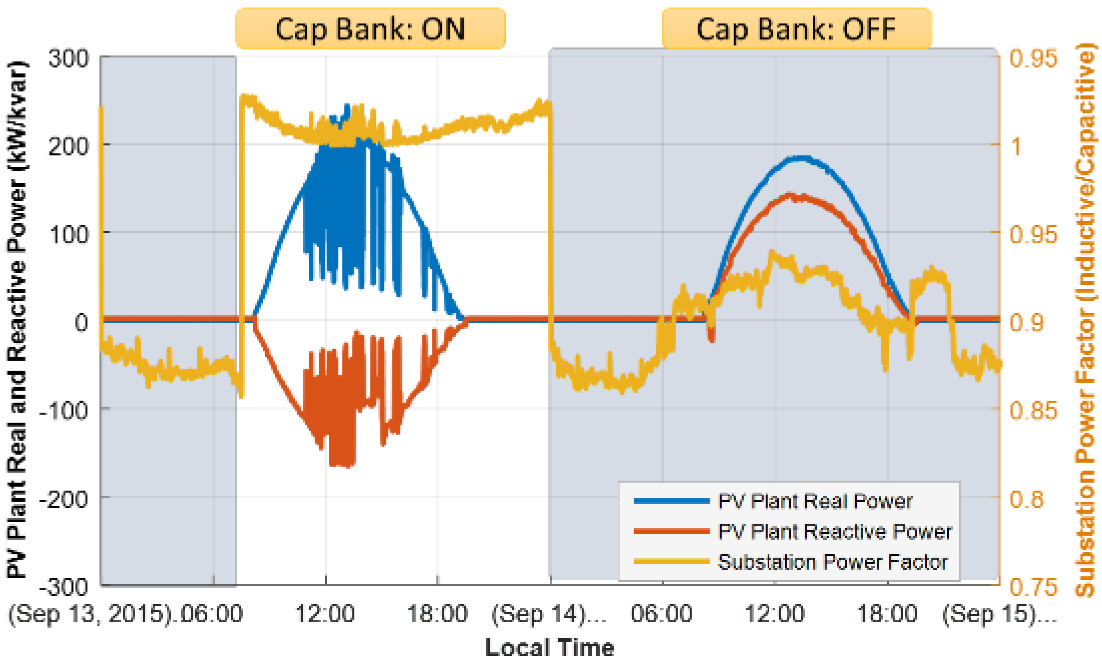


Figure 6-45
Remotely Managed PF Control at the F1 PV Plant

Several things can be noted in these results:

1. The PV plant's reactive power level (red trace) moves in proportion to the plant's real power level (blue trace) as defined by a power factor function.
2. During the first test day, with the capacitor on, the power factor was positive (slightly excessive capacitance on the feeder), so the control system operated the inverter to produce inductive Vars.
3. During the second test day, with the capacitor off, the power factor was negative (insufficient capacitance on the feeder), so the control system operated the inverter to produce capacitive Vars.
4. During the second day, the inverter was operated all day at a PF so as to produce as many capacitive Vars as possible, but was not sufficient to bring the power factor at the substation (yellow trace) to unity.
5. During the first day, there was a period of time when power factor at the substation successfully reached unity, and in response the control system reduced the power factor of the inverter. This is shown in greater detail in the zoomed-in view in Figure 6-46.

