The Economic Impact of Real Power Management of Solar Photovoltaic Systems

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Technical Update, January 2019

EPRI Project Manager

N. Enbar

ELECTRIC POWER RESEARCH INSTITUTE
3420 Hillview Avenue, Palo Alto, California 94304-1338 ▪ PO Box 10412, Palo Alto, California 94303-0813 ▪ USA
800.313.3774 ▪ 650.855.2121 ▪ askepri@epri.com ▪ www.epri.com

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Principal Investigators
S. Coley
T. Hubert
J. Peppanen

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ABSTRACT

Rising grid penetrations of solar photovoltaic (PV) systems can have adverse distribution power quality, reliability, and safety impacts. The conventional approach for mitigating these adverse impacts is to apply distribution upgrade measures, such as reconductoring or modified voltage regulation schemes. These measures can, however, be costly and their implementation can result in long delays in PV project construction. An alternative method is to employ autonomous smart inverter grid support functions that adjust the active and/or reactive power output of PV systems to mitigate the adverse distribution impacts caused by solar PV. Implementing smart inverter functions that directly alter PV real power output is a sensitive topic due to current compensation mechanisms that provide payment for real power but not for reactive power support. An equally sensitive topic is the implementation of the Volt-VAR function with VAR priority into PV system operation, which can also result in curtailed PV active power output.

This report assesses the real power control methods required to achieve marginal improvements in distribution hosting capacity of 25% or more. It first presents analytical results from distribution system modeling of large scale PV systems connected to a sampling of distribution feeders. Based on findings, an economic evaluation is performed of the costs and benefits of implementing the Volt-VAR with VAR priority and Limit Maximum Real Power smart inverter functions to increase the hosting capacity. Results are intended to inform investment and operational decisions that aim to economically increase distributed PV penetrations; they also seek to inform decisions related to compensation mechanisms for PV and other distributed energy resources.

Keywords

Solar Photovoltaic (PV)
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PRIMARY AUDIENCE: Personnel involved in DER integration and impact studies

SECONDARY AUDIENCE: Distribution System Planners, Distributed PV System Developers

KEY RESEARCH QUESTION

Two strategic research questions are addressed:

1. What amount of curtailment from customer-owned PV is required to achieve a 25% increase in hosting capacity on a sampling of evaluated distribution circuits?

2. Is real power curtailment of distributed PV systems the least-cost option to mitigate the impacts of rising PV penetrations on distribution feeders?

RESEARCH OVERVIEW

This report identifies when curtailing PV system output as a means for mitigating grid impacts due to rising PV penetrations can be more economical than conventional grid upgrade approaches. Specifically, it assesses the economic impact of controlling the real power output of distributed PV systems that are required to achieve marginal improvements in distribution hosting capacity of 25% or more. System modeling results of large scale PV systems connected to a sampling of distribution feeders are used to evaluate the costs and benefits of using select smart inverter functions to mitigate identified impacts.

KEY FINDINGS

- Using smart inverter functions which curtail PV system real power output can be a more economical solution to increase distribution system hosting capacity than conventional grid upgrades.
- Solar PV curtailment was observed to be minor when Volt-VAR control with reactive power priority was employed.
- Using smart inverter functions tends to be economic when the hosting capacity is voltage constrained.
- Using smart inverter functions may be economic when the hosting capacity is thermally constrained if large upgrade projects are otherwise needed.
- Smart inverter functions are more economical when new, costly equipment is otherwise needed to mitigate distribution constraints.
- PV system designs with higher DC/AC ratios result in higher expected curtailments via real power limiting smart inverter functions.

WHY THIS MATTERS

Utilities and solar PV developers are keenly interested in the economic implications of interconnecting and operating PV systems under high PV penetration scenarios. Identifying least cost solutions, and the respective economic impacts of those solutions, can inform investment and operational decisions which can, in turn, help to realize the full value of distributed solar PV.

HOW TO APPLY RESULTS

Findings indicate that managing the real power of distributed solar PV can economically increase PV penetrations above calculated grid hosting capacity levels. Future research, development, and demonstrations that identify the value of distributed energy resource management systems (DERMS) or that test real power management functions in a real-world setting will help the industry continue to realize the full value of distributed PV and other distributed energy sources.

LEARNING AND ENGAGEMENT OPPORTUNITIES

Findings can be enhanced through engagement in related research activities on flexible interconnection, active power management, and through EPRI's DERMS interest group.

EPRI CONTACTS: Steven Coley, Engineer III, scoley@epri.com

PROGRAM: Integration of Distributed Energy Resources, P174

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

CONTENTS

LIST OF FIGURES

LIST OF TABLES

1
INTRODUCTION AND BACKGROUND

Rising grid penetrations of solar photovoltaic (PV) systems can have adverse distribution power quality, reliability, and safety impacts. PV hosting capacity is a metric that quantifies how much PV generation a given distribution system, or a system location, can accommodate before unacceptable adverse impacts are experienced. Different approaches are employed to increase PV hosting capacity. The conventional approach is to apply distribution upgrade measures, such as reconductoring or modified voltage regulation schemes. These measures can, however, be costly and their implementation can result in long delays in PV project construction and/or interconnection. An alternative method is to employ autonomous smart inverter grid support functions that modify the active and/or reactive power output of PV systems to mitigate any adverse distribution impacts.

Smart inverter functions that are best understood (both technically and economically) and that are more straightforward to implement have been addressed in recommendations to California's Rule 21 tariff by the Smart Inverter Working Group (SIWG) Phase 1 [1]. These Phase 1 functions include the Volt-VAR function analyzed in this report. The functions subsequently identified by the SIWG in Phase 3, such as Volt-Watt and Limit Maximum Real Power (LMRP) functions, are more challenging to evaluate; their ability to technically and economically mitigate impacts are less straightforward. Implementing smart inverter functions that directly alter PV real power output is a sensitive topic due to current compensation mechanisms that provide payment for real power but not for reactive power support. An equally sensitive topic is the implementation of the Volt-VAR function with VAR priority into PV system operation, which can also result in the curtailment of PV active power output.

An objective, transparent, and comprehensive benefit-cost framework is needed to evaluate the technical and economic impacts of smart inverter functions that manage real power. To this end, EPRI's Integrated Grid Benefit-Cost Framework [2] has been applied to evaluate the economic impact of employing smart inverter functions to increase the hosting capacity of distribution circuits. Although real power output of solar PV systems can be curtailed, it is not known how deeply, how frequently, or for what duration such curtailments are needed in order to increase the grid's hosting capacity.

This study assesses the ability of Volt-VAR with VAR priority and Limit Maximum Real Power functions to increase the hosting capacity of a sampling of large utility-scale PV systems by 25%. A techno-economic comparison of these smart inverter functions and conventional distribution upgrade measures has been performed for five California utility feeders that represent a diversity of feeder topologies, voltage classes, and other characteristics. The results from this assessment are intended to inform investment and operational decisions that aim to economically increase distributed PV penetrations as well as inform decisions related to compensation mechanisms for PV and other distributed energy resources (DER).

This report is divided into the following five chapters.

Chapter 2: Distribution System Modeling and Economic Analysis Approach – Describes key data sources (e.g., solar production data, feeder load data, and distribution feeder models) used in the analysis, as well as the general approach employed for the technical and economic impacts assessments.

Chapter 3: Annual PV Curtailment from Smart Inverter Functions to Increase Hosting Capacity by 25% – Provides results detailing the annual energy impacts of employing the Volt-VAR smart inverter function with reactive power priority (which curtails real power, if necessary), as well as the Limit Maximum Real Power smart inverter function.

Chapter 4: Cost of Conventional Upgrades to Increase Hosting Capacity by 25% – Details the analysis approach used to determine conventional upgrade measures to increase the PV hosting capacity on selected distribution feeders by at least 25%; the cost of these mitigation measures is also provided.

Chapter 5: Economic Comparison of Smart Inverter Functions and Conventional Upgrades – Describes the results of the economic study comparing the costs and benefits of using smart inverter functions as opposed to conventional upgrade measures to increase PV hosting capacity. A sensitivity analysis on key factors such as PV system DC/AC ratio, PV system location (northern California vs. southern California), and alternative setpoints for the LMRP function is also provided to describe potential variations in results if different assumptions are used.

Chapter 6: Conclusions and Next Steps – Recaps study findings and identifies key factors that utilities and DER owners should consider as they continue to explore economic solutions for increasing penetrations of distributed PV systems.

2
DISTRIBUTION SYSTEM MODELING AND ECONOMIC ANALYSIS APPROACH

Properly analyzing the technical and economic impacts of using SIWG Phase 3 smart inverter functions to increase PV system hosting capacity requires the use of a number of key data sources and assumptions. What follows is a description of the solar PV production data, distribution feeder load data, distribution feeder models, and key assumptions and approaches used in the technical and economic analysis presented in this report.

Solar PV Production Data

Modeling the intermittency of solar PV is an important input for accurately determining the potential for increasing hosting capacity. In this study, measurement data was collected from a 200-kW PV plant located in Northern California; this data was recorded at a one-minute resolution from August 1, 2012 to July 31, 2015. The PV plant output was normalized to its DC system rating and linearly scaled to the appropriate PV penetration for each modeled scenario.

The PV plant is a commercial rooftop system that has a 10-degree tilt and is south facing—a typical design configuration for large commercial rooftop PV installations in California. The DC/AC ratio[1] of the PV plant is 1.0, which is significant because there is no clipping of the power output due to inverter saturation. This means the power output data derived from the system can be a good approximation for the available DC power and accounts for appropriate system losses, including module temperature. Accounting for degradation due to increased module temperature is significant in this study because available DC power can be reduced by as much as ~20% relative to its nameplate rating on hot summer days.[2] Accounting for these losses is important so the analysis does not overestimate the additional curtailment induced by implementing smart inverter functions.

