ELECTRIC POWER RESEARCH INSTITUTE

RECOMMENDED SMART INVERTER SETTINGS FOR GRID SUPPORT AND TEST PLAN

Interim Report

April 2018

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THE SMART INVERTER PERFORMANCE ASSESSMENT IS FOCUSED ON THE DISTRIBUTION SYSTEM.

Introduction

Inverter-based distributed energy resources (DERs) such as photovoltaics (PV) are becoming more commonplace in the distribution system. These resources are also bringing more challenges for the electric distribution service provider. These planning and operational challenges range from leveraging system benefits provided by a DER as well as coping with the adverse impacts to power quality and reliability that a DER might cause.

To meet these challenges, utilities have begun utilizing inverters that have advanced functions that are deemed "smart" compared to traditional inverters. With appropriate functionality and settings, these smart inverters have positive attributes that have been validated through modeling/simulation and laboratory assessments. However, due to the complexities of testing inverters in the real-world, the benefits have yet to be fully demonstrated in the field.

In 2017, National Grid and the Electric Power Research Institute (EPRI) initiated a collaborative multi-year research project to select candidate solar PV sites from actual field deployments, calculate smart inverter settings for the selected sites, and then monitor the performance of the PV systems as the sites operate with and without those settings in the field. The overall goals are to 1) determine how well the applied settings work based on field measurements and, when necessary, 2) refine the underlying routine used to develop those settings. Because the project spans multiple years, this interim report focuses on work that was performed in 2017: the identification of candidate feeders and determination of smart inverter settings, and deployment of measurement devices, with a test plan for performance assessment, as shown in Figure 1.

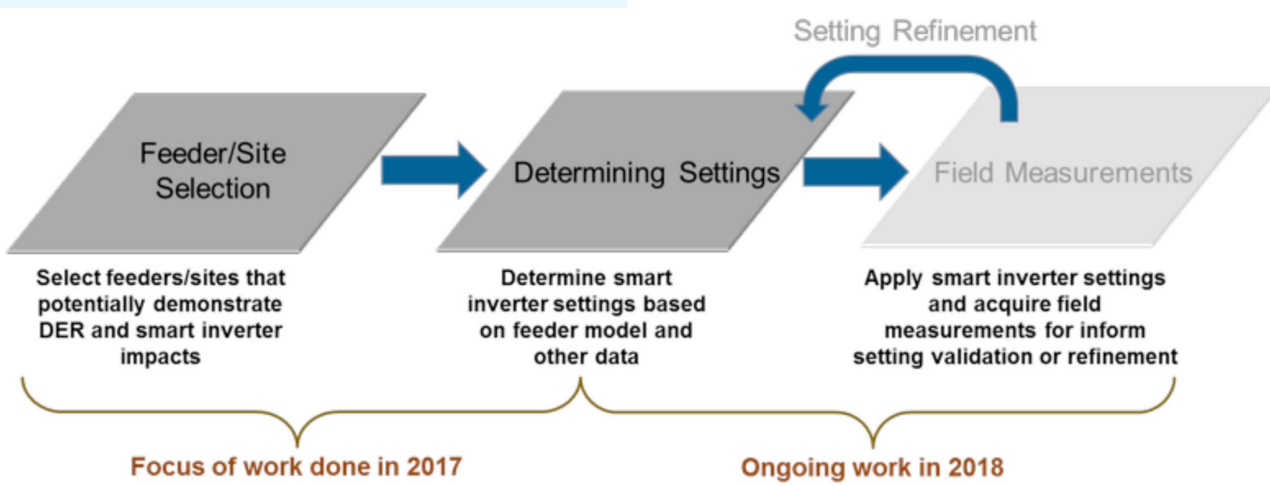


Figure 1 – Project Plan

Objective and Scope of National Grid Solar Phase II Program

Under Massachusetts' Green Communities Act of 2008, National Grid saw a potential to develop a better understanding of DER and the technologies behind it by owning and operating its own solar facilities. National Grid's initiative began with the Solar Phase I Program, which resulted in the development of 5 megawatts of utility-owned solar generation on underutilized and remediated sites.

Through the years, National Grid recognized the needs and desires of its customers to increase the current penetration level of clean distributed generation (DG). The current methods and procedures for commissioning DG sites can be a lengthy process that comes at a significant financial cost. National Grid identified this as a deterrent to the growth of renewable DG and looked for innovative solutions to the problem.

On June 30, 2014, the Massachusetts Department of Public Utilities (DPU) found National Grid's Solar Phase II program to be in the best interest of the public and consistent with Massachusetts' energy policies. Through this program, National Grid is taking a leading approach among utilities nationally, seeking to maximize the operational benefits of and minimize the cost to integrate the fastest-growing type of DG, solar PV. Minimization of PV integration costs is of particular importance to achieve higher penetration of renewable generation. Use of advanced inverters, which typically do not increase the equipment cost, can support the reduction of PV integration costs.

Through the Solar Phase II initiative, National Grid will own and operate an additional 16 megawatts of solar generation. Part of the objectives of the Solar Phase II program is to test the operation and value of smart inverters to gain an understanding of whether the advanced functions that they offer provide the opportunity for higher penetration of solar generation in National Grid's service territory. The successful implementation of this program will help National Grid and the industry to improve its practices to integrate renewable generation into its grid to effectively support the goals of customers, states, and government agencies.

Some of the principles behind National Grid's implementation of this program are based on the following concepts:

- Targeted deployment of solar-generation sites will maximize potential benefits.
- Configuration of individual sites will minimize adverse impacts and improve operational conditions.
- Testing communication and control schemes before solar sites are built will minimize or eliminate significant integration costs.
- Coordination of solar sites will improve system conditions and asset utilization.

To identify the ideal locations for this program, an initial assessment of the loading of all the feeders and transformers in Massachusetts was conducted. The following criteria were used to select feeders and substations for this project:

- Feeders with summer normal capacity above 9 MW and expected to be loaded beyond 90% by 2015 (Capacity Relief candidate).
- Transformer with summer normal capacity above 20 MW and expected to be loaded above 95% on normal conditions or expected to be loaded above 100% under contingency by 2015 (Capacity Relief candidate).
- Feeders with an expected peak load (summer normal) below 4 MW (Advanced Inverter Functionality testing candidate).
- Feeders with high levels (with a nameplate power rating above 5 MW) of PV generation capacity (Advanced Inverter functionality testing candidate). This required the collection of information and correct geographical placement of all the existing and projected solar sites in National Grid's territory.

