ELECTRIC POWER
RESEARCH INSTITUTE

EMPLOYING ACTIVE POWER CURTAILMENT OF DISTRIBUTION-CONNECTED SOLAR PHOTOVOLTAICS: ECONOMIC AND REGULATORY CONSIDERATIONS

December 2017

TABLE OF CONTENTS

This white paper was prepared by Jeff Roark, Steven Coley, Tanguy Hubert, and Nadav Enbar of the Electric Power Research Institute.

ABSTRACT

Increasing grid penetrations of distributed photovoltaics (PV) are beginning to challenge the capacity limits of existing distribution grid infrastructure in certain locations. Prior research and demonstration efforts have shown that advancements in the active and reactive power control of solar PV can resolve many of these "hosting capacity" issues. However, the economic signals present today at the distribution level are not designed to efficiently guide the use of these new control capabilities.

There are many complex technical, market, and legal issues related to developing economic signals and regulatory structures that can help facilitate services at the distribution level. Within this broad context, questions persist regarding practical approaches for compensating PV owners for the lost energy value when their systems' active-power exports[1] to the grid are curtailed to allow more PV systems onto a distribution circuit. This white paper examines three key questions for regulators and policymakers to consider when evaluating the economics of curtailing distribution-connected solar PV, and the regulatory framework for enabling such curtailments:

1. What are the utility's obligations to accommodate PV interconnection requests, specifically those that could increase the level of exported power beyond the existing hosting capacity of distribution circuits?
2. What are possible mechanisms for specifying the terms of curtailment?
3. What types of compensation and settlement mechanisms can be considered, consistent with the obligations of the utility?

BACKGROUND

Economic and policy forces are encouraging growth in distributed energy resources (DER), such as solar PV,[2] to the extent that grid interconnections may soon exceed the limits of many distribution circuits. If the limits of the current system are allowed to halt further development of PV, it may undermine policy objectives that seek to increase DER penetration on the electricity system to meet renewable energy generation and emission reduction goals.

Each distribution circuit has a *limited* capacity to host additional PV. The term *PV hosting capacity* is defined as the amount of PV that can be accommodated under given control and infrastructure configurations, and without deteriorating grid reliability or power quality beyond acceptable limits. For brevity, the term is often used to refer to the PV capacity that can be accommodated under the *existing* control and infrastructure configurations for a feeder. When the existing PV hosting capacity is depleted, customers may be constrained from adding more PV on the circuit until some modification is made to increase it.

1 In this paper, the term "PV exports" always refers to *active* power exports of distribution-connected PV. Active power is the power that is actually consumed or utilized in an AC circuit. It is also referred to as true power or real power and is measured in the unit of a Watt.

2 Many issues discussed throughout this paper have applicability to many types of DER. This paper specifically focuses on the example of solar PV.

The concept of hosting capacity is inherently *locational*: two sections of the same distribution feeder, or even two points of interconnection within the same feeder section, may be able to accommodate different quantities of PV. For this reason, customers connected to the same feeder may face different hosting capacity limitations, depending on the level of PV penetration at their respective points of interconnection.

From a technical standpoint, hosting capacity *can* be increased for any distribution circuit. Additional investment in infrastructure upgrades is a first possibility (e.g., reconductoring, substation upgrades, the implementation of energy storage, etc.). Improved operational strategies making better use of existing distribution equipment may also help increase hosting capacity limits. Finally, adjustments to the operating characteristics of PV, such as the reactive power control, may also beneficially impact hosting capacity limitations, sometimes without requiring grid investments.

Hosting capacity for PV is *not* the same as *nameplate* capacity. The amount of connected nameplate capacity could be much higher than the grid's hosting capacity if the real pwer of PV is actively managed. This paper assumes that exporting PV is part of the motivation for interconnecting PV, leading to possible impacts on distribution system operations.

Among the choices at hand for policymakers and regulators is setting the bounds of *what utilities must do* when hosting capacity is exhausted and prospective PV owners want to connect additional PV. Policy choices and standards can also determine *what prospective PV owners must do* to participate in this effort, possibly leveraging some of the new grid support capabilities of inverters such as Phase 3 smart inverter functions identified by SWIG for the Rule 21 tariff proceedings[4] (see sidebar, "White Paper Context"). However,

3 For the purposes of this paper, *export power* is defined by the net export of power to the grid (i.e. PV output less load at the point of interconnection). In the absence of local consumption (also termed "self-consumption"), all PV output is exported to the grid. Smart inverter functions control the power output at the terminal of the PV system, but can be leveraged to indirectly control the net active/reactive power exported to the grid at the point of interconnection.

4 There may be other reasons to use these advanced functions which alter the active power and curtail the output of PV systems – for example to respond to a signal from the bulk system to optimize grid operations via a market signal or for security or reliability purposes. The contents of this paper do not address the full range of reasons for curtailment of PV exports but focus on curtailment for the purposes of increasing interconnected nameplate capacity of PV on the distribution system.

5 http://www.energy.ca.gov/contracts/GFO-16-309/

WHITE PAPER CONTEXT: CALIFORNIA ENERGY COMMISSION-FUNDED RESEARCH

This white paper is a component of a California Energy Commission (CEC) award for Grant Funding Opportunity (GFO) 16-309 (Group 4), titled "Advanced Smart Inverter Capabilities to Support High-Penetration Solar."[5] The CEC project seeks to evaluate the smart inverter functions recommended for California Rule 21,[6] by the smart inverter working group's (SWIG) third phase (Phase 3),[7] that can address the challenges posed by increasing PV penetrations on distribution. This white paper addresses a few key issues that arise when considering a central aim of the GFO: to provide "data and/or tools that can be used to determine fair levels of compensation for reducing customer's power output to support grid functions."

The phase 3 smart inverter functions[8] identified by SWIG for the Rule 21 tariff proceedings are challenging with respect to their economic impact to DER asset owners and other ratepayers because they alter the real power flows of distributed energy resources connected to the distribution system. These curtailments impact investment returns due to present monetary compensation mechanisms of real power as opposed to reactive power support.

This paper does not recommend cost recovery or compensation mechanisms that can facilitate real power curtailments; rather it provides commentary to inform proceedings that seek to develop these mechanisms. Likewise, future EPRI research to fulfill the broader objectives of the CEC project will not present or endorse explicit solutions. Efforts will involve (1) further examining key questions to consider when assessing the economics of curtailing distribution-connected solar PV, and (2) evaluating the economic implications of real-power management functions through an objective, transparent, and comprehensive benefit-cost framework. For the latter activity, EPRI's Integrated Grid Benefit-Cost Framework[9] will be employed to study the quantitative economic impacts of using a selection of Phase 3 smart-inverter functions to increase the hosting capacity of five distribution circuits in California by 25%.

6 California's Electric Rule 21 is a tariff that describes the interconnection, operating, and metering requirements for generation facilities to be connected to a utility's distribution system in the state. See: http://www.cpuc.ca.gov/Rule21/.