The PV system's size was normalized to its DC nameplate rating and then linearly scaled to match the appropriate size needed for each modeling scenario. Further, each modeling scenario imposed a DC/AC ratio of 1.3 for the modeled PV output to provide an aggressive estimate of PV curtailments using smart inverter real power management functions. As shown in Figure 2-1, the annual normalized PV output fluctuated throughout the year with lower power output in the winter months, which is typical of a PV system of this design in Northern California. Further, the PV output never exceeded 0.769, which is indicative of the DC/AC ratio of 1.3. Figure 2-2 highlights a few sample days in April 2012 to illustrate the variability of solar output as well as

[1] The DC/AC ratio is a ratio of a PV plant's total DC system size (i.e., the sum of the nameplate rating of all of the plant's PV modules) to its AC rating (i.e., the sum of the nameplate rating of all of the plant's PV inverters).

[2] Typical solar panels have a temperature coefficient of ~0.5%/°C above PV module cell temperatures of 25°C, as specified on the nameplate rating at standard test conditions. It is common in hot sunny climates for modules to reach cell temperatures of above 60°C, which can result in a ~20% loss in available DC power. This phenomenon is why PV systems typically don't clip available DC power due to inverter saturation unless they are designed with high DC/AC ratios.

the inverter saturation, or "clipping", that can occur when the available DC power is higher than the apparent power rating of the inverter.

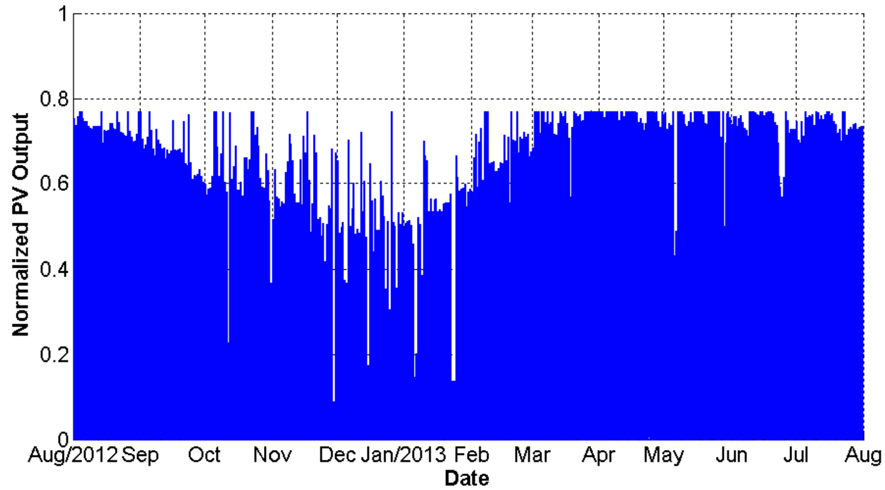

Figure 2-1
Normalized PV generation for the fixed 10° tilt PV system in Palo Alto, CA between August 1, 2012 and July 31, 2013

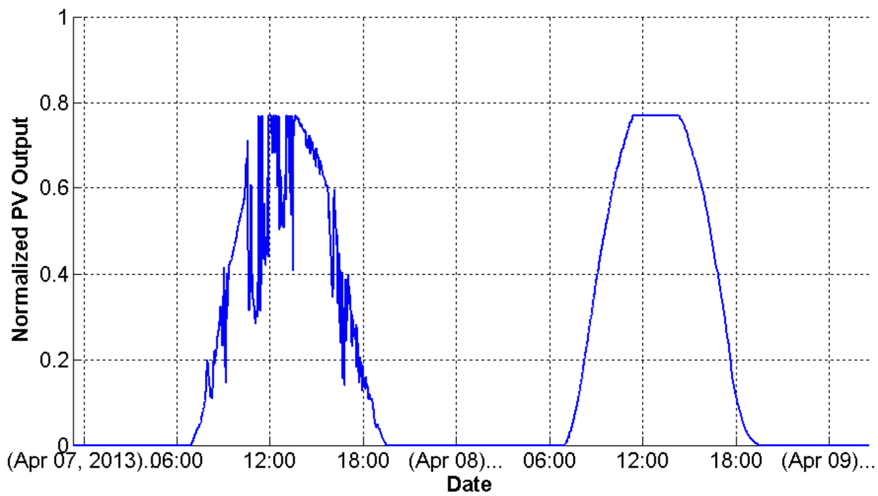

Figure 2-2
Normalized PV generation for the fixed 10° tilt PV system in Palo Alto, CA on April 7 and 8, 2013

Distribution Feeder Load Data

Measured load data at 30-minute resolution from one of five Northern California distribution feeders (described below) was used for this study. Load measurements occurred during the same time period as the solar measurements (August 1, 2012 through July 31, 2013) and were conducted in the same area to capture any dynamic relationships between the load and solar output. The load was linearly scaled based on the peak loading conditions assessed for each of the respective feeders in this study. Both the load and solar PV data was cleansed to remove outliers and anomalies. In a few instances where there was missing load or solar data, the data was recreated using values from adjacent days.

As shown in Figure 2-3, the feeder load peaked in December when solar output was low. The largest amount of reverse power flow (indicated as negative Net Load) occurred in the summer months when load levels were low and PV output was high.

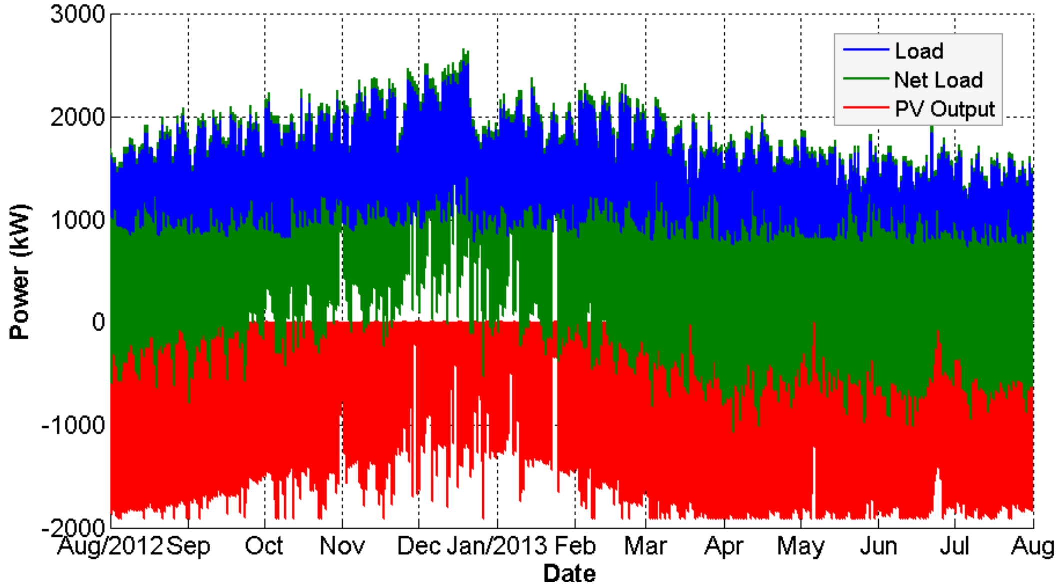

Figure 2-3
Modeled load, net load, and PV generation for August 1, 2012 thru July 31, 2013

Distribution Feeder Models

Five feeders were selected from the 16 feeders characterized in EPRI's California Solar Initiative (CSI) 3 and 4 projects to represent a diversity of circuit sizes, loading conditions, and topologies [3] [4]. The feeders are introduced in Figure 2-4, while an overview of feeder characteristics is given in Table 2-1. Scenario-based analysis compared PV deployed at three locations along the feeder (front, middle, and end), which are described in Table 2-2.

Feeder 631 has the least buses, the lowest rated loading, and the least number of voltage regulation devices. Feeder 2885 has the largest rated loading and 11 voltage regulating devices—the most of the five evaluated feeders. Feeder 888 has the most loads, and the second highest rated load, despite being a very short feeder. Feeder 683 has the most nodes, but the second least total rated loading.

The feeders were modeled in EPRI's Open Distribution Simulation Software (OpenDSS), an open source grid modeling software that is ideally suited for studying the integration of distributed generation on distribution feeders. MATLAB was used to perform the repeated simulations of various settings and combinations of loading and PV profiles and locations.