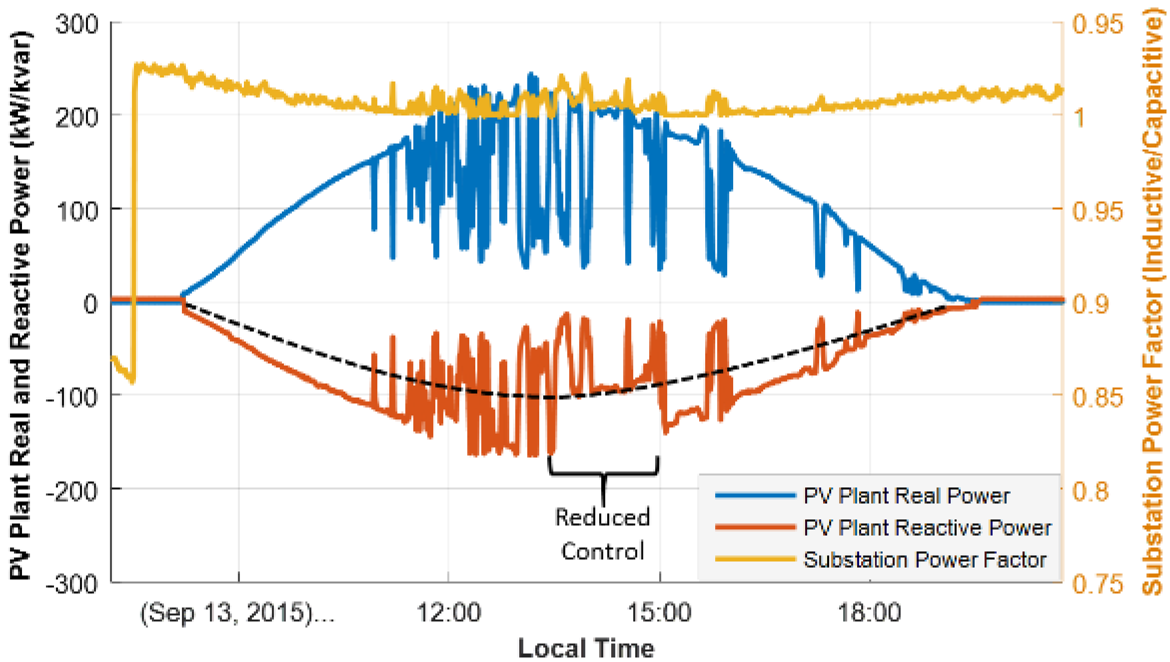


Figure 6-46
Remote PF Control

6. Inverter PF control mode is not an effective means of managing PF at the substation because the reactive power output varies with solar irradiance. This can be seen in the side-by-side comparison shown in Figure 6-47. The chart on the left is the second day of inverter remote Power Factor Control testing at the F1 site described above. The chart on the right is a day of remote Volt-VAR Control testing at the H1 site described in a previous section. In the Volt-VAR control case, the reactive power output steps immediately to a high value upon launch of the control function. In the PF case, although a high level of reactive power is needed immediately upon turn-on, the plant Var output rises slowly with the real power production.

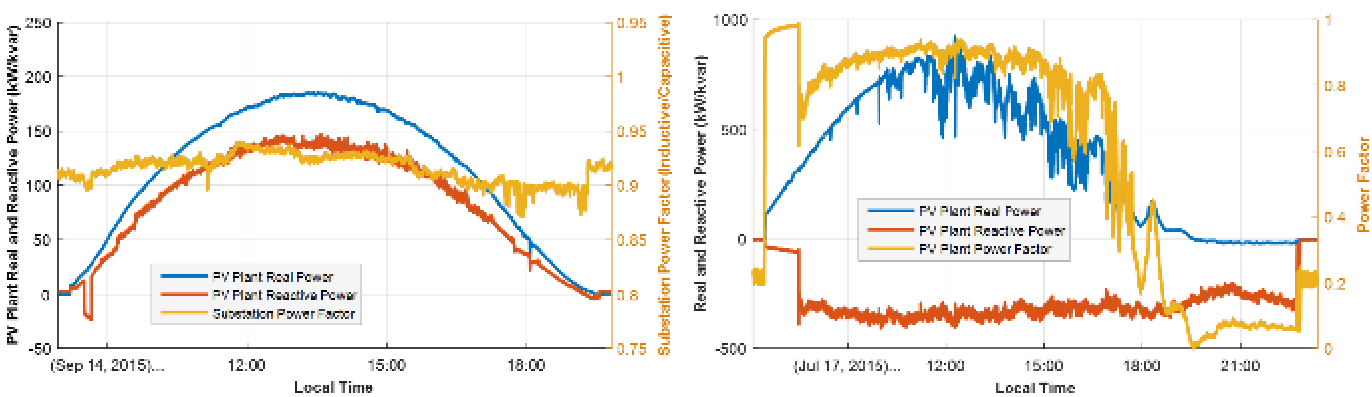


Figure 6-47
Comparison of PF Control and Volt-VAR Control for Substation PF Use Case

Test Phase 3 - Autonomous Volt-VAR Control with Maximum Capacitance Settings, Cycled Operation

This phase of testing utilized the Autonomous Volt-VAR function. But unlike the tests conducted at the H1 and E1 sites, this test used the Volt-VAR configuration illustrated in Figure 6-48.

