California Solar Initiative

RD&D: Research, Development, Demonstration and Deployment Program

Final Project Report:

Analysis to Inform CA Grid Integration Rules for PV

Inverter Settings for Transmission and Distribution System Performance

Grantee:

Electric Power Research Institute (EPRI)

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Preface

The goal of the California Solar Initiative (CSI) Research, Development, Demonstration, and Deployment (RD&D) Program is to foster a sustainable and self-supporting customer-sited solar market. To achieve this, the California Legislature authorized the California Public Utilities Commission (CPUC) to allocate **$50 million** of the CSI budget to an RD&D program. Strategically, the RD&D program seeks to leverage cost-sharing funds from other state, federal and private research entities, and targets activities across these four stages:

- Grid integration, storage, and metering: 50-65%
- Production technologies: 10-25%
- Business development and deployment: 10-20%
- Integration of energy efficiency, demand response, and storage with photovoltaics (PV)

There are seven key principles that guide the CSI RD&D Program:

1. **Improve the economics of solar technologies** by reducing technology costs and increasing system performance;
2. **Focus on issues that directly benefit California**, and that may not be funded by others;
3. **Fill knowledge gaps** to enable successful, wide-scale deployment of solar distributed generation technologies;
4. **Overcome significant barriers** to technology adoption;
5. **Take advantage of California's wealth of data** from past, current, and future installations to fulfill the above;
6. **Provide bridge funding** to help promising solar technologies transition from a pre-commercial state to full commercial viability; and
7. **Support efforts to address the integration of distributed solar power into the grid** in order to maximize its value to California ratepayers.

For more information about the CSI RD&D Program, please visit the program web site at www.calsolarresearch.ca.gov.

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ABSTRACT

The fourth solicitation of the California Solar Initiative (CSI) Research, Development, Demonstration and Deployment (RD&D) Program established by the California Public Utilities Commission (CPUC) supported the Electric Power Research Institute (EPRI), National Renewable Energy Laboratory (NREL), and Sandia National Laboratories (SNL) with data provided from Pacific Gas and Electric (PG&E), Southern California Edison (SCE), and San Diego Gas and Electric (SDG&E) conducted research to determine optimal default settings for distributed energy resource advanced inverter controls. The inverter functions studied are aligned with those developed by the California Smart Inverter Working Group (SIWG) and those being considered by the IEEE 1547 Working Group. The advanced inverter controls examined to improve the distribution system response included power factor, volt-var, and volt-watt. The advanced inverter controls examined to improve the transmission system response included frequency and voltage ride-through as well as dynamic voltage support.

This CSI RD&D project accomplished the task of developing methods to derive distribution focused advanced inverter control settings, selecting a diverse set of feeders to evaluate the methods through detailed analysis, and evaluating the effectiveness of each method developed. Inverter settings focused on the transmission system performance were also evaluated and verified.

Based on the findings of this work, the suggested advanced inverter settings and methods to determine settings can be used to improve the accommodation of distributed energy resources (PV specifically). The voltage impact from PV can be mitigated using power factor, volt-var, or volt-watt control, while the bulk system impact can be improved with frequency/voltage ride-through.

Keywords

Advanced Inverters
Distribution System
Transmission System
Photovoltaics
Settings

EXECUTIVE SUMMARY

The fourth solicitation of the California Solar Initiative (CSI) Research, Development, Demonstration and Deployment (RD&D) Program established by the California Public Utilities Commission (CPUC) supported the Electric Power Research Institute (EPRI), National Renewable Energy Laboratory (NREL), and Sandia National Laboratories (SNL) with data provided from Pacific Gas and Electric (PG&E), Southern California Edison (SCE), and San Diego Gas and Electric (SDG&E) conducted research to determine optimal default settings for distributed energy resource advanced inverter controls. The inverter functions studied are aligned with those developed by the California Smart Inverter Working Group (SIWG) and those being considered by the IEEE 1547 Working Group. The advanced inverter controls examined to improve the distribution system response included Power Factor, Volt-Var, and Volt-Watt. The advanced inverter controls examined to improve the transmission system response included frequency and voltage ride-through as well as Dynamic Voltage Support.

This CSI RD&D project accomplished the tasks of developing settings and/or methods to derive advanced inverter control settings, selecting a diverse set of scenarios to evaluate the settings/methods through detailed analysis, and evaluating the effectiveness of each setting/method developed.

Industry Challenge

Various incentive programs have increased the number of solar PV system interconnection requests to levels never before seen. Utilities must evaluate these interconnection requests to ensure proper operation of the grid is maintained. The use of advanced inverters can offset some of the potential adverse impacts from PV such as voltage violations and system stability. The settings necessary to offset the potential adverse impact depend on a number of transmission system, distribution system, and PV system characteristics. The ongoing changes to the power system and the PV systems interconnecting makes the complexity of detailed studies and determination of settings difficult. This typically results in avoided studies to utilize advanced inverters to solve current violations. Also, there is the perception that advanced inverters should not participate in voltage regulation, yet recent revisions to interconnection standards allow these devices to participate[1].

Project Goal

The objective of this project, entitled *Analysis to Inform CA Grid Integration Rules for PV*, was to determine recommended settings to assist utilities in taking advantage of these resources. However, some settings have been found to be dependent on the feeder/PV scenario. Therefore, an additional goal is to provide the utility the best procedures (methods) in which to easily determine the settings for the scenario in hand.

1 IEEE Standard for Conformance Test Procedures for Equipment Interconnecting Distributed Resources with Electric Power Systems -- Amendment 1, IEEE Standard 1547.1a, 2014.

Benefits

As the number of PV applications and installations increases, utilities are faced with a greater need to evaluate the aggregate impact of these systems. In most cases, it means an increased number of detailed impact studies or applications that do not get approved. The advanced inverter methods and settings developed in this project provide a mechanism to improve the distribution system performance (as it relates to voltage) when accommodating higher levels of PV. Similarly, the settings provided improve the bulk system performance as it relates to stability. A reduction of these adverse issues, as well as allowing the fast track of applications to achieve these higher penetrations, can result from the use of advanced inverters with the settings derived from the methods included in this report.

Approach

This project sought to provide utilities in California (CA) with a useable and accurate way to determine the most applicable settings for advanced inverter controls to improve transmission and distribution system performance. The overall project approach was accomplished via the key tasks outlined in Figure 1. This report will highlight each of the main tasks.

Distribution System

- Develop Methods to Derive Settings
- Select Feeders
- Apply Methods and Determine Feeder Impact

Transmission System

- Setup of a WECC 2024 Heavy Summer Case with 10.5% of Distributed PV
- Investigate Different Modeling Approaches
- Perform Stability Analysis and Determine System Performance Impact

Figure 1. Overall Project Approach

Project Summary

Distribution Focus

Advanced inverters have functionality that can allow better integration of distributed energy resources such as PV to the distribution system. From the distribution system's perspective, these functions include non-unity power factor settings, volt-var settings, and volt-watt settings. This is not an all-inclusive list of settings, but includes those that are at the top of the mind for most inverter manufacturers and distribution planners.

This report summarizes the analysis approach (methods) in which appropriate settings for each of the control functions can be derived. A high level summary of these methods is provided in Table 1. Ideally there would be one global setting that works in all situations for each control function, however, as determined in this research, the control settings are strongly linked to the feeder in which the control will be applied. Several methods for each control function are created such that the utility can make use of the data/tools available to make the determination of control settings. Multiple methods are proposed ranging from low-complexity approaches when the availability of data/tools is limited to more complex approaches when data/tools are abundant and detailed feeder models are available.

Table 1. Basic Details of Methods to Determine Advance Inverters Settings*

Level	Complexity	Power Factor	Volt-var	Volt-watt
0	None	Unity Power Factor	Disabled, Unity Power Factor Applied	Disabled, Unity Power Factor Applied
1	Low	Based on Feeder X/R Ratio	Generic Setting	Generic Setting
2	Medium	Based on Feeder Model and PV Location	Based on Feeder Model and PV Location	Not Analyzed
3	High	Based on Feeder Model and PV Location	Based on Feeder Model, PV Location, and Service Transformer Impedance	Not Analyzed

*Note it is assumed that the advanced inverters have the capability to provide the necessary reactive power at all times. Analysis follows recommended oversizing of the inverter by 10%. The other option instead of oversizing the inverter (to make sure that reactive power is available from the inverter) would be to have the inverter operate allowing reactive power to have priority over active power when the device becomes limited due to its kVA rating. Inverters operated under an active power priority scheme would not allow reactive power to be used to mitigate voltage issues when the device is operated at its rating.

The advanced inverter settings/methods are developed against feeder models, yet the applicability to different feeder models is necessary to gauge the methods' effectiveness. The models built/validated in the previous CSI RD&D Solicitation 3 project feeder analysis were leveraged in this study to meet that need. The feeders selected from the previous study ranged from those with limited to significant impact from distributed PV. The feeder voltage impact was the primary driver used in the feeder selection process. Voltage impact was used because voltage issues are the primary beneficiary from advanced inverters improving distribution system performance. The voltage impact was quantified by the feeder's hosting capacity which further leveraged the previous analysis. The previous analysis became the baseline distribution system impact from PV in which advanced inverters were examined to improve.

The distribution feeder's hosting capacity was shown to improve with the use of advanced inverters using the settings derived with the various methods as illustrated in Figure 2. Some control functions performed better than others, and the more complex methods (L3) did generally allow better accommodation of PV.

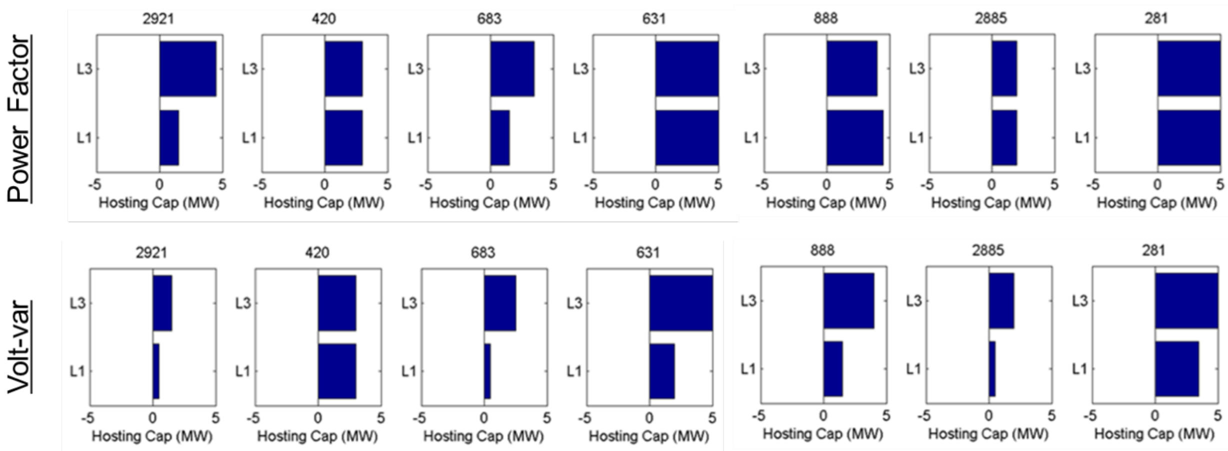

Figure 2. Change in Hosting Capacity with Advanced Inverter Control

Transmission Focus

From a transmission system perspective, this study assessed the stability impacts of a relatively low interconnection-wide penetration level of distributed energy resource (DER), PV on the 2024 Western Electricity Coordination Council (WECC) Heavy Summer system utilizing different control strategies and parameters for the DER PV. Two sets of control settings were assessed for the DER PV, the existing IEEE Standard 1547-2003 parameters and the updated CA Rule 21 parameters. The CA Rule 21 parameters increase the voltage and frequency ride through parameters of the DER PV allowing it to stay connected to the system during voltage and frequency deviations. Additionally, the CA Rule 21 parameters allow for the reconnection of DER PV if the plant has tripped following a contingency event.

Overall, it was determined that there are no significant stability issues regardless of the control parameters applied for the chosen relatively low interconnection-wide penetration level of DER PV. However, it was determined that operating the DER PV with the CA Rule 21 parameters can bring further stability benefits to the system. The voltage ride-through settings for the CA Rule 21 parameters can be beneficial to the voltage stability of the system by allowing the DER PV to reconnect following a fault. The updated frequency ride-through settings of CA Rule 21 are very robust, although it is difficult to assess on the 2024 WECC heave Summer Case. Additionally, further stability improvements seem to exist when utilizing advanced smart-inverter functionality like Dynamic Voltage Support or Frequency response. A more detailed analysis is needed to fully assess DER PV's capability to provide dynamic stability support to the system.

Findings

The performance of the control methods and application of settings on the distribution system:

- Power Factor and Volt-var Method Level 3 provide additional benefit with regards to increasing hosting capacity
- Power Factor Method Level 1 generally provides high benefit but requires the most reactive power to do so

- Volt-var Method Level 1 is the least complex but has one of the most effective uses of reactive power
- Volt-watt Method Level 1 should be used in conjunction with power factor or volt-var control since these reactive power control functions should prevent the unnecessary curtailment of real power when operated first

The performance of the control methods and application of settings on the transmission system:

- No serious stability issues with a relatively low penetration of DER PV of 10.5% in a WECC 2024 Heavy Summer case.
- New CA Rule 21 voltage and frequency ride-through settings improve system reliability.
- Further stability improvements seem to exist when utilizing advanced smart-inverter functionality.
- More detailed analysis needed to fully assess the capability of DER PV to support system stability dynamically.

Project Team

This CPUC/CSI project combines the experience of individuals across the industry, including:

- Electric Power Research Institute – Project Lead
- National Renewable Energy Laboratory – Project partner
- Sandia National Laboratories – Project partner
- Itron – Program Manager

Utility Partners:

- Southern California Edison (SCE)
- Pacific Gas & Electric (PG&E)
- San Diego Gas & Electric (SDG&E)

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1 INTRODUCTION

High penetrations of solar PV can impact distribution system operations and power quality, and it is becoming necessary for PV inverters to provide grid support services to mitigate these impacts and increase the cumulative benefits from the distributed generation. To allow this service, the California Public Utilities Commission (CPUC) is currently implementing advanced inverter functionality into Rule 21 in a phased process including the power factor, volt-var, volt-watt, frequency ride-through, voltage ride-through, and dynamic reactive current support capabilities. While these functions[2] are becoming more common, very little work has been done to address the implementation of the function settings and the impact these common functions will have on grid performance.

Methods have been proposed[3] to determine site specific inverter settings, but results show how those settings are highly dependent on the specific scenario analyzed. Previous work also showed that advanced inverter functions can be used for improving feeder response under high penetration scenarios[4,5,6], which can ultimately improve PV hosting capacity. From these results, there is obviously some potential advantage to applying advanced inverter controls to PV interconnections, but the question of how to determine those settings with minimal side effects remains. There is a significant lack of guidelines and available tools for determining effective advanced inverter functions.

The fourth solicitation of the California Solar Initiative (CSI) Research, Development, Demonstration and Deployment (RD&D) Program established by the CPUC supported the Electric Power Research Institute (EPRI), National Renewable Energy Laboratory (NREL), and Sandia National Laboratories (SNL) with data provided from Pacific Gas and Electric (PG&E), Southern California Edison (SCE), and San Diego Gas and Electric (SDG&E) conducted research to determine optimal default settings for distributed energy resource advanced inverter controls.

Working with the three investor-owned utilities, the project team evaluated the impacts of utility-scale PV on the distribution system through detailed analysis of hosting capacity (the ability to accommodate PV without adverse impacts for reliability or power quality). The results of this analysis led to the realization of the dependency of hosting capacity to all characteristics that

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2 "Common Functions for Smart Inverters, Version 2," EPRI, Technical Report 1026809, 2012.

3 Rylander M., Smith, J., Li H., "Determination of Advanced Inverter Settings to Improve Distribution System Performance," Solar Integration Workshop. Berlin, Germany. November 2014.

4 Smith, J., Seal, B., Sunderman, W., Dugan, R., "Simulation of Solar Generation with Advanced Volt-Var Control," 21st International Conference on Electricity Distribution, CIRED, Frankfurt, Germany, 2011

5 NREL PV Handbook - R. Seguin, J. Woyak, D. Costyk, J. Hambrick and B. Mather, "High-Penetration PV Integration Handbook for Distribution Engineers," NREL, Technical Report TP-5D00-63114, 2016.

6 J. Seuss, M. J. Reno, M. Lave, R. J. Broderick, and S. Grijalva, "Multi-Objective Advanced Inverter Controls to Dispatch the Real and Reactive Power of Many Distributed PV Systems," Sandia National Laboratories SAND2016-0023, 2016.

define a distribution feeder. When advanced inverter controls are utilized, the hosting capacity, and hence distribution system response, can be improved. However, just as hosting capacity is dependent on feeder characteristics, so are the advanced inverter control settings that provide the most benefit to the distribution system. Therefore, one of the goals of this project is to better define the advanced inverter control settings to ensure improved distribution system response.

The other goal of this project is to assess the system stability impacts of distributed PV inverters primarily on the California transmission system. Using the WECC 2024 Heavy Summer Transmission Expansion Planning Policy Committee (TEPPC) case, 5.4 GW of distributed photovoltaic (DER PV) generation was integrated into the California power system region and the stability impacts on the system were observed and assessed. The primary focus of this analysis was to analyze the new frequency and voltage ride-through inverter settings as they have been specified in recent updates to Rule 21 from a transmission system stability and reliability perspective. Further emphasis was placed on analyzing the impact of fault-induced delayed voltage recovery (FIDVR) on voltage ride-through of DER PV and potential benefits of advanced inverter functions like Dynamic Voltage Control for the bulk transmission system. This report presents the methodology details and process used to integrate the DER PV into the system model and discusses the results observed from the study.

2
DISTRIBUTION ANALYSIS FRAMEWORK

The project has several steps that occur in the distribution analysis and determination of advanced inverter settings. As part of a previous CSI RD&D Solicitation #3 project[7], the first step was to collect utility feeder characteristic data for the three California investor owned utilities: SDG&E, PG&E, and SCE. The characteristics of each utility's feeders were then clustered to identify approximately five feeder groups for each utility[8]. A feeder from each group, best representing its constituent cluster, was selected to perform detailed PV impact analysis. The impact analysis involved modeling the feeder in detail and performing millions of PV impact scenarios[9]. The results from that impact analysis then informed the feeder selection and baseline hosting capacity for this project and report.

In this this project, the selected feeders are used for examining the impact of advanced inverter controls. The advanced inverter controls examined to improve the distribution system response included

- Power Factor
- Volt-Var, and
- Volt-Watt.

In this project, various methods have been designed to determine settings for each control to minimize the voltage impact from distributed generation. Those methods were then applied to the selected feeders and PV deployment scenarios established under the previous CSI project. The impact/benefit from each of those methodologies could then be compared to determine the control's overall effectiveness.

Feeder Modeling

The modeling and analysis approach is performed entirely in the OpenDSS (Open-source Distribution System Simulator). The OpenDSS tool has been used for more than a decade in support of various research and consulting projects requiring distribution system analysis. Many of the features found in the program have been originally intended to support the analysis of distributed generation interconnected to utility distribution systems. Other features support analysis of such things as energy efficiency in power delivery and harmonic current flow. The OpenDSS is designed to be indefinitely expandable so that it can be easily modified to meet future needs.

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7 Alternatives to the 15% Rule: Final Project Summary. EPRI, Palo Alto, CA: 2015. 3002006594.

8 Clustering Methods and Feeder Selection for California Solar Initiative. EPRI, Palo Alto, CA: 2014. 3002002562.

9 Alternatives to the 15% Rule: Modeling and Hosting Capacity Analysis of 16 Feeders. EPRI, Palo Alto, CA: 2015. 3002005812.

The base electrical feeder model used in the analysis consists of all primary and secondary power delivery elements from the substation transformer to the individual customer. Control elements such as capacitors and regulators are included with fully implemented control algorithms using setpoints, delays, and bandwidths provided by the utility. Loads are based on SCADA or AMI measurements, and depending on the location of measurement, load is allocated to each individual customer. The complete model is usually derived from a number of data sources, including the simulation platform database (CYME or SynerGi), field measurements, billing information, and GIS data.

Leveraging the previous CSI modeling work[10], the seven feeders selected for the current analysis had been converted, modified, and validated.

Baseline Hosting Capacity Analysis

The analysis[11] approach includes the analysis of utility-class (large-scale) PV systems. These utility-class systems include centralized 500 kW systems interconnecting to the three-phase feeder primary through a step-up transformer. Utility-scale PV systems are stochastically deployed at five locations on each feeder. These locations were selected to try to capture a range of locations on the feeder from the substation to the far end. The stochastic nature of the analysis develops thousands of potential distributed PV deployments that capture the unpredictability of 'where' and 'how much' PV will eventually be installed.

Each feeder's response is addressed by determining a hosting capacity for PV. The hosting capacity is determined when a stochastically created PV deployment causes the feeder-wide response to exceed established thresholds. Since feeder hosting capacity can widely vary based upon the size and location of solar PV, thousands of different PV deployment scenarios are simulated to determine the range in hosting capacity values that might occur.

Framework

The baseline PV impact analysis is a combination of power flow and fault studies. These studies examine a large variation of PV deployment scenarios, load levels, and fault locations/types. The analysis determines the 'worst case' feeder response that would occur in any condition.

The power flow analysis is conducted for four base load levels:

- Absolute maximum – maximum feeder load level derived from 8760 feeder measurement data; irrespective of time-of-day
- Absolute minimum – minimum feeder load level derived from 8760 feeder measurement data; irrespective of time-of-day
- Midday maximum – maximum feeder load level derived from 8760 feeder measurement data; 11am-1pm local time considered only

10 Alternatives to the 15% Rule: Modeling and Hosting Capacity Analysis of 16 Feeders. EPRI, Palo Alto, CA: 2015. 3002005812.

11 Analysis of High-Penetration Solar PV Impacts for Distribution Planning: Stochastic and Time-Series Methods for Determining Feeder Hosting Capacity. EPRI, Palo Alto, CA: 2012. 1026640

- Midday minimum – minimum feeder load level derived from 8760 feeder measurement data; 11am-1pm local time considered only

The absolute maximum and minimum loads are used to derive a bounding envelope for the worst-case conditions. The midday maximum and minimum loads determine more probable bounds for the feeder response. These midday load levels occur when PV can produce full output. In this solicitation #4 analysis, only the midday load levels were analyzed.

Issues to Analyze

Distributed generation planning criteria and limits have been identified by both North American and European practices. Table 2-1 shows a summary of criteria used in the analysis to identify potential issues. The flags in this table are applied for study purposes and are not necessarily planning limits currently applied in the industry. These values are used across all feeders to allow uniform comparisons to be made. The criteria that have been identified fall into the following general categories of potential concern:

- Voltage
- Loading
- Protection

Although loading and protection issues were analyzed in the baseline analysis, they are not included in the solicitation #4 analysis since the application of advanced inverters to improve distribution performance are not geared to improve those issues. Advanced inverters will have an implication on those issues, however that impact is outside of the scope of this project. The main application of advanced inverters in this project is to prevent adverse distribution system voltage impacts.

Table 2-1. . Monitoring Criteria and Flags for Distribution PV Analysis

Category	Criteria	Basis	Flag
Voltage	Overvoltage	Feeder voltage	≥ 1.05 Vpu at primary ≥ 1.05 Vpu at secondary
	Voltage Deviation	Deviation in voltage from no PV to full PV	≥ 3% at primary ≥ 5% at secondary ≥ ½ bandwidth at regulators
	Unbalance	Phase voltage deviation from average	≥ 3% of phase voltage
Loading	Thermal	Element loading	≥ 100% normal rating
Protection	Element Fault Current	Deviation in fault current at each sectionalizing device	≥ 10% increase
	Sympathetic Breaker Tripping	Breaker zero sequence current due to an upstream fault	≥ 150A
	Breaker Reduction of Reach	Deviation in breaker fault current for feeder faults	≥ 10% decrease
	Breaker/Fuse Coordination	Fault current increase at fuse relative to change in breaker fault current	≥ 100A increase
	Anti-Islanding	Percent of minimum load	≥ 50 %
	THDv	Total harmonic voltage distortion	≥ 5%

Calculating Hosting Capacity

The calculation of Hosting capacity is best explained via illustration as shown in Figure 2-1. The figure shows the maximum primary feeder voltage versus total PV penetration. Recall that when applying the hosting capacity method, a wide range of possible PV sizes and locations are simulated. For each simulation, the feeder response is recorded and then post-processed to determine if and when any criteria from Table 2-1 is violated. When analyzing overvoltage, the absolute highest voltage anywhere on the feeder is determined. Each marker in Figure 2-1 shows the absolute maximum primary feeder voltage for each unique PV deployment. Once the maximum voltages are determined, the results are then broken down into three regions (A-green, B-yellow, C-red) identified in the figure.

Region A includes PV deployments, regardless of individual PV size or location, that do not cause maximum primary voltages to rise above the ANSI 105% voltage threshold (threshold shown by horizontal red line).

At the start of Region B, the first PV deployment exceeds the voltage threshold. This PV penetration level is termed the **Minimum Hosting Capacity** because the total PV in the deployment is the lowest of those analyzed that cause adverse impact. At the same penetration level there are many PV deployments that do not cause an adverse impact due to more optimal sizes/locations of individual PV systems. Perhaps most of these PV systems are located in areas of the feeder where the voltage is low and there is more headroom, or closer to the substation where the feeder is stronger. As penetration increases further, more and more scenarios begin to cause further impact and eventually result in a violation. It is likely in these PV deployment scenarios that the PV is located further from the substation where the feeder is weak, or near a line regulator or capacitor bank and therefore has less headroom. The rightmost side of Region B defines the **Maximum Hosting Capacity** where all PV deployments, regardless of individual PV sizes or locations, cause primary voltages to exceed the threshold. This is the maximum penetration level that can be accommodated under the given feeder conditions. Region C identifies PV deployments that exceed the threshold regardless of individual PV sizes or locations. Aggregate PV of this magnitude will be problematic.

Feeder hosting capacity is the range indicated by Region B (yellow). This hosting capacity range depicts more/less optimal PV deployments. The minimum and maximum hosting capacity are metrics for determining the range of aggregate PV that can be accommodated on a feeder. The hosting capacity is similarly calculated for all issues shown in Table 2-1.

For the purposes of this Solicitation #4 analysis, the term hosting capacity refers to when 50% of the analyzed scenarios have a violation. This is the **Median Hosting Capacity** which occurs inside the yellow Region B. This quantification of hosting capacity depicts the average PV scenario. This metric of hosting capacity is used throughout the rest of the report to convey the impact of advanced inverters for a typical PV scenario (as compared to best/worst case PV scenario).

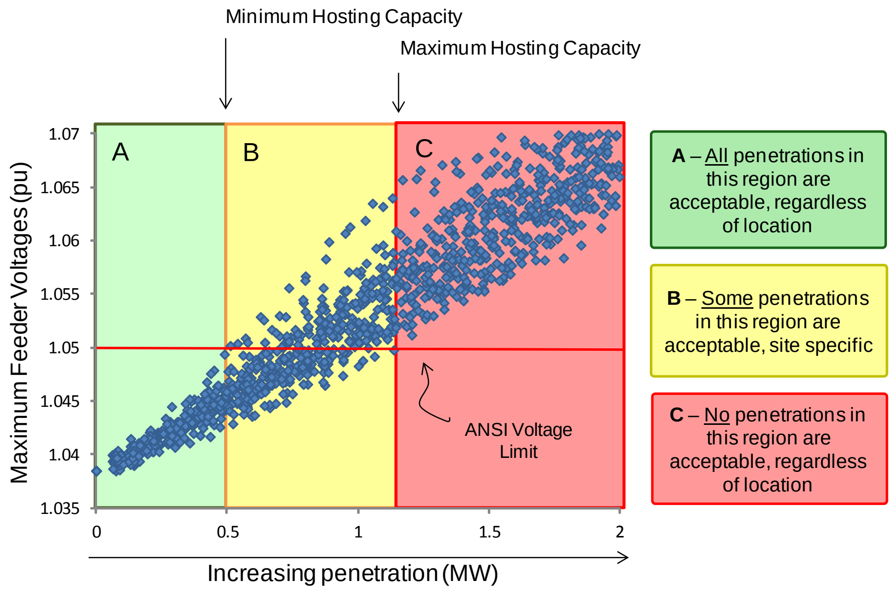

Figure 2-1. Example Calculation of Hosting Capacity

Feeder Characteristics and Hosting Capacity Results from the Previous CSI RD&D Solicitation #3 Project

How a feeder responds to photovoltaic generation is dependent on the individual feeder's characteristics. Although feeder characteristics are a key factor in the feeder response from distributed PV, additional factors include the PV size, location, and output. The distribution system connected PV will ultimately mold the overall feeder response. The main characteristics of each feeder analyzed in the previous CSI RD&D Solicitation #3 project are shown in Figure 2-2. The characteristics cover a range in values as indicated by the maximum and minimum values. All characteristics have an impact on feeder hosting capacity, however, not all are equally important.