The identified feeders and sites were then grouped into towns where the request-for-proposal process was targeted. The result was the creation of the 18 advanced PV sites shown in Table 1. Site 18 has energy storage in addition to PV.

Table 1 – National Grid Solar Phase II Site Details

Site Number	Site Name	City/Town	Feeder Number	Rated kW at Unity PF	Max var Capability
1	Kelly 1 Rd.	Sturbridge	413L2	1000 kW	600 kvar
2	Kelly 2 Rd.	Sturbridge	413L2	1000 kW	600 kvar
3	Oxford Rd.	Charlton	406L3	650 kW	650 kvar
4	Blossom 1 Rd.	Fall River	115W52	1000 kW	600 kvar
5	Blossom 1 Rd	Fall River	115W52	1000 kW	600 kvar
6	Groton School Rd.	Ayer	201W1	1000 kW	600 kvar
7	Main St.	Dighton	19W73	1000 kW	600 kvar
8	Boutilier Rd.	Leicester	21W2	650 kW	650 kvar
9	Frank Mossberg Dr.	Attleboro	9L2	650 kW	650 kvar
10	Richardson Ave.	Attleboro	8L3	1000 kW	600 kvar
11	Auburn Rd.	Millbury	26W2	650 kW	650 kvar
12	Groton Rd.	Shirley	227W3	1000 kW	600 kvar
13	Old Upton Rd.	Grafton	304W2	650 kW	650 kvar
14	Groveland St.	Abington	93W4	1000 kW	600 kvar
15	Stafford St.	Leicester	406L1	680 kW	408 kvar
16	Carpenter Hill Rd.	Charlton	413L4	840 kW	504 kvar
17	Paterson Rd North	Shirley	227W3	1000kW	600 kvar
18	Paterson Rd South (PV) Paterson Rd South (Storage)	Shirley	227W3	500 kW 500 kW/1 MWh	300 kvar 300 kvar

Since its inception, National Grid's Solar Phase II initiative has been at the forefront of discussions about the renewables industry. National Grid is one of the first utilities in the United States to implement advanced inverter technologies, taking an innovative approach to maximizing the operational benefits while also transforming the renewables industry by removing existing technical and procedural barriers.

National Grid's "integrate versus interconnect" doctrine is representative of the sustainable, forward-thinking culture of National Grid. Through National Grid's Solar Program Phases I and II, a group of technological advances are explored, which, when combined, can create an advanced PV facility. Included among the explored technologies are:

1. Advanced inverters (often referred to as "smart inverters").
2. Energy-storage systems.
3. Azimuth shifting of PV arrays.
4. Targeted site selection.
5. Closed-loop SCADA and plant-level control.

The vision is for these facilities to be integrated into the distribution system.

Importance of Smart Inverter Grid Support Functions

Among the technologies explored in National Grid's Solar Phase II program, advanced inverters are the focus of this project. With the arising issues caused by DER integration, more and more utilities have recognized the need for inverter technologies to provide grid support. Voltage-related issues are often the most limiting issues regarding integrating higher penetration of DER. In many cases, the

use of inverter controls (advanced functions that support the grid) can be the least cost solution for mitigating those issues. An example of this is shown in Figure 2. Moreover, previous studies[1] have shown that advanced inverter functions can also significantly increase a feeder's remaining hosting capacity.[2]

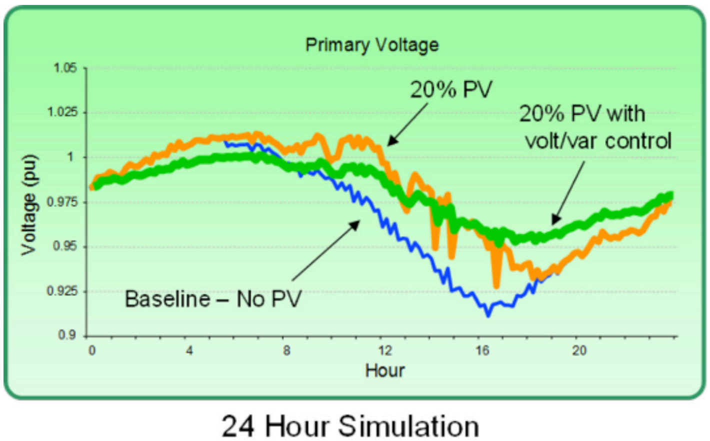


Figure 2 – Simulated Voltage Smoothing with Volt-var Control

A common set of inverter grid support functions has been developed by the industry.[3] Power factor control, volt-var control, and volt-watt control are common grid-support functions targeting voltage-related issues at the distribution level. Among them, power factor control is probably the most well understood and used. Nearly all large three-phase DERs that interconnect to the grid have this function, and vendors for smaller single-phase units have adopted this capability as well. In addition, the IEEE 1547 Working Group has recently voted to allow a DER to provide reactive power control if the local utility allows it.

INVERTER FUNCTIONS EXAMINED IN THIS STUDY INCLUDE VOLT-VAR AND POWER FACTOR.

Challenges of Identifying Functions Settings

While the industry is moving forward with the adoption of advanced inverter functions, determining appropriate settings for these functions is critical to ensure that DERs provide the response that is anticipated. A DER with a power factor close to unity may not be effective at mitigating voltage issues caused by it, while low power factors could exacerbate voltage issues, increase the need for reactive-power resources, and increase power losses. Additionally, power factor settings that work for one DER site may not work for another location, even within the same feeder. A systematic approach is needed to address these issues. Exhaustive simulations of the potential settings could identify the appropriate power factor settings.[4, 5] However, this method requires intensive simulations, especially when multiple DERs are on the feeder and the number of possible combinations of power factor settings is very large. Similarly, to the complexities of power factor settings, Figure 3 illustrates a very limited sample of the potential volt-var settings that could be applied in the field. Slopes, setpoints, and deadbands are just a few of the characteristics used to define a particular volt-var setting.

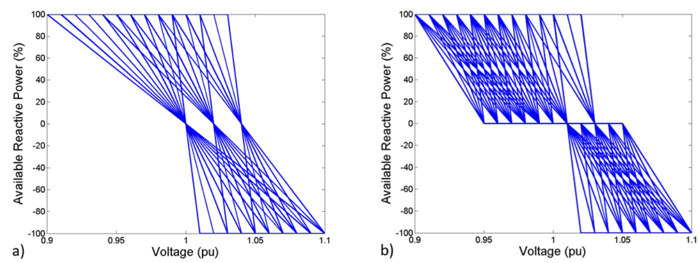


Figure 3 – Sample of Volt-var Settings a) No Dead Band and b) With Dead Band

Feeder/Site Selection for Assessing Performance

The site-selection task is of utmost importance to demonstrate the potential benefits of advanced inverter functions through data derived from field measurements.