7 The SWIG grew out of a collaboration between the California Public Utilities Commission (CPUC) and the CEC has pursued development of advanced inverter functionality over three phases. (http://www.cpuc.ca.gov/General.aspx?id=4154)

8 http://www.energy.ca.gov/electricity_analysis/rule21/documents/phase3/

9 *The Integrated Grid: A Benefit-Cost Framework.* EPRI, Palo Alto, CA: 2015. 3002004878

economic tradeoffs between additional grid investment, solar PV investment, and solar PV operational modification arise when determining how best to use these new capabilities to increase PV penetration (see sidebar: "Illustrating the Tradeoffs of Methods for Increasing PV Penetration").

If, at the distribution level, precise and visible locational and temporal economic signals[10] could adequately reflect the distribution constraints that limit PV hosting capacity (e.g., voltage or thermal violations), the economic signals could help guide PV operations, including possible curtailment of PV exports. Such signals could reveal economic opportunities and tradeoffs which might enable prospective PV owners to autonomously manage their power exports so the distribution system operates close to least-cost operating points. They might also help reveal tradeoffs between additional grid investment, solar PV investment, and PV operational modifications when it comes to determining which technical approach is the most economically efficient to increase penetration at a given location.

There are many complex technical, market, and legal issues related to developing economic signals and regulatory structures that can help facilitate the use of DERs or increasing grid penetration of renewables. Within this broad context, questions persist regarding practical approaches for compensating PV owners for the lost energy value when their systems' active-power exports to the grid are curtailed to allow more PV systems onto a distribution circuit. While it may seem counterintuitive to curtail a zero-cost energy source like PV, market dynamics can create conditions of oversupply where locational energy prices are negative, thereby justifying the curtailment. Additionally, curtailment is needed if PV exports are expected to cause a system violation, thereby diminishing system reliability, imposing additional costs, or potentially causing safety hazards.

10 For the purposes of this paper, *economic signals* are defined as the market rules and prices which govern how PV systems export power to the distribution system, and how investments in new PV systems are made and shape expectations for returns on those investments. Examples include retail rate tariffs and compensation mechanisms (i.e. net energy metering [NEM], feed-in-tariffs, time-of-use rates), interconnection rules (i.e., capacity or energy restrictions to be eligible for a NEM tariff, annual true up mechanism for net export billing credits), among others.

ILLUSTRATING THE TRADEOFFS OF METHODS FOR INCREASING PV PENETRATION

High levels of PV penetration above the PV hosting capacity limit on distribution circuits can cause reliability and power quality violations such as temporary overvoltage. Depending on the circumstance, there may be multiple solutions requiring circuit upgrades that would resolve these issues. Smart inverters with reactive and active power control on PV installations may also be used to help mitigate voltage violations. In some circumstances, the approach leveraging smart inverter functions may require a specific PV system design (i.e., different DC/AC ratio) and/or curtailment of real power output compared to what would have been the case if a grid upgrade had occurred. Determining the least cost solution involves examining the economic tradeoffs among multiple alternatives, as illustrated in Table 1.

Table 1 – Tradeoffs among Alternative Solutions to Increasing Penetration by Mitigating Voltage Violations caused by PV Interconnections

Solution	Description of Alternative	Type of DER Support Provided to Mitigate Voltage Violations	Grid Investment Costs	PV Investment Costs	Marginal Energy Costs	Total Costs
Base Case	Grid upgrade; baseline PV system design; baseline marginal energy costs from Grid + PV	No DER support provided	Base Cost ($)	Base Cost ($)	Base Cost ($)	Base Cost ($)
Alternative 1:	No grid upgrade; oversize inverter relative to PV panel rating; baseline marginal energy costs from Grid + PV	Reactive power support	Decrease (relative to base case)	Increase (relative to base case)	No Change (relative to base case)	?
Alternative 2:	No grid upgrade, baseline PV system costs; increased marginal energy costs from Grid due to PV curtailment	Reactive power support; Active power support (via PV curtailment)	Decrease (relative to base case)	No Change (relative to base case)	Increase (relative to base case)	?

This hypothetical example is intended to be illustrative and may not reflect actual cost implications in practice which will vary based on each unique circumstance. In the table, the marginal energy costs are assumed to be less expensive with more PV production because PV systems have no marginal energy costs. Also, a larger AC/DC ratio is assumed to be a more expensive PV system design due to the need for a larger inverter relative to the DC module rating. If the base case had an original optimal AC/DC ratio that caused "clipping" of the potential DC energy production, this could result in a decrease in marginal energy costs for Alternative 1 due to additional power output of the PV system. It may also be that the least-cost solution is some combination of incremental steps in two or more alternatives—grid investment upgrades, PV system design changes, and PV output curtailment.

There are a number of reasons for curtailment of PV exports, but this white paper focuses specifically on curtailment for the purposes of preventing grid level violations and increasing PV penetration on the distribution system. It examines three key questions for regulators and policymakers to consider when evaluating the economics of curtailing distribution-connected solar PV, and the regulatory framework for enabling such curtailments:

- What are the utility's obligations to accommodate PV interconnection requests, specifically those that could increase the level of exported power beyond 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?

OBLIGATIONS OF THE UTILITY

Traditional Obligation to Serve

As part of the regulatory compact, public utilities have had a traditional "obligation to serve"; they have been expected to offer universal service within an exclusive territory in exchange for an opportunity to earn a reasonable return on prudently invested capital.[11] The service obligations of a utility at the distribution level can be subdivided several ways:

- the obligation to connect
- the obligation to maintain a reliable connection
- the obligation to maintain a reliable quality of voltage, and
- the obligation to deliver energy.

The obligation to maintain a connection has another obligation embedded within it: the obligation to provide capacity for customers' combined maximum loads, as well as to provide the strength or stiffness to supply high temporary inrush currents.[12] There may be other obligations that distribution engineers might also point to, including prudent protection schemes (relaying and circuit-breaking) for safety to protect the public, employees, and expensive equipment.

11 The costs associated with prudent investment in assets (including the cost of capital) and operational activities (including fuel and energy purchases) pursuant to the utility's obligations are often termed "revenue requirements." Revenue requirements set the amount of revenue that must be collected from utility customers (sometimes referred to as ratepayers) through rate schedules and allocated to different rate classes as approved by the appropriate regulatory body.

12 Inrush current is the maximum, instantaneous current drawn by an electrical device when first turned on. Inrush currents can be 8–10 times higher than the steady-state consumption for motor-based loads.

Some of the various obligations of a distribution utility are not absolute. There are exceptions and gray areas where standards may or may not be set in various jurisdictions. For example, the obligation to connect is not absolute with most utilities. Some limits are based on the cost to connect balanced against the expected revenue from the customer once connected. A utility might not be expected to extend a line for 20 miles over harsh terrain to connect one vacation home as it would impose too much cost on other customers. A prospective high-cost-to-connect customer may be required to contribute toward construction cost as a condition of connection. Further, developers adding significant potential load to a feeder may be required to contribute to circuit upgrades if future revenues from that load are not expected to recover the additional cost of circuit upgrades. However, once customers are connected, the obligation of the utility to serve with adequate reliability and quality applies fully.

