CALIFORNIA ENERGY COMMISSION

Energy Research and Development Division

**FINAL PROJECT REPORT**

# Impact Assessment and Secure Implementation of California Rule 21 Phase 3 Smart Inverter Functions

**Gavin Newsom, Governor**

**February 2021 | CEC-500-2021-013**

**PREPARED BY**:

**Primary Authors**:
Ajit Anbiah Renjit
Tom Tansy
Bob Fox
Candace Suh Lee
Jouni Peppanen
Steven Coley
Tanguy Hubert
Hamed Valizadeh Haghi
Zachary Pecenak
Matthew Rylander
Jan Kleissl
Lloyd Cibulka
Steve Wheat
Gregory Thompson

Electric Power Research Institute
3420 Hillview Ave.
Palo Alto, CA 94304
Phone: 650-855-2121 | Fax: 650-855-2721
https://www.epri.com

**Contract Number**: EPC-16-079

**PREPARED FOR**:
California Energy Commission

Bryan Lee
**Project Manager**

Fernando Piña
**Office Manager**
**ENERGY SYSTEMS RESEARCH OFFICE**

Laurie ten Hope
**Deputy Director**
**ENERGY RESEARCH AND DEVELOPMENT DIVISION**

Drew Bohan
**Executive Director**

# PREFACE

The California Energy Commission's (CEC) Energy Research and Development Division supports energy research and development programs to spur innovation in energy efficiency, renewable energy and advanced clean generation, energy-related environmental protection, energy transmission and distribution and transportation.

In 2012, the Electric Program Investment Charge (EPIC) was established by the California Public Utilities Commission to fund public investments in research to create and advance new energy solutions, foster regional innovation and bring ideas from the lab to the marketplace. The CEC and the state's three largest investor-owned utilities — Pacific Gas and Electric Company, San Diego Gas & Electric Company and Southern California Edison Company — were selected to administer the EPIC funds and advance novel technologies, tools, and strategies that provide benefits to their electric ratepayers.

The CEC is committed to ensuring public participation in its research and development programs that promote greater reliability, lower costs, and increase safety for the California electric ratepayer and include:

- Providing societal benefits.
- Reducing greenhouse gas emission in the electricity sector at the lowest possible cost.
- Supporting California's loading order to meet energy needs first with energy efficiency and demand response, next with renewable energy (distributed generation and utility scale), and finally with clean, conventional electricity supply.
- Supporting low-emission vehicles and transportation.
- Providing economic development.
- Using ratepayer funds efficiently.

*Impact Assessment and Secure Implementation of California Rule 21 Phase 3 Smart Inverter Functions* is the final report for the Impact Assessment and Secure Implementation of California Rule 21 Phase 3 Smart Inverter Functions to Support High Photovoltaic Penetration project (Contract Number EPC-16-079) conducted by the Electric Power Research Institute, Inc. The information from this project contributes to the Energy Research and Development Division's EPIC Program.

For more information about the Energy Research and Development Division, please visit the CEC's research website (www.energy.ca.gov/research/) or contact the CEC at ERDD@energy.ca.gov.

# ABSTRACT

This document is the final report for the Impact Assessment and Secure Implementation of California Rule 21 Phase 3 Smart Inverter Functions project conducted by the Electric Power Research Institute (EPRI) to support high PV penetration. A diverse team of stakeholders carried out the project, including EPRI, SunSpec Alliance, University of California, San Diego (UCSD), Sunrun, SMA, Enphase Energy, Kyrio, SolarEdge, ABB, and OpenEGrid.

The project analyzed a representative set of California distribution feeders to determine the level and duration of control needed to gain a 25 percent increase in hosting capacity above the baseline achieved with Rule 21 Phase 1 functions such as power factor and volt-var control. The solar availability information was used with modeling to determine the statistical time and locational probabilities of how the Phase 3 functions would operate. This information was used to conduct a comprehensive economic analysis to determine the value to the grid and compensation means to distributed energy resources asset owners.

Moreover, the project assessed the practicality and applicability of Rule 21 Phase 3 functions by physically incorporating them into residential inverters from SMA and ABB. These inverters were fully evaluated under controlled conditions at the advanced inverter test facility at UCSD. Following this, a field pilot of 57 residential inverters was conducted within San Diego Gas & Electric territory using a Sunrun aggregation system. The project also accomplished developing a certification procedure by which any system or device can be checked for compliance to the IEEE 2030.5 communication standard and Rule 21 smart inverter functions, which is a major step toward achieving interoperability.

The project also established an IEEE 2030.5 Public Key Infrastructure for California, removing a significant impediment for California Rule 21 compliance that protects California grid investments.

**Keywords:** interoperability, smart inverters, distributed energy resources (DER), distribution system, CA Rule 21.

Please use the following citation for this report:

Renjit, Ajit Anbiah. 2021. Electric Power Research Institute (EPRI), Palo Alto, CA. *Impact Assessment and Secure Implementation of California Rule 21 Phase 3 Smart Inverter Functions*. California Energy Commission. Publication Number: CEC-500-2021-013.

# TABLE OF CONTENTS

# LIST OF FIGURES

Page

# LIST OF TABLES

Page

# EXECUTIVE SUMMARY

## Introduction

California has set the stage for a carbon free future by mandating 100 percent of its electricity from renewable energy and zero-carbon energy-based resources by 2045. Although it is expected that more than 50 percent of this energy will originate from large renewable solar, wind, and hydro power plants, a significant percentage will need to come from distributed energy resources (DER), which are owned and operated by people and businesses of California as self-generation. These DER are primarily photovoltaic (PV) systems whose net energy effect on the electricity grid may vary widely during a day, season, and year, depending upon weather and customer decisions.

Established in 1982 by the California Public Utilities Commission (CPUC), California Electric Rule 21 is a set of rules governing how these energy technologies may interconnect to the electric distribution systems of the state's investor owned utilities (IOUs) – Southern California Edison, Pacific Gas and Electric Company, San Diego Gas & Electric Company, Bear Valley Electric, Liberty Utilities, and PacifiCorp Power. These advanced DER technologies include energy storage and distributed generation such as roof-top solar. The Rule 21 tariff gives customers wishing to install generating or storage facilities on their premises access to the electric grid while protecting the safety and reliability of the distribution and transmission systems at the local and system levels.

The California Rule 21 Smart Inverter Working Group — sponsored by the CPUC and the California Energy Commission (CEC) — determined that DER must support the electricity grid and have accessible communication capabilities. Specifically, Rule 21 requires the use of advanced, smart inverters that are more flexible in how they connect to and communicate with the grid. Smart inverters are equipment that converts direct current to alternating current and allow solar installations to remain connected to the grid at a wider range of frequencies and voltages. Each investor-owned utility is responsible for administering Rule 21 in its service territory and maintaining its own version of the rule.

Phase 1 of the Smart Inverter Working Group required inverters to implement key autonomous functions. Recent studies — including those by the U.S. Department of Energy and the CEC — have proven that the Phase 1 functions can increase the grid's ability to accommodate distributed solar generation, bringing value to consumers and utilities alike. These same studies have also demonstrated that the functions are practical — supportable by the current state of inverter technology. Commercial products are now available that support these functions.

During Phase 2, to ensure the IOUs can communicate with all DER, the Smart Inverter Working Group selected a default communications protocol, Institute of Electrical and Electronics Engineers (IEEE) 2030.5, which all installations must support although other communication protocols are permitted. This protocol requires cyber certificates so that connections can be properly secured, but the necessary infrastructure to administer such certificates does not exist. The Phase 3 functions proposed by the working group include advanced functions that have the potential to bring significant additional benefit but are less understood (technically) and involve economic uncertainty because of their impact on PV generation. These functions need to be modeled, assessed, and sufficiently tested in real products in the lab or in the field to better understand how they should be used or configured and determine the extent to which their optimal utilization use would impact asset owners economically.

## Project Purpose

This project directly addressed four critical gaps that are impeding progress toward the full use of smart inverter capabilities:

1. Provided understanding of the technical implementation and methods of using the Phase 3 inverter functions. While it is straightforward to understand that PV generation could be curtailed, it is not known how deeply, how frequently, or for what duration such curtailments would be needed to increase the grid hosting capacity to 25 percent or more. Hosting capacity is the amount of solar PV output that could be accommodated without violating power quality constraints or reliability and without requiring infrastructure or equipment upgrades. Additionally, it is not known whether such curtailments could be autonomous (such as volt-watt or frequency-watt functions) or would need to be dispatched (real power level or percentage limit functions) to have a substantial impact.
2. Built on technical findings and answered economic questions that naturally result from any functions impacting PV production and value to the asset owner. The complexity of energy rate structures worldwide reveals that the value of energy is not simple to assess. Furthermore, with the arrival of large quantities of variable renewable energy, the complexity of these valuations only becomes more complex.
3. Provided a ready testing and certification framework that cohesively covers Rule 21 requirements to allow for speedy delivery of well-tested, and fully compliant Rule 21 solutions to the marketplace. Configurable functions are naturally complex to test. Careful consideration is required to identify the optimal balance between test sufficiency/efficacy and test time/cost.
4. Provided a comprehensive cybersecurity strategy for DER communication interfaces that use the IEEE 2030.5 protocol, maximizing asset and data protection for a secure and resilient distribution grid.

## Project Process

The research was done by a diverse research team led by the Electric Power Research Institute that included Sunspec, the University of California, San Diego, Sunrun, Enphase, Kyric, and SMA. The researchers modeled the impact of Phase 3 functions on California IOU distribution circuits to determine the level and duration of control needed to gain a 25 percent increase in hosting capacity. The team leveraged the results from the functional impact modeling to perform an economic assessment of the Phase 3 functions to determine the value to the grid and compensation means to DER asset owners.

Using key findings from the impact modeling and economic assessment, the researchers further assessed the practicality and ability to implement Phase 3 functions by the physical incorporation into residential inverters by SolarEdge, SMA, and ABB. To achieve market readiness and compliance with Rule 21, the researchers developed a well-defined testing and certification process. This included (1) development of certification test procedures so that products supporting Rule 21 functions could be validated and (2) extending the SunSpec

System Validation Platform software to provide a test harness for testing product conformance. The compliance test procedure and the test software were released free of charge under an open source license. Bench-scale verification of Phase 3 functions was conducted at the University of California, San Diego laboratory. The results of these testing-validated Phase 3 functions can be supported by wide-range of commercial products.

Field environments bring real-world conditions and system scales into play that are missing in the laboratory environment. This project deployed 57 SolarEdge residential PV inverters with the new Phase 3 functionality at a field site in San Diego, California, in the San Diego Gas & Electric Company service territory. The researchers integrated these sites and systems into the Sunrun system via cellular communication and connected them to the modified Sunrun operations center to complete the end-to-end system for field testing. Each site had device-level metering and the project team monitored performance of the Phase 3 systems for a year.

To enable the California to communicate securely with smart inverters across customer sites, the project developed, tested, and successfully deployed the necessary cybersecurity infrastructure to enable secure transactions. This process involved the development of a trusted third party — one that is compliant with regulatory standards and housed within secure, independently audited environments — to ensure a circle of trust for mutually authenticated communication between involved entities.

## Project Results

The project achieved the following results that provide value to DER stakeholders in California.

### Impact Analysis to Increase Feeder Hosting Capacity

The team evaluated hosting capacity for solar PV systems on 5 California distribution feeders. In particular, Phase 3 functions to improve hosting capacity by 25 percent were assessed and compared against conventional distribution system upgrades. The study determined that specific volt/VAR and volt/watt functions can improve hosting capacity by 25 percent. Limiting real power function can also help in hosting capacity increase but results in significant curtailment of power when not coordinated with a utility's DER management system.

### Economic Assessment to Increase Feeder Hosting Capacity

Based on previous findings from impact assessment, the project team performed an economic cost-benefit evaluation. Results showed (1) smart inverter functions tend to be economical when hosting capacity is voltage constrained and (2) smart inverter functions are more economical when new, costly equipment is otherwise needed to mitigate distribution system constraints. The results informed decisions related to compensation mechanisms for PV when it gets curtailed.

### Compliance Test Framework for California Rule 21 Validation

The project team developed compliance test procedures for smart inverter communications to meet California Rule 21 requirements. In addition, the project developed open sourcing of a smart inverter compliance test software. This software can be used by the industry to test DER to comply with the requirements specified in California Rule 21.

### Implementation of Phase 3 Functions and Laboratory Evaluation

Phase 3 smart inverter functions were implemented in physical inverters for the laboratory testing and commercialization. SMA and ABB inverters were implemented with Phase 3 functions and the products sent to the University of California, San Diego laboratory for functional testing. Functional testing was conducted based on the approved test procedures for California Rule 21. The inverters successfully demonstrated the implementation of Phase 3 functions as well as communication interoperability between utility and customer devices (in the form of gateways).

### Implementation of Phase 3 Functions and Field Demonstration

The project team modified the design of a SolarEdge residential solar inverter to support Phase 3 functions, allowing these functions to be monitored and managed remotely. Similarly, the team modified the Sunrun aggregation headend software system to include the communication interface to monitor and control these inverters. Test results verified that commercial smart inverters with California Rule 21 Phase 3 functions were able to successfully meet the Rule 21 requirements. Cellular communications between the Sunrun server and the site proved to be reliable with no major interruptions to control events.

### Cybersecurity Testing and Deployment of Public Key Infrastructure (PKI)

The Electric Power Research Institute assessed and tested cybersecurity in the laboratory environment on inverters with California Rule 21 Phase 3 functions enabled. The results were documented of the tests and the assessment of the inverter communication plan for California as per Rule 21. It is crucial that a fully functional cybersecurity infrastructure for California be deployed that meets Rule 21 requirements, thus enabling a secure communication network between utilities and customer inverters (servers and gateways).The project established this infrastructure for California Rule 21, implemented security requirements, and now provides access to the resulting security services to utilities, DER manufacturers, and DER system owners and operators.

## Knowledge and Technology Transfer

Project deliverables were intended to provide enduring public benefit in three main forms: (1) free publicly available specifications and available compliance procedures and test scripts with open-source licensing enabling faster time-to-market at minimal expense; (2) a readily available product conformance and certification program that would substantially advance the industry's ability to produce products faster; and (3) extensive marketplace engagement.

The Electric Power Research Institute works with more than 400 utilities, and the SunSpec Alliance is the primary association of solar inverter manufacturers. Collectively, these relationships positioned the team to broadly and effectively disseminate project findings and information to the industry. Both organizations met with members face-to-face multiple times per year, met by conference call and webcast daily and weekly, and informed the stakeholder bodies of the status and findings of the project.

In addition, public education and awareness of the project results were enhanced through the following activities. Exact details of the events and presented articles are covered in Chapter 8.

- Public showcase event at Intersolar North America: SunSpec is an Intersolar global partner and has produced the Intersolar Solar Finance and Asset Symposium program for the past six years. This public showcase event targets independent power producers, financiers, and utilities and typically attracts 250 qualified professionals.

- Project whitepapers and contributed articles: SunSpec featured the project whitepapers and project related articles in leading industry web sites and research portals.
- Two public webinars: SunSpec conduct several educational webinars with project partners targeting California stakeholders (ratepayers, utilities, operators, investors and equipment manufacturers), to inform of the findings and progress of this project.

## Key Lessons Learned

1. Advanced inverter functions varied in effectiveness depending on the feeder. Certain functions and associated settings showed increase in hosting capacity across all feeders and locations.
2. To increase the amount of DER capacity significantly beyond hosting capacity limits, DER management systems are needed that manage output based on real-time grid conditions.
3. Using smart inverter functions tends to be economical when the hosting capacity is constrained due to voltage issues on a distribution feeder. Smart inverter functions are more economical when new, costly equipment is otherwise needed to mitigate distribution constraints.
4. Using smart inverter functions may not be economical when the hosting capacity is thermally constrained if large upgrade projects are otherwise needed. Research is needed to explore the capability of the DER management system to address constraints caused by DER.
5. PV system designs (direct current/alternating current ratios) can impact the amount of PV curtailment due to smart inverter functions.
6. Testing the capabilities of commercial smart inverters in the lab and field for California Rule 21 compliance validated such functions. Communication systems using cellular networks worked reliably in the lab and field with minimum interruption.
7. Testing identified the need for DER gateways for smart inverter communication to enable the following:
    - Cybersecurity
    - Protocol translation capability
    - Scheduling capability
    - Cohesiveness in smart inverter communication across diverse brands
    - Failsafe modes of operation when utility communication is lost
    - Load unmasking
    - Prioritization of DER commands when multiple masters are managing DER
8. Communication test procedures developed for smart inverters must be targeted for maximum efficiency. The test procedures must be not only comprehensive but also able to be performed at a reasonable cost. This objective required that the tests emphasize the more critical and relevant features through all the test cases. It became clear as a result of this project that an ongoing effort is needed to maintain and improve the test

procedures as experience is gained in testing and deployment of Rule 21 compliant systems.

## Benefits to California

This project helped overcome three major barriers to achieving the state's energy goals: (1) demonstrating that California Rule 21 Phase 3 functions can be used feasibly, safely, and predictably via standardization, (2) demonstrating that DER levels connecting to the grid can be increased by 25 percent or more by using the Phase 3 advanced control functions, and (3) enabling a secure, scalable, and affordable cybersecurity infrastructure that can be accessed by all Californians now and in the future.

Specific benefits that accrue from this project include:

- Lower costs: Decreased costs enable more Californians to own and operate solar generation. This benefit accelerates the availability of advanced function inverters that are compatible with California Rule 21 Phases 1–3 and enables DER systems to provide grid support functions that otherwise require expensive physical grid upgrades. Open standard test procedures and certification criteria remove financial barriers for vendors, thus stimulating the inverter market without increasing cost.
- Greater reliability: Improved reliability equates to delivery of standardized DER control functions that minimize and ease reverse power flows, voltage sags/dips, and other conditions that degrade grid stability and DER performance. As a result, grid reliability and availability of access to locally harvested solar energy increase.
- Increased safety: The standard method for demonstrating compliance to California Rule 21 Phase 3 requirements eliminates the diversity in proprietary solutions and enables dynamic electrical control functions to be used safely at scale.
- Environmental benefits: DER systems can be grid-connected at 25 percent higher rates, nearly doubling the total potential market for fuel- and emissions-free solar PV.
- Consumer appeal: Advanced functionality and increased security helps PV system owners to participate in emerging wholesale ancillary grid services markets (such as scheduling that facilitate and supports the continuous flow of electricity supply) and aggregation networks, thus diversifying the potential revenue sources available for PV owners.

The Electric Power Research Institute estimates that a 25 percent increase could give California ratepayers a total present worth net benefit of more than $50 million. The details underlying this calculation are provided in Chapter 9.

# CHAPTER 1: Introduction

## Background

California has set the stage for a carbon-free future by mandating 100 percent of its electricity from renewable energy and zero-carbon energy-based resources by 2045. Although it is expected that more than 50 percent of this energy will originate from large renewable solar, wind, and hydro power plants, a significant percentage will need to come from distributed energy resources (DER), which are owned and operated by people and businesses of California as self-generation. These DER consist primarily of photovoltaic (PV) systems whose net energy impact on the grid may vary widely during a day, season, and year, depending upon weather and customer decisions.

Over the last few years, the Smart Inverter Working Group (SIWG) — sponsored by the California Public Utilities Commission (CPUC) and the California Energy Commission (CEC) — determined that DER must be grid-supportive and have accessible communication capabilities. This effort resulted in update of California Rule 21 (CA Rule 21), the regulations for interconnection of DER by California investor-owned utilities (IOUs). SIWG's Phase 1 required DER to implement key functions autonomously, while Phase 2 addressed the communication requirements for supporting these Phase 1 functions as well as additional Phase 3 DER functions.

The SIWG Phase 2 communication requirements identified the need for utilities to manage the DER dispersed throughout their jurisdictions. Such management necessarily involves monitoring and controlling these resources, in most cases indirectly through aggregators or facility management systems. To ensure that these utilities can communicate with all DER, the SIWG Phase 2 selected a default communications protocol — namely IEEE 2030.5, which all installations must support — although other communications protocols are permitted. These communication requirements were codified in the IOU Rule 21, with DER manufacturers given a short period of time to implement the IEEE 2030.5 communications protocol.

The CA Rule 21 SIWG and the CA Rule regulation address the interconnection of advanced inverters to the California distribution grid. In late 2014, this initiative introduced a range of control functions and data communications. This groundbreaking action set the stage for an interactive electrical grid capable of hosting increased levels of renewable solar resources. The smart inverter functionalities were organized into three phases based on stakeholder support, evidence of technical benefits, and market readiness.

Current mandatory CA Rule 21 Phase 1 functions address priority needs, including the ability of DER to ride-through grid disturbances and multiple methods of providing reactive power (vars) to help regulate grid voltages. Recent studies, including those by the U.S. Department of Energy and the CEC, have proven that these Phase 1 functions can increase the grid's ability to accommodate distributed solar generation, bringing value to consumers and utilities alike. These same studies have also demonstrated that the functions are practical — supportable by the current state of inverter technology. Commercial products are now available that support these functions.

Certification and compliance test frameworks have been developed, also through California Energy Commission support, and are now available to prove that products properly implement the Phase 1 requirements. These extensive tests ensure that diverse DER product types and brands will work properly together. The SIWG Phase 3 includes functions that have the potential to bring significant additional benefit but are less understood (technically) and involve economic uncertainty because of their impact on real power production. At the present time, these functions:

- Have not been modeled to understand how they should be utilized or configured
- Have not been sufficiently implemented or tested in real products in the lab or in the field
- Have not been assessed to determine the extent to which their optimal utilization would impact asset owners economically

The CA Rule 21 Phase 2 identifies communication requirements to support the advanced inverter functions, making it possible to remotely monitor and manage DER. IEEE 2030.5 is identified as the default protocol for utility integration. This protocol requires cyber certificates so that connections can be properly secured, but a Public Key Infrastructure (PKI) does not presently exist to support this use.

# CHAPTER 2: Impact Analysis of California Rule 21 Phase 3 Smart Inverter Functions

## Purpose

This purpose of the task is to comprehensively evaluate the smart inverter functions recommended for CA Rule 21, Phase 3. The goal is to address the challenges posed by increasing PV penetrations on the distribution grid such as reverse power flows, generation variability, significant voltage variations, and increased cybersecurity risks. These functions, which include real power management, have the potential to contribute significantly to the achievement of state energy goals including the new renewable portfolio standard (RPS) goal of 50 percent by 2030.

Smart inverter functions that were best understood both technically and economically and were more straightforward to implement have been addressed in the SIWG Phase 1. The functions identified in Phase 3 are more challenging, in terms of uncertainty regarding their implementation and their technical impact to the grid or economic impact or both to DER asset owners and other ratepayers. Implementing Phase 3 functions, which alter the real power flows of solar photovoltaic systems owned by consumers, is a sensitive topic due to monetary compensation mechanisms of real power as opposed to reactive power support.

## Scope

The overarching goal of this task is to inform stakeholders regarding the successful use and configuration of Phase 3 functions through a comprehensive assessment of CA Rule 21 Phase 3 functions by computer modeling and analysis. The project leveraged successful research in the areas of distribution circuit modeling by EPRI and the University of California, San Diego (UCSD) and extended the work performed in existing SunSpec and EPRI California Energy Commission projects to provide technical and economic guidance regarding implementation of the Phase 3 functions. This report also incorporates lessons learned and data collected by EPRI from California Solar Initiative (CSI) Phase 3 and 4 projects including hosting capacity (HC) analysis, distribution circuit models for California IOUs, distribution planning using EPRI's Distribution Resource Integration and Value Estimation (DRIVE) tool, and distribution system dynamic simulations using EPRI's OpenDSS electric power distribution system simulator (DSS).

## Hosting Capacity Analysis Method

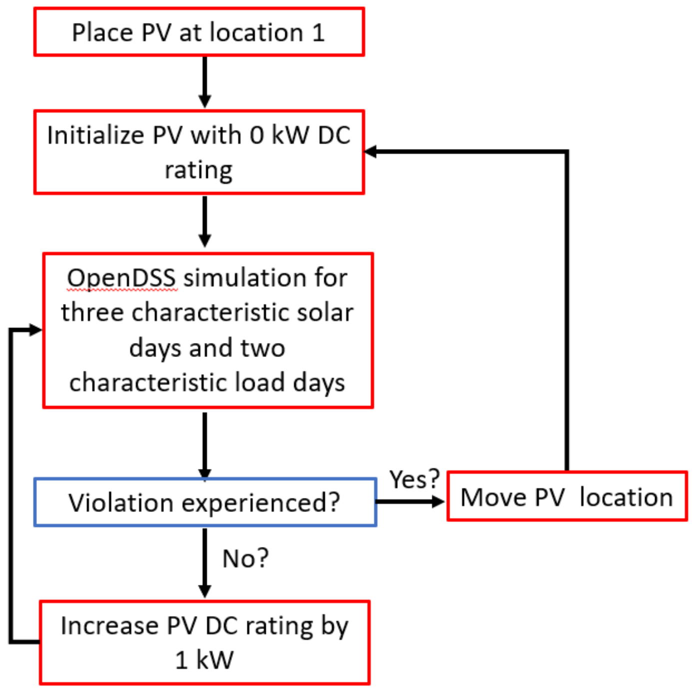
### Hosting Capacity Criteria

Following Rylander et al., [2] HC is referred to as the amount of solar PV output that could be accommodated without violating power quality constraints or reliability and without requiring infrastructure or equipment upgrades.

Figure 1 flowchart represents the process of determining HC used in this project. The HC was determined by increasing the PV DC power rating in 1 kW increments until one of the following is encountered:

- Voltage exceeding $\pm 5$ percent of the nominal feeder voltage (Range A for service voltage in ANSI standard C84.1).
- Current exceeding thermal rating of conductor or transformer. During this analysis all overloads occurred on conductors.

**Figure 1: Flowchart for Determining Baseline Hosting Capacity Analysis for Three Photovoltaic Locations on Each Feeder**




Source: Electric Power Research Institute

In this project, five feeders were studied. Rather than simulating feeders for a myriad of different permutations of small PV systems distributed across the feeders, a single utility-scale PV system is tested at three separate feeder locations at the front, middle, and end of the feeder. This approach allows performance of detailed sensitivity analyses of the impacts of the Phase 3 functions and their settings. The voltage or thermal issues experienced at these three carefully selected locations are expected to be representative of issues encountered with more realistic smaller and distributed PV systems.

## Load Data

An annual time-series of substation loading with 15-minute resolution was obtained from a real California distribution feeder in the same geographic region of the solar profile [3]. While the different feeders would experience different load profiles, for the purpose of a standardized comparison, all analyzed feeders were assumed to have the same load.

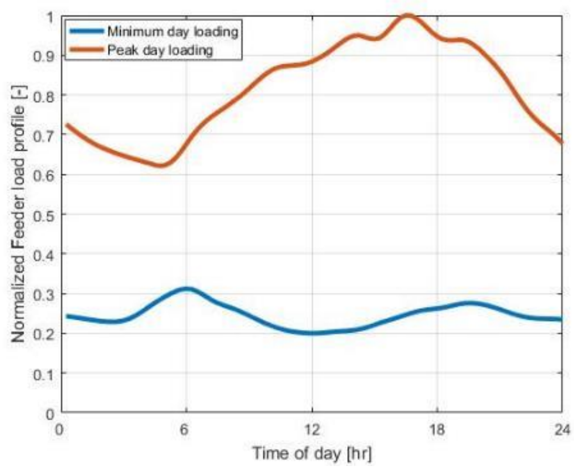
Individual load consumption data are generally not available for privacy reasons. As such data are the aggregate of individual feeder loads, substation load represents a sensible proxy for loading and thus is applied to every load in the feeder in typical distribution system studies [4], [5], [6]. While identical loads on all nodes would not be appropriate for simulating localized power quality such as on small feeder branches, the focus here is on power quality on the feeder trunk and load aggregation is then appropriate. The substation demand time-series for each day has been normalized using the annual peak load to provide a load shape.

This load shape is applied to each load on the feeder, where it is used as a multiplier on the rated load to determine demand. Characteristic loading days are chosen to approximate extremes of feeder loading, considering the days of lowest and greatest aggregate load from the yearlong loading time series, as shown in Figure 2.

The smallest load day was chosen because the node voltages are expected to be highest and thus, most susceptible to overvoltages (voltages larger than 1.05 pu) once PV sources are added. Similarly, low load levels consume less PV generation locally creating larger reverse power flows that may violate thermal limits. In this case, PV curtailment was most likely to be needed to counteract these effects, and/or reactive power from PV sources could reduce overvoltages.

During the peak load day, PV penetration is expected to cause less issues as it offsets load, thus raising voltages that are expected to be low to start with and reducing losses by supplying energy locally. During high load times, PV inverters can provide reactive power to support feeder voltage regulation at night.

**Figure 2: Characteristic Load Profiles Considered in Hosting Capacity Analysis**




Source: Electric Power Research Institute

## Solar Data

This section described the procedure for creating 1-minute resolution solar radiation time series to form a set of characteristic solar generation days (specifically a clear, partly cloudy, and overcast day) for the distribution feeder analysis. The high temporal resolution allows capture of the high variability of solar irradiance during cloud cover. High frequency solar irradiance data over a year are a critical input to studies of high PV penetration on distribution feeders. Annual data capture seasonal variations in cloud cover and solar incidence angles needed to understand metrics such as annual losses, PV generation, and curtailment on the feeders. High-resolution data are needed to capture the minute-scale variability introduced by cloud cover. Such solar irradiance data are rare, but UCSD has deployed weather-monitoring stations that capture and record real-time measurements of solar radiation with 1-second resolution.

The station at Mandell Weiss Theatre located at (32.870800° North, 117.241448° West) in La Jolla, California, was selected. Measurements span four years of near-continuous operation. The period between December 15, 2016 and December 15, 2017 was used for the study. The three days with missing data were replaced with the same calendar date from an earlier year that featured a full dataset for the day.

Point irradiance overestimates the variability of a large solar installation, which can be geographically wide. However, sub-minute irradiance variability typically averages out across a geographic area over a minute as effects are localized and move across the area in an uncorrelated fashion. Therefore, the 1-second irradiance time-series was averaged to 1 minute to better represent the PV variability of a large PV system as well as variability that is relevant to distribution feeder operation.

### Indices for Classification of Daily Variability

The variability of solar time-series is typically classified according to two criteria: 1) daily variability index [7] and 2) daily average clear sky index [8]. These indices provide information on the state of the cloud cover and its changes.

#### *Daily Variability Index*

To quantify the effect of fluctuations with respect to the daily irradiance time-series, a variability index (defined as VS consistent the original reference) is used following Lave et al. [7].

$$RR_{\Delta t}^{Irr}(t) = \frac{1}{\Delta t}\left(\Sigma_{t}^{t+\Delta t} Irr - \Sigma_{t-\Delta t}^{t} Irr\right)$$

$$\mathrm{VS}_{\mathrm{RR}}(\Delta t) = 100\% \max\left[RR_o \times P\left(\left|RR_{\Delta t}^{Irr}\right| > RR_o\right)\right]$$

The daily ramp rate time-series ($RR_{\Delta t}^{Irr}(t)$) is calculated considering changes in global horizontal solar irradiance ($Irr$) between consecutive measurements ($\Delta t = 1\,\mathrm{sec}$ ). The equation weights the probability (*P*) of an irradiance ramp event by magnitude with respect to a set threshold, $RR_o$. The greater the fluctuations relative to the limit, the higher the VS assigned to the daily irradiance.

#### *Daily Clear Sky Index*

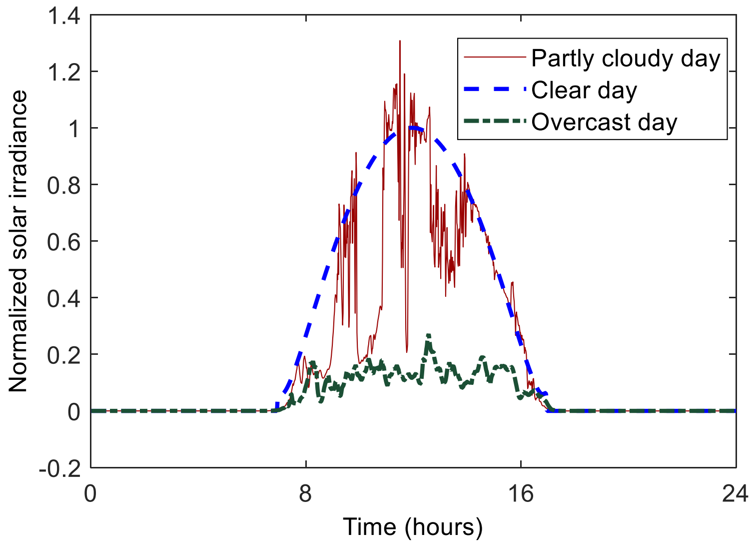
The clear sky index ($\kappa_T$) relates the measured irradiance ($Irr$) to the expected clear sky irradiance ($Irr_{csk}$). A $\kappa_T$ of unity indicates clear sky conditions are present, while reductions from unity indicate cloud cover. A smaller $\kappa_T$ indicates thicker clouds. The clear sky irradiance is determined using the Ineichen-Perez clear sky model [9] and climatological Linke turbidity factor from the Solar Radiation Database (SoDa). For more information on the Linke turbidity modeling of clear sky irradiance see Reno et al. [10].

$$\kappa_T(t) = \frac{Irr\ (t)}{Irr_{csk}(t)}$$

### Representative Clear, Partly Cloudy, and Overcast Days

A clear day is defined as $\kappa_T$ exceeding 0.95 for more than 95 percent of the day. Similarly, an overcast day is defined as $\kappa_T$ less than 0.35 for at least 95 percent of the day. The remaining days were classified as partly cloudy. The yearlong irradiance time-series contained 91 overcast days, 187 partly cloudy days, and 87 clear days. A day from each classification is given in Figure 3 (clear: July 7, 2017, partly cloudy: July 29, 2017, overcast: June 3, 2017). The three days were all chosen in summer, as high solar generation produces the greatest integration impacts. The partly cloudy day was chosen because it had the highest relative VS for the month of July. These three days will be used throughout the rest of the analysis as representative days to avoid the computational burden that would be related to running thousands of annual quasi-static time-series (QSTS) analyses.

**Figure 3: Daily Irradiance Time Series**



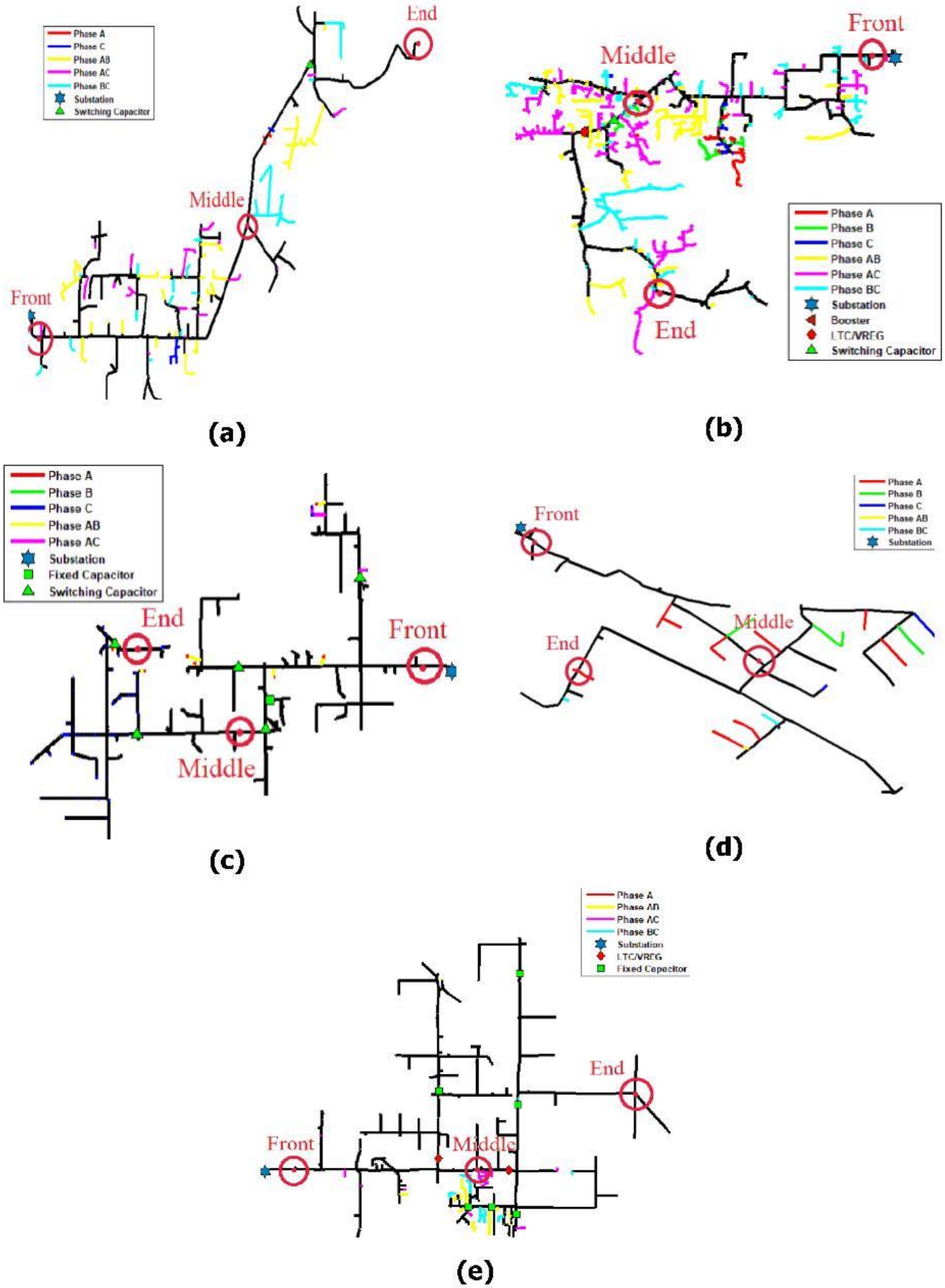

**Three representative solar days from the time series, clear, partly cloudy, and overcast. All-time series are normalized to the peak irradiance on the clear day.**

Source: Electric Power Research Institute

## Distribution Feeders

The analysis in this report was performed on five disparate electric grids representing real California distribution feeders. The five feeders represent a range of sizes, loading conditions, and topologies, chosen from the 16 feeders characterized in EPRI's CSI 3/4 project [3] [11].

The feeders are introduced in Figure 4, an overview of feeder characteristics is given in



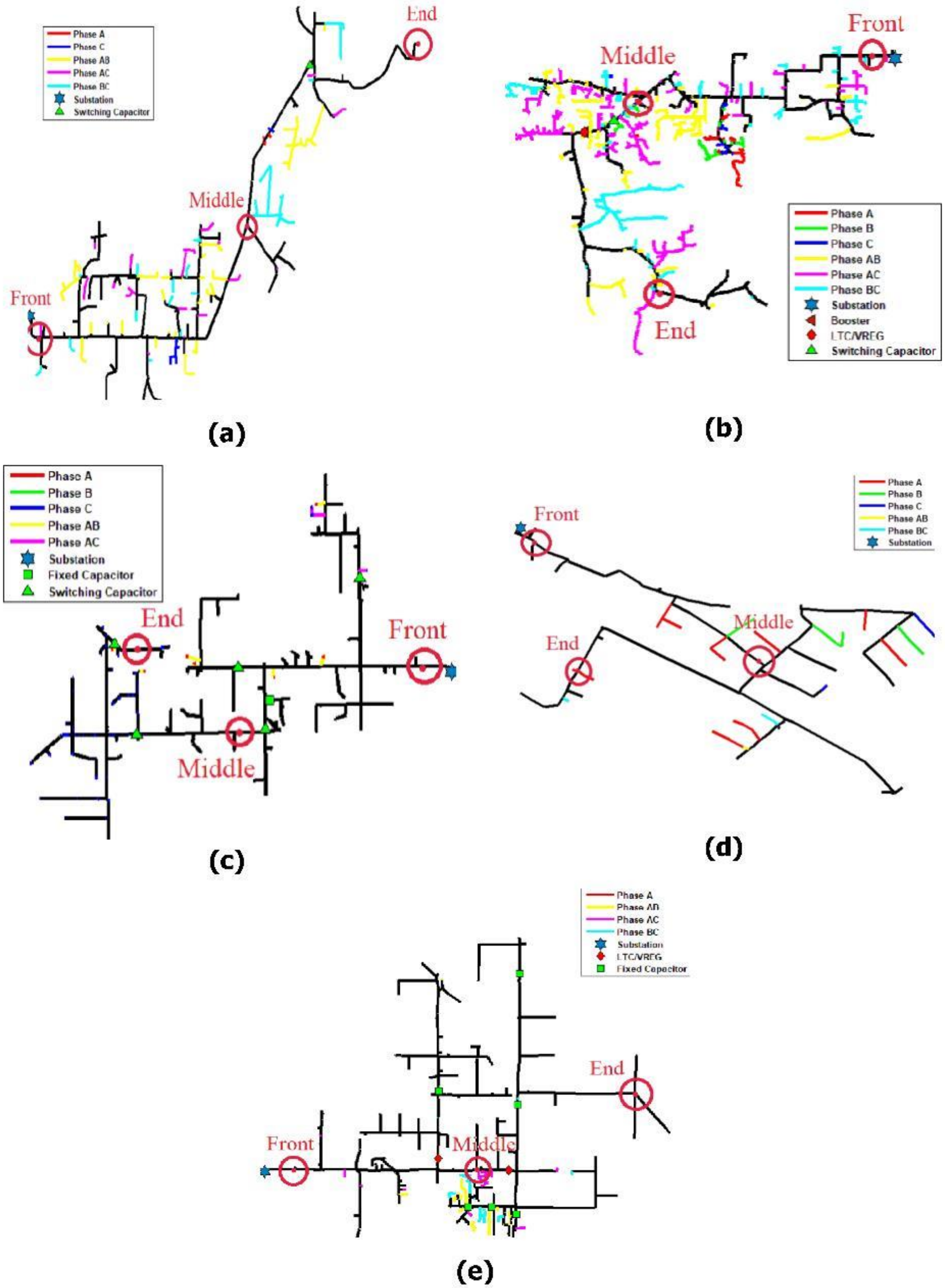

**For Feeders (a) 631 (b) 683 (c) 2921 (d) 888 (e) 2885.**

Source: Electric Power Research Institute

The feeders were modeled in EPRI's OpenDSS, an open-source grid modeling software ideally suited for studying the integration of distributed generation on distribution feeders. MATLAB was used as a wrapper to perform the repeated simulations of various settings and combinations of loading and PV profiles and locations.

Table 1, and the PV locations are provided in Table 2. The five feeders represent a range of sizes, rated loading conditions, and topologies. Feeder 631 has the least buses, the lowest rated loading, and the least number of voltage regulation devices (2). Feeder 2885 has the largest rated loading and most voltage regulating devices (11). Feeder 888 has the most loads, and the second highest rated load, despite being a very short feeder. Feeder 683 has the most nodes, but the second least total rated loading.

## Figure 4: Circuit Plot by Phase




**For Feeders (a) 631 (b) 683 (c) 2921 (d) 888 (e) 2885.**

Source: Electric Power Research Institute

The feeders were modeled in EPRI's OpenDSS, an open-source grid modeling software ideally suited for studying the integration of distributed generation on distribution feeders. MATLAB was used as a wrapper to perform the repeated simulations of various settings and combinations of loading and PV profiles and locations.[1]

**Table 1: Overview of Five Feeders Selected for Study**

| | Feeder 631 | Feeder 683 | Feeder 888 | Feeder 2921 | Feeder 2885 |
|---|---|---|---|---|---|
| Longest length (km) | 11.7 | 17.9 | 2.8 | 15.5 | 11.9 |
| Number of buses | 1505 | 3411 | 1489 | 1365 | 2170 |
| Feeder type | 4-wire | 4-wire | 4-wire | 4-wire | 3-wire |
| Number of nodes | 3015 | 5710 | 3561 | 3466 | 5137 |
| Number of loads | 514 | 1139 | 1238 | 746 | 1220 |
| Total rated load (MVA) | 4.4 | 7.1 | 17.6 | 8.5 | 24.3 |
| Number of load tap changers | 1 | 2 | 5 | 1 | 5 |
| Number of capacitors | 1 | 1 | 0 | 6 | 6 |

**Nodes are defined as all the phases of each bus. The longest length is the distance from the substation to the farthest node on the feeder. The number of capacitors covers both switched and fixed capacitor banks.**

Source: Electric Power Research Institute

## Photovoltaic Systems

### Location

For each of the feeders, three locations for PV systems were identified at the feeder head, middle, and end following the streamlined HC approach outlined in Rylander et al. [2]. The following parameters were considered in the selection of the PV hosting bus: 1) the feeder short-circuit impedances, 2) X/R ratios, 3) equipment ratings, and 4) nearby voltage regulation equipment locations. The locations of the PV systems on each feeder are given in Table 2 along with the distance from the substation, the short circuit current, and the X/R ratio.

Best candidates for hosting should have X/R ratios appropriate to their location. In specific, the selected bus on the feeder head should have a low short-circuit impedance and high X/R ratio, the bus on the middle feeder should have a medium short-circuit impedance and medium X/R ratio, and the bus on the feeder end should have a high short-circuit impedance and low X/R ratio. Bus selection was limited to three-phase feeder main lines and locations without very low upstream element ratings. Finally, adjacency to voltage regulation equipment was

[1] The different days were assumed to be independent in the QSTS. In other words, information from the final time step of one day had no bearing on the first-time step of the next day, which is desired given the jump experienced in loading.

considered. For example, a location immediately downstream of a voltage regulator or immediately adjacent to a capacitor bank is avoided since the effects of PV penetration would be stifled.

### Modeling

For the transposition from global horizontal irradiance to plane-of-array irradiance, the PV systems are assumed to be oriented due south with a 20º tilt from the horizon for the translation from global horizontal irradiance to plane-of-array irradiance. The irradiance time series is fed directly into OpenDSS. In the OpenDSS PV model, PV conversion efficiency was assumed constant, specifically, temperature effects were ignored. PV efficiency (and output) at peak irradiance is overestimated by 15 percent given typical PV cell temperatures of 55°C for peak irradiance around 1 kW/m$^2$, standard test conditions for PV efficiency of 25°C, and typical decreases in efficiency with temperature of 0.5 percent/K. The efficiency of the inverter was assumed to be 100 percent, which is close to the typical efficiencies of 98 percent at peak irradiance. Other losses are ignored.

The ratio of AC inverter rating to DC PV rating is 1:1.2. This indicates that the inverters are undersized, which has been common practice [12]. Due to convergence issues for Feeder 2885 in OpenDSS, the AC to DC ratio was set to 1.0, but the maximum irradiance was clipped to 0.8 kW/m$^2$ to achieve similar active power feed-in as on the other feeders.