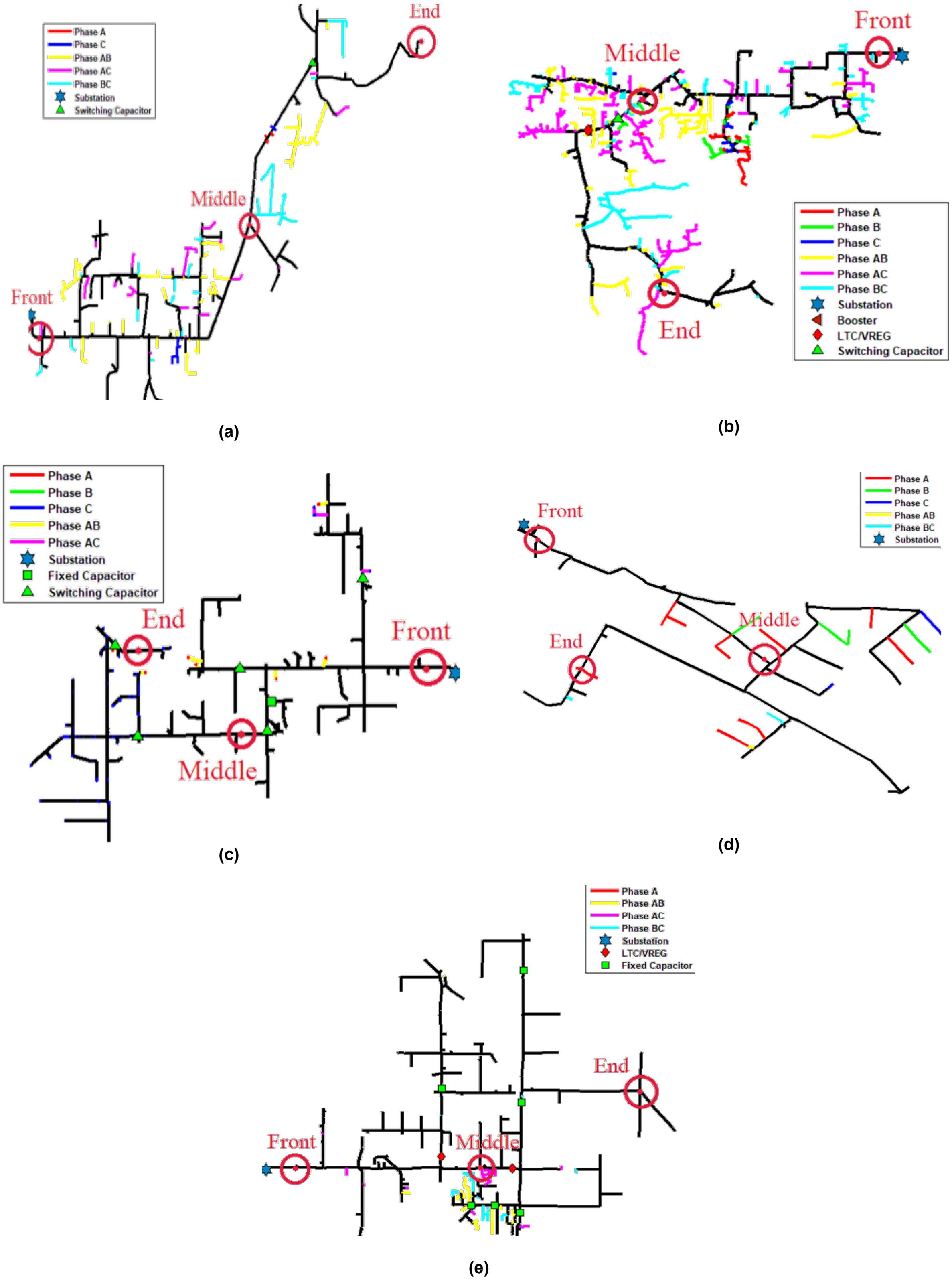

Figure 2-4
Circuit plot by phase for feeders (a) 631 (b) 683 (c) 2921 (d) 888 (e) 2885

Table 2-1
Overview of the five feeders selected for study

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

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

Table 2-2
Location information for the PV systems on each feeder

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

Notes: The distance is the distance from the substation.

System Baseline Performance

Prior analysis performed by the University of California San Diego (USCD) [5] established a baseline hosting capacity for each of the three locations on each of the five assessed feeders. This baseline served as the basis for determining the location and type of smart inverter functions needed to improve grid performance. The hosting capacity assessment involved doing detailed time series analyses in OpenDSS using "worst case" design day conditions. It included two load profiles (peak load and minimum load) as well as three PV load shapes (clear, partly cloudy, and overcast).

The impacts analysis found that seven of the 15 feeder locations had a hosting capacity limited by a voltage constraint and that eight of the 15 locations were constrained by a thermal constraint. Per Table 2-3, except for feeder 888, the limited/smallest hosting capacity occurred when the PV system was at the feeder end. By contrast, Feeder 888 was limited at the feeder head and showed high PV hosting capacity amounting to a PV penetration of 132%. This unexpected result can be attributed to the fact that Feeder 888 is extremely short, heavily loaded, and has five voltage regulators. The feeders displayed a mix of both thermal and voltage hosting capacity limitations. Feeder 683 was the only feeder that was limited completely by thermal overloads, while feeder 2921 was limited completely by voltage violations.

Table 2-3
Summary of hosting capacity on each studied feeder for the three selected PV system locations

	PV at feeder front	PV at feeder middle	PV at feeder end	PV hosting capacity*
Feeder 631	7,622 kW Thermal	5,182 kW Voltage	1,385 kW Thermal	31.5%
Feeder 683	13,980 kW Thermal	12,500 kW Thermal	4,060 kW Thermal	23.2%
Feeder 888	23,286 kW Voltage	26,042 kW Thermal	25,804 kW Thermal	132.2%
Feeder 2885	12,522 kW Thermal	10,845 kW Voltage	3,511 kW Voltage	14.5%
Feeder 2921	4,447 kW Voltage	2,190 kW Voltage	1,535 kW Voltage	18.1%

Note: The hosting capacity percentage values are defined as the ratio of the DC rating of the PV system and the feeder rated (i.e., peak) load.

With the exception of Feeder 888, the movement of the PV towards the end of the feeder and reduction in loading decreased hosting capacity. These conclusions were expected, as higher loading causes more PV power to be consumed locally and reduces the likelihood and magnitude of reverse power flows. Meanwhile, the end of the feeder tends to have smaller conductors which are farther away from the voltage regulators or substation.

Time Series Analysis to Increase Hosting Capacity with Smart Inverter Functions

As previously discovered [6], approximately 50% of the nodes on most of the modeled feeders required PV to provide capabilities beyond Phase I reactive power functions. To assess the capability of Phase 3 functions to reach 25% and higher hosting capacities, UCSD performed time-series analysis of four advanced functions: 1) Volt-VAR control with VAR priority, 2) Volt-VAR control with Watt priority, 3) Volt-Watt control, and 4) limit maximum real power (LMRP). What follows is a summary of the findings.

- Volt-VAR control with Watt priority was ineffective across all feeders and PV locations due to the saturation of inverters. (Inverters on four out of five feeders used a DC/AC size ratio of 1.2 during peak irradiance, restricting the support of reactive power from the inverter.)
- Volt-VAR control does not alleviate thermal constraints.
- Volt-VAR with VAR priority was able to relieve voltage violations but at the cost of some active power being curtailed.
- Volt-Watt control was ineffective for both voltage and thermal constraints. The ineffectiveness was due to two major issues:
  - Imbalance in phase voltage causing large differences between maximum voltage and mean phase voltage on which the inverter controls.
  - Voltage setpoints being too high to effectively curtail real power to lower voltages below violation.
- LMRP function was shown to be effective for both thermal and voltage constraints.[3]

Given prior modeling outcomes, only Volt-VAR with reactive power priority and LMRP settings were used in this study considering they were shown to be the only functions capable of increasing hosting capacity. Though there are a variety of settings for these functions that were successful at increasing hosting capacity by 25%, a single reference setting was used in this report that was successful at all locations and feeders. Further details are described in Chapter 3.

Economic Assessment

Organized energy markets determine locational marginal prices (LMP) that convey the economic value of providing or using a unit of energy at a particular time and location; but there is currently no such economic price signal for managing real-time energy flows at the distribution level. In the absence of distribution-level energy markets, a major gap exists regarding the time and locational value of using Phase 3 functions. A number of key questions and considerations exist that are related to the economics of curtailing distribution-connected solar PV, including those listed below [7].

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

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

[3] In the technical analysis, LMRP of 70% avoided all violations at PV penetration level 25% beyond the baseline hosting capacity. The economic analysis in this report was based on 80% since it results in peak PV generation equal to the baseline hosting capacity, avoids most of the violations, and results in more realistic curtailment.

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

To address the first question, this report uses quasi-static time series simulations in OpenDSS to analyze the impact that select smart inverter functions have on PV power production over a one-year simulation. Specifically, Volt-VAR control with reactive power priority and limit maximum real power setting of 80% (fixed throughout the whole year) are analyzed.

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

3

ANNUAL PV CURTAILMENT FROM SMART INVERTER FUNCTIONS TO INCREASE HOSTING CAPACITY BY 25%

Scenarios using Smart Inverter Functions

For each feeder location that had a hosting capacity limited by a voltage constraint, a Volt-VAR smart inverter function with reactive power priority was employed that was able to successfully mitigate the constraint. For locations that were thermally constrained, the LMRP function was employed at an 80% level. A summary of these scenarios is provided in Table 3-1.

For all scenarios, it was assumed that the PV system had a DC/AC ratio of 1.3. Each individual PV system deployment will have its own optimal DC/AC ratio given project specific economics, but a consistent ratio was used throughout the analysis given its potential impact on end results. While a DC/AC ratio of 1.3 may be a slightly high estimate given today's typical project economics, this assumption yields results that may slightly overestimate PV system curtailments. A sensitivity analysis that examines the impact of different DC/AC ratios for the LMRP function is provided in Chapter 5.

Table 3-1
Scenarios using smart inverter functions

	PV at feeder front	PV at feeder middle	PV at feeder end
Feeder 631	LMRP=80%	Volt-VAR w/ VAR priority	LMRP=80%
Feeder 683	LMRP=80%	LMRP=80%	LMRP=80%
Feeder 888	Volt-VAR w/ VAR priority	LMRP=80%	LMRP=80%
Feeder 2885	LMRP=80%	Volt-VAR w/ VAR priority	Volt-VAR w/ VAR priority
Feeder 2921	Volt-VAR w/ VAR priority	Volt-VAR w/ VAR priority	Volt-VAR w/ VAR priority

Volt-VAR with Reactive Power Priority

Volt-VAR functions allow PV smart inverters to counteract voltage deviation from the desired voltage reference. Volt-VAR functions operate by producing or consuming reactive power according to a fixed Volt-VAR curve that specifies the reactive power as a control action against the voltage measured at the inverter's point of coupling (see Figure 3-1).

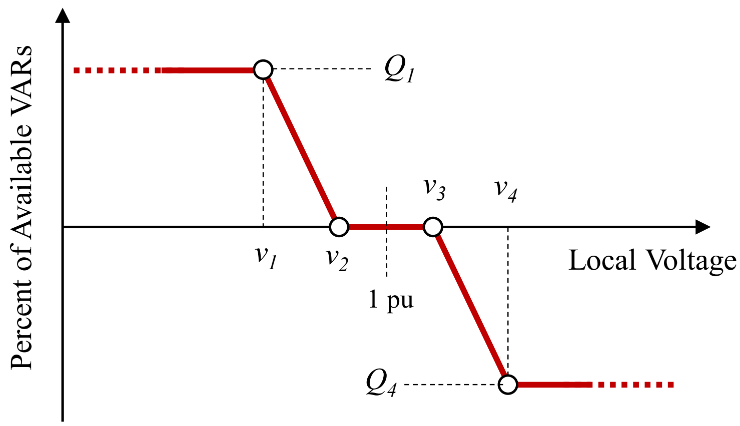

Figure 3-1
Illustration of the Volt-VAR function

The setpoints for the Volt-VAR curve used in this analysis are shown in Table 3-2. This setting was successful at increasing the hosting capacity for all seven voltage constrained cases. It was selected because it achieves the hosting capacity increase, has one of the lowest curtailments across all feeders that resulted from the hosting capacity assessment[4], and is similar to the Rule 21 default curve with the exception of a lower reactive power setpoint of 0.25 instead of 0.3 and slightly tighter v1 and v4 values.