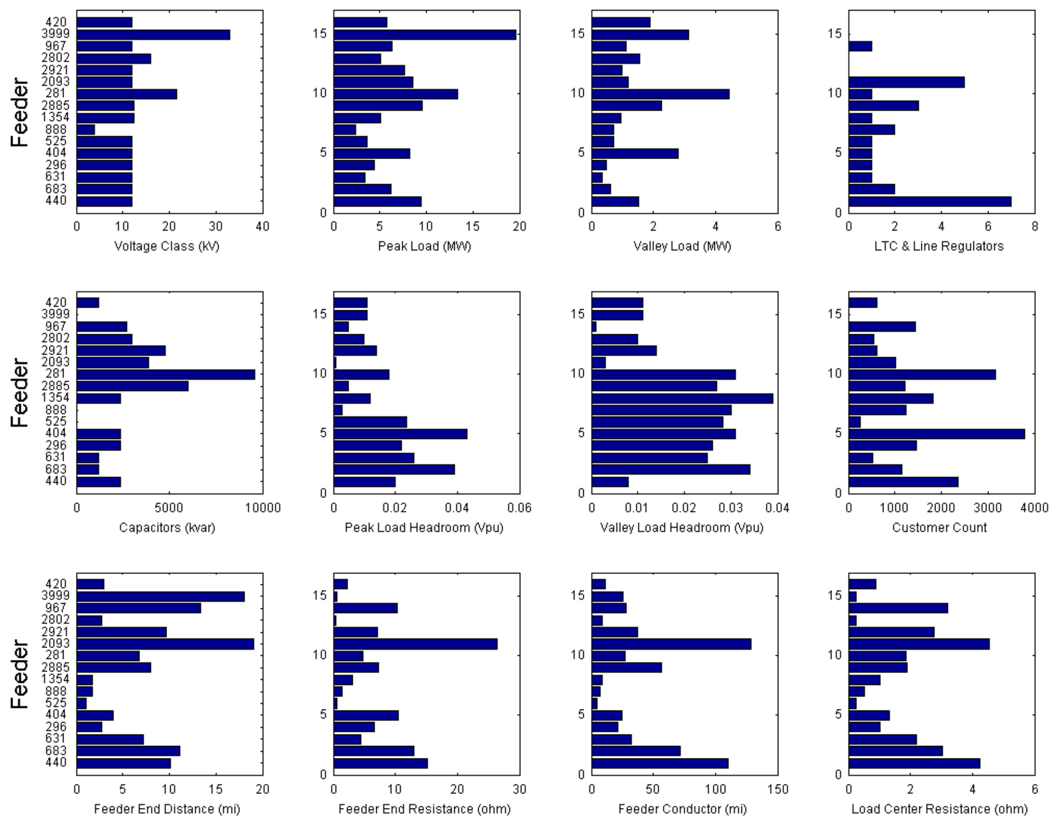

Figure 2-2. Characteristics of Analyzed Feeders in Previous CSI RD&D Solicitation #3 Project

Hosting Capacity Results

The hosting capacity method was applied to all 16 feeders. Hosting capacity values were calculated separately for each potential issue on each feeder. The primary issues used to identify aggregate feeder hosting capacity include:

1. Primary Overvoltage: If voltages might exceed ANSI limits
2. Primary Voltage Deviation: If the variable resource could impact sensitive equipment or cause unacceptable fast voltage fluctuations
3. Regulator Voltage Deviation: If additional tapping might occur
4. Secondary Voltage Deviation: If the variable resource could impact sensitive equipment or cause unacceptable fast voltage fluctuations
5. Secondary Overvoltage: If voltages might exceed ANSI limits
6. Sympathetic Breaker Tripping: If the breaker might inadvertently trip on ground current due to a parallel feeder fault
7. Breaker Reduction of Reach: If the breaker may lose visibility to remote feeder faults
8. Breaker/Fuse Coordination: If variable resource could cause mis-coordination between fuses and other automatic protection devices
9. Element Fault Current: If protection devices may need to be rated higher due to additional fault current

The feeders identified from each utility for modeling and analysis have been chosen based on their different characteristics – a goal of the clustering analysis. These characteristics inherently make each feeder more/less susceptible to impact from distributed generation. The range of impact based on issue specific hosting capacity is shown in Figure 2-3 for utility-class PV. Each colored region represents no issues (green), issues dependent upon PV location (yellow), and issues regardless of PV location (red)[12]. The maximum penetration analyzed for utility-class PV was based on the voltage class of the feeder (10/20 MW below/above 15 kV, respectively).

The range in hosting capacities for each feeder was due to the possible PV locations. In the analysis, the deployed PV could be located close to the start-of-circuit (i.e. the substation) or could be located in the extremities of the feeder. The key takeaway from this figure is that no two feeders have the same ability to accommodate PV without the need to modify the feeder or implement mitigation measures. This was expected based on the feeders chosen from clusters of different characteristics.

[12] Alternatives to the 15% Rule: Modeling and Hosting Capacity Analysis of 16 Feeders. EPRI, Palo Alto, CA: 2015. 3002005812.

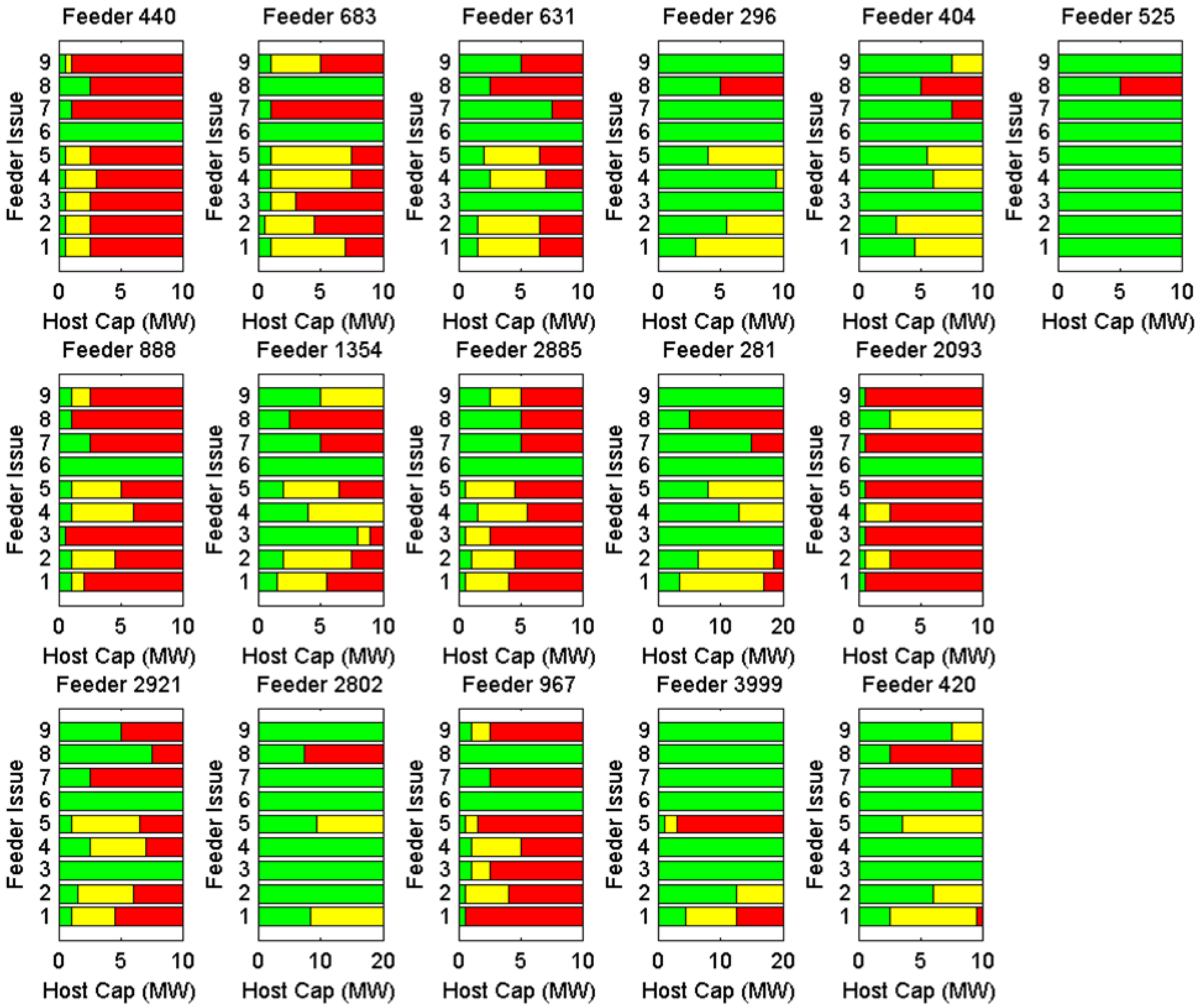

Figure 2-3. Detailed Hosting Capacity Assessment of 16 Feeders from CSI RD#D Solicitation #3 Project[13]

Summary

The detailed feeder analysis showed that the specific characteristics of the feeder under study had a significant influence on the impact from photovoltaics. The feeders analyzed for each utility cover a range in characteristics chosen to span the diverse set of feeders. Whether impact occurs, can be generalized based on the characteristics of the feeders chosen; however, the magnitude of impact cannot be determined based solely on those characteristics. How those characteristics interact dynamically within the model ultimately dictate the amount of PV that can be hosted (accommodated). For all feeders that have penetration limitations based on voltage issues, advanced inverters could be used as mitigation.

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[13] Alternatives to the 15% Rule: Final Project Summary. EPRI, Palo Alto, CA: 2015. 3002006594.

Advanced Inverter Analysis

Feeder Selection

Seven feeders needed to be chosen from those in Figure 2-3 for further analysis with advanced inverters. The selection criteria for those seven feeders included:

- Utility
  - 2-3 feeders from each utility
  - Each utility represented in the analysis
- Impact
  - 3 high impact / low hosting capacity feeders
  - 2 moderate impact / moderate hosting capacity feeders
  - 2 low impact / high hosting capacity feeders
- Voltage Class
  - Low/Medium/High
  - Majority of the feeders are in the 12 kV class
- Equipment
  - Certain equipment such as regulators have a direct relationship to low hosting capacity
  - Several feeders chosen have regulators

The final feeder selection is documented in Table 2-2.

Table 2-2. Characteristics of Seven Selected Feeders for Advanced Inverter Analysis

Feeder Name	Peak Load (MW)	Farthest 3-phase Bus (km)	PV Hosting Capacity	Nominal Voltage (kV)	Line Regs	Switching Caps
683	3.6	17.9	Low	12	1	1
631	3.4	11.7	Moderate	12	0	1
888	2.2	2.8	Low	4	0	0
2885	9.2	11.9	Low	12	1	6
281	16.7	10.3	High	21	0	6
2921	6.4	15.5	Moderate	12	0	6
420	5.0	4.7	High	12	0	1

Determination of Recommended Settings to Improve Distribution System Performance

One of the goals of the project was to provide guidance on the best (recommended) settings for the various types of advanced inverter controls that can improve the distribution system performance. Power factor, volt-var, and volt-watt control are applied to the seven feeders selected from the Solicitation #3 feeder analysis. Along with the feeders used in the Solicitation #3 analysis, the same PV deployments were also used. For the advanced inverter setting analysis, each of those PV deployments were modified with advanced inverter control. In that form, the feeder hosting capacity results from the advanced inverter analysis could be compared to the hosting capacity results from the baseline Solicitation #3 (unity power factor) analysis. Due to the additional complexity of looking at various advanced inverter settings, the scope of the Solicitation #3 project was reduced to

- Utility-scale PV
- Midday Peak and Midday Offpeak loading
- Voltage issues

The desire was to find the optimal setting for each of the control types that works on each of the various feeders. However, just as hosting capacity is dependent on the specific feeder, the best settings for each of the control types also are dependent on the type of feeder.

The concept of varying benefit from different control settings is easily demonstrated in the application of global power factor settings. The 11 unique inductive power factor settings shown in Figure 2-4 are applied to each of the PV systems in each of the PV deployments for Feeder 888. The more inductive the setting is, the higher the hosting capacity on the feeder becomes based on primary overvoltage. However, the inductive nature of the PV system can begin to overcompensate the voltage change from PV real power and thus reduce hosting capacity based on primary undervoltage.

Based on improvement of the median hosting capacity of the feeder, the optimal setting for Feeder 888 would appear to be near 0.97 as shown in Figure 2-5. That setting is not always the most optimal as illustrated in the results for Feeder 2885. Based on different feeder characteristics and the impact from real and reactive power, the most optimal setting changes. This result is the driving factor behind NOT providing a single recommended setting in this analysis, however, only providing recommended methods in which the best settings can more easily be determined.

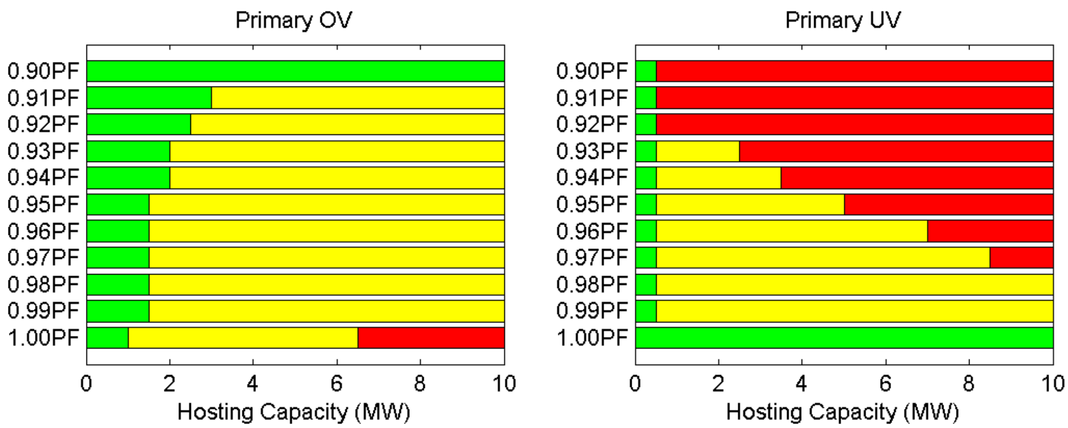


Figure 2-4. Hosting Capacity of Feeder 888 Based on Over/Under-Voltage with Power Factor Settings

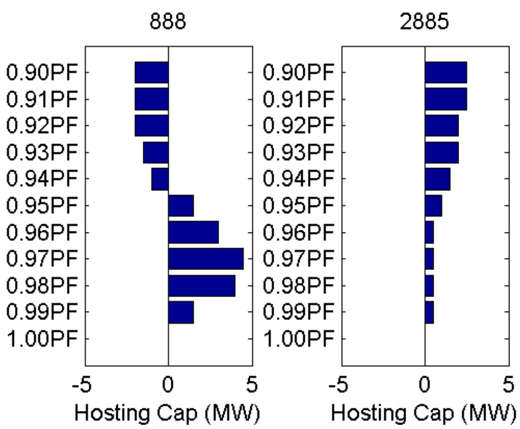


Figure 2-5. Increase in Median Hosting Capacity (Compared to Unity Power Factor) on Two Feeders

The methods that will be discussed in the following chapter are briefly described in Table 2-3. These methods include various levels of complexity. The various levels are designed to work with different input data and simulation resources. The lower level methods could be applied with little to no feeder information and spreadsheet tools, while higher levels require more detailed information and software tools to determine exact settings. Higher level settings were sought to further improve distribution system response as shown in Figure 2-6.

Table 2-3. Basic Details of Methods to Determine Advance Inverters Settings

Level	Complexity	Power Factor	Volt-var	Volt-watt
0	None	Unity Power Factor	Disabled, Unity Power Factor Applied	Disabled, Unity Power Factor Applied
1	Low	Based on Feeder X/R Ratio	Generic Setting	Generic Setting
2	Medium	Based on Feeder Model and PV Location	Based on Feeder Model and PV Location	Not Analyzed
3	High	Based on Feeder Model and PV Location	Based on Feeder Model, PV Location, and Service Transformer Impedance	Not Analyzed

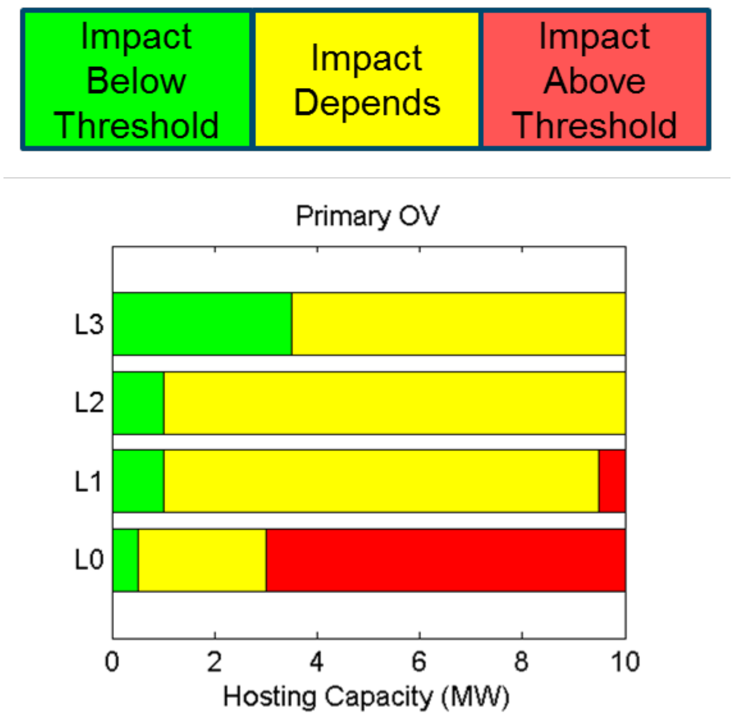
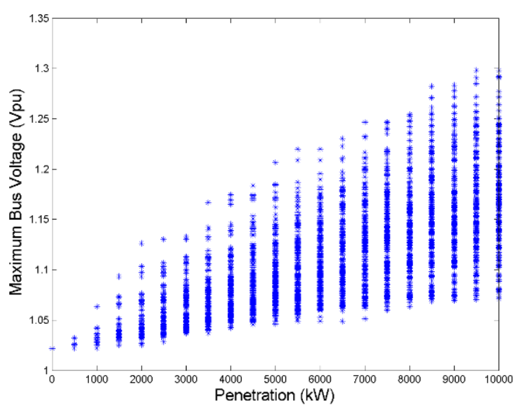


Figure 2-6. Benefit from more Complex Methods to Determine Settings

3
METHODS TO DETERMINE DISTRIBUTION FOCUSED SETTINGS

The methods derived in this analysis are geared around improving the distribution system response from PV. One way to quantify the impact to the distribution system is to observe the benefit the advanced inverter could provide in terms of hosting capacity. The primary distribution system benefit targeted in this analysis is that to system voltage. As shown in Figure 3-1a, the higher levels of penetration from distributed PV can increase the voltage on the system if advanced inverters are not utilized. Each marker in the figure illustrates the maximum voltage from a specific PV deployment. Each deployment may consist of one to twenty individual PV systems. As shown in Figure 3-1b, there are settings that can prevent voltage rise however, at high penetration can start to overcompensate the voltage change. Note: different y-axis scales in the figure.

The main focus of each of the methods is to minimize the voltage change occurring from increased levels of PV. The impact on voltage deviation inherently includes impact on the absolute voltage magnitudes at the primary, secondary, and voltage regulation nodes on each feeder.

a)


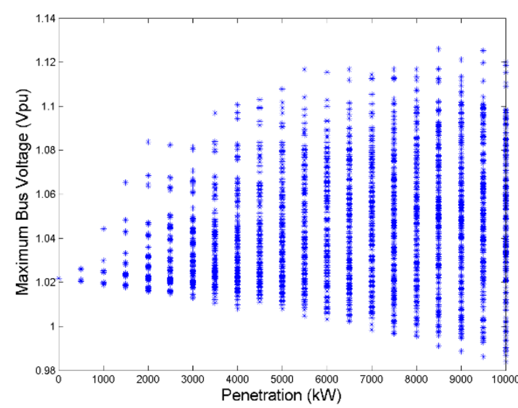
b)


Figure 3-1. Detailed Voltage Response for a) Unity Power Factor b) Inductive Power Factor

Inverter Functions to Improve Distribution System Hosting Capacity

The three main advanced inverter functions targeted for this analysis are:

- Power Factor – Inductive output based on the real power generated
- Volt-Var – Inductive or capacitive output based on the voltage at the PV inverter
- Volt-Watt – Maximum real power output based on the voltage at the PV inverter

Each of these functions can have a direct impact on the operation of the distribution system. Additional advanced inverter functions such as Frequency-Watt, Voltage Ride-Through, and

Frequency Ride-Through have a more direct impact on the bulk power system and therefore those functions are discussed separately in this report.

For each of the advanced inverter functions considered for distribution system impact, multiple methods are developed in order to determine settings based on the data and tools readily available to the distribution engineer. This has been done to be cognizant of how distribution planning engineers have to cope with various levels of data and resources available to them for examination.

Locational Impact on Inverter Settings

The location of DER along a distribution system can impact what smart inverter function and setting is most appropriate. As the resistance of the distribution system determines the voltage rise from DER active power output, the reactance of the distribution system determines the effectiveness of var control to help prevent the voltage rise. The equivalent resistance (and reactance) also varies along a distribution system from one point on the distribution to another.

This point is illustrated in Figure 3-2a where the X/R ratio (ratio of reactance to resistance) at all medium-voltage points along the feeder is shown. Near the feeder substation, the X/R ratio is predominantly driven by the highly reactive substation transformer and transmission system. Because distribution feeder conductors and cables are mostly resistive by nature, the effective X/R ratio begins to drop rather quickly the further from the substation.

A simple calculation can be used for estimating the amount of reactive power needed to regulate the voltage at a given point and mitigate the voltage rise induced by the active power injection.

$$Power\ Factor = \frac{\frac{X}{R}}{\sqrt{\left(\frac{X}{R}\right)^2 + 1}}$$

Using this equation, the corresponding DER power factor needed at each point along the feeder to regulate the voltage is shown (Figure 3-2b). Observable from this graphic one can easily deduce that just beyond the mid-point of the feeder, a power factor of less than 0.9 would be required in order to prevent voltage rise from the DER.

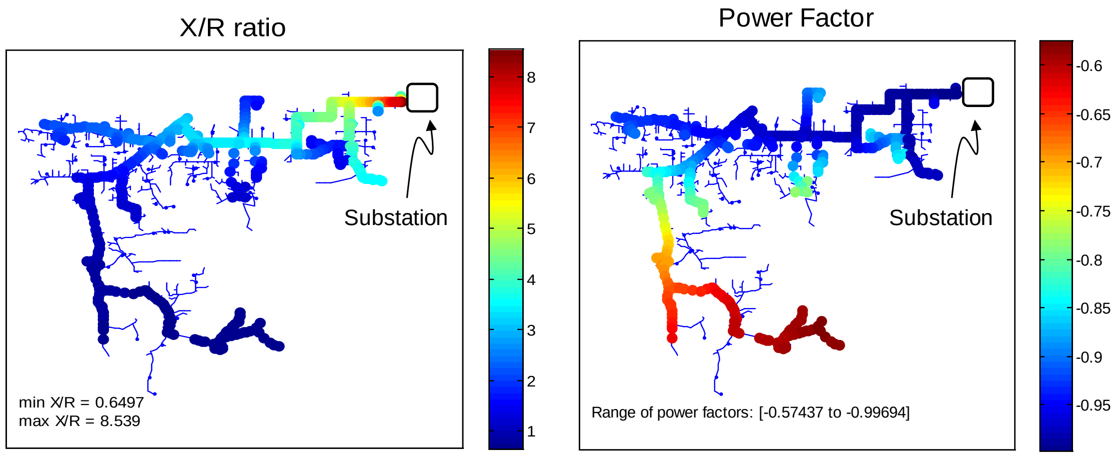


Figure 3-2. Distribution Feeder X/R Ratio (A) and Associated Power Factor (B) to Mitigate DER Voltage Rise

This point is further illustrated in Figure 3-3 that divides the feeder into three representative zones. A description is provided for each of these zones.

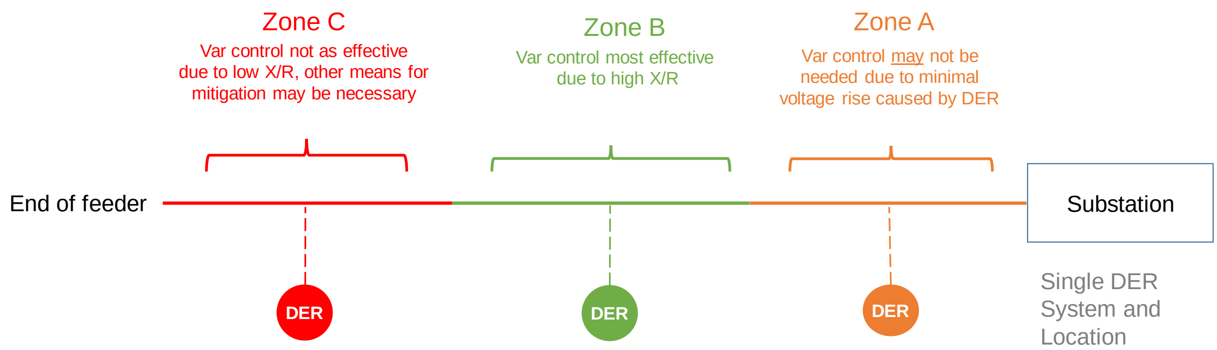


Figure 3-3. Distribution Feeder Regions Where DER Var Control is Most or Less Effective

Zone A

- The X/R ratio is relatively high near the substation
- The actual impedance (resistance) is still relatively low and PV is less likely to actually raise the voltage significantly
- The use of reactive power control is likely not needed to prevent voltage rise.

Zone B

- The impedance (resistance) of the distribution system has increased and the PV system is more likely to cause voltage rise.
- The X/R ratio is still high enough such that reasonable levels of reactive power control can help mitigate the voltage rise.
- The use of reactive power control to mitigate voltage rise from DER is most effective.

Zone C

- The greatest amount of impedance (resistance) is located further from the substation.
- Zone spans from where the X/R ratio = ~1.7 (associated with DER power factor of 0.9) to the end of the feeder.
- The PV has a high probability of causing higher changes in voltage.
- The feeder resistance has increased such that X/R ratios have decreased considerably.
- If DER reactive power were required to mitigate voltage rise in this region, a power factor below 0.9 would be required.
- As a result of increased losses due to low power factors, it is recommended that other solutions be utilized to mitigate voltage rise. These solutions could consist of
  - Volt/watt control (active power curtailment)

- Volt/watt control in combination with some level of reactive power control
- Traditional grid reinforcement measures (reconductoring, etc.)

To illustrate the unique X/R characteristics of distribution feeders as well as provide insight regarding where reactive power control will and will not be effective to mitigate voltage rise from DER, the test feeders used in this study are examined. For all nodes within the distribution feeder models, the X/R ratio is calculated. A box-and-whisker plot of this information is shown in Figure 3-4. This plot shows the minimum and maximum values, as well as the median (50%) and quartiles (25% and 75%). As shown in this graphic, the median point along the feeder is near or below the 50% mark. For example, for feeder 631, approximately 50% of the feeder nodes are in Zone C and have an X/R ratio below 1.8. For five of the seven feeders, the critical breakpoint between Zone B and C occurs at or around 50% of the nodes on each of the feeders.

In other words, for approximately 50% of the nodes on five of the seven feeders test feeders, additional mitigation beyond var control will likely be required to prevent voltage rise from PV at those locations.

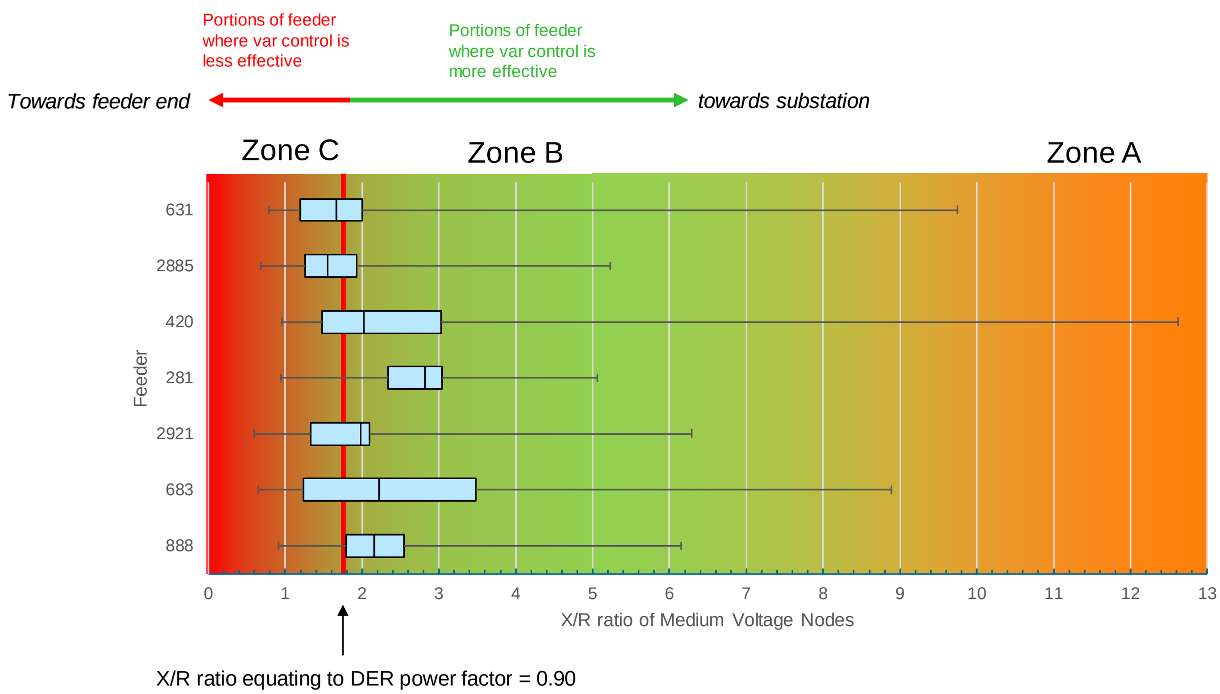


Figure 3-4. Study Feeder X/R Ratios

One might be inclined to develop rules-of-thumb regarding distance from substation in order to determine what power factor is needed however this would be erroneous as different feeders have different construction types, conductors, and configurations that all impact the effective impedance (and X/R) seen at all points along the feeder. The most effective means for determination are through normal distribution feeder models that take these characteristics into consideration.