Usually, new consuming customers are connected without requiring feeder upgrades, because a feeder typically has some extra capacity, or headroom, to allow for growth. When upgrading a feeder, allowing headroom for growth makes economic sense because upgrades are costly and "lumpy;" they are impractical to do in small increments. Headroom may be added to allow for a period of years, 10 or more, before a feeder would be due for an upgrade at expected growth. The cost of headroom is rolled into distribution system costs and recovered through rates.

There is no charge for consuming a bit of headroom when a new customer is added. Further, if a new customer pushes total load over the feeder's limit, the utility does not charge that customer for the cost of the upgrade. The upgrade will add headroom that the new customer will use, but it will also be used by future customers and by growth in consumption of existing customers; thus, the cost of the upgrade is allocated to all distribution customers.

Hosting Capacity and Headroom

Headroom can be thought of in terms of PV hosting capacity as well, as in the amount of headroom for additional PV. Of course, this is a different number than the headroom for load because it acts oppositely to load. *PV hosting capacity* is the total PV capacity that the feeder can currently accommodate; *PV headroom* is the amount of PV hosting capacity remaining at the current penetration level. There can be numerous limiting factors: voltage violations, harmonic distortion, thermal limits, or protection limits, to name a few. With PV, these limiting issues are most likely associated with power being exported from one or more sites rather than simply offsetting the load at the site.[13] They are mostly location-specific; one or two export sites on a single-phase line could cause voltage violations, especially if the inverters do not help manage the voltage.

Obligations to Connect and Take Energy from DER; Policy Alternatives

When PV headroom is insufficient to accommodate new uncontrolled PV connections, what are the obligations of the distribution utility, apart from the traditional obligations, to connect and deliver energy to loads? When upgrading a circuit to increase hosting capacity, does the same logic that applies to adding headroom to serve load apply to adding enough hosting capacity headroom to accommodate expected PV growth? Small amounts of PV may not exceed the hosting capacity limit, but they diminish the headroom of hosting capacity left on the feeder. This means that while initial PV installations may not require mitigation, imposing a cost, they remove available hosting capacity headroom, potentially deferring costs to later PV installations. How these costs are allocated between first comers and late comers is one of many regulatory issues that must be resolved.

Important questions with respect to PV (and other DER) accommodation may yet be undecided in many jurisdictions. The issues that raise the important questions may not arise until hosting capacity is reached on a significant number of feeders (even if the hosting capacity headroom may already be very low in some locations). There are a range of pathways that policymakers can take regarding the utility's obligation to accommodate PV and other DER. Four alternatives, among potentially others, are discussed below. Note: these policy alternatives do not necessarily apply uniformly to all circumstances. Thresholds based on policy or regulatory objectives could dictate the relevance of a policy alternative to a given circumstance. For example, a utility may be obligated to accommodate all PV up to a certain threshold, at which point, that obligation would cease or another obligation would apply.

Alternative #1: Utility Obligated to Accommodate All PV Exports

In this circumstance, the utility would be required to increase physical hosting capacity via infrastructure upgrades to allow full simultaneous output for all PV installations regardless of location. Full accommodation would resolve any first-come, first-serve issues, but it could prove costly and wasteful, especially if the bulk system absorbs a surplus of generation on many days.

Why build a distribution infrastructure to accept all PV exports if this energy cannot be accepted beyond the substation? Further, if this obligation is absolute, then it would appear to be inconsistent with limits on the obligation to connect new load, limits often based on the ability of the new load to be roughly compensatory to the cost of connection over time. It is hard to avoid the rate-design issues that apply to PV; if PV export is accommodated, does the PV export support the cost of accommodation? If not, are there other social values or objectives that override the local conditions? These are important issues for policymakers to decide.

Alternative #2: Utility Not Obligated to Accommodate PV Exports Beyond Existing Hosting Capacity

A contrary policy to Alternative 1 would not require the utility to upgrade feeders to increase hosting capacity at all. This approach would let the utility decide whether to add headroom to accommodate PV exports based on business conditions. For example, a distribution utility might make decisions based on business arrangements and associated revenue for delivering PV energy to the bulk system.

Within this paradigm, would the added revenue achieved under certain business conditions cover the utility's costs over time? This assessment might be consistent with the obligation to connect and serve load; if the costs of an upgrade are not expected to be recovered by the revenues from set out business arrangements, then the PV exporters might contribute to construction or decide not to connect and export in that location. Separately, first-come, first-serve issues might consequently lead to issues of equity among PV owners; the first comers would take advantage of the PV hosting capacity headroom, and the rest might face prohibitive costs. There are economic implications to consider too. For example, if mid-day energy is expensive, there may be economic incentives for the utility to incur the cost of an upgrade, and export a lower cost form of energy.

Alternative #3: Utility Not Obligated to Accommodate Via Upgrades, but Can Accommodate with Curtailment

Another version of Alternative #2 would allow for PV exports to be curtailable by the utility when it causes violations[14] so that more of the variable resource could be accommodated on the feeder. Curtailable PV might be able to operate for much of the year, but would be curtailed at certain times. This alternative may perhaps require infrastructure investment to actively manage PV exports.

13 *Impact of High-Penetration PV on Distribution System Performance: Assessment of Regulation Control Options for Voltage Mitigation.* EPRI, Palo ALto, CA: 2012. 1024355.

14 Prior interconnection studies and/or screens would need to determine if violations are expected given the active power exports of PV without curtailment.

Of course, if the utility is not obligated to deliver all export energy, then it would similarly not be obligated to compensate PV owners for lost energy sales. In this situation, it would be the PV owners' prerogative to work with the utility to establish a plan for accommodation. First-come, first-serve issues might be handled by making all PV subject to curtailment, with the proviso that curtailment would be locational, and not necessarily evenly distributed. However, owners of existing distributed generators may be opposed to increasing penetration in their locations, as they could lose the ability to fully export. This is consistent with conditions independent generators face at the bulk level.

Alternative #4: Utility Obligated to Either 1) Upgrade and Accommodate or 2) Curtail and Compensate

Another policy alternative might require that the utility be "financially" obligated to either 1) upgrade and accommodate PV, or 2) curtail PV and compensate accordingly. Under this utility obligation, compensation costs for curtailment would likely be recoverable from customers and allocated through a rate making process (similar to system upgrade costs). The utility would, on behalf of its customers, determine the economic tradeoffs of grid upgrades versus curtailment.

Stripped of complicating factors (for which there are many), the central idea is straightforward: it is economic to upgrade the grid and add delivery capacity if the value of the additional energy delivered is more than the cost of the upgrade.[15] Said another away, an upgrade would be worthwhile if the savings in total energy costs (i.e. the difference in total energy costs with and without the grid upgrade) are greater than the cost of the upgrade itself.