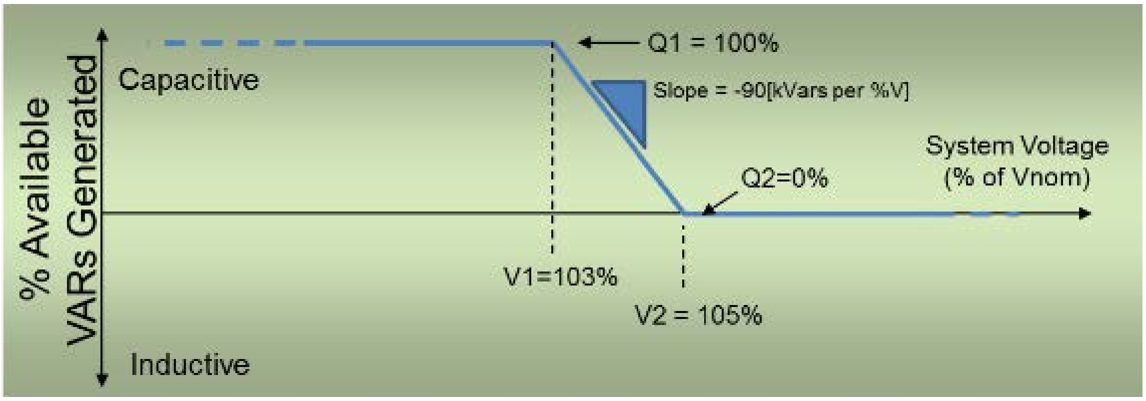


Figure 6-48
Maximum Capacitive Support Volt-VAR Settings

These settings provide a maximum capacitive Var behavior, in which the inverter's Var output is held at the maximum available level (still giving Watts precedence) up until the local voltage is too high. Between 103 and 105% Vnominal, the Var output is linearly reduced to zero.

This function was toggled 15 minutes on/off throughout the testing. Figure 6-49 and Figure 6-50 provides scatterplots of 1 second voltage and reactive power measurements taken at the F1 site, each over a continuous three hour test period. The points in Figure 6-49 are from a period when the capacitor bank was on and those in Figure 6-50are from a period when the capacitor bank was off.

In both cases, the points were along the sloping section of the Volt-VAR curve, where the reactive power produces by the PV plant is being limited because the local voltage is becoming too high. The measured points (blue dots) lie along a linear distribution and trend as indicated by the red line. This trend line shows a horizontal shift from the configuration equating to a fixed voltage measurement error of approximately 0.6%.

During each of these two periods, the voltage at the PV plant varied over a range of approximately 0.75%. As expected, when the capacitor bank was on (Figure 6-49) the voltages were slightly higher at the PV plant than when the capacitor bank was off (Figure 6-50).

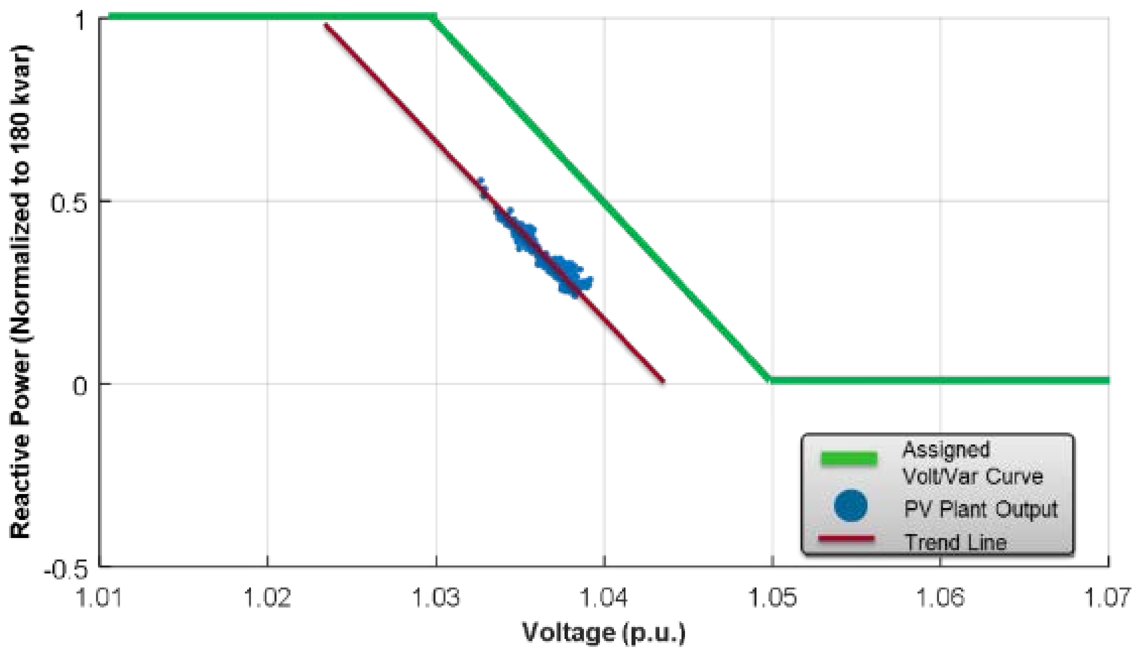


Figure 6-49
Volt-VAR Curve Settings and Data from the F1 Test Site, Capacitor Bank On