These assumptions overestimate impacts of PV real power (overestimate over-voltages and reverse power flow) and underestimate the ability of PV systems to counteract high voltage conditions through volt-var control (VVC) with watt priority. For example, in this report, the amount of reactive power support the inverter can provide becomes zero for irradiance greater than ~0.8 kW/m$^2$. In reality, for an irradiance of 0.8 kW/m$^2$, losses would limit the DC output to 0.85 (temperature efficiency) x 0.98 (inverter efficiency) = 0.83 of AC capacity, which would decrease real power output by 17% and permit reactive power operation at 55 percent (=$\sqrt{(1 - 0.832)}$ ) of inverter capacity. The ability for reactive power provision would only go to zero at 0.96 kW/m$^2$, as PV DC output then equals the AC rating of the inverter. However, as the worst conditions, (highest irradiance), typically determine the HC, and since irradiances exceeding 0.96 kW/m$^2$ were observed on the partly cloudy and clear days, the HC metrics reported later in this chapter are realistic. This means that reactive power support would indeed not be available during the conditions that define HC. For accurate estimation of feeder power quality metrics and curtailment, more accurate and realistic PV performance models are recommended for future studies.

**Table 2: Location Information for Photovoltaic Systems on Each Feeder**

| | PV Location | Distance (km) | $I_{sc}$ (A) | $X_1/R_1$ |
|---|---|---|---|---|
| Feeder 631 | Front | 0.7 | 6426 | 5.14 |
| | Middle | 6.0 | 1928 | 1.94 |
| | End | 11.7 | 959 | 1.27 |
| Feeder 683 | Front | 0.7 | 5576 | 4.61 |
| | Middle | 7.6 | 1701 | 2.40 |
| | End | 15.0 | 523 | 0.69 |
| | Front | 0.1 | 9871 | 4.81 |
| Feeder 888 | Middle | 1.2 | 2846 | 2.41 |
| | End | 2.4 | 1907 | 1.00 |
| | Front | 1.0 | 4693 | 4.16 |
| Feeder 2921 | Middle | 7.3 | 1631 | 2.27 |
| | End | 14.6 | 920 | 1.95 |
| Feeder 2885 | Front | 0.8 | 71368 | 3.54 |
| | Middle | 4.5 | 2884 | 2.10 |
| | End | 9.4 | 984 | 0.81 |

**Distance refers to the distance from the substation.**

Source: Electric Power Research Institute

# Baseline Hosting Capacity Assessment

## Baseline Hosting Capacity Determination and Measures that Increase Hosting Capacity

While PV systems offer environmental benefits, large amounts of PV output on distribution feeders can result in adverse power quality or reliability impacts. For example, when the power injection from the PV systems exceeds the consumption of local load, reverse power flows occur. In extreme cases, such circumstances can lead to over-voltages on the injection bus as well as overloading of component thermal ratings. In addition, fluctuations in PV generation due to intermittent cloud cover can lead to rapid fluctuation of feeder voltages [13].

The HC of the five feeders in their original configuration and without infrastructure upgrades (here referred to as the baseline HC) was analyzed first. In total, more than 4 million QSTS simulations were run in the baseline HC analysis considering the three characteristic solar days, two characteristic load days, three PV locations, and PV increments of 1 kW on the five feeders. The smallest PV rating that violates the thermal ratings of feeder equipment or causes over-voltages is given for each feeder and PV location. Under-voltages were not considered, as they are not caused by the addition of PV penetration to a feeder. HC is also expressed as PV penetration, defined as the ratio of the DC rating of the PV system and the feeder rated load.

In the following sections, feeder modifications are presented that allow increases of the baseline HC by 25 percent using conventional measures and smart inverter Phase 3 functions.

## Baseline Hosting Capacity Results

The baseline HC for the feeders is introduced in Table 3. For all feeders, except for Feeder 888, the limiting/smallest HC occurs when the PV system is at the feeder end. Feeder 888 is limited at the feeder head and shows high PV HC amounting to 132 percent PV penetration. The unexpected result can be attributed to the fact that Feeder 888 is extremely short, heavily loaded, and has five voltage regulators. The feeders display a mix of both thermal and voltage HC limitations. Feeder 683 is the only feeder that is limited completely by thermal overloads, while Feeder 2921 is limited completely by voltage violations.

**Table 3: Summary of Hosting Capacity on Each Feeder for Three Selected Photovoltaic System Locations**

| | PV Source at Feeder Front | PV Source at Feeder Middle | PV Source at Feeder End | PV Hosting Capacity |
|---|---|---|---|---|
| Feeder 631 | 7,622 kW<br>Thermal<br>Minimum load<br>Clear and cloudy | 5,182 kW<br>Voltage<br>Minimum load<br>Cloudy | 1,385 kW<br>Thermal<br>Minimum load<br>Clear or cloudy | 31.5% |
| Feeder 683 | 13,980 kW<br>Thermal<br>Minimum load<br>Cloudy | 12,500 kW<br>Thermal<br>Minimum load<br>Cloudy | 4,060 kW<br>Thermal<br>Minimum load<br>Clear or cloudy | 23.2% |
| Feeder 888 | 23,286 kW<br>Voltage<br>Minimum load<br>Clear | 26,042 kW<br>Thermal<br>Minimum load<br>Cloudy | 25,804 kW<br>Thermal<br>Minimum load<br>Cloudy | 132.2% |
| Feeder 2885 | 12,522 kW<br>Thermal<br>Minimum load<br>Clear and cloudy | 10,845 kW<br>Voltage<br>Minimum load<br>Cloudy | 3,511 kW<br>Voltage<br>Minimum load<br>Clear | 14.5% |
| Feeder 2921 | 4,447 kW<br>Voltage<br>Minimum load<br>Cloudy | 2,190 kW<br>Voltage<br>Minimum LOAD<br>Clear or cloudy | 1,535 kW<br>Voltage<br>Minimum load<br>Clear or cloudy | 18.1% |

**Colored entries indicate the PV location with the lowest HC on the feeder. Blue highlights thermal constraints on HC, while red indicates voltage constraints on HC.**

Source: Electric Power Research Institute

For all feeders, the overcast scenario produces the least constraints on HC. This result is expected, since HC is limited by peak production of PV, which is not a concern under low irradiance.

With the exception of Feeder 888, both the movement of the PV source towards the end of the feeder, and reduction in loading decreases HC. These conclusions are also expected, since higher loading causes more PV power to be consumed locally and reduces the likelihood and magnitude of reverse power flows, while the end of the feeder tends to have smaller conductors that are farther away from the voltage regulators or substation.

For most scenarios, the hosting capacities for clear and partly cloudy days are similar because overvoltage violations and thermal violations are usually driven by the maximum solar irradiance. Since the partly cloudy day contains a clear period around noon, its maximum solar irradiance is similar to that of the clear day.

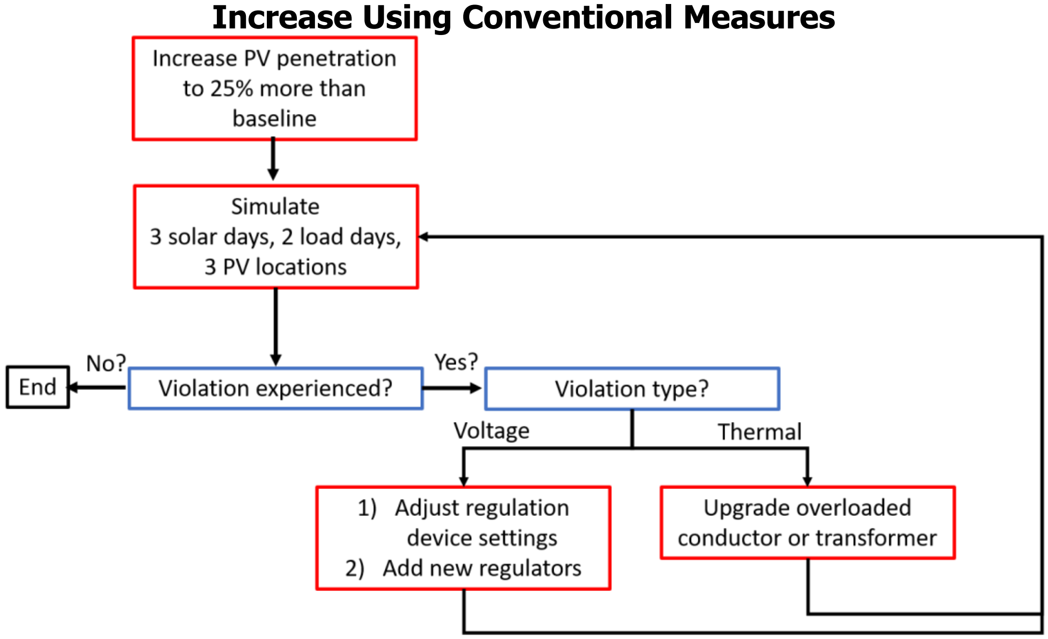
## Conventional Upgrades to Increase Hosting Capacity by 25 Percent

### Conventional Upgrade Method

Increasing the HC of distribution feeders using conventional methods can be realized through either adjustment of existing feeder devices or through the addition of new devices or power lines. For economic reasons, priority is given to adjustment of existing devices, while new devices are added only if adjustments are insufficient. Expert-selected changes to regulator device settings or conductor ratings were attempted through trial and error but follow some logical hierarchy. The flowchart for the process is given in Figure 5. The hierarchy of adjustments to resolve voltage violations is:

1. Adjust existing voltage regulation devices.
    a. Adjust capacitor voltage control setpoints.
    b. Adjust load tap changer (LTC) and/or voltage regulator settings.
    c. If a. and b. are not sufficient to increase HC,
        - Reset adjusted settings to original utility settings.
        - Go to (2).
2. Add a new LTC or voltage regulator and determine sufficient settings and best locations based on the feeder voltage profile improvements.
    a. If there was an undervoltage, add capacitor and determine proper settings.

**Figure 5: Flowchart Describing Process of Realizing 25 Percent Hosting Capacity Increase Using Conventional Measures**




Source: Electric Power Research Institute

On the analyzed feeder models, capacitor bank controls were represented as either voltage controlled or fixed. Other capacitor bank control modes such as time and temperature were not considered.

For thermal constraints, an overloaded conductor is replaced with a conductor with a larger cross section, and an overloaded transformer is replaced with a transformer with a larger rating. These steps are performed until an increase in HC of at least 25 percent is realized.

## Conventional Upgrade Results

A summary of the new HC values for the feeders considering conventional upgrades is given in Table 4, and the associated measures are described in Table 5. Since voltage regulator steps are discrete, the HC gains were often significantly larger than 25 percent. Each feeder required a unique solution to reach the desired result. Feeder 683 was corrected using the same approach for all three feeder locations — by reducing by 1 Volt the upper limit at which the capacitor was turned off. The largest increase in HC (85 percent) was realized for Feeder 2921 with the PV source at the front of the feeder by simply turning off all capacitor banks in the feeder.

**Table 4: Hosting Capacity for Five Feeders After Conventional Upgrades**

| | PV Source at Feeder Front | PV Source at Feeder Middle | PV Source at Feeder End | PV Hosting Capacity | Increase in Hosting Capacity |
|---|---|---|---|---|---|
| Feeder 631 | 11,427 kW Thermal | 6,825 kW Voltage | 1,830 kW Thermal | 41.6% | 31% |
| Feeder 683 | 17,894 kW Thermal | 16,500 kW Thermal | 5,196 kW Voltage | 72% | 28% |
| Feeder 2885 | 15,652 kW Thermal | 13,773 kW Voltage | 4,810 kW Voltage | 19.8% | 29% |
| Feeder 2921 | 8,226 kW Voltage | 3,022 kW Voltage | 1,918 kW Voltage | 22.6% | 49% |
| Feeder 888 | 29,574 kW Voltage | 33,334 kW Thermal | 32,771 kW Thermal | 168.0% | 27% |

**The increase in HC is calculated with respect to the baseline.**

Source: Electric Power Research Institute

Reconductoring was required to resolve thermal violations for eight out of 15 feeder–PV location combinations. Voltage violations of Feeder 2885 at the end PV location and Feeder 2921 at the front PV location were resolved by adjusting the regulator/capacitor settings (Step 1 of the method). The remaining voltage violations (five out of 15 feeder–PV location combinations) required adding a new LTC or voltage regulator.

Increases in HC resulting from modifications to regulation equipment settings are convenient for utilities compared to the addition of new regulators or reconductoring of distribution lines.

Modifications of settings involve a fast, easy, and economical DER integration strategy that is already employed by utilities in practice. However, these settings represent deviations from the optimal settings chosen for the feeders before the presence of DER and could incur a trade-off such as increased losses or larger wear and tear on voltage regulators. Such unintended consequences of the revised settings were not examined here due to time constraints. However, the results shown here indicate that simple and economic integration measures can often result in considerable increases in feeder baseline HC.

**Table 5: Conventional Infrastructure Upgrade Measures Implemented to Achieve at Least 25 Percent Increase in Hosting Capacity for Each Photovoltaic Location**

| Feeder | Front Location | | Middle Location | | End Location | |
|---|---|---|---|---|---|---|
| | PV Penetration Increase | Hardware Upgrade | PV Penetration Increase | Hardware Upgrade | PV Penetration Increase | Hardware Upgrade |
| Feeder 631 | 33% | Re-conductor 512 ft of line, OH-AAC | 31% | Add 1 voltage regulator | 32% | Reconductor 100 ft of line, OH-CU |
| Feeder 683 | 28% | Re-conductor 199 ft of line, OH-AAC | 32% | Re-conductor 199 ft of line, OH-AAC | 28% | Reconductor 199 ft of line, OH-AAC |
| Feeder 2885 | 25% | Re-conductor 1,135 ft of line, OH-AAC | 27% | Add 1 voltage regulator | 37% | Lower voltage setpoint of voltage regulator |
| Feeder 2921 | 85% | Switch off all capacitors | 28% | *Add 1 voltage regulator | 25% | *Add 1 voltage regulator |
| Feeder 888 | 27% | Add 1 capacitor | 28% | *Re-conductor 1,700 ft of line, OH-AAC and *Re-conductor 385 ft of line, UG-AAC | 27% | *Reconductor 1,700 ft of line, OH-AAC and *Reconductor 385 ft of line, UG-AAC |

**The new hosting capacities are summarized in Table 4. The increase in HC is calculated with respect to the baseline. A star indicates that the upgrades on that feeder are the same for multiple PV locations. For distribution line upgrades, UG and OH indicate underground and overhead lines, respectively. AAC and CU indicate aluminum and copper type conductors, respectively. Additional details on the upgrades are presented in Appendix A.**

Source: Electric Power Research Institute

## Annual Metrics with Conventional Upgrades

Table 6 lists the summary results for the annual QSTS performed at 15-minute resolution using the full year of irradiance and load data. These metrics, which represent the economics associated with feeder operation, are used in a later phase of this project to perform a cost-benefit analysis of smart inverter Phase 3 functions.

**Table 6: Quasi-Static Time-Series Summary Results of Feeder Load, Losses, and Photovoltaic Generation**

| Feeder | PV Location | Total Losses (MWh) | Total PV Generation (MWh) | Total Load (MWh) | Total Losses (%) |
|---|---|---|---|---|---|
| Feeder 631 | End | 857 | 2,905 | 21,282 | 4.0 |
| | Middle | 819 | 10,607 | 21,282 | 4.0 |
| | Front | 888 | 15,601 | 21,282 | 4.1 |
| Feeder 683 | End | 655 | 8,880 | 13,119 | 5 |
| | Middle | 804 | 27,340 | 13,119 | 6 |
| | Front | 1030 | 30,470 | 13,119 | 7.8 |
| Feeder 888 | End | 524 | 6,027 | 54,718 | 1.0 |
| | Middle | 488 | 6,034 | 54,718 | 0.9 |
| | Front | 464 | 5,383 | 54,718 | 0.9 |
| Feeder 2885 | End | 2,170 | 7,693 | 69,529 | 3.1 |
| | Middle | 2,256 | 7,770 | 69,529 | 3.2 |
| | Front | 2,287 | 7,769 | 69,529 | 3.2 |
| Feeder 2921 | End | 715 | 3,094 | 25,816 | 2.7 |
| | Middle | 713 | 4,330 | 25,816 | 2.7 |
| | Front | 713 | 9,072 | 25,816 | 2.7 |

**For selected feeders with conventional upgrades based on hourly analysis for yearlong operation.**

Source: Electric Power Research Institute

# Phase 3 Inverter Functions to Realize 25 percent Greater Hosting Capacity

Smart inverter functions can help to increase feeder PV HC potentially at a fraction of the cost of conventional measures. This project examined the following Phase 3 functions available on smart inverters to control the distribution system voltage and reduce reverse power flows:

- Volt-var
- Volt-watt
- LMRP, meaning watt curtailment independent of voltage

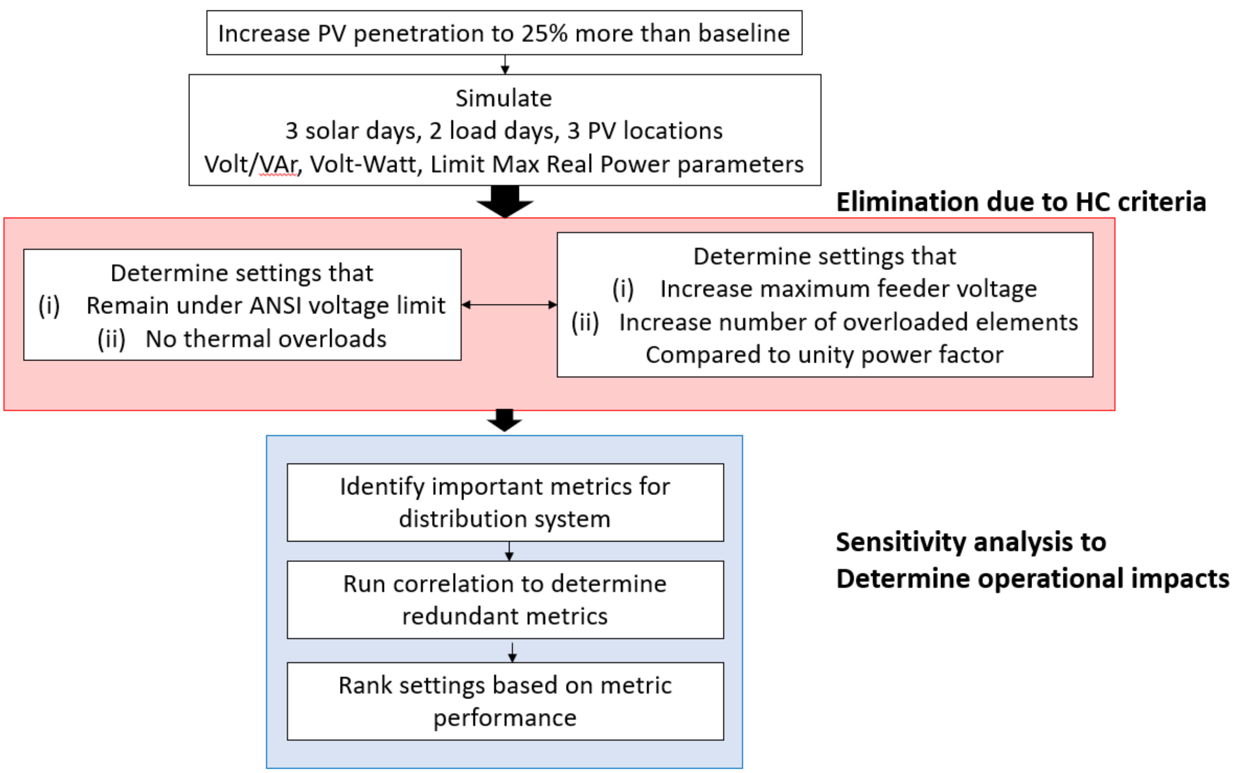
These functions were recommended by the SIWG of the CPUC and CEC for inclusion in Rule 21 as mandatory or optional capabilities for all inverter-based DER systems [14]. Further, these functions were included in the revised IEEE 1547-2018 [15].

Phase 3 functions influence active (LMRP, volt-watt) and reactive power (volt-var) provided by the PV systems to flatten feeder voltage profiles and reduce reverse power flows, thereby enabling greater feeder HC. PV impact studies with smart inverter Phase 3 functions are complex due to complicated interaction between smart inverters and capacitors, voltage regulators, and LTCs. Modeling these interactions comprehensively is quite complex as many possible solutions and scenarios exist. The third and the last stage of the PV impact analysis examines smart inverter Phase 3 functions and builds upon earlier sections as follows:

1. Establish the baseline PV hosting with uncontrolled PV active power and no reactive power.
2. Identify recommended conventional upgrades. Again, only uncontrolled PV active power and no reactive power are considered.
3. Identify recommended Phase 3 function and settings within those functions.

The last stage involves simulating a large number of Phase 3 function settings and scenarios. As in the baseline simulations, each feeder was simulated under the same 18 combinations of load, PV profile, and PV location. This section introduces the analyzed functions and corresponding settings and investigates the settings that achieve 25 percent increase in HC. A detailed sensitivity analysis with the objective of identifying settings that perform well regarding various distribution and PV system metrics is conducted later. The overall process used in the third stage of this study is introduced in the flowchart in Figure 6.

**Figure 6: Setting Determination Process for Phase 3 Smart Inverter Functions**




**Flowchart describing the process of determining which settings should be recommended for Phase 3 smart inverter functions.**

Source: Electric Power Research Institute

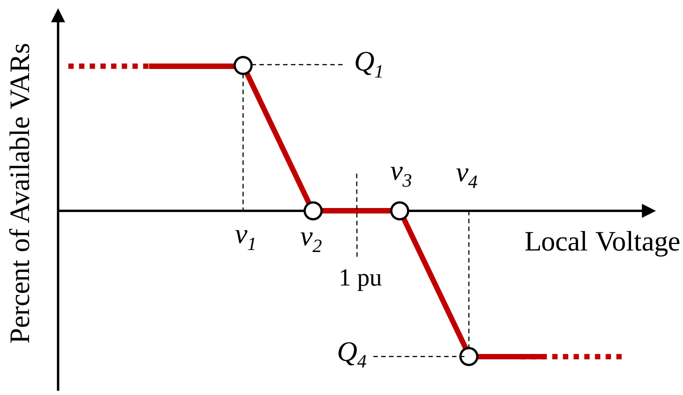
## Inverter Control Functions

OpenDSS supports Phase 3 inverter functions in QSTS simulations. The numerical implementation of inverter control settings and accuracy of the inverter model in OpenDSS have been successfully validated [16]. Since the specific objective for the Phase 3 PV inverter functions depends on individual feeder characteristics and PV location, a wide range of settings is examined and feeder impacts are quantified. The infinite number of all control settings is discretized uniformly to identify the best settings within each function. The studied functions and control settings are introduced in the following subsections.

### Volt-Var

Volt-var functions allow PV smart inverters to counteract voltage deviation from the desired voltage reference. Volt-var functions operate by producing or consuming reactive power according to a fixed volt-var curve that specifies the reactive power as a control action against the voltage measured at the inverter's point of coupling (Figure 7).

**Figure 7: Volt-var Curve**



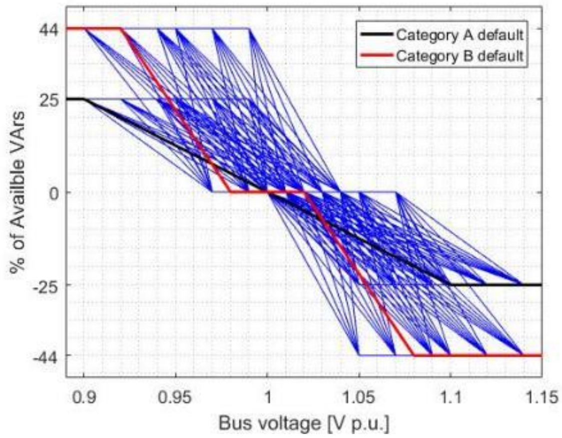

**Volt-var curve using available reactive power of PV system to control voltage. Values of $v_1, v_2, v_3, v_4, Q_1,$ and $Q_4$ are modified as shown in Figure 8 [17] .**

Source: Electric Power Research Institute

Figure 7 describes the volt-var function. Var-priority VVC outputs reactive power from the inverter following the same control curve, but instead limits real power so that reactive power needs can be fully satisfied. Therefore, var-priority volt-var curtails the real PV power output if there is insufficient inverter capacity to provide sufficient var output to regulate voltage based on the droop curve. Since the maximum var output is 44 percent, real power output below 90 percent = $\sqrt{(1-0.44^2)}$ of the inverter rating does not require curtailment.

Figure 8 and Table 7 show the complete set of 368 volt-var function settings, which were not required to be symmetric.

**Figure 8: Analyzed Volt-Var Settings Resulting in 368 Unique Curves**




**The default curves, according to Table 10 in the IEEE 1547-2018 standard, are shown in black and red for category A and B, respectively.**

Source: Electric Power Research Institute

**Table 7: Volt-Var Parameters and Analyzed Settings**

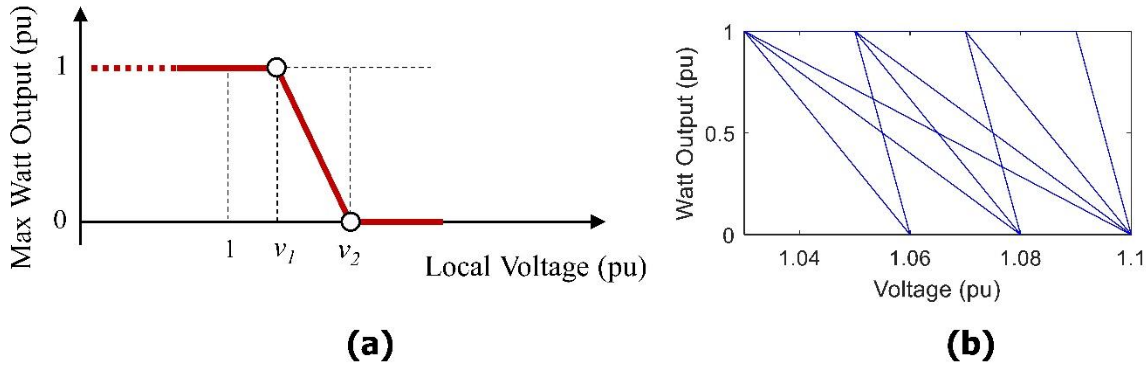
| Volt-var Parameter | Analyzed Settings |
|---|---|
| Deadband ($v_3 - v_2$) | 0, 0.02, 0.04, 0.06, and 1 V pu |
| Maximum reactive power support ($Q_1 = -Q_4$) | 25%, 44% |
| Droop slopes ($Q$ / [$v_2 - v_1$]) | 2–44% |
| Nominal voltage ([$v_2 + v_3$]/2) | 1, 1.02, and 1.04 V pu |

Source: Electric Power Research Institute

### Volt-Watt

The volt-watt function allows the PV inverter to be configured using a piece-wise linear curve limiting watt output as a function of the voltage at the point of coupling. PV power output is curtailed as the voltage at the point of coupling increases, which reduces voltage and PV export onto the grid, albeit at the cost of eliminating potential PV generation and therefore revenue for the PV system owner. Figure 9 (a) shows the concept. Figure 9 (b) presents the array of settings selected in this study to sample the infinite number of possible curves. The curve provides nine droop rates between 14.2 percent and 100 percent per 0.01 pu, $v_1$ = 1.03, 1.05, 1.07, and 1.09 V pu, $v_2$ = 1.06, 1.08, and 1.10 V pu. Consistent with the volt-watt implementation in OpenDSS, the average voltage across the three PV phases is used as reference to the curve.

**Figure 9: Settings Curve of Volt-Watt Function and Analyzed Volt-Watt Settings**




**(a) Settings curve of volt-watt function [18]. The deadband starts at 1 V pu and ends at $v_1$, and the watt output is curtailed based on the steepness of the droop slope past $v_1$. (b) The analyzed volt-watt settings (nine curves) extend beyond the lowest and highest voltage points shown in the figure.**

Source: Electric Power Research Institute

**Table 8: Volt-Watt Parameters and Analyzed Settings**

| Volt-Watt Parameter | Analyzed Settings |
|---|---|
| Deadband ($v_1$– 1) | 0.03, 0.05, 0.07, and 0.09 V pu |
| Droop slopes (1 / [$v_2$ – $v_1$]) | 14.2–100% |

Source: Electric Power Research Institute

### Limit Maximum Real Power Mode

The limited maximum real power (LMRP) function imposes an upper limit on the real power generation of the PV system since adverse PV effects generally occur during peak PV output. Curtailing maximum power presents a simple method for reducing adverse PV effects, while maintaining the ability to feed in all PV generation during most hours of the year. The maximum level of generation is defined as a percentage of the maximum AC watt capability, independent of voltage. LMRP mode setpoints varied from 0 (no PV output is allowed) to 100 percent (PV output is unconstrained), at 10 percent increments of the PV inverter rating. Rather than limiting real power of PV inverters only in conditions of actual local grid stress such as volt-watt mode, LMRP mode always curtails PV real power independent of feeder conditions. LMRP mode is expected to reduce PV impacts but at the cost of greater losses of potential generation incurred by PV owners compared to volt-watt mode.

## Function Settings that Support 25 Percent Greater Hosting Capacity

Using the defined inverter settings, more than 35,000 daily QSTS simulations were performed for each of the 90 combinations of feeder, load, solar day, and PV location. The PV rating was set to be 25 percent more than the baseline HC. ANSI voltage violations and thermal violations were detected to confirm whether the settings successfully enabled the increased HC. Table 9 tabulates the number of settings that successfully provide the 25 percent HC increase. The remaining part of this subsection summarizes the observations; additional details are provided in the following subsection.

**Table 9: Settings That Achieve 25 Percent Hosting Capacity Increase Over Baseline for Maximum Voltage and Overload Criteria**

| | | Voltage Below ANSI Limit (1.05 V pu) | | | No Thermally Overloaded Components | |
|---|---|---|---|---|---|---|
| | PV Location | var-Priority Volt-var (368) | Volt-Watt (9) | LRMP (11) | Volt-Watt (9) | LRMP (11) |
| Feeder 631 | ***End*** | 368 | 9 | 11 | 0 | 8 |
| | Middle | 169 | 0 | 8 | 0[2] | 8 |
| | Front | 368 | 9 | 11 | 0 | 8 |
| Feeder 683 | ***End*** | 368 | 9 | 11 | 0 | 8 |
| | Middle | 368 | 9 | 11 | 0 | 8 |
| | Front | 368 | 9 | 11 | 0 | 8 |
| Feeder 888 | End | 368 | 9 | 8 | 0 | 8 |
| | Middle | 368 | 9 | 8 | 0 | 8 |
| | ***Front*** | 17 | 0 | 8 | 9 | 11 |
| Feeder 2885 | ***End*** | 29 | 0 | 8 | 9 | 11 |
| | Middle | 53 | 0 | 8 | 9 | 11 |
| | Front | 368 | 9 | 8 | 0 | 8 |
| Feeder 2921 | ***End*** | 134 | 1[3] | 8 | 9 | 11 |
| | Middle | 143 | 1 | 8 | 9 | 11 |
| | Front | 92 | 0 | 8 | 9 | 11 |

**PV locations shown in bold italic indicate the location with the lowest HC as identified in Table 3. The red and blue highlights indicate the locations where local HC was limited by voltage and thermal overload, respectively.**

Source: Electric Power Research Institute

Compliant Phase 3 inverter function settings are determined based on the HC criteria introduced earlier in this chapter. A brief summary is provided here, but details on inverter saturation and interaction between inverters and other voltage regulators are presented in the following sections.

VVC increased HC by 25 percent on every feeder; the smallest number of settings increased HC at the end of Feeder 888, where only 17 settings were successful. Thirteen settings increased HC universally across the seven voltage-limited feeder – PV location scenarios.

[2] Thermal and a voltage violation were present at 25 percent greater HC.

[3] First setting reduced maximum voltage to below 1.05 V pu.

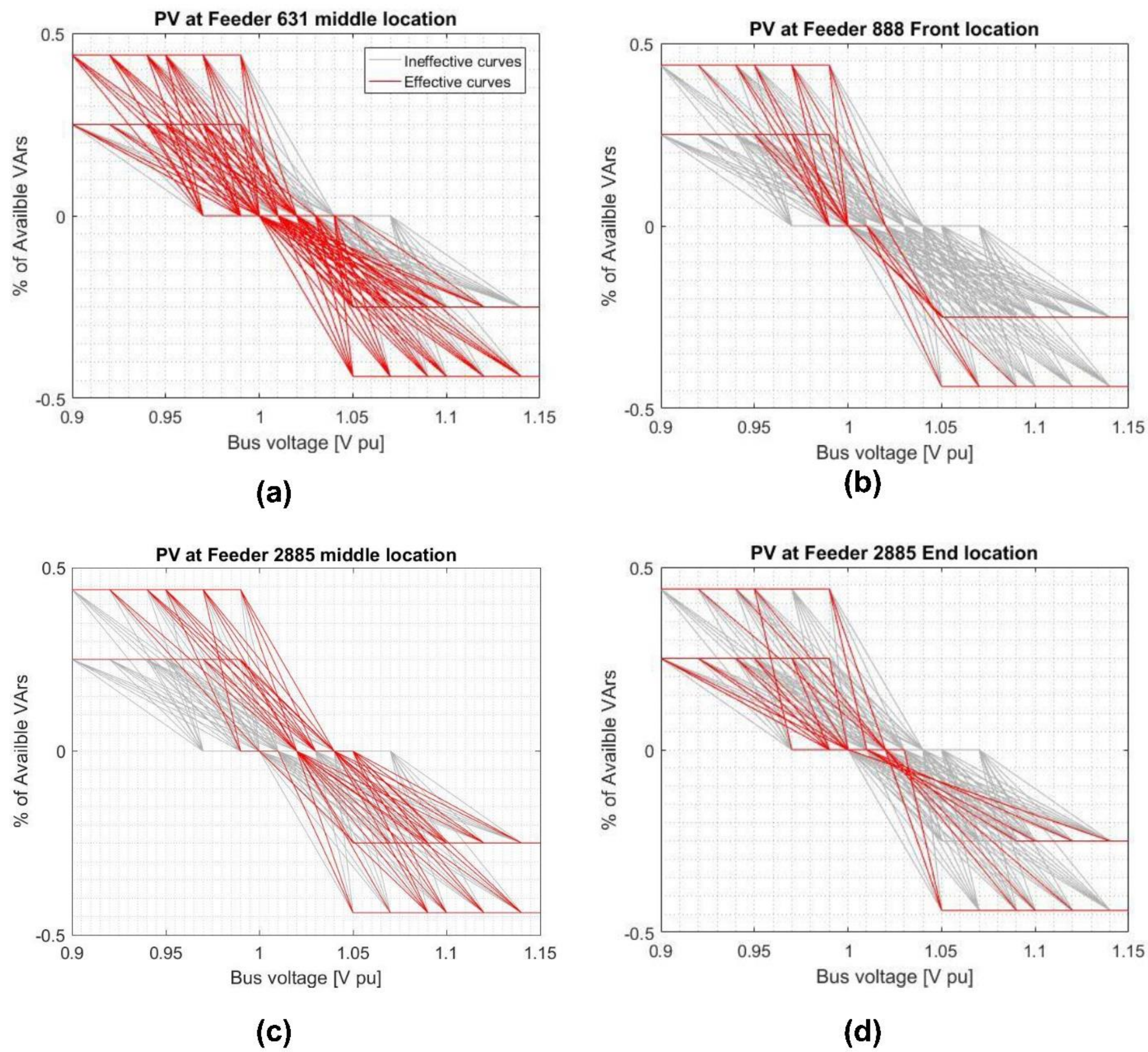
Volt-watt control was ineffective due to the way the three-phase PV inverters measure the reference voltage. The inverters average voltages across the three phases as reference for the control actions. This implementation of volt-watt control in OpenDSS is consistent with reality for three-phase PV systems. Since differences in phase voltage lead to lower average voltages compared to the maximum voltage, volt-watt control might not operate even if a single phase violates voltage standards. Therefore, it is important for system operators to determine an appropriate reference voltage for the control of large three-phase PV systems, particularly under high voltage unbalance. By contrast, in practice, most PV systems on distribution feeders are single-phase, and the PV systems on the phase with the overvoltage would then be more effective in volt-watt control.

Limiting the maximum real power of the PV system, the HC was able to be realized on every feeder when the power output was limited to 70 percent or less for thermal and voltage violations. This result is trivial as 70 percent (LMRP setting) x 125 percent (PV penetration compared to baseline) = 88 percent, indicating that the PV output for LMRP = 70 percent never exceeds the output for the baseline HC. Dynamic adjustments of the LRMP settings through, for example, a DERMS, were not studied in this project.

### Volt-Var Settings

Volt-var control improves the feeder maximum voltage compared to the baseline. Thirteen volt-var settings achieve the 25 percent HC increase for all feeders and all PV locations across the six days studied. The curves that achieve the 25 percent HC increase are plotted for each voltage limited PV location in Figure 10 and Figure 11. In general, curves with a $v_3$ setpoint (start of droop slope for high voltage) farther from 1 V pu are less effective at achieving the HC increase. Similarly, curves with a $v_4$ setpoint (voltage where maximum var consumption is reached) farther from 1 V pu tend to be less effective; however, a larger reactive power threshold (44 percent instead of 25 percent) can compensate for a larger $v_4$.

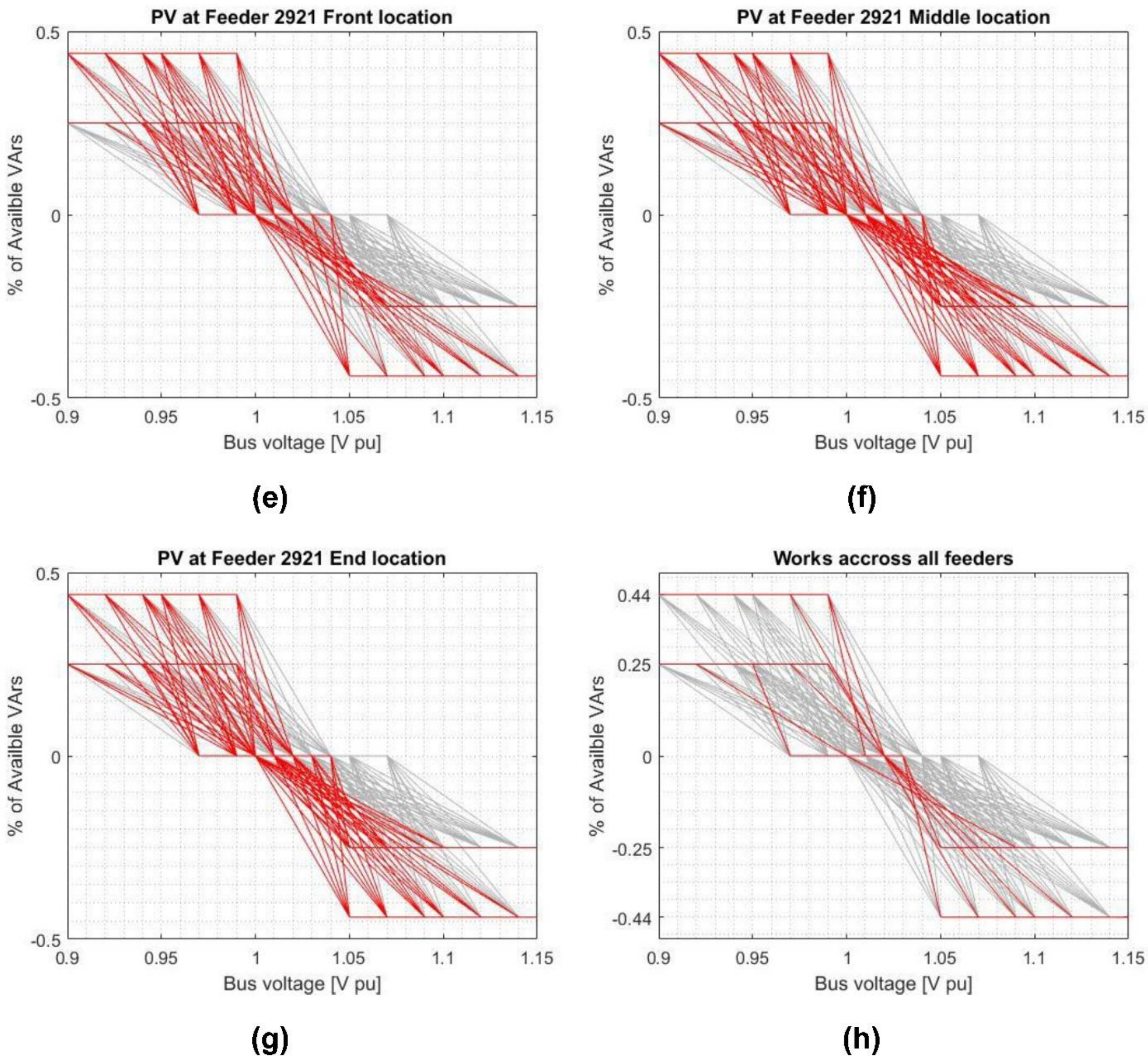
**Figure 10: Curves that Produce 25 percent Increase in Hosting Capacity for Volt-Var Control for Different Feeders and Photovoltaic Locations (a-d)**




**(a) Feeder 631 – PV at feeder middle, (b) Feeder 888 – PV at feeder front, (c) Feeder 2885 – PV at feeder middle, (d) Feeder 2885 – PV at feeder end.**

Source: Electric Power Research Institute

**Figure 11: Curves that Produce 25 Percent Increase in Hosting Capacity for Volt-Var Control for Different Feeders and Photovoltaic Locations (e-h)**



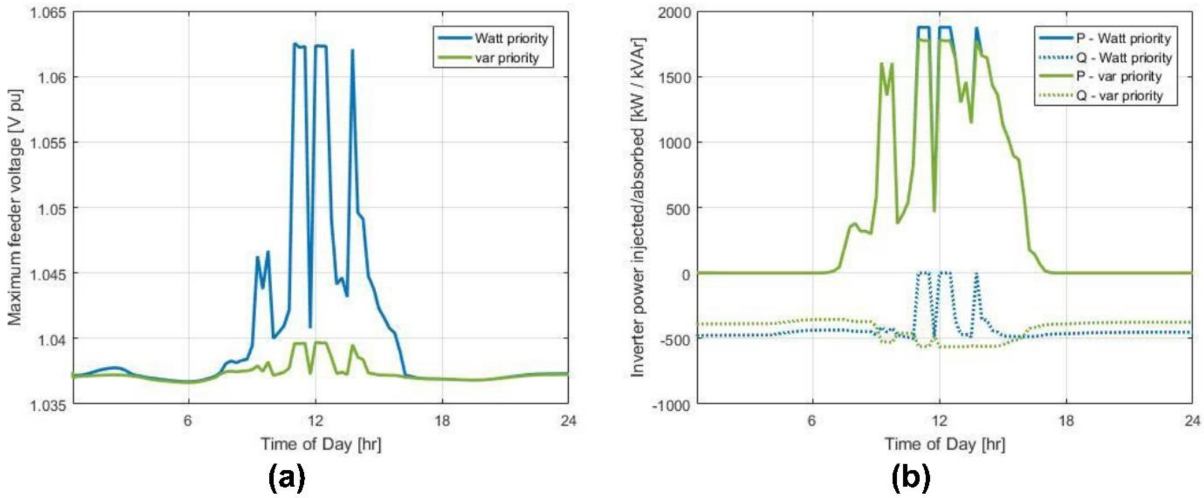

**(e) Feeder 2921 – PV at feeder front, (f) Feeder 2921 – PV at feeder middle, (g) Feeder 2921 – PV at feeder end, and (h) the 13 curves that work for all seven scenarios plotted in (a–g). Other feeders/locations are excluded since there are no voltage violations.**

Source: Electric Power Research Institute

In total, 13 curves are found to be universal because they achieve the 25 percent HC increase for the seven voltage limited scenarios tested. These curves (volt-var settings 53, 139, 279, 280, 282, 284, 286, 322, 343, 344, 346, 348, and 350) show no distinct relationship to slope or dead-band used. The most aggressive curves did not work across all feeders, as they tended to interact with existing feeder regulation to cause over-voltages. The default volt-var settings (not shown) were not found in this group.

The effect of reactive power priority on the control is stark, as observed in Figure 12, for one example day for Feeder 2921. However, when var priority is considered, some of the PV power is curtailed to allow for var absorption (Figure 12b). The result is a significant drop in voltage from 1.062 to 1.039 V pu.

**Figure 12: Comparison of Watt and Var Priority**




**Comparison of watt and var priority for setting 180 on Feeder 2921 when the PV source is at the end of the feeder for the partly cloudy day with minimum feeder loading. (a) Voltage time series. (b) Active and reactive power output from the inverter.**

Source: Electric Power Research Institute

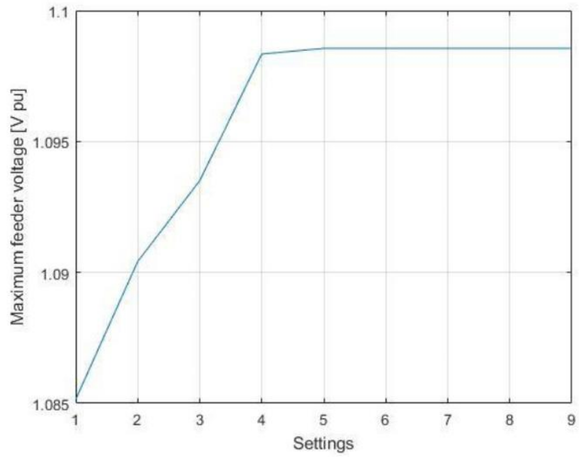
## Volt-Watt Settings

Only one of the volt-watt settings provides the 25 percent HC increase on any feeder. It is trivial that settings 4–9 are unable to increase HC, since the setpoint $v_1$ is at least 1.05, indicating that the inverter will not operate until a violation is already reached. However, for settings 1–3, where the setpoint $v_1$ is 1.03, one would expect the control to reduce overvoltages.

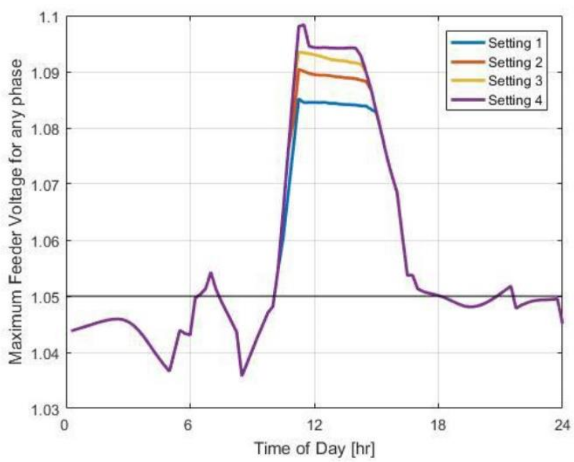
Feeder 2885 provides insight as to why this does not happen. On this feeder, the maximum voltage is close to 1.10 V pu when the PV source is at the end of the feeder for the clear and partly cloudy days under minimum loading. However, despite the high voltage, volt-watt control remains unable to bring the maximum voltage below 1.05 pu, even for setting 1, which demands zero real power output above 1.05 V pu (Figure 13). With the PV system being three-phase, the volt-watt control implemented in OpenDSS uses the average of the three phases as its reference measurement. Since the loading is unbalanced on Feeder 2885, the other two phases have a lower voltage, and thus the average voltage peaks around 1.055, as seen in Figure 13(c). As a result, only settings 1–3 activate, but they only curtail real power partially to reduce the average phase voltage below 1.05 V pu. The voltage of Phase 1 still far exceeds 1.05 V pu. A recommendation is for the inverter control to work on the maximum measured phase voltage (as opposed to the mean). Alternatively, an inverter implementation that works on a phase-by-phase basis could mitigate this problem.