Table 3-2
Setpoints used for the Volt-VAR function

Point	Local Voltage Setpoint *(per unit)*	Reactive Power Setpoint *(per unit)*
1	0.95	0.25
2	0.97	0
3	1.03	0
4	1.05	-0.25

Limit Maximum Real Power

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

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

The LMRP function of 80% was used because it represents an increase in available DC capacity by 25%. As shown in shown in Figure 3-2, the maximum available AC power remains the same in order to prevent any potential thermal overload. However, the system size has increased, allowing for more total energy production, but with a slightly lower yield relative to the new DC rating.

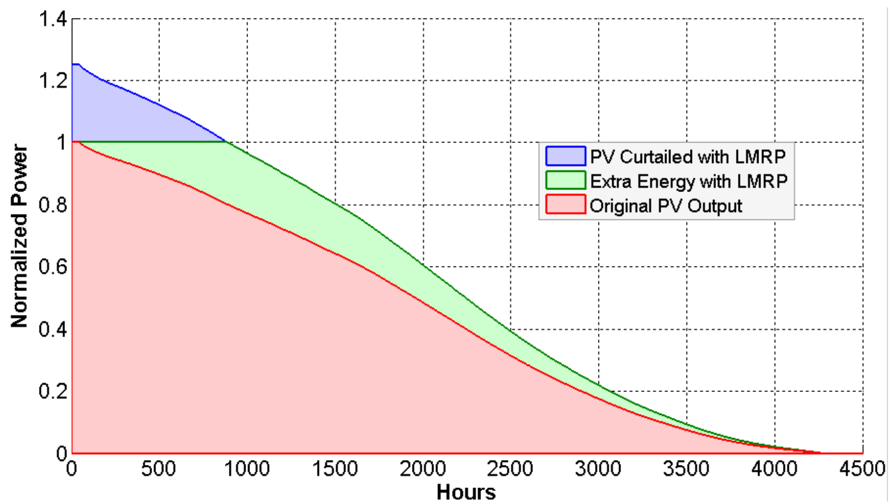

Figure 3-2
Normalized power duration curve showing PV curtailment and extra energy produced using the LMRP function at an 80% level

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

PV System Curtailment Results

The PV system capacity factor, normalized to the solar PV system's DC rating, is a measure of the annual energy production. For the PV system location and design used in this analysis, the annual capacity factor was measured to be 16.97%. Employing the smart inverter functions, as shown in Table 3-3, can reduce the annual energy yield due to curtailments. The modeling results from the annual simulations show that the Volt-VAR function with reactive power priority trigger very minimal curtailments, a maximum of 0.08%. However, the LMRP function results in a much higher curtailment of 4.87% given the design of the PV system. Curtailments for the LMRP function are the same for each scenario considering they were calculated independent of distribution system modeling and based solely on the normalized PV power profile.

Table 3-3
PV system curtailment results from annual simulations

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

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

Looking further at the results, the minimal curtailment using the Volt-VAR function is due to the low reactive power setting (Q=0.25), meaning that real power is limited by only a maximum of 96.8%.[6] However, the LMRP function limits power to 80%. Further, curtailment only happens when the inverter is saturated which rarely occurs. As shown in Figure 3-3, sometimes available PV power is below the limit of the Volt-VAR function, but rarely is it below the limit of the LMRP function. This can be caused by a variety of factors including the PV system's orientation and location, the time of year (given the sun's position in the sky), or a reduction in performance due to temperature impacts.

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

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

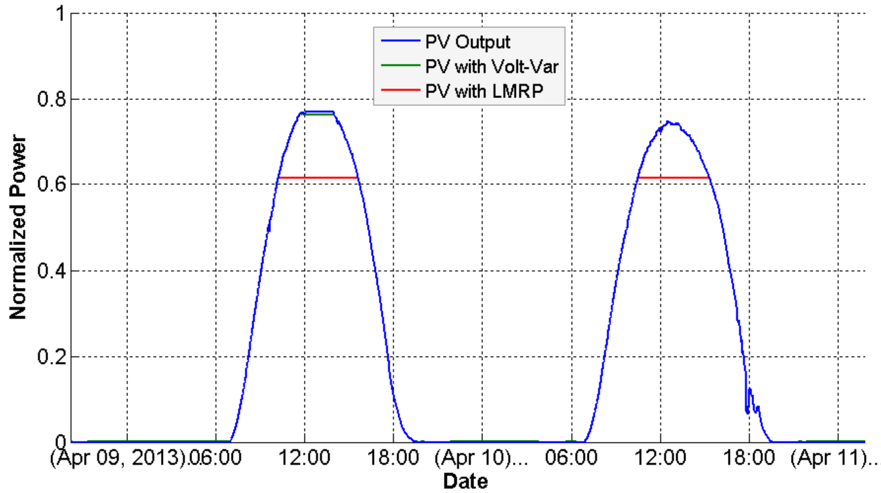

Figure 3-3
Normalized PV power showing curtailment using the Volt-VAR function with Reactive Power Priority and Limit Maximum Real Power function at 80%

Notes: PV power is normalized to the DC rating. Given that the DC/AC ratio is 1.3, the maximum power output relative to the DC rating is 76.9% and thus the maximum curtailment from the Volt-VAR function is $76.9\% \times 96.8\% = 74.5\%$.

Further, the amount of time during the entire year that the available PV power is near the 96.8% limit of the inverter (given the DC/AC ratio size of 1.3) does not occur very often. As shown in Figure 3-3, this happens for only ~50 hours out of the entire year. Alternatively, the LMRP function limits the power output for nearly 90 hours per year.

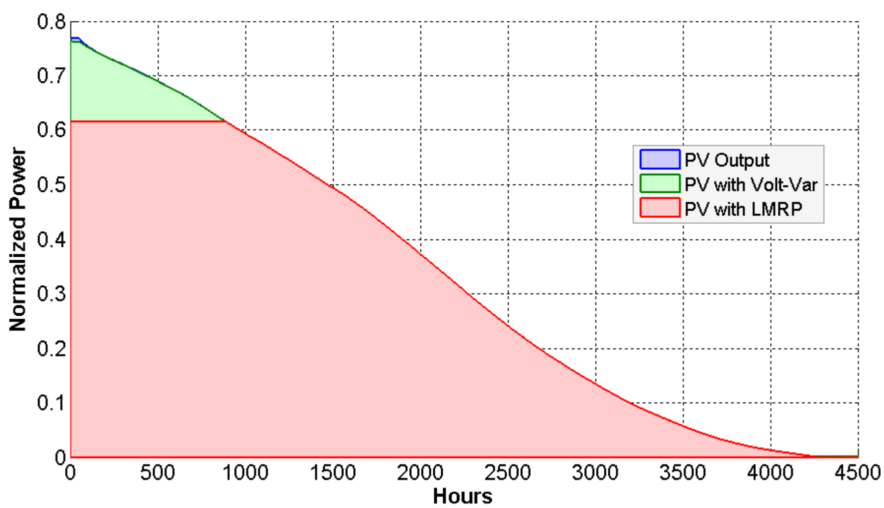

Figure 3-4
Normalized PV power production profile showing curtailment using the Volt-VAR function with Reactive Power Priority and Limit Maximum Real Power function at 80%

4

COST OF CONVENTIONAL UPGRADES TO INCREASE HOSTING CAPACITY BY 25%

The previous chapter analyzed the technical impacts of activating smart inverter functions to increase hosting capacity at various locations for the feeders evaluated in this study. This chapter analyzes the costs associated with the alternative, "conventional", course of action typically undertaken to increase hosting capacity. The conventional and smart inverter-based approaches are subsequently compared to each other in Chapter 5.

Process for Selecting Conventional Upgrades that Increase Hosting Capacity by 25%

Increasing the hosting capacity of distribution feeders using conventional methods can be realized by either adjusting existing feeder devices, or by adding new devices or power lines. For economic reasons, priority was given to the adjustment of existing devices, while new devices were added only if adjustments were insufficient. Changes to regulator device settings or conductor ratings were attempted through trial and error, but followed a logical hierarchy. The flowchart for the process is given in Figure 4-1. Following is the hierarchy of adjustments used to resolve voltage violations:

1. Adjust existing voltage regulation devices
    a. Adjust capacitor voltage control set points
    b. Adjust LTC and/or voltage regulator settings
    c. If a. and b. are not sufficient to increase hosting capacity,
        i. Reset adjusted settings to original utility settings
        ii. Go to (2).
2. Add a new LTC or voltage regulator and determine sufficient settings and best locations based on the feeder voltage profile improvements.
    a. If undervoltage from 2, add capacitor and determine sufficient settings.

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

For thermal constraints, an overloaded conductor was replaced with a conductor with a larger cross-section, and an overloaded transformer was replaced with a transformer with larger rating. These steps were performed until an increase in hosting capacity of at least 25% was realized.