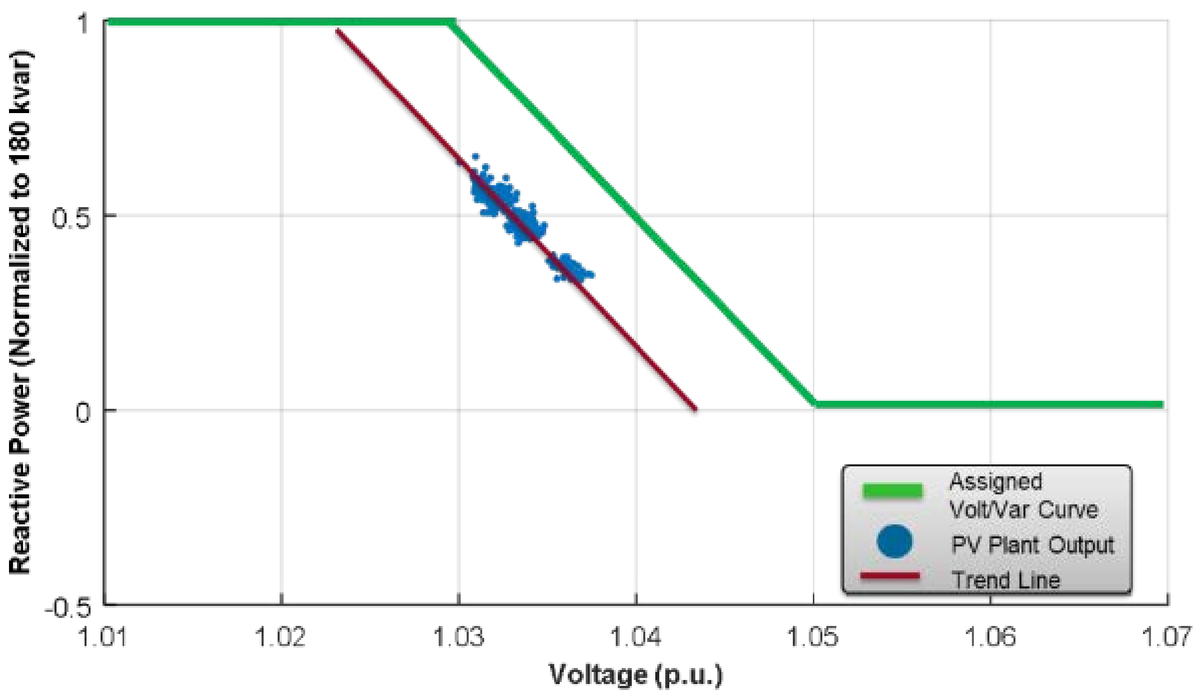


Figure 6-50
Volt-VAR Curve Settings and Data from the F1 Test Site, Capacitor Bank Off

Figure 6-51 shows a time plot of several monitored parameters at the PV plant for a single day of cycled Volt-VAR control.