For a closer look at the savings in total energy costs that can be achieved from a grid upgrade, we examine what happens to total energy costs when an upgrade occurs and *PV exports are not curtailed* compared to when *an upgrade does not occur* and *PV exports are curtailed* under the assumptions of this policy alternative.

1. The utility avoids (saves) the energy costs it no longer has to procure by some other means[16] to balance supply and demand in the amount equal to PV exports that would otherwise be curtailed.
2. The utility avoids (saves) the cost it would have otherwise paid (compensated) PV owners for the curtailed PV exports.
3. The utility incurs an additional cost associated with compensating PV owners for the PV exports that would otherwise be curtailed.

The savings associated with an upgrade are equivalent to the savings from avoided energy procurement from other sources, plus the savings from compensation for curtailed PV exports, less the cost of additional energy purchases from PV exports (that would otherwise be curtailed), less the cost of the upgrade (see Figure 1[17]). Note: The equation depicted in Figure 1 is in a simplified form; expectations of *when* curtailment happens are just as important as how much total curtailment occurs because the cost of energy varies by time.

15 This is the same principle that is the basis for any cost-benefit analysis of any expansion of delivery capacity, both transmission and distribution.

16 Depending on the type of utility, procurement could be in the form of increased output from its own dispatchable resources or through energy purchases on the market.

17 Technically, the equation would be the sum of expected curtailed PV exports "CE(t)" (measured in kWh) for some discrete time interval "t" (say, measured in hours) multiplied by the summation of the value of energy (measured in $/kWh) at time "t" from the three categories: grid energy costs from other sources "G(t)", plus curtailed energy costs "C(t)", less PV export costs (value paid to PV owners) = "PV(t)"; for all time "t=0 (installation of grid upgrade) to T= LT (end of life of expected life of grid upgrade). Or $\sum_{t=0}^{t=LT} CE(t) \times [G(t)+C(t)-PV(t)]$ and then discounted back to present worth, less the costs for upgrading the grid.

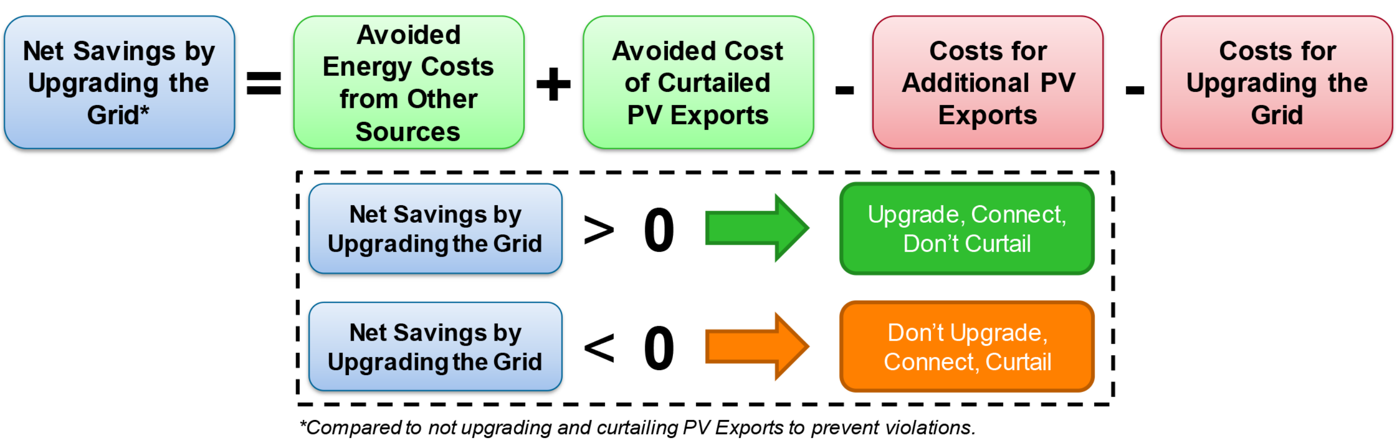


Figure 1 – Calculation of Total Savings to Justify Grid Upgrade under Policy Alternative #4
Note: If the total savings shown in the equation are positive, then it is more economic (least total cost) for the utility to pursue the upgrade than curtail. If the total savings are negative, then it is more economic for the utility to curtail PV exports.

While the concept is simple, further examination of this policy alternative raises questions that reveal the complexity of the issue. What follows are observations for two such questions.

How should compensation for curtailed energy exports be determined?

While this paper does not recommend any specific compensation mechanism, nor does it advocate for a particular way to set compensation, several things become apparent when examining various levels of compensation relative to the other monetary factors shown in Figure 1.

1. *The compensation amount for curtailed PV energy exports will determine outcomes.* Even without compensation for curtailment, it can be economic to upgrade grid infrastructure to accommodate more PV exports if the costs for PV exports are less than the energy costs from other sources. Adding compensation for curtailment, increases the incentive to upgrade grid infrastructure instead of curtailing. However, if compensation is set too high, costs could become excessive.
2. *Expectations of future energy costs procured from other sources also drives future outcomes, posing a challenge.* The energy costs from other sources at the time of curtailment will impact which case – upgrade and accommodate or curtail and compensate – is the better economic outcome. This requires estimating future energy costs at discrete time intervals and estimating when curtailment is likely to occur. While a proper discussion of these topics is outside the scope of this paper, several issues can be noted regarding the complexity of the challenge:
    a. Estimating the costs of procuring energy from other sources at any given time is highly complex because it depends on the regulatory structure, supply and demand dynamics of energy markets,[18] and uncertain future policy decisions.
    b. Estimating the exact moment, and how often, PV curtailment is needed is complex due to fluctuations in load and PV output.

    Both estimates impact decisions related to compensation (i.e., a utility or its regulator may desire to estimate how often curtailment is needed to estimate appropriate compensation measures) and expectations of returns (i.e., PV system investors may desire some assessment of risk regarding how much energy they will be able to export, and how much they will be compensated).
3. *The amount paid for PV exports will also drive outcomes.* The lower the costs of purchasing PV exports, the higher the incentive for upgrading the grid to accommodate it as a potentially lower cost resource. If payments for PV exports are high, then there is less incentive to upgrade the grid and accommodate its exports.

How can the amount of actual curtailed energy be practically verified?

There is a technical challenge associated with verifying how much energy would have been exported from a PV system if curtailment had not occurred. This is necessary information to determine how much energy was actually curtailed so that compensation can be applied appropriately. The challenge is difficult and currently requires modeling the many factors which impact the amount of PV energy exported at any given time including inverter availability, irradiance, module temperature, soiling levels, and behind the meter load, among others. Standard PV systems are not equipped to measure and communicate what would have been their maximum power point if they have been curtailed.