Selection Criteria

The PV sites for this study were selected from a list of candidate locations based on the highest likelihood of providing noticeable results from a demonstration. This includes impact of active power output as well as reactive power support. It is critical for a successful demonstration that the potential adverse impact of the site can be mitigated with the use of the smart inverters.

1 Smith, J., Rylander, M., Sunderman, W., "The Use of Smart Inverter Controls for Accommodating High-Penetration Solar PV", Distributech Conference and Exhibition, San Diego, CA, Jan 2013

2 *Grid Impacts of Distributed Generation with Advanced Inverter Functions: Hosting Capacity of Large-Scale PV Using Smart Inverters.* EPRI, Palo Alto, CA: 2013. 3002001246

3 *Common Functions for Smart Inverters, Version 4.* EPRI, Palo Alto, CA: 2012. 3002008217.

4 *Analysis Method and Results for Determining Optimal Inverter Settings for Improved Integration of Solar PV.* EPRI, Palo Alto, CA: 2015. 3002007131.

5 M. Rylander, H. Li, and J. Smith, "Determination of Smart Inverter Control Settings to Improve Distribution System Performance," CIGRE U.S. National Committee 2014 Grid of the Future Symposium, Houston, TX, Oct 2014.

Sites are also limited to those that are not susceptible to the impact from other existing DERs on the feeder. These other sites would potentially obscure the demonstration because the field monitoring would be subject to the impacts from those DERs and their settings.

Selection Analysis

To select sites ideal for assessing effectiveness of advanced inverter settings, sites were chosen based upon expected impact that a DER has on voltage, considering:

- With no reactive power control (unity power factor).
- With reactive power control.

Sites where smart inverters were not anticipated to have much impact were not considered for this study because the objective of the demonstration is solely to test the impact of advanced inverter settings.

Hosting capacity is a criterion used to create an index for feeder/site selection. Hosting capacity reduction from no DER condition to the condition with DER at unity-power-factor, measures the impact of DER active power. Hosting capacity increase from DER at unity-power-factor to DER with reactive-power-control measures smart inverter capability to mitigate voltage related issues. The change in hosting capacity for the three scenarios is illustrated for a feeder in Figure 4.

Another key criterion in site selection is the requirement for the inverter to have sufficient capacity. If the inverter is not oversized and the active power (watts) has precedence, then the DER system cannot provide reactive power at full output when the reactive-power capability may be needed the most. In a watts-precedence mode, the inverter gives precedence to active power and limits reactive power when the total current in the inverter reaches its rating. On the other hand, if the inverter has a reactive power (var) precedence, the active power is reduced when the device hits its voltage-ampere (VA) limit.

Figure 5 shows the voltages under three different scenarios: 1) unity power factor, 2) power factor control with a watts-precedence setting, and 3) power factor control with a var-precedence setting. The voltage with the PV at unity power factor (denoted by the blue curve) goes beyond the ANSI 1.05 Vpu limit at midday. The power factor control with a watts-precedence setting (orange curve) helps reduce the voltage. However, as the active power increases near full output at midday, the inverter's capability to provide reactive compensation decreases and therefore the ability to mitigate overvoltage decreases. The worst-case condition occurs when the active power reaches full output and the reactive power drops to zero, resulting in the voltage suddenly jumping to the high voltage condition that occurs if the DER is operating at unity power factor. As a comparison, the power factor control with a var-precedence setting (gray curve) successfully mitigates the overvoltage. This example clearly demonstrates that the reactive power capability is very important.

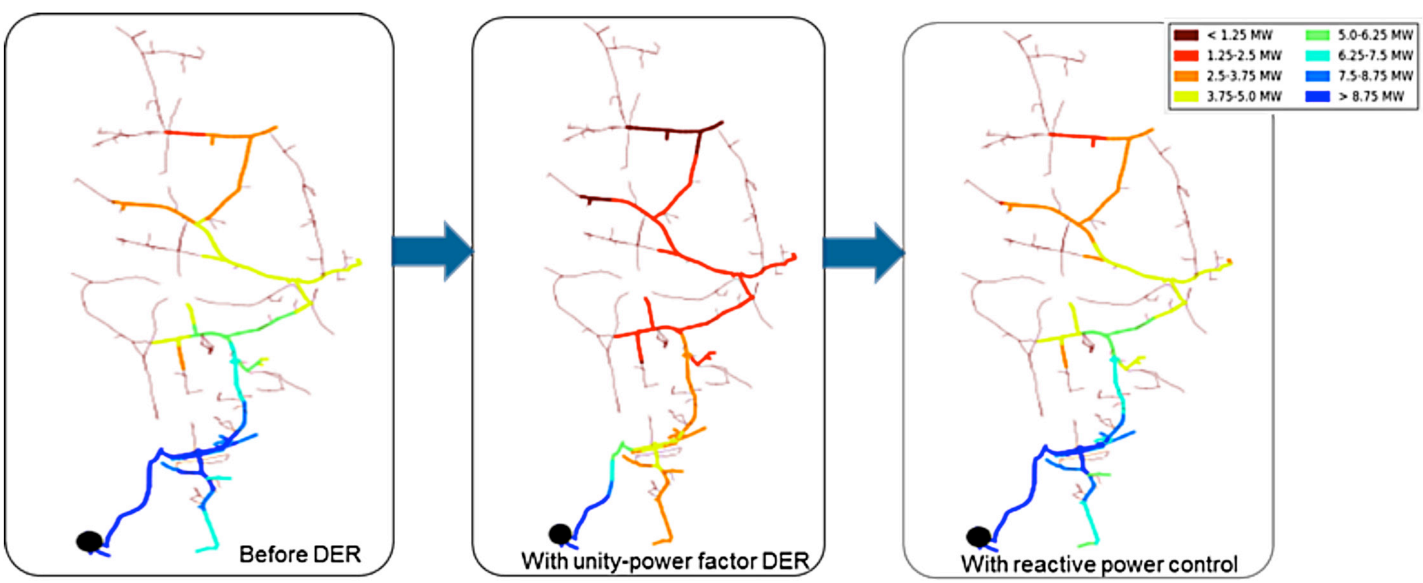


Figure 4 – Hosting Capacity Before DER, with DER Operating at Unity Power Factor, and with DER with Reactive Power Output