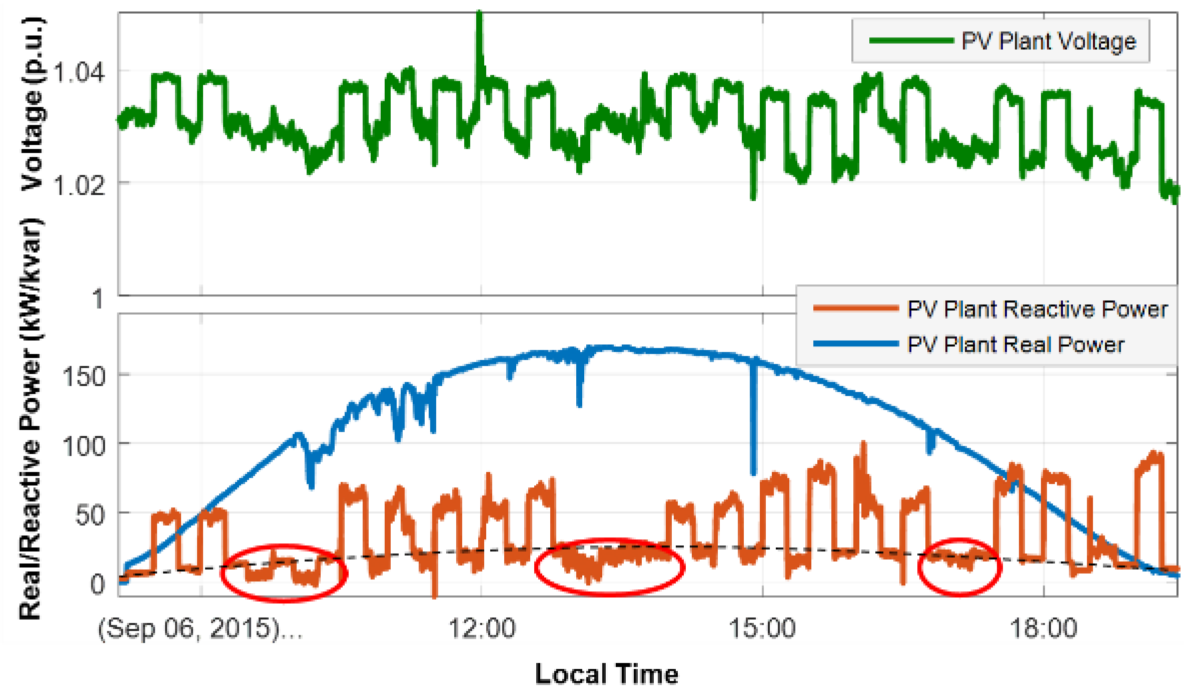


Figure 6-51
Cycled Volt-VAR Testing at the F1 PV Site

The top frame of this figure shows the three-phase average voltage at the PV plant. The bottom frame shows the real (blue trace) and reactive (red trace) power generated by the PV plant. As indicated by the real power output, this test day was mostly clear.

Several observations can be made from this data.

1. The cycling on/off of the inverter's Volt-VAR function has a notable impact on the voltage at the PV plant, with approximately 50kVars resulting in approximately 1% voltage shift. The capacitive Vars generated raise the voltage.
2. The voltage at the plant is naturally high, fluctuating in the 1.02 p.u. to 1.04 p.u. range over the test day.
3. Although the plant is capable of generating 180KVars, it does not generate more than 75KVars during this test day because the range of voltages that occurred are on the portion of the Volt-VAR curve that is sloping toward zero (see Figure 6-48). This is the core goal of this test – showing that the plant can do what capacitors can't in that it can variably generate Vars, constraining itself so as not to push the local voltage too high.
4. During the 15-minute periods when the Volt-VAR function is off, the reactive power is non-zero. As indicated by the black dashed trend line, it returns to an arched error level that peaks around 20KVars – consistent with what was observed in the baseline testing and shown in Figure 6-43.

5. There were three periods of time during the test day, identified with red ovals, during which the Volt-VAR function was not successfully activated. This was caused by configuration errors and the pseudo-manual control process used to carry out the testing. It can be seen, particularly in the red oval to the left, that some form of Volt-VAR activations were actually received by the inverter, but resulting in negative shifts rather than the desired capacitive support.
6. As illustrated in the expanded view of Figure 6-52, the reactive power generated by the inverter increases when the voltage at the site decreases. The relationship is 30kVars per -03%V, or -90[kVars per %V], matching the configured slope of the Volt-VAR curve in this voltage range as identified in Figure 6-48.