Summary of Policy Alternatives

Table 2 summarizes the policy alternatives discussed above that define a utility's obligations to accommodate PV interconnection, and provides accompanying insights. The overarching takeaway is that setting the bounds of *what utilities must do* when hosting capacity is exhausted and prospective PV owners want to connect more PV to the grid has many implications. If the utility is obligated to accommodate all PV exports, it is hard to avoid the rate-design issues that apply to PV. For example, if PV export is accommodated, will it support the cost of accommodation? If not, are there other social values or objectives that can override local conditions? If the utility is not obligated to accommodate PV beyond PV hosting capacity, how should first-come, first serve issues be handled? Should first comers be able to take advantage of existing headroom, leaving latecomers to face the costs of integrating PV after available headroom has been expended? Allowing PV curtailments could potentially serve as a way to increase PV capacity on a circuit, however there are economic implications to be considered.

18 The basics of electricity markets shows us that the marginal price of energy is dependent on location of interconnection, can vary with time, and can be negative.

Table 2 – Example Policy Alternatives Defining a Utility's Obligations to Accommodate PV Interconnection

Policy Alternatives Explored	Insights
1) Utility Obligated to Accommodate All PV Exports	Resolves any first-come, first-serve issues. Could induce excessive costs and has rate-design implications.
2) Utility Not Obligated to Accommodate PV Exports Beyond Existing Hosting Capacity	Has first-come, first-serve issues. Utility could upgrade the grid to accommodate more PV based on business arrangements.
3) Utility Not Obligated to Accommodate Via Upgrades, but Can Accommodate with Curtailment	Increases PV capacity, but with relatively less energy compared to Alternative #1. Raises issues of who to curtail and by how much as more systems are added above the prior hosting capacity limit.
4) Utility Obligated to Either Upgrade and Accommodate, or Curtail and Compensate	Compensation costs for curtailment would likely be recoverable from customers and allocated through a rate making process. Incentivizes less curtailments compared to policy Alternative #3. Raises issues about how to set compensation amounts and how to verify the actual amount of curtailed energy.

MECHANISMS FOR CURTAILMENT

For a utility to meet its obligations to serve, the technical requirements of grid connected devices – including curtailment mechanisms and associated requirements – are typically stated in an interconnection agreement granting permission to export. These agreements may explicitly state requirements – such as the California Rule 21 tariff – and they may also refer to existing interconnection standards such as IEEE Standard 1547.

There are a variety of ways in which curtailment mechanisms and associated requirements can be written into interconnection agreements. What follows is an introduction to some of the different control alternatives that exist today for curtailing PV exports. A description of how these alternatives can be used to support two categories of curtailment mechanisms – *required* curtailment and *voluntary* curtailment – is also discussed.

Control Alternatives for Curtailing PV Exports

From a control standpoint, PV exports to the distribution system can be controlled via two approaches:

1. *Explicit Curtailment,* in which control signals indicating requested curtailment levels are sent to the PV units, modifying their output, and eventually the amount of power exported to the grid.
2. *Curtailment via Local Control Functions,* in which curtailment levels are determined locally through the use of smart inverter functions (e.g., maximum power limit, volt-watt, frequency-watt) that are configured by the entity managing the curtailment.

Required Curtailment

Required curtailment involves the utility instructing a PV system connected to distribution to curtail its power exports for a specified reason. This can be accomplished through the use of a distributed energy resource management system (DERMS), possibly paired with a Distribution Management System (DMS). These control systems identify grid operating needs and send control signals to PV systems accordingly. This signal can carry an explicit active power curtailment level, or configure and activate an inverter function that is locally executed, such as maximum power limit or volt-watt, resulting in autonomous active power curtailment based on some local parameter (e.g., active power export, voltage). Another form of required curtailment could consist of predefined smart inverter settings established at the time of interconnection, thus not requiring real-time connectivity between the utility control systems and PV inverters

Voluntary Curtailment

Voluntary curtailment involves PV owners choosing to curtail their power exports based on available incentives. However, while voluntary curtailment mechanisms imply that PV owners have the choice to curtail, this decision may become binding once made. For example, PV owners offering voluntarily curtailment services to the utility in exchange for financial compensation are likely to be obligated to deliver this service by contract, or face penalties.

Separately, curtailment may be needed to prevent violations of a utility's service obligations. As such, the nature of voluntary curtailment may require the utility to have other options available in real time in order to mitigate potential violations if the customer fails to voluntarily curtail, or does not comply with binding curtailment contracts.

Similar to required curtailment, voluntary curtailment is executed via direct control signals requesting a specific curtailment level, or smart inverter functions configured to autonomously control curtailment based on operational parameters monitored in real time (e.g., voltage). Voluntary curtailment may be the result of an economic decision from the PV owner to accept a utility-provided inducement.

Table 3 – Curtailment Mechanisms and Compensation
Notes: NC = No financial compensation for curtailment of PV exports; C = Compensation for curtailment of PV exports. The numbers in parenthesis are referred to in the text of this section.

	Policy Alternative	Relevant Curtailment Mechanism		
		No Curtailment	Required Curtailment	Voluntary Curtailment
1	Utility Obligated to Accommodate All PV Exports	NC (1)		
2	Utility Not Obligated to Accommodate PV Exports beyond Existing Hosting Capacity	NC (2)		
3	Utility Not Obligated to Accommodate Via Upgrades, but Can Accommodate with Curtailment		NC (3)	NC (4)
4	Utility Obligated to Either Upgrade and Accommodate or Curtail and Compensate	NC (5)	C (6)	C (7)

Applicability of Curtailment Mechanisms

For each of the four policy alternatives detailed above, required and voluntary curtailments may be applied in different ways to reduce PV exports. Further, financial compensation for curtailed PV exports may or may not be applicable. Table 3 summarizes curtailment and compensation scenarios across the four examined policy alternatives.

Per Table 3:

- When the utility is obligated to accommodate all PV exports (Alternative #1), curtailment never occurs and thus there is no need to provide financial compensation for curtailed exports because it should never occur (table cell 1).
- When the utility is not obligated to accommodate PV exports beyond existing hosting capacity (Alternative #2), it would not connect any additional systems that could cause a violation[19] and thus curtailment is never needed. Like Alternative #1, there is no need to provide financial compensation for curtailment because it is never needed (table cell 2).
- When the utility is not obligated to accommodate via upgrades, but may curtail PV exports to allow more PV interconnections (Alternative #3), the utility may choose to impose curtailment without compensation because it is not obligated to compensate (table cell 3). PV owners may also choose to work with the utility to establish a plan for increasing PV accommodation. Voluntary curtailments of PV exports may be part of this plan, but are not compensated, again because there is no obligation to compensate (table cell 4).
- There are a number of available options when the utility is obligated to *either* upgrade and accommodate *or* curtail and compensate (Alternative #4). The utility may choose to accommodate based on measures that involve investment in conventional infrastructure upgrades (e.g., reconductoring, equipment upgrades). In this case, no curtailment of PV exports would be needed (table cell 5). The utility may also choose to curtail PV exports, in which case interconnected PV would be required to curtail, but would be financially compensated for responding to curtailment signals (table cell 6). Finally, the utility may also choose to rely on voluntary curtailments, in which PV owners would be induced to curtail based on financial compensation levels. Utilities would only pursue this option if it is more economic than grid upgrades (table cell 7).