Reactive Power Capability and Performance Categories in IEEE P1547

In order to account for the locational impact on inverter settings as well as different DER technology capabilities, IEEE P1547 is proposing categories for voltage regulation performance and reactive power capability requirements. The Authority Having Jurisdiction (AHJ) would then assign one of the following two normal operating performance categories to specific DERs:

- **Category A:** covers minimum performance capabilities needed for Area electric power system (EPS) voltage regulation and are reasonably attainable by all state-of-the-art DER technologies. This level of performance is deemed adequate for applications where the DER penetration in the distribution system is lower, and where the DER power output is not subject to frequent large variations.

- **Category B:** covers all requirements within Category A and specifies supplemental capabilities needed to adequately integrate the DER in local Area EPS where the DER penetration is higher or where the DER power output is subject to frequent large variations.

Table 3-1 shows the minimum reactive power injection and absorption capability as proposed in IEEE P1547 Draft 5 (August 2016).

Table 3-1. Minimum reactive power injection and absorption capability as proposed in IEEE P1547 Draft 5 (August 2016)

Normal Operating Performance Category	Injection (Over-Excited) Capability as % of Nameplate Apparent Power (kVA) Rating	Absorption (Under-Excited) Capability as % of Nameplate Apparent Power (kVA) Rating	Applicable Voltage Range
A	44	25	DER rated voltage
B	44	44	ANSI Range A

To deal with power quality issues caused by increasing DER penetration, especially of variable-generation DER, the majority of the DER should have Category B performance. However, DER connected to a point of common coupling (PCC) that is relatively close to the substation as well as non-variable-generation DER may have less impact on the distribution system voltage than DER that are connected close to the end of a feeder or DER with power output that is subject to frequent large variations. In those cases, it is reasonable to interconnect a limited amount of DER capacity that is limited to Category A voltage regulation performance and reactive power capability.

When making the assignment of performance categories to DER types, it is recommended that the AHJ consider the following questions:

1. Is it impractical for the given DER type to be designed to meet Category B?
2. Is the power output of the DER constant and not subject to frequent large variations?

3. Is the rating of the DER, relative to the distribution system short-circuit strength at the point of common coupling, small such that the DER does not have significant impact on distribution voltage?

4. Is the projected penetration of all DER types allowed to interconnect with Category A capability and performance relatively small compared to the total load level on the particular feeder?

Depending on the answers to these questions the assignment of performance Category A to the particular DER type grouping may be appropriate from the standpoint of power quality issues caused by increasing DER penetration. In certain cases, however, the AHJ might consider imposing higher levels of voltage regulation performance and reactive power capability requirements, but may also consider the overall benefit to impact ratios.

Particularly in areas of high DER penetration and where the predominant DER types involve inherent power output variability (e.g., solar PV), requirements for DER to meet Category B performance may be necessary.

Power Factor Control

Power factor control, volt-var control, and volt-watt control are several common grid support functions targeting voltage issues at the distribution level. Among them, power factor control is the most commonly used function. Nearly all large three-phase PV systems interconnecting to the grid have power factor control capability, and vendors for smaller single-phase units are adopting this capability as well.

Determining appropriate settings is critical to ensure the inverter provides the anticipated response. If appropriate inverter settings are chosen, one or multiple PV systems can mitigate the voltage impacts caused by the active power injection. The method to determine the power factor setting for a single PV system is easily understood and well documented[14] using the detailed feeder model, yet the method for multiple PV systems can quickly become more complex[15]. Table 3-2 lists three methods growing in complexity to calculate power factor settings for single or multiple PV systems on a feeder.

In the derivation of these methods, it has been assumed that the PV system inverters have the capability to provide the necessary reactive power at all times. Analysis follows recommended oversizing of the inverter by 10%. The other option instead of oversizing the inverter (to make sure that reactive power is available from the inverter) would be to have the inverter operate allowing reactive power to have priority over active power when the device becomes constrained due to its KVA rating. Inverters operated under an active power priority scheme would not allow reactive power to be used to mitigate voltage issues when the device is operated at its rating.

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[14] J.-H. Im and S.-H. Song, "Calculation and compensation of PCC voltage variation using a grid connected inverter of a wind turbine in a weak grid," in 31st International Telecommunications Energy Conference (INTELEC), 2009.

[15] A. Samadi, R. Eriksson, L. Soder, B. G. Rawn, and J. C. Boemer, "Coordinated Active Power-Dependent Voltage Regulation in Distribution Grids With PV Systems," IEEE Transactions on Power Delivery, vol. 29, 2014.

Table 3-2. Summary of Power Factor Calculation Methods for Multiple PV Systems

Level #	Method	Calculation Method	Data Requirements	Grid Performance	Power Factor Setting
L1	Mean Feeder X/R	Hand calculation	Mean primary node X/R on feeder	Limited improvement based on actual DER location.	Single Setting on each feeder
L2	Weighted Average X/R @ PV Location	Spreadsheet calculation	Primary node X/R, feeder voltage profile, and PV size/location	Effective for single PV system. Limited improvement for multiple PV systems	Few Settings on each feeder
L3	Sensitivity-Based Algorithm	Algorithm using iterative load flows	Detailed load flow model with PV size/location	Effective approach for single or multiple systems	Customized setting for each PV system

Level 1

The Level 1 method is a simple estimation that applies the mean X/R ratio of a feeder to calculate a single power factor setting for the whole feeder. Although that single setting may not always be very effective, the mean X/R ratio based method provides a quick and simple estimation with limited information.

Setting

Level 1 method does not require PV location information. All PV systems on the feeder will have the same power factor setting which is calculated as:

$$pf \cong \frac{\left({}^{X}/_{R}\right)_{mean}}{\sqrt{\left(\left({}^{X}/_{R}\right)_{mean}\right)^{2} + 1}}$$

Where X and R are the reactance and resistance to the primary node, respectively, and pf is the resultant power factor. The applied X/R ratios can be further adjusted by incorporating standard interconnect transformer percent load loss at full load (%loadloss) and percent reactance (XHL) as in:

$$\frac{X}{R} = -\frac{X}{R} - \left[\left(\frac{\%loadloss}{100}\right) + \frac{X}{R}\left(\frac{XHL}{100}\right)\right]\sqrt{1 + \left(\frac{X}{R}\right)^{2}})$$

The procedure to determine the power factor setting is based on:

- Calculate X/R ratio to all three-phase primary nodes on the feeder, adjust ration for typical interconnect transformer losses, and then determine the mean of those X/R ratios.
- If the calculated power factor setting is below 0.9, set it to 0.9. This threshold value can be higher/lower. The assumed 0.9 power factor threshold is based on oversizing inverters by approximately 10% and thus not exceeding inverter limits during full active power output.

- Optional: PV systems that induce minimal voltage impact (less than 1% voltage rise at its point of interconnection with unity power factor) can be set to unity power factor. This primarily applies to large PV systems. Note – This is not applied in this study.

Basis

- One single setting that can be applied to all PV systems on a feeder
- Limited feeder information is needed
- Mean as opposed to Median X/R is used since the ratio tends to exponentially decrease along a feeder. Mean ratio would tend to result in slightly higher power factors.
- Setting is independent of load location
- Setting can be applied to large or small PV
- Settings do not change as new PV is installed

Level 2

If the sizes and the locations of the PV systems are known, the Level 2 method uses the PV size-weighted average X/R ratio to all the PV systems to calculate a single power factor setting. This method provides the effective setting for a single PV system, however, similar to the Level 1 method, the weighted average X/R based method is only an approximation for multiple PV systems.

Setting

The weighted X/R ratio of all PV systems can be used to calculate the power factor setting as in:

$$pf \cong \frac{\left({}^{X}/_{R}\right)_{weighted}}{\sqrt{\left(\left({}^{X}/_{R}\right)_{weighted}\right)^2 + 1}}$$

where the applied X/R ratios are adjusted by incorporating the known interconnect transformer percent load loss at full load (%loadloss) and percent reactance (XHL) as in:

$$\frac{X}{R} = -\frac{X}{R} - \left[\left(\frac{\%loadloss}{100}\right) + \frac{X}{R}\left(\frac{XHL}{100}\right)\right]\sqrt{1 + \left(\frac{X}{R}\right)^2})$$

The procedure to determine the power factor settings is based on:

- Calculate the weighted average X/R ratio based on the X/R ratio to all PV systems on the feeder after adjusting the X/R ratio for the known interconnect transformers. The weighting is based on the size of the PV systems. Therefore, if there are two PV systems, the settings would be more strongly influenced by the X/R ratio to the larger system.
- If the calculated power factor setting is below 0.9, set it to 0.9. This threshold value can be higher/lower. The assumed 0.9 power factor threshold is based on oversizing inverters by approximately 10% and thus not exceeding inverter limits during full active power output.
- Optional: PV systems that induce minimal voltage impact (less than 1% voltage rise at its point of interconnection with unity power factor) can be set to unity power factor and

excluded from the weighted average power factor calculation. This primarily applies to large PV systems. Note – This is applied in this study.

Basis

- The power factor setting is based on where the PV is electrically centered on the feeder
- Only one setting is applied to all systems unless an individual PV system's power factor was set to unity
- Settings would need to be periodically updated when new systems come online

Level 3

The Level 3 method is the most complex but also the most effective by using a sensitivity analysis to determine the voltage deviations from power factor settings. This method requires the feeder model and the PV systems size and location to perform the calculations.

Setting

The sensitivity-based method approximates the aggregate impacts from all the PV systems on the voltage deviation of a particular node by linearization as shown in Figure 3-5 and the following equations.

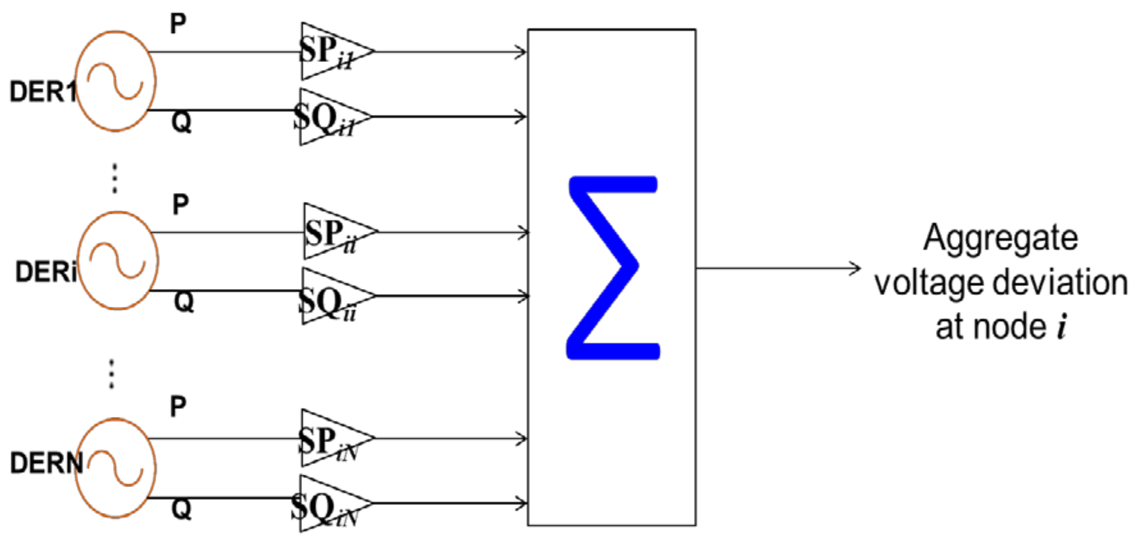

Figure 3-5. Linearization of Aggregate Impacts on Voltage Deviation

The sensitivity factors SP_{ij} and SQ_{ij} are defined as

$$SP_{ij} = \frac{\Delta V_{ip}}{\Delta P_j}, SQ_{ij} = \frac{\Delta V_{iQ}}{\Delta Q_j}$$

where ΔP_j is the active power change of the PV at node j and ΔV_{ip} is the resulting voltage change at node i due to ΔP_j. SQ_{ij} is defined in the similar way. SP_{ij} and SQ_{ij} are the sensitivities of voltage at node i with respect to the active power and reactive power of the PV at node j.

The voltage change at node i caused by the PV at node j can be expressed as the sum of SP_{ij} times the PV active power and SQ_{ij} times the PV reactive power as in

$$\Delta V_i = SP_{i1}\Delta P_1 + SQ_{i1}\Delta Q_1 + \cdots SP_{iN}\Delta P_N + SQ_{iN}\Delta Q_N$$

The total voltage change at node *i* caused by multiple PV systems on the feeder can be expressed where *N* is the number of the PV systems connected on the feeder.

The voltage change at each PV primary node can be formulated as

$$\Delta V = SP * P + SQ * Q$$

where $\Delta V = [\Delta V_1, \Delta V_2, \ldots, \Delta V_N]^T$; $P = [P_1, P_2, \ldots, P_N]^T$; $Q = [Q_1, Q_2, \ldots, Q_N]^T$; *SP* and *SQ* are sensitivities matrices composed of SP_{ij} and SQ_{ij} respectively.

The objective is to mitigate the voltage deviations:

$$min \sum_{i=1}^{N} \Delta V_i^2$$

If the power factor of the PV is limited, the constraint can be expressed as:

$$\left|\frac{Q_i}{P_i}\right| \leq a$$

where *a* can be derived from the power factor limit. So far, the voltage deviation mitigation has been mathematically formulated as a nonlinear optimization problem. And the power factor setting for each PV system can be easily calculated once the reactive power variables are solved through the optimization.

Basis

- The interaction of all PV systems with power factor settings is best determined through system analysis
- The optimization procedure expedites that calculation of settings rather than running through an infinite number of combinations
- Each system has a unique setting that will change as new PV systems come online

Volt-var Control

The advanced inverter with the volt-var control function can mitigate voltage rise, and when set properly, will only activate when necessary. Another advantage of the volt-var control is that it can operate as both inductive and capacitive. Several methods to determine volt-var control settings are presented that offer advantages in a variety of feeder conditions. In the derivation of these methods, it has been assumed that the advanced inverters have the capability to provide the necessary reactive power at all times.

Level 1

This is a default benign setting suggested by the IEEE1547 working group and analyzed through time-series analysis[16] that could be applicable in any feeder/PV scenario. The primary objective of a default volt-var setting is to help mitigate unacceptable voltage conditions either caused by the PV or the existing voltage condition of the feeder. The mitigation includes both minimizing overvoltage conditions and, in the case of variable generation such as solar and wind, minimizing the voltage variations.

Setting

The interconnect voltage determines the output of the advanced inverter as show in Figure 3-6. Details of the control include:

- Inside the deadband (0.98 Vpu to 1.02 Vpu) the inverter would effectively provide no reactive power
- Outside of the deadband the inverter is importing/exporting reactive power based upon the feeder average voltage
- At ANSI range of 1.05 Vpu and 0.95 Vpu, 22% of kVA rating is demanded
- Maximum reactive power demand would only occur with voltages at/below 0.92 Vpu or at/above 1.08 Vpu
    - The maximum reactive capacity correlates to +/- 0.9 power factor at full real power output. This correlates to 44% of the inverter's kVA rating based on the inverter being oversized by 10%
    - Oversizing the inverter more/less would impact the values applied

Basis

- Benign setting allows low reactive demand within ANSI limits
- Wide dead band reduces the need for reactive power when voltage is within the tolerance
- Single setting for all systems on feeder reduces the chance of interaction between inverters

[16] Analysis to Inform CA Grid Integration: Methods and Default Settings to Effectively Use Smart Inverter Functions in the Distribution System. EPRI, Palo Alto, CA: 2015. 3002007139.

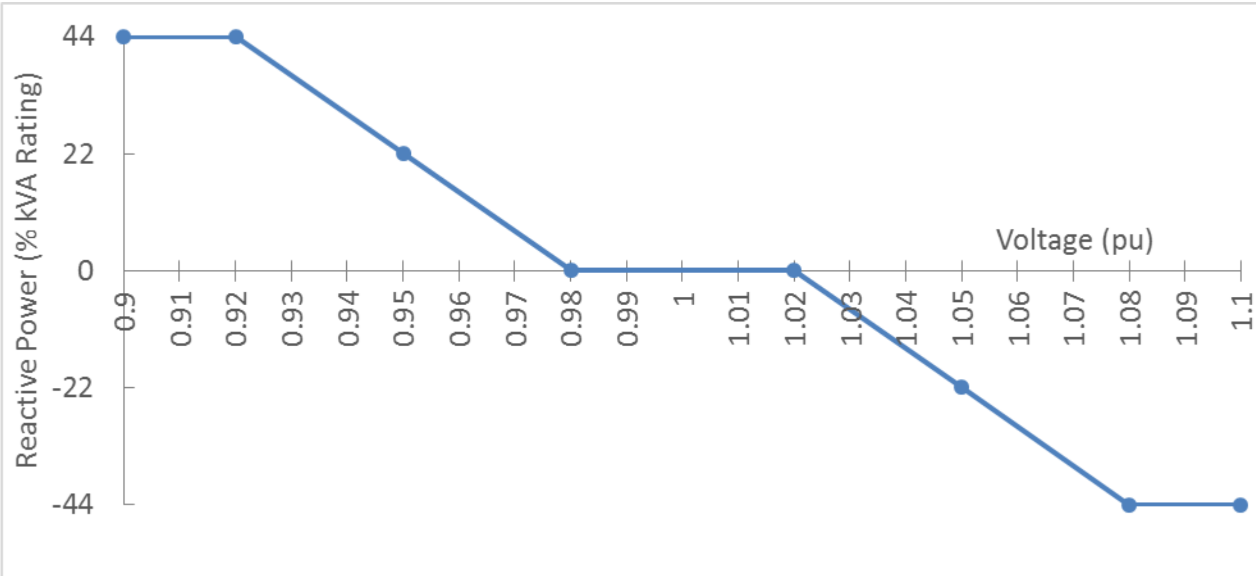

Figure 3-6. Level 1 Volt-var Setting

Level 2

The Level 2 method provides a feeder specific setting. There are two options for the Level 2 setting based on the distribution feeder voltage profile. Based on the feeder voltage profile for midday peak and midday minimum load conditions, the distribution planner will determine which Level 2 option to apply.

Setting

- The maximum voltage of all primary nodes on a feeder during midday peak load are determined
  - If a node has multiple phases, the average of the individual phase voltages is considered.
- The maximum voltage of all primary nodes on a feeder during midday minimum load are determined
  - If a node has multiple phases, the average of the individual phase voltages is considered.
- The average of the two maximum values for the two load conditions is calculated and the value (V_{max}) is used to determine the volt-var option to apply

Option 1: Feeders with V_{max} >1.02

Option 1 implies that the feeder voltage profile may be approaching the upper ANSI limit. On such a feeder, there will be two regions based on the average node voltages i.e. "Region A" and "Region B" as shown in Figure 3-7.

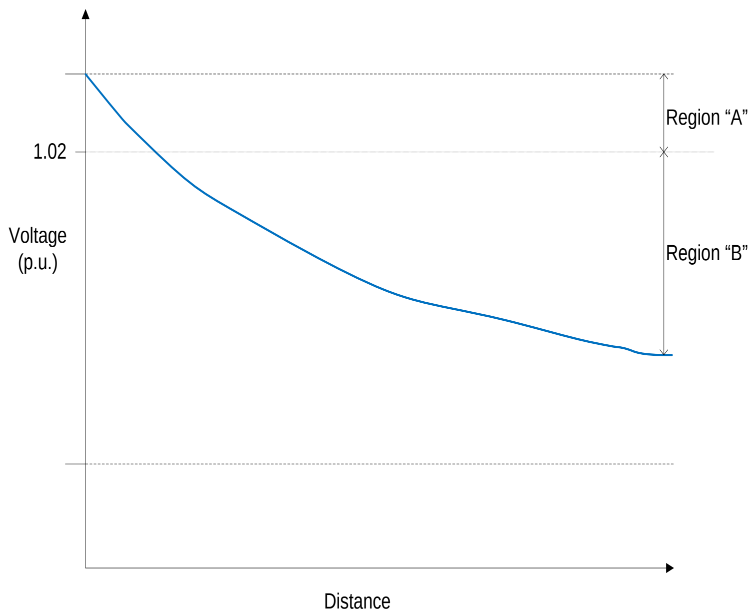

Figure 3-7. Example of Feeder with V_{max} > 1.02 Vpu

If the inverter's average primary node voltage is in Region A, then the Region A curve shown in Figure 3-8 is applied. This curve is the same as the Level 1 setting. The idea is that nodes with high voltages may be near the head of the feeder where benefit from reactive power is minimal.

If the average primary node voltage is in Region B, then the Region B curve shown in Figure 3-8 is applied. These locations are usually at higher impedance and can benefit more from additional reactive power.

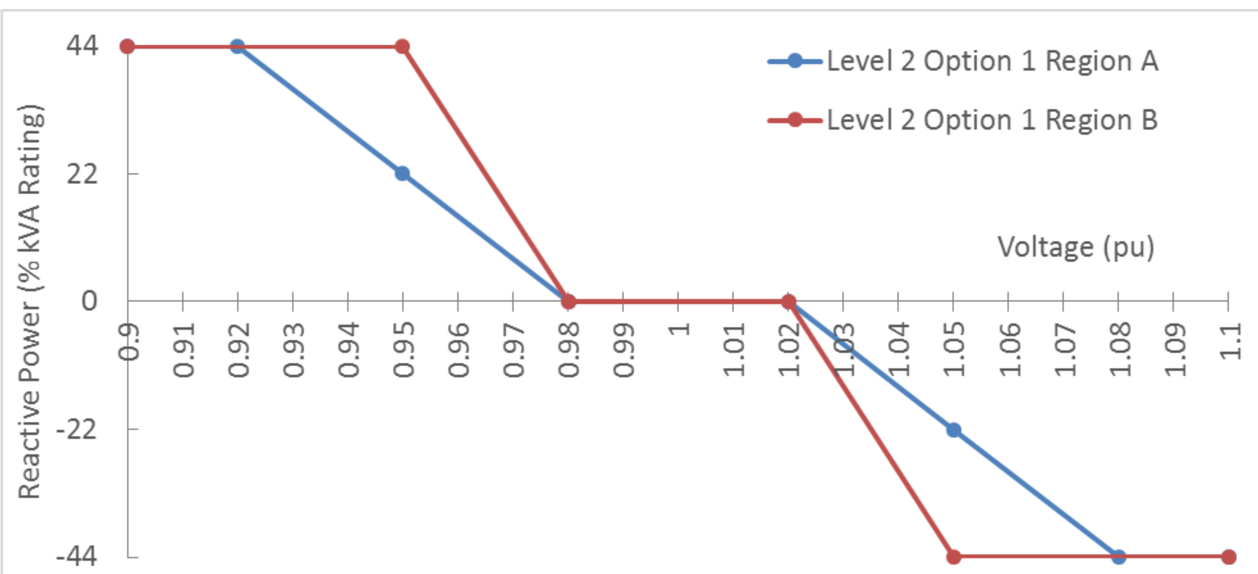

Figure 3-8. Level 2 Option 1 Region A and Region B Settings

Option 2: Feeders with V_{max} <= 1.02

Option 2 implies that the feeder voltage profile is well below the upper ANSI limit. Feeders of this type may have relatively flat voltage profiles as shown in Figure 3-9. These feeders may not typically have node voltages operating in the inductive region of the default Level 1 volt-var setting. Thus for the control to have more effectiveness at reducing voltage deviations, the deadband is adjusted as illustrated in Figure 3-10. The upper deadband voltage (V_{UDB}) can be reduced based on the maximum of 1.0 Vpu and V_{max}. The lowest the upper deadband can go is 1.0 Vpu to maintain a minimum 2% deadband.

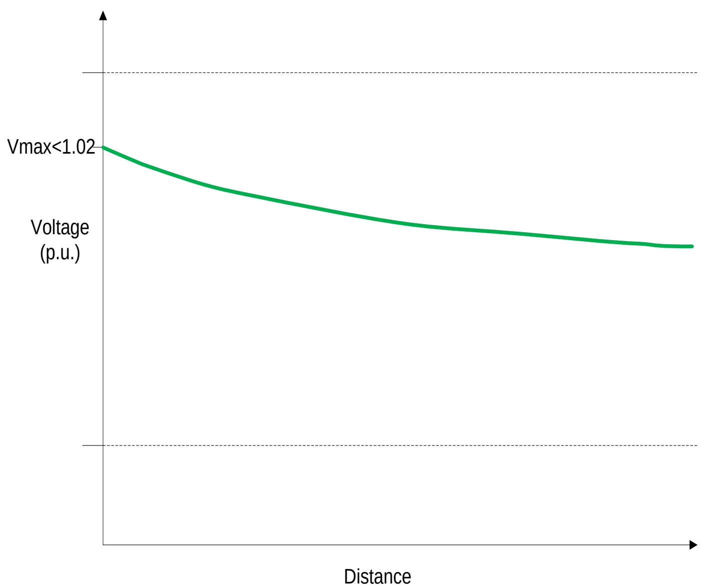

Figure 3-9. Example of Feeder with V_{max} <= 1.02 Vpu

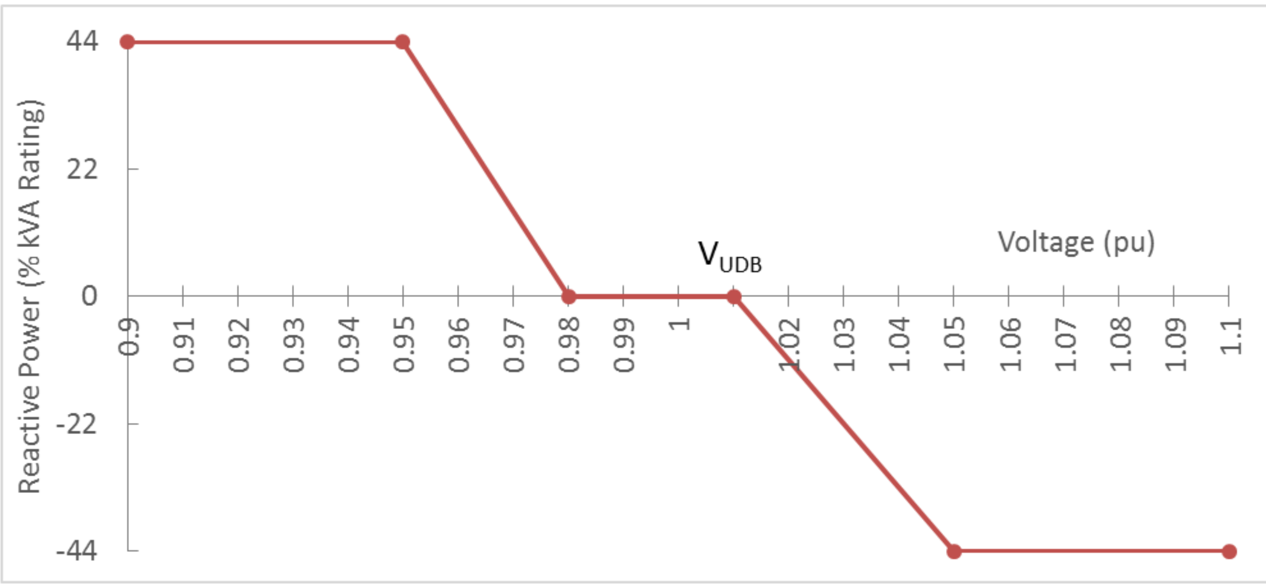

Figure 3-10. Level 2 Option 2 Settings

Basis

- Settings are adjusted based on the feeder specific voltage profile
- More effective use of reactive power by not requiring reactive power from PV at locations that cannot influence voltage
- More aggressive demand for reactive power where the system is weaker

Level 3

The Level 3 method transforms the Level 2 volt-var setting based on the impedance of the interconnect transformer. Conceptually, this is the same as applying the Level 2 setting (and reactive power requirement) based on the voltage at the medium-voltage side of the interconnection transformer.