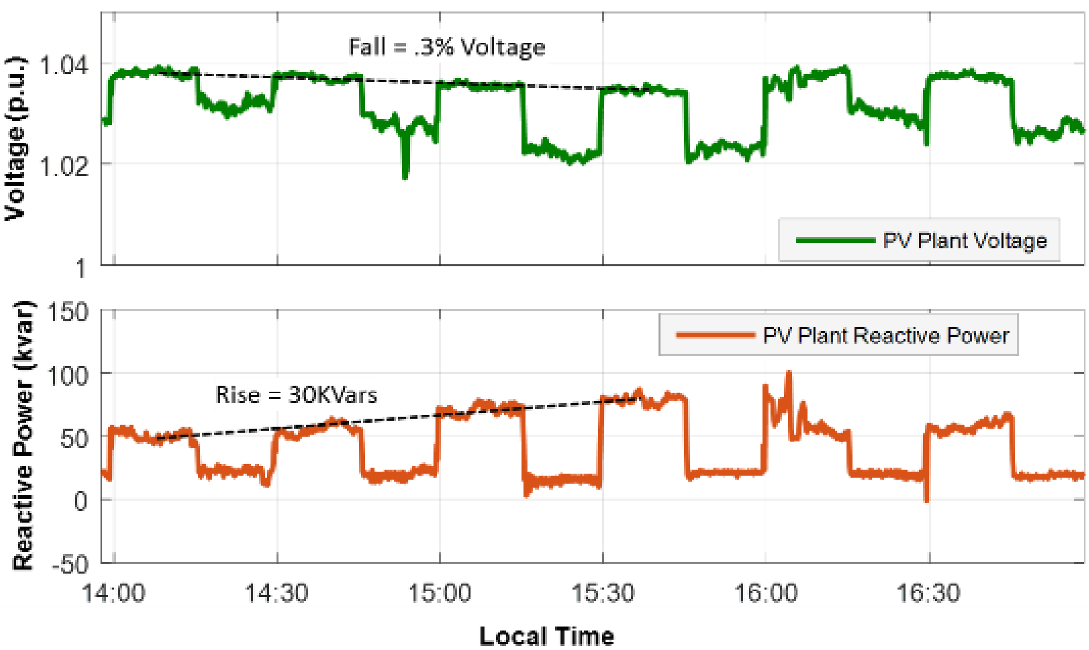


Figure 6-52
Cycled Volt-VAR Control at F1, Expanded View

Figure 6-53 shows the voltage duration curves for monitored points throughout the F1 feeder during cycled Volt-VAR control testing. The top frame represents times when the Volt-VAR function was active and the bottom frame times when the function was inactive.

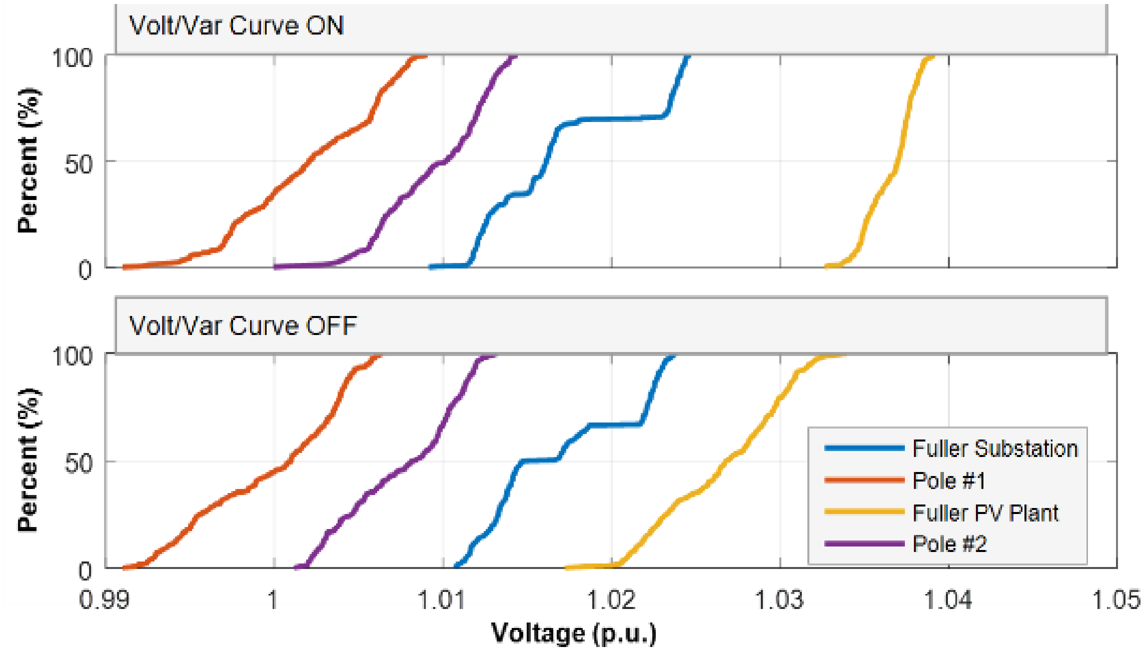


Figure 6-53
Typical Duration Curve of Voltages at F1

Unlike the Volt-VAR testing performed at the H1 and E1 test sites, the Volt-VAR function setting at F1 was capacitive Vars only, tending to raise voltage. This effect can be seen at the PV plant, as shown in the yellow trace. With the Volt-VAR function on, the voltages at the PV plant are higher (shifter to the right) and less variable (steeper curve). No significant impact can be seen in this view at the other monitoring points due largely to the smaller scale of the PV plant at the F1 site.

Figure 6-54 provides an alternative view (box and whiskers) of the voltages and variability throughout the same test day at the F1 site. In this view, the significant voltage shift and tightening at the PV plant is evident. It can also be seen that the voltage is slightly higher at the other monitoring points on the feeder, a positive impact in spite of limited plant size.