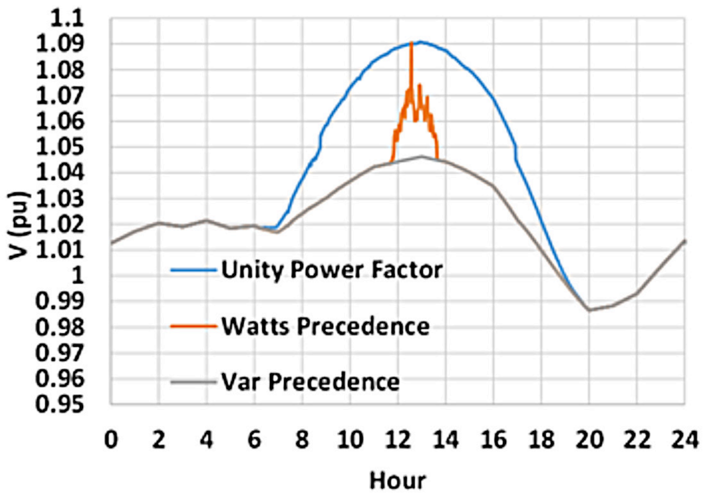


Figure 5 – Voltage Comparison with Different Inverter Scenarios

Feeders and Sites Selected

Eighteen PV sites located across fourteen feeders with different characteristics were examined to select the feeders/sites that could significantly benefit from the grid-support functions of a smart inverter related to reactive power and could produce noticeable demonstration results. These feeders/sites are characterized in Table 2.

The feeder/site-selection process included an assessment based upon both active and reactive power impacts from the PV sites. The expected impacts are considered only for the voltage issues:

- Primary overvoltage
- Primary voltage deviation
- Regulator voltage deviation
- Primary undervoltage

Table 2 – Feeders/Sites Proposed for Demonstration

Site Number	Feeder	Nominal Voltage (kV)	Peak Load (MW)	Site X/R	DER Size (kW)	Existing DERs
1	1	13.2	2.2	2.3	1000	No
2	1	13.2	2.2	2.3	1000	No
3	2	13.2	12.2	2.3	650	Yes
4	3	13.8	3.5	1.57	1000	No
5	3	13.8	3.5	1.57	1000	No
6	4	13.8	9.4	8.8	1000	Yes
7	5	13.8	21.6	4.98	1000	Yes
8	6	13.8	5	5.14	650	Yes
9	7	13.2	11.3	3.4	650	Yes
10	8	13.2	10.2	4.78	1000	No
11	9	13.8	16.4	4.35	650	No
12	10	13.8	9.6	2.32	1000	Yes
13	11	13.8	9.9	2.74	650	Yes
14	12	13.8	10.5	3.97	1000	No
15	13	13.8	8.9	2.54	680	Yes
16	14	13.2	3.6	2.51	840	Yes
17	4	13.8	9.4	4.67	1000	Yes
18	4	13.8	9.4	4.61	1000	Yes

Primary undervoltage is not typically a concern for PV. However, smart inverters pulling reactive power can potentially be an issue if the inverter causes an undervoltage.

The DRIVE (Distribution Resource Integration and Value Estimation)[6] tool was used for the impact assessment, while hosting capacity was used to quantify the impact index used to rank sites for the demonstration project. Using the DRIVE tool, the hosting capacity at the specific PV site was determined for each voltage issue for the three scenarios:

- Scenario 1: No PV.
- Scenario 2: All DERs online, and the PV site under study at unity power factor.
- Scenario 3: All DERs online, and the PV site under study at 0.95 power factor (absorbing var).

The comparison in hosting capacity for each voltage issue is then determined between the scenarios as

- Active power impact = Scenario 1 – Scenario 2
- Reactive power impact = Scenario 3 – Scenario 2

The impact of active power measures the reduction in hosting capacity due to integrating PV with unity power factor, while the impact of reactive power measures the potential hosting capacity increase due to the specific PV with a smart inverter. Note that none of the existing DER sites had smart inverters at the beginning of this project. Sites with either low active-power impact or low reactive-power impact were not desired as ideal demonstration sites.

To calculate a single hosting capacity metric, the minimum impact of active power and the minimum impact of reactive power were determined for each voltage issue. Because the existing DER sites do not have smart inverter capabilities, they limited the potential increase in hosting capacity engendered by installations of new DER sites with smart inverters. Finally, the average of the minimum-impact values defined the metric for a single impact. Figure 6 illustrates this calculation for Site #10.

Minimum

Issue	HC Reduction (MW)	HC Increase (MW)	Min Impact (MW)	Average	Impact Factor
Primary Over-Voltage	1	1.6	1		0.55
Primary Under-Voltage	0	0	0		
Primary Voltage Deviation	0.6	1	0.6		
Regulator Voltage Deviation	0.6	0.8	0.6		

Figure 6 – Example of Calculating Index Factor Site Impact for Four Voltage Issues

Again, calculating the index factor for sites with low DER active-power impacts and/or low DER reactive-power impacts resulted in a low impact index. The impact indexes ranking the sites for field demonstration and monitoring are shown in Figure 7. Not all feeders/sites were susceptible to high impact from DER with smart inverters. Sites #17 and #18 significantly stand out as excellent site candidates, whereas sites 1, 2, 4, 5, 10, and 12 are fair candidates. Other sites having a lower index are less likely to have quantifiable impact in the demonstration.

HIGH IMPACT SITES ARE TARGETED FOR THE DEMONSTRATION, BUT ALL SITES WILL BE STUDIED SEPARATELY BY NATIONAL GRID.

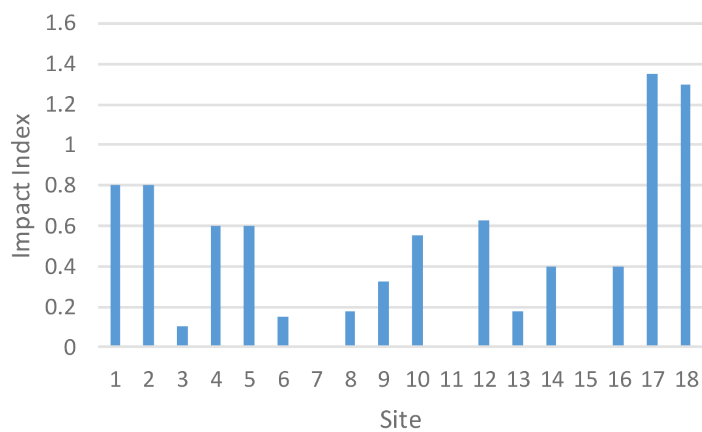


Figure 7 – Simulated Voltage Smoothing with Volt-var Control

Determining Advanced Inverter Settings for National Grid Solar Phase II PV Systems

Advanced inverter settings range from out-of-the-box to those requiring a detailed study. Out-of-the-box settings are designed to provide slight improvement with very low risk of adverse impact. Tailored settings found via a detailed study can maximize improvement and are very specific for the impact factors used in the derivation of the settings. These settings often require updates as the system changes. System changes may include changes in load and DER penetration.