Feeder 2921 is much less imbalanced, and the three-phase voltages are nearly identical. Therefore, the most aggressive setting (1) — and only that setting — reduces feeder voltages below the limit resulting in a HC increase of 25 percent.

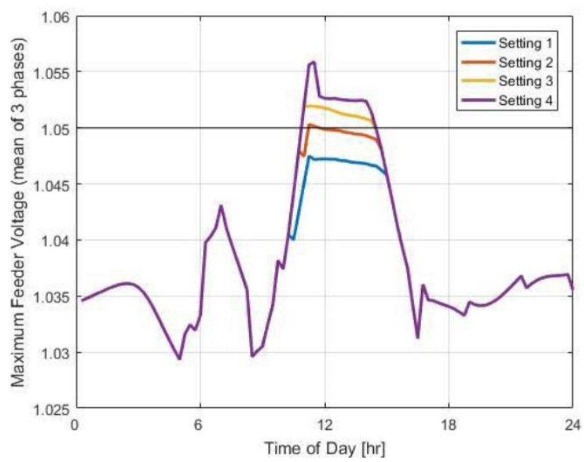
**Figure 13: Effect of Volt-Watt Control**




(a)




(b)




(c)

**Effect of volt-watt control during the partly cloudy day with minimum loading on Feeder 2885 when average phase voltage is used as reference for control. (a) The maximum feeder voltage as a function of the volt-watt settings. (b) The maximum feeder voltage time series for the first four volt-watt settings. (c) The mean feeder voltage for the first four volt-watt settings.**

Source: Electric Power Research Institute

## Limit Maximum Real Power Settings

As shown, LMRP behaves as expected where a 70 percent or smaller limit of real power output always satisfies a 25 percent increase in HC. LMRP settings greater than 80 percent should lead to at least one violation on each feeder since it represents an increase in effective PV penetration on the feeder from the baseline HC. On the contrary, settings less than 75 percent should produce fewer overloads and lower feeder voltages. This behavior is observed for every feeder, where settings 1–8 (0–70 percent) always work, but higher settings cause at least one violation.

The only anomaly to the expected behavior occurs for Feeder 888, where setting 1 (0 percent PV production) causes an overload. With 0 percent of PV power (no PV system), on the peak loading days, feeder voltages drop extremely low, and all LTCs/voltage regulators turn on to support voltage, resulting in an overvoltage in the middle of the feeder. However, this is an effect of deficiencies in the coordination of LTC settings for Feeder 888.

## Sensitivity Analysis of Phase 3 Functions

As discussed, the success of Phase 3 function settings was judged solely based on their ability to achieve a 25 percent increase in HC. In this section, a more granular method to assess the Phase 3 function settings is developed. As in the previous section, the assessment is based on modeling the utility feeders, applying various functions and various settings within each function, and analyzing the impact on power quality. Settings are ranked through metrics. After presenting the results for individual metrics, rankings based on all metrics are combined. Results for 18 solar-load-PV location days are exemplified on Feeder 631 in this section; the other feeders are presented in Appendix A. The objective in this section is not to propose universally optimal settings. Rather, the impact of settings on key feeder impact and power quality metrics is catalogued to allow the reader to understand general setting performance and then select settings that outperform in metrics most applicable to specific situations.

### Metrics for Performance Evaluation and Feeder Impact

#### Selected Metrics

Metrics are measured at points of coupling of the PV systems at feeder head, feeder middle, and feeder end locations. The selected performance metrics, their descriptions, abbreviations, and target responses are presented in Table 10.

**Table 10: Selected Metrics Used to Analyze Performance of Phase 3 Function Settings**

| Metric | Description | Metric Abbreviation | Best Response |
|---|---|---|---|
| Max Feeder MV Voltage | Maximum feeder voltage at medium voltage buses | MaxMV | Decrease maximum voltage |
| kvarh Feeder Head | Total reactive energy at feeder head | kvarh | Closest to zero |
| LTC Operations | Number of LTC operations | LTCOp | Decrease LTC operations |
| Reg Operations | Number of regulator operations | RegOp | Decrease regulator operations |
| Cap Operations | Number of cap operations | CapOp | Decrease cap operations |
| Feeder Losses | Total active losses in energy | Losses | Decrease losses |
| VVI at Inverter Terminals | Voltage variability index at inverter terminals at the respective end, middle, and front locations | VVI | Decrease variability |
| Unique Overloads | Number of unique overloaded elements | Overloads | Decrease number |
| PV Generation | Total active energy generation from PV sources | PVkWh | Minimize curtailment |

Source: Electric Power Research Institute

Although 21 metrics were recorded during the simulations, redundant metrics — or ones that quantify a similar or identical pattern of the simulation data — were eliminated. The remaining metrics facilitate the sensitivity analysis by preserving the most critical information to assess each setting. The voltage variability index (VVI) is calculated according to the definition in EPRI 3002008557 [17]. While some of the metrics are similar to the HC criteria of ANSI voltage limits and thermal limits, they provide a more granular assessment of the performance of the 389 different function settings.

## Sensitivity Analysis Results for Feeder 631

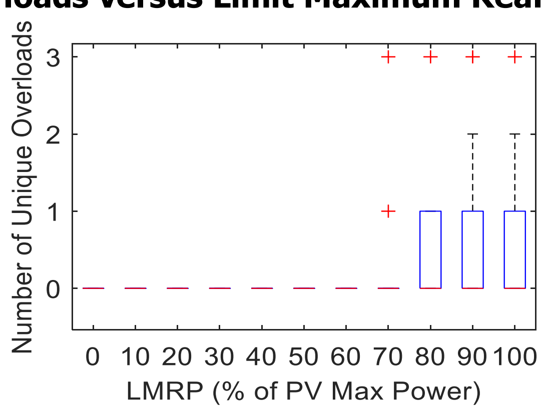
### Limit Maximum Real Power Function

Thermal loading limits can restrict the PV HC on a given feeder. For medium amounts of PV penetration, the typical response is a reduction in upstream power flow on the feeder. However, at high PV penetration, PV systems can cause overloads and increase losses because of reverse power flows upstream that exceed the initial power flow without PV addition. Reverse power flow is especially widespread if the PV systems are not co-located with large loads and if they are located at the end of the feeder, where the upstream power flow before the PV source is smallest and can most easily be reversed by PV generation. The sensitivity of the element overloading to the LMRP function settings is presented in this section.

Figure 14 shows the sensitivity of the number of overload elements against LMRP settings from 0–100 percent as a box and whisker plot. A box and whisker plot is a way of graphically comparing distributions between several sets of data through their five-number summaries. In each box, the central red mark is the median, the edges of the box are the 25th and 75th percentiles, the whiskers extend to the most extreme data points not considered outliers, and outliers are plotted individually by plus signs. An outlier is a value that is more than 1.5 times the interquartile range away from the top or bottom of the box. Throughout this section, results for the 18 simulations (three solar days, two load days, and three PV locations) for Feeder 631 are aggregated for each X-axis value in the box-whisker plots.

The LMRP mode reduces the number of overloads compared to the unrestricted PV active power feed-in at the same PV penetration. This makes sense because in a reverse power flow situation, the curtailment of active power output from PV penetration decreases the total line current or element loading compared with the uncurtailed power flow.

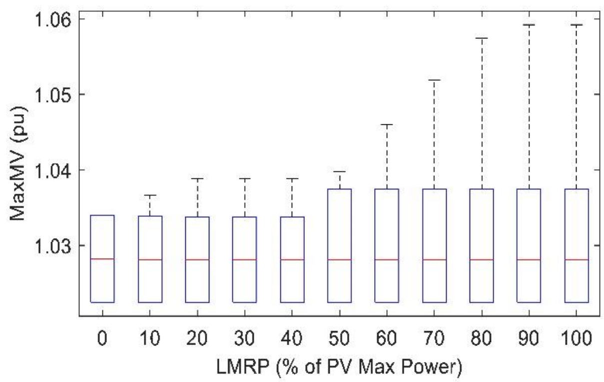
**Figure 14: Overloads versus Limit Maximum Real Power Settings**



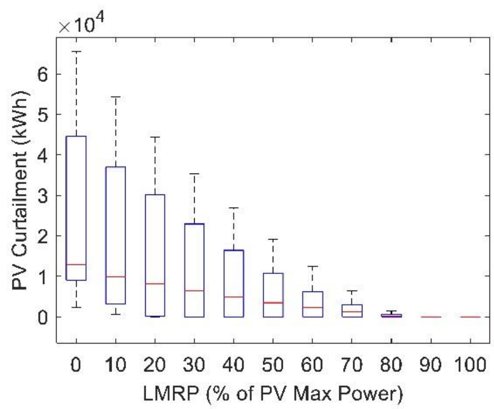

Source: Electric Power Research Institute

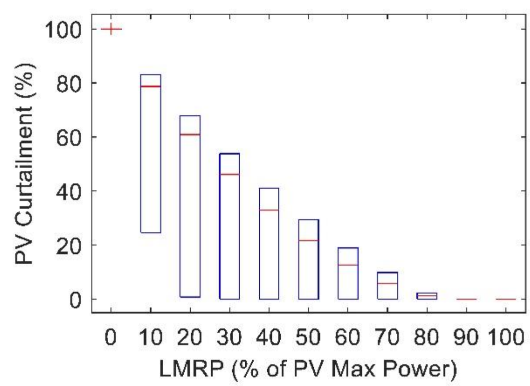
Figure 15 (a) shows the recorded maximum voltage vs. LMRP settings. As expected, more real PV power curtailment results in smaller maximum feeder voltage. This holds especially true for the minimum load days. The maximum voltage for peak load days is far less sensitive to LMRP settings, which causes the median of 18 days, shown by the red lines inside the box plots, to be almost flat. Figure 15 (b–c) shows the amount of curtailed PV generation vs. LMRP settings. The best LMRP setpoint of 70 percent curtails just enough energy to prevent violations.

**Figure 15: Maximum Voltage and Amount of Curtailed Photovoltaic Generation versus Limit Maximum Real Power Settings**




**(a)**



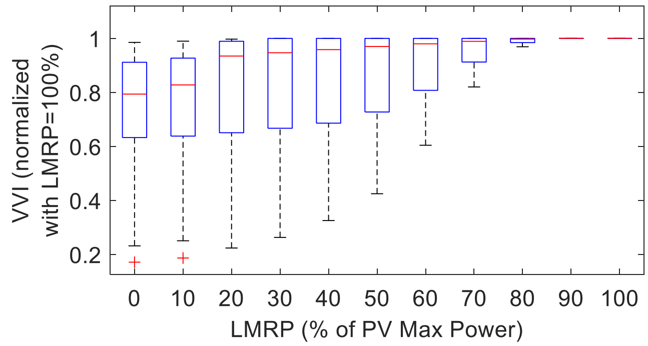

**(b)** **(c)**

**(a) Maximum MV vs. LMRP settings. Curtailed PV generation in (b) kWh and (c) percent curtailed vs. LMRP settings.**

Source: Electric Power Research Institute

The VVI is presented in Figure 16, which shows a clear trend of lower variability for lower real power limits. This makes sense considering that the diurnal cycle and cloud transients cause PV sources to modulate feeder voltage at higher penetrations. With greater PV curtailment, the largest voltages will be less extreme and variability will decrease.

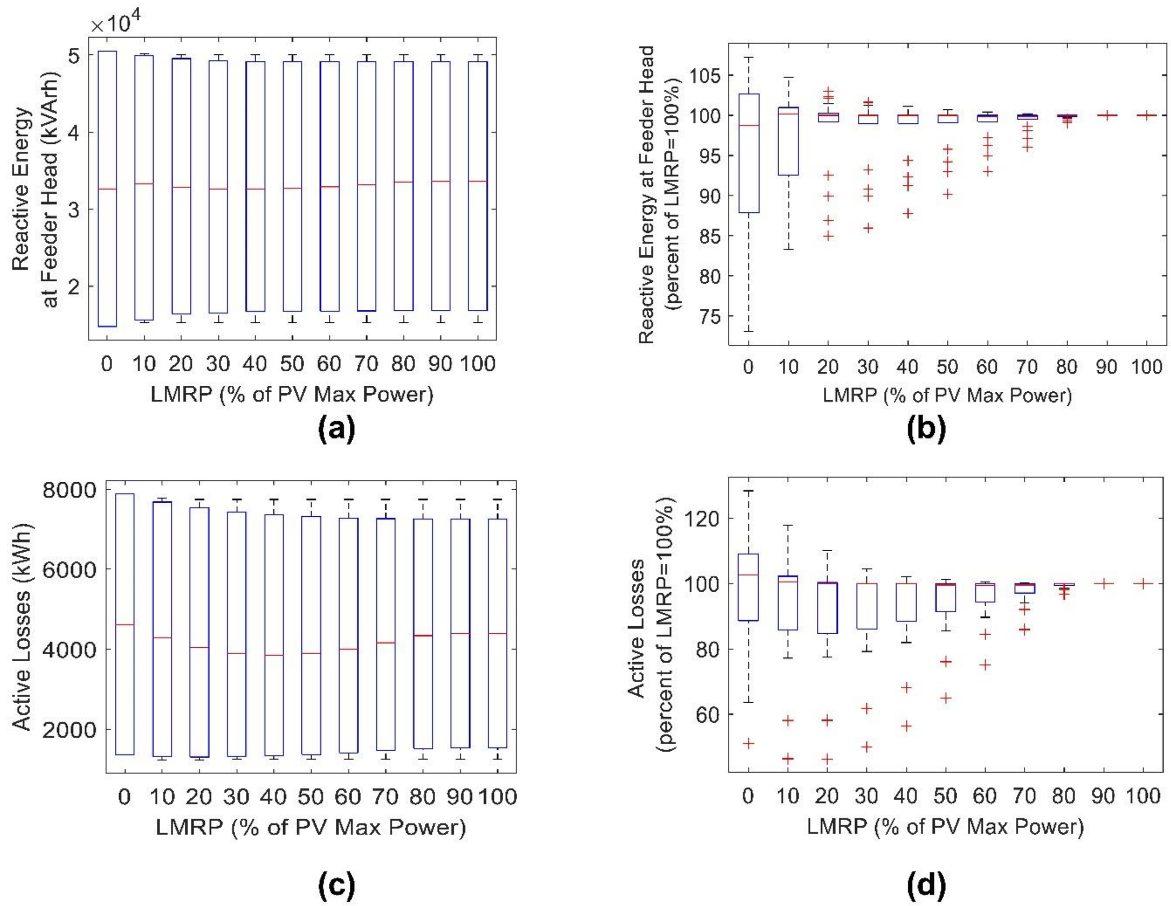
**Figure 16: Normalized Voltage Variability Index at Respective Inverter Terminal versus Limit Maximum Real Power Settings**




Source: Electric Power Research Institute

Finally, Figure 17 (a–b) shows there is no significant change of the reactive energy at the feeder head due to the LMRP settings, as expected. Similarly, losses, as seen in Figure 17 (c–d) did not necessarily decrease for smaller LMRP settings since var injection was not controlled by the LMRP. The non-linear behavior of the median losses is because both high and low LMRP percentages can increase losses due to the increased line power flows in the feeder upstream and downstream directions, respectively.

**Figure 17: Reactive Energy at Feeder Head and Feeder Losses versus Limit Maximum Real Power Settings**



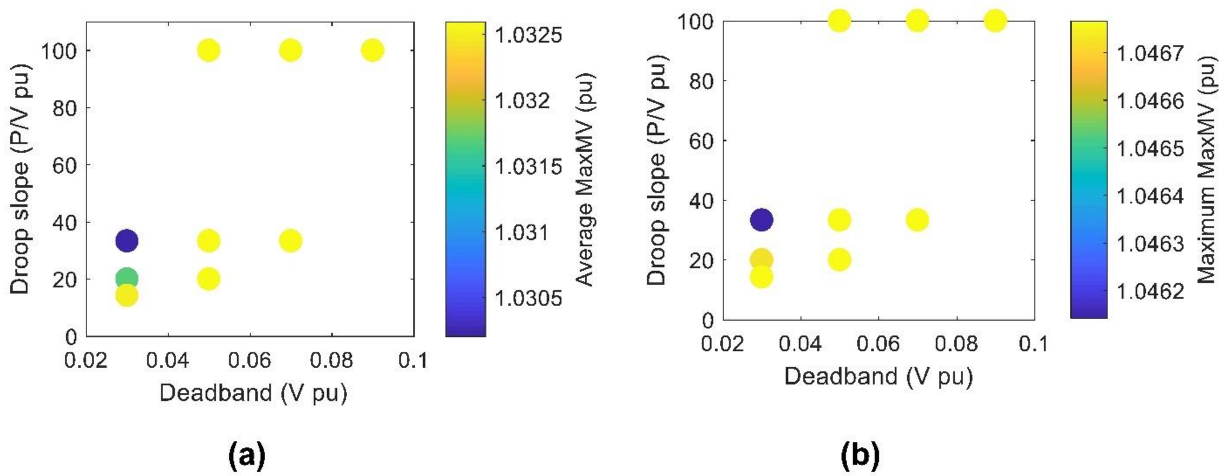

Source: Electric Power Research Institute

In summary, choosing the best LMRP setting depends on the utility objectives and feeder requirements. Under most conditions, the effectiveness of the LMRP setting depends monotonically on how much real power is curtailed.

**Volt-Watt Function**

The maximum feeder MV voltage (abbreviated by MaxMV) is shown in Figure 18. MaxMV is defined as the highest voltage on any phase of any bus in a 24-hour period. The axes are the two parameters of volt-watt control: the deadband and the droop slope of the PV curtailment with the local voltage. The color corresponds to the value of the metric. The average and maximum MaxMV, as shown in Figure 18 (a–b), respectively, are calculated for the 18 combinations of PV/load days and three locations.

**Figure 18 Average MaxMV (a) and Maximum MaxMV from End and Middle Photovoltaic Locations (b), versus Volt-Watt Deadbands and Slopes**



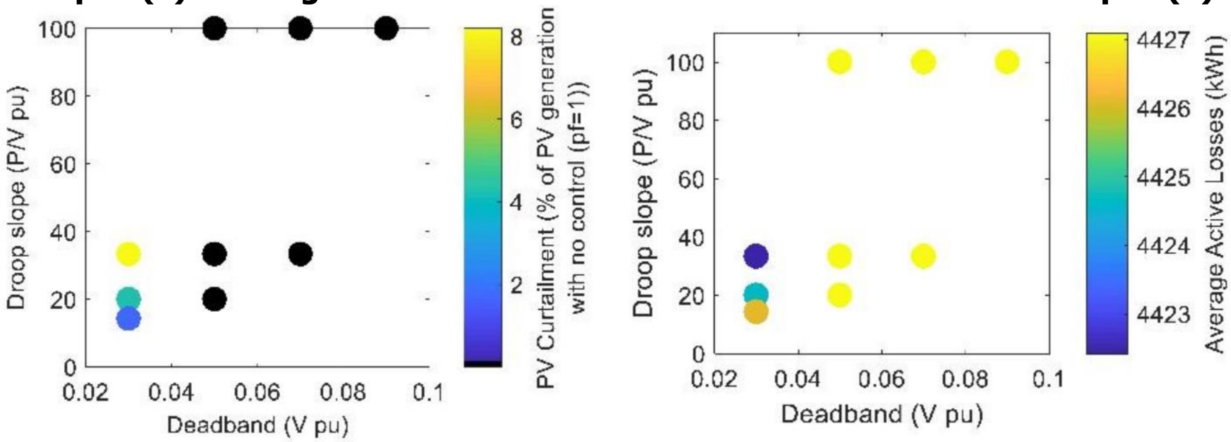

Source: Electric Power Research Institute

The volt-watt function curtails PV output based on the steepness of the volt-watt slope once the voltage at the inverter point of coupling exceeds $V_1$. Since volt-watt operates based on the average voltage of the three phases and the average voltages were often below 1.03 pu, volt-watt did not activate for most settings. The volt-watt function did not enable a 25 percent increase in HC for any scenario with thermal overloads.

Figure 19 (a) shows the maximum curtailed PV power. The settings with the larger deadbands never curtail power; thus, the feeder response is the same as without volt-watt control.

Generally, only small deadbands and — within the group of settings with small deadbands — high droop slopes result in an improvement from the volt-watt function. Overall, the best settings begin to curtail power as soon as the average local voltage exceeds $V_1$ = 1.03 V pu. The best volt-watt settings are therefore the most aggressive ones. A similar pattern was seen for all other metrics. As an example, Figure 19 (b) shows average active losses, but the other metrics are not shown.

**Figure 19: Maximum Photovoltaic Curtailment versus Volt-Watt Deadbands and Slopes (a). Average Active Losses vs. Volt-Watt Deadbands and Slopes (b)**




(a) (b)

**Black color represents zero curtailment.**

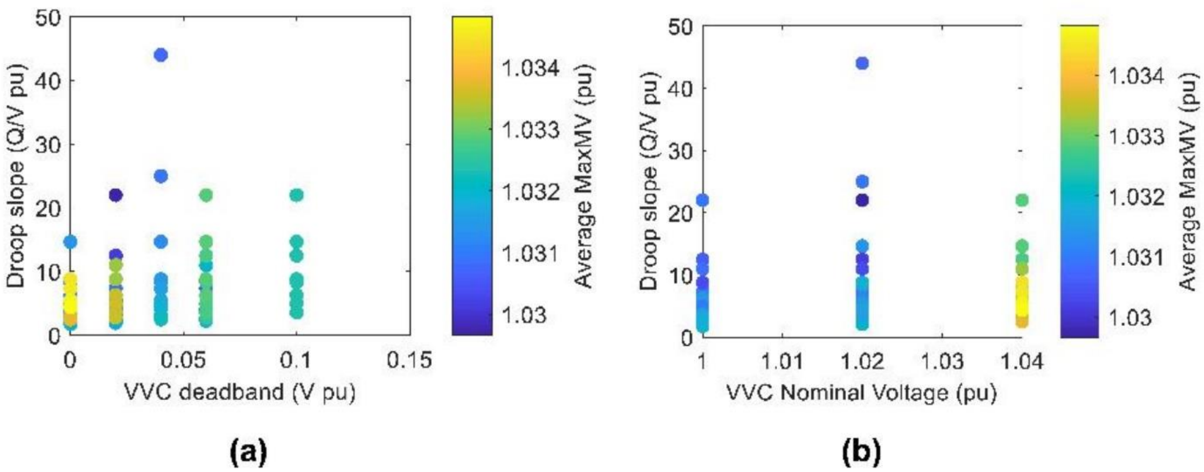
Source: Electric Power Research Institute

## Volt-Var Function and Voltage and Thermal Metrics

The var-priority mode for VVC curtails the real power output of the PV system if there is insufficient inverter capacity to provide enough vars to regulate voltage based on the droop curves of Figure 8. Var-priority volt-var is permissible under IEEE 1547-2018 [15] to ensure that the PV system remains capable of absorbing or injecting reactive power to the full extent of the reactive power capability ranges at 25 percent and 44 percent of the kVA inverter rating.

Figure 20 illustrates use of the average MaxMV over all PV/load days and locations under var-priority mode vs. setting parameters. Figure 20 (a) illustrates that the three larger deadbands of 0.04, 0.06, and 0.1 V pu yield lower MaxMV than zero and 0.02 V pu deadbands. This is because a moderate deadband helps control the voltage within the 0.95–1.05 pu limits while allowing the voltage to fluctuate to some extent without an adverse reactive power response. While there was no strong trend for the relationship between droop slope and maximum voltage, milder slopes seem to lead to lower maximum voltages. Figure 20 (b) reveals a strong trend of the higher nominal voltages (near 1.04 V pu) yielding higher MaxMV values, as expected. This confirms that the var-priority volt-var settings with nominal voltages close to 1 V pu generate or absorb more reactive power and more successfully reduce MaxMV than the settings with nominal voltages of 1.04 V pu.

**Figure 20: Average Maximum MV Voltage versus Var-Priority Volt-Var Setting Parameters**



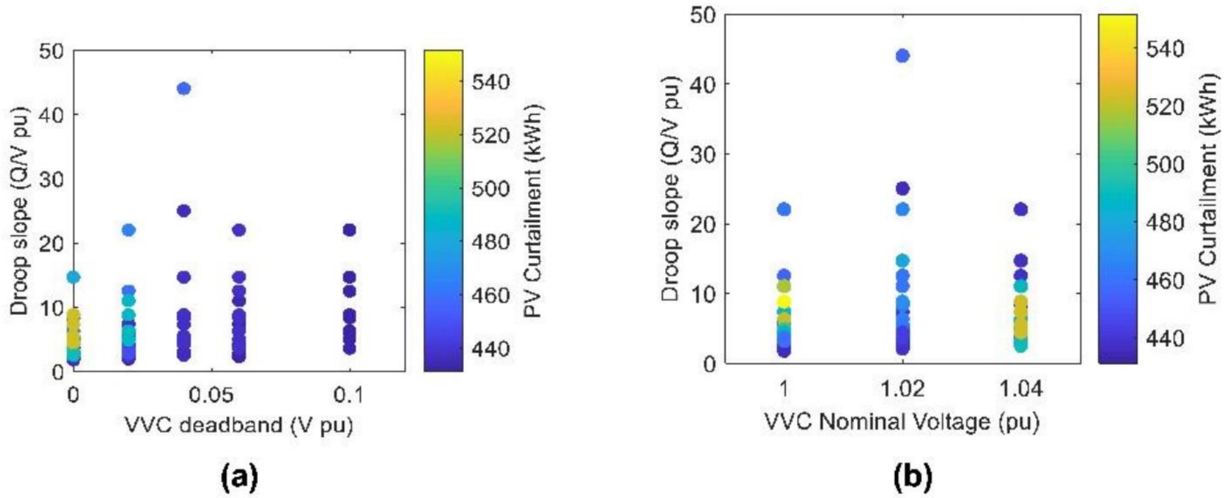

**Average over 18 solar load PV location days. (a) volt-var control deadband and (b) volt-var control nominal voltage.**

Source: Electric Power Research Institute

The var capacity to mitigate the voltage rise during peak PV generation is made available by curtailing PV generation during some periods on the partly cloudy and clear days. Therefore, the trade-off of improved voltage control is a loss in PV generation and revenue for the PV system owner. Figure 21 (a) illustrates that the smaller deadbands curtail more active power, on average. This does not necessarily translate into reduced MaxMV in Figure 20 (a), as other parameters of the volt-var curve ultimately determine the voltage reduction. For example, smaller deadbands result in milder var slopes on average, which in turn leads to higher MaxMV.

PV energy curtailment to achieve reactive power priority might be considered undesirable. However, Figure 21 shows that the amount of curtailment is small due to the infrequent coincidence of peak real PV power output with minimal load and a considerable voltage excursion requiring reactive power from the inverter. The energy curtailment changes only by 0.9 percentage points (from 5.2 percent to 6.1 percent) with different volt-var curve settings. In addition, oversized PV inverters will experience far less real power curtailment. In conclusion, the curtailment is independent of the specific volt-var setting parameters, which suggests that a setting could be chosen primarily based on voltage metrics.

**Figure 21: Average Photovoltaic Curtailment versus Var-Priority Volt-Var Setting Parameters**

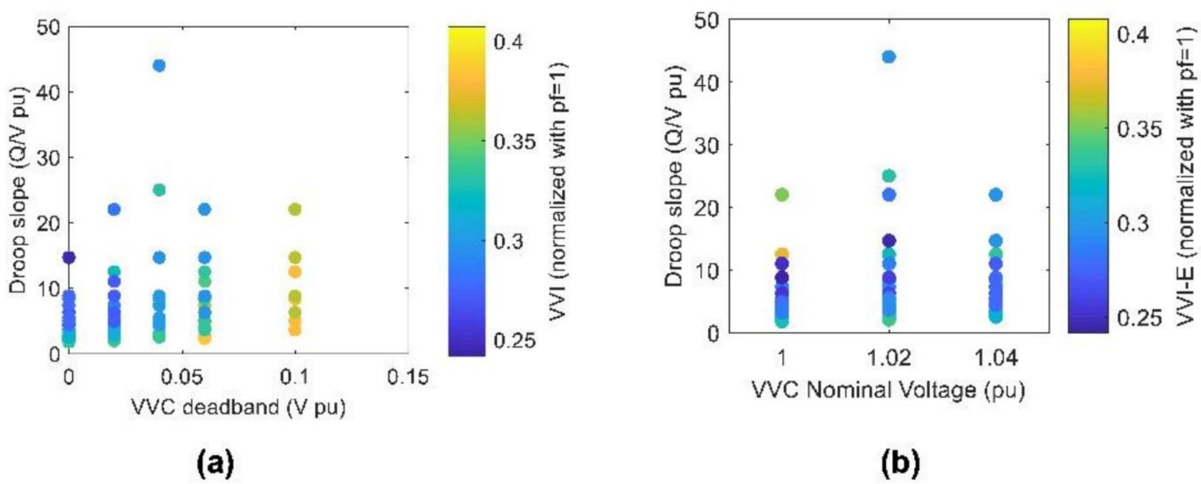



**(a) volt-var control deadband and (b) volt-var control nominal voltage. Total uncurtailed PV generation ranges between 2,348 – 65,503 kWh per day for all PV days and increased hosting capacities on all locations. The curtailment in the figure corresponds to 5.2 – 6.1 percent of total PV generation on the corresponding PV day/location.**

Source: Electric Power Research Institute

Figure 22 (a) shows the metric VVI at the inverter point of coupling vs. deadband and droop slope settings, while Figure 22 (b) shows the same metric but replacing deadband with nominal voltage. Milder droop slopes and larger deadbands result in higher voltage variability.

**Figure 22: Average Voltage Variations versus Var-Priority Volt-Var Setting Parameters**

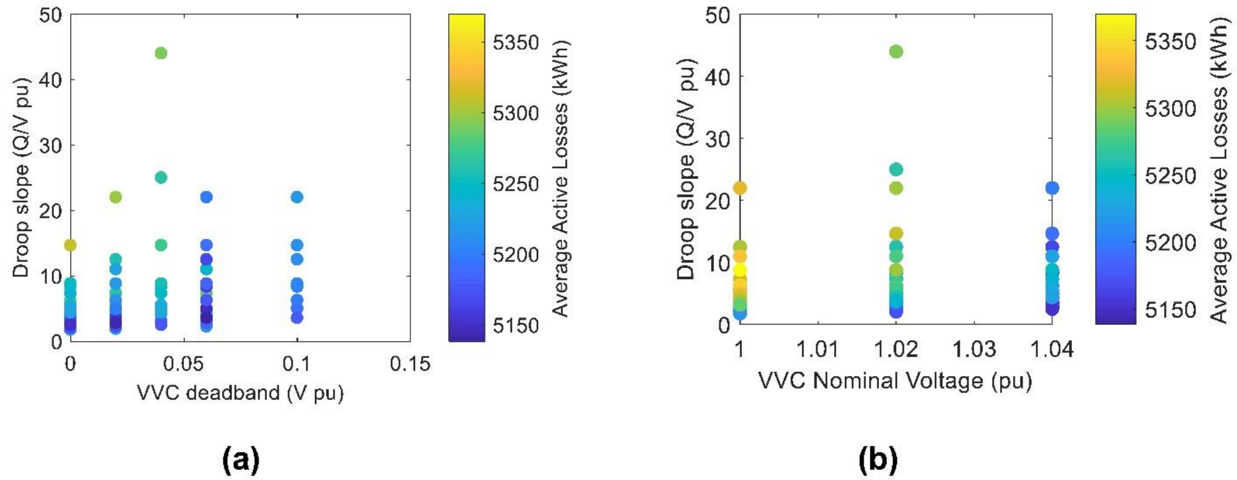



**(a) volt-var control deadband and (b) volt-var control nominal voltage.**

Source: Electric Power Research Institute

Figure 23 illustrates an increase in active losses with nominal voltages closer to 1 pu. This increase is expected since both the curtailment of PV generation and var injection triggered by a smaller nominal voltage increase the total line current, thus increasing losses. No clear trend exists for the relationship between losses, deadband, and control droop slope. The var-priority VVC settings change losses only by 3 percent or less.

**Figure 23: Average Feeder Loss versus Var-Priority Volt-Var Setting Parameters**

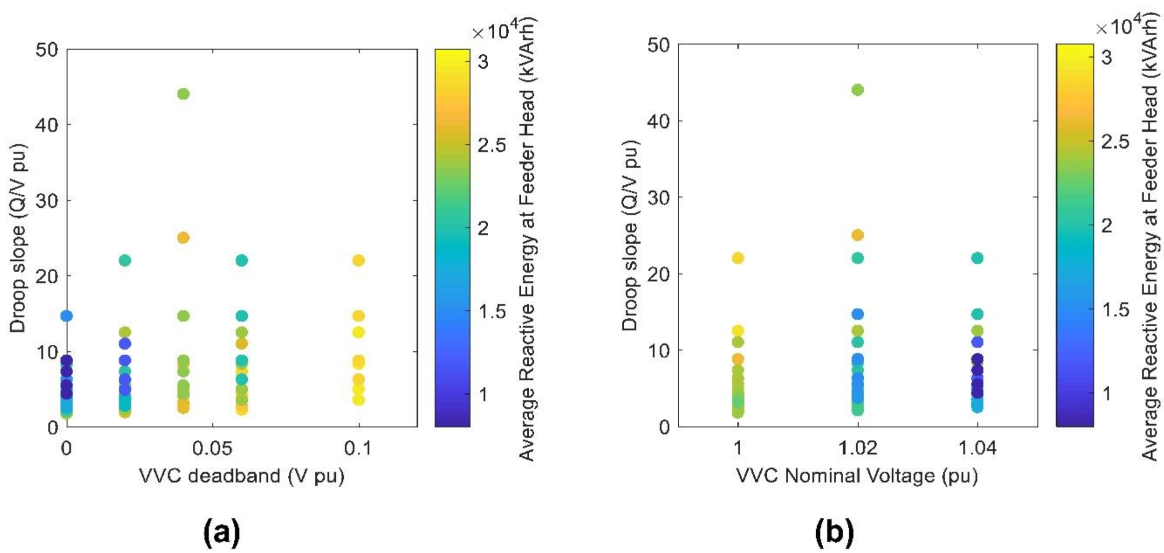



**(a) volt-var control deadband and (b) volt-var control nominal voltage.**

Source: Electric Power Research Institute

As shown in Figure 24, higher kvarh strongly correlate with larger deadbands and nominal voltages closer to 1 V pu. This is mainly because these settings reduce the amount of reactive energy absorbed or generated locally by the PV inverters.

**Figure 24: Average Reactive Energy at Feeder Head versus Var-Priority Volt-Var Setting Parameters**

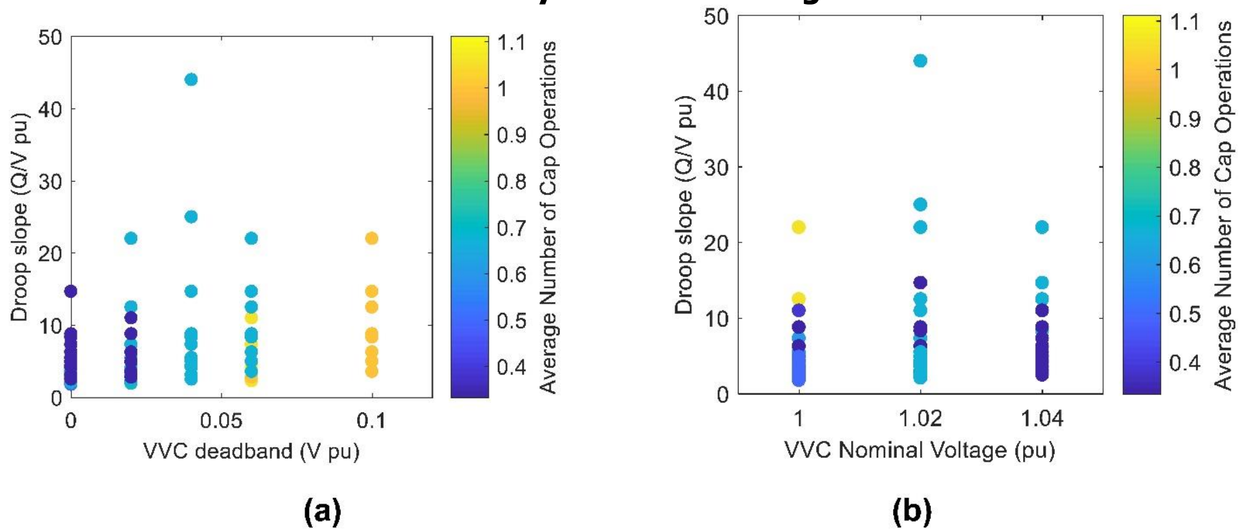



**(a) volt-var control deadband and (b) volt-var control nominal voltage.**

Source: Electric Power Research Institute

Figure 25 shows a reduction in the average number of capacitor operations. The largest 0.1 V pu deadband leads to the largest number of capacitor operations on average. This is expected as var-priority VVC with smaller deadbands taps into the reactive power capacity of the PV systems more effectively, thus reducing the need for capacitor operations or any other voltage regulation device. The nominal voltage setting did not show a trend for the number of capacitor operations.

**Figure 25: Average Number of Capacitor (cap) Operations versus Var-Priority Volt-Var Setting Parameters**




**(a) volt-var control deadband and (b) volt-var control nominal voltage.**

Source: Electric Power Research Institute

## Overall Performance Ranking of Settings

In this section, the individual metrics presented earlier are aggregated to yield a single performance index considering the non-redundant metrics with equal importance. This performance index is computed as the average rank of all settings for each metric. For example, a specific volt-var setting would be ranked for each of the nine metrics and its overall performance index is then the average rank.

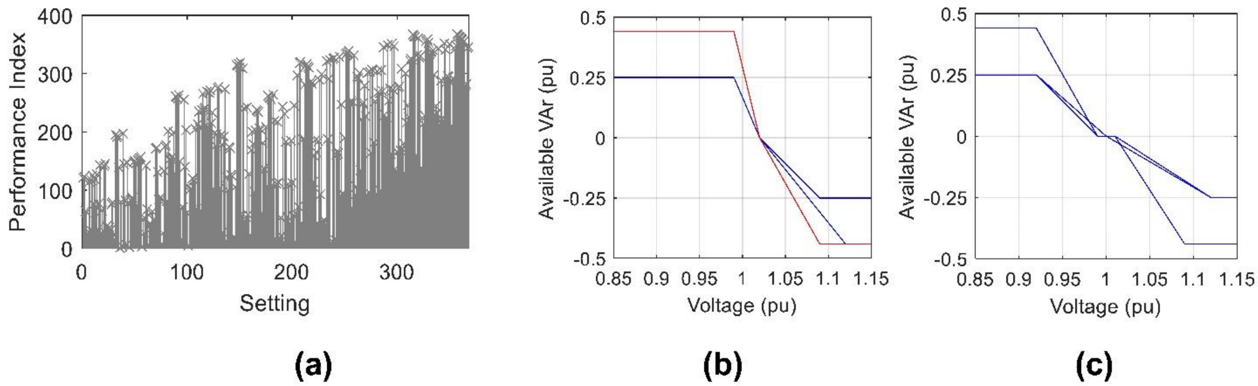
Let $s = \{s_1, s_2, \ldots, s_n\}$ be the set of all settings and $m = \{m_1(s_i), m_2(s_i), \ldots, m_p(s_i)\}, i = 1, \ldots, n,$ be the set of ranks of average (over the 18 load, solar, and PV locations) feeder impact metrics for each setting. The performance index ($P_i$) of each setting is obtained as

$$P_i = \frac{1}{p}\left[m_1(s_i) + m_2(s_i) + \cdots + m_p(s_i)\right], i = 1, \ldots, n$$

The performance index facilitates the interpretation of the comprehensive simulation dataset obtained from the sensitivity analysis. Settings with a smaller performance index provide a more positive feeder impact with respect to the selected metrics. The performance index value depends on the total number of analyzed settings for each Phase 3 function, (the index reached a maximum of 368, 9, and 11 for volt-var, volt-watt, and LMRP, respectively). The performance index, as defined here, is by no means the definitive outcome of the analysis in this report. The performance index without weights, as presented, is the simplest approach to combining multiple metrics to allow them to be examined simultaneously. Instead, the practitioner could determine the best setting by assigning different weights to each ranking according to the specific application as $w = \{w_1, w_2, \ldots, w_p\}, \sum_p w_p = 1$. However, here, equal weights $w_1 = w_2 = \cdots = w_p = \frac{1}{p}$ are used. This weighting can be changed by the utilities when, for example, an improvement in voltage variability and losses would be considered less important than increases in LTC operations.

Figure 26 provides the three best and three worst settings based on the performance index for Feeder 631. In general, the settings that provide effective control action (corresponding to more aggressive curves) do not necessarily have a better performance index. For example, more aggressive droop control curves use more reactive energy by design (and thereby increase losses) to achieve the best voltage outcome. In practice, this trade-off needs to be resolved on a case-by-case basis. Most utility engineers would consider voltage variability and MaxMV objectives to be paramount and thus assign lower weights to metrics such as reactive energy that are compromised by aggressive VVC. Figure 26 also provides a comparison between watt- and var-priority VVC.

**Figure 26: Overall Performance of Volt-Var Settings for Feeder 631**




**(a) performance index, (b) three best settings, and (c) three worst settings for var-priority volt-var.**

Source: Electric Power Research Institute

# CHAPTER 3: Economic Analysis of Rule 21 Phase 3 Smart Inverter Functions

## Purpose and Scope

This study assesses the ability of volt-var with var priority and LMRP functions to increase the HC of a sampling of large utility-scale PV systems by 25 percent. A techno-economic comparison of these smart inverter functions and conventional distribution upgrade measures has been performed for five California utility feeders that represent a diversity of feeder topologies, voltage classes, and other characteristics. The results from this assessment are intended to inform 1) investment and operational decisions that aim to economically increase distributed PV penetrations and 2) decisions related to compensation mechanisms for PV penetrations and other DER.

## Economic Assessment

Organized energy markets determine locational marginal prices (LMPs) that convey the economic value of providing or using a unit of energy at a particular time and location; however, there is currently no such economic price signal for managing real-time energy flows at the distribution level. In the absence of distribution-level energy markets, a major gap exists regarding the time and locational value of using Phase 3 functions. A number of key questions and considerations exist that are related to the economics of curtailing distribution-connected solar PV sources, including those listed below [19].

- What are the utility's obligations to accommodate PV interconnection requests that exceed the existing HC of distribution circuits?
- What are possible mechanisms for specifying the terms of curtailment?
- What types of compensation and settlement mechanisms can be considered, consistent with utility obligations?

Analysis comparing the economic impact of employing active power management smart inverter functions is scarce. Therefore, this report assesses a range of economic cost-benefits of managing real-time PV power flows on a selection of distribution circuits and deployment scenarios. The report specifically explores two strategic research questions:

1. What amount of curtailment from customer-owned PV sources is required to achieve a 25 percent increase in HC on a sampling of evaluated distribution circuits?
2. Is real power curtailment of distributed PV systems the least-cost option to mitigate impacts of rising PV penetrations on distribution feeders?

To address the first question, this report uses QSTS simulations in OpenDSS to analyze the impact that select smart inverter functions have on PV power production over a one-year simulation. Specifically, VVC with reactive power priority and an LMRP setting of 80 percent (fixed throughout the whole year) are analyzed.

The second question is addressed by evaluating the cost-benefits of serving the load on each distribution circuit. This is done through a comparison of deployment scenarios involving Phase 3 control functions to a base case scenario in which conventional mitigation measures are employed to reach a 25 percent increase in HC. The costs associated with curtailment of PV production that result from the Phase 3 control functions are evaluated by applying the average bulk system locational marginal energy price from the California Independent System Operator (CAISO). Prices represent the same time and location of the solar PV generation and feeder load data (Northern California from August 1, 2012 – July 31, 2013).

## Annual Photovoltaic Curtailment from Smart Inverter Functions to Increase Hosting Capacity by 25 Percent

### Scenarios Using Smart Inverter Functions

For each feeder location that had a HC limited by a voltage constraint, a volt-var smart inverter function with reactive power priority was employed that was able to successfully mitigate the constraint. For locations that were thermally constrained, the LMRP function was employed at an 80 percent level. A summary of these scenarios is provided in Table 11.

For all scenarios, it was assumed that the PV system had a DC/AC ratio of 1.3. Each individual PV system deployment will have its own optimal DC/AC ratio given project-specific economics, but a consistent ratio was used throughout the analysis given its potential impact on end results. While a DC/AC ratio of 1.3 may be a slightly high estimate given today's typical project economics, this assumption yields results that may slightly overestimate PV system curtailments. A sensitivity analysis that examines the impact of different DC/AC ratios for the LMRP function is provided later in this report in Table 20.

**Table 11: Scenarios Using Smart Inverter Functions**

| | PV Source at Feeder Front | PV Source at Feeder Middle | PV Source at Feeder End |
|---|---|---|---|
| Feeder 631 | LMRP=80% | volt-var w/var priority | LMRP=80% |
| Feeder 683 | LMRP=80% | LMRP=80% | LMRP=80% |
| Feeder 888 | volt-var w/var priority | LMRP=80% | LMRP=80% |
| Feeder 2885 | LMRP=80% | volt-var w/var priority | volt-var w/var priority |
| Feeder 2921 | volt-var w/var priority | volt-var w/var priority | volt-var w/var priority |

Source: Electric Power Research Institute

### Volt-Var with Reactive Power Priority

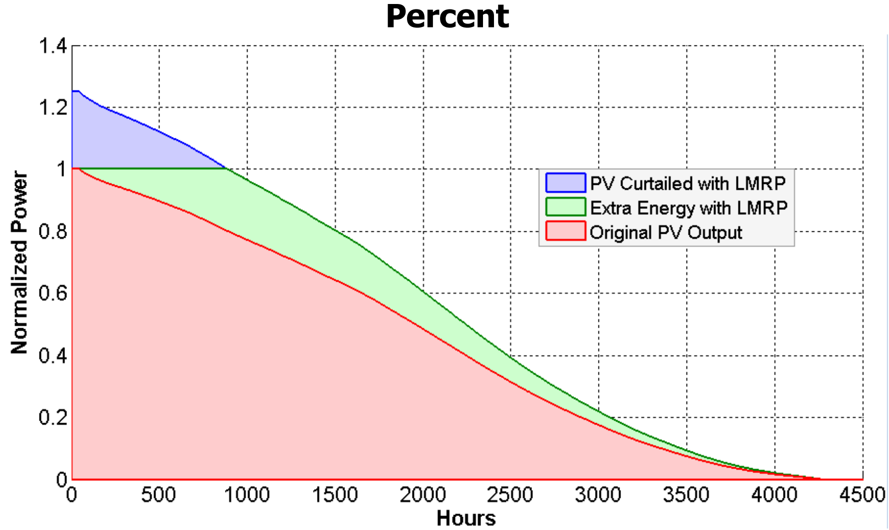
The LMRP setpoint for the volt-var curve used in this analysis — 80 percent — was successful at increasing the HC for all seven voltage constrained cases. The setpoint was selected because it achieves the HC increase, has one of the lowest curtailments across all feeders that resulted from the HC assessment[4], and is similar to the Rule 21 default curve with the exception of a lower reactive power setpoint of 0.25 instead of 0.3 and slightly tighter $V_1$ and $V_4$ values.