There are multiple compensation mechanisms that could be used when compensation is applicable; these are described in the next section.

COMPENSATION AND SETTLEMENT MECHANISMS

If utilities are obligated to either upgrade and accommodate or curtail and compensate (Alternative #4), there are several compensation and settlement mechanisms that may be used. These mechanisms determine the compensation levels received by PV owners for curtailing exports, and/or penalties for failure to curtail exports when contractually obligated. There are two basic approaches to compensation and settlement: *administratively-determined* or *market-based*. Each has its own set of benefits and challenges, some of which are discussed below.

Administratively-determined Settlement

Under the administratively-determined approach, compensation/penalty levels are established at the time of interconnection based on estimations of value, or to elicit certain outcomes. Compensation levels may be based on the estimated value of the energy curtailed, possibly using historical trends of the locational marginal price (LMP) at the closest substation or projections of LMP based

19 It is theoretically possible to have an economic outcome of upgrading to accommodate if the costs of the PV system exports are much less than procuring energy from other sources and the estimated total energy savings are greater than the cost of the grid upgrade.

on models and assumptions about the future. They may also be informed by estimating the utility's avoided cost of not curtailing exports. Penalty levels for not following through with contractually agreed upon curtailments may be based on estimates of the extra cost the utility incurs to maintain normal operations despite the exports. The administratively-determined settlement approach can be used for both required and voluntary PV curtailment. In both cases, curtailment levels are directly determined by operational considerations (e.g., voltage violations).[20]

In general, this settlement approach is relatively simple in its execution. Medium- to long-term contracts governed by this approach, and that clearly define accompanying compensation schemes and performance requirements, may also support the financing of PV and other DER projects by providing some level of certainty around expected revenues (or losses) related to curtailment. However, administratively-determined settlement may not promote economically efficient outcomes when applied uniformly across a certain class of customers, if assumptions prove inaccurate or if curtailment amounts fail to materialize.

Market-based Settlement

A range of market-based mechanisms may also be used to determine the compensation or penalty levels related to curtailment of PV exports.

Competitive Bids for PV Curtailment

A utility that is obligated to either accommodate or curtail may choose to solicit competitive bids from PV owners willing to voluntarily curtail their PV exports as an alternative to infrastructure upgrade. Should curtailment be selected over conventional circuit upgrades, a contractual agreement would likely be established with the PV owner(s) willing to curtail and the compensation levels set based on the bids submitted. In this arrangement, selected PV owners become contractually committed to deliver the curtailment service, and may be penalized for failure to curtail. Once the contractual agreement is executed, curtailment levels are directly determined by operational considerations (e.g., voltage violations).[21] A main challenge associated with the competitive bids approach regards issues related to market power. For example, only a small number of sizable PV systems may be capable of curtailing their exports in a way that can benefit system operations. In such a scenario, a small number of market participants could influence the local energy market, potentially distorting the market's efficiency.

Organized Distribution Energy Market

A second market-based approach consists of creating an organized energy market at the distribution level. Time- and location-dependent market prices would be generated at multiple distribution nodes based on electricity supply and demand. PV export curtailments and the associated compensation or penalty would be determined accordingly.

Several approaches have been proposed to compute nodal prices. The concept of distribution locational marginal pricing (DLMP) mirrors the LMP concept already in use today at the wholesale market level, with components reflecting the costs related to energy generation, delivery constraints (voltage, thermal, etc.), and losses.[22] Under the DLMP approach, end-users import and export energy at the DLMP value for the distribution node they are connected to. DLMP directly reflects any binding constraints limiting hosting capacity (voltage, thermal limits, etc.), similar to the way LMP reflects congestions affecting the transmission system. Consequently, DLMP values could help guide curtailment of PV exports at the distribution level.

For example, if surplus energy is available at a certain time on a certain distribution node leading to an over-voltage condition, the corresponding DLMP value at that node would become negative. Similar to the transmission system, any PV system exporting to this node while nodal prices are in negative territory would have to pay for the privilege of exporting. In this context, DLMP values can act as economic signals that directly guide the decision to export or curtail, based on distribution system requirements to maintain voltage and loading levels within their normal operating limits. Each PV owner sets their own curtailment levels in response to the temporal variations of DLMP at the distribution node to which their PV system is interconnected.

Complexity of the DLMP Approach

While conceptually similar to LMP, the level of complexity introduced by DLMP is much higher from an implementation standpoint. For one, the number of distribution nodes is much larger than the number of transmission nodes (substations). Distribution feeders are also operated unbalanced, meaning that there could be a differ-

20 This paper focuses on curtailment of PV exports resulting from limitations of the distribution system. Other reasons to curtail include economic considerations involving the LMP at the substation to which the distribution feeder is connected.

21 See previous footnote.

22 For example: R. Yang, Y. Zhang, Three-Phase AC Optimal Power Flow Based Distribution Locational Marginal Price, IEEE PES ISGT Conference, 23-26 April 2017.

ent price for each of the three phases at each distribution node. As a result, establishing nodal prices would require significant computational power given the number of nodes considered and a massive deployment of telemetry equipment to record the transactions executed at each distribution node. While increased granular pricing (both temporal and locational) benefits economic efficiency, it also requires increased transaction costs that may trump the expected efficiency gains. Finding the right balance between the increased complexity and the increased efficiency is a topic of ongoing research.

Other challenges associated with the DLMP approach for guiding PV curtailments include issues related to market power. Certain distribution feeders, or feeder sections, may be particularly prone to binding constraints related to voltage or loading limitations, with only a small number of sizable PV systems capable of curtailing their exports in a way that can benefit system operations. In such scenarios, a small number of market participants could potentially influence the local energy market, potentially distorting market efficiency.

The concept of "LMP+D" has been proposed to simplify the DLMP approach.[23] The idea is to decrease the complexity of implementation while still achieving some level of temporal and locational pricing granularity. For a given distribution feeder, the LMP+D approach leverages the LMP value coming out of the wholesale market for the substation serving the feeder. Based on the feeder characteristics, a fixed "D" component is added to capture the costs related to distribution congestion (i.e., voltage or thermal limitations) and losses at the distribution level.

The simplified LMP+D approach does not require complex price computations at multiple distribution nodes, and can still inject some time- and locational- granularity. However, the impacts of binding *distribution* constraints are not captured in this price formation mechanism. While the LMP+D approach may help relieve binding constraints at the *transmission* level, as captured in the "LMP" part, it may not be as efficient in guiding PV curtailment to alleviate voltage or thermal constraints at the *distribution* level since the "D" part is constant.

23 For example: State of New York, Department of Public Service. *Staff White Paper on Ratemaking and Utility Business Models.* Case 14-M-0101. July 28, 2015, page 90.