6 *Defining a Roadmap for Successful Implementation of a Hosting Capacity Method for New York State.* EPRI, Palo Alto, CA: 2016. 3002008848.

Methods

The proper inverter settings for a site can be determined with different methods that vary by the type of data required by the researcher and available computational resources.[7, 8] These methods are defined by various levels of complexity as shown in Table 3. The lower complexity level methods could be applied with little to no feeder information and using only spreadsheet tools, whereas levels with higher degree of complexity require more detailed feeder information and using software tools. The Level 3 methods for power factor and volt-var, as shown in Table 3, are the primary focus of this demonstration project.

In contrast to the proposed methods, which leverage prior work, very detailed analyses could alternatively be conducted to derive tailored settings for a specific day[9] or based on specific day-types.[10, 11] Both methods, which are tailored to maximize the benefits of smart inverters, require advanced control to update settings on a regular basis.

The Level 3 settings that are used in this demonstration are designed to be tailored to a feeder/condition but are dispatched over a longer period. This period might be on the order of seasonal or annually. In this period, it is likely that smart inverters installed at the demonstration sites will be operating in conditions different from those originally used in the determination of settings. As settings are utilized, however, an inverter should be within the range of the original design conditions. The intent is to improve the overall feeder performance but not to optimize the performance for each period. The art of optimizing performance is currently being researched, and there are potential methods to combine the advanced functions of smart inverters to better integrate this improvement.[12]

7 *Analysis to Inform CA Grid Integration Rules for PV: Final Report on Inverter Settings for Transmission and Distribution System Performance.* EPRI, Palo Alto, CA: 2016. 3002008300.

8 M. Rylander and M. Reno, "Methods to Determine Recommended Feeder-Wide Advanced Inverter Settings for Improving Distribution System Performance," IEEE Photovoltaic Specialists Conference, Portland, OR, 2016.

Power Factor

The Level 3 power factor settings are based on the feeder model, DER locations, and interconnect transformer data. The procedure for determining settings are as follows:

1. Conduct a short-circuit analysis to determine resistance (R) and reactance (X) to the primary node of the PV site point of interconnection.
2. Adjust the X/R ratio for the PV site interconnect transformer resistance (R_{xfmr}) and reactance (X_{xfmr}):

$$\left(\frac{X}{R}\right)_{adjusted} = \frac{X}{R} + [(R_{xfmr}) + \frac{X}{R}(X_{xfmr})]\sqrt{1+\left(\frac{X}{R}\right)^2}$$

3. Calculate the PV site power factor using the adjusted X/R:

$$Powerfactor = \frac{\left(\frac{X}{R}\right)_{adjusted}}{\sqrt{\left(\left(\frac{X}{R}\right)_{adjusted}\right)^2 + 1}}$$

4. Adjust PV site power factor for additional DER on the feeder:
    a. Use the full power flow model with DER interconnection transformers to simulate and observe the potential voltage change at the proposed PV site.
    b. Calculate the reactive power needed to mitigate the voltage change at the PV site.
    c. The additional amount of reactive power needed is used to adjust the PV site power factor setting.
5. If the power factor calculated in step 3 is less than 0.9, limit it to 0.9.

9 M. Rylander and J. Smith, "Determination of Smart Inverter Control Settings to Improve Distribution System Performance," CIGRE Grid of the Future Symposium, Houston, Texas, 2014.

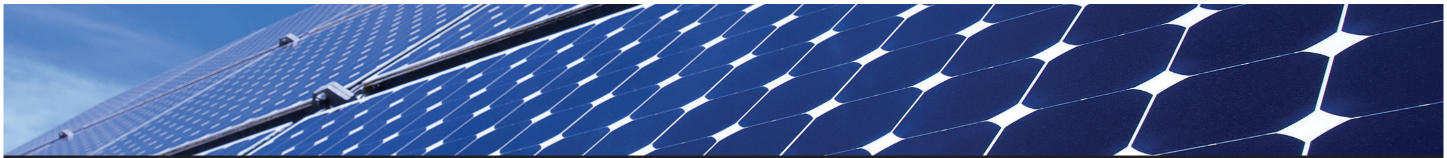
10 M. Rylander and S. Abate, "Integrated Control of Photovoltaic Inverters to Improve Distribution System Performance," CIGRE Canada Conference, Toronto, Ontario, 2014.

11 S. Abate and M. Rylander, "Smart Inverter Settings for Improving Distribution Feeder Performance," IEEE PES General Meeting, Denver, CO, 2015.

12 M. Rylander and H. Li, "Default Volt-Var Inverter Settings to Improve Distribution System Performance," IEEE PES General Meeting, Boston, MA, 2016.

Table 3 – Methods to Determine Smart Inverter Settings

Level	Complexity	Power Factor	Volt-Var
0	None	Unity Power Factor	Disabled, Unity Power Factor
1	Low	Based on Feeder X/R Ratio	Generic Setting
2	Medium	Based on Feeder Model and PV Location	Based on Feeder Model and PC Location
3	High	Based on Feeder Model, PV Location and Service Transformer Impedance	Based on Feeder Model, PV Location, and Service Transformer Impedance



The fifth step is applied to prevent a PV site from demanding excessive reactive power, which can occur when the PV location is too remote on the feeder for the inverter to effectively counter the rise in active power voltage using reactive-power inverter functions.

Volt-var

The Level 3 volt-var setting is a slight modification of the Level 1 generic volt-var setting proposed by the IEEE 1547 Working Group. The Level 3 volt-var setting is adjusted based on the interconnection transformer and the voltage at the point of connection to target control of the medium-voltage node. An example of this adjustment is shown in Figure 8.