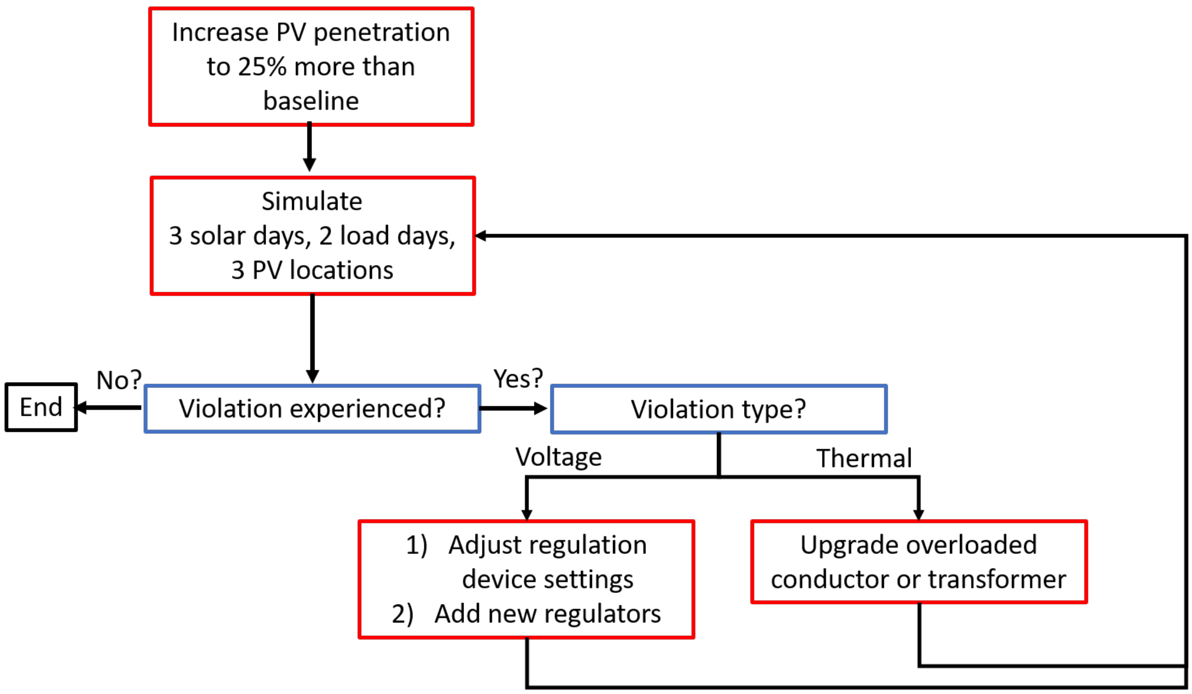

Figure 4-1
Flowchart of the process for realizing a 25% hosting capacity increase using conventional measures

Conventional Upgrade Results

A summary of the new hosting capacity values for the feeders considering conventional upgrades is given in Table 4-1 and the associated measures are described in Table 4-2. Since voltage regulator steps are discrete, the hosting capacity gains were often significantly larger than 25%. Each feeder required a unique solution to reach the desired result. For example, for all three feeder locations on Feeder 683, the upper limit at which the capacitor was turned off was reduced by 1 V. The largest increase in hosting capacity (85%) was realized for feeder 2921 with the PV at the front of the feeder by simply turning off all capacitor banks in the feeder.

Reconductoring was required for resolving thermal violations of 8 out of 15 feeder-PV location combinations. Voltage violations of feeders 2885 at the end PV location and 2921 at the front PV location were resolved by adjusting the regulator/capacitor settings (step 1 of the methodology). The remaining voltage violations (5 out of 15 feeder-PV location combinations) required adding a new LTC or voltage regulator.

Increases in hosting capacity resulting from modifications to regulation equipment settings are more convenient for utilities than those achieved by adding new regulators or reconductoring distribution lines. Modifying settings is a fast, easy, and economical DER integration strategy that is already employed by utilities in practice. However, these settings represent deviations from the optimal settings chosen for the feeders before the presence of DER, and thus could incur a trade-off, such as increased losses or larger wear and tear on voltage regulators. Such unintended consequences of the revised settings were not examined as part of this study due to time constraints. However, the economic analysis results described in this report indicate that, in some cases, simple integration measures can result in considerable increases in feeder baseline hosting capacity.

Table 4-1
Hosting capacity for the five feeders after conventional upgrades

	PV at feeder front	PV at feeder middle	PV at feeder end	PV hosting capacity	Increase in Hosting Capacity
Feeder 631	11427 kW Thermal	6825 kW Voltage	1830 kW Thermal	41.6%	31%
Feeder 683	17894 kW Thermal	16500 kW Thermal	5196 kW Voltage	72%	28%
Feeder 2885	15652 kW Thermal	13773 kW Voltage	4810 kW Voltage	19.8%	29%
Feeder 2921	8226 kW Voltage	3022 kW Voltage	1918 kW Voltage	22.6%	49%
Feeder 888	29574 kW Voltage	33334 kW Thermal	32771 kW Thermal	168.0%	27%

Notes: The increase in hosting capacity was calculated with respect to the baseline.

Table 4-2
Conventional upgrade measures implemented to achieve at least a 25% increase in hosting capacity for each PV location

Feeder	Front Location		Middle Location		End Location	
	PV Penetration Increase	Upgrade	PV Penetration Increase	Upgrade	PV Penetration Increase	Upgrade
Feeder 631	33%	Reconductor 512 ft of line, OH-AAC	31%	Add 1 voltage regulator	32%	Reconductor 100 ft of line, OH-CU
Feeder 683	28%	Reconductor 199 ft of line, OH-AAC	32%	Reconductor 199 ft of line, OH-AAC	28%	Reconductor 199 ft of line, OH-AAC
Feeder 2885	25%	Reconductor 1135 ft of line, OH-AAC	27%	Add 1 voltage regulator	37%	Lower voltage setpoint of voltage regulator
Feeder 2921	85%	Switch-off all capacitors	28%	*Add 1 voltage regulator	25%	*Add 1 voltage regulator
Feeder 888	27%	Add 1 capacitor	28%	*Reconductor 1700 ft of lines, OH-AAC and *Reconductor 385 ft of lines, UG-AAC	27%	*Reconductor 1700 ft of lines, OH-AAC and *Reconductor 385 ft of lines, UG-AAC

Notes: The table summarizes the new hosting capacities. The increase in hosting capacity was calculated with respect to the baseline. A star indicates that the upgrades on that feeder are the same for multiple PV locations. For distribution line upgrades, UG and OH indicate underground and overhead lines, respectively. AAC and CU indicate aluminum and copper type conductors. Full details of the upgrades are presented in [5].

Financial and Costing Assumptions

Table 4-3 presents the financial parameters assumed for an illustrative investor-owned utility (IOU) used for the analysis described in this report. These parameters, together with the asset lifetimes presented in Table 4-4, were used to calculate the economic carrying cost (ECC) for each of the hardware upgrades identified in Table 4-2. The ECC calculated for each hardware upgrade reflects the real annualized value of the upgrade considering the equipment life and its expected replacement costs. It annualizes the capital cost associated with the upgrade in order to compare it to the annualized energy costs of curtailment.

Table 4-3
Financial assumptions for an illustrative investor-owned utility

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

Capital costs for each hardware upgrade were estimated based on publicly available costing information. In particular, The National Renewable Energy Laboratory (NREL) Distribution System Upgrade Unit Cost Database [8] was used. This database consists of a compilation of cost information from publicly available utility cost guides, as well as anonymized cost information from actual projects.

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

- In some cases, the conductor size required for the upgrade was too far from the conductor types listed in the NREL database. The costs for these conductors were extrapolated using a line of best fit based on the current rating of known wire costs. Section A.1 in Appendix A provides the details for these calculations.
- Similarly, the cost for the large 2,600 kVAR capacitor bank required for the front location of Feeder 888 was extrapolated based on the costs listed in the NREL database for three smaller capacitor sizes. Section A.2 in Appendix A provides the details for these calculations.
- Finally, for the multiple conductor upgrades required for Feeder 888, the total cost was calculated by identifying the new line ratings for each line segment and then extrapolating out to identify the costs of large conductor sizes not given in the NREL database.

In addition to hardware upgrades, settings adjustments were also identified as necessary for two feeder locations: 2885-end and 2921-front (see Table 4-2). These adjustments represented a one-time cost, mainly reflecting the need to dispatch a distribution engineer on-site to work on the equipment. No new hardware installation was required; the existing hardware was simply re-configured. The one-time costs associated with these two settings adjustments were obtained from the NREL cost database. To make the time allocation of these one-time expenses consistent with the annualized capital costs associated with the hardware upgrades using the ECC, it was assumed that 10% of these one-time expenses could be apportioned annually for 10 years.

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

Table 4-4 summarizes the total annualized cost of the distribution measures required under the conventional network reinforcement approach for each of the feeder locations considered in this study.

Table 4-4
Summary of costs for conventional upgrades

Feeder	Location	Conventional Measure	Quantity	Unit	Cost ($/unit)	Source	Total Cost (Capital or One-Time Expense) ($)	Lifetime (years)	ECC% (for capital), or 10% apportionment (for one-time expenses)	Annualized Avoided Capital Cost ($)	Annualized One-time Expense ($)	Annualized Cost of Conventional Upgrades ($)
631	Front	OH-AAC	512	ft	560	NREL	286,720	50	9.38%	26,880	-	26,880
631	Middle	Add 1 voltage regulator	1	n/a	150,000	NREL	150,000	25	10.65%	15,980	-	15,980
631	End	OH-CU	100	ft	110	NREL	11,000	50	9.38%	1,031	-	1,031
683	Front	OH-AAC	199	ft	1,660	Extrapolation (See A.1)	330,340	50	9.38%	30,969	-	30,969
683	Middle	OH-AAC	199	ft	1,660	Extrapolation (See A.1)	330,340	50	9.38%	30,969	-	30,969
683	End	OH-AAC	200	ft	1,660	Extrapolation (See A.1)	332,000	50	9.38%	31,125	-	31,125
2885	Front	OH-AAC	1135	ft	1,010	Extrapolation (See A.1)	1,146,350	50	9.38%	107,471	-	107,471
2885	Middle	Add 1 voltage regulator	1	n/a	150,000	NREL	150,000	25	10.65%	15,980	-	15,980
2885	End	Lower voltage setpoint of voltage regulator	1	n/a	2,500	NREL	2,500	N/A	10.00%	-	250	250
2921	Front	Switch-off all capacitors	1	n/a	7,200	NREL	7,200	N/A	10.00%	-	720	720
2921	Middle	Add 1 voltage regulator	1	n/a	180,000	NREL	180,000	25	10.65%	19,176	-	19,176
2921	End	Add 1 voltage regulator	1	n/a	180,000	NREL	180,000	25	10.65%	19,176	-	19,176
888	Front	Add 1 capacitor	2600	kVAR	35	Extrapolation (See A.1)	89,700	17	12.26%	10,997	-	10,997
888	Middle	OH-AAC	1700	ft	1,325	Extrapolation (See A.1)	2,252,500	50	9.38%	211,173	-	211,173
888	Middle	UG-AAC	385	ft	250	NREL	96,250	30	10.16%	9,776	-	9,776
888	End	OH-AAC	1700	ft	1,325	Extrapolation (See A.1)	2,252,500	50	9.38%	211,173	-	211,173
888	End	UG-AAC	385	ft	250	NREL	96,250	30	10.16%	9,776	-	9,776

Notes: Blue highlighted rows represent voltage-limited cases that implement Volt-VAR control with VAR power priority to increase hosting capacity. Orange highlighted rows represent thermally limited cases that implement the LMRP function of the PV system.