Setting

The Level 2 setting will be transferred over the interconnection transformer by modifying each of the four points marked in the example of Figure 3-11. For the example setting, the third point should have a voltage of 1.02 pu on the high side of the interconnection transformer when there is no reactive power output from the PV inverter. Assuming full power output, the voltage can be calculated on the PV side. This can be calculated as:

- Assuming, full output of 500kW PV system with 1000kVA interconnection transformer
- Using the 1000kVA transformer as the power base
- Real Power (P) injection = 0.5 pu
- R is the per unit resistance of the transformer = 0.006726
- The voltage change across the transformer $V_{PV} - 1.02 = \frac{P}{V_{PV}} * R$
- ${V_{PV}}^2 - 1.02 * V_{PV} - P * R = 0$
- $V_{PV} = \frac{1.02 + \sqrt{1.02^2 + 4 * P * R}}{2} = 1.0233$

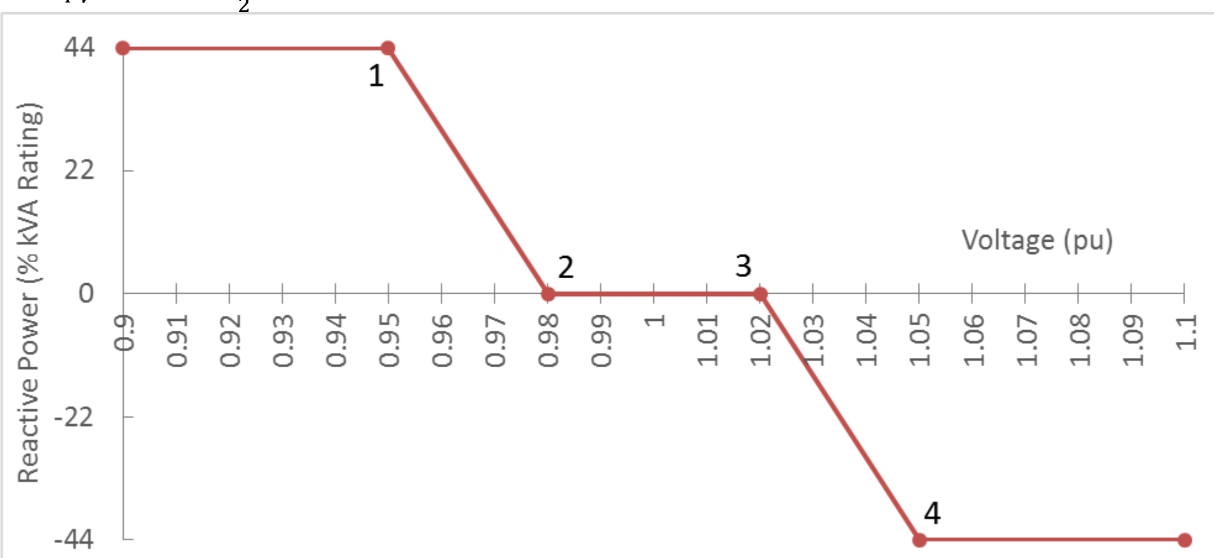

Figure 3-11. Example Volt-Var Curve

The same method can be applied for each of the other points on the graph. For the second point (0.98, 0), the PV is still assumed to be at full power output with no reactive power output. For the fourth point (1.05, -44), the reactive power is being absorbed to equal 0.9 power factor, and the voltage on the other side of the transformer should be 1.05 Vpu. For the first point (0.95, 44), the reactive power is being injected to equal 0.9 power factor and the voltage on the other side of the transformer should be 0.95 Vpu.

Another major problem for transforming the volt-var curve across the interconnection transformer is voltage unbalance on the medium-voltage system. For voltage unbalance standards, the phase voltage must be within 0.03 Vpu of the average voltage. This means that for an average voltage of 1.05 Vpu on the medium voltage side, there could be a phase voltage of 1.08 Vpu. In order to build some cushion into the volt-var curve for voltage unbalance, maximum and minimum setpoints are moved in away from the ANSI limits by 0.01 Vpu. The volt-var curves are shown in Figure 3-12 with the original volt-var curve applied to the medium-voltage side and then transformed to the low-voltage side.

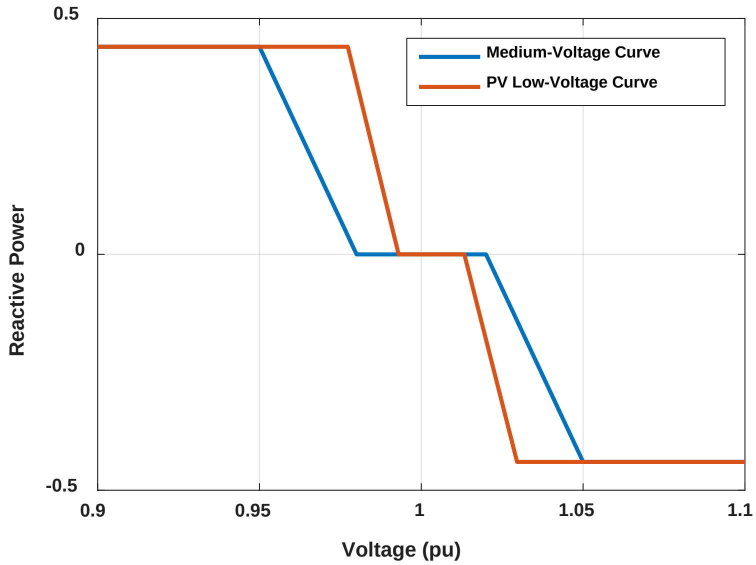

Figure 3-12. Original and Adjusted Volt-var Curve

Basis

- Settings are adjusted based on the feeder specific voltage profile
- Settings are further adjusted to account for the interconnect transformer (similar to power factor methods)
- Inverter operates on setting that would mimic reactive power output based on primary node voltage
- Setting inherently becomes more aggressive in that the inverter may be at full reactive power output within the ANSI limits.

Volt-Watt Control

There is only one method/setting defined for Volt-Watt control. Only one method/setting is defined because reactive power control functions (Volt-Var or Power Factor) should be utilized before Volt-Watt is applied. The method/setting is independent of the feeder/deployment of PV, and setting is designed around not curtailing real power unless the system is experiencing voltage violations. This setting is shown in Figure 3-13.

Level 1

Setting

- Delayed control (does not curtail power when voltage is within ANSI limits)
- Real power is only curtailed if the inverter output exceeds the real power value shown at the specific voltage (i.e., at 1.075 Vpu, the maximum real power output from the inverter can be 50%. If the inverter is at 50% real power output, the inverter does not curtail.)
- Real power output must be Zero at 1.1 Vpu

Basis

- If voltages are high without PV, then the inverter should not be limited to what it can produce.
- Ideally, reactive power functions would prevent Volt-Watt from being applied
- Volt-Watt should be considered a secondary option

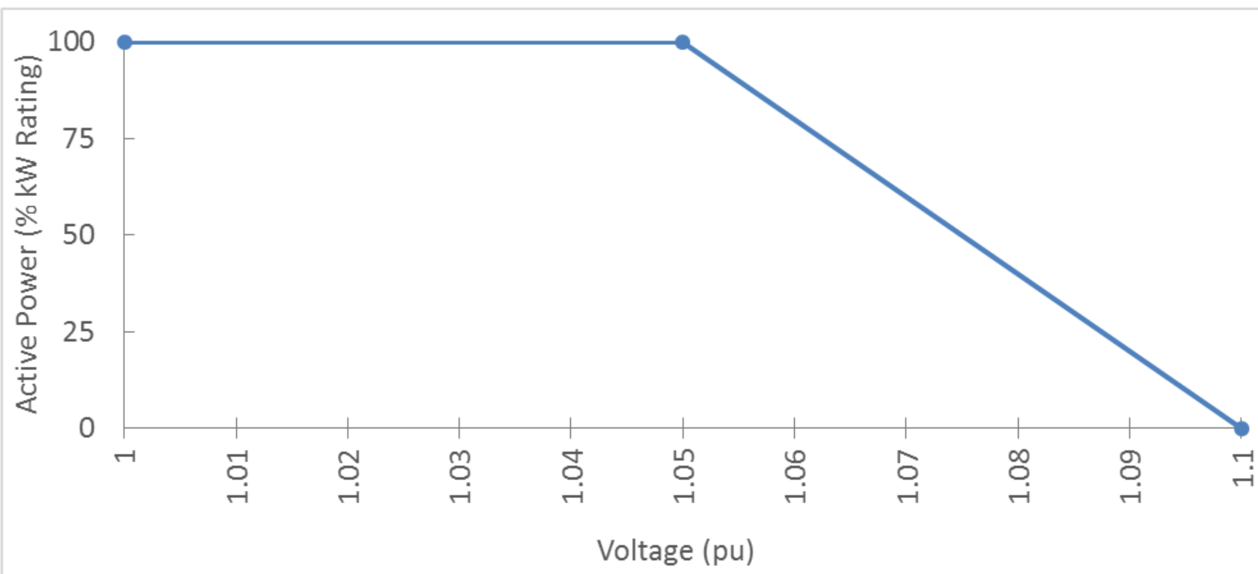

Figure 3-13. Level 1 Volt-watt Setting

Additional Considerations (Reconnection and Ramp-Rate Control)

A number of solutions exist for limiting the impact that a sudden connection or reconnection of PV could have on sudden changes in voltage, including

- Ramp rate control

- Random reconnection time

Ramp Rate Control

For non-islanded systems, limiting the ramp-rate of PV active power output is less of a concern as it relates to distribution impacts.

The larger the PV system the larger the potential impact on voltage. However, the size of the PV system works in its favor of limiting actual flicker impacts[17]. Larger PV systems can cause greater magnitude change in voltage, but at a slower frequency. Similarly, the aggregation effect of multiple systems across a wide service area can provide smoothing as well (Figure 3-14). Actual flicker is observable when both the magnitude of voltage change and the frequency for which it occurs reaches certain thresholds.

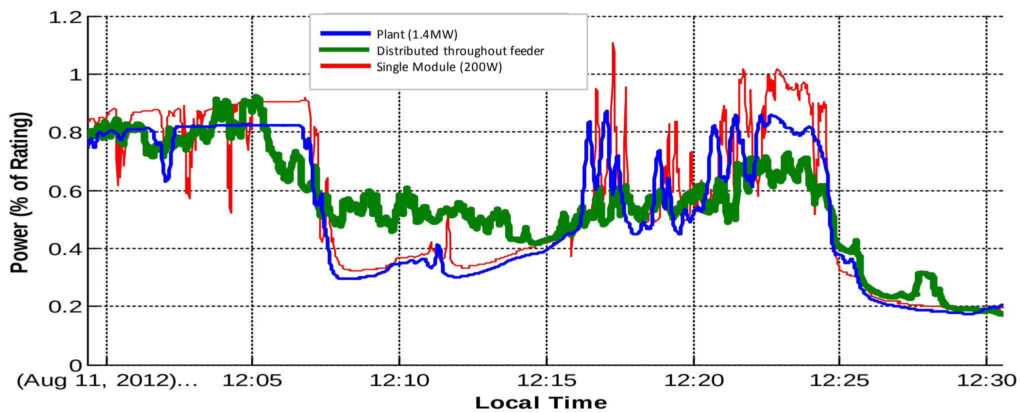

Figure 3-14. Sample Illustration of Normal Ramping Effects of Distributed PV (Plant:1.4MW, Distributed:200W panels throughout feeder, and Single Module:200W panel)

EPRI has shown previously that solar PV ramping due to solar active power output variations does not result in observable levels of flicker, which would be one of the main reasons for imposing ramp rate limits as it relates to distribution-level impacts[18,19].

Ramp-rate control could be used to limit the steady-state voltage fluctuations created by solar PV in order to help reduce mechanical switching operations of line regulators and load tap changers. However, there are other means for providing this mitigation as described in this report.

During reconnection of a solar PV system, a ramp-rate control may need to be utilized when volt/var control is used. When the use of a function such as volt/var control is used a sudden connection of PV (during the morning hours, for example) can result in a sudden change in voltage (Figure 3-15). This could be particularly problematic for larger PV systems that impact the primary voltage and are using a volt/var control that takes advantage of “percent available var” settings.

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[17] Voltage flicker according to IEEE 1453. Not to be confused with voltage fluctuations.

[18] Survey of Harmonic and Flicker of PV Systems. EPRI, Palo Alto, CA: 2015. 3002005983

[19] Impact of High-Penetration PV on Distribution System Performance: Example Cases and Analysis Approach. EPRI, Palo Alto, CA: 2011. 1021982.

In this scenario, the active power production could be rather low which can result in a significant amount of reactive power capacity. A sudden introduction of reactive power could result in a rather significant change in voltage that exceeds that normally produced during normal PV operation.

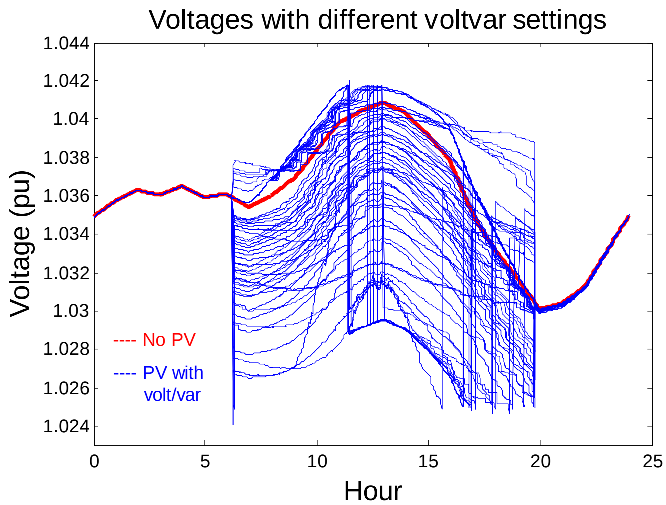

Figure 3-15. Sample Illustration of Sudden Change In Voltage with Onset of PV Connection,[20]

A var ramp-rate control from zero to full var capacity on the order of 1-5 minutes would be sufficient to avoid large fluctuations in var output that could adversely impact voltage and potentially result in flicker.

Random Reconnection Time

Once the voltage and frequency return to acceptable levels after a disturbance, PV can reconnect. In order to avoid the sudden, synchronized reconnection of many PV systems after a disturbance, random reconnect times are recommended. A random reconnect time from 1-5 minutes is sufficient to avoid abrupt changes in voltage due to reconnection.

[20] Smith., J., Rylander, M., "Determining Recommended Settings for Smart Inverters", EPRI Smart Inverter Workshop, Santa Clara, CA, May 2014

4 FEEDER RESPONSE FROM DISTRIBUTION FOCUSED SETTINGS

There is obvious benefit to the distribution system by using advanced inverters to mitigate adverse voltage impacts. That benefit is quantified in terms of increasing hosting capacity. That benefit, however, will depend on the feeder, method, and issues that are examined.

The results for Feeder 631 in Figure 4-1 show a tradeoff for different power factor settings applied to all PV systems on the feeder. The yellow region illustrates the aggregate penetration when adverse impacts begins to occur, while the red region illustrates when adverse impacts occur in all scenarios. By decreasing the power factor to absorb more reactive power, the risk of over-voltage violations decreases, and the over-voltage hosting capacity increases dramatically. On the other hand, more inductive power factors introduce some under-voltage issues starting around 4MW of PV. Looking at Figure 4-1, there is obviously an optimal power factor that provides the highest OVERALL hosting capacity. The overall hosting capacity may be limited further due to thermal constraints if PV systems are placed in weak areas of the feeder.

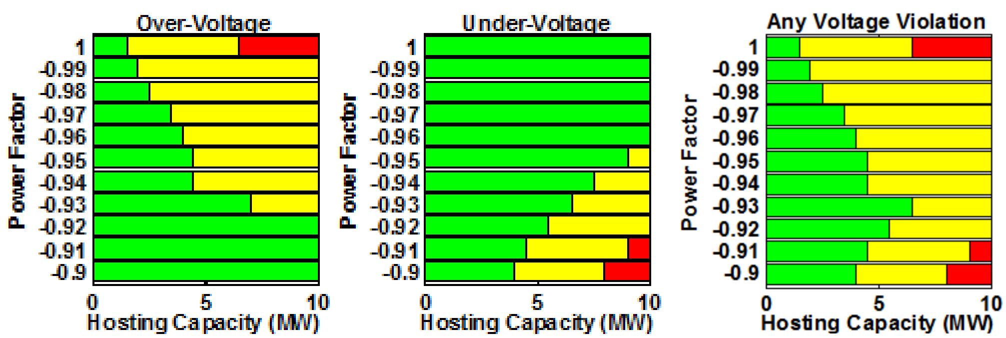

Figure 4-1. Hosting Capacity for Feeder 631 at Various Lagging Power Factors

For the purposes of this study, hosting capacity refers to the midpoint of the yellow region (median hosting capacity) by limitations from either over or under voltage. The hosting capacity methodology is more fully described in the earlier section, and here it is reshown in terms of **Median Hosting Capacity**. This quantification of hosting capacity is used throughout the rest of the report to depict the impact of advanced inverters. Median hosting capacity is used to simplify the comparison of benefit and impact that the advanced inverter could have on the distribution system. Median levels taken from the stochastic analysis also more appropriately depict the more realistic scenario rather than the worst/best case. The median hosting capacity reported is the minimum of the overvoltage median and undervoltage median. A similar yet different approach (not taken) would calculate the median hosting capacity of all scenarios considering overvoltage and undervoltage issues simultaneously. For the purpose of this analysis, however, the results are considered very similar.

> **Median Hosting Capacity:** Defined when 50% of the analyzed scenarios have a violation. The hosting capacity quantified based on the average case.

Distribution Benefit and Impact from Advanced Inverter Controls

The methods provided to determine advanced inverter settings do mitigate the voltage rise from PV. However, in most cases, there is an impact to the distribution system that allows the increase in the hosting capacity. This impact can come in the form of increased losses or the need for local reactive power compensation. Therefore, the change in hosting capacity, losses, and reactive power compensation are all compared between each of the control methods and the baseline unity power factor scenario. The median hosting capacity scenario is used to extract all data points. An example is shown in Figure 4-2 for one feeder identifying the impact and benefit from advanced inverters. Ideally, more complex methods would be better tuned thus providing greater increase in hosting capacity while having a low impact on losses and reactive power. Due to the limited improvement from Volt-watt settings analyzed, Volt-watt is left out of this comparison.

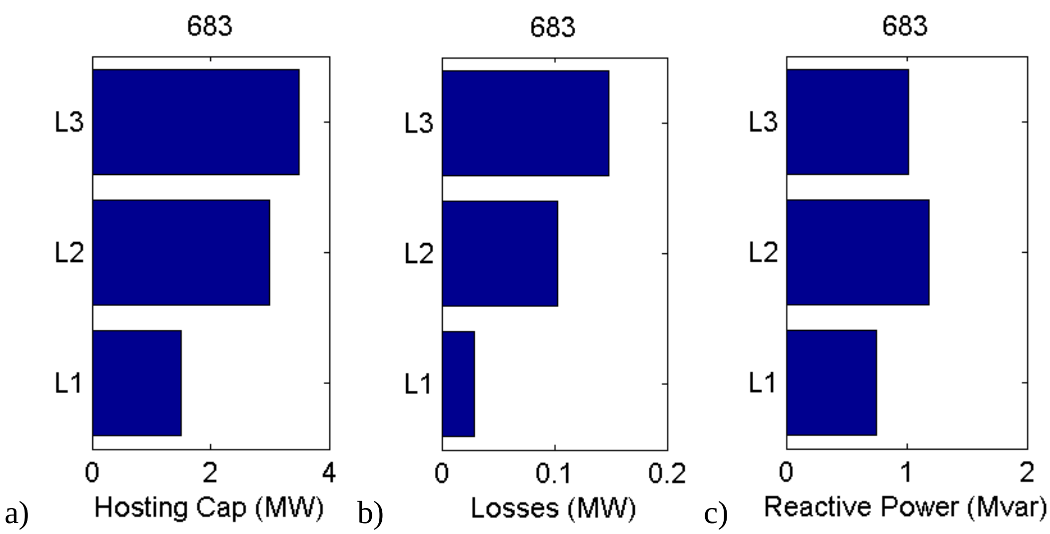

Figure 4-2. Power Factor Increasing a) Hosting Capacity, b) Losses, and c) Reactive Power

Hosting Capacity

For the seven feeders analyzed, there is a hosting capacity improvement from the power factor settings as shown in Figure 4-3. Level 1 and Level 3 show improvement across all feeders while Level 2 has one feeder that decreases hosting capacity. The baseline hosting capacity shown above the figure depicts the hosting capacity of the feeders under unity power factor. Adding the complexity of Level 3 does have the potential to increase hosting capacity for two feeders. This occurs on feeders with medium to low baseline hosting capacity. Additional benefit from Level 3 will also be shown with regards to reactive power demand, or a lack of it.

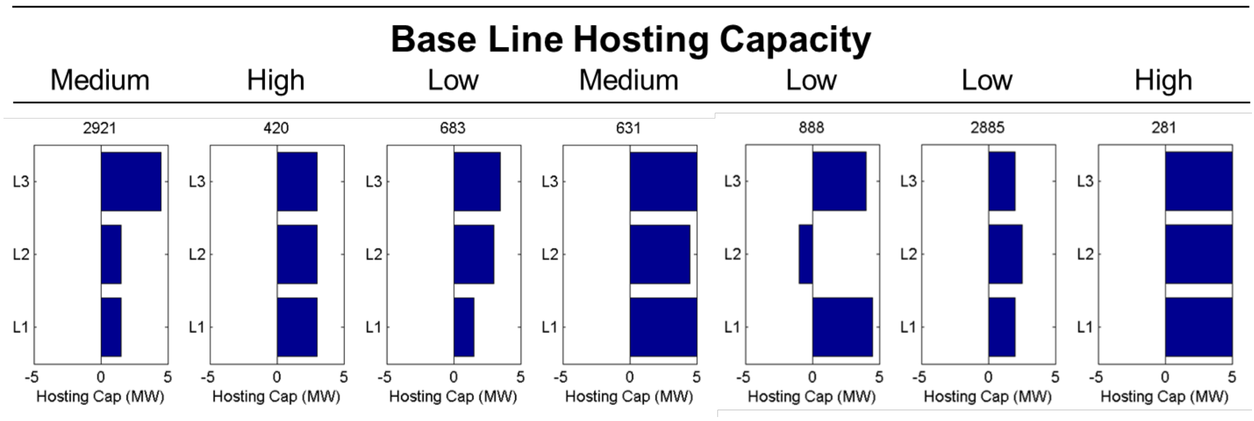

Figure 4-3. Change in Hosting Capacities – Power Factor

Overall for Volt-var settings, all methods and settings increase hosting capacity as shown in Figure 4-4. More complex methods do provide additional benefit with regards to hosting capacity. The additional benefit occurs on three feeders for Level 2 and six feeders for Level 3. However, the additional benefit from Level 3 also comes with the increase in reactive power demand.

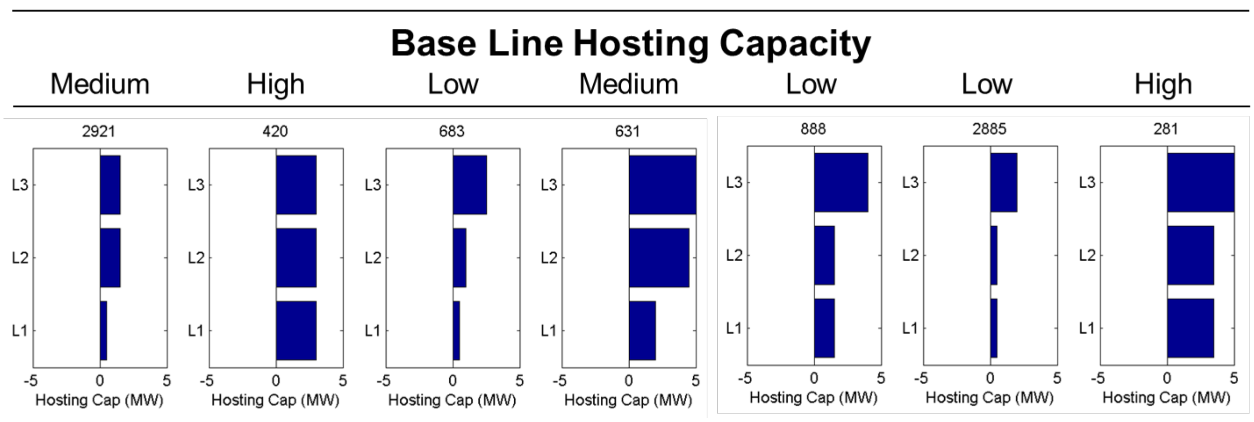

Figure 4-4. Change in Hosting Capacities – Volt-var

- Power Factor
  - Level 1 settings increase hosting capacity on all feeders
  - Level 2 settings show signs of increased hosting capacity yet could have negative impacts on voltage constrained feeders (not all necessary factors on some feeders included in method)
  - Level 3 settings can further improve hosting capacity with the most benefit to feeders with low/moderate hosting capacity
- Volt-var
  - Level 1 settings improve hosting capacity and are most effective on feeders with high hosting capacity
  - Level 2 settings provide slight additional benefit in terms of hosting capacity

- Level 3 settings are more aggressive and increase hosting capacity but reactive power required needs to be considered
- Overall
  - Level 1 volt-var settings show hosting capacity increase without any modeling or data analysis
  - Level 1 power factor methods are simple and often perform similarly to Level 3 methods
  - Level 3 power factor method performs similarly to Level 3 volt-var method (with the exception of Feeder 2921)

Losses

Losses are generally negligible as shown in Figure 4-5 and Figure 4-6 yet it is necessary to be aware that to attain higher hosting capacities, the inverters will increase the losses on the distribution system. These losses are due to the reactive demand from the inverters.

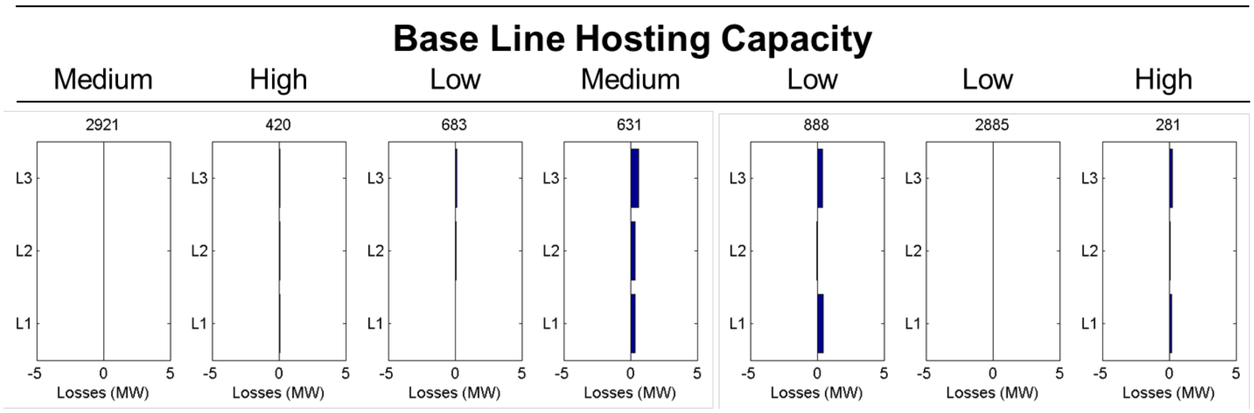

Figure 4-5. Change in Losses – Power Factor

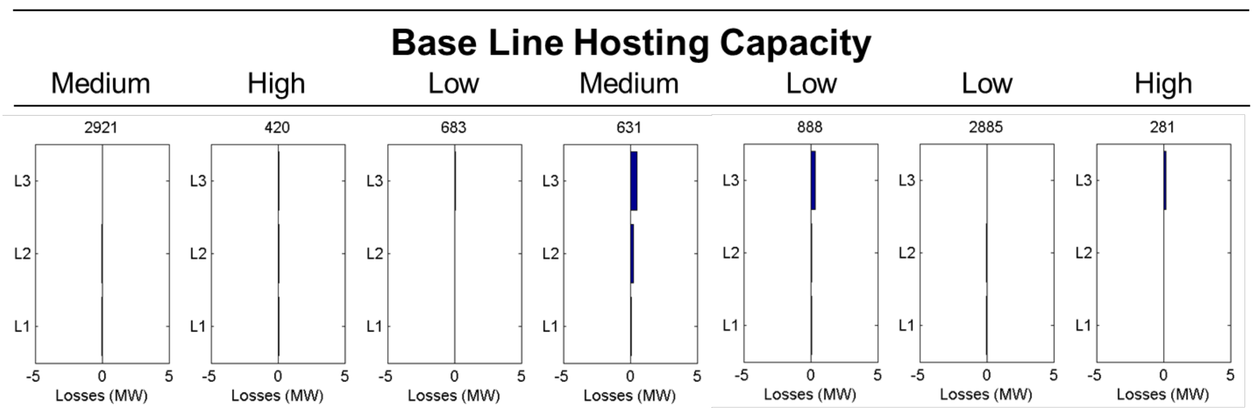

Figure 4-6. Change in Losses – Volt-var

Reactive power

Reactive power is not necessarily a problem or an adverse impact on the distribution system, yet the need for reactive power should be made apparent due to its impact on voltage stability and strain on existing distribution assets.

As designed, higher levels of power factor methods tend to utilize reactive power more effectively. This is done when inverters that have no ability or need to move voltage, don't demand reactive power. Under power factor Level 1, all inverters regardless of location would have the same power factor setpoint. Under Level 2, only inverters in certain regions of the feeder would require reactive power, and under Level 3, the individual systems could have different settings due to their influence on system voltage. Overall, higher levels require similar or less reactive power as lower levels shown in Figure 4-7. Even slight increases in reactive power may not be problematic as long as coupled with greater increases in hosting capacity.