### Limit Maximum Real Power

The LMRP function imposes an upper limit on the real power generation of the PV system, since adverse PV effects generally occur during peak PV output. Curtailing maximum power presents a simple methodology for reducing adverse PV effects, while maintaining the ability to export PV generation during most hours of the year. The maximum level of generation is defined as a percentage of the maximum AC watt capability, independent of voltage. LMRP mode setpoints varied from 0 (no PV output is allowed) to 100 percent (PV output is unconstrained). Rather than limiting real power of PV inverters only in conditions when the voltages are too high or too low, as volt-var or volt-watt, LMRP always curtails PV real power independent of feeder conditions. Therefore, the LMRP function is expected to result in the highest amounts of PV curtailments compared to other functions.

The LMRP function of 80 percent was used because it represents an increase in available DC capacity by 25 percent. As shown in shown in Figure 27, the maximum available AC power remains the same to prevent any potential thermal overload. However, the system size has increased, allowing for more total energy production, but with a slightly lower yield relative to the new DC rating.

**Figure 27: Normalized Power Duration Curve Showing Photovoltaic Curtailment and Extra Energy Produced Using Limit Maximum Real Power Function at 80 Percent**




**Notes: PV power is normalized to the original AC rating. With the LMRP function set to 80 percent, the new system size is 25 percent percent higher than the original, yet the power output never exceeds the original peak value (shown at the height of the green area). While there is some curtailed energy (blue area), the increased size allows for more total energy (green area) than the original PV size (red area).**

Source: Electric Power Research Institute

[4] The HC assessment was performed using design day criteria instead of an annual simulation. Design days consisted of peak and minimum loading with three different solar day types: clear, variable, and overcast.

### Photovoltaic System Curtailment Results

The PV system capacity factor, normalized to the solar PV system's DC rating, is a measure of the annual energy production. For the PV system location and design used in this analysis, the annual capacity factor was measured to be 16.97 percent. Employing the smart inverter functions, as shown in Table 12, can reduce the annual energy yield due to curtailments. The modeling results from the annual simulations show that the volt-var function with reactive power priority trigger very minimal curtailments, a maximum of 0.08%. However, the LMRP function results in a much higher curtailment of 4.87 percent given the design of the PV system. Curtailments for the LMRP function are the same for each scenario considering they were calculated independent of distribution system modeling and based solely on the normalized PV power profile.

**Table 12: Photovoltaic System Curtailment Results From Annual Simulations**

| **Feeder** | **Location** | **PV System DC Size (kW)** | **Unconstrained Capacity Factor** | **Capacity Factor using SI Function** | **Curtailment** (% of Unconstrained Output) |
|---|---|---|---|---|---|
| 631 | Front | 12,385 | 16.97% | 16.14% | 4.87% |
| | Middle | 8,420 | 16.97% | 16.97% | 0.00% |
| | End | 2,250 | 16.97% | 16.14% | 4.87% |
| 683 | Front | 22,720 | 16.96% | 16.14% | 4.87% |
| | Middle | 20,315 | 16.96% | 16.14% | 4.87% |
| | End | 6,600 | 16.96% | 16.14% | 4.87% |
| 2885 | Front | 20,350 | 16.96% | 16.13% | 4.87% |
| | Middle | 17,325 | 16.96% | 16.94% | 0.08% |
| | End | 5,705 | 17.11% | 16.95% | 0.94% |
| 2921 | Front | 7,225 | 16.96% | 16.96% | 0.00% |
| | Middle | 3,560 | 16.96% | 16.96% | 0.04% |
| | End | 2,495 | 16.97% | 16.96% | 0.08% |
| 888 | Middle | 42,320 | 16.96% | 16.14% | 4.87% |
| | End | 41,930 | 16.96% | 16.14% | 4.87% |

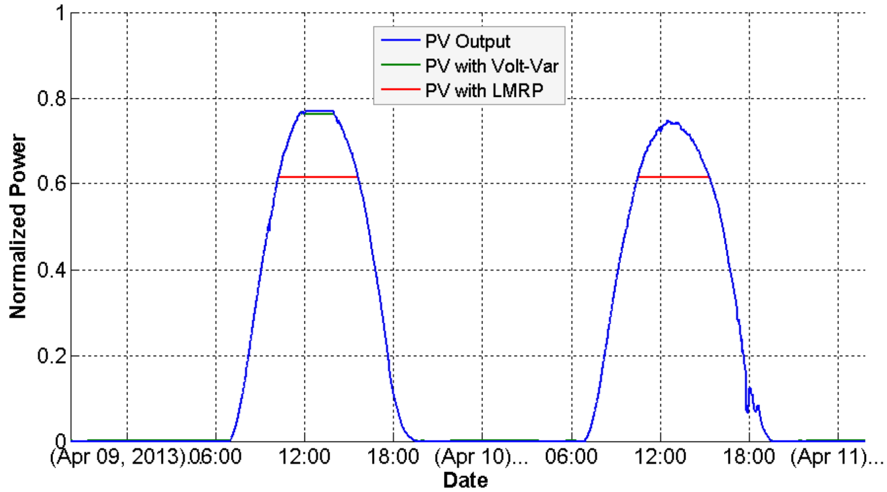
**Notes: Blue highlighted rows represent voltage limited cases that implement VVC with reactive power priority to increase HC. Orange highlighted rows represent thermally limited cases that implement the LMRP function of the PV system. The Feeder 2885-end scenario (highlighted in purple) had a small modeling error resulting in slightly higher PV capacity factor in the unconstrained cases that yielded slightly higher curtailments.[5]**

Source: Electric Power Research Institute

[5] The Feeder 888-front scenario (not included in the table) had a model convergence issue that prevented an accurate assessment of the curtailment impacts of the volt-var function; the scenario was thus omitted from the study.

Looking further at the results, the minimal curtailment using the volt-var function is due to the low reactive power setting (Q=0.25), meaning that real power is limited by only a maximum of 96.8 percent.[6] However, the LMRP function limits power to 80 percent. Further, curtailment only happens when the inverter is saturated, which rarely occurs. As shown in Figure 28, sometimes the available PV power is below the limit of the volt-var function, but rarely is PV power below the limit of the LMRP function. This can be caused by a variety of factors including the PV system's orientation and location, the time of year (given the sun's position in the sky), or a reduction in performance due to temperature impacts.

**Figure 28: Normalized Photovoltaic Power Showing Curtailment Using Volt-Var Function with Reactive Power Priority and Limit Maximum Real Power Function at 80 Percent**



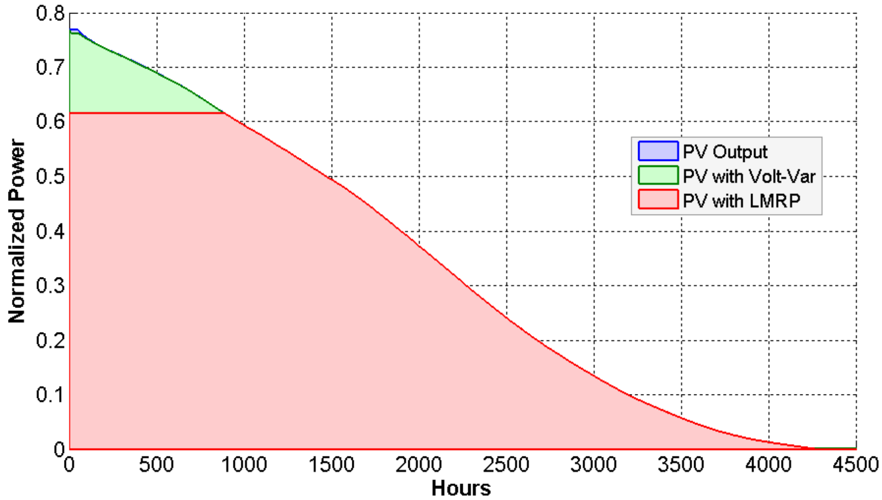

**Notes: PV power is normalized to the DC rating. Given that the DC/AC ratio is 1.3, the maximum power output relative to the DC rating is 76.9 percent; thus, the maximum curtailment from the volt-var function is $\mathbf{76.9\ percent \times 96.8\ percent = 74.5\ percent}$.**

Source: Electric Power Research Institute

Further, the amount of time during the entire year that the available PV power is near the 96.8 percent limit of the inverter (given the DC/AC ratio size of 1.3) is low. As shown in Figure 29, this happens for only ~50 hours out of the entire year. Alternatively, the LMRP function limits the power output for nearly 90 hours per year.

[6] The relationship of real power ($W$), reactive power ($Q$), and apparent power ($S$) is $S^2 = W^2 + Q^2$. Thus, the available real power with $Q = 0.25$ is $W = \sqrt{1-Q^2} = \sqrt{1-0.25^2} = 0.968$

**Figure 29: Normalized Photovoltaic Power Production Profile Showing Curtailment Using Volt-Var Function with Reactive Power Priority and Limit Maximum Real Power Function at 80 Percent**




Source: Electric Power Research Institute

## Cost of Conventional Upgrades to Increase Hosting Capacity by 25 Percent

### Financial and Costing Assumptions

Table 13 presents the financial parameters assumed for an illustrative IOU used for the analysis described in this report. These parameters, together with the asset lifetimes presented in Table 14, were used to calculate the economic carrying cost (ECC) for each of the hardware upgrades identified in Table 5. The ECC calculated for each hardware upgrade reflects the real annualized value of the upgrade considering the equipment life and its expected replacement costs. The ECC annualizes the capital cost associated with the upgrade to compare it to the annualized energy costs of curtailment.

**Table 13: Financial Assumptions for Illustrative Investor-Owned Utility**

| Parameter | Value |
|---|---|
| Debt/Equity Ratio | 50% |
| Interest Rate | 5% |
| Return on Equity | 12% |
| Discount Rate | 8% |
| Inflation Rate | 2% |
| Federal Income Tax Rate | 35% |
| State Income Tax Rate | 5% |
| Property Tax Rate | 0.5% |

Source: Electric Power Research Institute

Capital costs for each hardware upgrade were estimated based on publicly available costing information. In particular, the National Renewable Energy Laboratory (NREL) Distribution System Upgrade Unit Cost Database [20] was used. This database consists of a compilation of cost information from publicly available utility cost guides as well as anonymized cost information from actual projects.

For each upgrade, when a type of equipment listed in the NREL database could be found with very close technical characteristics, the unit cost of that equipment was applied to the upgrade considered in the analysis. However, some upgrades required special treatment, as discussed below.

- In some cases, the conductor size required for the upgrade was too far from the conductor types listed in the NREL database. The costs for these conductors were extrapolated using a line of best fit based on the current rating of known wire costs. Appendix A, Extrapolation of Line Sizes and Unit Costs, provides the details for these calculations.
- Similarly, the cost for the large 2,600 kvar capacitor bank required for the front location of Feeder 888 was extrapolated based on the costs listed in the NREL database for three smaller capacitor sizes. Appendix A, Extrapolation of Capacitor Bank Size, provides the details for these calculations.
- Finally, for the multiple conductor upgrades required for Feeder 888, the total cost was calculated by identifying the new line ratings for each line segment and then extrapolating out to identify the costs of large conductor sizes not given in the NREL database.

In addition to hardware upgrades, settings adjustments were also identified as necessary for two feeder locations: Feeder 2885-end and Feeder 2921-front (see Table 5). These adjustments represented a one-time cost, mainly reflecting the need to dispatch a distribution engineer on-site to work on the equipment. No new hardware installation was required; the existing hardware was simply reconfigured. The one-time costs associated with these two settings adjustments were obtained from the NREL cost database. To make the time allocation of these one-time expenses consistent with the annualized capital costs associated with the hardware upgrades using the ECC, it was assumed that 10 percent of these one-time expenses could be apportioned annually for 10 years.

For each feeder location, the total annual cost of implementing the conventional measures was finally calculated by adding the annualized capital cost of any required hardware upgrades to the annualized one-time expense associated with adjusting settings when needed, as per the technical analysis.

Table 14 summarizes the total annualized cost of the distribution measures required under the conventional network reinforcement approach for each feeder location considered in this study.

**Table 14: Summary of Costs for Conventional Upgrades**

| Feeder | Location | Conven-tional Measure | Quantity/Unit | Cost ($/unit) | Source | Total Cost (Capital or One-Time Expense) ($) | Lifetime (years) | ECC% (for capital), or 10% apportion-ment (for one-time expenses) | Annualized Avoided Capital Cost ($) | Annual-ized One-time Expense ($) | Annualized Cost of Conventional Upgrades ($) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **631** | Front | OH-AAC | 512 ft | 560 | NREL | 286,720 | 50 | 9.38% | 26,880 | - | 26,880 |
| **631** | Middle | Add 1 voltage regulator | 1 | 150,000 | NREL | 150,000 | 25 | 10.65% | 15,980 | - | 15,980 |
| **631** | End | OH-CU | 100 ft | 110 | NREL | 11,000 | 50 | 9.38% | 1,031 | - | 1,031 |
| **683** | Front | OH-AAC | 199 ft | 1,660 | Extra-polation* | 330,340 | 50 | 9.38% | 30,969 | - | 30,969 |
| **683** | Middle | OH-AAC | 199 ft | 1,660 | Extra-polation* | 330,340 | 50 | 9.38% | 30,969 | - | 30,969 |
| **683** | End | OH-AAC | 200 ft | 1,660 | Extra-polation* | 332,000 | 50 | 9.38% | 31,125 | - | 31,125 |
| **2885** | Front | OH-AAC | 1135 ft | 1,010 | Extra-polation* | 1,146,350 | 50 | 9.38% | 107,471 | - | 107,471 |
| **2885** | Middle | Add 1 voltage regulator | 1 | 150,000 | NREL | 150,000 | 25 | 10.65% | 15,980 | - | 15,980 |
| **2885** | End | Lower voltage setpoint of voltage regulator | 1 | 2,500 | NREL | 2,500 | N/A | 10.00% | - | 250 | 250 |

| Feeder | Location | Conven-tional Measure | Quantity/Unit | Cost ($/unit) | Source | Total Cost (Capital or One-Time Expense) ($) | Lifetime (years) | ECC% (for capital), or 10% apportion-ment (for one-time expenses) | Annualized Avoided Capital Cost ($) | Annual-ized One-time Expense ($) | Annualized Cost of Conventional Upgrades ($) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **2921** | Front | Switch-off all capaci-tors | 1 | 7,200 | NREL | 7,200 | N/A | 10.00% | - | 720 | 720 |
| **2921** | Middle | Add 1 voltage regulator | 1 | 180,000 | NREL | 180,000 | 25 | 10.65% | 19,176 | - | 19,176 |
| **2921** | End | Add 1 voltage regulator | 1 | 180,000 | NREL | 180,000 | 25 | 10.65% | 19,176 | - | 19,176 |
| **888** | Front | Add 1 capacitor | 2600 kVAR | 35 | Extra-polation* | 89,700 | 17 | 12.26% | 10,997 | - | 10,997 |
| **888** | Middle | OH-AAC | 1700 ft | 1,325 | Extra-polation* | 2,252,500 | 50 | 9.38% | 211,173 | - | 211,173 |
| **888** | Middle | UG-AAC | 385 ft | 250 | NREL | 96,250 | 30 | 10.16% | 9,776 | - | 9,776 |
| **888** | End | OH-AAC | 1700 ft | 1,325 | Extra-polation* | 2,252,500 | 50 | 9.38% | 211,173 | - | 211,173 |
| **888** | End | UG-AAC | 385 ft | 250 | NREL | 96,250 | 30 | 10.16% | 9,776 | - | 9,776 |

**For distribution line upgrades, UG and OH indicate underground and overhead lines, respectively. AAC and CU indicate aluminum and copper type conductors, respectively. Additional details on the upgrades are presented in Appendix A.**

**Notes: Blue highlighted rows represent voltage limited cases that implement VVC with var priority to increase HC. Orange highlighted rows represent thermally limited cases that implement the LMRP function of the PV system.** ****See Appendix A, Extrapolation of Line Sizes and Unit Costs***

Source: Electric Power Research Institute

# Economic Comparison of Smart Inverter Functions and Conventional Upgrades

## Energy Value

The analysis conducted in the previous sections indicated that energy curtailment could result from the activation of Phase 3 smart inverter functions. To compare the economic potential of using smart inverter functions with the use of conventional upgrades, the value of lost energy production when functions are activated must be calculated. Considering solar PV generation has no marginal costs of energy production, the net cost of curtailed solar energy can be estimated as the avoided wholesale energy purchase cost at the feeder head. This cost was captured using the average LMP in Northern California from the California Independent System Operator (California ISO).[7]

The average LMP over the 12-month period — August 1, 2012 – July 31, 2013 — was $34.79/MWh, as shown in Table 15. The average monthly price was fairly stable, with a low of $27.64/MWh occurring in September 2012 and a high of $38.28/MWh occurring in March 2013. There was larger variation at the hourly average per month, with a high of $111/MWh at 4 PM on August 2012 and a low of $16/MWh at 2 AM on August 2012. Weighting the hourly average price to the amount of PV generation yields an average price of $36.31/MWh. This PV weighted average price was used as the representative value of energy curtailments because it was representative of the average avoided energy costs from the solar PV plant.

**Table 15: Average California Independent System Operator Locational Marginal Prices ($/MWh) in Northern California August 1, 2012 – July 31, 2013**

**Average CAISO Locational Marginal Prices ($/MWh) in Northern California**
*(Aug 1, 2012 - July, 31, 2013)*

| Month | Hour 0 | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | Average |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **1** | 31 | 31 | 29 | 31 | 30 | 39 | 36 | 50 | 44 | 32 | 38 | 56 | 32 | 30 | 30 | 31 | 40 | 50 | 55 | 59 | 39 | 39 | 33 | 30 | **38.1** |
| **2** | 40 | 31 | 30 | 30 | 27 | 32 | 42 | 35 | 33 | 32 | 30 | 28 | 32 | 32 | 31 | 31 | 33 | 39 | 44 | 35 | 46 | 34 | 34 | 32 | **33.9** |
| **3** | 35 | 33 | 33 | 30 | 29 | 31 | 37 | 50 | 37 | 39 | 58 | 43 | 38 | 37 | 36 | 37 | 36 | 35 | 38 | 38 | 42 | 53 | 39 | 32 | **38.2** |
| **4** | 32 | 27 | 19 | 22 | 27 | 35 | 33 | 33 | 43 | 37 | 37 | 46 | 59 | 35 | 42 | 36 | 34 | 39 | 40 | 35 | 43 | 34 | 42 | 32 | **35.8** |
| **5** | 27 | 27 | 23 | 24 | 21 | 28 | 23 | 38 | 27 | 30 | 34 | 39 | 36 | 35 | 42 | 39 | 51 | 47 | 46 | 40 | 47 | 39 | 40 | 30 | **34.6** |
| **6** | 32 | 27 | 26 | 25 | 25 | 28 | 26 | 27 | 26 | 30 | 32 | 37 | 35 | 39 | 40 | 39 | 43 | 43 | 46 | 41 | 39 | 37 | 36 | 30 | **33.7** |
| **7** | 30 | 25 | 24 | 27 | 31 | 31 | 29 | 28 | 32 | 36 | 38 | 40 | 43 | 43 | 44 | 44 | 43 | 46 | 50 | 46 | 45 | 38 | 34 | 31 | **36.6** |
| **8** | 21 | 19 | 16 | 16 | 18 | 21 | 19 | 22 | 23 | 23 | 27 | 27 | 27 | 28 | 57 | 88 | 111 | 75 | 69 | 44 | 57 | 33 | 26 | 20 | **36.9** |
| **9** | 23 | 22 | 20 | 20 | 21 | 22 | 22 | 22 | 26 | 30 | 26 | 26 | 27 | 28 | 35 | 37 | 34 | 39 | 34 | 45 | 29 | 28 | 25 | 22 | **27.6** |
| **10** | 28 | 27 | 25 | 22 | 25 | 28 | 39 | 33 | 37 | 36 | 43 | 33 | 42 | 32 | 32 | 32 | 51 | 48 | 62 | 48 | 35 | 32 | 35 | 28 | **35.5** |
| **11** | 26 | 25 | 25 | 26 | 25 | 28 | 28 | 31 | 47 | 35 | 32 | 44 | 48 | 31 | 31 | 33 | 35 | 44 | 41 | 37 | 36 | 32 | 29 | 27 | **33.2** |
| **12** | 24 | 24 | 24 | 22 | 24 | 26 | 34 | 31 | 36 | 43 | 32 | 28 | 26 | 28 | 30 | 32 | 30 | 46 | 48 | 41 | 40 | 47 | 42 | 26 | **32.7** |
| **Average** | **29** | **26** | **24** | **24** | **25** | **29** | **30** | **33** | **34** | **34** | **36** | **37** | **37** | **33** | **38** | **40** | **45** | **46** | **48** | **43** | **42** | **37** | **35** | **28** | **34.8** |
| **Normalized PV Output** | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.01 | 0.04 | 0.07 | 0.10 | 0.13 | 0.14 | 0.14 | 0.13 | 0.11 | 0.08 | 0.04 | 0.01 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | **Sum = 1.0** |

**PV Weighted Average Price: $36.31**

Source: Electric Power Research Institute

[7] California ISO real-time price data from http://www.energyonline.com/Data/GenericData.aspx?DataId=19&CAISO___Real-time_Price using the "LMP" values representing Northern California.

### Economic Evaluation of Using Smart Inverter Functions to Increase Hosting Capacity by 25 Percent

The value of using the smart inverter functions to increase the distribution system HC can be calculated by subtracting the cost of the total curtailed energy from the savings realized by the avoided annualized cost of the conventional upgrades. It was assumed that the only cost of deploying the smart inverter functions was that of the curtailed energy. Furthermore, there was no additional cost to making the inverter capable of operating with the smart inverter function and no additional cost for determining the appropriate setting.[8]

Using smart inverter functions that curtail PV system real power output can be a more economical solution for increasing distribution system HC than conventional grid upgrades.

In general, results indicate that using smart inverter functions that curtail PV system real power output can be a more economical solution for increasing distribution system HC than conventional grid upgrades. Results from the study, as shown in Table 16, indicate that some scenarios show a positive economic value of deploying smart inverters as opposed to conventional upgrades, while other scenarios show a negative value.

A few overarching findings from the results include the following:

- Using smart inverter functions tends to be economical when the HC is voltage constrained. In cases that were voltage limited, using the volt-var function with reactive power priority was more economical than using conventional measures for upgrades. The only case that resulted in a negative value was one in which there was a minor modeling error that overestimated curtailment from the PV system.
- Smart inverter functions are more economical when new equipment is otherwise needed to mitigate distribution constraints. The two voltage-limited cases that had the least value (Feeder 2885-end and Feeder 2921-front) required modifying equipment settings rather than adding voltage regulators. Because modifying these settings is not as expensive as adding new equipment, cases that would only require a change in settings of existing equipment may not benefit from using smart inverters as an alternative.
- Using smart inverter functions may be economical when the HC is thermally constrained if large upgrade projects are otherwise needed. The thermally limited cases required the use of the LMRP function to increase HC but resulted in significantly larger curtailments compared to use of the volt-var function with reactive power priority. Though the costs of the LMRP function were high, the LMRP function was still more economical than conventional upgrades in cases where very long reconductoring projects were needed to mitigate the voltage constraints.

[8] The true cost of the additional energy purchases using advanced inverter functions would also need to account for the change in distribution system losses and energy consumption given the voltage sensitivity of losses and native load. However, these two aspects were not included in this study for two reasons. First, the load voltage sensitivity models in the analyzed feeder models were deemed to be insufficiently accurate to capture the small changes in load energy consumption caused by the smart inverter functions. Second, the change in losses caused by smart inverter functions was expected to be too small to accurately capture, as the losses would also be influenced by load voltage sensitivities, which were not sufficiently modeled.

**Table 16: Economic Comparison of Smart Inverter Functions and Conventional Upgrades to Increase Hosting Capacity by 25 Percent**

| Feeder | Location | Total Energy Curtailed *(MWh/year)* | Annualized Cost of Activating the Smart Inverter Functions *($/year)* | Annualized Avoided Cost of Conventional Upgrades *($/year)* | Value of Using Smart Inverter Functions *($/year)* |
|---|---|---|---|---|---|
| 631 | Front | 896 | $32,529 | $26,880 | ($5,649) |
| | Middle | 0 | $0 | $15,980 | $15,980 |
| | End | 163 | $5,910 | $1,031 | ($4,878) |
| 683 | Front | 1,643 | $59,657 | $30,969 | ($28,688) |
| | Middle | 1,469 | $53,342 | $30,969 | ($22,373) |
| | End | 477 | $17,330 | $31,125 | $13,795 |
| 2885 | Front | 1,471 | $53,409 | $107,471 | $54,062 |
| | Middle | 22 | $799 | $15,980 | $15,181 |
| | End | 64 | $2,323 | $250 | ($2,073) |
| 2921 | Front | 5 | $168 | $720 | $552 |
| | Middle | 2 | $74 | $19,176 | $19,102 |
| | End | 1 | $47 | $19,176 | $19,128 |
| 888 | Middle | 3,060 | $111,122 | $220,948 | $109,826 |
| | End | 3,032 | $110,098 | $220,948 | $110,850 |

**Notes: Blue highlighted rows represent voltage limited cases that implement VVC with reactive power priority to increase HC. Orange highlighted rows represent thermally limited cases that implement the LMRP function of the PV system. The Feeder 2885-end scenario (highlighted in purple) had a small modeling error resulting in slightly higher PV capacity factor in the unconstrained cases that yielded somewhat higher curtailments.**

Source: Electric Power Research Institute

## Implications for Pricing Strategies for Solar Photovoltaic Exports

As the quantity of distributed renewable energy resources continues to grow, the utility industry must address the disconnect that exists between the time- and location-dependent value of energy that is common at the bulk system, with the historical norm of flat volumetric electricity retail rates. Proper price signals are needed to incentivize economically efficient investment and operation of distributed PV sources and other DER. While there is little to no marginal cost of producing energy from renewable resources, exporting excessive amounts of renewable energy has natural limits if there is insufficient local demand, if power quality or reliability limits are compromised, or if delivery capacity constraints prevent the energy from being transmitted and distributed to other consumers.

There is ongoing debate, which extends beyond the scope of this study, about the appropriate pricing strategies to employ for distributed solar PV exports. For example, there are regulatory issues to consider that relate to rate structures and their levels. Additional areas of debate surround utility fixed cost recovery, cross-subsidization between customer classes, and technical issues related to the development of organized energy markets at the distribution level. To provide guidance on these issues, some of the findings from this study can be used to inform future pricing strategies for solar PV sources and other DER.

### Long-Term Impacts of Solar Photovoltaic Curtailment

This study reveals that curtailing real power output of solar PV penetrations can be more economical than paying for the cost of grid upgrades in some circumstances. Further, the economic comparison from this study likely overestimates the relative cost of deploying smart inverter functions because this study only considered impacts in Year 1 and did not examine long-term impacts. The reason: PV system output typically degrades over time by 0.7–1.5 percent per year depending on the technology [21]. Consequently, the percentage of time that a PV system inverter is saturated will be less over a PV system's lifetime than during its first year of operation.

Ultimately, the percentage of lifetime energy curtailment from real power management functions is likely to be less than the percentage of energy curtailment in the first year. This means that even if the annual cost of curtailment in the first year is higher than the annualized cost of conventional measures, lifetime comparisons that account for PV degradation may shift the economics in favor of using smart inverter functions that curtail real power.

### Assessing the Total Value of Solar

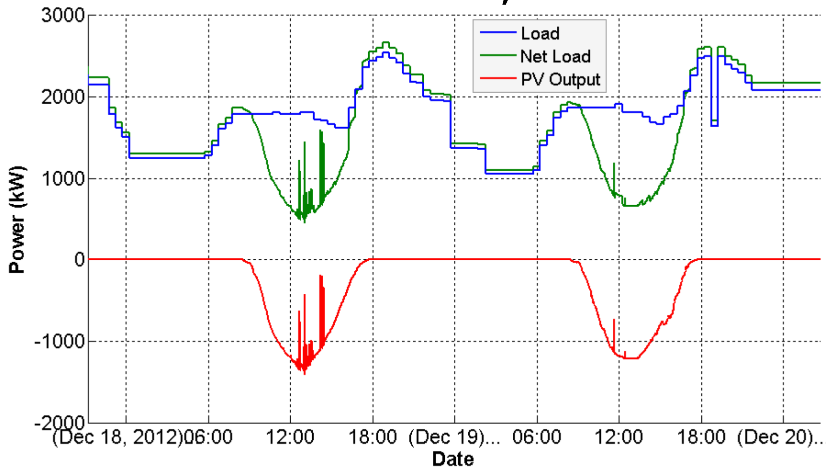
One of the more confusing aspects of developing administratively set prices for DER is the discrepancy between retail and wholesale electricity prices. For a variety of reasons, retail rate structures, particularly for residential and small commercial utility customers, are generally dominated by a volumetric energy rate. Given the conventional cost of service ratemaking principles, a utility's fixed cost associated with meeting peak capacity demands is recovered through this volumetric rate. Valuing DER exported energy through mechanisms such as net energy metering can, as a result, cause regulatory issues such as cross-subsidization between customer classes.

Valuing DER exports at a utility's avoided cost is appropriate considering all customers share in those savings. However, if the locational and temporal characteristics of DER exports can be adequately relied upon to avoid or defer conventional grid upgrades that a utility would otherwise make to serve its customers, a utility's avoided costs may be higher than what is represented through wholesale LMPs. To calculate this value, a fully integrated planning approach is needed that considers DER across all aspects of the electric system [22].

A disconnect may exist between the results presented herein and the financial impacts to PV system owners whose compensation for solar PV generation is valued at retail electricity prices because this study valued solar PV curtailment at wholesale electricity prices. The value associated with the curtailed energy may be higher than wholesale rates. However, if curtailed energy helps reduce capacity needs in the electric system — without an integrated planning study that considers DER as a non-wires alternative to meeting capacity needs associated with growing load — it is difficult to consider the economic value of DER exports at any number other than the wholesale electricity price.

The feeder loads analyzed in this study, as seen in Figure 30, show that the peak loading condition actually occurs in the evening when there is no solar generation. Therefore, it may be safe to assume that there is little distribution capacity relief and thus little value above wholesale market prices for the energy being curtailed. While there may be bulk system capacity value for the energy in the middle of the day (when curtailment occurs), assessing that value is outside the scope of this study. Further, if there is bulk system value for energy, but it is needed outside of the curtailment time frame, that value would not get factored into the value associated with the active power management functions in this study because there was no loss of PV generation during those time frames.

**Figure 30: Modeled Load, Net Load, and Photovoltaic Generation, December 18–19, 2012**




Source: Electric Power Research Institute

Lastly, considering that solar PV curtailment occurs in the middle of the day when the inverter is fully saturated, the value of that energy may actually decrease over time as PV penetrations increase. The diminishing returns of solar PV value as PV penetrations increase occurs because of downward pressure on wholesale energy market prices and a shift of the peak load to nighttime hours when PV generation is not available [23].

## Sensitivity Analysis

### Variation from Different Volt-Var Functions

Rather than apply a generic function to multiple sites, two different volt-var functions were assessed for the three locations on Feeder 2921 to evaluate the potential variation in curtailments if optimal smart inverter settings were selected for each individual site. The volt-var settings used in the sensitivity analysis are shown in Table 17. Prior modeling results revealed that these functions were also capable of increasing the PV HC at the feeder locations by 25 percent. The "maximum" curtailment function has a more aggressive slope that is anticipated to curtail PV power more than the original function. Alternatively, the "minimum" curtailment function has a less aggressive slope and thus is anticipated to result in fewer PV curtailments.

**Table 17: Volt-Var Settings for Sensitivity Analysis**

| Function | Point | **Local Voltage Setpoint** (per unit) | **Reactive Power Setpoint (**per unit) |
|---|---|---|---|
| Maximum Curtailment | 1 | 0.95 | 0.44 |
| | 2 | 1.0 | 0 |
| | 3 | 1.0 | 0 |
| | 4 | 1.05 | -0.44 |
| Minimum Curtailment | 1 | 0.9 | 0.44 |
| | 2 | 0.97 | 0 |
| | 3 | 1.03 | 0 |
| | 4 | 1.12 | -0.44 |

Source: Electric Power Research Institute

Annual simulations revealed that the "minimum" curtailment function resulted in slightly lower annual curtailment at each of the three locations, as shown in Table 18. However, the reduction was negligible considering the annual curtailment was already very small. The maximum curtailment function resulted in a higher curtailment at each location and ranged from 0.51 percent – 0.76 percent reduction in annual energy output.

**Table 18: Annual Curtailment Results for Sensitivity Analysis of Volt-Var Function**

| Volt-var Function | Location | PV System Size (kW) | Unconstrained Capacity Factor | Capacity Factor Using SI Function | Curtailment (% of Unconstrained Output) |
|---|---|---|---|---|---|
| | Front | 7,225 | 16.96% | 16.96% | 0.00% |
| Reference Case | Middle | 3,560 | 16.96% | 16.96% | 0.04% |
| | End | 2,495 | 16.97% | 16.96% | 0.08% |
| Maximum Curtailment | Front | 7,225 | 16.96% | 16.88% | 0.51% |
| | Middle | 3,560 | 16.96% | 16.84% | 0.75% |
| | End | 2,495 | 16.97% | 16.84% | 0.76% |
| Minimum Curtailment | Front | 7,225 | 16.96% | 16.97% | -0.02% |
| | Middle | 3,560 | 16.96% | 16.96% | 0.03% |
| | End | 2,495 | 16.97% | 16.96% | 0.07% |

Source: Electric Power Research Institute

The increased curtailment from the "maximum" curtailment volt-var function reduced the value of employing the smart inverter function to increase PV HC, as shown in Table 19. Still, the single scenario in which the conventional upgrade was more economical was the case where only settings of existing regulation equipment needed to be updated, which resulted in a minor expense. For the other two scenarios that required additional regulating equipment, using smart inverters was the more economical solution.

**Table 19: Economic Sensitivity Analysis of Volt-Var Functions Comparing Smart Inverter Functions and Conventional Upgrades to Increase Hosting Capacity by 25 Percent**

| Volt-var Function | Location | Total Energy Curtailed *(MWh/year)* | Annualized Cost of the SI Functions *($/year)* | Annualized Cost of Conventional Upgrades *($/year)* | Difference in Value *($/year)* |
|---|---|---|---|---|---|
| Reference Case | Front | 5 | $168 | $750 | $552 |
| | Middle | 2 | $74 | $19,176 | $19,102 |
| | End | 1 | $47 | $19,176 | $19,128 |
| Maximum Curtailment | Front | 59 | $2,142 | $750 | ($1,422) |
| | Middle | 39 | $1,433 | $19,176 | $17,743 |
| | End | 27 | $963 | $19,176 | $18,213 |
| Minimum Curtailment | Front | 3 | $107 | $750 | $613 |
| | Middle | 1 | $49 | $19,176 | $19,127 |
| | End | 1 | $34 | $19,176 | $19,142 |

Source: Electric Power Research Institute

### Variation of the Limit Maximum Real Power Function

While using the LMRP function at a constant value of 80 percent will increase the available DC power by 25 percent, it can be informative to understand the curtailment impacts by setting the LMRP function to different settings that may enable even larger penetrations of solar with more total energy production. Because the LMRP function is independent of grid conditions, it can be considered as a "worst case" solution with the highest amount of curtailment needed to increase PV penetrations. Thus, it is useful to see what these "worst case" curtailments might look like to achieve even higher increases in PV penetrations beyond 25 percent. For example, Table 20 shows the relationship between the LMRP function settings and the associated increase in available DC capacity that can be connected to the grid.

**Table 20: Relationship Between Limit Maximum Real Power Setting and Potential Increase in Connected Direct Current Capacity**

| LMRP Setting | Potential Increase in Connected DC Capacity |
|---|---|
| 100% | 0% |
| 90% | 11% |
| 80% | 25% |
| 70% | 43% |
| 60% | 67% |
| 50% | 100% |
| 40% | 150% |

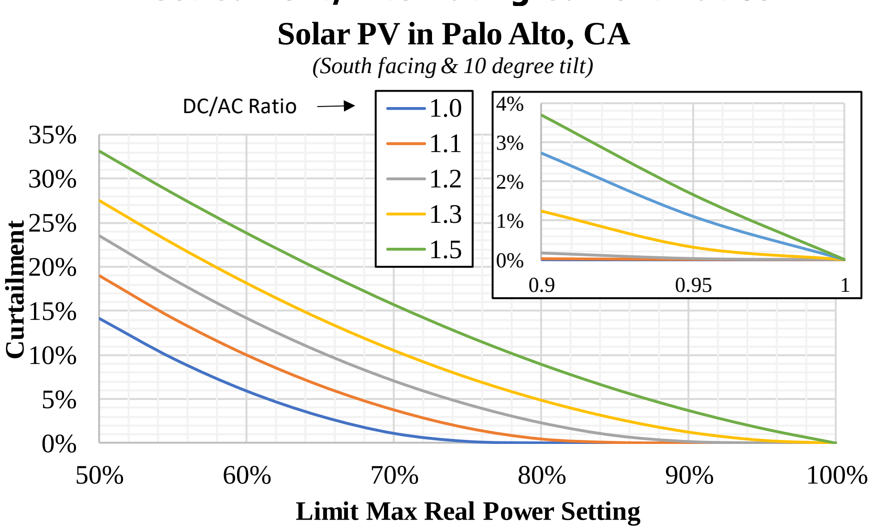
Source: Electric Power Research Institute

### Solar Photovoltaic Curtailment Variation Based on Limit Maximum Real Power Setting and Direct Current/Alternative Current Ratio

Using typical meteorological year data from NREL's PVWatts [24] calculator, a sensitivity analysis was performed using different DC/AC ratios and LMRP settings. Findings provided in Figure 31 reveal that PV systems designed with higher DC/AC ratios result in higher PV curtailment when the LMRP function is used. This curtailment is mainly driven by the fact that PV systems with higher DC/AC ratios spend more time with inverters at saturation and thus have a greater potential for more frequent curtailments.

Further, curtailments for PV systems with DC/AC ratios of 1.0 are shown to be very small, only exceeding 5 percent of annual energy once the LMRP is set to 60 percent or less. This finding indicates that even if smart inverter functions can reduce real power output, depending on the system design, the amount of curtailment may be negligible. It is thus important to consider factors that impact available DC power such as PV system orientation and location, temperature degradation, module mismatch, and/or DC wiring losses.

**Figure 31: Annual Solar Photovoltaic Curtailment in Palo Alto, California from South Facing 10° tilt system at Different Limit Maximum Real Power Settings and Direct Current/Alternating Current Ratios**

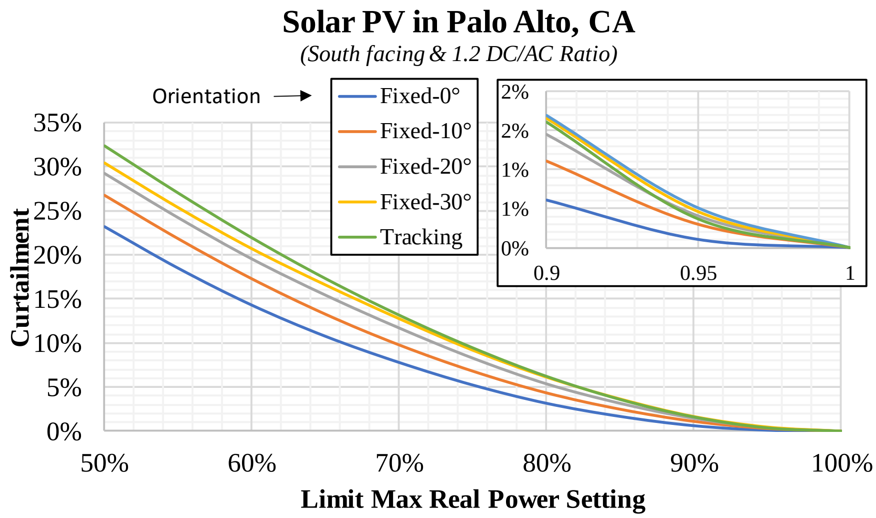



Source: Electric Power Research Institute

### Solar Photovoltaic Curtailment Variation Based on Limit Maximum Real Power Setting and Photovoltaic System Orientation

Considering that PV orientation can also have an impact on the availability of DC power, an additional sensitivity study was performed to examine varying PV system orientations and LMRP values. Results, provided in Figure 32, illustrate that the variation in PV system orientation does not have as large an impact as the DC/AC ratio; however, the variation could be significant. At an LMRP level of 80 percent, the variation in energy curtailment between a fixed 0° tilt system and a tracking system was near 4 percent.

**Figure 32: Annual Solar Photovoltaic Curtailment in Palo Alto, California, from South Facing System Sized with 1.2 Direct Current/Alternating Current Ratio at Different Limit Maximum Real Power Settings and Orientations**




Source: Electric Power Research Institute

# CHAPTER 4:
# IEEE 2030.5 Common Smart Inverter Profile Compliance Test Procedure and SunSpec System Validation Platform for Test Automation

The SunSpec System Validation Platform (SVP) is used to perform the CA Rule 21 smart inverter testing in the UCSD Smart Inverter Laboratory.

## SunSpec System Validation Platform

The objective of the SunSpec SVP is to provide an automated framework for testing.

The general approach in the SunSpec SVP is to provide an environment that can manage and execute test scripts that utilize libraries affording access to all necessary components in the test system. This approach allows for the same test logic to be applied in testing scenarios that may be using different physical components to implement a set of test cases.

Due to the permutations created by multiple device settings under multiple electrical conditions contained in the UL 1741 SA/CA Rule 21 test cases, it is impractical to run a comprehensive set of tests without a high level of automation. The SunSpec SVP is capable of interfacing to all the components in the UCSD Smart Inverter Laboratory to provide full automation.

The SunSpec System Validation Platform is distributed as a single Windows setup executable. The SunSpec SVP installation Windows executable is self-contained and does not require Python to be installed on the system.

### Simple Procedural Test Scripts

A key objective of the system is to keep the logic in the test scripts as simple as possible. The test scripts are written in a procedural style with the logic being tied directly to the test protocol documentation. This allows scripts to be created, updated, and understood by a larger group of users of the system. Higher complexity interactions with system components are built into support libraries.

### Support Libraries

Support libraries provide blocks of functionality required in the system. In general, support libraries are written in a modular, object-oriented style providing objects with rich functionality to be used by test scripts.

### Python

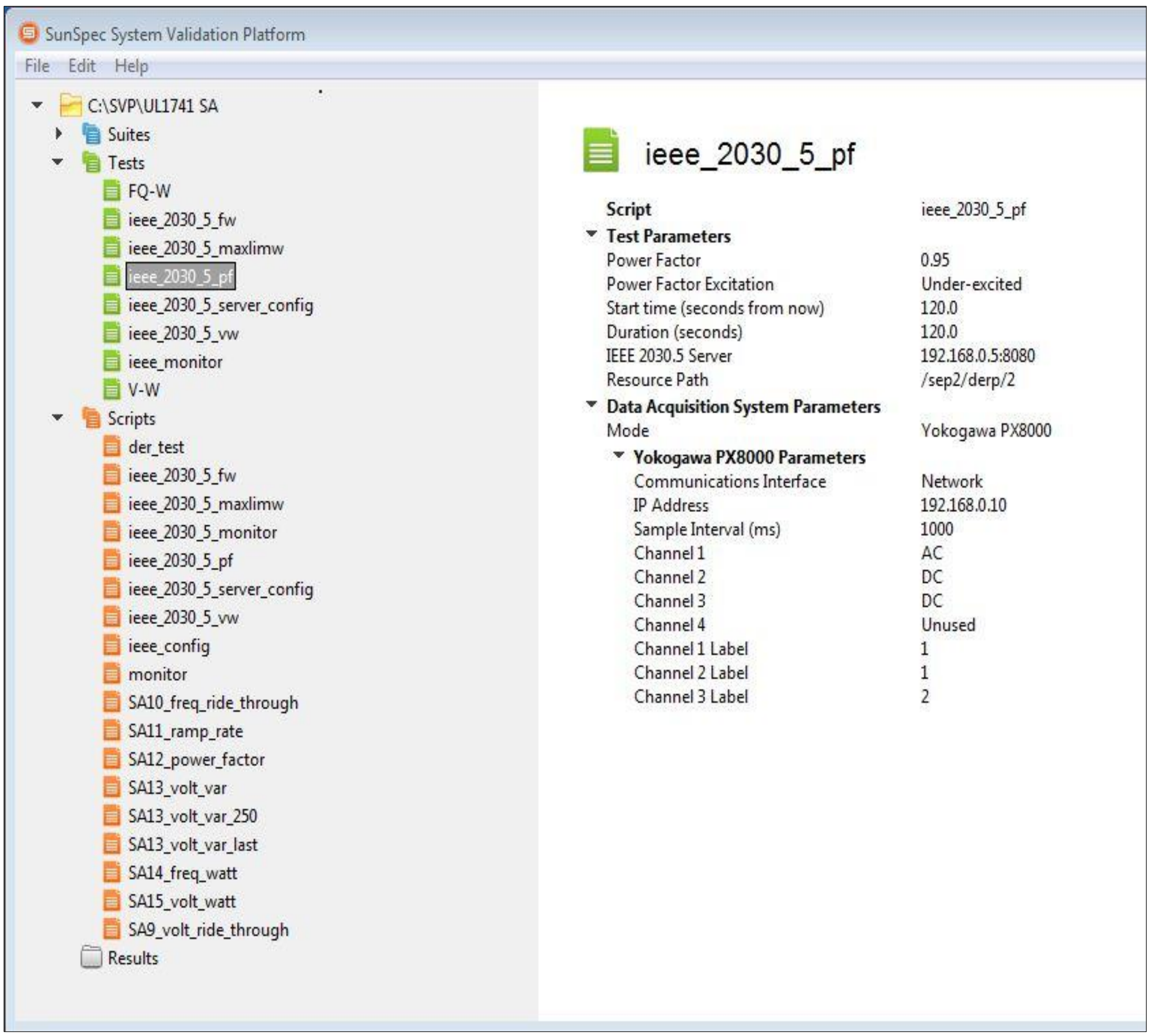
The Python language was chosen for its robustness, ease of use, and multi-platform support. Python is an easy to learn, powerful programming language. It has efficient high-level data structures and a simple but effective approach to object-oriented programming. Python’s elegant syntax and dynamic typing, together with its interpreted nature, make it an ideal language for scripting and testing.