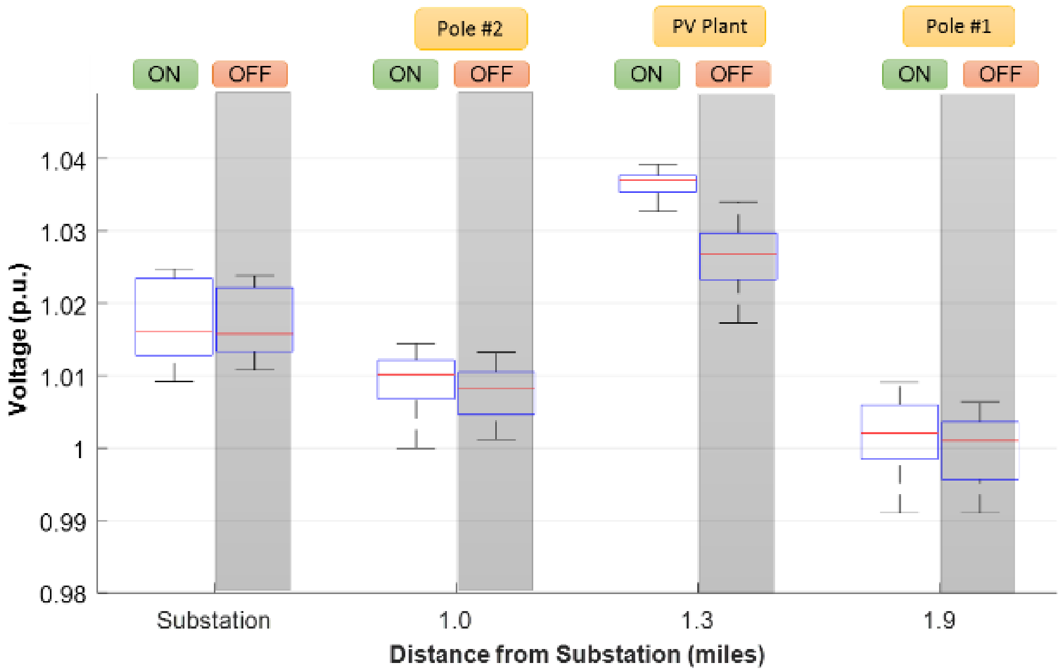


Figure 6-54
Volt-VAR Impacts at Monitoring Points on the F1 Feeder

Figure 6-55 shows a histogram of voltage occurrences at the F1 PV plant site, both with and without the Volt-VAR function operating. This view more than any other shows the impact of the function in terms of reducing voltage variability. This is the result of the site conditions and the Volt-VAR configuration aligning such that the inverter was operating on the slope of the curve (i.e. regulating voltage) during the testing. As with other sites, there was no sign of functional instability or oscillatory behavior at the F1 site.

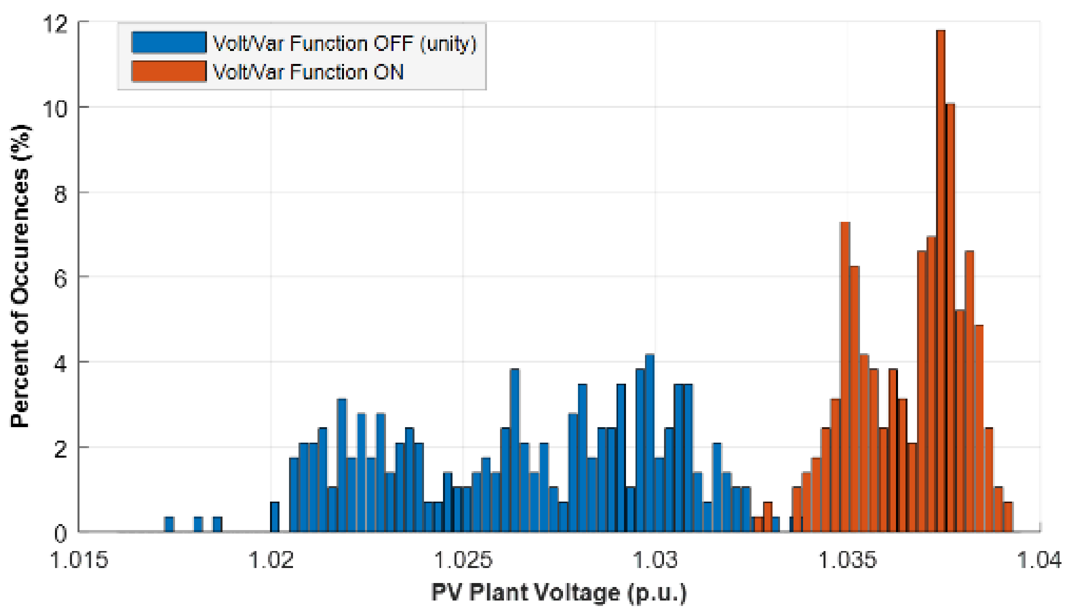


Figure 6-55
Typical Histogram of Voltage at the F1 PV Plant

Low Voltage Ride Through Operation

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.