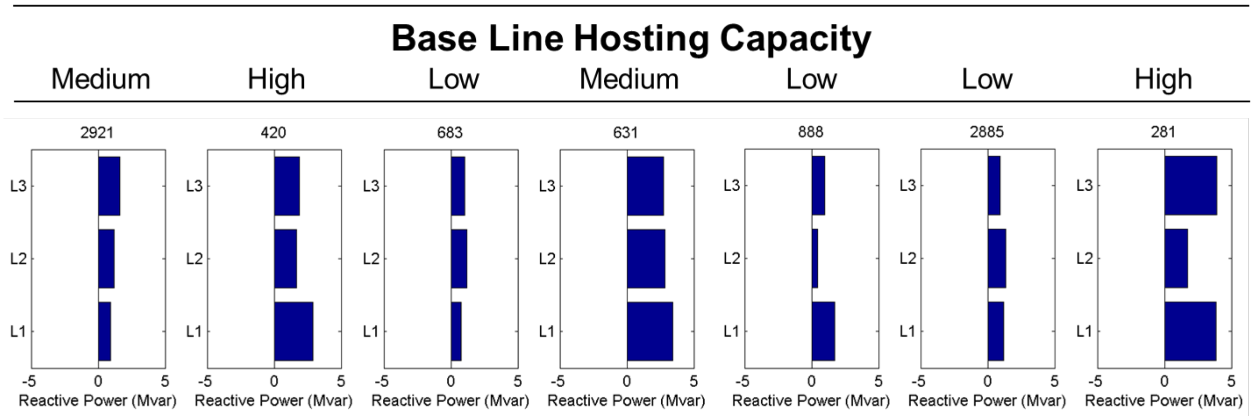

Figure 4-7. Change in Reactive Power – Power Factor

The reactive power requirement from the Volt-var methods is considerably less than that from the power factor methods as shown in Figure 4-8. One reason for this is that each inverter, even with the same control settings, demands reactive power based on its local voltage. In addition to this, the reactive power demanded is dependent on the interconnection voltage.

Unlike the Level 1 setting which is feeder independent, the Level 2 method is designed to be tuned to the feeder model. The reactive power demand for Level 2 remains similar to Level 1 with the exception on Feeders 2921 and 631 where the hosting capacity increased as well. As discussed previously, the Level 3 setting increases hosting capacity, but does so by increasing the reactive power required.

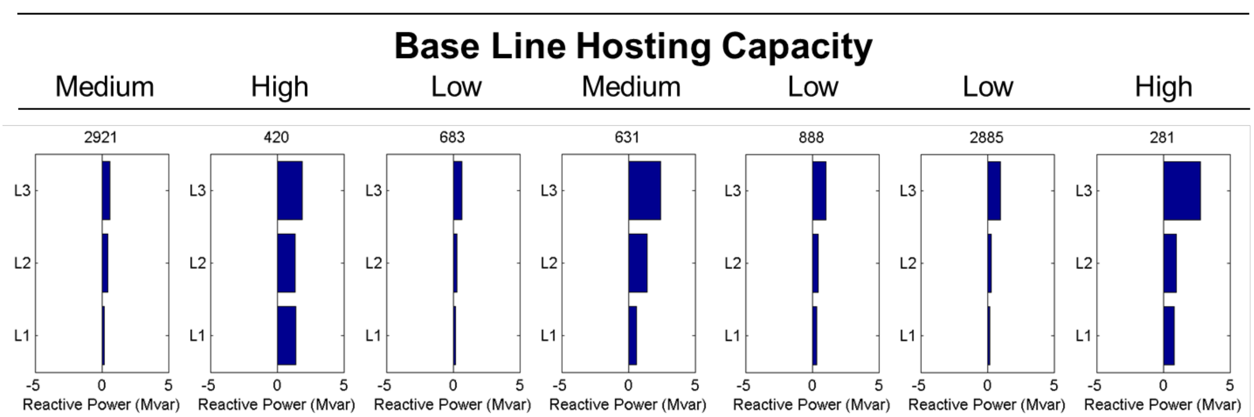

Figure 4-8. Change in Reactive Power – Volt-var

- Power Factor
  - Level 1 settings require the most reactive power
  - Level 2 settings generally require less reactive power
  - Level 3 settings don't always reduce reactive power which can be an artifact of higher hosting capacities
- Volt-var
  - Level 1 settings require very little reactive power
  - Level 2 settings require slightly more reactive power than Level 1
  - Level 3 settings are more aggressive and require more reactive power
- Overall
  - Volt-var Level 1 settings require the least reactive power as compared to all methods
  - High reactive demand for all power factor methods and volt-var Level 3
  - Level 3 power factor method requires similar reactive power to Level 3 volt-var method (with the exception of Feeder 2921)

Benefit / Impact Analysis

The ratio of benefit to impact is examined to determine how much strain the methods place on the distribution system to attain higher hosting capacities. For this examination, losses are ignored. The ratio compares MW of additional hosting capacity (HC) to the Mvar needed for reactive power (RP) compensation. The ratio of benefit to impact is examined even though these are not equitable quantities. On some feeders, the required reactive power compensation may also not be considered an adverse distribution system impact, thus the desired method utilized could be solely chosen based on hosting capacity.

The ratio of hosting capacity benefit to reactive power impact should increase for more complex methods, illustrating higher hosting capacities and the effective use of reactive power. For power factor control, that generally does occur between Level 1 and Level 3 methods as shown in Figure 4-9. As previously shown, the hosting capacity for power factor Level 3 only increased for 2 of 7 feeders, thus the Level 3 method more effectively uses reactive power to increase hosting capacity. Level 2 methods do not show a consistent ratio increase for the seven feeders due to lower hosting capacities, higher reactive compensation needs, or a combination of the two.

The hosting capacity benefit from Volt-var Level 1 was low, but in terms of the reactive power required to attain a higher hosting capacity, the Level 1 setting works similarly to more complex methods. Level 2 methods also show a high ratio of benefit to impact. The more aggressive Level 3 settings that show a significant improvement in hosting capacity also require more reactive power to do so.

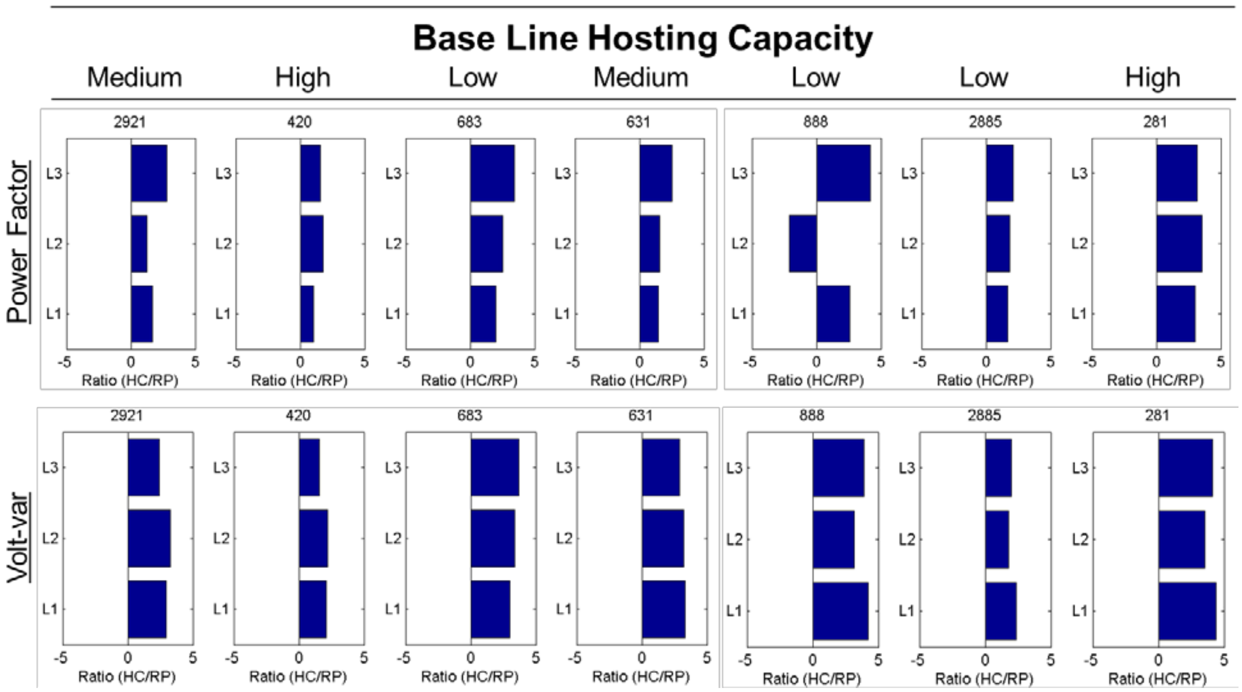

Figure 4-9. Ratio of Change in Hosting Capacity to Change in Reactive Power

- Overall
  - Power factor Level 1 and Level 2 have the least effective use of reactive power
  - Level 3 power factor and Level 3 volt-var provided similar increase in hosting capacity and also demand of reactive power, thus their overall Benefit to Impact ratio is comparable
  - Volt-var Level 1 had low improvement in hosting capacity yet the control settings have some of the most effective use of reactive power

Due to limited improvement in hosting capacity and not significant improvement in effective use of reactive power, there are not significant advantages to using the Level 2 methods of Volt-var and power factor. If there were no constraint on reactive power requirement, the preferred methods may include Volt-var Level 3, Power Factor Level 1, and Power Factor Level 3. When reactive compensation is a limiting factor, the preferred methods may only include Volt-var Level 1 or Power Factor Level 3. Ultimately, the computational requirements to determine the settings for power factor Level 3 may outweigh the value of the results. Therefore, the last method, which happens to be the least complex, is Volt-var Level 1.

Alternatively, when reactive power is not a limiting factor, power factor Level 1 may appear desirable due to the potential improvement to hosting capacity along with simple calculations for settings. However, another important factor that should be considered is how well the Level 1 settings are determined. To examine this, a brute force sweep of power factor settings was analyzed on each feeder.

The brute force analysis, illustrated in Figure 4-10, verified that the Level 1 method did in-fact provide a setting that was close to the most optimal for each feeder (Level 1 setting is highlighted in Red). However, the brute force method also identified that if the setting was not chosen properly, the benefit to impact ratio could quickly shift from positive to negative, such as on Feeder 683. This is caused by the sudden decrease in hosting capacity and/or excessive reactive power demand. Based on the seven analyzed feeders, a positive impact is shown as long as the single feeder-wide power factor setting remains equal to or above 0.96.

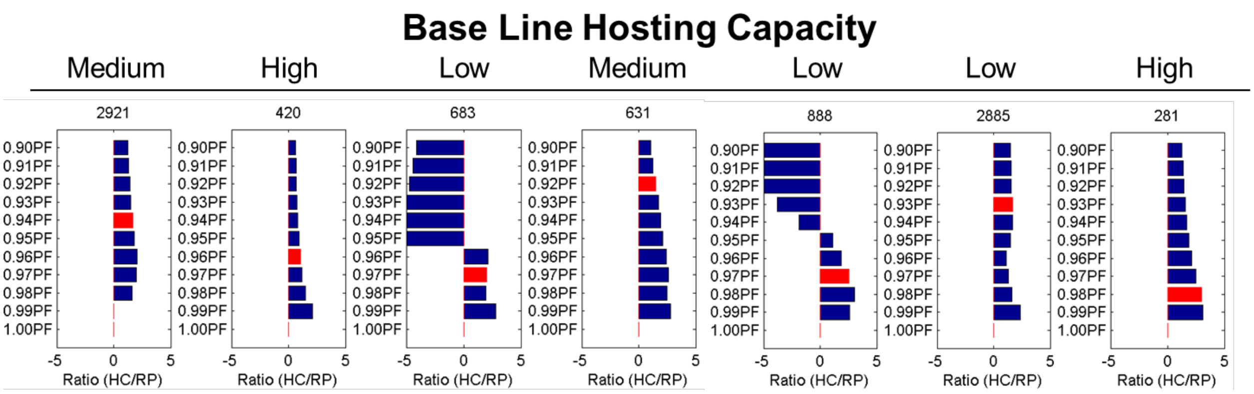

Figure 4-10. Ratio of Change in Hosting Capacity to Change in Reactive Power for Power Factor Brute Force Analysis (Level 1 Power Factor Settings are Highlighted in Red)

Considerations of the Methodology/Results

The results are influenced by several key considerations. While most of these have been mentioned throughout the document, this section provides a comprehensive discussion on potential questions surrounding the methodology/results.

First, the hosting capacity analysis only investigates voltage issues and utility-scale PV systems at five potential interconnection locations (from the feeder-head to feeder-end) on each feeder. In this way, the results could be significantly driven based on the PV size and locations selected by the project team. Also, by only investigating voltage issues, any other commonly analyzed hosting capacity metrics (thermal, harmonics, protection) have been removed for this advanced inverter settings study. Only investigating voltage impacts occurred because advanced inverters primarily impact voltage. The quantified increase in hosting capacity with use of advanced inverters, however, should not be used as a reference for how much more PV can be installed on any given feeder. Other feeders as well as more/less optimal PV locations and sizes will also influence the true change in feeder hosting capacity. Additionally, other limitations such as conductor thermal rating may prevent any projected increases in hosting capacity. Other impacts such as harmonics or protection could also be adversely affected by the over-use of reactive power. The hosting capacity evaluation criteria applied in this study should only be interpreted for developing the methodology of determining settings to improve feeder voltage.

Second, all analyses for power factor and volt-var assume that the inverter is over-rated to provide reactive power even when the PV is at full DC power output. This assumption allowed the focus to be on determining beneficial settings of the advanced inverters, but it also means that the benefit of those settings may not exist when the inverter is not over-rated.

Lastly, the benefits and impacts of advanced inverters were quantified primarily using static snapshot hosting capacity analysis. Time-series analysis was only performed in the derivation of methodologies. Any interactions between advanced inverters and existing distribution regulation equipment (or each other) is not quantified across the test feeders. Another limitation of a snapshot analysis is the inability to fully evaluate different volt-watt algorithms. To appropriately evaluate and recommend volt-watt settings, a time-series analysis would need to examine total energy curtailed to remove voltage issues. However, the use of reactive power based control should precede curtailment of any real power.

5

INVERTER SETTINGS FOR THE TRANSMISSION SYSTEM PERFORMANCE

The goal of this part of the study was to assess the system stability impacts of distributed PV inverters on the California transmission system. Using the WECC 2024 Heavy Summer TEPPC case, 5.4 GW of DER PV generation was integrated into the California power system and the stability impacts on the system were observed and assessed. The focus was to analyze the new frequency and voltage ride-through inverter settings as they have been specified in Rule 21 from a transmission system stability and reliability perspective. Further emphasis was placed on analyzing the impact of fault-induced delayed voltage recovery (FIDVR) on voltage ride-through of DER PV and potential benefits of advanced inverter functions for the transmission system. This section presents the methodology used to integrate the DER PV into the system model and discusses the results observed.

Study Footprint and Background

The DER PV was incorporated into the four California areas in the WECC data set using GE PSLF as simulation environment; SCE, Los Angeles Department of Water and Power (LADWP), SDG&E and PG&E. The WECC 2024 Heavy Summer Case had a total of 45,799 MW of load and 38,529 MW of generation in the four-area study footprint. Of the 45,799 MW of total load in the system, 43,447 MW (94.8%) of it was represented using the CMPLDW complex load model. The CMPLDW model includes a representation of the distribution feeder system, the HV/LV transformer and tap changer as well as the static, electronic, and motor load components at the low voltage level. It is a detailed representation that accurately captures the dynamic impacts of load on the transient stability of the power system.

To incorporate the DER PV, the CMPLDWG complex load model was selected. The CMPLDWG model is functionally similar to the CMPLDW model, however, it includes an additional set of parameters for a DER PV generator connected to the LV distribution bus which can be seen in Figure 5-1. The PV model at the distribution bus is a very simplified representation of the PV inverter (PVD1), but it captures the essential dynamics related to tripping of DER PV due to abnormal voltage and frequency conditions which are necessary to study the impact on the stability of the transmission system.

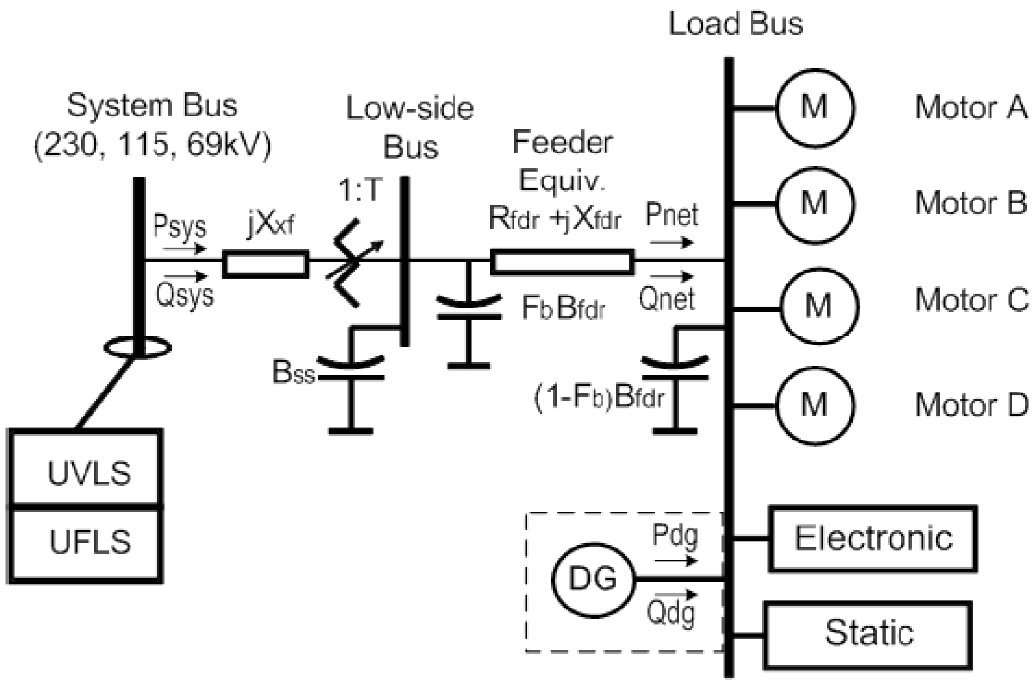

Figure 5-1. The schematic representation of the CMPLDWG model. Source: WECC

Utilizing the CMPLDWG model for dynamic analysis, the 5,400 MW of new PV generation were netted into the existing CMPLDW models in the study footprint. The 5,400 MW of DER PV was selected based on the results of NREL's Western Wind and Solar Integration Study Phase 3 (December 2014)[21]. It amounted to a 14% penetration level by total generation in the study footprint, and a 10.5% penetration level with the newly netted load.

Additionally, some of the case studies also utilized WECC's distributed PV (PVD1) model, Figure 5-2.

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21 Western Wind and Solar Integration Study Phase 3: Frequency Response and Transient Stability. NREL. National Renewable Energy Laboratory: December 2014.

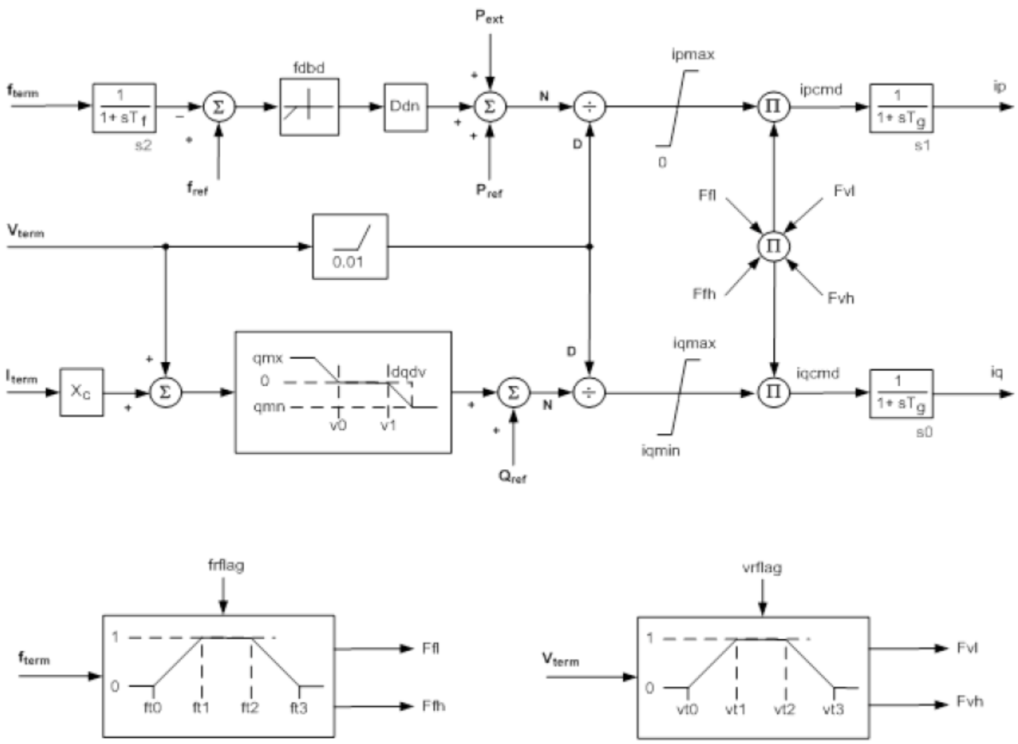

Figure 5-2. The block diagram for the PVD1 model. Source: GE PSLF User Manual.

There are several ways to represent DER PV in the bulk system model and this analysis will follow the model represented in Figure 5-3.

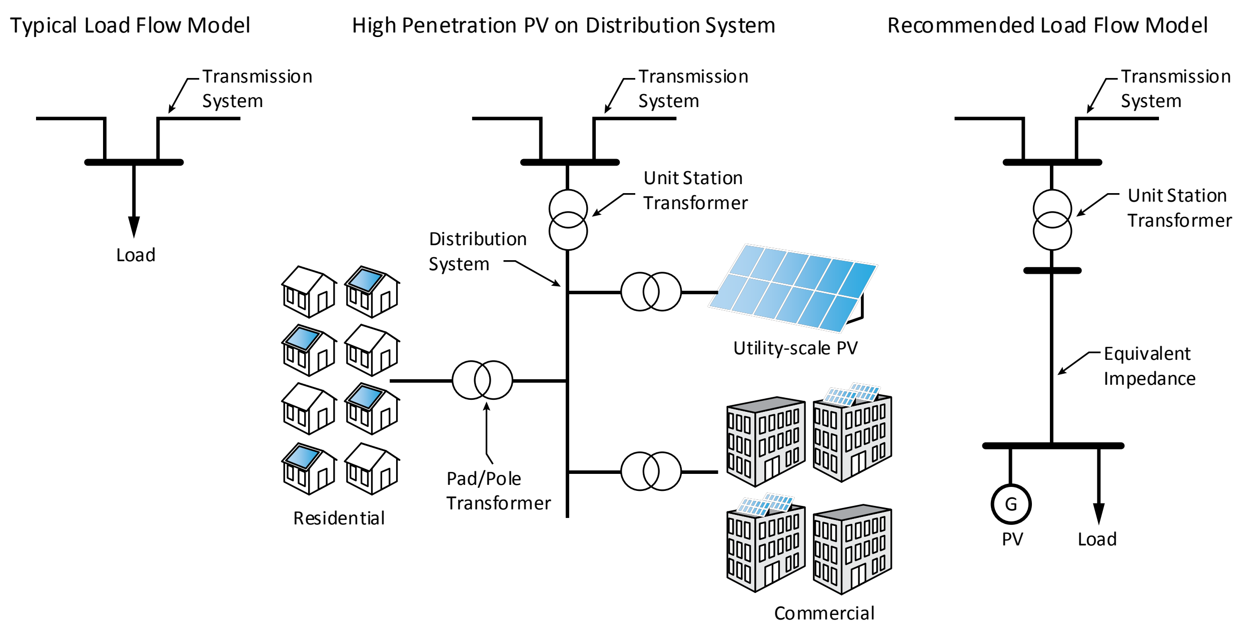

Figure 5-3. Representation of DER PV in the bulk transmission system model. Source: own figure based on WECC.

By modeling the DER PV as described by Figure 5-3, the DER PV will be modeled explicitly into the power flow base. To continue to utilize the complex load model along with the PVD1 model, the system was modified as follows:

- At four select transmission nodes that have been reported as being sensitive to FIDVR, the CMPLDWG model was replaced with the CMPLDW model and PVD1 model connected to a low voltage bus.
- An equivalent circuit was constructed explicitly in the power flow case, i.e. the step-up transformer and equivalent feeder impedances were modeled and solved for the power flow case, Figure 5-3.

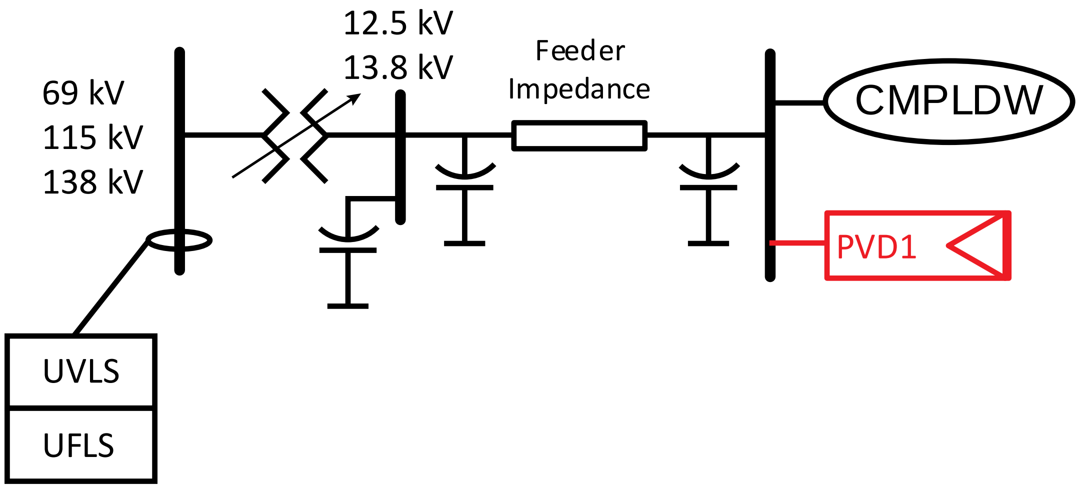

Figure 5-4. Equivalent circuit modeled in the power flow case.

The impedances in the circuit in Figure 5-4 were determined based on typical distribution feeder data provided by NREL. The representation of this equivalent circuit can have significant impacts on the system and should take into account the size of the load and the voltage of the distribution node. Incorrectly representing this circuit can lead to convergence issues in the power flow case, exaggerated losses in the distribution system, or inaccurately represent the response from the DER PV.

- The equivalent circuit values in the CMPLDW model (X_{xf}, R_{fdr}, and X_{fdr} from Figure 5-1) were then reduced below the jumper threshold tolerance in GE PSLF to appear as short-circuits. This allowed for the dynamic representation of load and the more complex PVD1 model for DER PV to be represented at the same node.

This model is an explicit representation of the DER PV in the power flow model and allows for reactive power priority mode. In this operating mode, the DER PV can control reactive current to help support voltage at the target node.

Study Method

System Setup

To successfully integrate 5,400 MW of new DER PV generation into the study footprint several steps were taken to modify the 2024 WECC Heavy Summer Base Case.

- First, load was increased proportionally at each load node in the steady-state power flow case in order to accommodate the new DER generation.
- Next, to initialize the dynamic simulation correctly a solved power case was necessary. To achieve this, the additional load in the study footprint was balanced by committing existing generation from *outside* California in two neighboring WECC areas, Northwest and Arizona. This new generation was necessary to achieve a steady-state solution and have all generators, including the slack units operating within their operating limits. By committing generation outside the footprint, the available reactive power reserves and short-circuit strength *in the study footprint* would remain relatively constant and allow the load/generation balance of the system to be maintained.
- Finally, the load models (CMPDLW) in the dynamic case were replaced with CMPLDWG models that retained the original load parameters (i.e. the CMPLDW dynamic data). Overall, 1,365 CMPLDWG models were used to represent the load and the 5,400 MW of DER PV.
- The DER PV is operated with a unity power factor, meaning that no reactive power is absorbed or injected by the DER PV in steady-state operation.

Inverter Settings

Three cases were initially assessed in this study using the CMPLDWG model;

- Base Case – The WECC 2024 Heavy Summer case with no DER PV.
- IEEE Std. 1547-2003 Parameter Case – The WECC 2024 Heavy Summer case with 5,400 MW of DER PV. The PV was modeled using the voltage and frequency trip parameters recommended by the IEEE 1547-2003 standard (no voltage or frequency ride-through).
- CA Rule 21 Parameter Case – The WECC 2024 Heavy Summer case with 5,400 MW of DER PV. The PV was modeled using the new CA Rule 21 parameters (with voltage and frequency ride-through)[22] as shown in Table 5-1 and Table 5-2.

[22] CPUC, "Interconnection (Rule 21),". Accessed January 21, 2015, http://www.cpuc.ca.gov/PUC/energy/rule21.htm.

Table 5-1. New CA Rule 21 Voltage Ride-Through Table

Region	Voltage at Point of Common Coupling (% Nominal Voltage)	Ride-Through Until	Operating Mode	Maximum Trip Time
High Voltage 2 (HV2)	V ≥120			0.16 sec.
High Voltage 1 (HV1)	110 < V < 120	12 sec.	Momentary Cessation	13 sec.
Near Nominal (NN)	88 ≤ V ≤ 110	Indefinite	Continuous Operation	Not Applicable
Low Voltage 1 (LV1)	70 ≤ V < 88	20 sec.	Mandatory Operation	21 sec.
Low Voltage 2 (LV2)	50 ≤ V < 70	10 sec.	Mandatory Operation	11 sec.
Low Voltage 3 (LV3)	V < 50	1 sec	Momentary Cessation	1.5 sec.