The Python interpreter and the extensive standard library are freely available in source or binary form for all major platforms from the Python website, https://www.python.org/, and may be freely distributed. The same website also contains distributions of and pointers to many free third-party Python modules, programs, tools, and additional documentation.

## California Rule 21 Phase 3 System Validation Platform Test Scripts

A set of SVP test scripts and test configurations have been developed to test the CA Rule 21 Phase 3 functionality. Each of the Phase 3 functions being tested have a corresponding test script that can be used to perform the testing for the function. For this project, the IEEE 2030.5 related test scripts have been added to the standard UL 1741 SA SVP testing directory. Figure 33 shows an example within SVP of the test scripts and corresponding configured tests.

**Figure 33: Example of Test Scripts and Configured Tests Within System Validation Platform**

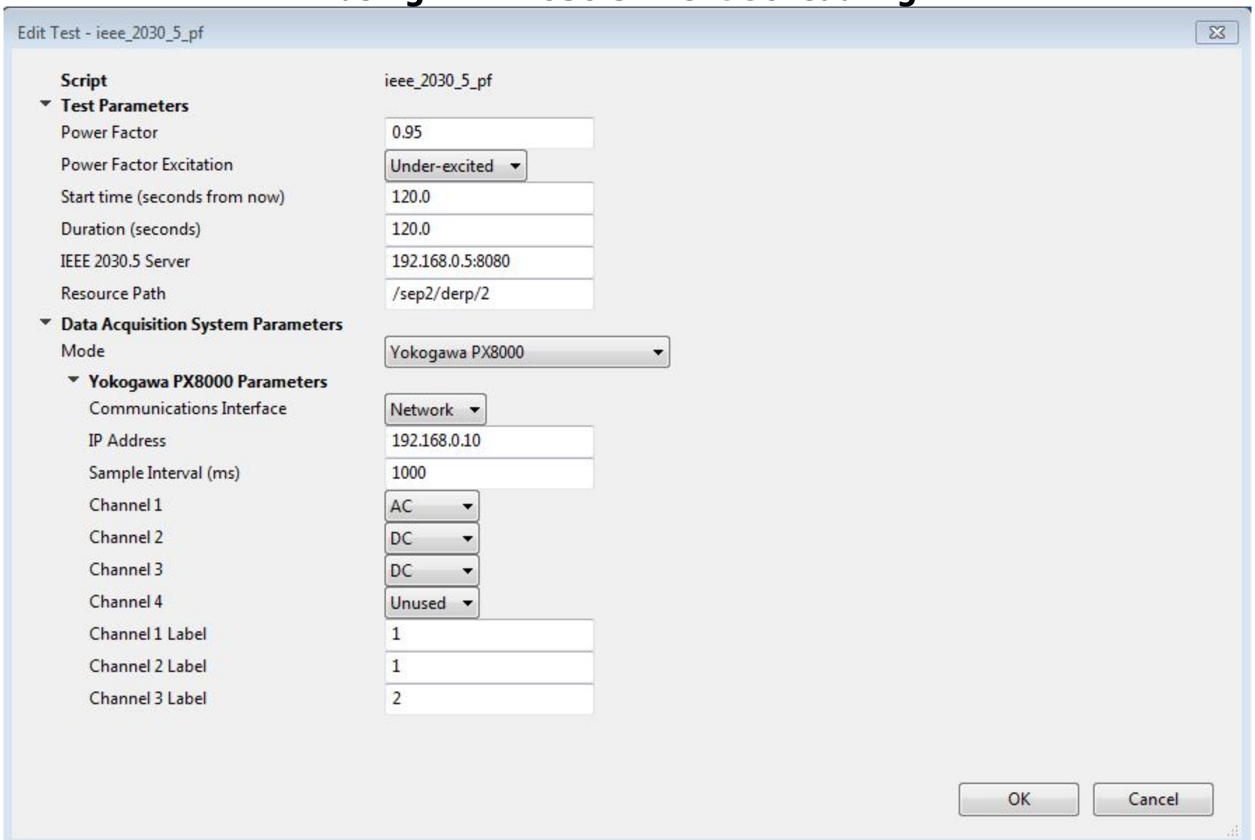



Source: SunSpec

SVP test scripts allow configuration of the adjustable parameters associated with the script. Once a test configuration has been created for a test script, it can be run as a test case. Figure

34 is an example of the configuration options for the scheduling of the fixed power factor function using IEEE 2030.5 event scheduling.

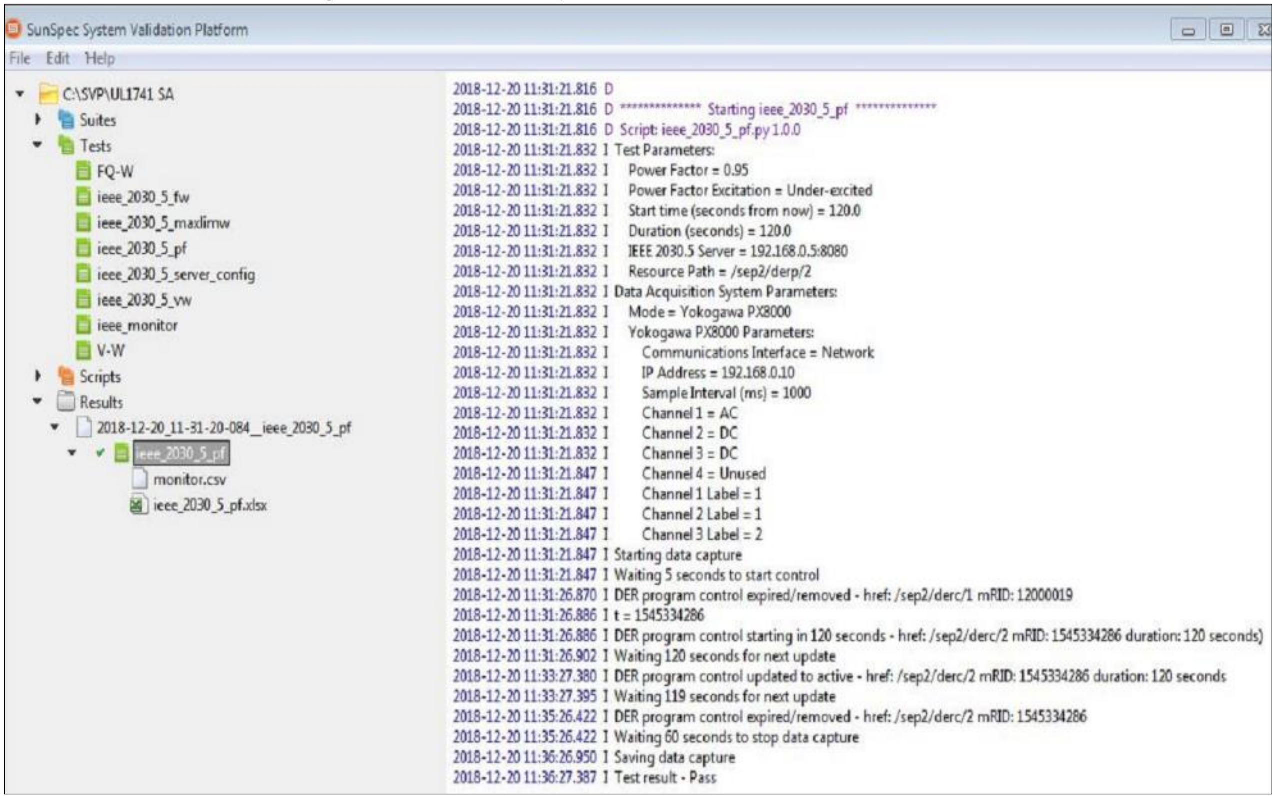
**Figure 34: Example Configuration Option for Scheduling of Fixed Power Factor using IEEE 2030.5 Event Scheduling**




Source: SunSpec

Once a test configuration is created, each execution of the test produces a results set consisting of the test log and any data sets that are collected during the test. All test results are archived in the SVP results directory along with a results manifest for each result that catalogs the artifacts produced by the test run. The results can be viewed in SVP or can be used as input for further results analysis. Figure 35 shows an example results set produced by a test run.

**Figure 35: Example of Test Run Results Set**




Source: SunSpec

Each test script may produce different results artifacts based on the functionality being tested and the results analysis performed by the test script. Test configuration options may also determine the contents of the results artifacts.

The test scripts used to perform the CA Rule 21 Phase 3 testing all produce a comma-separated values (CSV, .csv) file containing the raw data samples collected during each test. Most test scripts also produce an Excel workbook containing the raw data samples as well as plots of the relevant test data for easier results inspection.

# CHAPTER 5: Laboratory Evaluation of Rule 21 Phase 3 Smart Inverter Functions

## Purpose

This task evaluated the performance of smart inverters for Phase 3 functions, which included monitoring of key data, disconnect/reconnect, limit maximum active power mode, frequency-watt mode, volt-watt mode, and scheduling of power values and modes. A key feature of Phase 3 testing is to activate these functions by means of commands from a control server via a communications gateway to the inverter, analogous to testing and operation of multiple servers in the field. The communications gateway employs the newly developed IEEE 2030.5 communications protocol, as required by Phase 3 functions.

## Implementing Phase 3 Functions in Smart Inverters (ABB and SMA) and Gateways

CA Rule 21/UL 1741 SA Phase 3 defines an additional set of advanced inverter functions to 1) further enhance inverter performance and grid support and 2) effect the changes in inverter values and operating modes for the Phase 3 functions tested for this project. The communications protocol employed is IEEE 2030.5 (approved December 2018), newly developed for inverter command and control.

Two commercial inverters, SMA and ABB, were used for this lab testing. Both inverters were upgraded to meet Rule 21 requirements and deployed at the UCSD lab.

The UCSD Smart Inverter Laboratory was designed to provide a controllable environment in which to test inverters to the new CA Rule 21/UL 1741 SA standards to evaluate the ability of the inverters to perform smart functions within the specified criteria. Testing needed to be consistent, repeatable, and reproducible. Data collection needed to be accurate, comprehensive, and sufficient to enable all stakeholders to accurately evaluate the performance of an inverter and either recognize compliance with the test criteria *or* identify shortcomings that could be rectified by software, firmware, or hardware updates or through adjustment of the inverter’s parameters.

## California Rule 21 Phase 3 Functions and Testing Criteria

The tests described in this document address smart inverter functionality contained in revisions to CA Rule 21, as specified in CPUC Proceeding R1109011 [25]. The final specification of Phase 3 functions is contained in Resolution E-4898.

The detailed requirements for CA Rule 21 Phase 3 functionality are derived from the following standards and specifications: UL 1741, IEEE 1547-2018, CSIP, and IEEE 2030.5-2018.

The IEEE 1547-2018 standard is used to provide the requirements for functions that are not specified in UL 1741 SA. The CSIP specifies how IEEE 2030.5 is used to provide communications with utility servers. The smart inverter functionality contained in the CA Rule 21 revision is summarized in Table 21.

**Table 21: Phase 3 California Rule 21 Smart Inverter Functions**

| ID | CA Rule 21 Smart Inverter Functionality | Source |
|---|---|---|
| 1 | Monitor Key Data | CSIP/IEEE 1547-2018 |
| 2 | Disconnect/Reconnect | IEEE 1547-2018 |
| 3 | Limit Maximum Active Power Mode | IEEE 1547-2018 |
| 4 | Set Active Power Mode | Not yet specified (Not tested) |
| 5 | Frequency Watt Mode | UL 1741 SA/IEEE 1547-2018 |
| 6 | Volt-Watt Mode | UL 1741 SA/IEEE 1547-2018 |
| 7 | Dynamic Reactive Power Support | Not yet specified (Not tested) |
| 8 | Scheduling Power Values and Modes | CSIP/IEEE 2030.5 |

Source: Electric Power Research Institute

## UL 1741 Supplement SA

The CA Rule 21 revision identifies UL 1741 Supplement SA as the testing standard for smart inverter functionality. UL 1741 Supplement SA addresses the general testing of a set of advanced inverter functions, with specific test inputs based on the source requirements document against which the functionality is being validated. Table 22 summarizes the UL 1741 SA sections that relate to required CA Rule 21 Phase 3 functionality.

**Table 22: UL 1741 SA Requirements/Test Protocols**

| UL 1741 SA Applicable Requirements/Test Protocols |
|---|
| SA14 – Frequency Watt Mode |
| SA15 – Volt Watt Mode |

Source: Electric Power Research Institute

## Monitor Key Data

The revision for smart inverters requires monitoring of active power, reactive power, voltage, frequency, operational state, connection status, alarm status, and operational state of charge.

- Input Parameters: The input parameters for this test are network configuration information for the equipment under test.
- Procedure: The equipment under test should be periodically accessed to verify the monitoring points specified above are being updated and are correct. If possible, the device can also be configured to report the monitored data to the IEEE 2030.5 server.
- Tests: Example test procedures include BASIC-027, BASIC-028, and BASIC-029 found in the SunSpec CSIP Conformance Test Procedures document.

### Disconnect/Reconnect

The Disconnect/Reconnect requirement is implemented using the Permit Service indication in the Enter Service functionality specified in IEEE 1547-2018.

- Input Parameters: The Enter Service parameters specify the voltage, frequency, and timing conditions that must be met to enter service (connect to the grid). The Permit Service flag is used to control whether a device should consider the other Enter Service parameters. If Permit Service is set to "false," and the device is in service, it should exit service (disconnect from the grid) and not attempt to reenter service until Permit Service is set to "true." Galvanic isolation is not required for disconnection.
- Procedure: While connected, a disconnect indication is sent to the equipment under test during power output monitoring. A connect indication is then sent to return the equipment to the connected state.
- Tests: Based on the requirements specified in IEEE 1547-2018, test procedure BASIC-009, found in the SunSpec CSIP Conformance Test Procedures document, is performed and evaluated for CA Rule 21.

### Limit Maximum Active Power Mode

The test limits maximum active power as a percentage of the maximum active power rating for the device.

- Input Parameters: The input parameter for this test is the percentage of maximum active power to apply to the device for testing.
- Procedure: The maximum active power setting is applied to the device while monitoring the power output of the equipment under test. The setting is then returned to full power output.
- Tests: Based on requirements specified in IEEE 1547-2018 and IEEE 1547.1, test procedure BASIC-010, found in the SunSpec CSIP Conformance Test Procedures document, is performed and evaluated for CA Rule 21.

### Frequency-Watt Mode

The tests in this section verify reductions in active power during overfrequency conditions and increase active power (if possible) during underfrequency conditions.

- Input Parameters: A start frequency of 60.05 Hz and a gradient of 40 percent active power reduction per hertz should be used.
- Procedure: Section SA14 in UL 1741 is used as the test criteria. The procedure in SA14 specifies increasing the frequency from nominal to the level where power is completely curtailed; frequency should then be reduced back to nominal while monitoring frequency and power.
- Tests: Based on the requirements specified in UL 1741 SA, the test case BASIC-012, found in the SunSpec CSIP Conformance Test Procedures document, can also be performed and evaluated for CA Rule 21.

### Volt-Watt Mode

The tests in this section verify reductions in active power during overvoltage conditions.

- Input Parameters: The default recommended setting is a reduction of 5 percent of active power rating per 1 percent of nominal voltage over 106 percent of nominal voltage. When nominal voltage is greater than 108 percent, active power should be reduced to 0 W.
- Procedure: Section SA15 in UL 1741 is used as the test criteria. The procedure in SA15 specifies increasing the voltage from nominal to the voltage level where power is completely curtailed and then reducing the voltage back to nominal while monitoring voltage and power.
- Tests: Based on the requirements specified in UL 1741 SA, the test case BASIC-011, found in the SunSpec CSIP Conformance Test Procedures document, can also be performed and evaluated for CA Rule 21.

### Scheduling Power Values and Modes

The tests in this section verify capability to schedule control events. The following controls must be supported: Volt-var, fixed power factor, and volt-watt.

- Input Parameters: It is important to provide parameters for each function being tested. Each test input specifies the function parameter along with the start time and duration of the function being tested.
- Procedure: Currently, the only specific method defined for scheduling is the normal IEEE 2030.5 control event mechanism, so the communication test procedures are used for verification. The input parameters are applied through the IEEE 2030.5 interface while the grid conditions are monitored.
- Tests: Based on the requirements specified in UL 1741 SA, the test case BASIC-011, found in the SunSpec CSIP Conformance Test Procedures document, is performed and evaluated for CA Rule 21.

### Communications Gateway

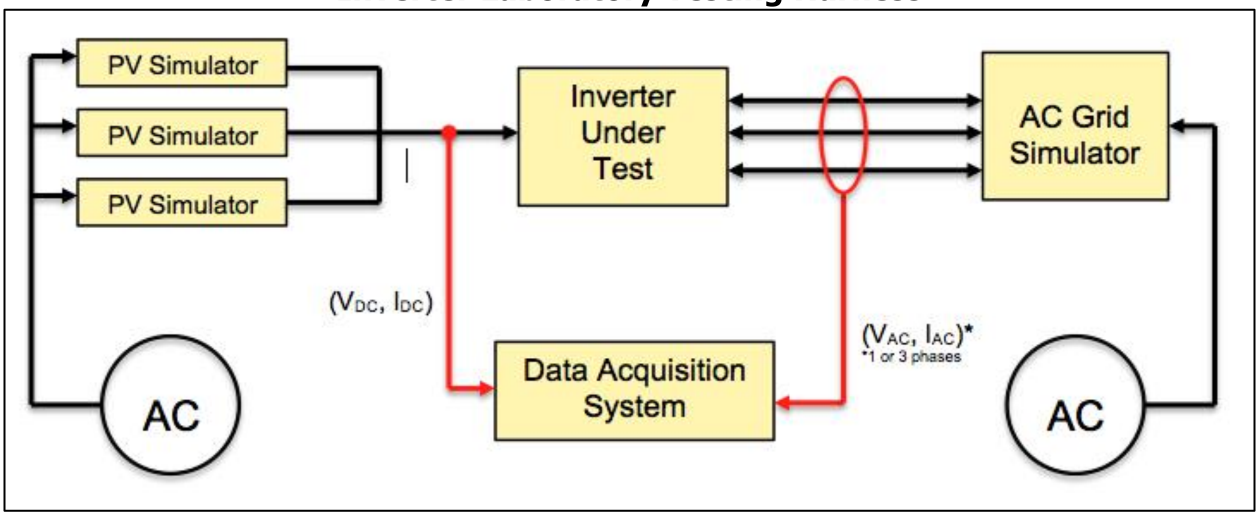
The aforementioned Phase 3 inverter functions were manipulated by means of a communications gateway, supplied by OpenEGrid, utilizing the newly developed IEEE 2030.5-2018 communications protocol. A remote server sends 2030.5 commands to the gateway, which translates the commands to Modbus commands, which are sent to the inverter under test (IUT). This procedure demonstrates how a server-gateway system using the secure 2030.5 protocol can monitor and control a fleet of inverters in the field.

## University of California, San Diego Smart Inverter Testing Laboratory [26]

### Testing Harness

The functional schematic of the testing setup is shown in Figure 36. The circles labeled “AC” represent the 480-V three-phase power supply from the utility via a 90-A breaker panel. The PV Simulators include three 10-kW programmable DC power supplies capable of simulating virtually any type of PV panel, string, or array. The simulators are connected to the DC inputs of the inverter and are programmed by the SunSpec test scripts to provide the required amount of power to drive the inverter to its required level of output or change the power level during testing, as needed. The AC Grid Simulator acts as the utility grid for the purpose of running tests and is programmable by the SunSpec scripts to simulate changing grid conditions, as required by the Rule 21 tests. The AC Grid Simulator accepts the AC output of the inverter and injects it back into the grid. The Data Acquisition System (DAS) measures DC current and voltage at the inverter input and AC RMS current and voltage at the inverter output. From these values, the DAS computes DC power; real, reactive, and apparent AC power; AC phase angle; and AC power factor. Data are sampled at 0.1-second intervals, tabulated in an Excel file, and graphed in Excel charts for visual analysis. Connection cables between the PV Simulator and inverter, and between the inverter and AC Grid Simulator, are equipped with a quick-disconnect converter for fast changeout of the IUT. Equipment specifications are detailed in the next section.

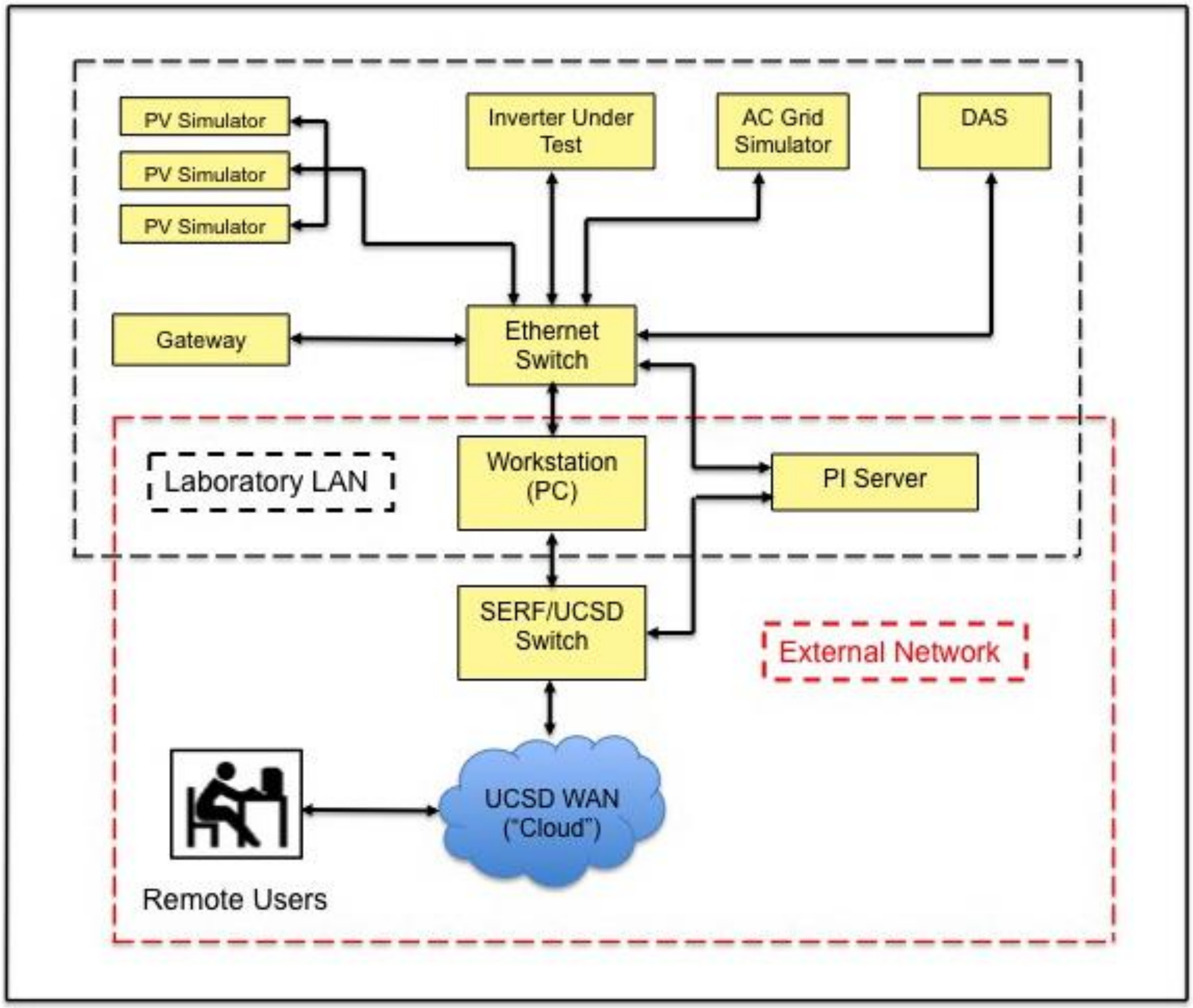
**Figure 36: Functional Schematic of University of California, San Diego Smart Inverter Laboratory Testing Harness**




Source: Electric Power Research Institute

Figure 37 shows the communication and control setup for the UCSD lab. The Lab Workstation houses the SunSpec SVP, which contains the test scripts that control the conduct of each test. Commands are sent and information retrieved via the Ethernet local area network (LAN) to/from all devices on the laboratory LAN (bounded by black dashed line). The Lab Workstation also runs a Dynamic Host Configuration Protocol (DHCP) server, so that each device on the LAN, when it starts up, is assigned a unique Internet Protocol (IP) address by the DHCP server for control purposes. An OSIsoft process information (PI) data archival and retrieval system is housed on a separate computer ("PI Server"). The Lab Workstation and the PI Server each have separate network interface cards (NICs) for communication with the UCSD wide area network (WAN). The gateway device is accessed remotely — through the WAN by a user with virtual private network (VPN) credentials — and is manipulated to send commands to the inverter through the LAN using the new 2030.5 communications protocol. The laboratory LAN is therefore insulated from the WAN (Internet) for security purposes. ("SERF" refers to the Science and Engineering Research Facility, the building housing the lab.)

**Figure 37: Schematic of University of California, San Diego Smart Inverter Laboratory Communications and Data Acquisition**




Source: Electric Power Research Institute

## Test Equipment Specifications

### Grid Simulator

The specifications of the AC Grid Simulator are given in Table 23. This device controls the grid voltage and frequency at the inverter's AC terminals according to test specifications.

**Table 23: Alternating Current Grid Simulator Specifications**

| Item | Specification |
|---|---|
| Manufacturer | California Instruments |
| Model | MX30-3 |
| Capacity | 30 kW (10 kW per phase) |
| AC Power Supply | 480 V (3-$\phi$) |
| Output Voltage Ranges | Low: 0–150 V; High: 0–300 V |
| Output Current Ranges | 0–66.6 A (Low V); 0–33.3 A (High V) |

Source: Electric Power Research Institute

## Photovoltaic Simulator

The specifications of each PV Simulator are given in Table 24. For the inverter used in this test, two PV Simulators were used to provide 3000 W each per DC input channel to produce rated inverter output of 6 kW AC.

**Table 24: Photovoltaic Simulator Specifications**

| Item | Specification |
|---|---|
| Manufacturer | Elgar |
| Model | TerraSAS ETS600X17E-PVF |
| AC Power Supply | 480 V (3-$\phi$) |
| Max. Output | 10 kW |
| Max. Output Voltage (DC) | 600 V |
| Short Circuit Current (DC) | 16.7 A |
| Interface | TerraSAS software |
| Tracking Speed | 200 Hz |
| Accuracy | Voltage: ± 0.02% of full scale<br>Current: ± 0.05% of full scale |
| Sampling Resolution | 200 kS/s |

Source: Electric Power Research Institute

## Data Acquisition System

The specifications of the DAS are given in Table 25. Measured parameters were AC and DC voltages and currents at the inverter terminals. Parameters that were calculated from these measurements include DC power; AC apparent, real, and reactive power; and AC phase angle, power factor, and frequency. Data were sampled at intervals of 0.1 second.

**Table 25: Data Acquisition System Specifications**

| Item | Specification |
|---|---|
| Manufacturer | Yokogawa |
| Model | PX8000 |
| Input Channels | (4) voltage, (4) current |
| Voltage Input | 1.5 – 1000 V |
| Current Input | 10 mA – 5 A |
| Sampling Rate (max) | 200 Ks/s |
| Display | Numeric + Waveform |
| Interfaces | GPIB, USB, Ethernet |

Source: Electric Power Research Institute

## Lab Workstation

The Lab Workstation is the “brain” and principal control center for the lab. Its specifications are given in Table 26. Tests are run using the SunSpec SVP. Each test sends the appropriate commands to the PV Simulator and Grid Simulator to program power levels, grid voltage, and frequency parameters; the SunSpec SVP also controls the DAS to record test data.

**Table 26: Test Lab Workstation Specifications**

| Item | Specification |
|---|---|
| Make & Model | Dell Precision T3620 Mini Tower |
| Name | SMINVLAB |
| Processor | 3.4 GHz Quad-Core Intel® i7-6700 |
| RAM | 16 GB |
| Storage | (2) 1 TB SATA 7200 rpm hard drives |
| Graphics | Dell HD 530 graphics card |
| I/O Devices | 23" Dell HD monitor, wired keyboard and multifunction mouse |
| Interfaces | (2) 1-Gbit NIC (Ethernet), RS-232, USB |
| Operating System | Microsoft Windows 7 Pro |
| Other | Microsoft Office 2016<br>Adobe Acrobat Pro |

Source: Electric Power Research Institute

## Data Archive System

The data archive system consists of an OSIsoft PI system residing on a separate workstation, configured to archive the test result data. While physically located in the same laboratory as the rest of the project equipment, the PI Workstation is not part of the laboratory LAN. The PI Workstation is connected to the UCSD WAN so that remote access, via a user ID/password setup, is available to authorized persons (Figure 37). Table 27 shows the specifications for the PI Workstation, as of this writing. These specs may change after further evaluation of the testing requirements.

**Table 27: PI Workstation Specifications**

| Item | Specification |
|---|---|
| Make & Model | Dell Precision T3620 Mini Tower |
| Name | SMINV-PI |
| Processor | 3.4 GHz Quad-Core Intel® i7-6700 |
| RAM | 32 GB |
| Storage | (2) 4-TB SATA 5400 rpm hard drives (2) additional HDD expansion slots |
| Graphics | Dell HD 530 graphics card |
| I/O Devices | 23" Dell HD monitor, wired keyboard and multifunction mouse |
| Interface | (2) 1-Gbit NICs (Ethernet), wireless NIC, RS-232, USB |
| Operating System | Microsoft Windows 10; Virtualization option (Hyper-V) enabled |
| Other | Microsoft Office |

Source: Electric Power Research Institute

## Communications Gateway

The communications gateway is a device for sending/receiving data and commands to/from the system controller (a server) and the inverter. The communications gateway here is the ARM-based quad-core processor with 2 GB RAM, with the device running the IEEE 2030.5 communications protocol (Table 28).

**Table 28: Communications Gateway Specifications**

| Item | Specification |
|---|---|
| Make & Model | OpenEgrid |
| Name | Gateway |
| Processor | ARM Quad-Core/2 GB Memory |
| Interface | Ethernet, USB, Cellular |
| Operating System | Linux Embedded |

Source: Electric Power Research Institute

## Inverter Under Test

The inverter used for these tests was a 6.0 kW commercial model from a major manufacturer, and was known to have successfully demonstrated all Phase 1 and Phase 3 functions. The inverter was installed in the UCSD Smart Inverter Laboratory Testing Harness, as shown in Figure 36, and instrumented (Figure 37).

## IEEE 2030.5 Server

The IEEE 2030.5 server functionality is implemented in conjunction with SunSpec SVP. An IEEE 2030.5 server process runs concurrently with SunSpec SVP. SVP test scripts cause configuration changes to be made in the 2030.5 server, which are then picked up by the

2030.5 gateway. These configuration changes are propagated to the IUT to cause changes in the settings for the functionality associated with each of the test cases.

## Security Considerations

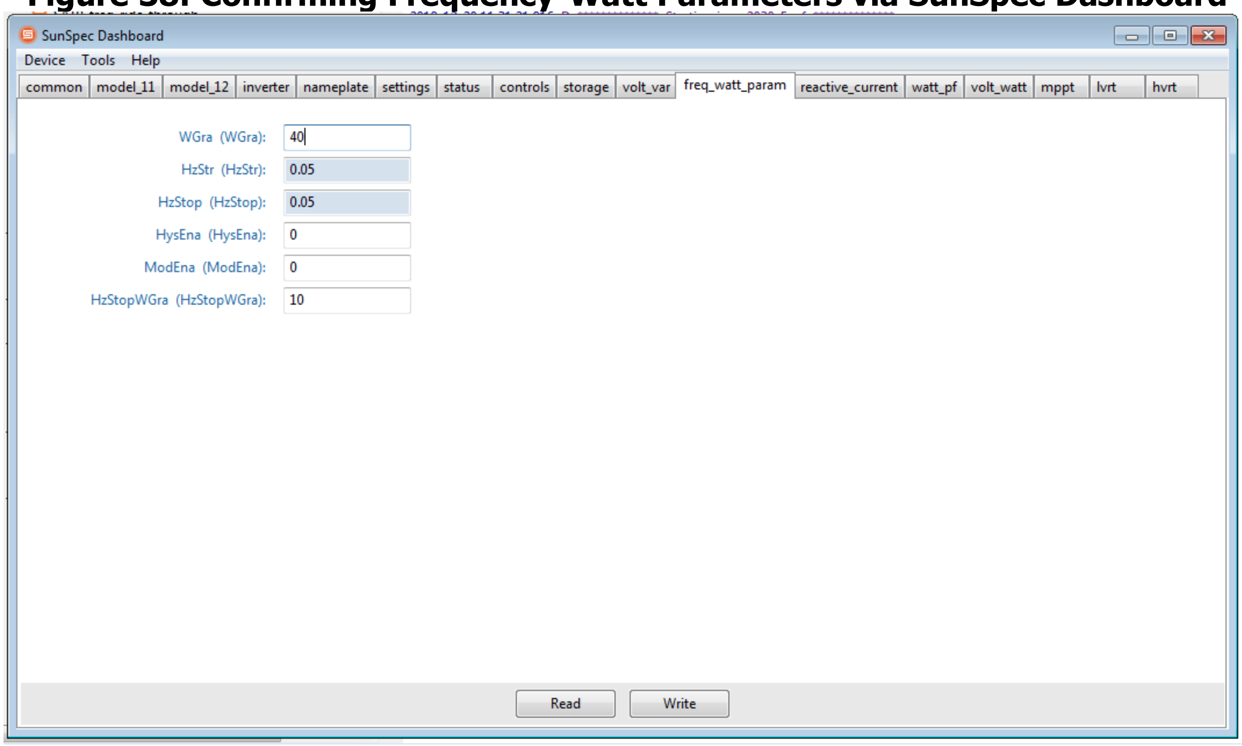
All communications between the 2030.5 server and client are performed using secure Transport Layer Security (TLS) connections replicating the production environment requirements. The SunSpec test PKI is used to issue IEEE 2030.5-2018 compliant certificates to both the 2030.5 server and the gateway client used in this testing environment. The SunSpec test PKI allows certificates to be created that conform to all production certificates, including the specification of device-specific information to be included in the certificate.

## Test Results and Analysis

### Monitor Key Data

For initial Phase 3 functional testing of the ability to monitor the status of the inverter, the SunSpec Dashboard was used to read and write settings and parameters to and from the inverter. For example, settings for the frequency-watt function are implemented by entering the desired numbers in the Dashboard (Figure 38) then clicking the "Write" button. After a few seconds, to allow the inverter time to change its settings internally, clicking the "Read" button will retrieve the settings from the inverter and overwrite the Dashboard page, confirming the settings and also demonstrating the ability to read status information from the inverter.

**Figure 38: Confirming Frequency-Watt Parameters via SunSpec Dashboard**



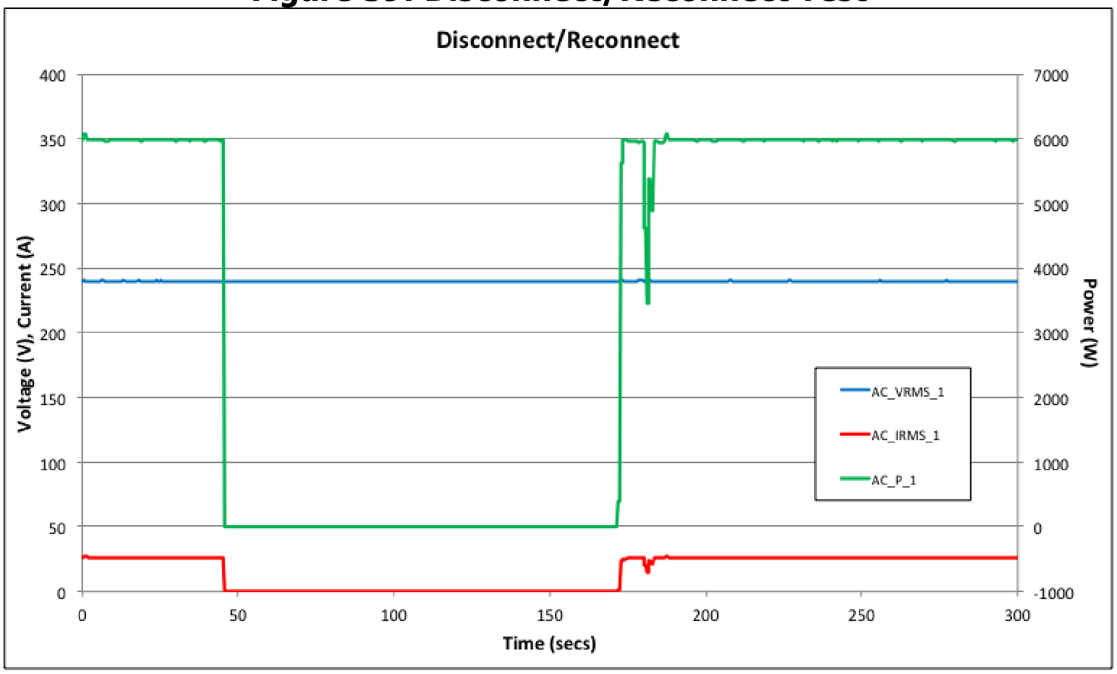

Source: SunSpec

To verify that 2030.5 communications can be used to perform this function, read requests were sent from the OpenEgrid 2030.5 server to the gateway, which then forwarded the request to the inverter. At the next polling interval, the inverter sent the requested information back to the gateway, which sent the information to the server. The information was verified by the server operator and confirmed via the SunSpec Dashboard. Read requests were verified in this manner for various other inverter settings and data.

## Disconnect/Reconnect Test

This test entailed first sending a 2030.5 command to disconnect the AC grid from the remote server to the OpenEgrid gateway — which translated the command to Modbus and forwarded it to the inverter — then sending a second command to reconnect to the grid via the same route. The inverter disconnected from the AC grid, as commanded, then reconnected after its internally set reconnection time, as shown in Figure 39.

**Figure 39: Disconnect/Reconnect Test**



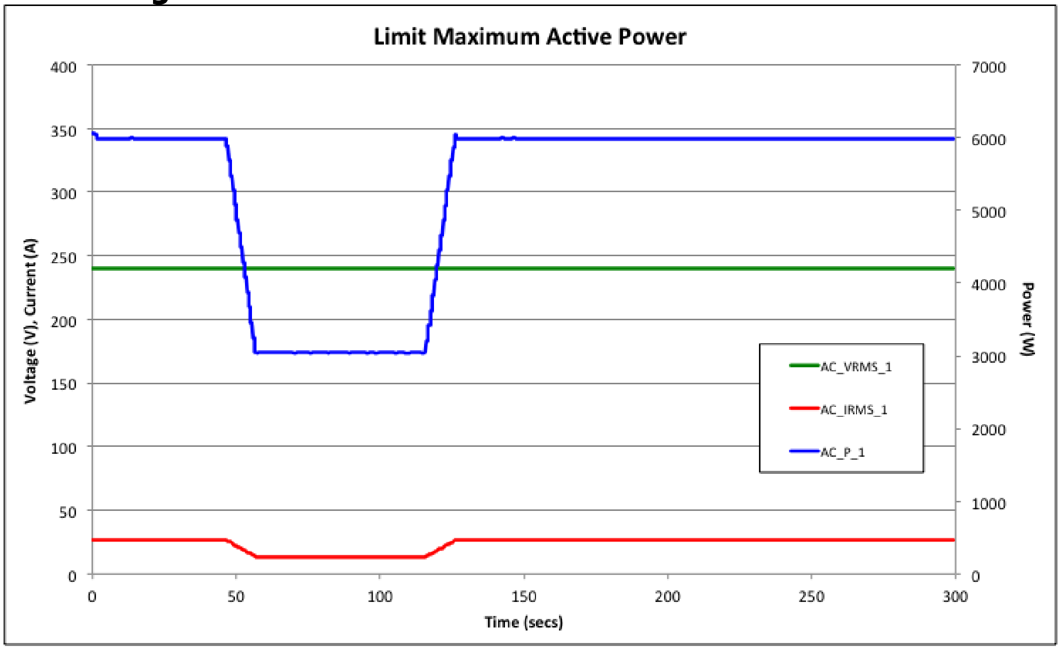

Source: Electric Power Research Institute

Both AC power and current drop to zero then return to their pre-disconnect levels. The actual time delay between disconnection and reconnection depends upon the timing of both the command sequencing and the polling interval of the communications protocol. This function has been successfully verified to perform as expected using IEEE 2030.5.

## Limit Maximum Active Power Mode Test

In this test, a 2030.5 command was sent from the control server to the communications gateway to affect an inverter power limitation of 50 percent of rated power at a specified time for a 60-second duration, after which the inverter would return to full power. Figure 40 shows the results of this test. Both AC power and current drop to 50 percent then return to 100 percent of their previous levels. The actual time delay between power curtailment and restoration depends upon the timing of the command sequencing and the polling interval of the communications protocol. This function has been verified to perform as expected.

**Figure 40: Limit Maximum Active Power Mode Test**

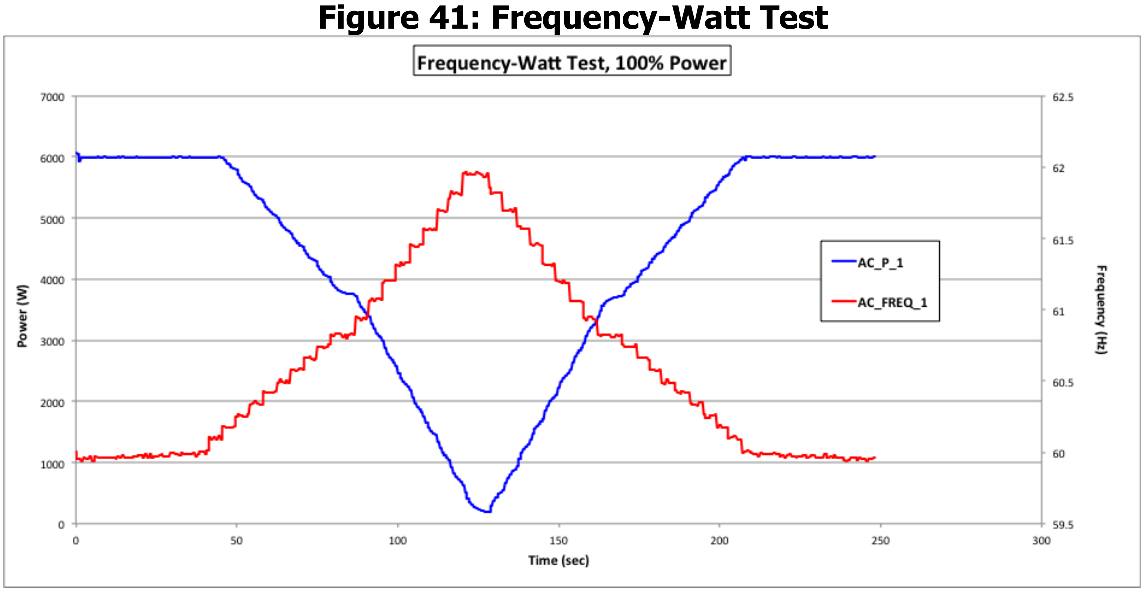



Source: Electric Power Research Institute

## Frequency-Watt Mode Test

In this test, a 2030.5 command was sent from the control server to the communications gateway to 1) enable the frequency-watt function and 2) change the start and stop frequency settings and the gradient of frequency change in percent $P_{nom}$/Hz. In this mode, the inverter will decrease its active power output as AC grid frequency increases above the nominal value of 60 Hz, beginning at the specified start frequency. (This is in accordance with the requirements for Rule 21.) The test results shown in Figure 41 are for a start frequency of 60.1 Hz and a gradient of 52 percent $P_{nom}$/Hz. The frequency-watt function was not enabled prior to this test; a 2030.5 command from the control server was sent, and then the test was initiated. As Figure 41 shows, the specified changes were successfully affected in the inverter, which responded to the frequency sweep appropriately.

**Figure 41: Frequency-Watt Test**

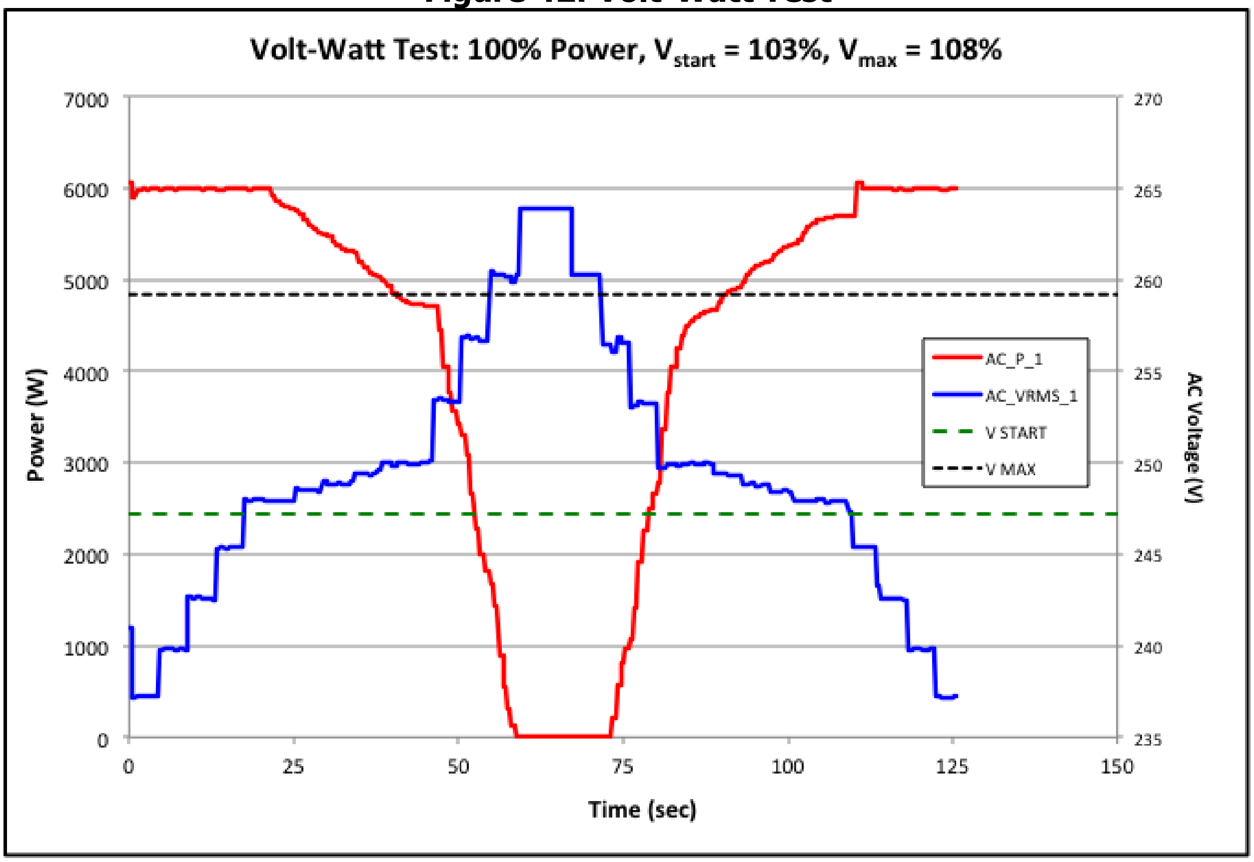



Source: Electric Power Research Institute

## Volt-Watt Mode

For this test, commands were sent from the 2030.5 server to the inverter to enable the volt-watt mode and set the start voltage to 103 percent, and maximum voltage to 108 percent, of the nominal AC voltage of 240 V. After a few seconds delay, to allow the inverter time to change its internal registers, the voltage sweep was initiated. The results of this test are shown in Figure 42. The inverter performed as intended, confirming the volt-watt function was initiated via 2030.5 communication.