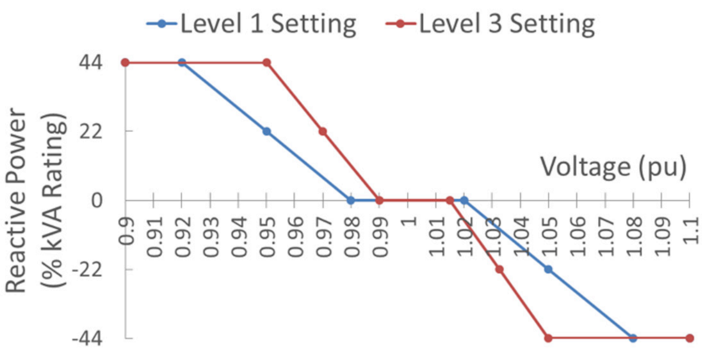


Figure 8 – Example Adjustment of Level 3 Volt-Var Setting

The procedure to adjust the control settings first requires the examination of the voltage range that the feeder normally operates within. To observe the feeder voltages, the analysis of the power flow in the feeder model is observed for multiple load levels. These load levels may include the peak and minimum load for each feeder. From the resulting voltages for each feeder, the maximum voltage (for all buses and all load levels) is determined. That value defines the Procedure A or B volt-var setting adjustment described below:

- ***Procedure A:*** If the maximum feeder voltage without DER during all load conditions is greater than 1.02 Vpu, the site-specific volt-var settings are based on the voltage at the DER site and the corresponding regions shown in Figure 9. The idea is that nodes with high voltages may be near the head of the feeder, where benefit from reactive power is minimal, while the locations with lower voltage usually have higher impedance and can benefit more from additional reactive power.
- ***Procedure B:*** If the maximum feeder voltage without DER during all load conditions is less than 1.02 Vpu, the site-specific volt-var settings are adjusted such that the upper deadband voltage (VUDB) is reduced to the maximum feeder voltage but limited to 1.0 Vpu to maintain a minimum 2% volt-var deadband. Feeders of this type may have relatively flat voltage profiles and may not have buses in the inductive region of the Level 1 volt-var setting. Thus, for the control to have more effectiveness at reducing voltage deviations, the deadband is adjusted as illustrated in Figure 10.

The final adjustment to the Level 3 volt-var settings is applied to consider the interconnect transformer. The primary voltage level volt-var setting is transferred over the interconnection transformer resistance (Rxfmr) and reactance (Xxfmr) by modifying each of the volt-var points considering full PV active power (Pgen) and the voltage/reactive power (V/Qgen) shown at each volt-var point using:

$$V_{new} = \mathrm{V} + \frac{P_{gen}}{V} * R_{xfmr} + \frac{Q_{gen}}{V} * X_{xfmr}$$

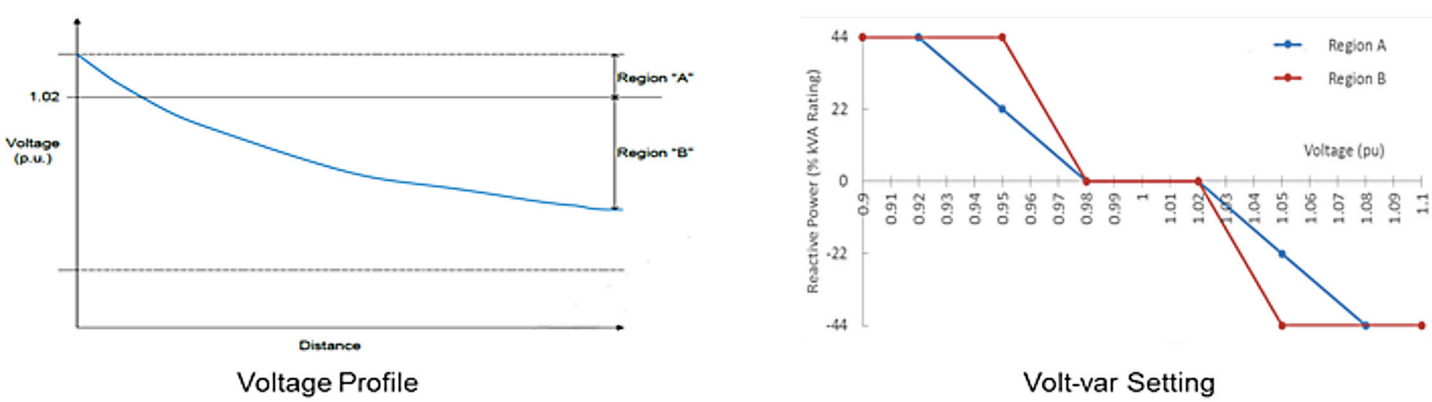


Figure 9 – Procedure A - Volt-var Adjustment

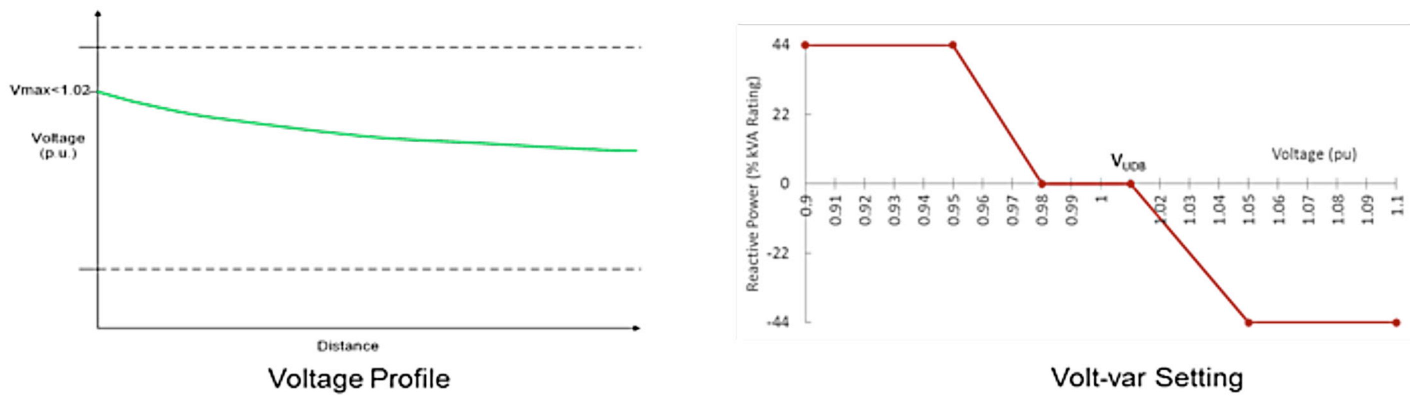


Figure 10 – Procedure B - Volt-var Adjustment

Settings

An example of applying the previously defined procedure was created with PV Site #10. The schematic of this feeder illustrating the PV location is provided in Figure 11. There is no existing DER on the feeder. The impedances to the primary bus of the PV location as well as the impedances of the interconnect transformer are shown inset in the table. The adjusted X/R ratio is calculated to be 6.2, and a final power factor of 0.987 is determined as:

$$\left(\frac{X}{R}\right)_{adjusted} = \frac{4.089}{0.856} + \left[(0.00744) + \frac{4.089}{0.856}(0.05954)\right]\sqrt{1 + \left(\frac{4.089}{0.856}\right)^2}$$

$$Powerfactor = \frac{6.2}{\sqrt{(6.2)^2 + 1}}$$

For this particular site, the power factor setting is rounded down to 0.98 to observe additional voltage compensation.