SUMMARY OF INSIGHTS AND CONCLUDING THOUGHTS

There are many issues for regulators and policymakers to consider when evaluating the economics of curtailing distribution-connected solar PV. In fact, the complexity of this topic and its myriad of issues are too numerous to adequately address within the limited scope of this paper. However, as discussed, the degree to which the utility is obligated to accommodate PV, available mechanisms for curtailment, and accessible curtailment compensation and settlement methods are among the key factors for determining the economic merits of pursuing active power curtailment. What follows are summarized insights intended to inform future regulatory and policy debate on the subject.

Setting the bounds of *what utilities must do* when hosting capacity is exhausted and prospective PV owners want to connect more PV to the grid has many implications that will influence outcomes. If the utility is obligated to accommodate all PV exports, it is hard to avoid the rate-design issues that apply to PV. For example, if PV export is accommodated, will it support the cost of accommodation? If not, are there other social values or objectives that can override local conditions? If the utility is not obligated to accommodate PV beyond PV hosting capacity, how should first-come, first serve issues be handled? Should first comers be able to take advantage of the existing headroom, leaving late-comers to face the costs of integrating PV after available headroom has been expended? Allowing PV curtailments could potentially serve as a way to increase PV capacity on a circuit, however economic implications should be considered.

The rationale for curtailing distributed PV exports centers on improving economic efficiency and preventing distribution system violations. While it may seem counterintuitive to curtail a zero-cost energy source like PV, market dynamics can create conditions of over supply where locational energy prices are negative, thereby justifying the curtailment. Additionally, curtailment is needed if the PV exports are expected to cause a distribution system violation, thereby diminishing system reliability, imposing additional costs, or potentially causing safety hazards.

Note: An organized energy market at the distribution level with time- and location-dependent electricity prices could, in theory, incorporate distribution system constraints into calculated nodal prices, thus improving economic efficiency while managing the distribution constraints. However, many challenges exist that must be overcome before this could reasonably be implemented.

Economic tradeoffs exist when comparing PV curtailment and distribution system upgrade options. Stripped of complicating factors (for which there are many), the central idea is fairly simple: It is economic to upgrade the grid and add delivery capacity if the value of the additional energy delivered is more than the cost of the upgrade. For example, if mid-day energy is expensive for the utility to procure, there may be economic incentives to incur an upgrade cost and deliver a lower cost form of energy. This tradeoff exists, whether compensation for PV curtailment occurs or not.

In instances where utilities are obligated to either *upgrade and accommodate* or *curtail and compensate*, the most economical pathway will be influenced by the level of compensation provided for curtailment. Regardless of its level, compensation for PV curtailment will increase the incentive to upgrade grid infrastructure. Meanwhile, if compensation is set too high, costs could become excessive.

There is also a technical challenge associated with verifying how much energy would have been exported from a PV system if curtailment had not occurred. Many factors impact the amount of PV energy exported at any given time including inverter availability, irradiance, module temperature, soiling levels, and behind the meter load, among others. Standard PV systems are not equipped to measure what would have been their maximum power point if they have been curtailed.

Expectations of future energy procurement costs will drive future outcomes related to PV curtailment, posing a challenge. Estimating the costs of procuring energy from other sources at any given time is highly complex because it depends on regulatory structure, supply and demand dynamics of energy markets, and uncertain future policy decisions. Predicting the exact moment and frequency that PV curtailment is needed is another complex undertaking due to fluctuations in load and PV output. Both estimates impact decisions related to curtailment compensation (i.e., a utility or its regulator may desire to estimate how often curtailment is needed to estimate appropriate compensation measures) and expectations of returns (i.e., PV system investors may desire some assessment of risk regarding how much energy they will be able to export, and how much they will be compensated prior to making investment decisions).

There are pros and cons to the various mechanisms available for compensating curtailment. Administratively-determined settlement mechanisms are relatively simple but are reliant upon engineered values and estimations which may not promote economic efficiency. Market-based mechanisms may, meanwhile, promote economic efficiency, but there are many challenges associated with implementing organized energy markets at the distribution level that could be costly to overcome. It is unclear if the potential benefits outweigh these costs.