**Figure 42: Volt-Watt Test**

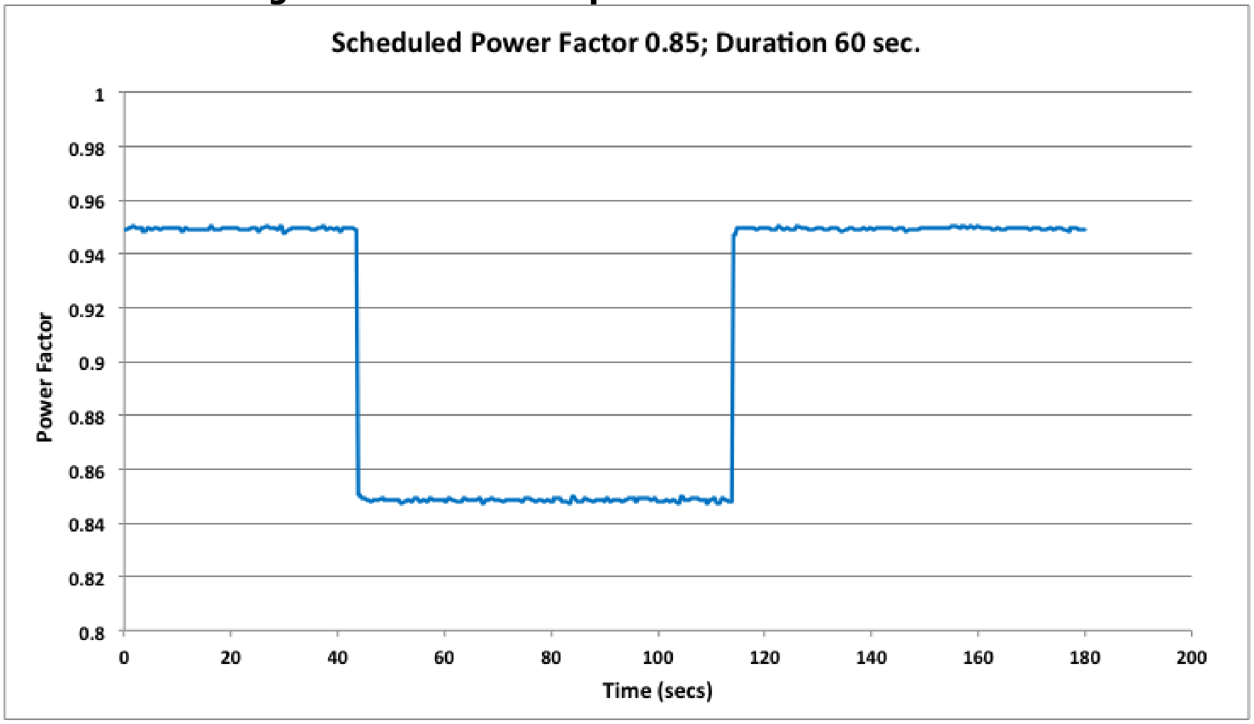



Source: Electric Power Research Institute

## Scheduling Power Values and Modes

In this test, the 2030.5 server sends a command to the gateway to change the inverter power factor. The inverter was initially at full rated power of 6000 W at a nominal power factor of 0.95. The test scheduled the power factor to be changed to 0.85 for a 60-second duration, after which the inverter reverts to the initial setting of 0.95. The test was started, the command was sent from the server, and the power factor was monitored for 200 seconds to capture the power factor changes. The results of the test are shown in Figure 43. The actual duration of the power factor change is a function of both the scheduled duration and the polling interval of the communication system. This function is shown to perform properly using the 2030.5 communications protocol, as expected.

**Figure 43: Schedule Specified Power Factor Test**




Source: Electric Power Research Institute

### Security Verification

Network traces were taken for the 2030.5 server to client gateway connect to verify that the required security attributes were present. The network traces confirmed that the TLS connections established conformed to the IEEE 2030.5-2018 security requirements, including format and content of certificates and choice of cipher suite and hashing algorithm.

# CHAPTER 6: Field Demonstration of Rule 21 Phase 3 Smart Inverter Functions

## Purpose

The goals of this task were to assess the behavior of the Phase 3 smart inverter functions in actual field environments. These environments naturally go beyond what is experienced in the laboratory by exposing the smart inverters to the voltage sags and swells, harmonics, solar variability, and communication challenges that naturally occur in field environments. A significant part of the smart inverter evaluation process involved field testing of the CA Rule 21 Phase 3 functions. The project had the following goals for this portion:

1. Enroll 50 residential customers for participation in the project.
2. Manage a program at Sunrun to execute tests and field questions from customers during the test phase.
3. Deploy communication systems and interfaces between Sunrun headend and inverters over cellular connection.
4. Test functional compliance of DER to Rule 21 Phase 3 functions.

By the completion of field testing, the complete set of functions in Table 27 will have been tested. Testing has been split into two phases. Functions that are part of the second phase have been placed in bold type in Table 29.

**Table 29: List of California Rule 21 Phase 3 Smart Inverter Functions to be Tested**

| No. | Functions |
|---|---|
| 1 | Limit Maximum Active Power Mode |
| 2 | Schedule Active Power Values and Modes |
| 3 | Monitor Key Data |
| 4 | Set Active Power Mode |
| **5** | **Volt-Watt Control** |
| **6** | **Frequency-Watt Control** |
| **7** | **Connect/Disconnect** |

Source: Electric Power Research Institute

# Customer Enrollment Process

## Approval and Design

Sunrun developed a programmatic approach for customer enrollment and participation in the project. The program, entitled Electric Avenue Program (Appendix A), was launched and marketed by Sunrun representatives, who were responsible for enrollment.

- During this process, Sunrun undertook a door-to-door marketing process and explained to potential participating customers the following:
    1. Definition of the program
    2. Partnering organizations
    3. Impact of this program on their control system as well as PV and energy storage devices
    4. Program duration
    5. Data captured and shared with the California Energy Commission and EPRI
- To initiate the program, a terms and conditions document was drafted and reviewed with Sunrun's legal, sales, and customer CARE groups.
- The outreach language on communications was approved and included consultants as a social proof-in-program messaging.
- Sunrun trained in-house teams on program details so they could field calls/questions during the program and tests.
- Sunrun approved customer payments for enrollment.
- Sunrun prepared internal systems for fleet management.

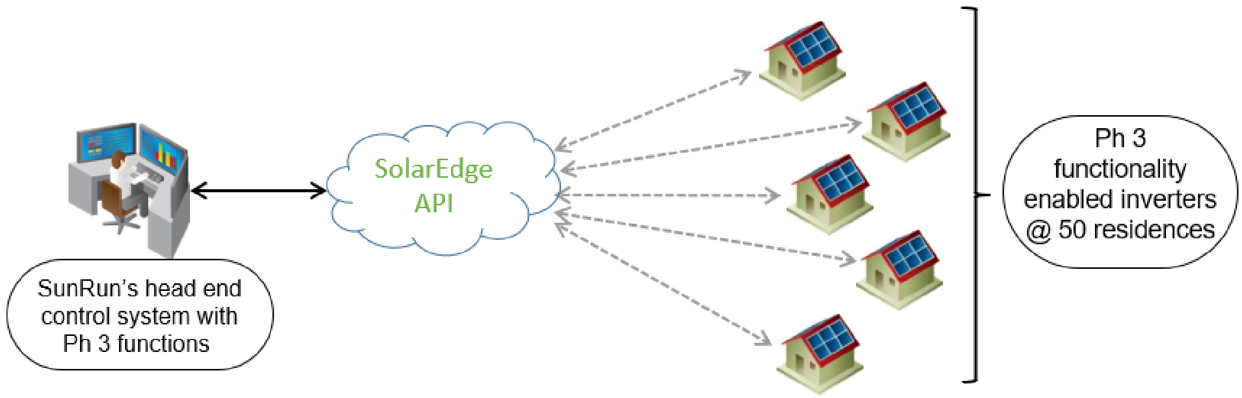
## Enrollment

Sunrun used email campaigns for the enrollment process, which was highly successful. Nearly 200 recently interconnected customers were contacted to participate in the Electric Avenue Program. The call to action was "Reply to email to confirm interest." The enrollment process lasted over two months resulting in 58 successful enrollments. After email acceptance, DocuSign sign-up was initiated and customers were registered in the program.

# Implementation Notes

To execute planned tests, Sunrun employed cloud-to-cloud integration with the inverter vendor, SolarEdge. Sunrun would schedule events in its DER Management System, which would then send commands to SolarEdge servers via proprietary representational state transfer (REST) application program interfaces (APIs), and in turn communicate with inverters in the field via another proprietary REST API. Systems in the field were securely connected to the Internet over 4G wireless technology. A communication concept diagram is provided in Figure 44.

**Figure 44: Field Test Communication Architecture**




Source: Electric Power Research Institute

For Sunrun to set and limit real power output on the AC side of the inverter, the commands to SolarEdge servers (Table 30) were updated via the aggregation platform, and functions were implemented into SolarEdge devices. More detail on the parameters for frequency-watt and volt-watt curves is given in the following section.

**Table 30: Commands for SolarEdge from Sunrun Aggregation Platform**

| Command | Available Parameters/Description |
| --- | --- |
| Set Active Power | Start time, end time, and total inverter power setting |
| Limit Active Power | Start time, end time, and total inverter power limit |
| Frequency-Watt | Start time, end time, and frequency-watt function parameters |
| Volt-Watt | Start time, end time, and volt-watt function parameters |
| Cancel an Event | Places the battery and inverter back into profile behavior for charging |

Source: Electric Power Research Institute

## Parameters Required

### Volt-Watt Function

Table 31 and Table 32 contain the volt-watt parameters defined in IEEE 1547-2018. The volt-watt curve with default IEEE 1547-2018 parameters is shown in Figure 45.

**Table 31: IEEE 1547-2018 Volt-Watt Parameters**

| Name | Description | Range |
|---|---|---|
| Voltage-Active Power Mode Enable | Enable voltage-active power mode | On/Off |
| Voltage/Power Curve Points | Voltage-active power curve points | See Table 30 |
| Open Loop Response Time | Time to ramp up to 90% of the new active power target in response to change in voltage. | 0.5–60 s |

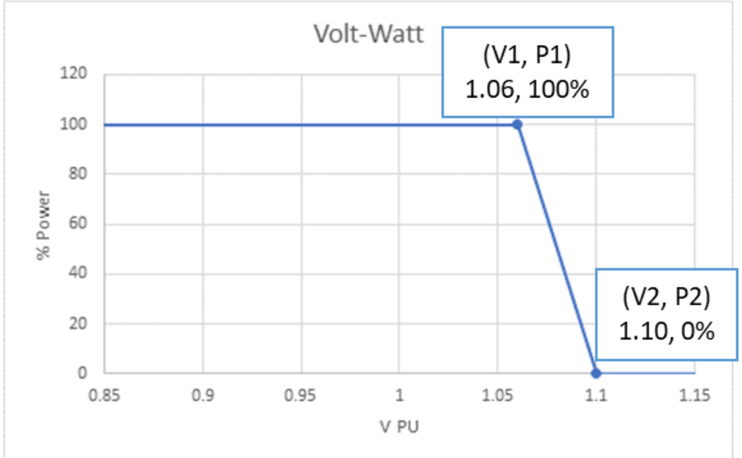
Source: Electric Power Research Institute

**Table 32: IEEE 1547-2018 Volt-Watt Curve Parameters**

| Voltage-Active Power Parameters | Default Parameters | Ranges of Allowable Settings | |
|---|---|---|---|
| | | Minimum | Maximum |
| $V_1$ | 1.06 $V_N$ | 1.05 $V_N$ | 1.05 $V_N$ |
| $P_1$ | $P_{rated}$ | N/A | N/A |
| $V_2$ | 1.10 $V_N$ | $V_1$ + 0.01$V_N$ | 1.10 $V_N$ |
| $P_2$ (Applicable to DER that can only generate electric power) | The lesser of 0.2 $P_{rated}$ or $P_{min}$ | $P_{min}$ | $P_{rated}$ |
| $P_2$ (Applicable to DER that can generate or absorb electric power) | 0 | 0 | $P_{rated}$ |
| Open Loop Response Time | 10 s | 0.5 s | 60 s |

Source: Electric Power Research Institute

**Figure 45: Default IEEE 1547-2018 Volt-Watt Curve**




Source: Electric Power Research Institute

## Frequency-Watt Function

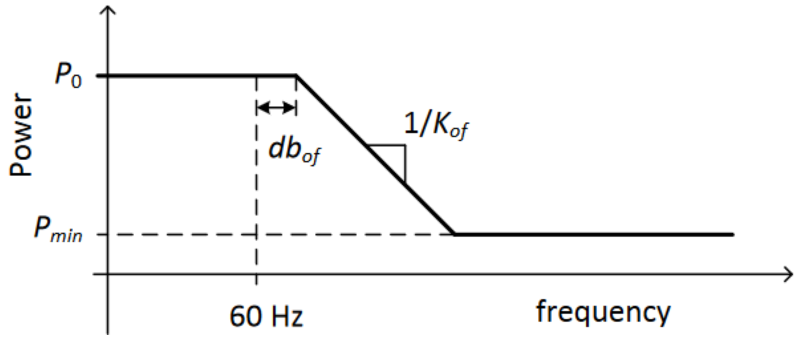
Table 33 shows the IEEE 1547-2018 default and allowable range of settings for the frequency-watt function. Parameters $db_{UF}$ and $db_{OF}$ refer to the underfrequency and overfrequency droop deadband, and parameters $k_{UF}$ and $k_{OF}$ are the underfrequency and overfrequency droop per-unit frequency change. $T_{response}$ is the duration from a step change in control signal input until the output changes by 90 percent of its final change before any overshoot. An example of the frequency-watt curve for overfrequency is shown in Figure 46.

**Table 33: IEEE-1547-2018 Frequency-Watt Parameters**

| Parameter | Default Settings | | | Ranges of Allowable Settings | | |
|---|---|---|---|---|---|---|
| | Category I | Category II | Category III | Category I | Category II | Category III |
| $db_{UF}$, $db_{OF}$ (Hz) | 0.036 | 0.036 | 0.036 | 0.017–1.0 | 0.017–1.0 | 0.017–1.0 |
| $k_{UF}$, $k_{OF}$ | 0.05 | 0.05 | 0.05 | 0.03–0.05 | 0.03–0.05 | 0.03–0.05 |
| $T_{response}$ (small-signal) (s) | 5 | 5 | 5 | 1–10 | 1–10 | 0.2–10 |

Source: Electric Power Research Institute

**Figure 46: Example of Frequency-Watt Curve for Over-Frequency**




Source: https://www.nrel.gov/docs/fy17osti/68884.pdf

## Connect/Disconnect

The Connect/Disconnect function is equivalent to the "cease to energize" and "return to service" commands in Rule 21. According to CA Rule 21, "the cease to energize command causes a DER system either to galvanically disconnect from or to 'cease to energize' the local and/or area EPS at the Referenced Point. The return to service command initiates the closing of the DER switch or ends the cease to energize state." The parameters for "cease to energize" and "return to service" are provided in Table 34 - Table 37.

**Table 34: "Cease to Energize" Command Parameters Defined in California Rule 21**

| Parameter | Description |
|---|---|
| Set Referenced Point State | A command that either instructs the switch at the Referenced Point to open or causes a "cease to energize" state at the Referenced Point. Function may include a time window or ramping for when the action takes place. |
| Monitor Referenced Point State | A query to monitor the Referenced Point. |

Source: Electric Power Research Institute

**Table 35: "Cease to Energize" Command Parameters Defined in California Rule 21: Optional Supporting Parameters**

| **Optional Parameter** (preset or sent as part of a command) | Description |
|---|---|
| Time Window | A time, over which the "cease to energize" operation is randomized. For example, if the Time Window is set to 60 s, then the "cease to energize" operation occurs at a random time from 0–60 second. This setting is provided to accommodate communication systems that might address large numbers of devices in groups. |
| Ramp Down Rate | A ramp down rate specifies the rate that the DER uses to decrease output to reach the "cease to energize" state. |
| Reversion Timeout | A time after which a command to "cease to energize" expires and the device returns to service. "Reversion Timeout = 0" means that there is no timeout. |

Source: Electric Power Research Institute

**Table 36: "Return to Service" Command Parameters Defined in California Rule 21**

| Parameter | Description |
|---|---|
| Permission to Return to Service | A command indicating that return to service is permitted. |
| Set Referenced Point State | A command that either instructs the switch at the Referenced Point to close or discontinues the "cease to energize" state at the Referenced Point. The function may include a time window or ramping for when the action takes place. |
| Monitor Referenced Point State | A query to monitor the Referenced Point. |

Source: Electric Power Research Institute

**Table 37: "Return to Service" Command Parameters Defined in California Rule 21: Optional Supporting Parameters**

| **Optional Parameters** (Preset or Sent as Part of a Command) | Description |
|---|---|
| Time Window | A time, over which the return to service operation is randomized. For example, if the Time Window is set to 60 s, then the return to service operation occurs at a random time between 0 and 60 s. This setting is provided to accommodate communication systems that might address large numbers of devices in groups. |
| Ramp Up Rate | A ramp up rate that specifies the rate that the DER uses to increase output after discontinuing the cease-to-energize state. |

Source: Electric Power Research Institute

## Measurement and Verification Plan

### Monitoring Equipment

Sunrun's monitoring equipment is housed within the SolarEdge Inverters installed in every solar + storage system. The monitoring system consists of the ANSI C 12.20 standard revenue grade AC meter inside the inverter whose functions are illustrated in Figure 46. Table 38 captures the site parameters monitored by the Sunrun aggregation system including its units and resolution. Table 39 and Table 40 identifies the data acquired from the battery and inverters respectively.

**Table 38: Capture Parameters by the Sunrun Aggregation System and its Resolution**

| Measurement Parameters | Units | Resolution of Data (min) |
|---|---|---|
| Revenue Grade Meter (RGM) Energy<br>(AC system output) | kWh (for interval) | 1 min |
| L1Data.acFrequency<br>(Single-phase frequency seen on AC side of inverter) | Hz | 1 min |
| L1Data.activeVoltage<br>(Single-phase voltage seen on AC side of inverter) | V | 1 min |
| L1Data.activePower<br>(Single-phase active power as seen on AC side of inverter) | W | 1 min |

Source: Electric Power Research Institute

**Table 39: Inverter Meter Values**

| Measurement Parameters | Units | Resolution of Data (min) |
|---|---|---|
| totalActivePower<br>(Active power component of inverter output) | W | 1 min |
| totalReactivePower<br>(Reactive power component of inverter output) | var | 1 min |
| totalEnergy<br>(Cumulative AC energy meter reading of specified inverter) | Wh | 1 min |
| dcVoltage<br>(Voltage as seen on DC side of inverter) | V | 1 min |

Source: Electric Power Research Institute

**Table 40: Battery Data**

| Measurement Parameters | Units | Resolution of Data (min) |
|---|---|---|
| DC Battery Power | W | 1 min |
| Battery Percentage State<br>(State of charge, SOC) | % | 1 min |
| Battery State | Battery state or mode — such as charging, discharging, idle, or off | 1 min |

Source: Electric Power Research Institute

## Volt-Watt Tests

### Volt-Watt Curve with Default IEEE 1547-2018 Parameters for Long Duration (Figure 47)

The purpose of this test is to see if the inverters respond accurately to default IEEE 1547-2018 parameters. It is recommended that this function runs for a 24-hour period to see how the inverters respond to a range of voltages measured throughout an entire day, even if voltages are not in the function's active region (above 1.06).

### Volt-Watt Curve with Action-Inducing Parameters for Short Duration (1–2 Hour Period)

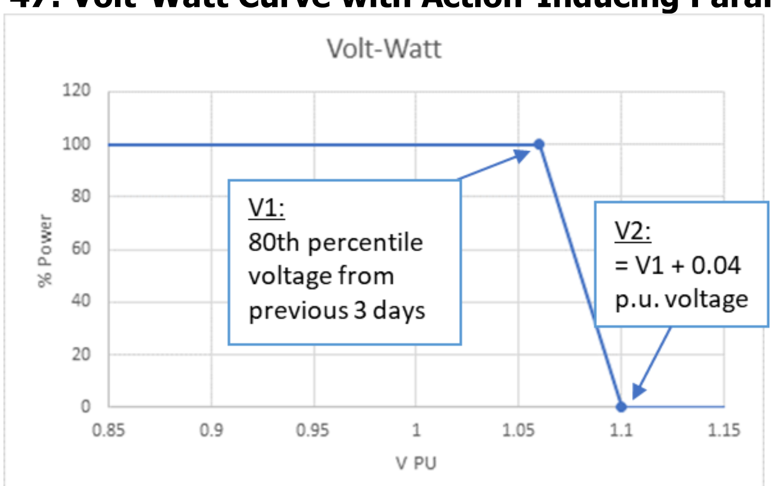
To validate the response of the volt-watt function, tests will need to be run for the following cases:

- Inverter is limited to 100 percent of its maximum real power rating (default behavior) with a voltage at or below $V_1$.
- Inverter is limited to X percent (below 100 percent) of its maximum real power rating based on the curve with a voltage at or above $V_1$.

The range of measured voltages during testing will be dependent on individual inverters and where they are connected to the grid. Therefore, it is possible to see only the default behavior (inverter is limited to 100 percent of its maximum real power rating), with reduction in the active power limit if system voltages are at or below $V_1$.

To select action-inducing parameters for this test, $V_1$ should be selected by taking the 80$^{th}$ percentile voltage from the three days following the test. Then, $V_2$ is $V_1$ + 0.04 pu voltage. Before running this test, it is important to make sure there is sufficient battery capacity to absorb solar in excess of expected limit. Therefore, it is recommended that the battery be nearly empty before starting the test.

**Figure 47: Volt-Watt Curve with Action-Inducing Parameters**




Source: Electric Power Research Institute

## Frequency-Watt Tests

### Frequency-Watt Curve with Default IEEE 1547-2018 Parameters for Long Duration

The purpose of this test is to see if the inverters respond accurately to default IEEE 1547-2018 parameters for underfrequency and overfrequency. It is recommended that this function run for a 24-hour period to see how the inverters respond to a range of frequencies measured throughout an entire day, even if frequencies are not in the function's active region.

### Frequency-Watt Curve with Action-Inducing Parameters for Short Duration (1-2 Hour Period)

To validate the response of the frequency-watt function, tests will need to be run for the following cases:

- Inverter is limited to 100 percent of its maximum real power output rating (default behavior) with a frequency at or below $db_{OF}$.
- Inverter is limited to X percent (below 100 percent) of its maximum real power output rating based on the curve with a frequency at or above $db_{OF}$.

The range of measured frequencies during testing will be dependent on individual inverters and where they are connected to the grid. Therefore, it is possible to see only the default behavior (inverter is limited to 100 percent of its maximum real power rating), with reduction in the active power limit if system frequencies are at or above $db_{OF}$.

To select action-inducing parameters for this test, $db_{OF}$ should be selected by taking the 95$^{th}$ percentile frequency from the three days following the test. Before running this test, it is important to make sure there is sufficient battery capacity to absorb solar in excess of the expected limit. Therefore, it is recommended that the battery be nearly empty before starting the test. The test may need to be repeated at different times and/or different days to observe responses to high frequency conditions.

## Connect/Disconnect

The Connect/Disconnect command only needs to be tested once or twice to ensure inverters can be disconnected and reconnected at the Reference Point. Different settings for the optional parameters (randomization time window, ramp down rate, and reversion timeout) may be given different arguments for each test.

## Measurements Needed for Verification

The latest IEEE 2030.5 CSIP document specifies that DER shall have the capability to report the monitoring data listed in Table 41. Systems in this field test have demonstrated that they can report active power (at various points, but importantly, at the inverter ac terminals), frequency, and phase voltage (only one voltage given single-phase devices). Reactive power has not been demonstrated. While it should technically be possible to monitor and report this measurement type, the request to do so was simply not part of the agreed-upon Monitoring and Verification (M&V) Plan; reactive power measurements may be added going forward.

**Table 41: Common Smart Inverter Profile Mandated Monitoring Points**

| Monitoring Data |
|---|
| Real (Active) Power |
| Reactive Power |
| Frequency |
| Voltage per Phase |

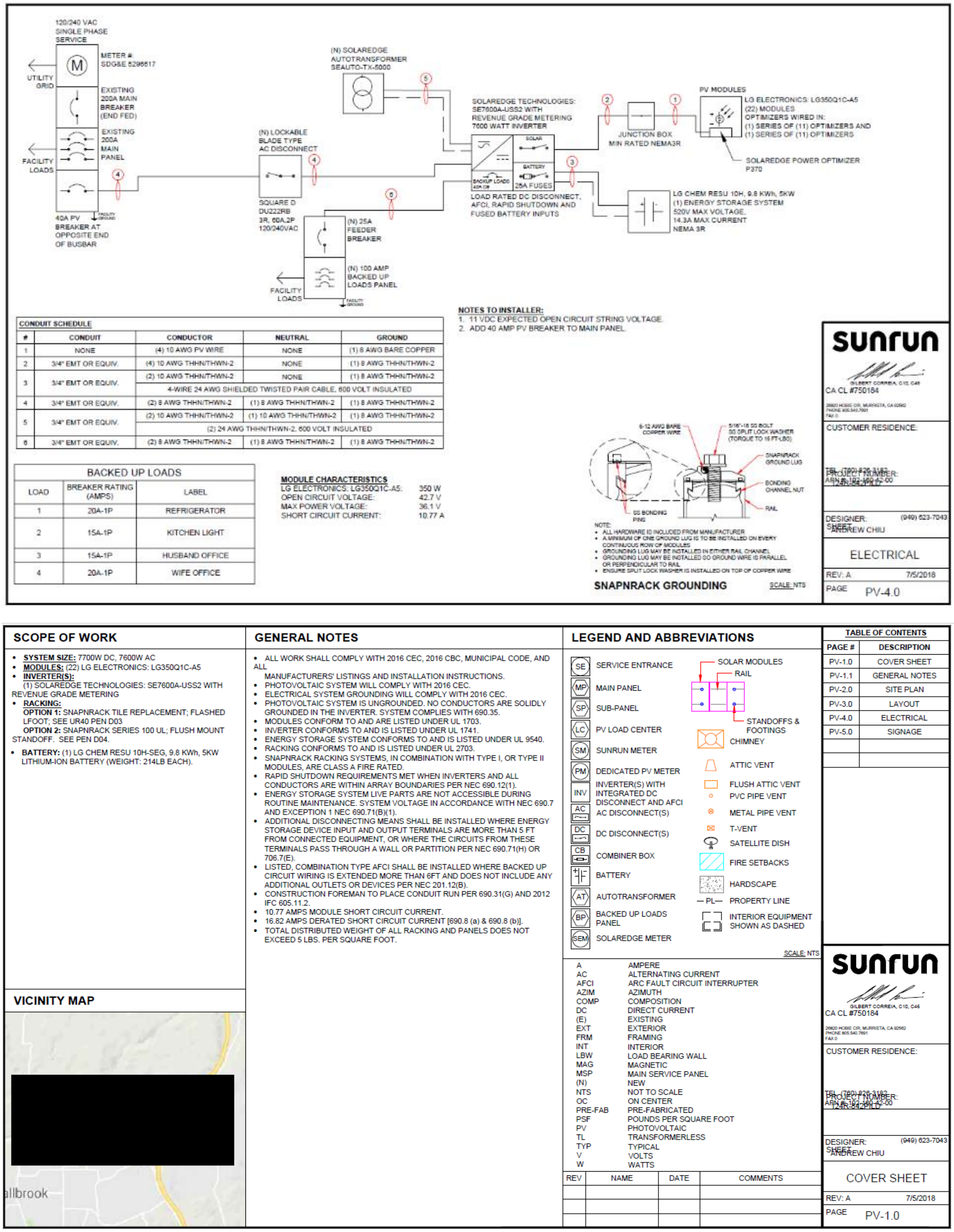
Source: Electric Power Research Institute

The desired data resolution for each function may vary. For example, frequency-watt mode can be configured to respond to rapid frequency changes or to longer-term frequency deviations. If the device is configured to respond to rapid frequency changes, a higher metering frequency, on the order of seconds, may be required. During these tests, only longer-term frequency deviations are considered for the purpose of frequency smoothing. Since the frequency-watt and volt-watt functions involve ramping, metering should still be fairly frequent, such as 1-minute resolution. For the limit active power function and set active power function, a lower resolution, such as every 15 minutes, is allowed.

## Typical Field Site Electrical Design

Figure 48 provides a typical site layout in San Diego where the field tests were conducted.

**Figure 48: One-Line Diagram of Field Demonstration Setup**




Source: Electric Power Research Institute

## Field Test Results

Table 42 provides a summary of field integration testing of the SolarEdge inverters from Sunrun's aggregation headend. These tests were conducted overall several days, with each function tested at every one of the 50 residential sites in San Diego Gas & Electric Company territory.

**Table 42: Field Test Results Summary**

| Phase 3 Functions | Implemented by Sunrun & SolarEdge | Field Tested | Tests Successful | Comments |
|---|---|---|---|---|
| Limit Maximum Active Power Mode | ✓ | ✓ | Yes | |
| Scheduling Active Power Values and Modes | ✓ | ✓ | Yes | |
| Monitor Key Data | ✓ | ✓ | Yes | |
| Set Active Power Mode | ✓ | ✓ | Yes | |
| Volt-Watt Control | ✓ | ✓ | Yes | |
| Frequency-Watt Control | ✓ | ✓ | No | Field conditions were static and not conducive to trigger a frequency event. |
| Connect/Disconnect | ✓ | No | N/A | This function could not be tested for many customers since they were concerned about loss of generation. |

Source: Electric Power Research Institute

Field test results indicate that SolarEdge inverters successfully demonstrated nearly all of the smart inverter functions, similar to what was observed during lab testing. The inverter and communication systems behaved as expected, also successfully demonstrating most of the smart inverter functionality tested.

### Limit Maximum Active Power Mode

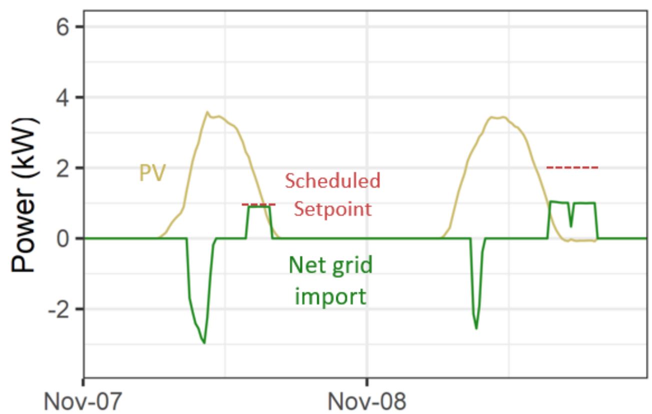
Different settings for maximum active power limits (25 percent, 50 percent, 75 percent, and 100 percent) were tested for the PV plus storage inverters (Table 43). The inverters successfully demonstrated limiting the maximum real power output similar to what was observed during lab testing. Figure 49 shows a sample limit maximum real power test at 25 percent for one site.

**Table 43: Limit Maximum Active Power Field Test Results Summary**

| Limit Maximum Active Power Output | Site #4 | Site #15 | Site #33 | Site #48 |
|---|---|---|---|---|
| 25% | ✓ | ✓ | ✓ | ✓ |
| 50% | ✓ | ✓ | ✓ | ✓ |
| 75% | ✓ | ✓ | ✓ | ✓ |
| 100% | ✓ | ✓ | ✓ | ✓ |

Source: Electric Power Research Institute

**Figure 49: Sample Limit Maximum Real Power Test at 25 Percent for Site #33**




Source: Electric Power Research Institute

## Scheduling Active Power Values and Modes

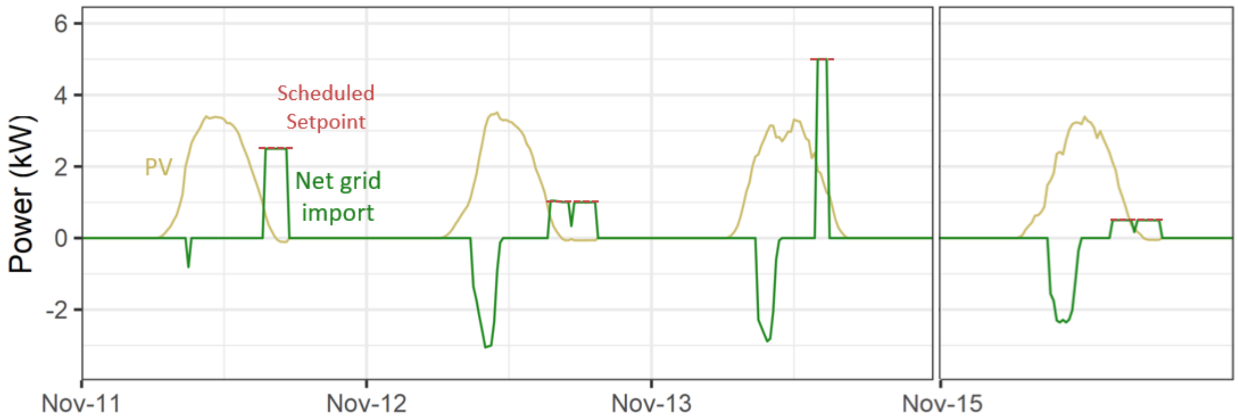
The energy storage (ES) in the PV+ES systems enabled the units to be dispatchable. Similar to the active power limit test cases, different settings for active power schedules (25 percent, 50 percent, 75 percent, and 100 percent) were tested for the PV plus storage inverters (Table 44). The real power limit function in the previous section serves as a limiting variable, which allows the inverter to stay anywhere below the limits. Unlike this function, the schedules are GOTO functions and maintain the output of the inverters at the determined setting. The inverters successfully demonstrated this function similar to what was observed during lab testing, as shown in Figure 50.

Table 44: Schedule Active Power Value Field Test Results Summary

| Active Power Schedules | Site #4 | Site #15 | Site #33 | Site #48 |
|---|---|---|---|---|
| 25% | ✓ | ✓ | ✓ | ✓ |
| 50% | ✓ | ✓ | ✓ | ✓ |
| 75% | ✓ | ✓ | ✓ | ✓ |
| 100% | ✓ | ✓ | ✓ | ✓ |

Source: Electric Power Research Institute

**Figure 50: Sample Active Power Schedule Test (Site #4)**




Source: Electric Power Research Institute

## Monitor Key Parameters

The Sunrun server was configured to monitor and save the measured output from each of the DER at the site, as shown in Figure 51. The measured parameters included the CSIP mandated points, as listed in Table 41. A total of 99.75 percent of data points from October 1, 2019 – November 23, 2019 were available from the 50 sites.

**Figure 51: Sample Monitoring Points (Site #33)**

| Index | timeStamp | acFrequency | acVoltage | activePower | totalActivePower | totalEnergy | dcVoltage | deliveredKwh | power | batteryPercentageState | batteryState |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 0 | 2019-10-01 00:00:00-07:00 | 60.01 | 244.19 | 37.00 | 37.00 | 8706490.00 | 394.98 | 0.00 | 0.00 | 31.00 | 6.00 |
| 1 | 2019-10-01 00:15:00-07:00 | 60.01 | 244.63 | 10.67 | 10.67 | 8706490.00 | 394.98 | 0.00 | 0.00 | 31.00 | 6.00 |
| 2 | 2019-10-01 00:30:00-07:00 | 59.99 | 243.84 | 22.00 | 22.00 | 8706490.00 | 395.10 | 0.00 | 0.00 | 31.00 | 6.00 |
| 3 | 2019-10-01 00:45:00-07:00 | 60.01 | 244.35 | 0.00 | 0.00 | 8706496.67 | 394.85 | 0.00 | 0.00 | 31.00 | 6.00 |
| 4 | 2019-10-01 01:00:00-07:00 | 60.01 | 244.16 | 11.00 | 11.00 | 8706500.00 | 394.02 | 0.00 | 0.00 | 31.00 | 6.00 |
| 5 | 2019-10-01 01:15:00-07:00 | 59.99 | 243.71 | 0.00 | 0.00 | 8706500.00 | 395.04 | 0.00 | 0.00 | 31.00 | 6.00 |
| 6 | 2019-10-01 01:30:00-07:00 | 60.01 | 244.52 | 20.33 | 20.33 | 8706500.00 | 394.56 | 0.00 | 0.00 | 31.00 | 6.00 |
| 7 | 2019-10-01 01:45:00-07:00 | 60.00 | 244.62 | 0.00 | 0.00 | 8706510.00 | 394.96 | 0.00 | 0.00 | 30.66 | 6.00 |
| 8 | 2019-10-01 02:00:00-07:00 | 60.01 | 244.09 | 0.00 | 0.00 | 8706510.00 | 394.42 | 0.00 | 0.00 | 30.50 | 6.00 |
| 9 | 2019-10-01 02:15:00-07:00 | 60.02 | 244.57 | 0.00 | 0.00 | 8706510.00 | 394.75 | 0.00 | 0.00 | 30.50 | 6.00 |
| 10 | 2019-10-01 02:30:00-07:00 | 60.01 | 244.38 | 0.00 | 0.00 | 8706520.00 | 395.19 | 0.00 | 0.00 | 30.50 | 6.00 |
| 11 | 2019-10-01 02:45:00-07:00 | 60.00 | 244.66 | 0.00 | 0.00 | 8706520.00 | 394.90 | 0.00 | 0.00 | 30.50 | 6.00 |
| 12 | 2019-10-01 03:00:00-07:00 | 59.98 | 244.93 | 13.00 | 13.00 | 8706520.00 | 395.21 | 0.00 | 0.00 | 30.50 | 6.00 |

Source: Electric Power Research Institute

## Set Active Power Mode

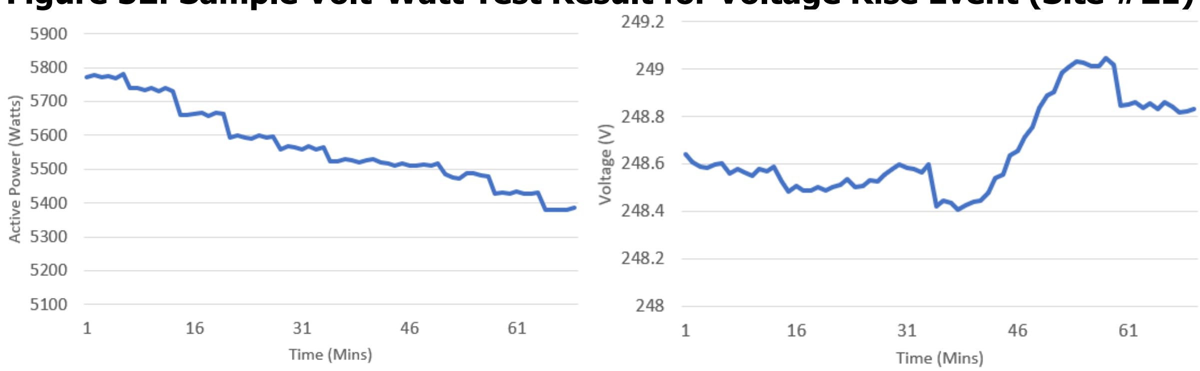
This function specifies an active power setpoint to the inverter. Such GOTO functions are applicable only for dispatchable DER-like energy storage or PV+ES systems. The function was tested along with the schedule active power function. The test results proved the inverters can support the set active power mode function.

## Volt-Watt Mode of Operation

Due to the static nature of the grid voltage, it was difficult to determine the output of the inverter to change when performing an autonomous volt-watt function test, as shown in Figure 52.

To determine action-inducing parameters for this test, $V_1$ for the volt-watt curve in Figure 46 was selected by taking the 80th percentile voltage from the three days before the test. Then, $V_2$ is $V_1$ + 0.04 pu voltage. Before running this test, investigators made certain that there was sufficient battery capacity to absorb solar in excess of the expected limit.

**Figure 52: Sample Volt-Watt Test Result for Voltage Rise Event (Site #21)**

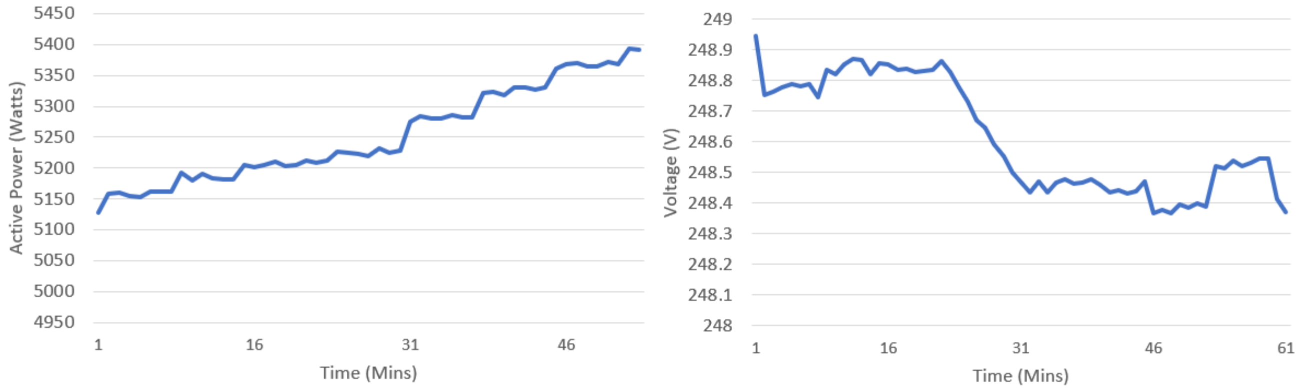



Source: Electric Power Research Institute

## Frequency-Watt Mode of Operation

Due to the static nature of the grid frequency, no changes were observed at the output of the inverter when performing an autonomous frequency-watt function test. The SolarEdge inverter registers were observed via the Sunrun aggregation platform Dashboard tool to verify that the inverter successfully updated and enabled its frequency-watt settings after scheduling the DER event. Figure 53 shows a sample volt-watt test result for a voltage drop event at one of the sites.

**Figure 53: Sample Volt-Watt Test Result for Voltage Drop Event (Site #34)**




Source: Electric Power Research Institute

# CHAPTER 7: Public Key Infrastructure Deployment and Cybersecurity Assessment

## Purpose

This task identified cybersecurity requirements of the communication and control interface for the CA Rule 21 Phase 3 functions and to deploy a digital certificate infrastructure to support secure communication using the IEEE 2030.5 protocol for DER in California.

## Public Key Infrastructure

### Overview

In anticipation of California Rule 21 data communication requirements to support smart inverter interconnection and utility access to DER, the project team lead the development of a scalable network security program in support of this project.

A critical network security issue was addressed when the California Public Utility Commission (CPUC) ratified the decision to use the communication protocol defined in the IEEE 2030.5-2018[9] standard ("IEEE 2030.5") as the default method for DER-to-utility communication. The IEEE 2030.5 protocol requires digital certificates[10] and mutual authentication so that connections can be secured between communicating entities.

This section describes how the project team has implemented the security requirements specified by the IEEE 2030.5 standard and now provides access to the resulting security services to utilities, DER manufacturers, and DER system owners and operators.

### SunSpec Public Key Infrastructure for IEEE 2030.5

The IEEE 2030.5 standard requires that at least one Public Key Infrastructure (PKI) be established to facilitate the exchange of digital certificates between communicating parties. A public key infrastructure (PKI) is a set of roles, policies, hardware, software and procedures needed to create, manage, distribute, use, store and revoke digital certificates and manage public-key encryption.[11], The purpose of a PKI is to facilitate the secure electronic transfer of information for a range of network activities such as e-commerce, internet banking and confidential email." As a result of this project, distributed energy can be added to the range of supported network activities that are secured by a PKI.

[9] IEEE Approved Draft Standard for Smart Energy Profile Application Protocol," in IEEE P2030.5/D2, March 2018, vol., no., pp.1-358, 1 Jan. 2018.

[10] *What Is a Digital Certificate*. IBM Knowledge Center, IBM Corporation, www.ibm.com/support/knowledgecenter/SSB23S_1.1.0.2020/gtps7/s7what.html.

[11] *Public Key Infrastructure*. Wikipedia, Wikimedia Foundation, 23 June 2020, en.wikipedia.org/wiki/Public_key_infrastructure.

Establishing a PKI is complex endeavor that requires the establishment of trust at each step in the process. The following sections describe the process that was used to establish the SunSpec Public Key Infrastructure[12].

## Certificate Policy Development

The starting point for implementing a PKI for the IEEE 2030.5 standard was to develop a Certificate Policy. According to the U.S. Department of the Treasury[13], "A Certificate Policy (CP) is defined in the Internet X.509 Public Key Infrastructure Certificate Policy and Certification Practices Framework[14] as 'a named set of rules that indicates the applicability of a certificate to a particular community and/or class of application with common security requirements'."

To determine the named set of rules for the SunSpec IEEE 2030.5 Certificate Policy[15], the authors relied on three inputs: 1) IEEE 2030.5 standard (and its 300+ pages of sometimes-subtle requirements), 2) the Common Smart Inverter Profile[16] (CSIP), and 3) the Kyrio Core Certificate Policy[17] that the SunSpec CP derives from. CSIP is a set of IEEE 2030.5 implementation guidelines developed in the California Rule 21 proceeding by the three Investor Owned Utilities (IOUs) and experts from the Smart Inverter Working Group (SIWG). SIWG is an ad hoc group of industry experts that also operates in the context of the CA Rule 21 proceeding. Kyrio is a cybersecurity consulting firm that assisted SunSpec in setting up the SunSpec PKI system.

Five particular challenges were faced while developing the IEEE 2030.5 CP:

1. The current version of IEEE 2030.5 stipulates that mandatory certificates must never expire and cannot be revoked. These requirements are counterintuitive to PKI experts and require special rules for managing devices and certificate-issuing entities that are

---

[12] *SunSpec Public Key Infrastructure (PKI).* SunSpec Alliance, SunSpec Alliance, 8 Sept. 2019, sunspec.org/sunspec-public-key-infrastructure/.