R (primary)	0.856
X (primary)	4.089
Transformer R	0.00744
Transformer X	0.05954

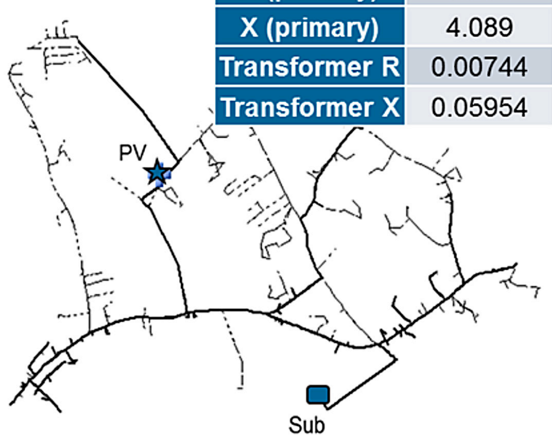


Figure 11 – PV Site #10 with Impedances Used in Power Factor Calculation

The volt-var settings for PV Site #10 were determined with the voltage profile for the two load levels shown in Figure 12. The maximum feeder voltage from the two conditions, based on all buses, was greater than 1.02 Vpu. Therefore, Procedure A was applied. Based on Procedure A, the voltage at the PV site was less than 1.02 Vpu. Thus, the Range B volt-var curve was applied for the location. Furthermore, the volt-var setting was adjusted based on the PV size and interconnect transformer impedance, as illustrated in Figure 13.

A unique setting was additionally derived for each PV site. Figure 14 illustrates those settings and the variance between sites. These settings were developed based on particular input parameters but were not tailored to a specific scenario. Therefore, these settings have the potential to provide system benefit that will vary depending on the real-world feeder conditions. Updates and changes to these settings may occur during the demonstration if the field conditions do not adequately represent the scenario used in the underlying derivation.

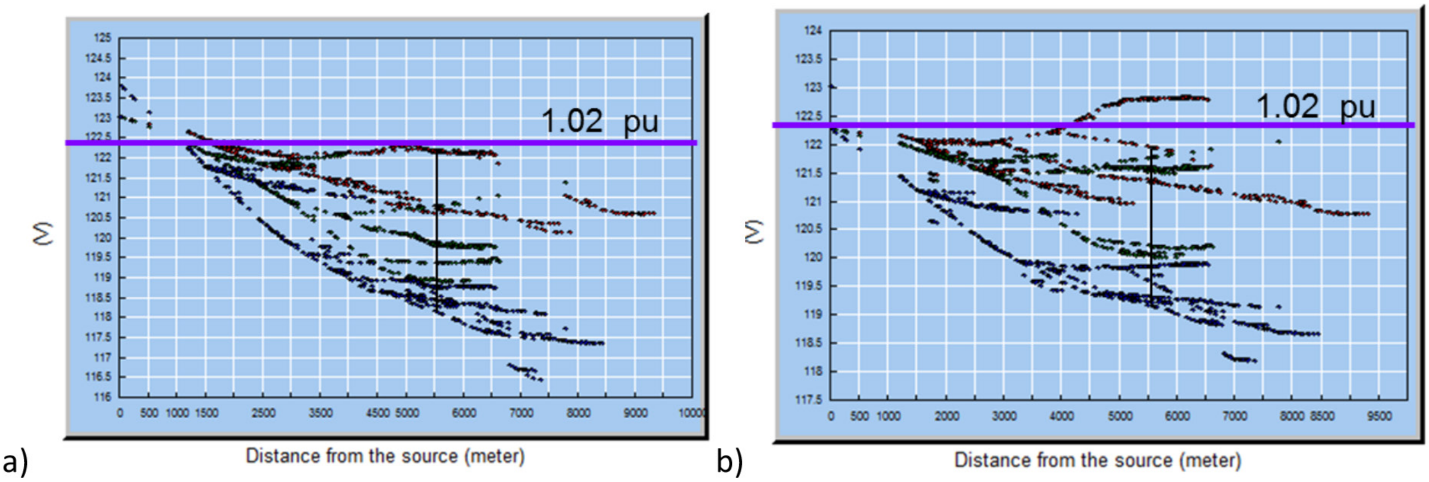


Figure 12 – Feeder #8 Voltage Profile Indicating PV Site #10 Voltage Range at a) Peak Load and b) Minimum Load

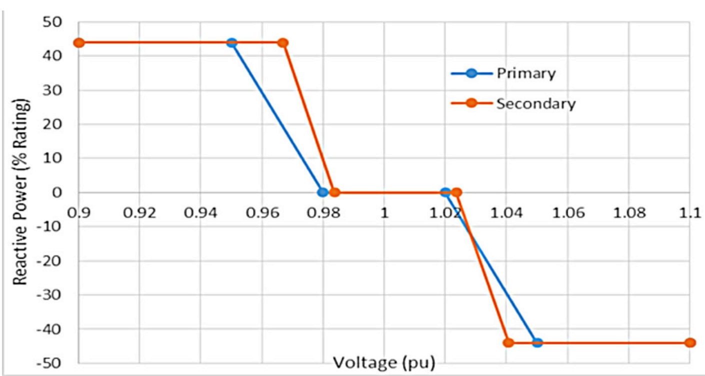
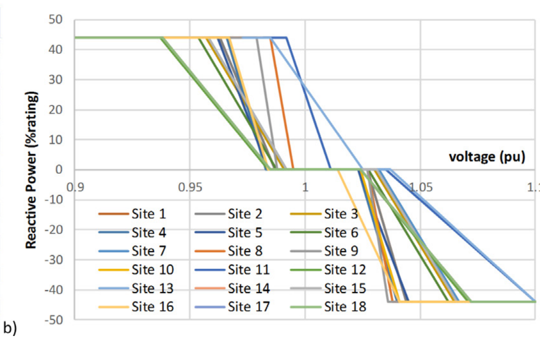