5
ECONOMIC COMPARISON OF SMART INVERTER FUNCTIONS AND CONVENTIONAL UPGRADES

This chapter analyzes the economic implications of activating Rule 21 Phase 3 smart inverter functions to increase hosting capacity by a set target of 25%, when compared to traditional network reinforcements and settings adjustments on existing distribution equipment.

Energy Value

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

The average locational marginal price over the 12-month period – spanning August 1, 2012 to July 31, 2013 – was $34.79/MWh, as shown in Table 5-1. The average monthly price was fairly stable with a low of $27.64/MWh occurring in September 2012 and a high of $38.28/MWh occurring in March 2013. There was larger variation at the hourly average per month, with a high of $111/MWh at 4:00pm on August 2012 and a low of $16/MWh at 2:00am on August 2012. Weighting the hourly average price to the amount of PV generation yields an average price of $36.31/MWh. This PV weighted average price was used as the representative value of energy curtailments because it was representative of the average avoided energy costs from the solar PV plant.

[7] CAISO Real-Time Price data from http://www.energyonline.com/Data/GenericData.aspx?DataId=19&CAISO___Real-time_Price using the "TH_NP15" values representing Northern California.

Table 5-1
Average CAISO locational marginal prices ($/MWh) in Northern California, August 1, 2012 – July 31, 2013

Average CAISO Locational Marginal Prices ($/MWh) in Northern California *(Aug 1, 2012 - July, 31, 2013)*																									
Month	**Hour**																								**Average**
	0	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	
1	31	31	29	31	30	39	36	50	44	32	38	56	32	30	30	31	40	50	55	59	39	39	33	30	**38.1**
2	40	31	30	30	27	32	42	35	33	32	30	28	32	32	31	31	33	39	44	35	46	34	34	32	**33.9**
3	35	33	33	30	29	31	37	50	37	39	58	43	38	37	36	37	36	35	38	38	42	53	39	32	**38.2**
4	32	27	19	22	27	35	33	33	43	37	37	46	59	35	42	36	34	39	40	35	43	34	42	32	**35.8**
5	27	27	23	24	21	28	23	38	27	30	34	39	36	35	42	39	51	47	46	40	47	39	40	30	**34.6**
6	32	27	26	25	25	28	26	27	26	30	32	37	35	39	40	39	43	43	46	41	39	37	36	30	**33.7**
7	30	25	24	27	31	31	29	28	32	36	38	40	43	43	44	44	43	46	50	46	45	38	34	31	**36.6**
8	21	19	16	16	18	21	19	22	23	23	27	27	27	28	57	88	111	75	69	44	57	33	26	20	**36.9**
9	23	22	20	20	21	22	22	22	26	30	26	26	27	28	35	37	34	39	34	45	29	28	25	22	**27.6**
10	28	27	25	22	25	28	39	33	37	36	43	33	42	32	32	32	51	48	62	48	35	32	35	28	**35.5**
11	26	25	25	26	25	28	28	31	47	35	32	44	48	31	31	33	35	44	41	37	36	32	29	27	**33.2**
12	24	24	24	22	24	26	34	31	36	43	32	28	26	28	30	32	30	46	48	41	40	47	42	26	**32.7**
Average	**29**	**26**	**24**	**24**	**25**	**29**	**30**	**33**	**34**	**34**	**36**	**37**	**37**	**33**	**38**	**40**	**45**	**46**	**48**	**43**	**42**	**37**	**35**	**28**	**34.8**
Normalized PV Output	0.0	0.0	0.0	0.0	0.0	0.0	0.01	0.04	0.07	0.10	0.13	0.14	0.14	0.13	0.11	0.08	0.04	0.01	0.0	0.0	0.0	0.0	0.0	0.0	**Sum = 1.0**
PV Weighted Average Price: $36.31																									

Economic Evaluation of Using Smart Inverter Functions to Increase Hosing Capacity by 25%

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

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

In general, results indicate that using smart inverter functions that curtail PV system real power output can be a more economical solution for increasing distribution system hosting capacity than conventional grid upgrades. Results from the study, as shown in Table 5-2, indicate that

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

some scenarios show a positive economic value of deploying smart inverters as opposed to conventional upgrades, while other scenarios show a negative value.

Table 5-2
Economic comparison of smart inverter functions and conventional upgrades to increase hosting capacity by 25%

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

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

A few overarching findings from the results include:

- **Using smart inverter functions tends to be economic when the hosting capacity is voltage constrained** – In cases that were voltage limited, using the Volt-VAR function with reactive power priority was more economical than using conventional measures for upgrades. The only case that resulted in a negative value was one in which there was a minor modeling error that overestimated curtailment from the PV system.

- **Smart inverter functions are more economic when new equipment is otherwise needed to mitigate distribution constraints** – The two voltage limited cases that had the least value (Feeder 2885-end and Feeder 2921-front) required modifying equipment settings rather than adding voltage regulators. Because modifying these settings is not as expensive as adding new equipment, cases that would only require a change in settings of existing equipment may not benefit from using smart inverters as an alternative.

- **Using smart inverter functions may be economic when the hosting capacity is thermally constrained if large upgrade projects are otherwise needed** – The thermally-limited cases required the use of the LMRP function to increase hosting capacity but resulted in significantly larger curtailments compared to the use of the Volt-VAR function with reactive power priority. Though the costs of the LMRP function were high, the LMRP function was still more economic than conventional upgrades in cases where very long reconductoring projects were needed to mitigate the voltage constraints.

Implications for Pricing Strategies for Solar PV Exports

As the quantity of distributed renewable energy resources continues to grow, the utility industry must address the disconnect that exists between the time and location-dependent value of energy that is common at the bulk system, with the historical norm of flat volumetric electricity retail rates. Proper price signals are needed to incentivize economically efficient investment and operation of distributed PV and other DERs. While there is little to no marginal cost of producing energy from renewable resources, exporting excessive amounts of renewable energy has natural limits if there is not enough local demand, if power quality or reliability limits are compromised, or if delivery capacity constraints prevent the energy from being transmitted and distributed to other consumers.

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

Long-Term Impacts of Solar PV Curtailment

This study reveals that curtailing real power output of solar PV can be more economical than paying for the cost of grid upgrades in some circumstances. Further, the economic comparison from this study likely overestimates the relative cost of deploying smart inverter functions because this study only considered impacts in year 1 and did not examine long term impacts. The reason: PV system output typically degrades over time by 0.7-1.5% per year depending on the technology [9]. Consequently, the percentage of time that a PV system inverter is saturated will be less over a PV system's lifetime than it is in its first year of operation.

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

Assessing the Total Value of Solar

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

Valuing DER exports at a utility's avoided cost is appropriate considering all customers share in those savings. However, if the locational and temporal characteristics of DER exports can be adequately relied upon to avoid or defer conventional grid upgrades that a utility would otherwise make to serve its customers, a utility's avoided costs may be higher than what is represented through wholesale locational marginal prices. To calculate this value, a fully integrated planning approach is needed that considers DER as a system resource across all aspects of the electric system [10].

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

The feeder loads that were analyzed in this study, as seen in Figure 5-1, show that the peak loading condition actually occurs in the evening when there is no solar generation. Therefore, it may be safe to assume that there is little distribution capacity relief and thus little value above wholesale market prices for the energy that is being curtailed. While there may be bulk system capacity value for the energy in the middle of the day (when curtailment occurs), assessing that value is outside the scope of this study. Further, if there is bulk system value for energy, but it is needed outside of the curtailment timeframe, that value would not get factored into the value associated with the active power management functions in this study because there was no loss of PV generation during those timeframes.

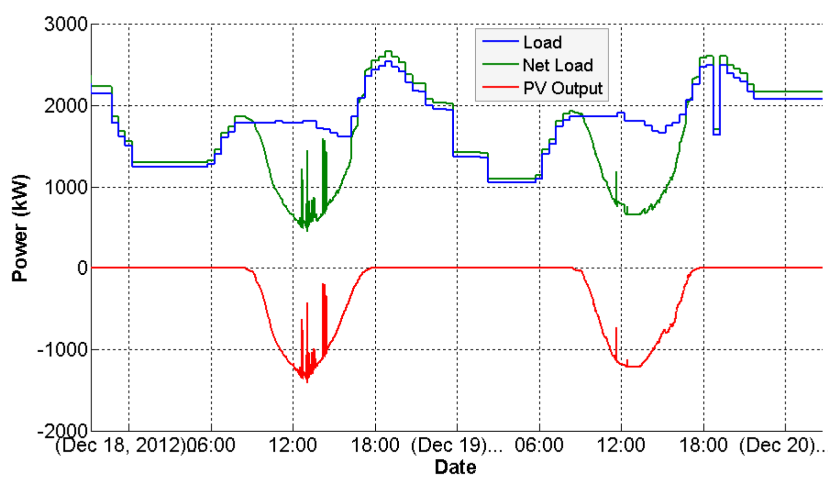

Figure 5-1
Modeled load, net load, and PV generation, December 18 and 19, 2012

Lastly, considering that curtailment of solar PV happens in the middle of the day when the inverter is fully saturated, the value of that energy may actually decrease over time as PV penetrations increase. The diminishing returns of solar PV value as PV penetrations increase occur because of downward pressure on wholesale energy market prices and a shift of the peak load to nighttime hours when PV generation is not available [11].

Sensitivity Analysis

Variation from Different Volt-VAR Functions

Rather than apply a generic function to multiple sites, two different Volt-VAR functions were assessed for the three locations on feeder 2921 to evaluate the potential variation in curtailments if optimal smart inverter settings were selected for each individual site. The Volt-VAR settings used in the sensitivity analysis are shown in Table 5-3. Prior modeling results revealed that these functions were also capable of increasing the PV hosting capacity at the feeder locations by 25%. The "maximum" curtailment function has a more aggressive slope that is anticipated to curtail PV power more than the original function. Alternatively, the "minimum" curtailment function has a less aggressive slope and thus is anticipated to result in less PV curtailments.