[13] Certificate Policies, United States Department of the Treasury, pki.treas.gov/cert_policies.htm#:~:text=A%20Certificate%20Policy%20(CP)%20is%20defined%20in%20the%20Internet%20X.&text=When%20a%20Certification%20Authority%20(CA,entity%20(i.e.%20certificate%20subject).

[14] Chokhani, S., et al. *Internet X.509 Public Key Infrastructure Certificate Policy and Certification Practices Framework.* IETF Tools, IETF Network Working Group, Nov. 2003, tools.ietf.org/html/rfc3647.

[15] *SunSpec Alliance Public Key Infrastructure - PKI Scope and Certificate Profiles.* SunSpec Alliance, SunSpec Alliance, 30 Apr. 2019, sunspec.org/wp-content/uploads/2019/08/SunSpecCertificatePolicy-V1.0-2019-02-13.pdf.

[16] *Common Smart Inverter Profile 2.0 - IEEE 2030.5 Implementation Guide for Smart Inverters*. Common Smart Inverter Profile Working Group, Mar. 2018, https://sunspec.org/wp-*content/uploads/2018/03/CSIPImplementationGuidev2.003-02-2018-1.pdf.*

[17] *Core Certificate Policy*. *SunSpec Alliance*, Kyrio, 15 Jan. 2019, sunspec.org/wp-content/uploads/2019/08/K-PKI-Core-CP-V1.0-2019-01-15.pdf.

no longer deemed trustworthy. Accordingly, multiple working sessions of the SunSpec/Sandia Cybersecurity Working Group18 were dedicated to debating this topic.

2. IEEE 2030.5 specifies a precise format and structure for certificate layout. The language used in the standard to describe counterparties is abstract and needed to be interpreted to match the physical entities participating in California Rule 21 networks. Considerable deliberation with digital security experts was required to interpret the requirements.
3. CSIP introduced the concept of an "Aggregator," which is an interpretation of IEEE 2030.5 capabilities used to fulfill a specific purpose. Aggregators share certain properties with IEEE 2030.5 client devices but are different in terms of their risk profile and therefore require special consideration. In this case, the CP was adapted to account for the use of optional IEEE 2030.5 capabilities to support server-to-aggregator interactions and the use of short-lived non-expiring) certificates.
4. IEEE 2030.5 mandates the use of at least one Certificate Authority (CA) and at least one of two types of Sub-CAs. The types of Sub-CAs are Manufacturers Certificate Authorities (MCAs, which are allowed but not mandated) and Manufacturers Issuing Certificate Authorities (MICAs, which are both allowed and mandated). The decision of whether to support one or two Sub-CA types was based on the fact that MCAs are more expensive to set up than MICAs, and more complex to shut down in the event of a security breech, but result in a lower marginal cost per certificate. The choice was made to authorize both types of sub-certificate authorities (Sub-CAs) but to promote the adoption of MICAs to reduce initial complexity.
5. The final challenge arose in the determination of how many CAs to authorize to serve the market. While the IEEE 2030.5 standard allows an unlimited number of CAs, experience with other use cases19 has shown that a smaller number is advisable given the inherent complexity of needing to install most device certificates in the factory and the need to validate certificates in the field, over a network, once the device is installed. Though many have questioned SunSpec's decision, the team decided to start with a single authorized CA and then grow the ecosystem as needed.

## SunSpec Test PKI

To facilitate testing and protocol compliance certification of DER communication devices, the project team established the free-to-the-public SunSpec Test PKI[20] service. Oriented toward product development and testing, this service is purposely devoid of the robust security features of a "production" PKI. This service has proven to be valuable by educating the market about security requirements and by providing fully-conformant digital certificates to support product development, interoperability and compliance testing.

---

[18] SunSpec/Sandia Cybersecurity Work Group. SunSpec Alliance, SunSpec Alliance, 2017, https://sunspec.org/cybersecurity-work-group/.

[19] DigiCert, ChargePoint and Eonti (2019), *Practical Considerations for Implementation and Scaling ISO 15118 into a Secure EV Charging Ecosystem*, https://www.chargepoint.com/files/15118whitepaper.pdf

[20] *Request SunSpec Test PKI Certificate Package. SunSpec Alliance*, SunSpec Alliance, 8 Sept. 2019, https://sunspec.org/request-sunspec-test-pki-certificate-package/.

## Certificate Dispensary Form

The SunSpec Test PKI features a simple web form located at [https://sunspec.org/request-sunspec-test-pki-certificate-package/](https://sunspec.org/request-sunspec-test-pki-certificate-package/). To effectively use this system, users must first download and understand the SunSpec Test PKI Application Note[21] and provide several pieces of information including the device model Object Identifier (OID) and the device serial number. Once successfully submitted, the form response returns a .zip file containing three valid device certificates, the device private key, the root certificate, and device certificates with errors for error testing. The device certificate files include all Sub-CA certificates in the certificate chain and the device private key.

## Internet Assigned Numbers Authority Private Enterprise Number

Creating the device model OID requires that the company seeking an OID require an Internet Assigned Numbers Authority Private Enterprise Number (IANA PEN). The Internet Assigned Numbers Authority[22] (IANA) is a service run by the Public Technical Identifiers (PTI) organization.

One of the responsibilities of IANA is to issue and assign Private Enterprise Numbers (PENs) to subscribing organizations. The IEEE 2030.5 standard requires that each organization that fulfills a role in the PKI trust chain must acquire an IANA PEN.

Following this logic, SunSpec adopted the policy that every company seeking to utilize the SunSpec Test PKI is required to acquire a valid IANA PEN. Having acquired this, the acquiring company is then prepared to complete certification testing and acquire access to the SunSpec Production PKI.

## SunSpec Certification for IEEE 2030.5/CSIP

The SunSpec Certification program for IEEE 2030.5/CSIP[23] uses the SunSpec Test PKI and serves as the entry criteria for companies wishing to participate in the SunSpec Production PKI described below. Completion of product certification — which includes conformance testing for critical IEEE 2030.5 communication and security functions performed by vetted- and approved SunSpec Authorized Testing Laboratories[24], a company/product declaration, a checksum of the software/firmware under test, and posting test results on the open SunSpec Product Certification Registry[25] — is an important security validation technique in its own right. For example, experience gathered by certifying 22 product lines from 19 company brands to date

---

[21] SunSpec Test PKI Certificates Application Note. *SunSpec Alliance*, SunSpec Alliance, Apr. 2019, sunspec.org/wp-content/uploads/2019/09/SunSpecTestPKICertificates.pdf.

[22] Internet Assigned Numbers Authority, Public Technical Identifiers, www.iana.org/.

[23] SunSpec IEEE 2030.5 / CSIP Certification. *SunSpec Alliance*, SunSpec Alliance, Jan. 2019, sunspec.org/2030-5-csip/.

[24] SunSpec Authorized Test Laboratories. *SunSpec Alliance*, SunSpec Alliance, 11 Mar. 2020, sunspec.org/sunspec-certified-authorized-test-laboratories/.

[25] SunSpec Certified Product Registry. *SunSpec Alliance*, SunSpec Alliance, 20 May 2020, sunspec.org/certified-registry/.

has revealed that improper digital certificate exchange is one of the leading defects discovered in the testing process.

## SunSpec Production PKI

The SunSpec Production PKI program is designed to increase stakeholder confidence in DER communication solutions, including those enabling interoperability of smart inverters, smart PV modules, EV charging, and energy storage.

Public Key Infrastructure is the preferred method of authentication for networked ecosystems due to its strength and scalability. In addition, advances in the hardware and semiconductor industries have allowed for strong authentication using Elliptic Curve Cryptography (ECC) and PKI to be implemented in small devices very economically.

The SunSpec Production PKI is designated as the method of authentication used for IEEE 2030.5 and is the method to be used for authenticating and securing communications for SunSpec Certified™ products and services. The program's initial focus is to fulfill California Rule 21 compliance.

The program will address the rollout of IEEE 1547™-2018. IEEE 1547 establishes uniform requirements for interconnection of DERs, such as photovoltaics and battery systems, with the electric power system. In addition to IEEE 2030.5, the SunSpec Production PKI will also support the other IEEE 1547 standard protocols: SunSpec Modbus and IEEE 1815.

SunSpec chose its initial SunSpec Production PKI service solution provider(s) — security consultant Kyrio, a subsidiary of CableLabs (https://www.kyrio.com/) and PKI infrastructure provider Sectigo, the world's largest commercial Certificate Authority (https://sectigo.com/about) — after soliciting bids in an open request for proposal process[26]. This agreement is non-exclusive, thus providing SunSpec with the flexibility to name additional PKI providers as needed.

## Continuous Improvement

To ensure that the SunSpec Public Key Infrastructure continues to evolve in with the contemporary cybersecurity landscape, SunSpec and Sandia teamed up to form the SunSpec/Sandia Cybersecurity Working Group. This group is open to the public, has more than 650 individual contributors, and has published five important papers including Recommendations for Trust and Encryption in DER Interoperability Standards[27]. This paper examines the cryptography requirements of the IEEE 2030.5 standard (as well as the requirements of the other IEEE 1547 standard protocols) to plan future upgrades to the standard and supporting infrastructure.

Finally, SunSpec Alliance staff actively participate in the IEEE 2030.5 technical committee, which is currently evaluating proposed enhancements (including PKI changes) to this important standard.

[26] "SunSpec Official PKI Provider Request for Proposal." *SunSpec Alliance*, SunSpec Alliance, 18 Sept. 2018, sunspec.org/wp-content/uploads/2019/09/SunSpecPKIRFP.pdf.

[27] Obert, James, et al. "Recommendations for Trust and Encryption in DER Interoperability Standards." *SunSpec Alliance*, Sandia National Laboratories, Feb. 2019.

# Red Team Cybersecurity Assessment and Security Best Practices for Secure IEEE 2030.5 Implementations

This section provides non-confidential recommendations to improve the cybersecurity of smart inverter communications for California's Rule 21 implementation. The recommendations are aimed at reducing cybersecurity risk of systems supporting DER.

The scope is limited to the knowledge gained from the Red Team penetration test conducted as part of this project to determine system vulnerabilities as well as related studies on DER integration using IEEE 2030.5 for CA Rule 21.

It is important to note that the recommendations discussed here are not intended to provide a complete set of cybersecurity requirements that addresses all possible cybersecurity risks in DER interconnection under Rule 21. A comprehensive set would consider many additional aspects of cybersecurity, including but not limited to:

- Cybersecurity of DER integration network
- Cryptographic key management
- Endpoint security for DER devices
- Personnel, physical, and environmental security
- Vulnerability and security update management
- Security monitoring and incident response

## Recommendations

### Recommendations on Smart Inverter and Gateway Device

Enabling smart inverter communication with a utility system creates opportunities for cyber attackers to gain access to the devices, manipulate data transmitted, or compromise utility systems. Depending on the scale, cyberattacks can cause adversarial effects on DER operation or distribution grid reliability. The following recommendations will help to reduce some of the cybersecurity risks by making it difficult to gain access or exploit the connectivity.

*Disable all unnecessary network interfaces (physical ports).*

A smart inverter or gateways may have multiple network interfaces, some of which may not be necessary for device operation. Disabling all unnecessary wired or wireless network interfaces will reduce the risk of them being misused to gain unauthorized access to the device.

*Disable all unnecessary network services and block unused software ports.*

Besides the physical network interface, the software running on a smart inverter or gateway may have unnecessary network services enabled. As an example, a smart inverter may run a web server on Transmission Control Protocol (TCP) port 80, providing some information using a graphical user interface. If this service is not essential in DER operation, it is recommended that the service be disabled to reduce the attack surface. Similarly, all TCP/User Datagram Protocol (UDP) ports that are not used must be blocked to reduce the risk of them being used for cyberattacks.

*Change the default password and do not display password.*

It is not uncommon to find a password or passphrase printed on the label of a smart inverter or gateway. Sometimes one default password is used for all devices manufactured by a vendor. These passwords are easily accessible by a cyber attacker who can use them to gain unauthorized access to the device. It is recommended that immediate change of passwords following the initial device installation be enforced.

*Protect the gateway-device connection.*

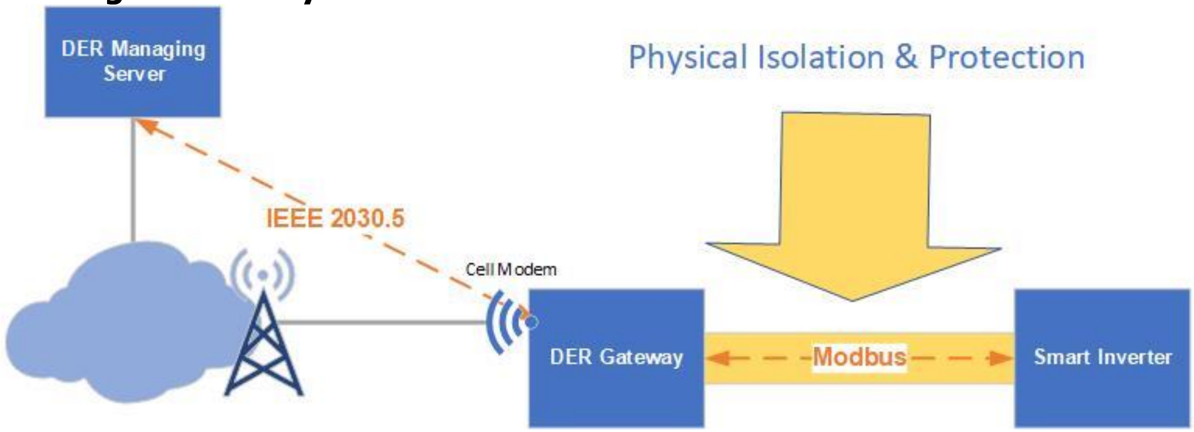
If the communication between a smart inverter and gateway device is in a cleartext protocol such as SunSpec Modbus or Distributed Network Protocol (DNP3), the connection must be protected to avoid exposing the clear text messages to other systems in the local area network. There is more than one way to achieve this. An additional security device such as a firewall can be used to limit the network from/to the smart inverter, or a bump-in-the-wire solution can be used to encrypt the traffic between the two devices. Both solutions require additional devices and proper administration of them to achieve the desired cybersecurity objective. To enforce these requirements, a security audit needs to be conducted before the commissioning of DER and periodically thereafter.

Another way to protect the cleartext communication is to minimize the physical exposure of the network components between the two devices. The following five requirements outline one possible way to achieve physical isolation and protection.

1. The gateway must be equipped with a dedicated Ethernet interface that can be connected to the smart inverter only.
2. The smart inverter must have a dedicated Ethernet interface that can be connected to the gateway only.
3. The distance between the two devices should be as short as possible.
4. The Ethernet cable must be physically protected to prevent tampering through means such as cable conduit, RJ45, and port lock.
5. Use of a wireless connection between the gateway and smart inverter must be discouraged because it is difficult to contain wireless signals physically.

Figure 54 shows one example of this physical isolation and protection approach where the gateway device provides the connection through a commercial cellular network.

**Figure 54: Physical Isolation and Protection of Cleartext Protocol**




Source: Electric Power Research Institute

*Follow best practices for the embedded device security.*

It is practical to assume a smart inverter or gateway device can be located in places where strong physical security measures are not guaranteed. If a malicious actor gains physical access to a smart inverter or a gateway device, they can extract substantial information by examining the embedded components. Cryptographic keys, in particular, can be extracted from the binary data stored in device memory or data storage. Therefore, it is critical to protect the data at rest for secure implementation of IEEE 2030.5, which requires local storage of cryptographic materials.

**Recommendations on CSIP/IEEE 2030.5 Implementation**

Faithful software implementation and secure configuration enable the intended cybersecurity measures in protocol standards. Most security breaches occur due to the vulnerabilities introduced in the implementation of the protocol stack or insecure configurations rather than the weakness of the cryptographic system. IEEE 2030.5 protocol mandates TLS 2.0 as the security feature. The recommendations in this section address two common problems that could undermine protections offered by the TLS standard [27].

*Allow a limited list of cipher suites with sufficient security strength.*

Allowing a weak cipher suite can reduce security strength and make the system susceptible to the downgrade attacks. IEEE 2030.5-2018 requires one cipher suite on all devices: TLS_ECDHE_ECDSA_WITH_AES_128_CCM_8. Additionally, the use of other cipher suites is allowed if they are equivalent to or stronger than the sole required cipher suite.

The recommended approach is to allow only a limited list of cipher suites, beginning with TLS_ECDHE_ECDSA_WITH_AES_128_CCM_8 and include a selection of other cipher suites with stronger capabilities. Final selection should depend on the hardware capabilities. However, identification of several cipher suites allows the flexibility over time to alter the preferred cipher suite by changing the order preference on the client without making other significant changes.

It is also recommended that the security strength of each cipher suite allowed be validated with reputable cybersecurity guidelines to ensure the flexibility does not undermine cybersecurity. NIST Special Publication 800-52, Revision 2 provides some guidelines for TLS 2.0 [28].

*Follow best practices for X.509 v3 attributes.*

The X.509 v3 attributes control the runtime behaviors of the TLS exchange. Inappropriate configurations may introduce unintended vulnerabilities to the system. A thorough understanding of various TLS options, certificate attributes, and their impact on cybersecurity will help to avoid unintended consequences from misconfiguration. There are some guidelines available, such as NIST 800-52 [28]. It is also recommended that a guideline be developed with appropriate default values specific to CA Rule 21 implementation to help the industry stakeholders in secure implementation and maintenance of systems.

**Recommendations on CSIP/IEEE 2030.5 Standard**

IEEE 2030.5 standard's PKI model has two important limitations in terms of cybersecurity. The first is that it does not support certificate revocation. The second is that it allows a Root Certificate Authority to sign a device directly. These two limitations allow a cyberattack scenario where an attacker can compromise a large number of IEEE 2030.5 clients for a significant duration and create a wide-scale impact. A detailed technical discussion on this topic is out of the scope of this document. However, these limitations have been previously discussed among the CA Rule 21 stakeholders and IEEE 2030.5 Working Group.

Unfortunately, these limitations do not have a simple solution. Because the issue originates from the standard itself, ultimately, the standard needs to be updated. The problem seems to be that there is insufficient technical investigation and testing performed for the industry to feel confident. Therefore, it is strongly recommended that solutions and workarounds be investigated immediately and tested thoroughly to provide the path forward.

**Recommendations on Network Security**

The cybersecurity of the communication network that provides connectivity to the smart inverter has a broader impact on grid security than that of individual devices. Network security best practices need to be followed for both local networks where the smart inverter is located as well as the WANs that support connectivity to the utility system.

A number of resources are available that provide guidelines, including EPRI Security Architecture for DER Integration Network [29].

# CHAPTER 8: Technology Transfer

This chapter summarizes the project team's activities to make the knowledge gained, experimental results, and lessons learned available to the public and key decision makers.

## Target Audience

To facilitate information dissemination, EPRI and project partner SunSpec Alliance have executed a multi-pronged outreach program to reach engineers and managers working in product development, software development, and cybersecurity for industry participants such as DER manufacturers, inverter manufacturers, aggregators, communication system providers, system integrators, utilities, regulatory agencies, and related organizations.

## Documents Available for Download in SunSpec and Electric Power Research Institute Portals

The specifications and related documents delivered by this program (IEEE 2030.5 application note, the Protocol Information Conformance Statement, and the IEEE 2030.5 test process logic document) are offered royalty-free under the MIT open source license. The SunSpec Alliance offers these documents from its website.

- SunSpec IEEE 2030.5/CSIP Certification and Supporting Resources – https://sunspec.org/sunspec-ieee-2030-5-csip-certification/
- SunSpec Specifications and Information Models – https://sunspec.org/download/
- Open Source IEEE 2030.5 Client Software and Conformance Test Scripts
- The open source client software delivered by this project (IEEE 2030.5 client software and conformance test scripts) is offered royalty-free under the MIT open source license and published in a public GitHub repository. The repository will be linked to the SunSpec Alliance website.
- Link to test script page on SunSpec.org – https://sunspec.org/download/
- Conformance test scripts were rendered in the Python language for easy readability and adoption. These scripts are natively executable via the SunSpec SVP software and may be adapted for execution within other test platforms.
- GitHub – https://github.com/sunspec/pysunspec

EPRI provides the following report on its website:

- *Employing Active Power Curtailment of Distribution-Connected Solar Photovoltaics: Economic and Regulatory Considerations*. EPRI, Palo Alto, CA: 2017. 3002010289.

## Results of Primary Outreach Activities

The knowledge gained from the project is made available to inverter and DER manufacturers, aggregators, end users, utilities, regulatory agencies, and other members of the public using EPRI and SunSpec Alliance distribution channels. These channels include websites, newsletters, educational events, and promotional events, as shown in Table 45.

**Table 45: Results of Outreach Conducted During Project**

| Audiences Reached | 2017 | 2018 |
|---|---|---|
| SunSpec – Unique website visitors | 8,209 | 18,552 |
| SunSpec – All mailing lists | 8,038 | 9,915 |
| SunSpec – Newsletter subscribers | 1,083 | 1,680 |
| SunSpec – Web event registrants | 1,226 | 486 |
| SunSpec – Member company employees | 734 | 773 |
| SunSpec – Cybersecurity work group members | 114 | 181 |
| SunSpec – Inverter work group members | 80 | 86 |
| **Email Campaigns Referencing IEEE 2030.5 Client** | | |
| *Campaigns targeting inverter and cybersecurity experts* | | |
| Total campaigns | 21 | 8 |
| Messages sent | 73,995 | 27,834 |
| Number of opens | 13,207 | 5,392 |
| Number of clicks | 1,556 | 691 |
| *Other campaigns targeting DER market participants* | | |
| Total campaigns | 56 | 41 |
| Messages sent | 196,070 | 208,141 |
| Number of opens | 34,617 | 37,515 |
| Number of clicks | 3,222 | 2,799 |
| **Web Events Referencing IEEE 2030.5 Client** | | |
| *Web events targeting inverter and cybersecurity experts* | | |
| Total web events | 5 | 0 |
| Total web event registrants | 463 | 0 |
| *Other web events targeting DER market participants* | | |
| Total web events | 3 | 5 |
| Total web event registrants | 476 | 283 |
| **SunSpec Live Events and Activities Featuring IEEE 2030.5 Client** | | |
| Solarplaza Solar Asset Management North America 2017 | 150+ | |
| SunSpec Alliance 2017 Annual Member Meeting | 89 | |
| Intersolar North America 2017 Finance Summit | 130+ | |
| Solarplaza Solar Asset Management North America 2018 (multiple presentations) | | 300+ |
| SunSpec Executive Summit on CA Rule 21 in San Francisco, California | | 64 |
| Intersolar North America 2018 Workshop on CA Rule 21 | | 68 |
| Gridvolution @ Solar Power International 2018 | | 100+ |
| SunSpec Alliance Annual Member Meeting and Digital Energy Summit, 2018 | | 87 |
| SunSpec online engineering at UCSD, Fall Term 2018: Secure Communication Networking for Distributed Energy Resources | | 17 |
| SunSpec IEEE 2030.5 test procedure downloads | | 528 |

Source: Electric Power Research Institute

## Policy Impact

All project artifacts (specifications, documents, and software) were disseminated to nonprofit organizations involved in state-level policy development to foster dialog regarding how open communication standards are positively impacting the grid. Minimally, project artifacts will be disseminated to TechNet, Silicon Valley Leadership Group, Clean Coalition, and the Interstate Renewable Energy Council.

## In-Person Events

The following is a list of the in-person events at which the SunSpec and EPRI teams have presented updates and information related to CA Rule 21, 2030.5/CSIP certification, the SunSpec PKI program, and related cybersecurity issues.

**October 3, 2019 – SunSpec Alliance 2019 Annual Member Meeting**

Description: SunSpec conducted its 2019 annual member meeting to update members on the CA Rule 21 program, cybersecurity, and PKI program initiatives.

**May 22–23, 2019 – 3rd Annual Smart Solar PV Forum Data Analytics and IoT**, featuring a case study on Cybersecurity, a Key Concern for Solar Power

Link: https://sunspec.org/smart-solar-pv-forum/

Description: The cybersecurity for the DER industry case study included a standards update emphasizing California Rule 21 and IEEE 2030.5/CSIP, managing network security at scale, emerging PKI for DER, and a SunSpec Certified™ program update.

**March 25, 2019 – California Rule 21: Roadmap to August 22, 2019, workshop at Solarplaza, Solar Asset Management North America event**

Link: https://sunspec.org/california-rule-21-roadmap-august-22-2019-2/

Description: SunSpec Alliance, provider of communication interface certification and PKI program services for IEEE 2030.5/CSIP, updated executives on the industry's readiness to meet the CA Rule 21 deadline, certification ecosystem status, and the SunSpec PKI program and its implications for cybersecurity.

This workshop was designed for manufacturing executives as well as hardware and software engineers, system integrators, independent engineers, utility companies, and installers of solar and energy storage systems in California.

**February 19, 2019 – Going Beyond Batteries to Provide Grid Flexibility Panel at the 5th Annual Electric Program Investment Charge (EPIC) Symposium**

Link: https://sunspec.org/5th-annual-electric-program-investment-charge-epic-symposium/

Description: This panel discussed how "smart" inverters and demand response are stepping up on the distribution side to meet grid needs while lowering electricity customers' utility bills.

**September 27, 2018 – SunSpec Alliance Annual Member Meeting and Digital Energy Summit as well as Solar Power International Technical Presentations**

Link: https://sunspec.org/sunspec-alliance-annual-member-meeting-digital-energy-summit/

At Solar Power International 2018 located in Anaheim, California, September 24-27, 2018, SunSpec conducted a technical symposium on IEEE 2030.5. An expo show floor presentation related to meeting the CA Rule 21 mandate (Wednesday, September 26) featured a condensed version of SunSpec's Gridvolution ("electricity grid in evolution") event and a 2018 member meeting.

**September 12, 2018 – Gridvolution: SunSpec Solar and Storage Finance Summit**

Link: https://sunspec.org/gridvolution/

Description: Gridvolution gives voice to DER stakeholders working to digitize information and interoperability of energy assets. This platform brings together those creating the industry digital energy reality, with standardized data communications touching every aspect of residential, commercial, and industrial solar and energy storage.

Speakers: Seventeen leading organizations participated on September 12, 2018, including Blu Banyan Solutions, CableLabs, CPUC, Chapman and Cutler LLP, Clean Power Research, EPRI, Fronius USA, kWh Analytics, Salesforce.com, SMA Solar Technology AG, Sandia National Laboratories, Sunrun, Texas Instruments, Tigo Energy, Wells Fargo, Wivity, and XBRL US.

## Curriculum

In concert with the UCSD Extension, SunSpec has transferred technology information through in-person executive workshops and a nine-week online technical course entitled, Secure Communication Networking for Distributed Energy Resources.

Technical course cohorts were offered and promoted in the following quarters: Fall 2018, Winter 2019, Spring 2019, and Summer 2019. Information on the course can be found at the following link: https://sunspec.org/technical-track-secure-communication-networking-distributed-energy-resources/

### CA Rule 21 Executive Training

Description: CA Rule 21 Executive Training Workshops were held in concert with the UCSD Extension program. This in-person workshop, hosted by the SunSpec Alliance, provided DER business executives, entrepreneurs, and others looking to enter the industry with foundational understanding of CA Rule 21. Topics included DER market dynamics; market sizing, business models, and competitive barriers; technical details regarding DER data communication and functional requirements; and considerations about how to deploy DER networks in California and across the United States. DER companies can be confident that those holding this certificate of completion possess such highly sought-after expertise.

### Conferences and Dates

The California Rule 21 Market Opportunity for Executives, January 24, 2019 – https://sunspec.org/california-rule-21-market-opportunity-executives/

July 18, 2018 - https://sunspec.org/executive-track-california-rule-21-market-opportunity-executives-2/

## Cybersecurity Work Group Meetings

The SunSpec Alliance Distributed Energy Resource (DER) Cybersecurity Work Group focuses on current issues in the U.S. DER industry and is supported by projects funded by Sandia

National Laboratories and the California Energy Commission. Work group meetings are currently conducted on a biweekly basis. More information can be found at this link: https://sunspec.org/sunspec-cybersecurity-workgroup/

## Webinars

SunSpec has hosted many webinars related to the CA Rule 21 relevant information. Technology transfer webinars include the following in chronological order.

**June 12, 2019 – Webinar Three in the SunSpec DER Cybersecurity Webinar Series:** Implement Strong Cybersecurity with PKI In the Distributed Energy Resource Industry

Link: https://sunspec.org/webinar-three-implement-strong-cybersecurity-pki-distributed-energy-resource-industry/

Description: In this final chapter of the SunSpec Alliance and Kyrio DER cybersecurity webinar series, the speakers covered a cohesive overview that shows how certification/conformance and security come together to help maintain the long-term integrity of a network ecosystem. What are certificates, and what do they accomplish? What is the process for gaining SunSpec certification and obtaining certificates? What is an Authorized Test Laboratory (ATL) and how do such labs relate to the security trust chain?

In addition, the session focused on some aspects of the current IEEE 2030.5 specification, what it is seeking to achieve, and how the industry can continue to work toward improving it.

Speakers for Webinar Three included the following:

- Tom Tansy, Chairman, SunSpec Alliance
- Ron Ih, Director, Business Development, Kyrio Security Solutions
- Damon Kachur, Vice President – IoT Solutions, Sectigo

**May 8, 2019 – Webinar Two in the SunSpec DER Cybersecurity Webinar Series: Cybersecurity Fundamentals for the DER Industry**

Link: https://sunspec.org/webinar-two-cybersecurity-fundamentals-der-industry/

Description: The SunSpec Alliance and Kyrio Webinar Two covered the basics of cybersecurity and how to apply and deploy it in a PKI environment. How can cybersecurity and PKI be used to maintain the integrity of a DER ecosystem? What are certificate policies and certificate authorities, and how do they help govern ecosystem compliance?

Webinar Two of the series covered the foundational elements of establishing a secure ecosystem for residential and commercial (behind the meter) solar and solar plus storage systems and how that ecosystem should be managed on an ongoing basis.

Speakers for Webinar Two included the following:

- Tom Tansy, Chairman, SunSpec Alliance
- Ron Ih, Director, Business Development, Kyrio Security Solutions
- Jay Johnson, Sandia National Laboratories

**December 13, 2018 – Cybersecurity Webinar: Securing California Rule 21 Networks**

Link: https://sunspec.org/cybersecurity-webinar-securing-california-rule-21-networks/

Description: This SunSpec webinar described the security requirements of IEEE 2030.5 and how they apply to California DER networks comprised of clients (including gateways and smart inverters with embedded communications), aggregators (and their "cousins" known as energy management systems), and utility servers. The discussion addressed cryptography options, credential management, revocation, the general concept of trust chains, and global supply chain implications.

Speakers:

Tom Tansy, chairman of the SunSpec Alliance, is responsible for developing and executing SunSpec's cybersecurity practice. In addition to managing SunSpec, Tansy also serves on the technical committee for the IEEE 2030.5 standard, serves as principal investigator on a number of California Energy Commission projects tasked with developing CA Rule 21 network technology, and is co-chair of the SunSpec/Sandia Cybersecurity Working Group.

Co-presenter Jay Johnson discussed PKI for CA Rule 21. Jay Johnson is a principal member of technical staff at Sandia National Laboratories and leads several multidisciplinary renewable energy research projects including the coordination of advanced DER interoperability testing in the United States, Europe, and Asia through the Smart Grid International Research Facility Network (SIRFN). Johnson also spearheads a $5M DER management project to provide voltage regulation and distribution protection through state estimation, optimization, and DER communications. He runs a laboratory-directed research and development project on virtual power plants to provide ancillary services and directs research projects focused on power system interoperability, control, optimization, and cybersecurity.

## Collateral Products

SunSpec has developed a full CA Rule 21 IEEE 2030.5/CSIP mark logo and use guidelines. This system will help ensure the market receives a standardized graphic to indicate compliance with the program. The logo and use guidelines are found at this link: https://sunspec.org/sunspec-ieee-2030-5-csip-certification/

## Podcasts

Industry podcasts were targeted to provide deep dive information related to the CA Rule 21 deliverables. For example, CA Rule 21 related content was reviewed on the industry podcast, SunCast, in September 2018. This podcast reached professionals throughout the industry. More information can be accessed at this link: https://www.mysuncast.com/suncast-episodes/111

## Newsletters

Mention of the CA Rule 21, cybersecurity, and PKI program specifics have been and will continue to be regularly mentioned in member email communications and monthly newsletters. A schedule of those communications and statistical results of outreach activities are included in Table 39.

## Media

SunSpec actively supports the media's understanding of CA Rule 21 Phase 2 communications, DER cybersecurity, and PKI initiatives.

Following is a list of representative articles:

- *Solar Power World* – "What's the status of the smart grid?" (April 8, 2019) https://www.solarpowerworldonline.com/2019/04/whats-the-status-of-the-smart-grid/
- *PV Magazine USA* – "Can you hack the grid using an inverter?" (March 1, 2019) https://pv-magazine-usa.com/2019/03/01/can-you-hack-the-grid-using-an-inverter/
- *Forbes* – "Cybersecurity: The Hackers Are Already Through The Utilities' Doors, So What's Next?" https://www.forbes.com/sites/peterdetwiler/2018/12/20/cybersecurity-the-hackers-are-already-through-the-utilities-doors-so-whats-next/#6f3ee755158b

## Authorized Test Laboratory and PKI Partner

In the course of this project, SunSpec has issued an authorized test laboratory (ATL) Request for proposal (RFP), vetted and approved ATLs, conducted an RFP for the PKI program, and conducted ATL training for 2030.5/CSIP certification and the PKI program.

**Links:**

- SunSpec Announces RFPs for Certified Test Lab and PKI Programs https://sunspec.org/sunspec-announces-rfps-certified-test-lab-pki-programs/
- SunSpec Certified Authorized Test Laboratories https://sunspec.org/sunspec-certified-authorized-test-laboratories/
- SunSpec Public Key Infrastructure (PKI) https://sunspec.org/sunspec-public-key-infrastructure-pki-program/
- A SunSpec CA Rule 21 PKI Primer https://www.kyrio.com/news-press/a-sunspec-ca-rule-21-pki-primer
- SunSpec PKI Program FAQs: https://sunspec.org/sunspec-pki-program-faqs/

# CHAPTER 9: Conclusions

## Benefits to Ratepayers

This project helps overcome three major barriers to achieving the state's energy goals by: 1) proving that CA Rule 21 Phase 3 functions can be deployed feasibly, safely, and predictably via standardization, 2) demonstrating that grid penetration levels can be increased by 25 percent or more using the Phase 3 advanced control functions, and 3) enabling a secure, scalable, and affordable cybersecurity infrastructure that can be accessed by all Californians now and in the future.

Specific benefits that accrue from this project include:

- Lower costs: Decreased costs enable more Californians to own and operate solar generation. This accelerates the availability of advanced function inverters that are compatible with CA Rule 21 Phases 1–3 and enables DER systems to provide grid support functions that otherwise require expensive physical grid upgrades. Open standard test procedures and certification criteria remove financial barriers for vendors, thus stimulating the inverter market without increasing cost.
- Greater reliability: Improved reliability equates to delivery of standardized DER control functions that ensure minimization and mitigation of reverse power flows, voltage sags/dips, and other conditions that degrade grid stability and DER performance. As a result, grid reliability and availability of access to locally harvested solar energy increase.
- Increased safety: The standardized method for demonstrating compliance to CA Rule 21 Phase 3 requirements eliminates the variability implied by proprietary solutions and enables dynamic electrical control functions to be used safely at scale. The availability of cybersecurity best practices and a PKI ensures that common security pitfalls are avoided as compliant systems are deployed in the field in volume.
- Environmental benefits: DER systems can be deployed at 25 percent higher grid penetration rates, nearly doubling the total potential market for fuel- and emissions-free solar PV.
- Consumer appeal: The advanced functionality and increased security delivered by this project enables PV system owners to participate in emerging wholesale ancillary grid services markets and aggregation networks, thus diversifying the potential revenue sources available.

EPRI estimates that a 25 percent increase could give California ratepayers a total present worth net benefit of more than $50 million. Table 46 shows the assumptions behind this calculation.

**Table 46: Calculations and Assumptions**

| Metric | Value | Assumptions/Basis |
|---|---|---|
| Residential PV Capacity (MW) | 3,268 | http://www.seia.org/state-solar-policy/california |
| Commercial PV Capacity (MW) | 2,326 | http://www.seia.org/state-solar-policy/california |
| Total PV Capacity (MW) | 5,594 | Sum of Residential and Commercial |
| 25% of Total Capacity (MW) | 1,399 | Total PV Capacity X 25% |
| Avg Cost of Solar ($/W) | $4.10 | Q2/Q3 2016 Solar Industry Update, SunShot, U.S. Department of Energy [NREL/PR-6A20-67246] (average between CA residential and non-residential costs) |
| Total Cost of 25% increase in Solar ($) | $5,733M | Total Capacity Increase X Cost of Solar |
| Average Solar Capacity Factor in CA | 18% | http://pvwatts.nrel.gov/pvwatts.php (default for Los Angeles, CA) |
| Total Energy Yield for 25% Increase in Solar (MWh/yr) | 2.213M | Capacity Increase X Capacity Factor X 8760 hrs/yr |
| Average Cost of Retail Electricity ($/MWh) | $162 | http://www.eia.gov/electricity/monthly/epm_table_grapher.cfm?t=epmt_5_06_a (avg of residential and commercial for Nov 2016) |
| Average Fixed Cost Percentage of Distribution Energy Sales | 60% | *Changing Utility Cost Pathways amid Rising Deployment of Distributed Energy Resources.* EPRI, Palo Alto, CA: 2016. 3002008211 |
| Average Variable Cost of Electricity ($/MWh) | $65 | Electricity Cost X 40% |
| Average Fixed Cost of Electricity ($/MWh) | $97 | Electricity Cost X 60% |
| Average Savings from the Variable Cost of Electricity ($/yr) | $143M | Variable Cost X Total Energy Yield |
| Capacity Contribution of PV | 65% | http://www.nrel.gov/docs/fy13osti/57582.pdf (range of 50-80% used for Western US; 65% used as an average estimate for CA) |
| Average Savings from the Fixed Cost of Electricity ($/yr) | $139M | Fixed Cost of Electricity X 65% Capacity Contribution X Total Energy Yield |
| Average Total Savings ($/yr) | $2.82M | Fixed Cost Savings + Variable Cost Savings |

| Metric | Value | Assumptions/Basis |
|---|---|---|
| Expected Life of PV System | 25 | http://www.nrel.gov/analysis/tech_footprint.html |
| Expected Energy Price Escalation Rate | 2.0% | Typical for inflation |
| Solar Degradation Rate | 1% | http://www.nrel.gov/docs/fy12osti/51664.pdf |
| Discount Rate | 3% | Typical for a Society Benefit-Cost Analysis |
| **Net Present Value of 25% Increase in Solar PV Systems** | **$51.1M** | Calculated using assumptions stated above |

Source: Electric Power Research Institute

## Key Lessons Learned

1. Advanced inverter functions similarly varied in effectiveness in a feeder-dependent manner.
   - VVC does not alleviate thermal limits to HC. When var priority was considered and some active power was curtailed, the effectiveness of VVC to relieve voltage violations increased. In fact, 13 settings were shown to increase HC across all feeders and PV locations.
   - Volt-watt control was shown to be completely ineffective in this study for voltage and thermally limited feeders/PV locations. The ineffectiveness is due to two major issues: 1) imbalance in phase voltage causing large differences between maximum voltage and mean phase voltage and 2) voltage setpoints being too high to effectively curtail real power to lower voltages below violation.
   - Finally, the LMRP function was shown to be effective when the maximum PV output was limited to 70 percent or lower.
2. Sensitivity analysis of the selected feeder impact metrics revealed that var priority volt-var function over a wide range of settings was able to mitigate essentially all overvoltage violations using the least amount of curtailment.
3. To increase the amount of DER capacity significantly beyond HC limits DER management systems are needed for real power management that relies on control signals sent by a DERMS-like utility control platform. This platform requests DER units to set or adjust their imports or exports to specific real power levels based on grid conditions.
4. Using smart inverter functions tends to be economical when the HC is voltage constrained.
5. Smart inverter functions are more economical when new, costly equipment is otherwise needed to mitigate distribution constraints.
6. Using smart inverter functions may not be economical when the HC is thermally constrained if large upgrade projects are otherwise needed. Research is needed to explore the capability of the DERMS to address constraints caused by DER.

7. PV system designs with higher DC/AC ratios result in higher expected curtailments via real power limiting smart inverter functions.
8. Testing the capabilities of commercial smart inverters in the lab and field for CA Rule 21 compliance validated such functions.
9. Communication systems using cellular networks worked reliably in the lab and field with minimum interruption.
10. The testing identified the need for DER gateways for smart inverter communication.
    - Standard smart inverters do not include the behaviors and business logic for integration of a smart inverter with California grid operations.
    - Both a DERMS and an advanced distribution management system (ADMS) are being evaluated and deployed by California utilities. These systems intend to connect with smart inverters, making them active parts of system operations. The following specific gaps were observed based on this project:
    - There is an absence of fail-safe modes at the inverter to restore reasonable default behavior when communication is lost with the DERMS/ADMS. This was noticed both during the lab and field testing by Sunrun. California utilities envision full (aggressive) use of DER capabilities at moments when needed but cannot allow DER to remain in such states if control is lost.
    - DERMS/ADMS do not feature scheduling capability. All smart inverters tested from leading manufacturers in this project did not have scheduling capability. They did not come with a real-time clock feature to schedule DER control modes and are not mandated by Rule 21. This is needed due to the bandwidth limitations and latencies of the communication networks that California utilities have available to use — for example, advanced metering infrastructure (AMI) or supervisory control and data acquisition (SCADA). The real-time clock feature is particularly needed for 1) reliable time-of-use control schemes such as active power limits that are effective only certain hours of the day or reactive power behaviors that differ by season, day, or hour, or 2) advanced notification of events to inverters that must take effect simultaneously, especially in utility or aggregator networks.
    - The communication protocols required for compatibility with California utility networks, specifically, IEEE 2030.5, require translation at the edge to interface to the common SunSpec Modbus and DNP3 protocol at the DER. The project required development of these protocol translation features.
    - There is a lack of prioritization control logics when more than one stakeholder (distribution operator or market operator) has some level of access. This is an immediate need that will enable multi-use applications in energy storage systems.
11. Cybersecurity features required in California for integration of smart inverters are presently lacking. In fact, all inverters tested in the project came with no cybersecurity enabled at the inverter level. Cybersecurity is an important factor in successful integration of smart inverters. Distributed energy resources are susceptible to various cyberattacks just like other grid-connected devices, and a large-scale cyberattack can cause major disturbance in the power grid. Addressing cybersecurity in DER can be

difficult for a number of reasons. Because distributed energy resources are often selected by customers, utility security requirements cannot be enforced directly. Moreover, distributed energy resources often have multiple local communication interfaces in addition to the utility interface, and the utility has little control over these other interfaces. The lack of standardized security requirements adds to these difficulties.

12. Numerous difficulties arise in managing and sustaining DER in integration.
    - 12.1 Particularly significant is the lack of support for inverter functions and protocols that are likely to evolve over time, leaving the utility or aggregator to deal with an evolving portfolio of dissimilar features and languages in the field. Integrating DER may look reasonable on day one, when the resources are homogeneous, but such integration becomes unmanageable over time. This was observed in the project when the inverter vendor was not ready to provide support for certain functions. The project team was compelled to develop these functions at the gateway. No grid codes in the world today require inverter vendors to provide support for futuristic grid support functions.
    - If functional or cyber issues are found, the utility has no ability to patch or fix them. Only a DER vendor can produce new firmware, but they are under no obligation to do so and may or may not remain in business when needed. Both utilities and customers are uncomfortable with the utility (or aggregator) making firmware upgrades to their inverters, expressing concerns that a glitch in the update process could render the customer's product nonfunctional or even damage it.
13. The IEEE 2030.5 specification is a complex communication standard. Test procedures developed for such standards must be targeted for maximum efficiency. The test procedures created for the IEEE 2030.5 functionality specified by the CSIP requirements must be not only comprehensive but also performable at a reasonable cost. This objective required that the tests emphasize the more critical and relevant features through all of the test cases.
14. It became clear as a result of this project that an ongoing effort is needed to maintain and improve the test procedures as experience is gained in testing and deployment of IEEE 2030.5 systems.

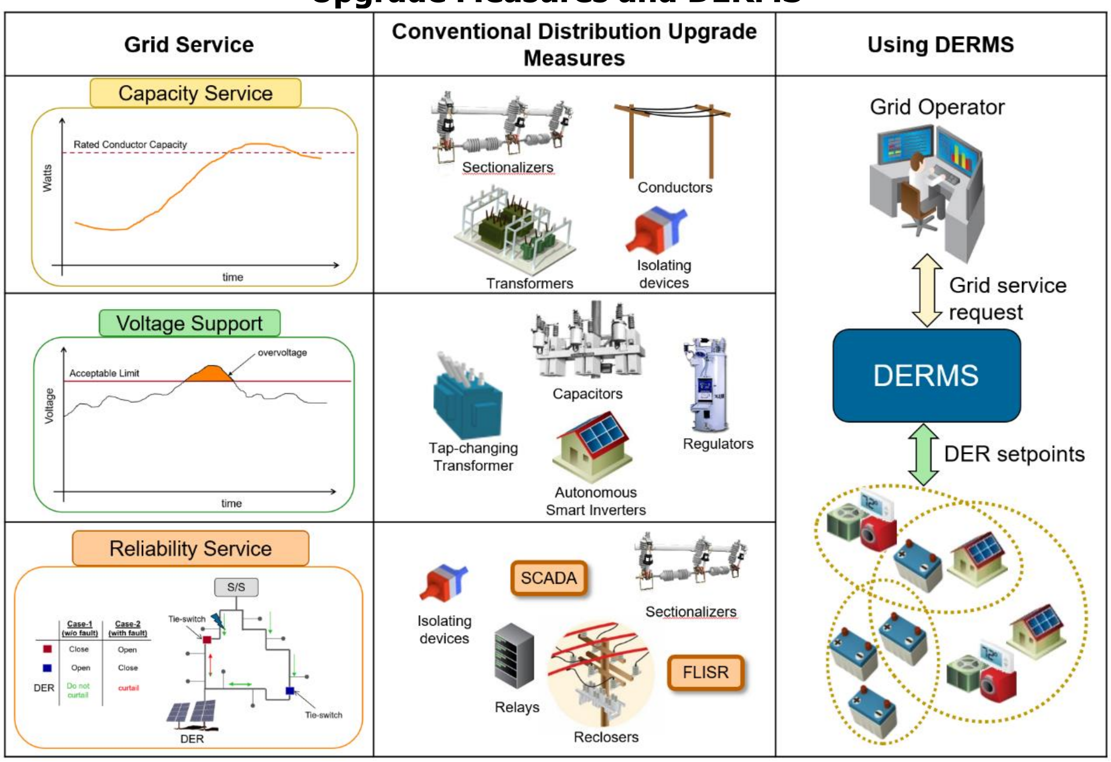
## Scope of Future Work

### Quantify the Value of Distributed Energy Resource Management System for Flexibility

Distribution systems must be planned and operated to ensure reliability and safety. With growing DER penetration levels, utilities have two categories of options to maintain distribution safety, quality, and reliability. The first category consists of applying conventional distribution upgrades. The second category involves leveraging the grid-supportive capabilities of the smart inverter. Extensive research was conducted in CEC 16-079 to study and understand the impacts and benefits of autonomous grid support functions of smart DER inverters. It was evident that smart inverter functions are highly uneconomical for thermal issues created by DER, resulting in high levels of curtailment.