Figure 13 – Adjustment of Level 3 Volt-Var Setting for Interconnection Transformer

Site #	Power Factor
1	0.94
2	0.94
3	0.90*
4	0.90*
5	0.90*
6	0.99
7	0.99
8	0.95
9	0.97
10	0.98
11	0.99
12	0.94
13	0.90*
14	0.98
15	0.90*
16	0.95
17	0.98
18	0.98

a)



b)

*Figure 14 – Site Settings for a) Power Factor and b) Volt-var (*Minimum power factor applied)*

Performance Assessment Plan

In 2018, advanced inverter settings identified for each PV site will be applied, and impact of the advanced grid support functions will be analyzed. Following five feeders, where PV systems are already in operation and the calculated impact factors shown in Figure 7 are relatively high, have been selected for detailed field measurement and performance assessment:

1. Feeder 413L2 in Sturbridge, MA (site # 1 & 2)
2. Feeder 115W52 in Fall River, MA (site # 4 & 5)
3. Feeder 227W3 in Shirley, MA (site # 12)
4. Feeder 21W2 in Leicester, MA (site # 8)
5. Feeder 9L2 in Attleboro, MA (site # 9)

Although site# 17 and #18 in Feeder 4 are ranked the highest on the impact index, they are not available for this demonstration project. These sites are being committed for three-year research project to design, develop, and demonstrate an integrated system of solar PV, energy storage, and facility load management at the utility distribution scale as part of the U.S. Department of Energy's SunShot initiative.[13]

EPRI intends to analyze the measured data from these selected sites and distribution feeders to evaluate the performance of the PV plants and to understand the impact of smart inverters on distribution voltages. Data analytics are intended to cover the following topics:

- ***Functionality:*** This includes confirming that inverters and plant controllers are operating properly; determining whether inverters are changing operating modes and settings when

13 http://www.cse.fraunhofer.org/shines

commanded; and quantifying how accurately inverters implement advanced functions based on target parameters, such as volt-var curves or fixed power factor settings.

- *Voltage Impacts:* Determine impacts that advanced inverter functions have on voltages both at the PV site level (secondary) and feeder level (primary), based on the available data. Daytime voltage profiles, statistical ranges, and aggregated quantities are expected to be correlated with advanced inverter functions. This includes quantifying voltage variability and voltage flatness across specific distribution circuits. Additionally, at sampled sites, multi-inverter interactions are intended to be studied to understand whether nearby inverters "fight" each other in an oscillatory manner when they attempt to control voltage independently in accordance with certain advanced functions.
- *Power Quality Implications:* Study common power quality factors—including flicker and momentary voltage events—in relation to the operations of advanced inverters. This is intended to identify how much advanced inverters are contributing to overall power quality on the distribution circuit.

Data Requirements

- Date and time stamp (GPS time-synched or all meters synchronized to a common time server)
- Voltage (Phase A-Neutral, Phase B-Neutral, Phase C-Neutral)
- Current (Phase A, Phase B, Phase C)
- Active Power (Delivered*, Received**)
- Reactive Power (Delivered*, Received**)
- Energy (Net, Delivered*, Received**)
- Reactive Energy (Delivered*, Received**)
- Power Factor (True and Displacement)
- Frequency
- Irradiance (plane-of-array)
- PV module temperature and ambient temperature.
- The command log file of the plant power-management controllers with time stamp to match smart inverter command/setting with actual system response.
- Plant O&M log with time stamp to know plant down time (planned/unplanned).

* *Delivered means delivered to the grid.*

** *Received means received from the grid.*

Monitoring Systems

Typical revenue-grade meters for the solar industry measure data at one-minute intervals. However, this resolution is not sufficient to monitor the voltage changes caused by fast irradiance changes due to cloud coverage, which is typically on the order of seconds. To fully monitor the sites' voltage and frequency conditions, the National Grid team needed to customize its standard version of feeder monitors and added the following features:

- Firmware upgrade allowing for extended storage and high resolution of captured data.
- A data logger allowing for 1-second data acquisition.
- Ability to push data to an external server.
- A clock connected to an orbiting satellite for high-accuracy timing across multiple data sources.
- A power supply that allows data capture and logging during low-voltage events.
- Communications to allow maintenance and continued access to data.

Figure 15 shows part of an installation of a feeder monitor that was at the point of common coupling to measure the combined power flow of Blossom Rd. 1 and Blossom Rd. 2 sites.

Test Plan

National Grid and EPRI developed test plans to verify the impact of different functions and settings to support voltage regulation, including power factor and volt-var settings shown in Figure 14 and the default settings proposed in the revised IEEE 1547-2018 standard for Category B DERs. Each function and setting will be tested for a week by periodically turning it ON and OFF to compare the impact on voltage for similar weather and loading conditions. Tests are planned to be repeated under different seasonal conditions (winter and summer).

Figure 15 – Feeder Monitor Installed to Monitor the Combined Outputs of Blossom Rd. 1 and Blossom Rd. 2 sites

Future Work

The continuation of this project involves finishing the deployment of the monitoring equipment and capturing the field measurements demonstrating the use of smart inverters to provide benefits to the distribution system as outlined in Figure 1. Based on the monitoring, adjustments to the settings as well as updates to the underlying methodology used in determining the settings, may occur. An orchestrated field demonstration of this type has yet to occur in the industry and should provide the best insight to benefits to and impacts on the distribution system from deploying smart inverters to improve integration to the distribution system.

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Primary Authors:
Huijuan Li, *EPRI*
Matt Rylander, *EPRI*
Aminul Huque, *EPRI*
Samer Arafa, *NG*
Justin Woodard, *NG*

Contributors:
Christ Trueblood, *EPRI*
Wes Forbes, *EPRI*
James Perkinson, *NG*

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EPRI CONTACTS

Matt Rylander, *Senior Technical Leader*
512.351.9938, mrylander@epri.com

Aminul Huque, *Principal Project Manager*
865.218.8051, mhuque@epri.com

Integration of Distributed Energy Resources (P174)

NATIONAL GRID CONTACTS

Samer Arafa, *Lead Engineer*
781.907.2647, samer.arafa@nationalgrid.com

Justin Woodard, *Principal Engineer*
781.907.1617, justin.woodard@nationalgrid.com

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Electric Power Research Institute
3420 Hillview Avenue, Palo Alto, California 94304-1338 • PO Box 10412, Palo Alto, California 94303-0813 USA
800.313.3774 • 650.855.2121 • askepri@epri.com • www.epri.com