Table 5-3
Volt-VAR settings for sensitivity analysis

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

Annual simulations reveal that the "minimum" curtailment function results in slightly lower annual curtailment at each of the three locations, as shown in Table 5-4. However, the reduction is negligible considering the annual curtailment was already very small. The maximum curtailment function resulted in a higher curtailment at each location and ranged from 0.51% to 0.76% reduction in annual energy output.

Table 5-4
Annual curtailment results for sensitivity analysis of the Volt-VAR function

Volt-VAR Function	Location	PV System Size (kW)	Unconstrained Capacity Factor	Capacity Factor using SI Function	Curtailment (% of Unconstrained Output)
Reference Case	front	7,225	16.96%	16.96%	0.00%
	middle	3,560	16.96%	16.96%	0.04%
	end	2,495	16.97%	16.96%	0.08%
Maximum Curtailment	front	7,225	16.96%	16.88%	0.51%
	middle	3,560	16.96%	16.84%	0.75%
	end	2,495	16.97%	16.84%	0.76%
Minimum Curtailment	front	7,225	16.96%	16.97%	-0.02%
	middle	3,560	16.96%	16.96%	0.03%
	end	2,495	16.97%	16.96%	0.07%

The increased curtailment from the “maximum” curtailment Volt-VAR function reduces the value of employing the smart inverter function to increase PV hosting capacity, as shown in Table 5-5. Still, the only scenario in which the conventional upgrade was more economical, was the case where only settings of existing regulation equipment needed to be updated; which results in a minor expense. For the other two scenarios that required additional regulating equipment, using smart inverters was the more economical solution.

Table 5-5
Economic sensitivity analysis of Volt-VAR functions comparing smart inverter functions and conventional upgrades to increase hosting capacity by 25%

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

Variation of the Limit Maximum Real Power Function

While using the LMRP function at a constant value of 80% will increase the available DC power by 25%, it can be informative to understand the curtailment impacts by setting the LMRP function to different settings that may enable even larger penetrations of solar with more total energy production. Because the LMRP function is independent of grid conditions, it can be considered as a “worst case” solution with the highest amount of curtailment needed to increase PV penetrations. Thus, it is useful to see what these “worst case” curtailments might look like to achieve even higher increases in PV penetrations beyond 25%. For example, Table 5-6 shows the relationship between the LMRP function settings and the associated increase in available DC capacity that can be connected to the grid.

Table 5-6
Relationship between Limit Maximum Real Power setting and potential increase in connected DC capacity

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

Solar PV Curtailment Variation based on Limit Maximum Real Power Setting and DC/AC Ratio

Using typical meteorological year data from the NREL's PVWatts [12] calculator, a sensitivity analysis was performed using different DC/AC ratios and different LMRP settings. Findings provided in Figure 5-2 reveal that PV systems designed with higher DC/AC ratios result in higher PV curtailment when the LMRP function is used. This is mainly driven by the fact that PV systems with higher DC/AC ratio spend more time with inverters at saturation, and thus have a greater potential for more frequent curtailments.

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

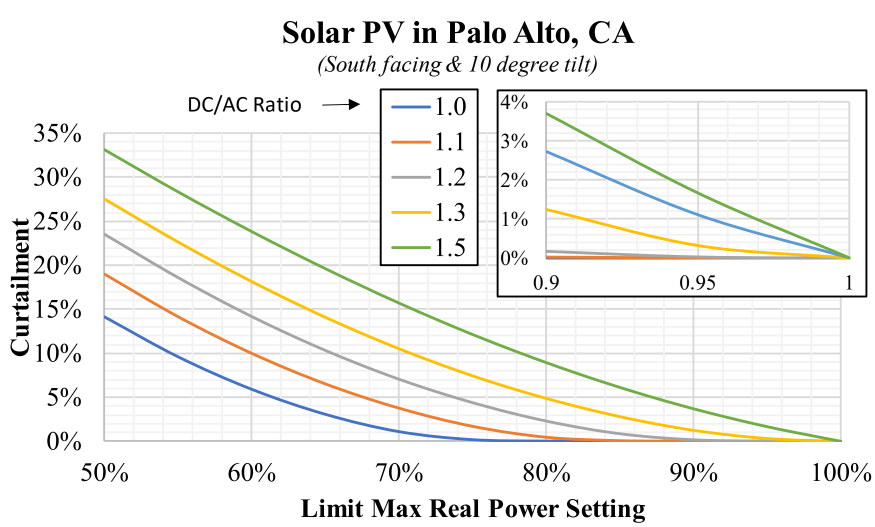

Figure 5-2
Annual curtailment of solar PV in Palo Alto, CA from a south facing 10° tilt system at different limit maximum real power settings and DC/AC ratios

Solar PV Curtailment Variation based on Limit Maximum Real Power Setting and PV System Orientation

Considering that PV orientation can also have an impact on the availability of DC power, an additional sensitivity study was performed to examine varying PV system orientations and LMRP values. Results, provided in Figure 5-3, illustrate that the variation in PV system orientation does not have as large an impact as the DC/AC ratio; however, the variation could be significant. At an LMRP level of 80%, the variation in energy curtailment between a fixed 0° tilt system and a tracking system was near 4%.

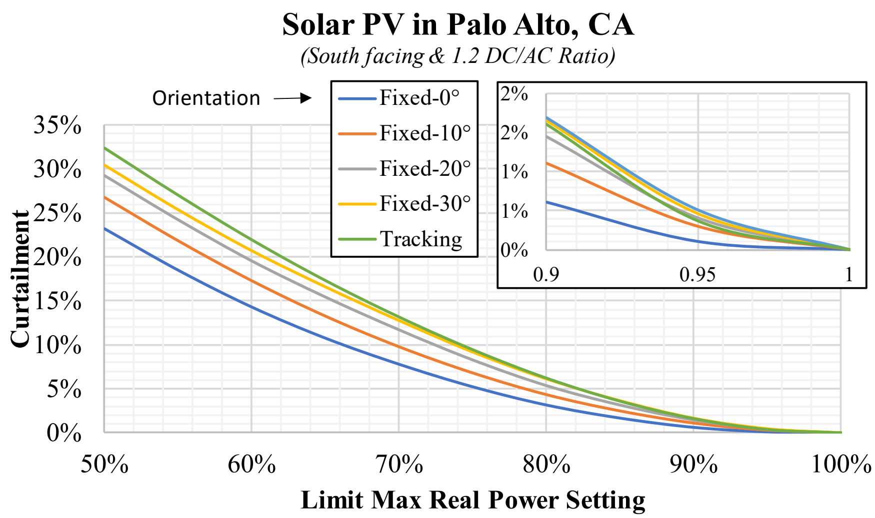

Figure 5-3
Annual curtailment of solar PV in Palo Alto, CA from a south facing system Sized with a 1.2 DC/AC ratio at different Limit Maximum Real Power settings and orientations

6
CONCLUSIONS AND NEXT STEPS

Utilities and PV developers are keenly interested in the economic implications of interconnecting and operating PV systems under high PV penetration scenarios. Though technically effective, conventional upgrade approaches for mitigating the grid impacts associated with rising levels of distributed PV can be costly. An alternative method is to provide interconnection options that require controls for curtailing PV system output.

From a control standpoint, autonomous inverter functions following a configurable response profile (e.g., Volt-VAR with VAR priority, Volt-Watt, etc.) as defined in IEEE Standard 1547 or in the European Network Code Requirements for Generators, can help defer costly system upgrades at higher DER penetration levels. Managed control is another emerging control approach for real power management that relies on control signals sent by a distributed energy resource management system (DERMS)-like utility control platform requesting DER units to set or adjust their imports or exports to specific real power levels, based on grid conditions.

As illustrated in Figure 6-1, PV production and curtailment both increase as the connected capacity of solar PV increases above the level that requires controls to mitigate grid constraints. As long as the total net value of the net increase in production (considering some energy is curtailed) exceeds the cost of the grid upgrade, managing the real power output will be more economical than upgrading the system—even if this means a minor amount of curtailment. However, at some point, the cost of curtailment is likely to exceed the cost of the grid upgrade, at which point upgrading the grid will become more economic.

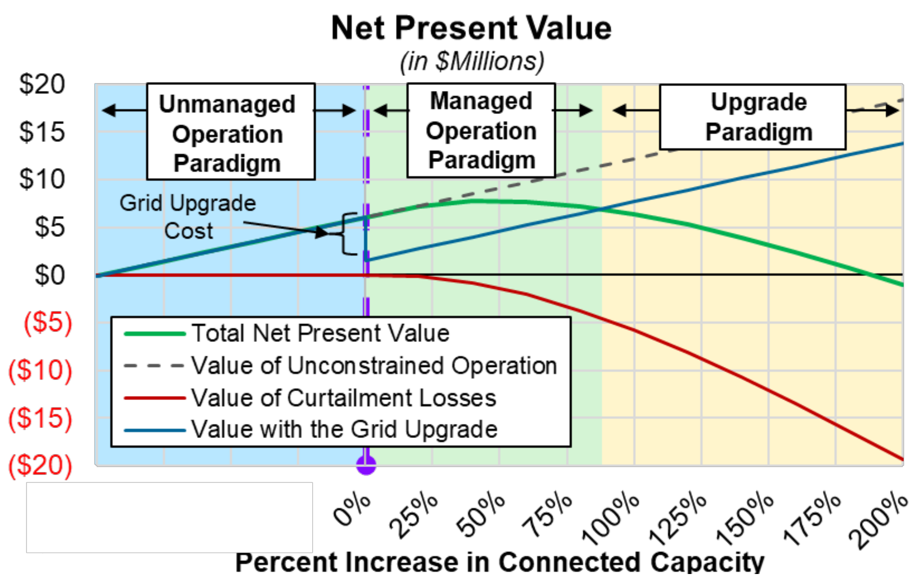

Figure 6-1
Illustration of the economic implications of active power management

Notes: The figure illustrates the Net Present Value of increasing PV penetrations above the limit for unmanaged operation. The dashed black line represents the theoretical value if an upgrade weren't needed while the blue line represents the value including the cost of an upgrade needed to continue full *output. The red line represents the opportunity cost associated with curtailing PV output. The green line represents the total net value including the increased value from extra production (due to larger system sizes) and the losses due to curtailment associated with a fixed output limit. The blue shaded area represents the paradigm where unmanaged operation can take place. The green shaded area represents the paradigm where managed operation makes the most financial sense because curtailment losses are less than the cost of the upgrade. The yellow shaded area is the paradigm where upgrading the grid makes the most sense because losses from curtailment are more than the cost of grid upgrades. Values are illustrative and will change given the costs and financing terms of individual circumstances.*