Research is needed to understand the technical and economic value of managing and coordinating DER based on the real-time state of the electric grid. The Distributed Energy Resource Management System (DERMS) has the capability of aggregating a portfolio of DER (a portfolio that can be comprised of similar or various DER technologies) to provide location-specific and time-dependent grid services. Some services offered by DERMS, which are illustrated in Figure 55, can result in reduced DER integration costs. Early EPRI studies showed that use of the DERMS could result in only 2–3 percent curtailment at sites where smart inverter functions resulted in 40–45 percent curtailment. While there are already several commercial DERMS solutions that claim to provide the services at reduced curtailment levels no assessments have been performed that determine the technical and economic value of the services enabled by the DERMS. To address this in California, detailed modeling and simulation studies supported by field demonstration are required to fully understand the incremental benefits gained by the DERMS and to evaluate how DERMS solutions are best utilized to integrate high DER penetration levels. Such studies will set the stage for California utilities to meet their grid modernization goals.

**Figure 55: Distribution Grid Services Provided by Conventional Distribution Upgrade Measures and DERMS**

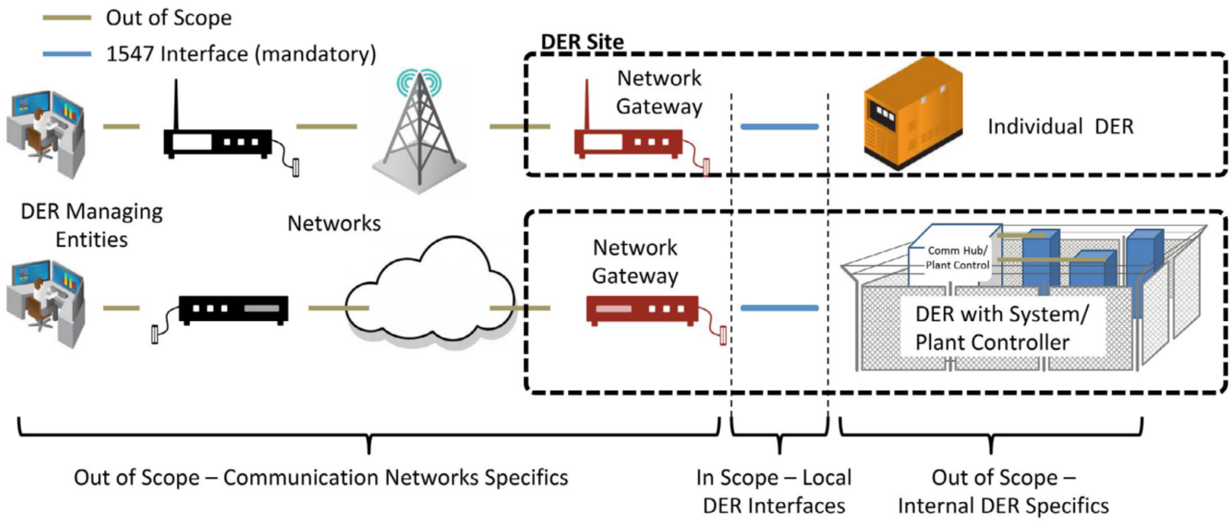



Source: Electric Power Research Institute

## Low-Cost, Secure DER Network Gateways for DER Integration

The gaps identified in the previous section can be addressed by expanding the role and uses of the local smart inverter network gateway shown in red in Figure 56. This figure — adapted from IEEE 1547-2018 as well as California's Rule 21 grid code and other global integration documents — recognizes the existence of the gateway. Gateways exist by necessity to bring DER onto the network of choice. Accordingly, the idea is to not add the gateway (as a new component), but rather to leverage it and develop it to perform new critical features that address California's needs. The potential to use the gateway in this way has been overlooked to date in utility planning and pilots.

**Figure 56: Utility Integration of Smart Inverters Using Gateways**




Source: Electric Power Research Institute

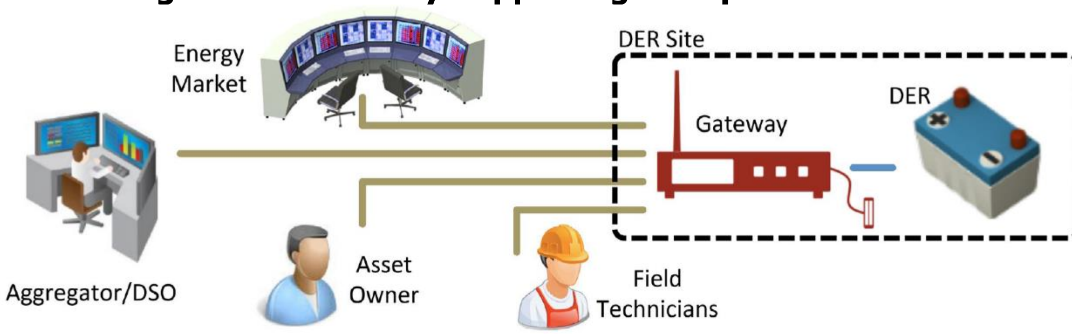
Without adding any substantial cost to the gateway, the following features should be developed in a reference implementation of the gateway to address integration gaps identified above.

1. Functionality and business logics to transform smart inverter behavior to fit California grid operations
    - Restoring healthy default behavior during network outages: CA Rule 21 smart inverters cannot determine when a significant loss of network connectivity has occurred and do not store a second, default configuration. To address this, features should be designed in the network gateway to allow California utilities to 1) define the criteria for each network type and use cases that identify when a loss of control has occurred and 2) determine and locally store default DER configurations to take effect if control is lost. If a gateway then determines that the upstream master (such as DERMS) loses communication, the gateway will locally adjust the smart inverter to the default, predetermined system setting for that DER.
    - Schedule-based behavior: To address the lack of schedule-based control in CA Rule 21, and the lack of dependability of remotely performing scheduled operations, a capability is needed to document the edge-scheduling requirements in the gateway. This capability will support, for example, hybrid control scenarios in which the utility uses the local gateway for day-to-day control actions (active power limits that are effective only certain hours of the day and reactive power behaviors that differ by season, day, or hour) plus network connectivity to the central server for oversight.
    - Advanced notification, synchronized actions and control timeout: In low bandwidth networks, there needs to be a way for DER to be informed about upcoming changes in setting over a long period of time to limit network usage. Local gateways address this issue by having awareness of time (a real-time clock

or network-time) and receiving control requests that include a start time/date and duration. Thereby, many DER could be informed over a period of time, yet the action could take place simultaneously. Synchronized DER actions are needed to achieve the vision of DER participation in energy markets.

- Multi-master scenarios and command prioritization: When inverters are utilized for multipurpose applications (for example distribution and bulk system services), there can be conflicting interests, where configurable prioritization logic needs to be defined and handled by the local control system. As illustrated in Figure 57, implementing this logic in an inverter gateway will address this need.

**Figure 57: Gateway Supporting Multiple User Access**

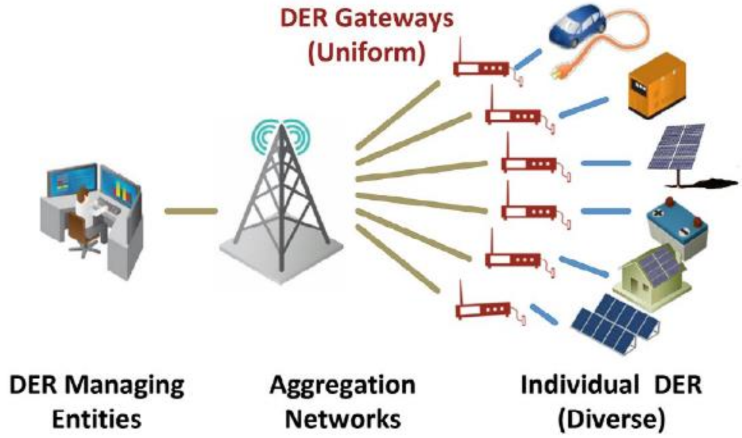



Source: Electric Power Research Institute

- Unification – Communication Protocol translation: IEEE 1547 allows three protocol options at the local inverter interface (SunSpec, DNP3, and IEEE 2030.5), each of which might be preferred for certain types of DER or integration environments (residential, industrial, or utility). However, California utilities plan to design their DER integration networks around IEEE 2030.5 in utility SCADA systems. Protocol translation in the gateway makes it possible to have a unified network protocol for all smart inverters while accommodating the various languages at the system edge.

2. Cyber-secure integration of smart inverters through gateways
   - Ensure that all cybersecurity risk associated with integrating DER through gateways is assessed and significant risks are mitigated through cybersecurity controls. The cybersecurity controls include technical or procedural measures — communication security, hardware/software security, security monitoring, security vulnerability and patch management, and crypto key management.
3. Centralized manageability and sustainable integration
   - Ensure functional enhancements and translations can be provided in gateways to produce a cohesive, uniform set of services from DER in the field, even though they are from different time periods and have different intrinsic capabilities. For example, new curve functions might vary one parameter that could be native in future DER (such as vars) based on another parameter (for example temperature). Such curve functions might be implemented in the gateways of legacy DER to make them similar in overall behavior, as shown in Figure 58.

**Figure 58: Uniform Gateways with Diverse Distributed Energy Resources**




Source: Electric Power Research Institute

Because the gateway will be a part of the DER-integrating network rather than a customer's hardware, this project will make the gateways firmware-upgradable from the headend (similar to how smart meters are upgraded today).

# LIST OF ACRONYMS

| Term | Definition |
|---|---|
| A | ampere(s) |
| AC | Alternating Current |
| ADMS | Advanced Distribution Management System |
| AMI | Advanced Metering Infrastructure |
| API | Application Program Interface |
| ATL | Authorized Test Laboratory |
| CAISO | California Independent System Operator |
| CEC | California Energy Commission |
| CPUC | California Public Utilities Commission |
| CSI | California Solar Initiative |
| CSIP | Common Smart Inverter Profile |
| CSV | Comma-Separated Values (.csv file) |
| DAS | Data Acquisition System |
| db | deadband |
| DC | Direct Current |
| DER | Distributed Energy Resources |
| DERMS | Distributed Energy Resources Management System |
| DHCP | Dynamic Host Configuration Protocol |
| DNP | Distributed Network Protocol |
| DOI | Digital Object Identifier |
| DSO | Distribution System Operator |
| DSS | Distribution System Simulator (EPRI's OpenDSS) |
| ECC | Economic Carrying Cost |
| EPIC | Electric Program Investment Charge |
| EPRI | Electric Power Research Institute |
| FLISR | Fault Location, Isolation, and Service Restoration |
| GB | gigabyte(s) |
| Gbit | gigabit(s) |
| GPIB | General Purpose Interface Bus |
| HC | Hosting Capacity |
| HD | High Definition |

| Term | Definition |
|---|---|
| HDD | Hard Disk Drive |
| Hz | hertz |
| IoT | Internet of Things |
| IOU | Investor-Owned Utility |
| IP | Internet Protocol |
| IUT | Inverter Under Test |
| K | Kelvin |
| kS/s | kilo samples per second |
| kVA | kilovolt-ampere(s) |
| kvarh | kilovar-hour |
| kW | kilowatt(s) |
| LAN | Local Area Network |
| LMP | Locational Marginal Price |
| LMRP | Limit Maximum Real Power |
| LTC | Load Tap Changer |
| m | meter(s) |
| mA | milliampere(s) |
| MWh | megawatt-hour(s) |
| MV | megavolt(s) |
| MaxMV | megavolt voltage |
| MVA | megavolt ampere(s) |
| NIST | National Institute of Standards and Technology |
| NREL | National Renewable Energy Laboratory |
| OLTC | On-Load Tap Changer |
| PI | Process Information |
| PKI | Public Key Infrastructure |
| pf | power factor |
| pu | per unit |
| PV | Photovoltaic |
| QSTS | Quasi-Static Time-Series |
| RAM | Random Access Memory |
| REST | REpresentational State Transfer |

| Term | Definition |
|---|---|
| RMS | root mean square |
| rpm | revolution(s) per minute |
| s | second(s) |
| SATA | Serial Advanced Technology Attachment |
| SCADA | Supervisory Control and Data Acquisition |
| SDG&E | San Diego Gas & Electric |
| SI function | Smart Inverter Function |
| SIWG | Smart Inverter Working Group |
| SunSpec SVP | SunSpec System Validation Platform |
| TCP | Transmission Control Protocol |
| TB | terabyte(s) |
| TLS | Transport Layer Security |
| UDP | User Datagram Protocol |
| USB | Universal Serial Bus |
| V | volt(s) |
| var | voltage ampere reactive power |
| VPN | Virtual Private Network |
| VVC | Volt-var Control |
| VVI | Voltage Variability Index |
| W | watt(s) |
| WAN | Wide Area Network |
| Wh | watthour(s) |

# REFERENCES

[1] 2030.5-2018, IEEE Standard for Smart Energy Profile Application Protocol.

[2] M. Rylander, J. Smith, and W. Sunderman. 2015, April 19–21. Streamlined method for determining distribution system hosting capacity, in 2015 IEEE Rural Electric Power Conference. DOI: 10.1109/REPC.2015.11

[3] "Screening distribution feeders: Alternatives to the 15% Rule." 2015. Available online: http://calsolarresearch.ca.gov/88-screening-distribution-feeders-alternatives-to-the-15-rule

[4] A. Nguyen, M. Velay, J. Schoene, V. Zheglov, B. Kurtz, K. Murray, B. Torre, and J. Kleissl. 2016. High PV penetration impacts on five local distribution networks using high resolution solar resource assessment with sky imager and quasi-steady state distribution system simulations. *Solar Energy* 132: 221–235. DOI: 10.1016/j.solener.2016.03.019

[5] J. Quiroz and M. Reno. 2012, June 3–8. Detailed grid integration analysis of distributed PV, in 2012 38th IEEE Photovoltaic Specialists Conference. DOI: 10.1109/PVSC.2012.6317683

[6] C. Li, V.R. Disfani, Z.K. Pecenak, S. Mohajeryami, and J. Kleissl. 2018. Optimal OLTC voltage control scheme to enable high solar penetrations. *Electric Power Systems Research* 160:318–326. DOI: 10.1016/j.epsr.2018.02.016

[7] M.S. Lave, M.J. Reno, and R.J. Broderick. 2015. Characterizing local high-frequency solar variability and its impact to distribution studies. *Solar Energy* 118:327–337. DOI: 10.1016/j.solener.2015.05.028

[8] J. Kleissl. 2013. *Solar Energy Forecasting and Resource Assessment*. Academic Press.

[9] R. Perez, P. Ineichen, R. Seals, J. Michalsky, and R. Stewart. 1990. Modeling daylight availability and irradiance components from direct and global irradiance. *Solar Energy* 44(5):271–289. DOI: 10.1016/0038-092X(90)90055-H

[10] M.J. Reno, C.W. Hansen, and J.S. Stein. 2012. *Global horizontal irradiance clear sky models: Implementation and analysis*. SANDIA report SAND2012-2389.

[11] California Public Utilities Commission. 2013. *California Solar Initiative annual program assessment: June 2013.* Available online: http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=5718

[12] J. Luoma, J. Kleissl, and K. Murray. 2012. Optimal inverter sizing considering cloud enhancement. *Solar Energy* 86(1):421–429. DOI: 10.1016/j.solener.2011.10.012

[13] M. Rylander, J. Smith, D. Lewis, and S. Steffel. 2013, July 21–25. Voltage impacts from distributed photovoltaics on two distribution feeders, in 2013 IEEE Power & Energy Society General Meeting. DOI: 10.1109/PESMG.2013.6672320

[14] California Public Utilities Commission, California Energy Commission. 2016. *SIWG Phase 3 DER functions: Recommendations to the CPUC for Rule 21, Phase 3 function key requirements, and additional discussion issues*.

[15] IEEE 1547-2018, IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces.

[16] EPRI. OpenDSS, Simulation Tool, OpenDSS. Available online: http://smartgrid.epri.com/SimulationTool.aspx.

[17] EPRI. 2016. *Smart grid ready PV inverters with utility communication: Results from field demonstrations*. Palo Alto, CA: Electric Power Research Institute. 3002008557.

[18] EPRI. 2016. *Common functions for smart inverters: 4th edition*. Palo Alto, CA: Electric Power Research Institute. 3002008217.

[19] *Employing active power curtailment of distribution-connected solar photovoltaics: Economics and regulatory considerations*. 2017. Palo Alto, CA: Electric Power Research Institute. 3002010289.

[20] NREL. 2017. Distribution System Upgrade Unit Cost Database. National Renewable Energy Laboratory. https://data.nrel.gov/submissions/77

[21] EPRI. 2015. *Solar PV market update, Volume 16: Q4 2015*. Palo Alto, CA: Electric Power Research Institute. 3002005779.

[22] EPRI. 2018. *A Strategic Approach to Pricing DER Power Transactions with the Electric Grid*. Palo Alto, CA: Electric Power Research Institute. 3002013324.

[23] D. Lew, N. Miller, K. Clark, G. Jordan, and Z. Gao. 2010, December. *Impact of high solar penetration in the Western Interconnection*. National Renewable Energy Laboratory. Technical Report NREL/TP-5500-49667. https://www.nrel.gov/docs/fy11osti/49667.pdf

[24] NREL. "NREL's PVWatts® Calculator." PVWatts® Calculator. National Renewable Energy Laboratory Available online: pvwatts.nrel.gov/

[25] California Public Utilities Commission (CPUC). 2011, September 22. R1109011 – Proceeding.

[26] L. Cibulka, T. Tansy, B. Fox, S. Martinez, and J. Kleissl. 2018, November. *Smart inverter performance testing to UL 1741 SA and CA Rule 21 criteria: Results from the UC San Diego Smart Inverter Laboratory*. California Energy Commission. CEC EPC-14-036.

[27] Internet Engineering Task Force. 2008, May. "Internet X.509 Public Key Infrastructure Certificate and Certificate Revocation List (CRL) Profile." Available online: https://tools.ietf.org/html/rfc5280

[28] K.A. McKay and D.A. Cooper. 2019, August. Guidelines for the Selection, Configuration, and Use of Transport Layer Security (TLS) Implementations. NIST|CSRC, National Institute of Standards and Technology. NIST Special Publication 800-52 Rev. 2. csrc.nist.gov/publications/detail/sp/800-52/rev-2/final

[29] EPRI. 2019. *Security Architecture for Distributed Energy Resources Integration Network: Risk-Based Approach for Network Design*. Palo Alto, CA: Electric Power Research Institute. 3002016781.

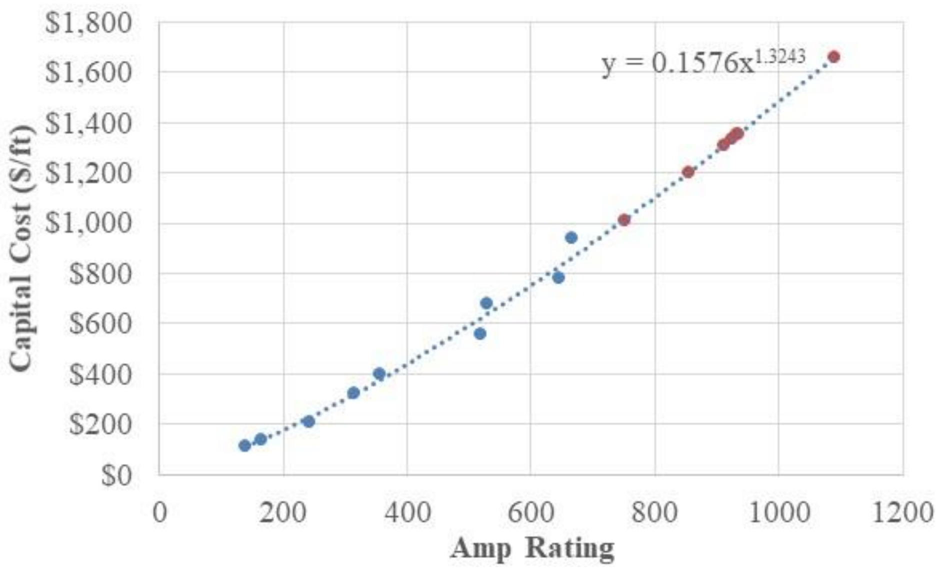
[30] *Utility Wire & Cable*. 2016. Priority Wire & Cable, Inc. http://www.prioritywire.com/brochures/Utility%20Catalog.pdf

# APPENDIX A: Equipment Cost Estimates Requiring Special Treatment

## Extrapolation of Line Sizes and Unit Costs

Estimated costs for conductor sizes that were not in the reference NREL Distribution System Upgrade Unit Cost Database [20] were extrapolated using a line of best fit based on the current rating of known wire costs. Figure A-1 shows this extrapolation, where the blue points represent reference capital costs and the orange points represent costs estimated using the power function line of best fit. Table A-1 provides the actual values used.

**Figure A-1: Estimation of Conductor Costs for Large Line Ratings**




Source: EPRI

**Table A-1: Estimation of Conductor Costs for Large Line Ratings**

| Line type | Amp Rating | Capital Cost ($/ft) | Estimated Cost ($/ft) |
|---|---|---|---|
| ACSR #4 | 140 | $110 | |
| ACSR #2 | 164 | $140 | |
| ACSR 1/0 | 242 | $210 | |
| ACSR 3/0 | 315 | $320 | |
| ACSR 4/0 | 357 | $400 | |
| ACSR 336.4 | 519 | $560 | |
| ACSR 336.4 | 529 | $680 | |
| ACSR 477 | 646 | $780 | |
| ACSR 477 | 666 | $940 | |
| Size Used for Upgrade | 854 | | $1,201 |
| | 750 | | $1,012 |
| | 912 | | $1,311 |
| | 924 | | $1,334 |
| | 933 | | $1,351 |
| | 935 | | $1,355 |
| | 1,090 | | $1,660 |

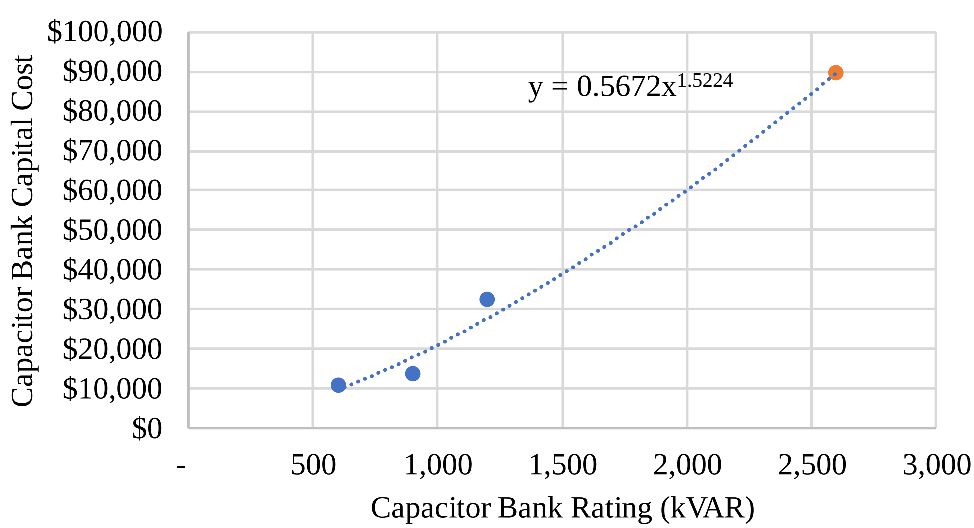
**Note: Amp ratings were estimated from the Priority Wire & Cable Data Sheet [30] using the ACSR – Aluminum Conductor Steel Reinforced specifications on pgs. 4–5.**

Source: EPRI

## Extrapolation of Capacitor Bank Size

Estimated costs for the large 2,600 kvar capacitor bank used in the analysis of the front location of Feeder 888, were extrapolated based on the costs listed in the NREL Distribution System Upgrade Unit Cost Database [20]. Costs for three smaller capacitor sizes (a mix of pole mount, pad mount, and fixed/switch capacitors) were plotted per kvar. Figure A-2 shows the extrapolation using a line of best fit where the blue points are reference capital costs and the orange point is the estimated cost of the large capacitor. Table A-2 provides the actual values used.

**Figure A-2: Estimation of Capacitor Bank Cost for 2,600 kvar Capacitor**




Source: EPRI

**Table A-2: Estimation of Capacitor Bank Cost for 2,600 kvar Capacitor**

| Rating (kvar) | Reference Cost | Estimated Cost | Cost per kvar | Notes |
|---|---|---|---|---|
| 600 | $10,723 | | 17.9 | Pole mount, anonymized source |
| 900 | $13,747 | | 15.3 | Pole mount, switched, anonymized source |
| 1,200 | $32,200 | | 26.8 | Pole mount, SCE unit cost guide |
| 2,600 | | $89,679 | 34.5 | |

Source: EPRI

Sunrun developed a programmatic approach — known as the Electric Avenue Program — to track customer enrollment and participation in a field demonstration of Rule 21 Phase 3 Smart Inverter Functions. Figure A-3 shows the promotional Q&A flyer and enrollment form distributed for the Electric Avenue Program. Figure A-4 shows scope of work and site plan detail for the field demonstration.

**Figure A-3: Promotional Q&A Flyer and Enrollment Form Distributed for Electric Avenue Program**

sunrun

# Electric Avenue Program
# Enrollment Form

- By participating in this Program, you may help improve the resilience of your local utility grid and unlock more solar and battery storage in California.
- You will receive a $250 gift card for your participation in December of 2019.
- The Program will consist of 20-30 discrete events spread across three years.
- To be eligible, you must have an installed and operational Sunrun Brightbox.
- You may withdraw enrollment at any time by contacting Sunrun (instructions below).
- This is just a summary; please review the full terms and conditions for all details.

Sunrun is pleased to invite you to the **Electric Avenue** Program ("Program"). Please read this form in its entirety and sign below where indicated if you consent to participation in the Program.

**What is the Electric Avenue Program?**
Sunrun partnered with two organizations to test the advanced capabilities of Brightbox systems. Together, our goal is to learn more about the potential for solar and battery storage to improve resilience of the utility grid, and ultimately allow for more solar and battery storage to be interconnected onto the grid.

**Who are the organizations Sunrun is partnering with?**
The Electric Power Research Institute (EPRI), is an independent, nonprofit organization devoted to helping the electricity sector through effective research and development programs for the benefit of society. The California Energy Commission (CEC), is the state's primary energy policy and planning agency, committed to reducing energy costs and environmental impacts of energy use while ensuring a safe, resilient, and reliable supply of energy.

**How will this Program affect my battery system?**
Minimally. Sunrun will (i) send signals to your Brightbox system to test advanced functionality and export energy from your battery to the grid up to 30 times in the next three years (ii) share with our Partners (EPRI and CEC) information about your Brightbox system about how your system responded to these signals. The Partners will then analyze this information to determine how well Brightbox systems conform to the most advanced specifications and future regulations for residential solar and battery storage systems on the California electric grid.

**What is the duration of the program?**

The Program will consist of 20-30 events, last a maximum of 4 hours each, spread over three years.

**What benefits will I receive for participating in the Program?**
Sunrun will send you a $250 gift card for your participation in the program. You can also feel great about helping to pave the way for more solar and battery storage adoption in the state of California.

**What data will be shared with EPRI and CEC?**
For the purposes of this Program, we will share the following information with our Partners: your solar system's energy production the status of your battery and smart inverter for a period before, during, and after the test events, your home address, and a unique identifier we will generate for your system.

**What if I still have questions or concerns about this program?**
Please contact Steve Wheat at Sunrun at steve.wheat@sunrun.com or 855-478-6786

**Sounds great! What do I have to do to participate?**
Just sign below. Participating in the Program will not require any additional service calls to your home or any hardware modifications to be installed for your Brightbox system. Once the Program concludes, Sunrun will stop sending these unique signals to your Brightbox to temporarily alter your Brightbox operations.

**I hereby consent to participate in the Electric Avenue Program:**

Signature: [redacted]

Full name: [redacted]

Date: 6/6/2019 | 3:46 PM PDT

Source: EPRI

## Figure A-4: Scope of Work and Site Plan Detail for Field Demonstration

### SCOPE OF WORK

- **SYSTEM SIZE:** 7700W DC, 7600W AC
- **MODULES:** (22) LG ELECTRONICS: LG350Q1C-A5
- **INVERTER(S):**
  (1) SOLAREDGE TECHNOLOGIES: SE7600A-USS2 WITH REVENUE GRADE METERING
- **RACKING:**
  **OPTION 1:** SNAPNRACK TILE REPLACEMENT; FLASHED LFOOT; SEE UR40 PEN D03
  **OPTION 2:** SNAPNRACK SERIES 100 UL; FLUSH MOUNT STANDOFF. SEE PEN D04.
- **BATTERY:** (1) LG CHEM RESU 10H-SEG, 9.8 KWh, 5KW LITHIUM-ION BATTERY (WEIGHT: 214LB EACH).

### GENERAL NOTES

- ALL WORK SHALL COMPLY WITH 2016 CEC, 2016 CBC, MUNICIPAL CODE, AND ALL MANUFACTURERS' LISTINGS AND INSTALLATION INSTRUCTIONS.
- PHOTOVOLTAIC SYSTEM WILL COMPLY WITH 2016 CEC.
- ELECTRICAL SYSTEM GROUNDING WILL COMPLY WITH 2016 CEC.
- PHOTOVOLTAIC SYSTEM IS UNGROUNDED. NO CONDUCTORS ARE SOLIDLY GROUNDED IN THE INVERTER. SYSTEM COMPLIES WITH 690.35.
- MODULES CONFORM TO AND ARE LISTED UNDER UL 1703.
- INVERTER CONFORMS TO AND IS LISTED UNDER UL 1741.
- ENERGY STORAGE SYSTEM CONFORMS TO AND IS LISTED UNDER UL 9540.
- RACKING CONFORMS TO AND IS LISTED UNDER UL 2703.
- SNAPNRACK RACKING SYSTEMS, IN COMBINATION WITH TYPE I, OR TYPE II MODULES, ARE CLASS A FIRE RATED.
- RAPID SHUTDOWN REQUIREMENTS MET WHEN INVERTERS AND ALL CONDUCTORS ARE WITHIN ARRAY BOUNDARIES PER NEC 690.12(1).
- ENERGY STORAGE SYSTEM LIVE PARTS ARE NOT ACCESSIBLE DURING ROUTINE MAINTENANCE. SYSTEM VOLTAGE IN ACCORDANCE WITH NEC 690.7 AND EXCEPTION 1 NEC 690.71(B)(1).
- ADDITIONAL DISCONNECTING MEANS SHALL BE INSTALLED WHERE ENERGY STORAGE DEVICE INPUT AND OUTPUT TERMINALS ARE MORE THAN 5 FT FROM CONNECTED EQUIPMENT, OR WHERE THE CIRCUITS FROM THESE TERMINALS PASS THROUGH A WALL OR PARTITION PER NEC 690.71(H) OR 706.7(E).
- LISTED, COMBINATION TYPE AFCI SHALL BE INSTALLED WHERE BACKED UP CIRCUIT WIRING IS EXTENDED MORE THAN 6FT AND DOES NOT INCLUDE ANY ADDITIONAL OUTLETS OR DEVICES PER NEC 201.12(B).
- CONSTRUCTION FOREMAN TO PLACE CONDUIT RUN PER 690.31(G) AND 2012 IFC 605.11.2.
- 10.77 AMPS MODULE SHORT CIRCUIT CURRENT.
- 16.82 AMPS DERATED SHORT CIRCUIT CURRENT [690.8 (a) & 690.8 (b)].
- TOTAL DISTRIBUTED WEIGHT OF ALL RACKING AND PANELS DOES NOT EXCEED 5 LBS. PER SQUARE FOOT.

### LEGEND AND ABBREVIATIONS

| | |
|---|---|
| SE | SERVICE ENTRANCE |
| MP | MAIN PANEL |
| SP | SUB-PANEL |
| LC | PV LOAD CENTER |
| SM | SUNRUN METER |
| PM | DEDICATED PV METER |
| INV | INVERTER(S) WITH INTEGRATED DC DISCONNECT AND AFCI |
| AC | AC DISCONNECT(S) |
| DC | DC DISCONNECT(S) |
| CB | COMBINER BOX |
| | BATTERY |
| AT | AUTOTRANSFORMER |
| BP | BACKED UP LOADS PANEL |
| SEM | SOLAREDGE METER |

SOLAR MODULES
RAIL
STANDOFFS & FOOTINGS
CHIMNEY
ATTIC VENT
FLUSH ATTIC VENT
PVC PIPE VENT
METAL PIPE VENT
T-VENT
SATELLITE DISH
FIRE SETBACKS
HARDSCAPE
—PL— PROPERTY LINE
INTERIOR EQUIPMENT SHOWN AS DASHED

SCALE: NTS

| | |
|---|---|
| A | AMPERE |
| AC | ALTERNATING CURRENT |
| AFCI | ARC FAULT CIRCUIT INTERRUPTER |
| AZIM | AZIMUTH |
| COMP | COMPOSITION |
| DC | DIRECT CURRENT |
| (E) | EXISTING |
| EXT | EXTERIOR |
| FRM | FRAMING |
| INT | INTERIOR |
| LBW | LOAD BEARING WALL |
| MAG | MAGNETIC |
| MSP | MAIN SERVICE PANEL |
| (N) | NEW |
| NTS | NOT TO SCALE |
| OC | ON CENTER |
| PRE-FAB | PRE-FABRICATED |
| PSF | POUNDS PER SQUARE FOOT |
| PV | PHOTOVOLTAIC |
| TL | TRANSFORMERLESS |
| TYP | TYPICAL |
| V | VOLTS |
| W | WATTS |

| REV | NAME | DATE | COMMENTS |
|---|---|---|---|
| | | | |
| | | | |
| | | | |

TABLE OF CONTENTS



### VICINITY MAP

[redacted]

sunrun


GILBERT CORREIA, C10, C46
CA CL #750184
26820 HOBIE CIR, MURRIETA, CA 92562
PHONE 805.540.7691
FAX 0


CUSTOMER RESIDENCE:

TEL. (760) 826-3182
APN #: 102-180-42-00
PROJECT NUMBER:
124R-842PILD

DESIGNER: (949) 623-7043
ANDREW CHIU

SHEET
COVER SHEET

REV: A 7/5/2018

PAGE PV-1.0

### GENERAL NOTES

A. GENERAL
1. Applicable codes. All projects shall comply with the following referenced codes:
a. 2016 California Electric Code (CEC)
b. 2016 California Building Code (CBC) and/or 2016 California Residential Code (CRC)
c. 2016 California Plumbing Code (CBC)
d. 2016 California Mechanical Code (CMC)
e. County of San Diego Consolidated Fire Code
B. ROOF
1. Roofing and weatherproofing. All roofing and weatherproofing installation shall comply with the following methods and requirements:
a. Any arrays integrated with the roofing material shall be Class "A" rated in accordance with ASTM E 108 or UL 790. (County of San Diego Building Code 92.1.1505.1, CBC 1505.8, CRC 902.3)
b. All roof penetrations shall be secure and weather-tight. (CRC 903..2)
c. Module installations shall not cover or block any roof plumbing or mechanical vent locations. (CPC 904, CPC 906, CMC 802.6, CMC 510.8)
2. Firefighter access requirements. All roof-mounted solar photovoltaic systems shall comply with the following:
a. Roof access points shall be provided per the following and in conformance with CRC R331.4.1 or CBC 3111.4.1 as applicable:
1. Located in areas not requiring placement of ground ladders over openings such as doors or windows.
2. Located at strong points of building construction in locations where access point does not conflict with overhead obstructions such as tree limbs, wires, or signs.
3. Inspector access requirements. A portable ladder complying with CAL-OSHA requirements shall be made available and secured in place for inspection.
C. ELECTRICAL
1. Wiring methods. All wiring installation shall comply with the following wiring methods and requirements:
a. Corrosion resistant conduit shall be used for all underground runs and installations. (CEC 690)
b. All exposed wiring shall be listed for wet location and sunlight resistant. All outdoor equipment shall be NEMA 3R rated. (CEC 690.31, CEC 310.8)
c. Photovoltaic DC conductors entering the building shall be installed in a metallic raceway. (CEC 690.31)
d. Markings shall be placed on interior and exterior DC conduit, raceway, enclosures, and cable assemblies every 10 feet -- and within 1 foot of turns or bends and within 1 foot above and below penetrations of roof/ceiling assemblies, walls, or barriers -- with minimum 3/8-inch-high white lettering on red background reading: "WARNING: PHOTOVOLTAIC POWER SOURCE." (CEC 690.31)
e. DC breakers shall be listed and rated for PV use. (CEC 705.12)
f. All equipment shall be identified on a warning placard clearly showing the location of all pertinent equipment and disconnects. Alternate power source placard shall meet the specifications of the San Diego Area Newsletter. The placard shall be metal or plastic, with engraved letters in a contrasting color to the placard, include the location of meter, disconnects, inverter, the array, and a footprint of the entire building and site. The placard will be attached by pop-rivets, screws, or other approved fasteners. Refer to the sample placard for alternative power source (diagram on the right) for further requirements. (CEC 110)
g. PV connection in panel board shall be positioned at the opposite (load) end from the input feeder location or main circuit location. (CEC 705.12)
h. If approved plans show de-rating of the main breaker, a placard label is required at the panel stating: "THIS PANEL HAS BEEN DE-RATED TO (insert amperage size). DO NOT INSTALL LARGER BREAKERS." Refer to the sample placard for alternative power source (diagram on the right) for further requirements. (CEC 690.53, CEC 690.17, CEC 705.10)
i. Wire sizing and terminations shall be in conformance with the sixty degree (60°) column of CEC Table 310.15(B)(16).
j. All exterior conduit placement and sizing shall have ambient temperature adjustments in conformance with the ASHRAE designated design temperate and comply with CEC 310.15(b)(3)(c).
k. Main service panel and buss bar ratings must be verifiable at time of inspection with fixed labeling.
l. Integrated and or micro-inverter systems shall have a rooftop AC disconnect and comply with CEC 690.14 (D) (1) and CEC 690.14 (D) (2).
m. PV system circuits installed on or in buildings shall include a rapid shutdown function that controls specific PV conductors in accordance with CEC 690.12 (1) through (5) and have the associated placard stating: "PHOTOVOLTAIC SYSTEM EQUIPPED WITH RAPID SHUTDOWN". Refer to the sample placard for alternative power source (diagram on the right) for further requirements.
2. Grounding methods. All grounding installation shall comply with the following grounding methods and requirements:
a. All modules shall be grounded in accordance with the CEC and the manufacturer's installation instructions. Approved plans and all reference documents shall be available on site for inspection verification. (CEC 250)
b. Third-party grounding devices must be specifically mentioned in the module manufacturer's installation instructions by device make and model. These installation instructions must be reviewed by the module listing agency as part of the listing of the module to UL 1703. Grounding devices listed to UL 2703 also may be acceptable if the device installation instructions mention the specific module make and model.
c. Unless specified by the manufacturer, all inverters (including micro-inverters) shall have a grounding electrode conductor with a minimum size of #8 copper wires. (CEC 690.47)
d. Electric service panels shall be grounded with a grounding electrode(s) that complies with CEC Article 250. Ground-rods shall be supplemented by a second ground-rod installed at least 6 feet apart. (CEC 690.47)
e. If the existing main service panel does not have verifiable grounding electrode, it shall be the contractor's responsibility to install a supplemental grounding electrode. Service grounding electrode must be verified at the time of inspection for all buildings. Buildings with a metallic water pipe system as the sole grounding electrode shall have a supplemental electrode installed. (CEC 690.47)
f. All combiner boxes shall be listed for DC current and listed by a nationally recognized testing agency. (CEC 690.4)
g. Manufacturer's technical cut sheets and installation manuals for all equipment and components shall be provided on site.
h. All terminals of the disconnecting means may be energized in the open position in conformance with CEC 690.17.
i. All electrical terminus torqueing shall be in accordance with the CEC, San Diego Area News Letter, and the manufacturer's installation instructions. (CEC 110.3 (B), CEC 110.14)
D. MISCELLANEOUS
1. Zoning requirements. All roof-mounted solar photovoltaic systems shall comply with:
a. County of San Diego zoning requirements per setbacks for Solar Photovoltaic Panels. Reference handout PDS#276 for further details.
2. Manufactured or mobile home requirements. All roof-mounted solar photovoltaic installations on manufactured or mobile homes require a permit from the State of California Department of Housing and Community Development (HCD). Contact HCD at (951) 782-4420 for further information.
E. GREEN BUILDING STANDARDS CODE (CALGREEN)
1. Construction waste reduction, disposal, and recycling: Reduce and/or salvage for reuse a minimum of 65 percent of the nonhazardous construction and demolition debris. (CalGreen 4.408.1)
Exception: Excavated soil and land-clearing debris.
Exception: Alternate waste reduction methods developed by working with local agencies if diversion or recycle facilities capable of compliance with this item do not exist or are not located reasonably close to the jobsite
The County of San Diego, Department of Public Works, Construction & Demolition (C&D) Facilities Guide is online at: http://www.sdcounty.ca.gov/dpw/recycling/Files/Construction_Guide_SJ8_Pgs_1-27.pdf.
2. Construction waste management plan: A construction waste management plan shall be prepared and available on site during construction. Documentation demonstrating compliance with the plan shall be accessible during construction for the enforcing agency. (CalGreen 4.408.2) The plan:
a. Identify the construction and demolition waste materials to be diverted from disposal by recycling, reuse on the project or salvage for future use or sale
b. Specify if construction and demolition waste materials will be sorted on-site (source-separated) or bulk mixed (single stream)
c. Identify diversion facilities where the construction and demolition waste materials will be taken
d. Identify construction methods employed to reduce the amount of construction and demolition waste generated
e. Specify that the amount of construction and demolition waste materials diverted shall be calculated by weight or volume, but not by both.
F. BATTERY BACKUP SYSTEM (BBS) AND ADVANCE ENERGY STORAGE (AES):
1. General Requirements: All battery and AES shall comply with the following:
a. All battery, BBS, and AES systems shall be installed in accordance with the CEC and the manufacturer's installation instructions. Approved plans and all reference documents shall be available on site for inspection verification. Additional fire and engineering requirements maybe required based on site specific review and inspections.
b. All inverter, charger, racking, and storage products shall be individual component listed, or full system and equipment listed, for battery and advance energy storage use by a nationally recognized testing agency complying with CEC article 480 and CEC article 690.
2. Electrical Requirements: All battery and advance storage systems shall comply with the following:
a. All combiner boxes, disconnects, and fuses shall be listed for DC current and listed by a nationally recognized testing agency complying with CEC article 480 and CEC article 690. Ground fault protection for battery, BBS, and AES shall comply with CEC 690.5 and storage overcurrent device(s) shall be installed in accordance with CEC 240.21 (H) and 690.71 (C).
b. All vented storage cells shall be equipped with flame arresters complying with CEC 480.10 (A) and all sealed storage cells shall be equipped with pressure-release vents complying with CEC 480.10 (B). The storage cells and battery locations shall comply with CEC 480.9 and CEC 690.71. The storage cells shall be located inside a lockable enclosure or room (CEC 690.71 (B) (2)) with adequate accessibility for all equipment (CEC 110.26 & CEC 480.8 (C)). Appropriate to the battery technology, sufficient ventilation shall be provided in accordance with CEC 480.9 (A). All racking and trays shall meet provisions within CEC 480.8.
c. Critical loads and critical loads centers shall be clearly identified and load calculations shall be available on site for inspection verification. The residential total battery system voltage, system wiring, and conductor sizing shall be calculated in accordance to CEC 690.8 (A) (4) and not exceed 50 volts (CEC 690.71 (B) (1)). All breaker and/or fuse rating protecting the conductors shall comply with CEC 690.8 (B) (1).
d. Circuit transformers and metering devices shall be listed for such use by a nationally recognized testing agency complying with CEC 690.60 and CEC 690.61.
e. All charge controllers required for BBS and AES shall comply with CEC 690.72.
f. All photovoltaic power system employing a diversion charge controller as the sole means of regulating the charging of a battery shall be equipped with a second independent means to prevent overcharging of the battery. (CEC 690.72 (B) (1))
g. Circuits containing a DC diversion charge controller and a DC diversion load shall comply with CEC 690.72 (B) (2).
h. All photovoltaic power system using utility-interactive inverters to control battery state-ofcharge by diverting excess power into utility system shall comply with (CEC 690.72 (B) (3)).
i. Buck/boost charge controllers and other DC power converters that increase or decrease the output current or output voltage with respect to the input current or input voltage shall comply with CEC 690.72 (C), 690.72 (C) (1), and 609.72 (C) (2).
j. All photovoltaic power system employing energy storage shall also be marked with the maximum operation voltage, including any equalization voltage and the polarity of the ground circuit conductor per CEC 690.55.
k. BBS or AES intended as stand-alone systems shall comply with all the requirements listed under CEC 690.16 (A) through (E).


sunrun
GILBERT CORREIA, C10, C46
CA CL #750184
26820 HOBIE CIR, MURRIETA, CA 92562
PHONE 805.540.7691
FAX 0
TEL. (760) 826-3182
APN #: 102-180-42-00
PROJECT NUMBER:
124R-842PILD
DESIGNER: (949) 623-7043
ANDREW CHIU


SHEET
GENERAL NOTES

REV: A 7/5/2018

PAGE PV-1.1


SITE PLAN DETAIL - SCALE = 3/32" = 1'-0"
SITE PLAN - SCALE = 1/128" = 1'-0"
ARRAY PITCH
TRUE AZIM
MAG AZIM
PV AREA (SQFT)
AR-01 18° 153° 142° 223.1
AR-02 18° 333° 322° 111.6
AR-03 18° 243° 232° 74.4
(E) RESIDENCE
(N) ARRAY AR-03
AT
INV
AC
BP
MP
SE
(N) ARRAY AR-02
(N) ARRAY AR-01
(E) RESIDENCE
FIRE SETBACKS
(3' TYP)
(N) CONDUIT RUN
(ON ROOF)
(N) ARRAY AR-01
SANTA MARGARITA DR
(E) DETACHED STRUCTURE
sunrun
CA CL #750184
DESIGNER:
(949) 623-7043
SITE PLAN
REV: A
7/5/2018
PAGE
PV-2.0
75.5%

Source: EPRI