Table 5-2. New CA Rule 21 Frequency Ride-through Table

System Frequency	Minimum Range of Adjustability (Hz)	Ride-Through Until (s)	Ride-Through Operational Mode	Trip Time (s)
f > 62	62 – 64	No Ride Through	Not Applicable	0.16
60.5 < f < 62	60.1 – 62	299	Mandatory Operation	300
58.5 < f < 60.5	Not Applicable	Indefinite	Continuous Operation	Not Applicable
57.0 < f < 58.5	57 – 59.9	299	Mandatory Operation	300
f < 57.0	53 – 57	No Ride Through	Not Applicable	0.16

A fourth case was also studied using the PVD1 DER PV model. In this case, the PVD1 was used at four nodes sensitive to FIDVR issues in order to assess the impacts of dynamic voltage control. As such, the case was titled:

- PVD1 Case – The WECC 2024 Heavy Summer case with 5,400 MW of DER PV. The PV was modeled using the new CA Rule 21 parameters and operated in reactive power (Q) priority mode. The time lag for the inverter was set at 0.02 sec. This is fairly fast for DER PV, but it was sufficient to study the impacts given the considerations of the bulk transmission system model. Four nodes utilized the PVD1 DER PV model.

Tuning of PVD1 model parameters

With the need to develop more representative bulk system level models of distribution-connected PV (DER PV) an investigation of how the voltage diversity present within distribution systems, along with the voltage dependent trip settings of DER PV systems interconnected under the default IEEE 1547-2003[23] settings, was undertaken. Specifically, the goal of this work was to inform the appropriate settings of bulk system level models, such as the PVD1 model[24], which were developed to represent the aggregate impact of many multiples of distribution-connected PV systems. This work was focused on the distribution system analysis of six circuits from SCE's service territory that were developed and validated as part of prior work on developing more accurate PV interconnection screens[25]. These circuits were specifically chosen out of the total set of more than 3,000 circuits in SCE's service territory as they were calculated to be representative of classes of distribution circuits. Thus, the six circuits studied approximate the widest cross-section of distribution circuit types possible using a limited number of modeled distribution circuits.

The specific DER PV impact that this work is focused on relates to the reliability of the bulk system to bulk system level faults when the bulk system contains considerable amounts of DER PV. The scenario considered is that a transmission/sub-transmission fault occurs which significantly reduces the voltage at one or multiple substations. This voltage sag propagates to the distribution system and thus affects the voltage present at the point of interconnection of the DER PV. The DER PV will disconnect if the voltage sensed is below 0.88 pu assuming that the DER PV was interconnected under the IEEE 1547-2003 interconnection standard and that the default settings within the standard were not modified by agreement between the utility and the PV system operator. The bulk system reliability concern is that the disconnection of DER PV during voltage sag events could, if DER PV penetration is a large enough fraction of total generation, lead to a considerable loss of generation for the overall, or part of the, bulk system.

Method

Detailed and validated OpenDSS models of the six distribution circuits were developed and used for the completion of this study. These models included secondary service runs from distribution transformers to customer service entrances in order to account for the voltage drop or rise seen in the distribution transformer and secondary service run. Additionally, the distribution circuit models have a full model of all the automatic voltage regulation equipment used on the circuits including control of the low-side substation transformer bus voltage. Many utilities use on-load tap changing (OLTC) transformers to regulate the voltage at the start of the connected distribution feeders. Others, including SCE, typically use switched capacitors placed on the high-voltage side of the substation transformer. For this study the start of circuit voltage for all circuits

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[23] IEEE 1547 Working Group, "IEEE 1547-2003," Standard for Interconnecting Distributed Resources with Electric Power System, 2003.

[24] WECC Renewable Energy Modeling Task Force, "Western Electricity Coordinating Council Dynamic Modeling Guide," April, 2014.

[25] M. Rylander, J. Smith, R. Broderick, B. Mather, "Alternatives to the 15% Rule: Modeling and Hosting Capacity Analysis of 16 Feeders," Electric Power Research Institute (EPRI) Report #3002005812, April, 2015.

was 1.039 Vpu as this was the voltage regulation goal of the substation start-of-circuit voltage during circuit loading conditions evaluated (peak annual daytime load).

The DER PV modeled for this study was both residential-scale roof-top PV (typical system sizes between 2-5 kW) and commercial-scale PV (10-150 kW system sizes). The deployment of residential- or commercial-scale PV was modeled as a function of both the distribution transformer rating and the estimated customer load at a given randomly selected customer location within the distribution circuit model. The models were first populated with DER PV systems randomly until the total PV penetration, as a percentage of annual peak circuit load, was approximately 14%. The calculation of the amount of generation lost due to a voltage sag at the distribution substation was completed via a 10-second quasi-static time-series (QSTS) simulation of an individual distribution circuit. The voltage sag was defined by a fault induced voltage sag waveform from a PSLF model of the Saugus transmission node in SCE's service territory. This waveform effectively set the voltage source set point of the substation source at every incremental time point during the QSTS simulation. All automatic voltage regulation devices on the circuit were locked in their pre-voltage sag setting as these devices are not typically fast enough to react to the relatively fast voltage sags seen during transmission faults. DER PV systems did react (i.e. disconnect) instantaneously to the voltage present at their respective POIs as it was assumed in this study that PV inverters would react very quickly (on the order of 10ms-100ms). The amount of DER PV-based generation lost due to voltage sags of varying severity was determined by subtracting the amount of DER PV online after the voltage sag from the total DER PV online prior to the voltage sag.

The analysis described above was completed for various voltage sag magnitudes and a percentage of DER PV (in terms of real power generation) that remained online was recorded. In order to estimate the amount of DER PV generation lost for a given voltage sag seen across a relatively large area or as represented in a bulk system study there was a need to aggregate the response of the above distribution circuits into a single approximate response. A given node in a transmission-level study likely contains no less than an entire distribution substation of distribution circuits. Without other information to inform the expected distribution system response – and the resulting response of DER PV interconnected on the distribution system – responses for each of the six distribution circuits studied were averaged together weighted by their peak loading. This averaging, and the resulting aggregate response, presumes that a given underlying distribution system being represented is comprised of an equal distribution of distribution circuits that are characterized by the chosen six representative distribution circuits. This is a rough approximation and alternate weighting factors could be used to aggregate the response at a transmission level if more was known about the characteristics of the constituent distribution system connected.

Results

Figure 5-5 shows an example output of the voltage sag analysis completed for this study. Both the voltage sag present at the start-of-circuit and the amount of DER PV generating before and after the voltage sag assuming IEEE 1547-2003 default voltage trip settings is shown. For this circuit the loss of DER PV due to this voltage sag, which sagged to approximately 0.92 V_{pu} resulted in a significant loss of DER PV generation of approximately 750 kW.

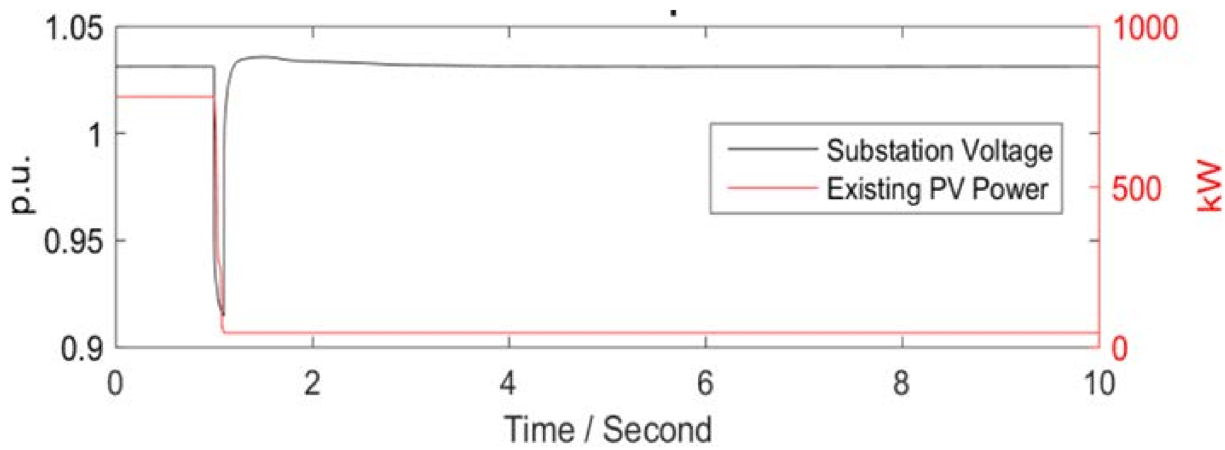

Figure 5-5. Example analysis results showing the voltage sag and the amount of DER PV generation before and after the voltage sag event.

All six circuits were evaluated for voltage sags with minimum voltage magnitudes between 0.94 and 0.85 V_{pu}. The results of the simulations are shown in Figure 5-6. The various amounts of DER PV generation lost due to specific voltage sag magnitudes indicates that the voltage diversity present on each circuit is different. Some circuits, such as circuits #2, #3, and #4 begin to see a loss of DER PV generation at relatively mild voltage sag conditions but somewhat evenly continue to lose generation until all generation is offline at voltage sag magnitudes of 0.85 – 0.86 V_{pu}. Other circuits exemplified by circuit #5 and #6 have a much steeper loss of DER PV generation but only at more severe voltage sags.

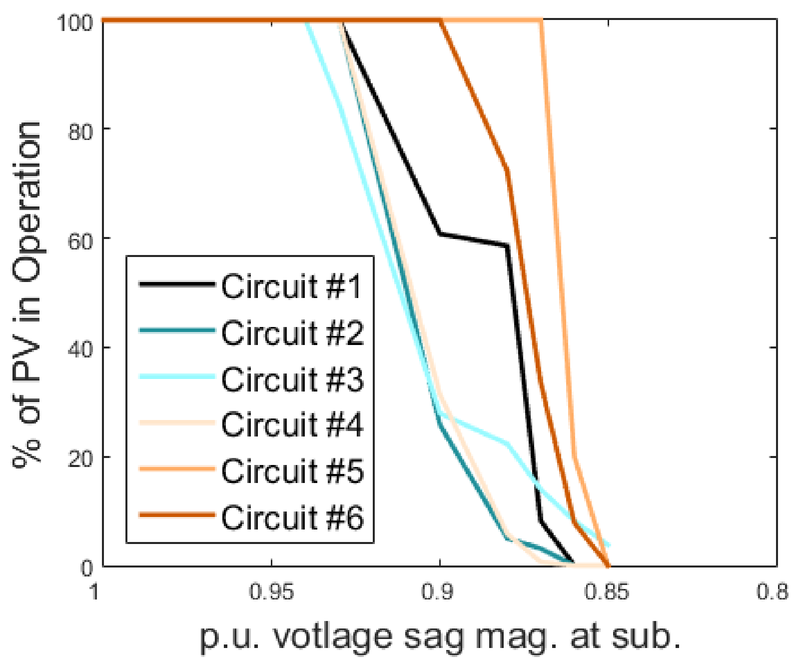

Figure 5-6. DER PV loss of generation as a function of voltage sag magnitude for the six circuits studied.

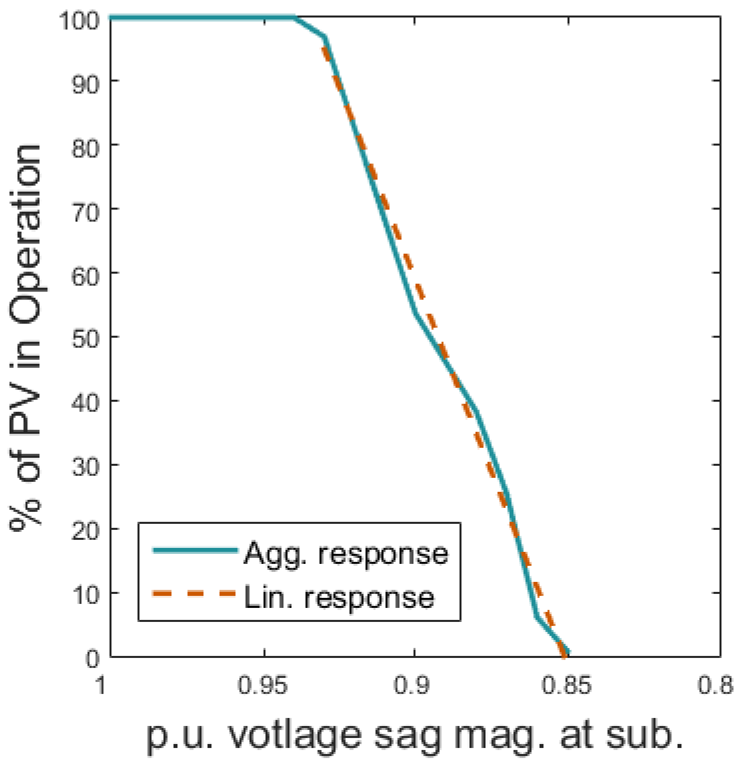

Figure 5-7. The aggregate response of a distribution system comprised of the circuits evaluated.

Figure 5-7 presents the aggregate response of a distribution system that would be comprised of an equal distribution of the circuits evaluated. This is effectively the annual peak load weighted average response of the circuits shown in Figure 5-6. Figure 5-7 shows both the calculated aggregate response and the linearized response which is equivalent to the following function:

$$DPV_{on-line}(\%) = 1203.9V_{sag,pu} - 1024.6 \quad \text{for} \quad 0.93 \geq V_{sag,pu} \geq 0.85$$

Conclusions

Six distribution circuits were evaluated regarding DER PV's response (tripping off-line) to voltage sags. These voltage sags were representative of sags caused by transmission-level faults which could reduce the voltage present on a wide area of distribution systems. QSTS analysis was used to simulate a 10 second period of time during which the voltage sag was modeled to occur at the substation feeding the distribution circuit. All six circuits showed different responses and these differences indicate at the voltage diversity across an entire circuit is different for different circuits. In order to develop an aggregate model of the response of a large distribution system as seen by a studied node in a transmission-level dynamic study an annual peak load weighted average approach was taken.

Summary of Model Parameters

The PV voltage and frequency trip parameters used in the analysis can be seen in Table 5-3. The main difference between the IEEE Std. 1547-2003 Parameters and the new CA Rule 21 Parameters are the ride-through voltages and frequencies. IEEE 1547-2003 trips the PV after the voltage falls below 0.9 pu and the frequency falls below 59.5 Hz. The new CA Rule 21 Parameters allow for the PV to remain connected through larger voltage and frequency excursions. Additionally, with the new CA Rule 21 Parameters the DER PV will reset and re-energize following the clearance of the fault.

Table 5-3. PV parameters for the studied cases

Parameter Description	IEEE 1547-2003 (CMPLDWG)	CA Rule 21 (CMPLDWG)	PVD1 (PVD1)
Inverter current lag time constant	NA	NA	0.02
Apparent current limit	1.2	1.2	1.2
Priority to reactive current (0) or active current (1)	NA	NA	0
Voltage tripping is latching (0) or partially self-resetting (>0 and <=1)	0	1	1
Voltage tripping response curve point 0	0.88	0.50	0.85*
Voltage tripping response curve point 1	0.90	0.52	0.94*
Voltage tripping response curve point 2	1.10	1.19	1.19
Voltage tripping response curve point 3	1.20	1.21	1.21
Frequency tripping is latching (0) or partially self-resetting (>0 and <=1)	0	1	1
Frequency tripping response curve point 0	59.5	56.5	56.5
Frequency tripping response curve point 1	59.7	57	57
Frequency tripping response curve point 2	60.3	61.9	61.9
Frequency tripping response curve point 3	60.5	62.1	62.1
Lower limit of deadband for voltage droop response	NA	NA	0.98
Upper limit of deadband for voltage droop response	NA	NA	1.02
Voltage droop response characteristic	0	0.05	0.05
Down regulation droop gain	0	0.05	0.05
Overfrequency deadband for governor response	NA	NA	-0.036
Line drop compensation reactance	NA	NA	0
Minimum reactive power command	NA	NA	-0.44
Maximum reactive power command	NA	NA	-0.44
Frequency transducer time constant	0.05	0.05	0.05
Voltage limit used in the high voltage reactive power logic	1.2	1.2	1.2
High voltage point for low voltage active power logic	0.8	0.88	0.88
Low voltage point for low voltage active power logic	0.4	0.5	0.5
Limit in the high voltage reactive power logic	-1.3	-1.44	-1.44
Acceleration factor used in the high voltage reactive power logic	0	0.7	0.7

*Determined by NREL through simulation on OpenDSS

A visual representation of the LVRT and HVRT settings is presented in Figure 5-8. The green area of the plot represents the Continuous Operation voltage region beyond which the existing IEEE Std. 1547-2003 requirements required tripping after 1–2 sec. and the new CA Rule 21 settings require voltage ride-through operation. Voltage ride-through operation means that the DER PV must remain online during abnormal voltage conditions and restore the pre-fault output quickly once the voltage recovers. The light blue area (Mandatory Operation), is the voltage region for which the new CA Rule 21 settings require low voltage ride-through of DER PV with continued infeed of power. In this area, the DER PV must remain online and inject primarily active power into the system. The long duration for the low voltage ride-through of up to 20 sec.

has been defined in order to make sure that DER PV would ride through FIDVR of typical duration at certain distribution buses in California. The dark blue area (Momentary Cessation), is the voltage region for which the new CA Rule 21 settings require low voltage ride-through of DER PV without any infeed of power. Cessation of DER PV to energize the system for voltage values below 0.5 pu has been specified in order to avoid coordination issues with (local) distribution system protection. Once the system voltage recovers into the Mandatory Operation voltage region, the DER PV restores power output. For any voltage sags of a certain voltage depth and a duration longer than the one specified in Figure 5-8 the DER PV is allowed to trip. Once tripped, Return to Service requirements specify the conditions and timing for the DER PV to reconnect back to the system.

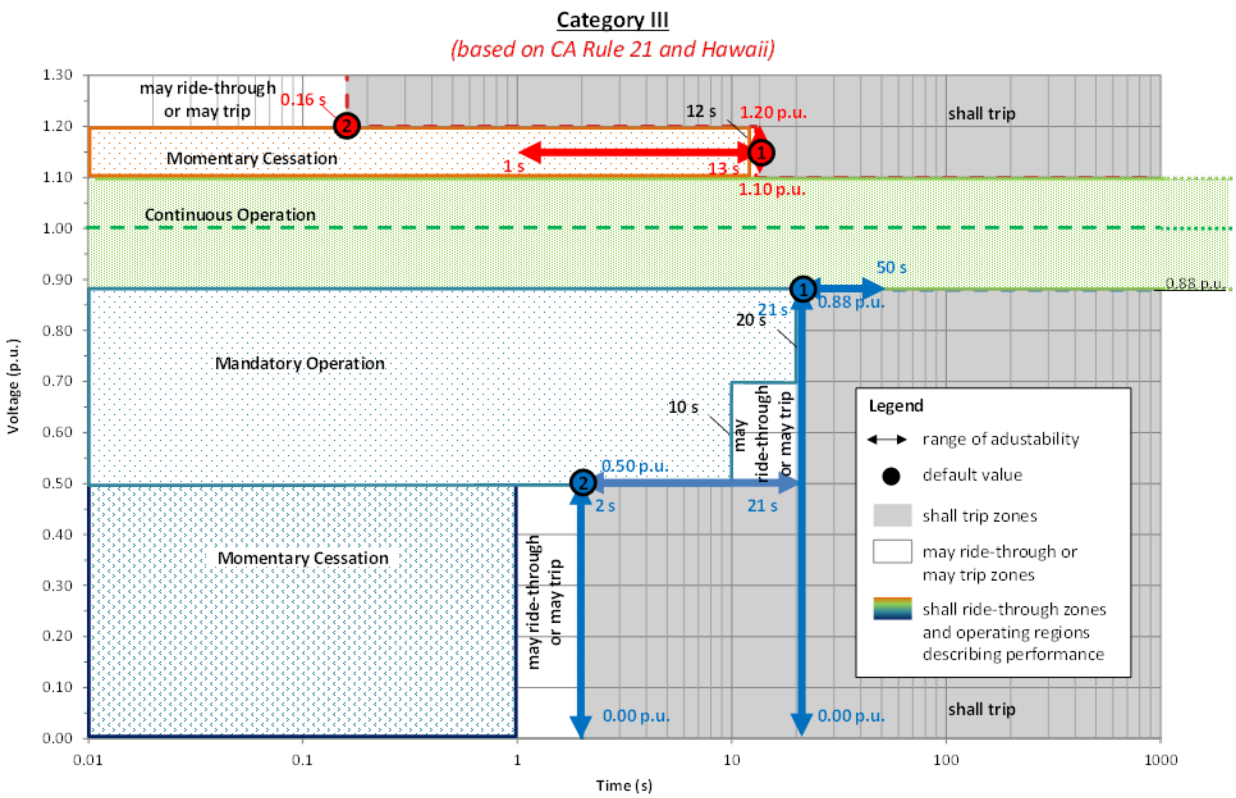

Figure 5-8. The proposed IEEE 1547-2003 Rule update and the current CA Rule 21 parameters for LVRT and HVRT

Contingency Cases

For the three cases using the CMPLDWG, nine contingency events were assessed. The largest load in the three largest areas of the study footprint were identified; SCE, SDG&E and PG&E.

- At each of these three buses, a single phase to ground and a three phase to ground fault were applied for six cycles (100 ms). These faults account for six of the applied contingencies.
- The impedance of the single phase to ground fault was such that the positive-sequence voltage drop was approximately 33% (i.e., retained voltage of 66%).

- The last three contingencies were the loss of two of the Palo Verde Nuclear units.

The case with the PVD1 model examined the impacts of a three-phase to ground fault at a node that was identified by an Investor-Owned Utility as being particularly sensitive to FIDVR impacts.

CMPLDWG Model Results

This section discusses the results of the contingency analysis. It focuses on three events in the SCE area, the single phase to ground fault, the three phase to ground fault, and a loss of generation event. The results from the rest of the contingencies were all very similar so these results are representative of the rest of the contingencies. Additionally, for all three cases assessed here, the single-phase induction motors were operated with no motor stalling.

Single Phase to Ground Fault

The first fault that was applied was a single phase to ground fault in the SCE area. The voltage at the faulted bus is seen in Figure 5-9. The voltage in the IEEE Std. 1547-2003 Parameters Case has the worst response. This is due to the DER PV tripping after the occurrence of the fault, Figure 5-10. The DER PV with CA Rule 21 Parameters reduce the active power output in proportion to the voltage drop. This is because the voltage does not fall below the trip level of 0.5 pu. The DER PV with the IEEE Std. 1547-2003 Parameters trip as soon as the voltage falls below 0.88–0.90 pu and worsens the voltage performance at the sub-transmission level.

The voltage at the low voltage distribution bus is presented in Figure 5-11. The voltage performance at the low voltage bus is similar to that at the sub-transmission level. Once again, this is due to the DER PV remaining online following the fault clearance with the new CA Rule 21 Parameters. Finally, the active power load at the distribution bus is presented in Figure 5-12. Here, the difference in the load level is due to the netting of the DER PV into the existing load. Additionally, one of the motor models in the CMPLDWG model reduces its active power consumption due to the fault. As a result, there is a slight decrease in the load following the fault. The IEEE Std. 1547-2003 Parameter Case and the Base Case have very similar performances as the DER PV simply trips off following the fault. In the new CA Rule 21 Parameters Case, the DER PV remains online and as a result there is a slight increase in the load.

The difference in the voltage trip behavior also impacts the bus frequency of the area. In Figure 5-13, the average bus frequency for the SCE area is shown. After the fault has been applied in the IEEE Std. 1547-2003 Parameter Case, the DER PV trips and negatively impacts the frequency of the system. With the new CA Rule 21 Parameters, the DER PV remains connected and supports the system frequency. The active power change in the DER PV that causes this frequency deviation is shown in Figure 5-14.