This report identifies when curtailing PV system output to mitigate grid impacts caused by rising PV penetrations can be more economic than upgrading the grid. Specifically, it assesses the economic impact of using real power control of distributed PV systems to achieve marginal improvements in distribution hosting capacity of 25% or more. System modeling results of large scale PV systems connected to a sampling of distribution feeders were used to evaluate the costs and benefits of using select smart inverter functions to mitigate identified impacts. Findings reveal that **using smart inverter functions that curtail PV system real power output can be a more economical solution for increasing distribution system hosting capacity than conventional grid upgrades**. High-level conclusions include:

- **Solar PV curtailment was observed to be minor when Volt-VAR control with reactive power priority was employed** – Across all cases where Volt-VAR control was used, annual curtailments were less than ~0.8% of annual energy production. Though this study did not conduct a multi-year analysis, annual degradation of PV systems would likely reduce total lifetime curtailments below curtailments in the first year. Further, a sensitivity analysis showed that identifying location specific Volt-VAR functions can reduce curtailments compared to using a standard function for all locations. However, given that PV curtailments are minor, the difference in economic value was also minor.
- **Using smart inverter functions tends to be economic when the hosting capacity is voltage constrained** – In cases that were voltage limited, using the Volt-VAR function with reactive power priority was more economic than using conventional measures for upgrades. The only case that resulted with a negative value was one in which there was a minor modeling error which overestimated curtailment from the PV system.
- **Smart inverter functions are more economic when new, costly equipment is otherwise needed to mitigate distribution constraints** – The two voltage limited cases which had the least value (Feeder 2885-end and Feeder 2921-front) required modifying equipment settings rather than adding voltage regulators. Modifying these settings was not as expensive as adding new equipment. As such, cases which only require a change in the settings of existing equipment may not benefit from using smart inverters as an alternative.
- **Using smart inverter functions may be economic when the hosting capacity is thermally constrained if large upgrade projects are otherwise needed** – The thermally-limited cases required the use of the LMRP function to increase hosting capacity but resulted in significantly larger curtailments compared to the use of the Volt-VAR function with reactive power priority. Though the costs of the LMRP function were high, the function was still more economic than conventional upgrades in cases where very expensive reconductoring projects were needed to mitigate the thermal constraints.

- **PV system designs with higher DC/AC ratios result in higher expected curtailments via real power limiting smart inverter functions –** The DC/AC ratio is a major driver of expected curtailment because smart inverter functions don't curtail PV system output unless the available DC power is higher than the apparent power limit of the inverter. Further, accounting for other factors, such as PV system degradation due to increased module temperature, panel orientation, and other forms of losses, can influence estimates of total expected curtailments from the use of smart inverter functions.

Next Steps

Results from this study indicate that using smart inverter functions that manage real power can be a favorable economic solution for mitigating the impacts caused by rising PV penetrations. However, there may be more opportunity to extract additional value for scenarios in which grid constraints are not local to the PV system or in which active management through the use of a DERMS may reduce PV curtailments compared to "set and forget" autonomous inverter functions. Using functions which react to grid conditions are likely to result in less curtailment of solar PV. Yet, given the lack of both agreed upon control strategies and real world deployments of DERMS-controlled DER, future research and development is still needed to understand the cost-benefit tradeoffs of using managed control schemes through a DERMS and/or DMS, as opposed to set-and-forget autonomous smart inverter functions.

7
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A

EQUIPMENT COST ESTIMATES REQUIRING SPECIAL TREATEMENT

A.1 Extrapolation of Line Sizes and Unit Costs

Estimated costs for conductor sizes that were not in the reference NREL Distribution System Upgrade Unit Cost Database [8] were extrapolated using a line of best fit based on the current rating of known wire costs. Figure 7-1 shows this extrapolation, where the blue points represent reference capital costs and the orange points represent costs that were estimated using the power function line of best fit. Table 7-1 provides the actual values used.

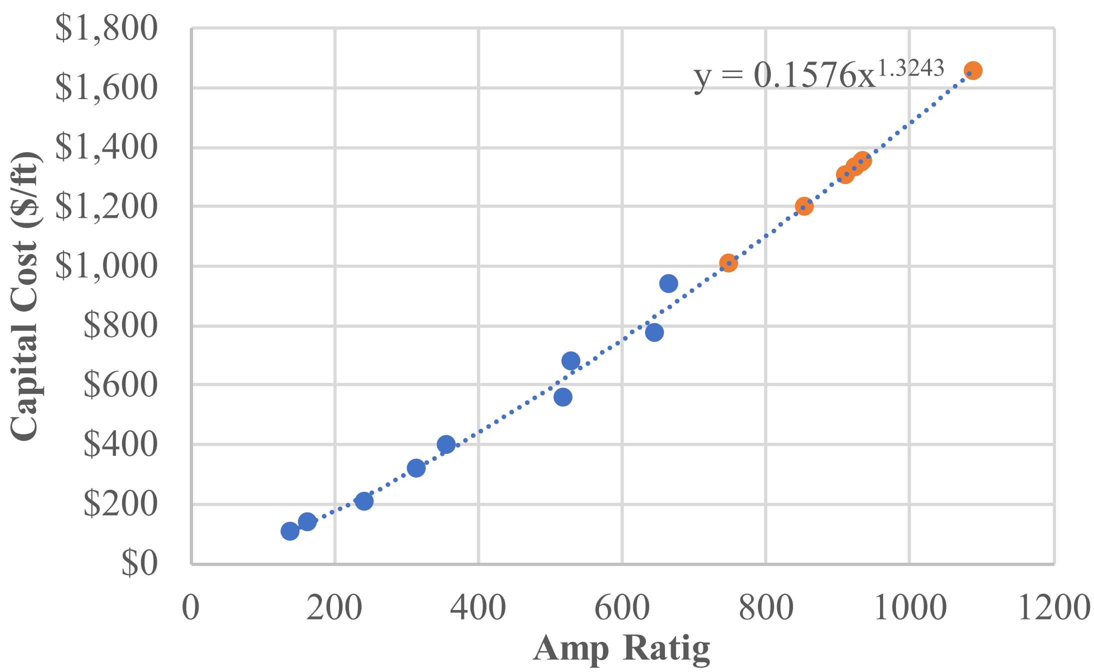

Figure A-1
Estimation of conductor costs for large line ratings

Table A-1
Estimation of conductor costs for large line ratings

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

Note: Amp ratings were estimated from the Priority Wire & Cable Data Sheet [13] using the ACSR – Aluminum Conductor Steel Reinforced specifications on page 4-5.

A.2 Extrapolation of Capacitor Bank Size

Estimated costs for the large 2,600 kVAR capacitor bank used in the analysis of the front location of Feeder 888, were extrapolated based on the costs listed in the NREL Distribution System Upgrade Unit Cost Database [8]. Costs for three smaller capacitor sizes (a mix of pole mount, pad mount, and fixed/switch capacitors) were plotted per kVAR. Figure 7-2 shows the extrapolation using a line of best fit where the blue points are reference capital costs and the orange point is the estimated cost of the large capacitor. Table 7-2 provides the actual values used.

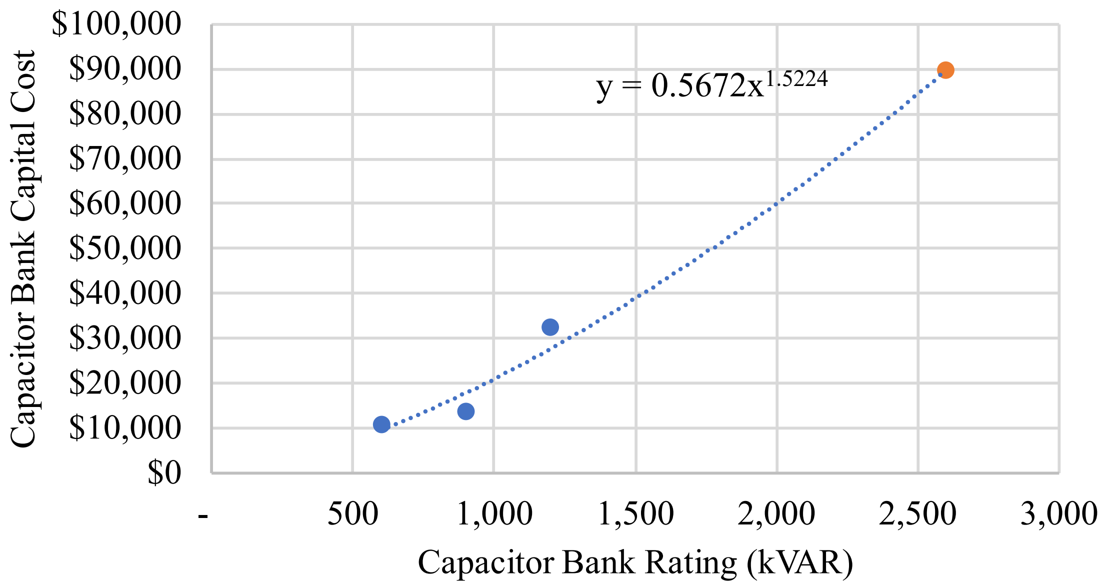

Figure A-2
Estimation of capacitor bank cost for the 2,600 kVAR capacitor

Table A-2
Estimation of capacitor bank cost for the 2,600 kVAR capacitor

Rating (kVAR)	Reference Cost	Estimated Cost	Cost per kVAR	Notes
600	$10,723		17.9	pole mount, anonymized source
900	$13,747		15.3	pole mount, switched, anonymized source
1,200	$32,200		26.8	pole mount, SCE unit Cost Guide
2,600		$89,679	34.5	

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