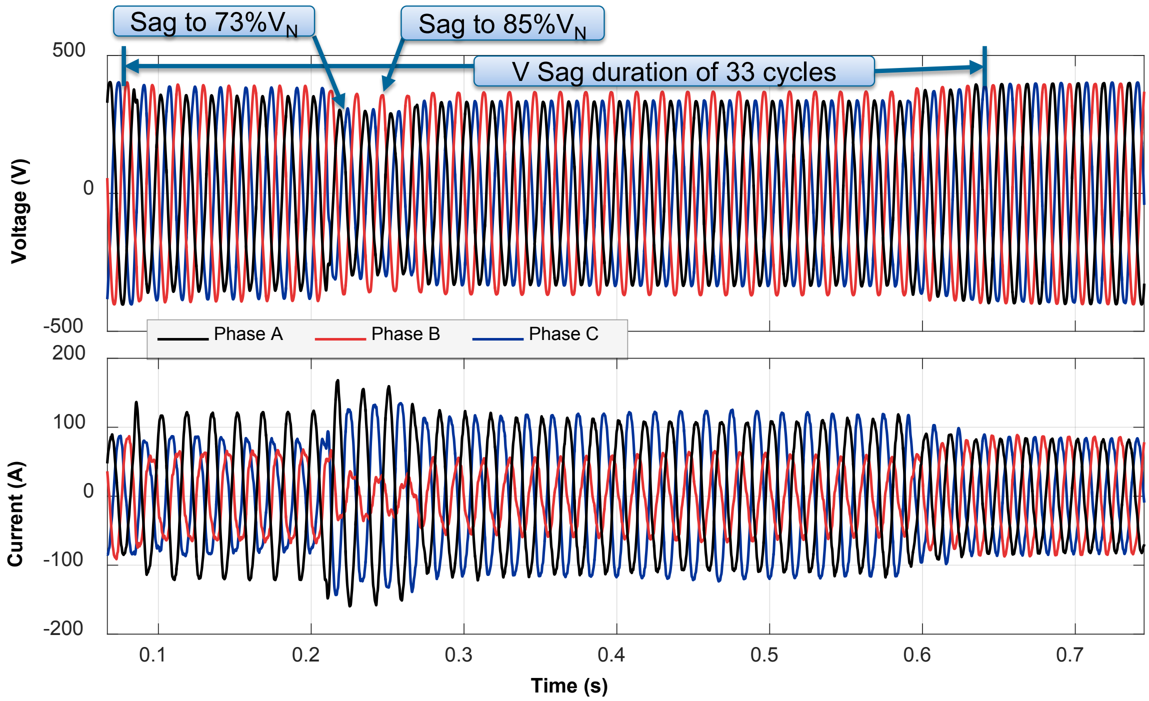


Figure 6-56
Smart Inverter Response to a Voltage Sag Event at F1 Site

Summary

A high level summary of the overall findings from demonstration are included below

- **Voltage measurement accuracy** of inverters may need to improve to be able to perform as expected
- **More grid impact could have been seen if the inverter had visibility into the medium voltage** via a DERMS or otherwise
- **Able to regulate voltage and reduce variability** including flatten the voltage profile along the feeder
- Determined there is significant value in two things:
  - **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.

- Functions require a disable and re-enable command when new curve is sent limiting the ability to update the control algorithm any more than a 1-minute rate
- In practice, it is suggested that function ramp-times would be significantly longer than the voltage measurement settling times and such overshoots would not occur.
- Inverter PF control mode is not an effective means of managing PF at the substation because the reactive power output varies with solar irradiance. However, Volt-VAR control is effective.
- Able to operate in **volt-VAR mode** on very different feeders over the course of several days **without any instability**.

7
LESSONS LEARNED AND CONCLUSIONS

In 2011, EPRI began a four-year effort 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 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 was divided into three phases: development, deployment, and demonstration. Within each phase, the key areas included: head-end communications for 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.

This project demonstration occurred at three sites over 8-months: two sites are located in Great Boston Area of Massachusetts (H1 and E1) and one site is located in Michigan (F1).

Inverter Development, Deployment and Demonstration Lessons Learned

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**.

  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 carried out independently.**

  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 Haverhill, Everett, and Fuller 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 Haverhill 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, come of the issues seen 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.

Technology Gaps and Future Research

As a result of this project, EPRI and the project team identified several gaps in current technology as well as future research needs. Below provides a summary:

- **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 interconnection certification is not enough when need to verify performance of smart inverter functionality.

- **Need wide scale adoption of standards and communication protocols to ensure interoperability**.

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