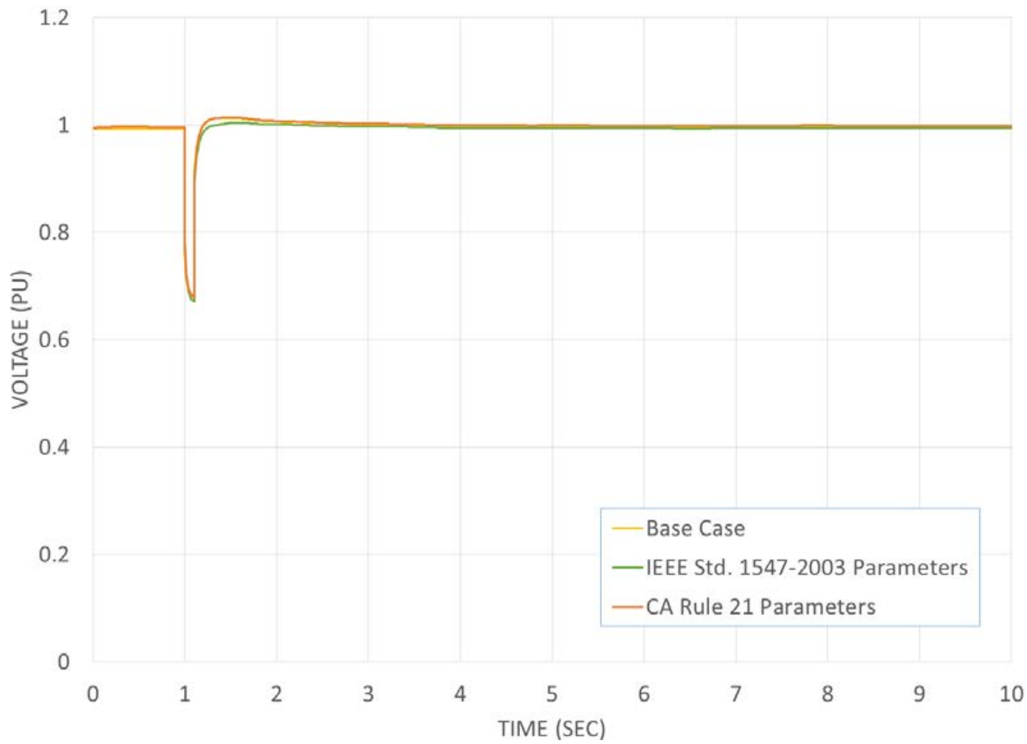

Figure 5-9. Voltage at the 69.0 kV sub-transmission bus

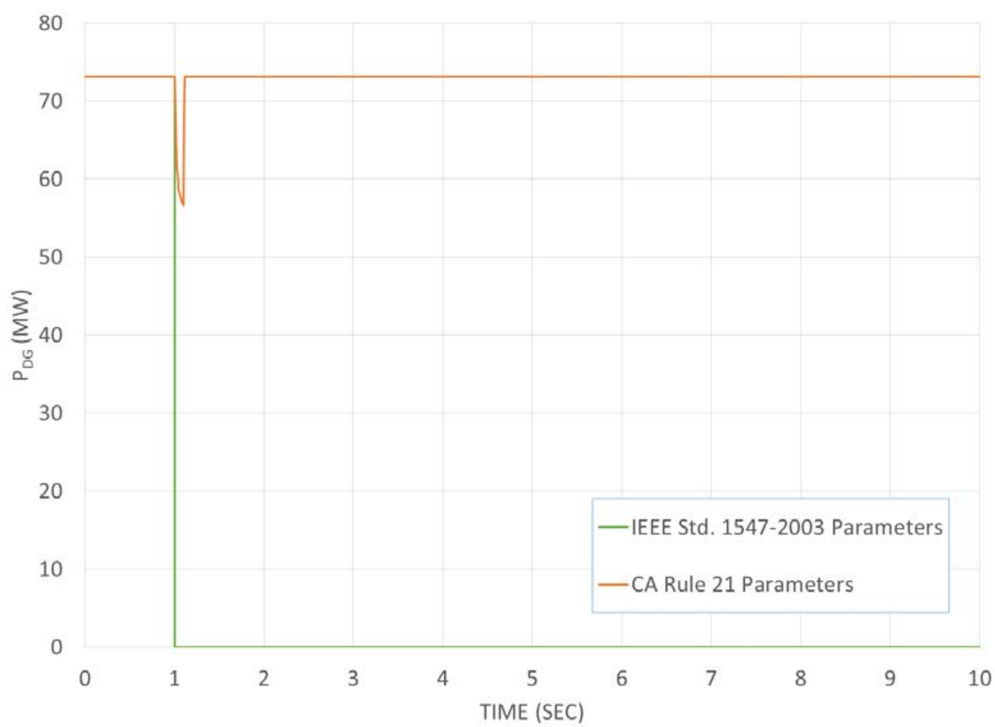

Figure 5-10. Active power output (P_{DG}) from the DER PV

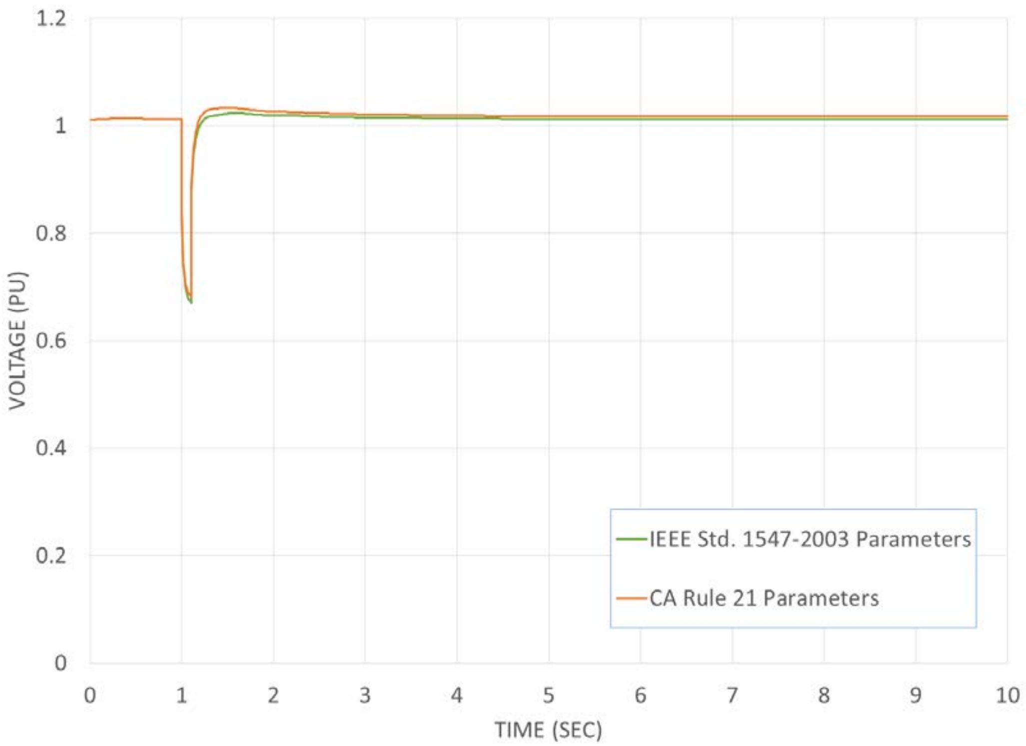

Figure 5-11. Low voltage distribution bus voltage

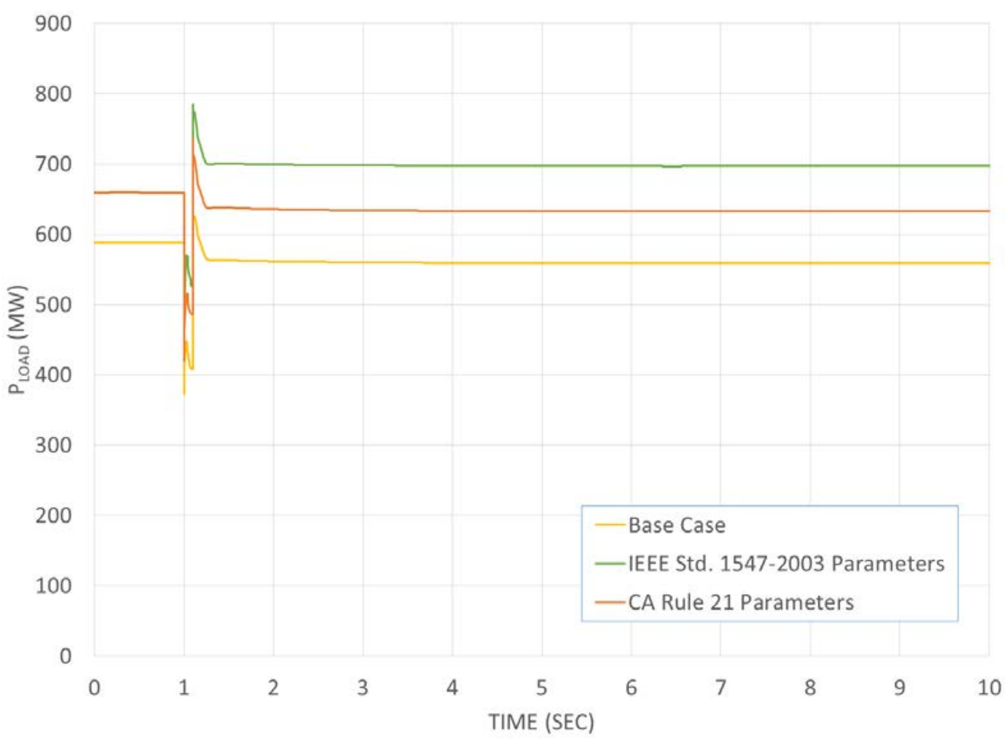

Figure 5-12. Active power load at the distribution level bus

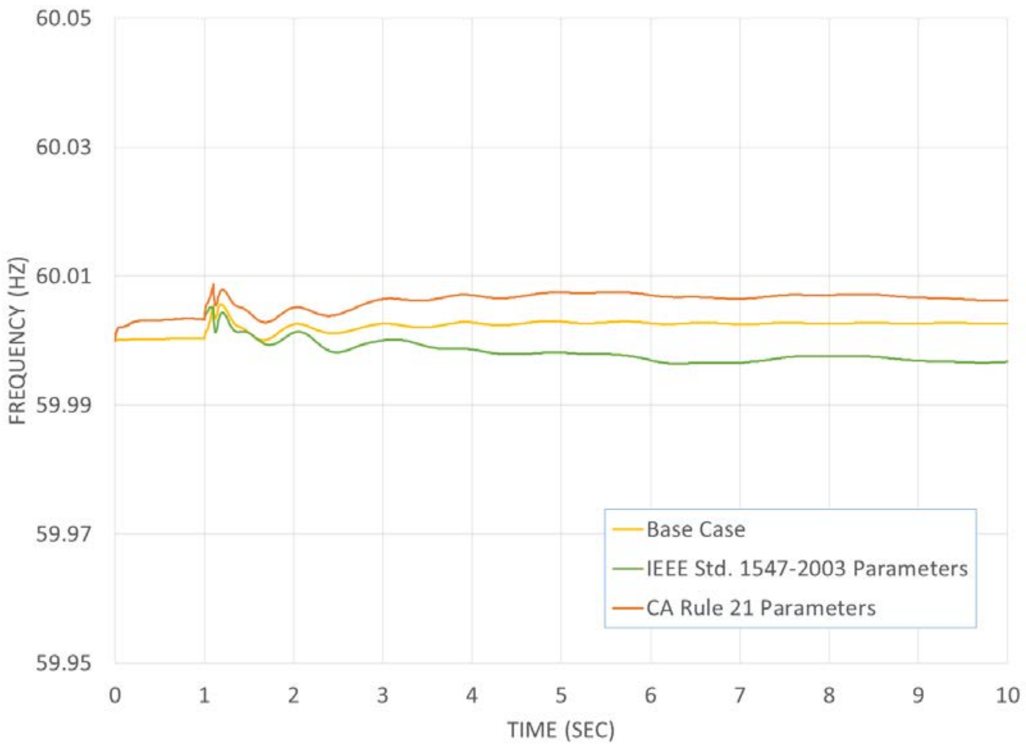

Figure 5-13. Average bus frequency for the SCE area for the three cases

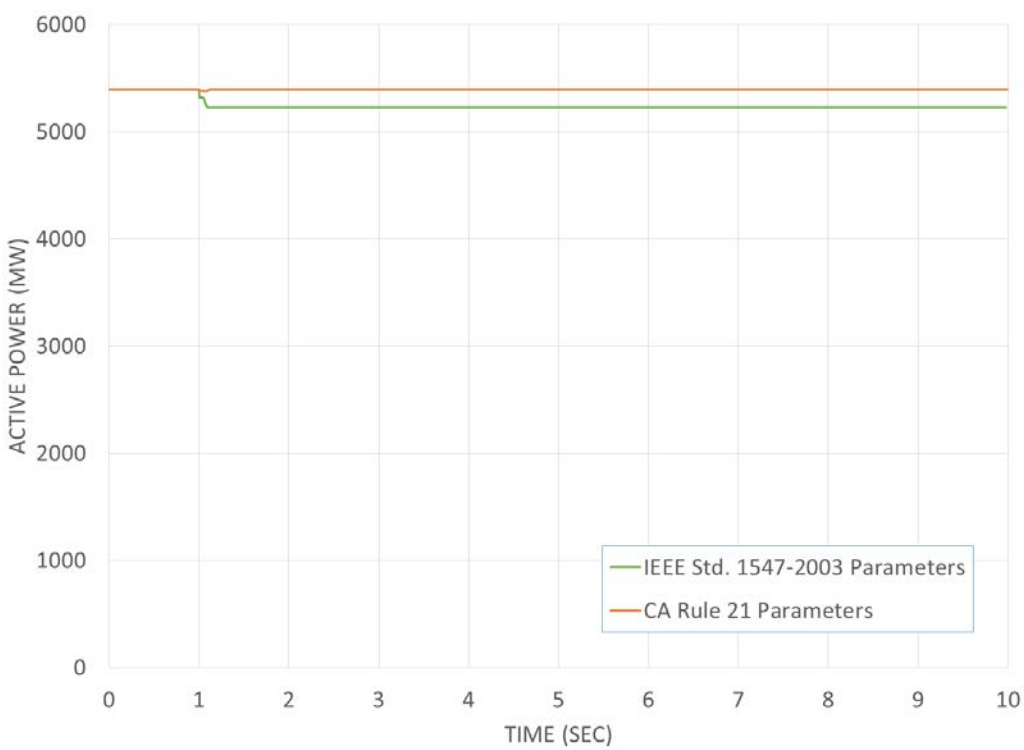

Figure 5-14. Active power output from DER PV in California.

Three Phase to Ground Fault

The next contingency was a three phase to ground fault applied at the same bus. Unlike the single phase to ground fault from the previous section, the voltage at the load bus was reduced to zero. The results for the event are seen in Figure 5-15 through Figure 5-20. With this more severe event compared to the single phase to ground fault, the sub-transmission bus voltage is more significantly impacted and the improved performance with the new CA Rule 21 Parameters is more apparent, Figure 5-15. Since the DER PV reconnects to the system following the voltage recovery (Figure 5-16), the voltage performance at the sub-transmission level and the distribution level (Figure 5-17) is improved. The performance of the load at the distribution bus remains unchanged, Figure 5-18. Additionally, there is a more significant impact in the average bus frequency for the SCE area, Figure 5-19. The aggregate active power response for all the DER PV that have been added to the California power system region is presented in Figure 5-20. With the IEEE Std. 1547-2003 Parameters, DER PV that is local to the voltage depression trips and that results in a total loss of approximately 500 MW in the California region. With the new CA Rule 21 Parameters, the DER PV restore output quickly when the voltage recovers. It is this difference in the dynamic response of DER PV that results in the voltage deviation that we observed in Figure 5-19.

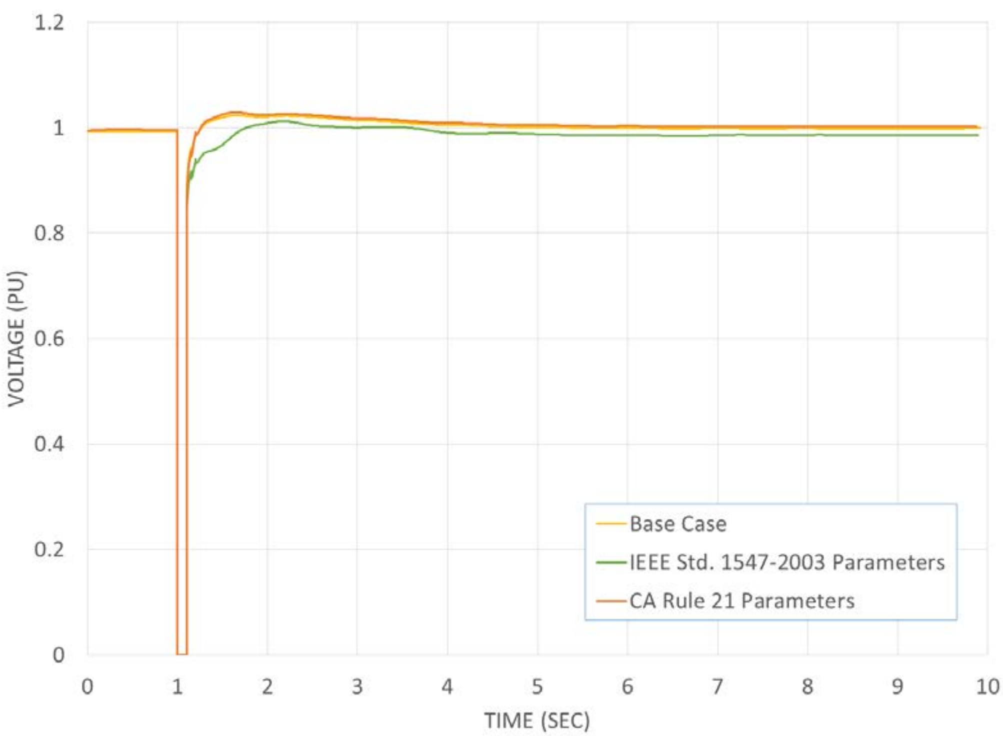

Figure 5-15. Voltage at the 69.0 kV sub-transmission bus

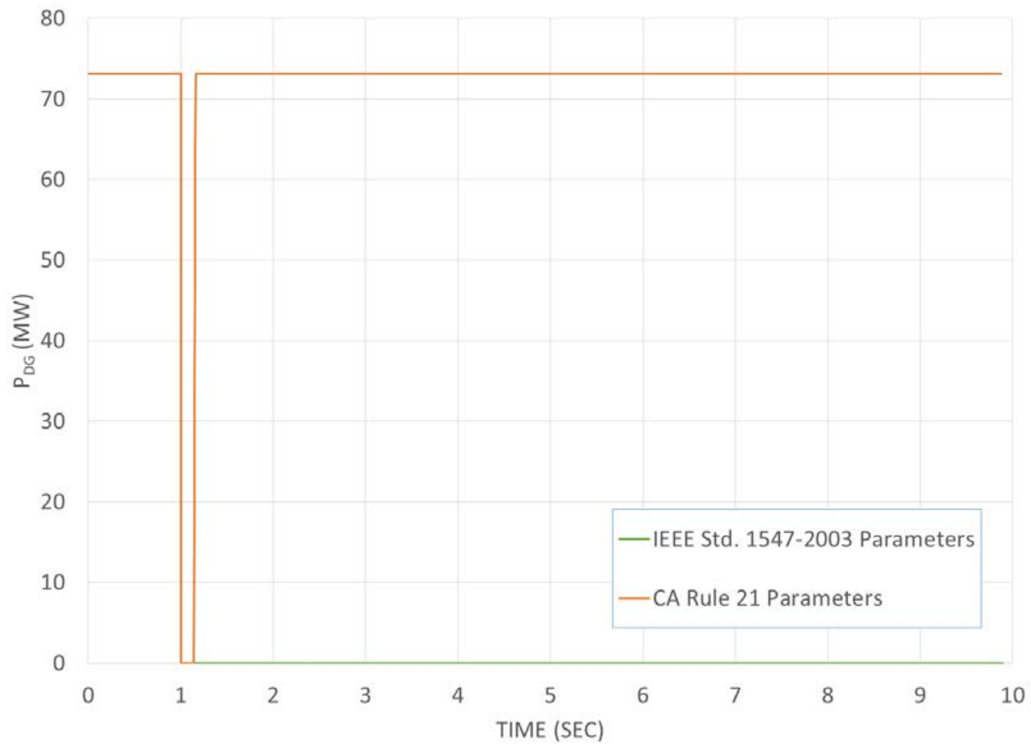

Figure 5-16. Active power output (P_{DG}) from the DER PV

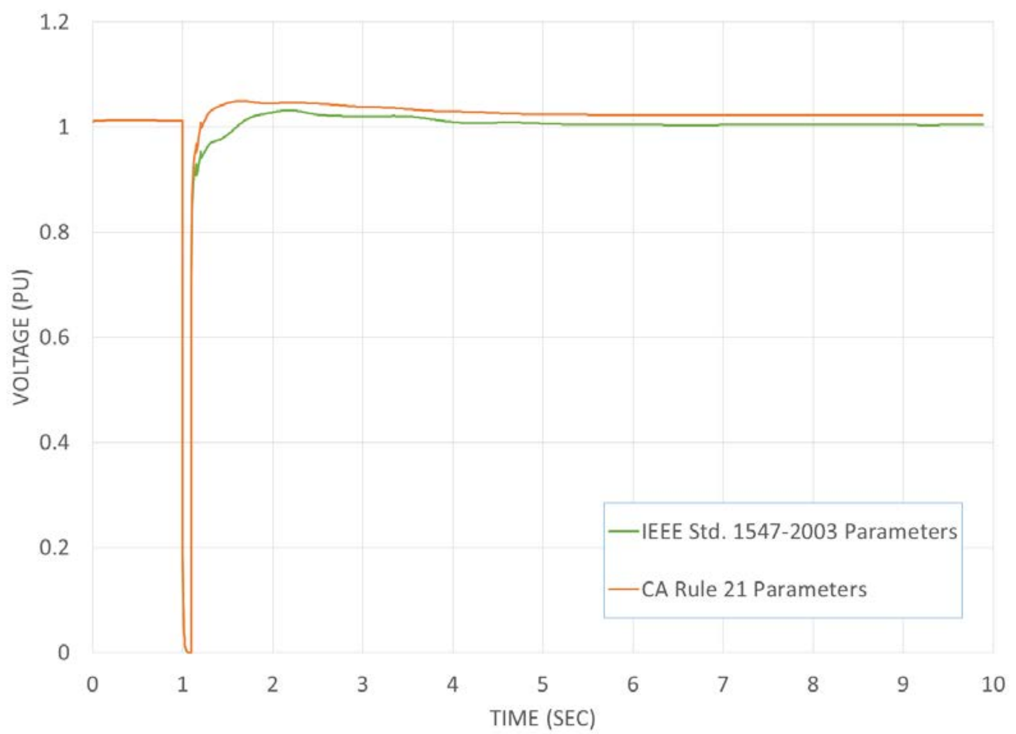

Figure 5-17. Low voltage distribution bus voltage

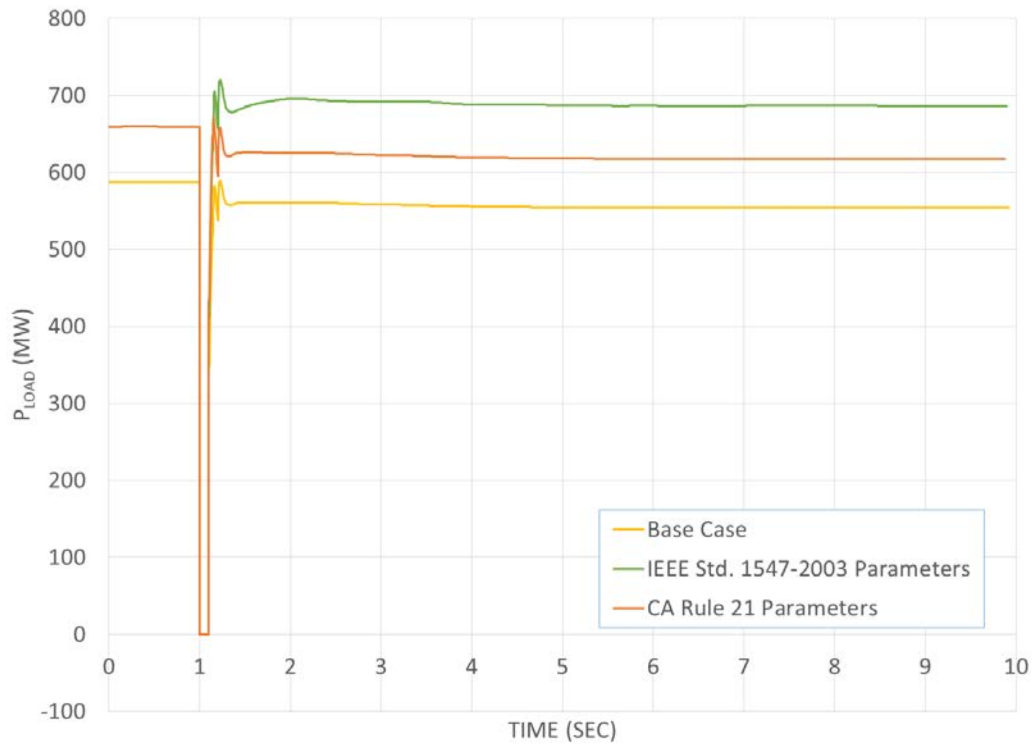

Figure 5-18. Active power load at the distribution level bus

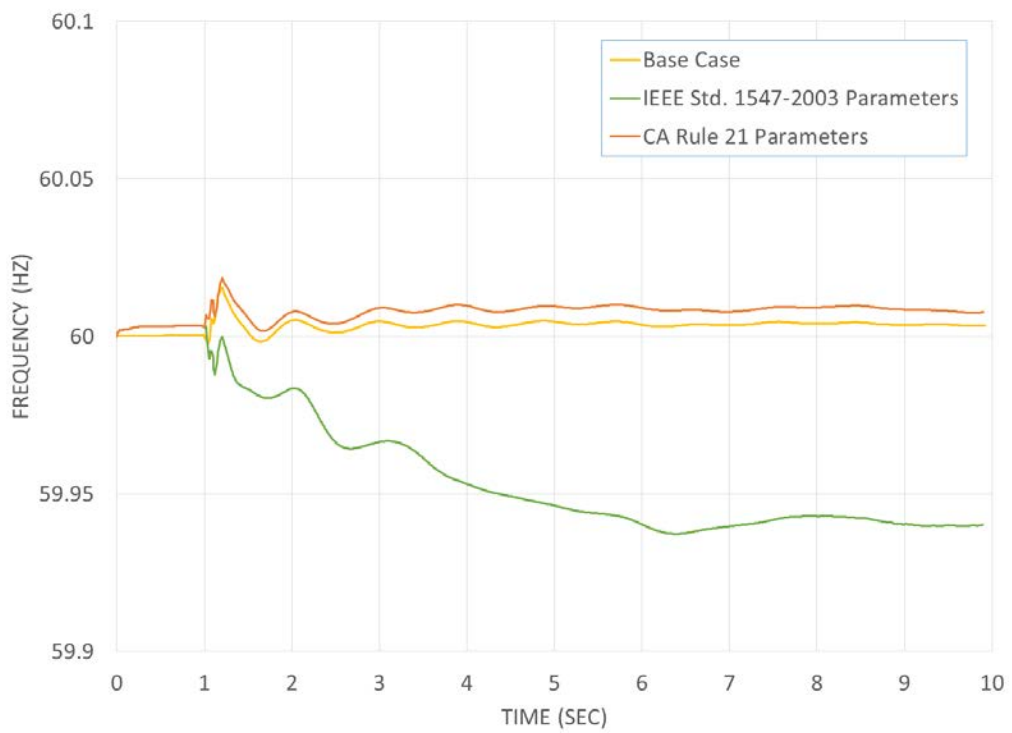

Figure 5-19. Average bus frequency for the SCE area

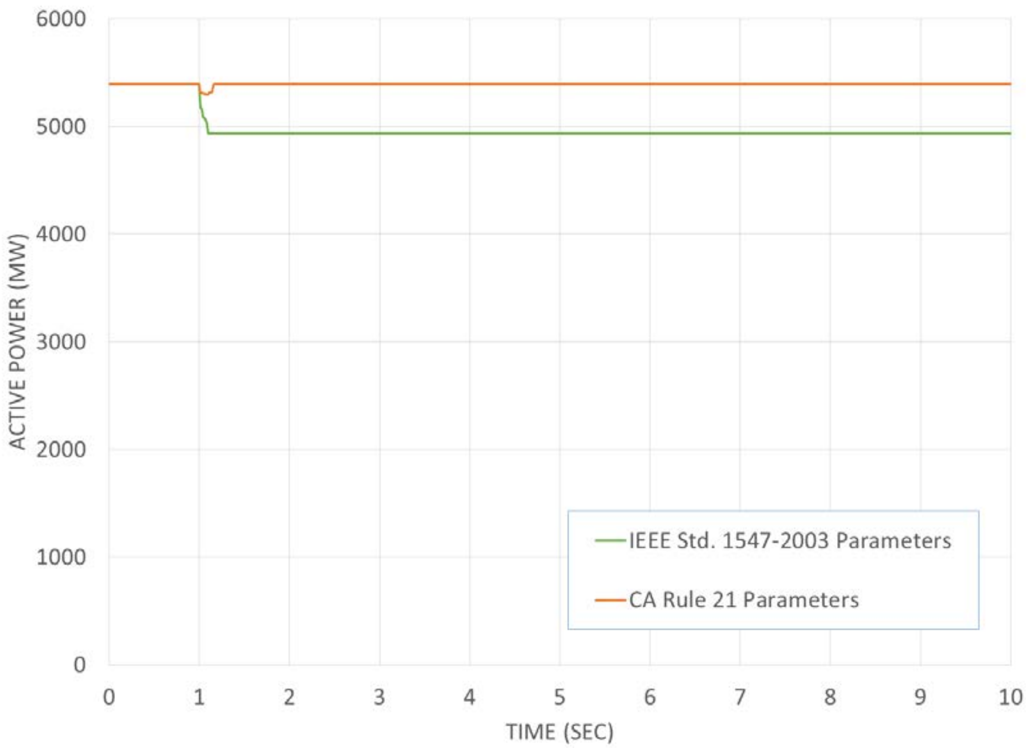

Figure 5-20. Active power output from DER PV in California

Loss of Generation Contingency

Finally, two of the Palo Verde units were tripped and the results were observed at a sub-transmission load bus and for the average bus frequency for the SCE region. The resulting frequency deviation is shown in Figure 5-21. The frequency deviation stays above the IEEE Std. 1547-2003 under-frequency trip settings of 59.3–59.7 Hz and no infeed from DER PV is lost. The bus voltage can be seen in Figure 5-22. The loss of the generator does have a slight impact on the voltage performance, but is not significantly impacted by the presence of the DER PV. Additionally, the impact on the active power loading at the distribution level bus is presented in Figure 5-23. This slight variation in distribution load following the contingency is due to the voltage-dependency of the dynamic load models rather than the response of the DER PV, Figure 5-24. In fact, Figure 5-24 shows that the loss of generation event has no impact on neither the active power injected by the DER PV at the chosen sub-transmission load bus nor the aggregate DER PV active power in California. All DER PV maintain a constant output throughout the simulated contingency.