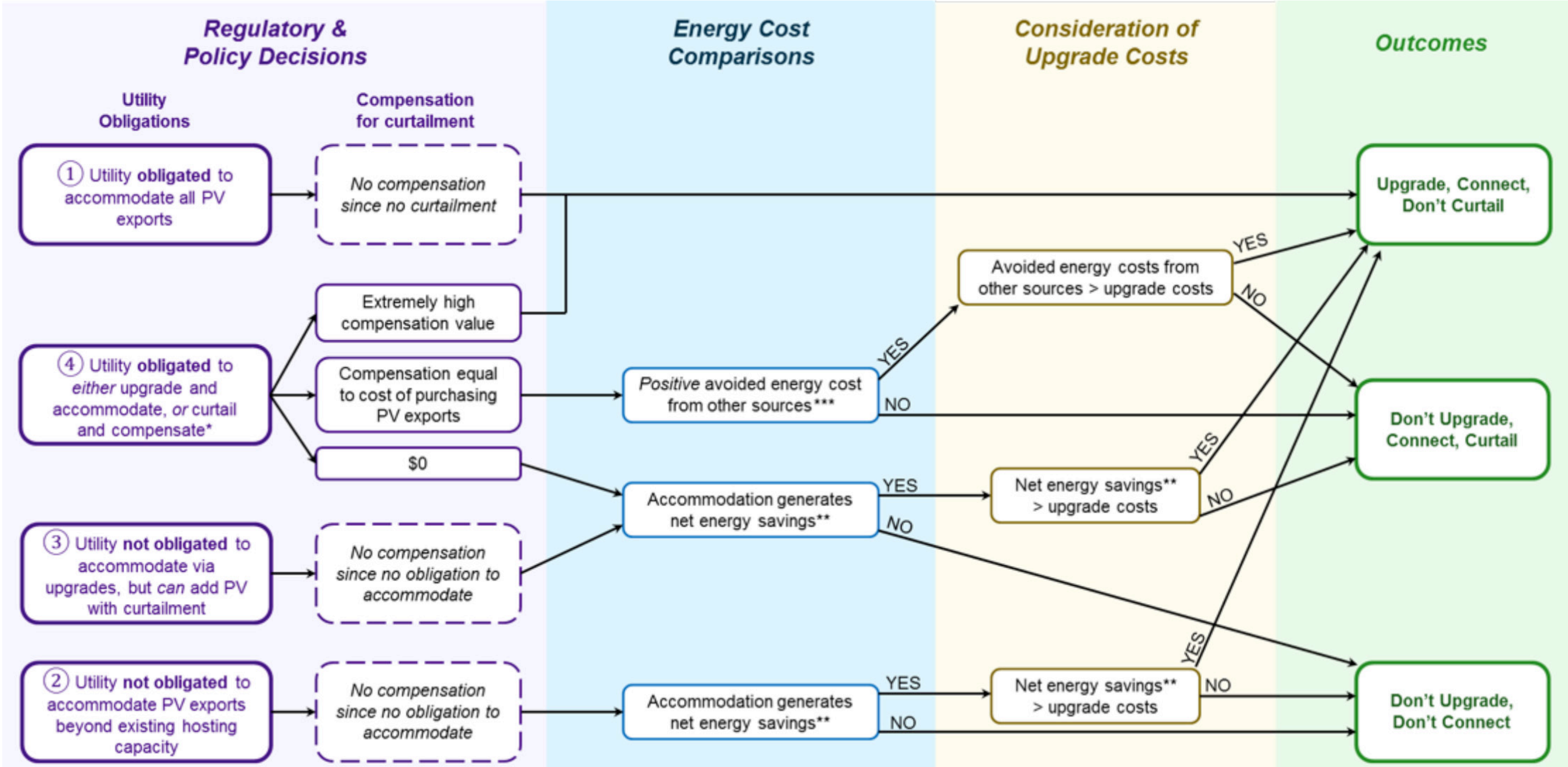
AN ORGANIZING FRAMEWORK

Multiple decision pathways emerge when considering viable options for economically increasing PV penetration through PV curtailment. Determining the most economic outcome will depend on regulatory and policy decisions regarding the utility's obligations to accommodate additional PV interconnection requests, compensation levels for curtailment of PV exports, and the costs associated with the procurement of energy from PV exports and other sources from the grid.

Figure 2 presents an organizing framework for understanding the economic outcomes associated with different scenarios that seek to increase PV penetration via curtailment of PV exports. It illustrates the interrelation of the main concepts presented in this paper, and is intended to raise awareness about the interconnectedness among the various factors that dictate which outcomes are most economic. These factors include:

- Regulatory and policy decisions about a utility's obligations, including compensation for curtailment of solar PV and how its amount is set (purple box in Figure 2);
- The relative cost of procuring electricity from different sources, such as from PV exports, market transactions, and conventional generation (blue box in Figure 2); and
- How expected savings compare to the costs of grid infrastructure (yellow box in Figure 2).

These interrelated factors eventually lead to one of three possible outcomes (green box in Figure 2): Upgrade, connect, don't curtail; or Don't upgrade, connect, curtail; or Don't upgrade, don't connect.



* The three alternative compensation amounts shown for Alternative (4) are illustrative examples. These amounts refer to the payments made to PV owners for t the curtailed export energy they would have otherwise produced. Other amounts not sown could be used. Amounts could be set through a variety of curtailment and settlement mechanisms as discussed in this paper.

** Net energy savings equal to the avoided energy costs from other sources (via market transactions or conventional generation dispatch) when accommodating PV exports, minus the costs for additional PV exports paid to PV owners exporting PV power to the grid.

*** Negative avoided energy costs from other sources could result if curtailment of PV exports occurs during times of negative locational marginal prices (LMPs in the area of PV interconnection.

Figure 2 – Example Pathways for Economic Outcomes to Increase PV Penetration by Considering Curtailment of PV Exports
Notes: Regulatory and policy decisions lead to different economic outcomes when PV interconnection requests exceed hosting capacity limits. Arrows represent least cost decision pathways based on prior decisions or comparisons. The diagrammatic depiction assumes energy costs are applied during PV curtailment. Outcomes to the right indicate whether the grid is upgraded or not, whether additional PV beyond existing hosting capacity is connected or not, and whether that PV is curtailed or not.

FUTURE RESEARCH PURSUITS

This white paper covers only a sampling of issues related to the economic and regulatory considerations germane to distributed PV curtailment. Other issues related to this topic as well as those more broadly relevant to the economic management of grid operations at the distribution level are candidates for future EPRI research. These include:

- Relationships between curtailment seeking to increase distribution system penetration of DER and curtailment in response to bulk system operations and market dynamics.
- Similarities and differences between transmission and distribution expansion in a grid with high penetrations of DER.
- Different regulatory structures and associated roles, responsibilities, and obligations of different parties to enable transactive energy through organized energy markets at the distribution level.
- The economic relationship between grid investments, generation investments, and load dynamics.
- Investment risks in regulated utility planning and structured energy markets.

REFERENCES AND RECOMMENDED READING

California Distribution Resource Plan Proceedings (R 14-10-013): http://www.cpuc.ca.gov/General.aspx?id=5071

Three-Phase AC Optimal Power Flow Based Distribution Locational Marginal Price. R. Yang, Y. Zhang. IEEE PES ISGT Conference, 23-26 April 2017.

Current Practices in Scheduling Distributed Energy Resources into System Operations: An Examination of Selected U.S. and International Regions. EPRI, Palo Alto, CA: 2017. 3002009483.

Changing Utility Cost Pathways amid Rising Deployment of Distributed Energy Resources. EPRI, Palo Alto, CA: 2016. 3002008211.

White Paper on Developing Competitive Electricity Markets and Pricing Structures. Tabors Caramanis Rudkevich. Albany, NY: April 2016.

Distribution System in a High Distributed Energy Resources Future. De Martini, P., Kristov, L., Future Electric Utility Regulation Report No. 2, October 2015.

Electric Industry Structure and Regulatory Responses in a High Distributed Energy Resources Future. Lawrence Berkeley National Laboratory, LBNL-1003823, Report No. 1, Berkeley, CA: November 2015.

Staff White Paper on Ratemaking and Utility Business Models. State of New York, Department of Public Service. Case 14-M-0101. July 28, 2015.

The Integrated Grid: A Benefit-Cost Framework. EPRI, Palo Alto, CA: 2015. 3002004878.

The Integrated Grid: Realizing the Full Value of Central and Distributed Energy Resources. EPRI, Palo Alto, CA: 2014. 3002002733.

EPRI RESOURCES

Nadav Enbar, *Principal Project Manager,*
Integration of Distributed Energy Resources
303.551.5208, nenbar@epri.com

Power Delivery & Utilization –Integration of Distributed Energy Resources (Program 174)

DISCLAIMER OF WARRANTIES AND LIMITATION OF LIABILITIES

THE ELECTRIC POWER RESEARCH INSTITUTE (EPRI) PREPARED THIS REPORT.

NOTE

For further information about EPRI, call the EPRI Customer Assistance Center at 800.313.3774 or e-mail askepri@epri.com.

The Electric Power Research Institute, Inc. (EPRI, www.epri.com) conducts research and development relating to the generation, delivery and use of electricity for the benefit of the public. An independent, nonprofit organization, EPRI brings together its scientists and engineers as well as experts from academia and industry to help address challenges in electricity, including reliability, efficiency, affordability, health, safety and the environment. EPRI members represent 90% of the electric utility revenue in the United States with international participation in 35 countries. EPRI's principal offices and laboratories are located in Palo Alto, Calif.; Charlotte, N.C.; Knoxville, Tenn.; and Lenox, Mass.

Together . . . Shaping the Future of Electricity

3002010289

May 2018

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