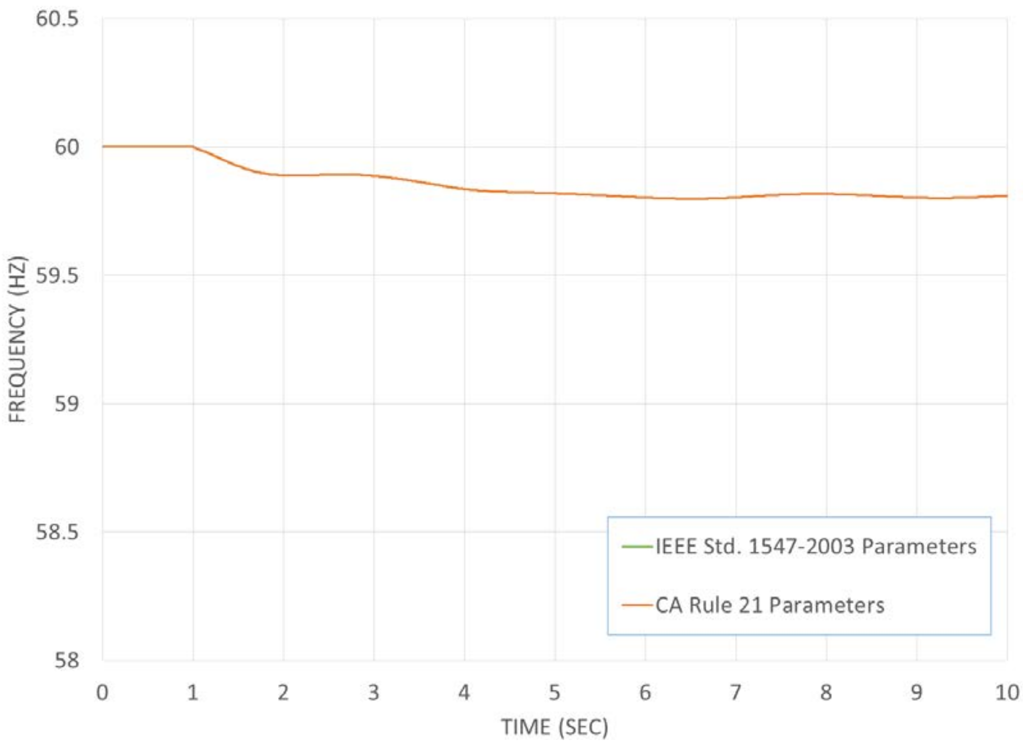

Figure 5-21. Average bus frequency for the SCE region

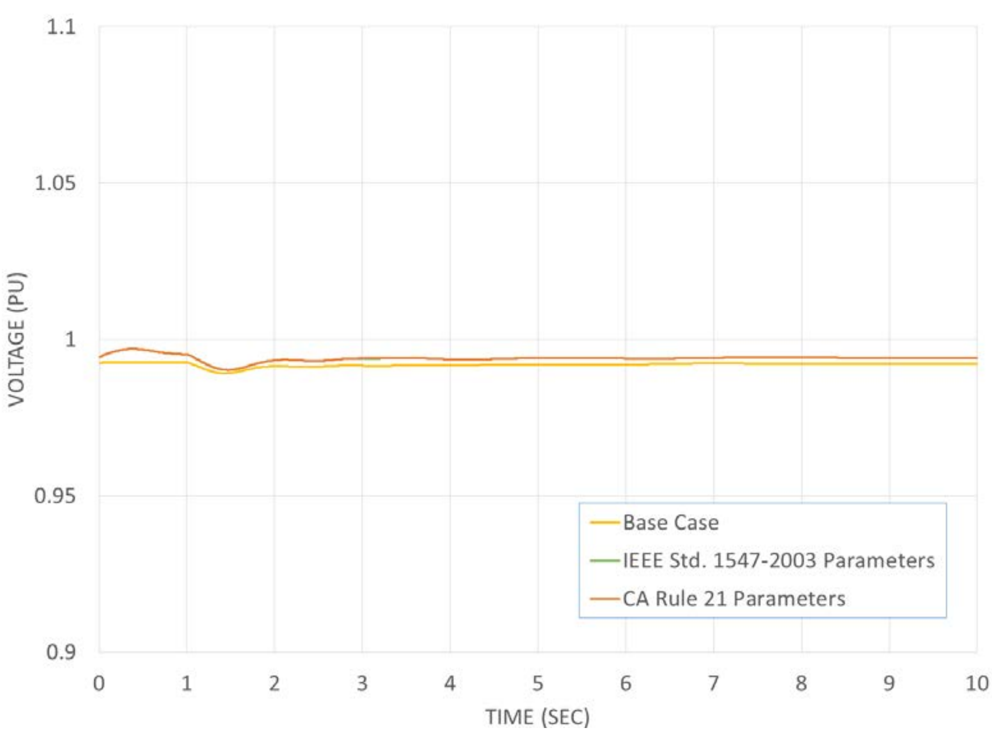

Figure 5-22. Voltage at the 69.0 kV sub-transmission bus

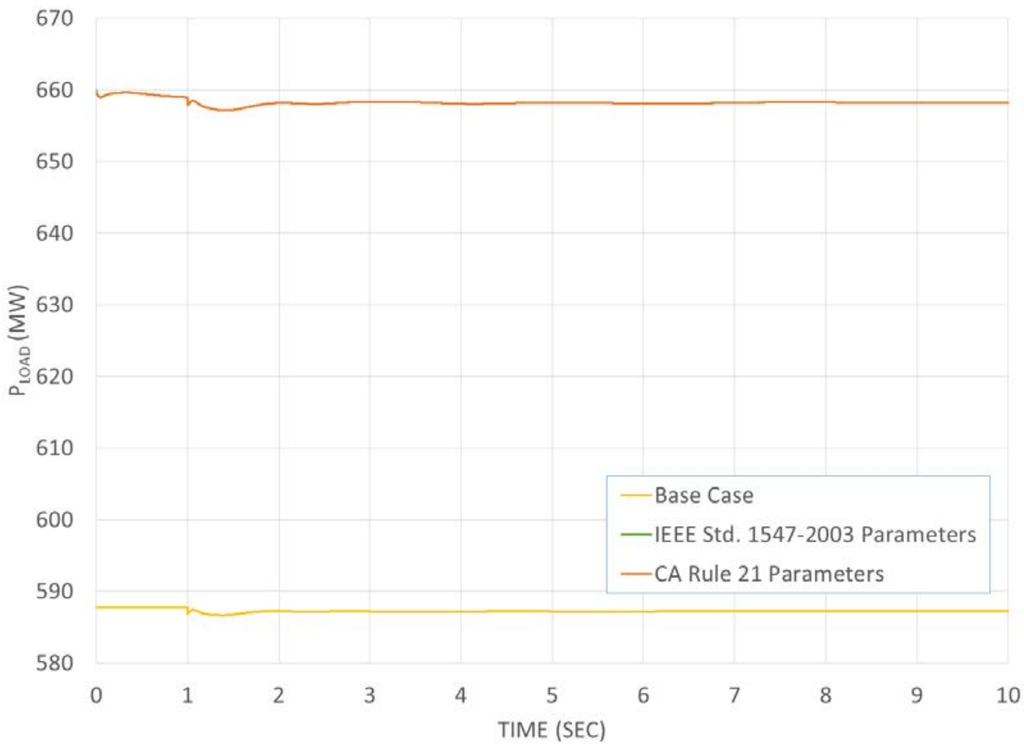

Figure 5-23. Active power load at the distribution level bus

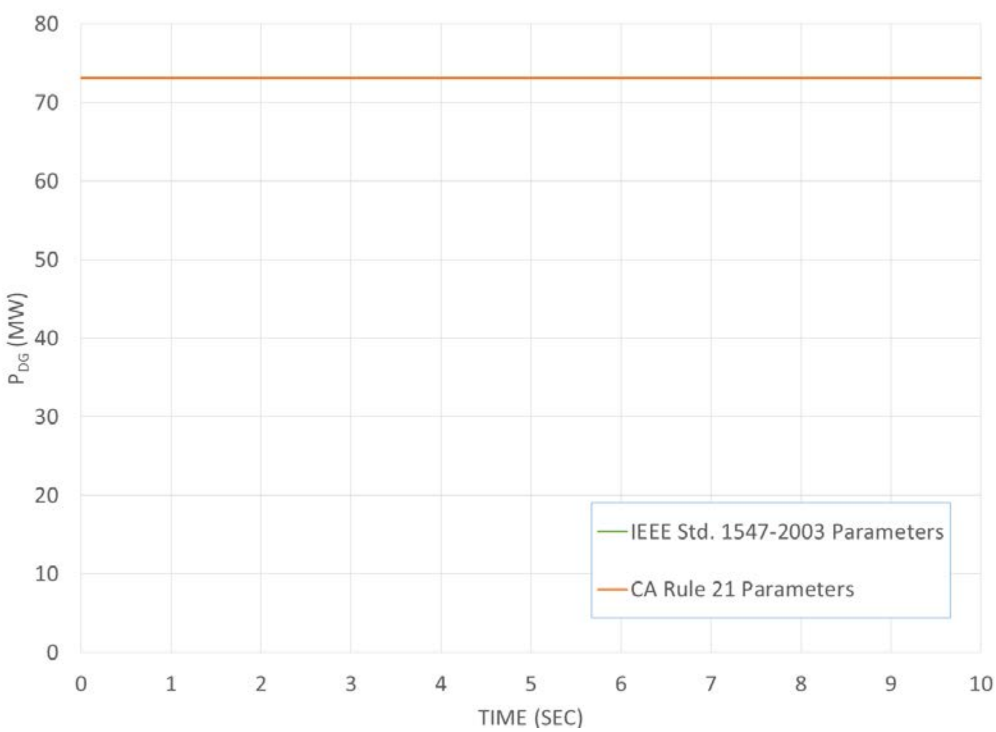

Figure 5-24. Active power output from the DER PV

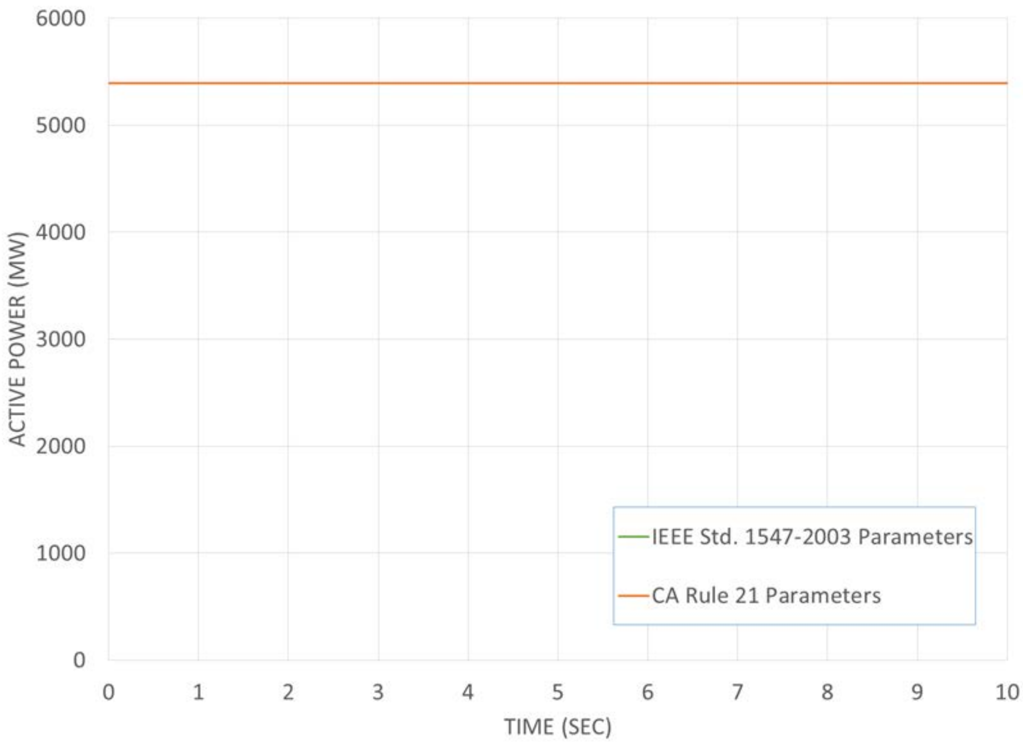

Figure 5-25. Active power output from DER PV in California

PVD1 Model Results

In this section, the PVD1 model results are presented for a three phase to ground fault. The CMPLDWG model was replaced with an equivalent circuit, the CMPLDW model and the PVD1 model to examine the impacts of fault-induced delayed voltage recovery (FIDVR). Using the methodology described, the DER PV was modeled at four nodes in the California region and the simulation time was increased to 60 sec. in order to adequately consider the FIDVR-related motor load time constants.

In the course of developing the network model, it was determined that the system is very sensitive to the representation of the equivalent feeder circuit used to connect the DER PV and the CMPLDW model. An example of typical feeder data is provided in Table 5-4. The impedance data provide here is for individual feeders in a distribution system with typical loading of approximately 10 MVA. As such, when representing them in the power flow case for the bulk transmission system, they should be scaled and paralleled by the size of the load. For example, using Cluster 7, a 100 MVA load would have the X and R values from Table 5-4, reduced by a factor of 10, 0.005 pu and 0.012 pu for X_{fdr} and R_{fdr} respectively. Using impedance data for a single feeder will result in non-convergent power flow cases. As such, it is important to model the feeder correctly when explicitly modeling the DER PV in the system.

Table 5-4. Typical Distribution Feeder Impedances on 100 MVA System Base

Cluster ID	kV	Z (pu)	X (pu)	R (pu)
4	12	0.29	0.13	0.25
6	20	0.13	0.05	0.12
8	4	0.68	0.33	0.59
7	12	0.11	0.06	0.10
8	12	0.39	0.19	0.34
1	12	0.41	0.21	0.35
2	12	0.29	0.15	0.25

The low voltage trip settings on the PVD1 model in Table 5-4 were adjusted from the new CA Rule 21 Parameter Case values based on simulations of a detailed distribution system as described in section 0.

Additionally, for these simulations, the single-phase induction motor was run with a stall setting of 0.033 sec. The introduction of the motor stalling significantly impacted the voltage performance of the network.

Three Phase to Ground Fault

A three-phase to ground fault as in the previous section was applied at a node that was particularly sensitive to FIDVR impacts. The motors were set to stall after 0.033 sec. and would stall following the fault. As observed in the Figure 5-26, this results in a significant FIDVR event, where the voltage recovery is delayed for approximately 15 sec. following the fault clearance. This result can be explained by the single phase induction motors in the CMPLDW model absorbing large amounts of reactive power during stalled operation. The voltage stays below normal operating conditions at a value of approx. 0.8 pu until the single phase induction motors are tripped by their thermal protection.

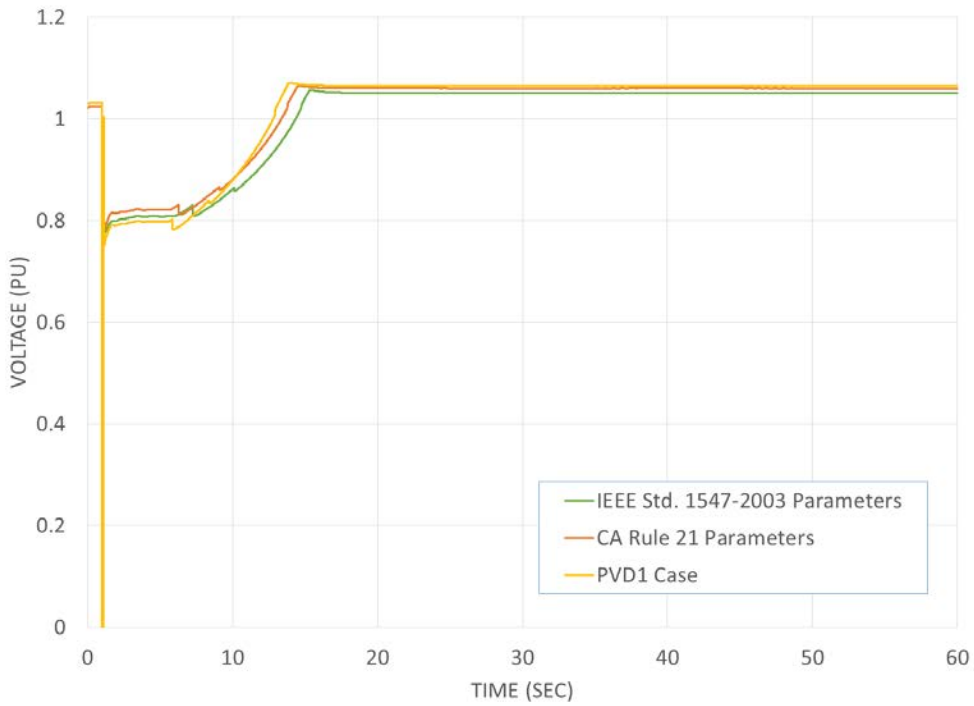

Figure 5-26. Voltage at the 115 kV sub-transmission bus for the three DER PV cases.

As shown in Figure 5-26, the voltage at the 115 kV sub-transmission bus in the PVD1 Case recovers from the FIDVR event the fastest, approximately 1 sec. faster than the results in the CA Rule 21 Parameters Case and 2.5 sec faster than the results in the IEEE Std. 1547-2003 Parameters Case. In the two latter cases, the DER PV operated in active power (P) priority mode, while in the PVD1 Case, the DER PV is operated in reactive power (Q) priority mode. The impact of Q priority on the active and reactive power injection from the DER PV is shown in Figure 5-27 and Figure 5-28.

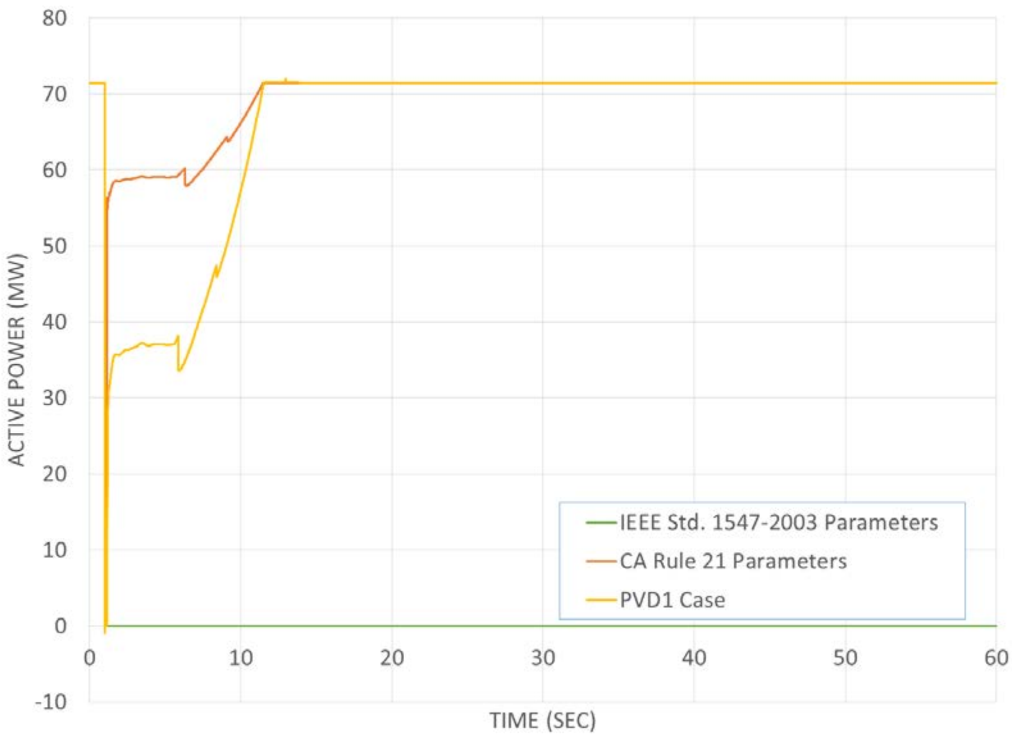

Figure 5-27. Active power injection from the DER PV for the three chases.

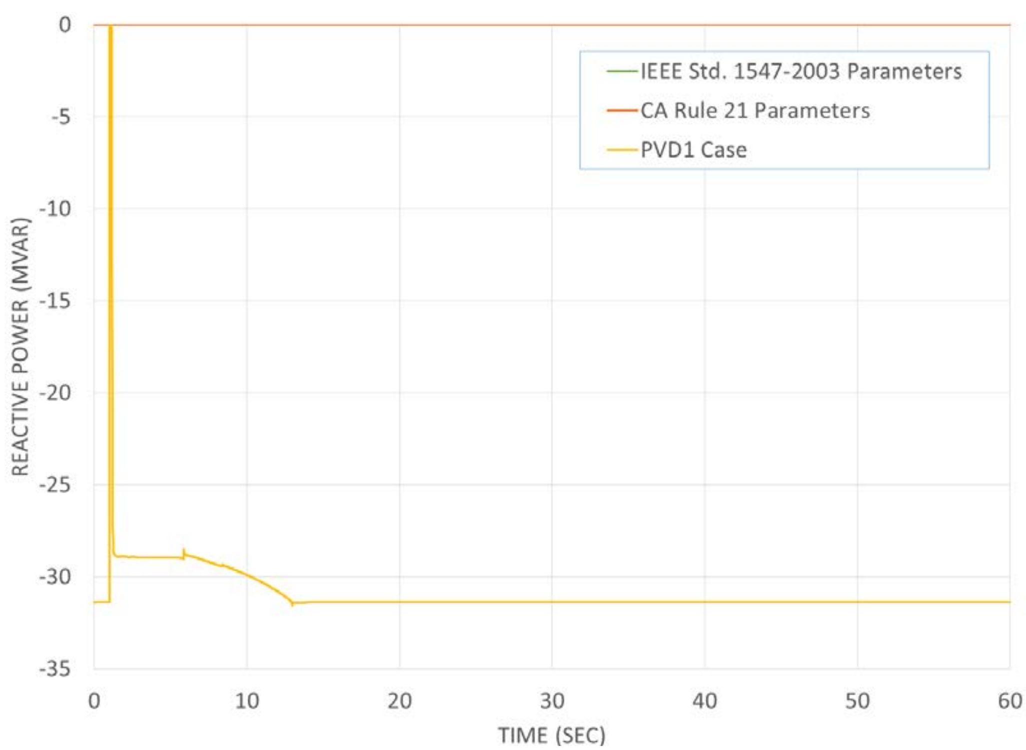

Figure 5-28. Reactive power injection from the DER PV for the three cases.

The active power injection from DER PV is reduced in the PVD1 Case allowing for increased reactive power injection into the system in order to support the local distribution system voltage.

Additionally, the pre-fault reactive power set-point of -31 MVAr in Figure 5-28 is different from the unity power factor pre-fault set-point of DER PV obtained for the CMPLDWG results. This indicates that the representation in the CMPLDWG model may under-estimate the reactive power consumption by the DER PV when voltage is controlled at the POI with steady-state voltage controls.

Similar to the previous section, the overall response of the DER PV was monitored for the entire state of California. In Figure 5-29, the active power response of all the newly installed DER PV can be seen for the three studied cases. Once again, the results in the CA Rule 21 Parameters Case and the PVD1 Case show a temporary cessation of the DER PV during the fault but restoration of power output following the recovery of the voltage. In the PVD1 Case, there is a slight decrease in the DER PV active power output which is due to the fact that the DER PV local to the fault is modeled as the PVD1 operating in Q priority mode. As such, there is a decrease in active power output in order to inject additional reactive power into the system.

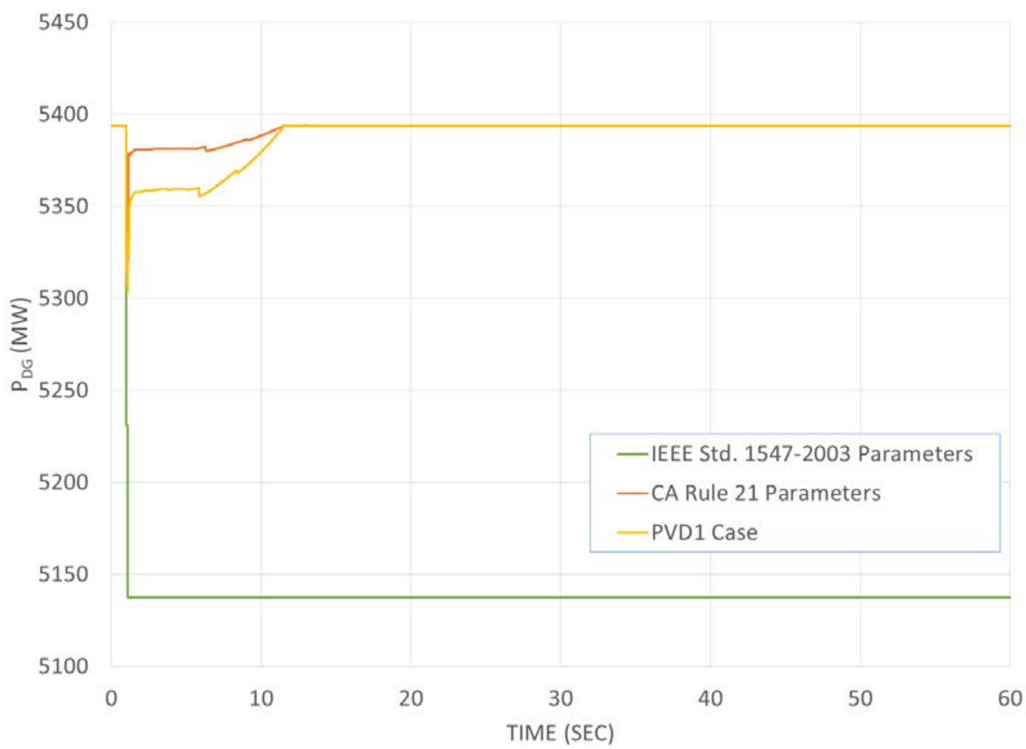

Figure 5-29. Active power response for DER PV in California.

Overall, operating at the assumed penetration level of 10.5% of load, there is not enough DER PV present in the system to substantially impact the voltage stability of the system even when the DER PV is explicitly modeled and operated in Q priority mode. As penetration levels increase, dynamic voltage support from DER PV could potentially benefit the system by providing reactive power support locally at the distribution level and thereby increase the voltage stability of the system. That said, application and specifications of dynamic voltage support from DER PV will be system-dependent and will largely depend on whether active or reactive power infeed is needed during the fault period.

Frequency Impacts with DER PV

In the previous section, a loss of generation event was considered. However, since the system utilized for this analysis is the WECC case, the frequency deviations were found not to be significant enough to impact the frequency ride-through or over-frequency droop settings of the equipment. This was shown for the largest contingency in the WECC, the loss of two of the Palo Verde units. In order to assess significant frequency impacts from DER PV, a different approach beyond the scope of this study would be required. System conditions would need to be modified in order to bring the system closer to frequency instability conditions. Such an instable system condition might be observed under low load conditions (instead high load conditions as in the Heavy Summer Case) and with high penetrations of DER PV significantly larger than the 10.5% of load considered in this study. As a result, low levels of committed synchronous generation would be expected, and that could result in frequency performance conditions that could actually be impacted by DER PV. Future work should investigate the potential benefits of advanced inverter functions of DER PV for the frequency performance under instable system conditions.

Results

Overall, the California region is able to accommodate a low penetration level of DER PV generation with no significant stability issues. The dynamics of the system are not significantly different compared to the Base Case without any DER PV. Using the IEEE Std. 1547-2003 Parameters can result in some voltage performance issues, but moving to the new CA Rule 21 Parameters will alleviate those issues. For the contingency cases investigated, the new CA Rule 21 Parameters for voltage and frequency ride-through showed robust system performance under the modeling assumptions.

The methodology used in this analysis kept the available level of dynamic reactive and inertial support from conventional generation in the study area constant to the WECC 2024 Heavy Summer TEPPC Case, i.e. generation in the study area remained unchanged, and the additional load was balanced with generation from outside the footprint. As a result, the WECC system analyzed in this study is strong compared to the limited system-wide penetration level of DER PV. Additionally, this study has shown that the equivalent circuit representing the distribution network can have significant impacts on the bulk system performance.

By utilizing the PVD1 model and explicitly modeling the DER PV, this study was able to produce indicative results that may support the benefit from DER PV to provide additional Dynamic Voltage Support to the bulk transmission system. However, the DER PV penetration level modeled in this study, while realistic for the 2024 system, was not high enough to see significant voltage or frequency stability impacts. However, results suggest that further work that aims at an improved understanding of potential benefits that DER PV may have on the stability of the bulk transmission system would be very useful. That said, application and specifications of dynamic voltage support from DER PV will be system-dependent and will largely depend on whether active or reactive power infeed is needed during the fault period. Furthermore, distribution system-related impacts such as protection coordination and power quality issues will have to be carefully considered before using dynamic voltage support from DER PV.

This study showed that using a large highly meshed system such as the WECC makes it difficult to capture and isolate the impacts of DER PV control directly. Future work should therefore pursue more detailed modeling of the DER PV in distribution networks using electro-mechanical transient (EMT) simulation environments in order to quantify in further detail the aggregate distribution system response at the substation level. The identified characteristics could then inform the aggregate modeling of DER PV by use of the PVD1 and CMPLDWG models to represent the behavior of DER PV more accurately in bulk system stability studies.

Additionally, the analysis should be completed under significantly higher penetration levels of DER PV. The level studied in this analysis, 10.5%, was not high enough to make a significant impact at the transmission level, but the results indicate that at higher penetration levels, potential benefits of advanced inverter functions may be found.

6
CONCLUSIONS

Advanced inverters have functionality that can allow better integration of distributed energy resources such as PV to the distribution system. At the distribution system level, these functions include non-unity power factor settings, volt-var settings, and volt-watt settings. This is not an all-inclusive list of settings, but includes those that are at the top of the mind for most inverter manufacturers and distribution planners.

This report summarizes the analysis approach (methods) in which appropriate settings for each of the advanced inverter control functions can be derived. Ideally, there would be one global setting that works in all situations for each control function, however, as determined in this research, the control settings are strongly linked to the specific feeder in which the control will be applied. For each advanced inverter function, several methods are created in such a way that the distribution engineer can make use of the data/tools available to make the determination of control settings. Multiple methods span the availability of limited data/tools to abundant data/tools with detailed feeder models.

The advanced inverter setting methods are developed against feeder models, yet the applicability to different feeder models is necessary to gauge the methods' effectiveness. The models built/validated in the previous Solicitation #3 feeder analysis were leveraged into this study to meet that need. The feeders selected from the previous study ranged from those with limited to significant impact from distributed PV. The feeder voltage impact was the primary driver used in the feeder selection process. Voltage impact was used because voltage issues are the primary beneficiary from advanced inverters improving distribution system performance. Hosting capacity was also used to quantify the voltage impact and further leveraged the previous analysis. The previous analysis became the baseline distribution system impact from PV in which advanced inverters were examined to improve.

The distribution feeders hosting capacity was shown to improve with the use of advanced inverters using the settings derived with the various methods. Some control functions did perform better than others, and the more complex methods did generally allow better accommodation of PV.

Findings

Regarding the performance of the control methods and application of settings:

- Power Factor and Volt-var Method Level 3 provide additional benefit with regards to increasing hosting capacity
- Power Factor Method Level 1 generally provides high benefit but requires the most reactive power to do so
- Volt-var Method Level 1 is the least complex and has one of the most effective uses of reactive power

- Volt-watt Method Level 1 should be used in conjunction with power factor or volt-var control while these reactive power control functions should prevent the unnecessary curtailment of real power when operated first

Regarding the performance of the bulk system related control methods and application of settings:

- No serious stability issues with the DER PV penetration of 10.5% in a WECC 2014 Heavy Summer case.
- New CA Rule 21 voltage and frequency ride-through improve system reliability.
- Further stability improvements seem to exist when utilizing advanced smart-inverter functionality.
- More detailed analysis needed to fully assess the capability of DER PV to support system stability dynamically.

Recommendations

Based on the findings of this work, the suggested advanced inverter methods to set control functions can be used to improve the accommodation of distributed energy resources (PV specifically) on the distribution system. The voltage impact from PV can be mitigated using power factor, volt-var, or volt-watt control. The complexity of setting control functions can be chosen at the discretion of the utility planner. More complex methods to determine settings can provide some additional benefit, while the most simplistic methods also allow benefit to occur through utilizing that control functionality.

Public Benefit

As the number of PV applications and installations increases, utilities are faced with a greater need to evaluate the aggregate impact of these systems. In most cases, it means an increased number of detailed impact studies or applications that do not get approved. The advanced inverter methods and settings developed in this project provide a mechanism to improve the distribution system performance (as it relates to voltage) when accommodating higher levels of PV. A reduction of voltage related issues as well as allowing the fast track of applications to achieve these higher penetrations can result from the use of advanced inverters with the settings derived from the methods included in this report.

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