Key Takeaways

Takeaway 1
Conservation voltage reduction (CVR) is a common utility strategy to improve grid operations by more efficiently managing voltage profiles at the distribution level. Distributed solar photovoltaics (PV) with smart inverters can improve the efficacy of CVR schemes by lowering overall system consumption, reducing peak demand, and decreasing greenhouse gas emissions.

Takeaway 2
Distributed PV with smart inverters can increase the benefits of utilities’ CVR schemes by over 10%. These improvements reduce customer energy consumption and peak demand by 0.4% annually, resulting in benefits of 1.0¢ to 2.9¢ for every kilowatt-hour (kWh) of PV generation. A detailed methodology and accompanying calculator are provided to facilitate replication of the benefits quantified herein.

Takeaway 3
Smart inverters are readily available today, and will soon be deployed by default with all distributed PV systems. Capturing smart inverter benefits via CVR schemes is straightforward and does not require incremental infrastructure investments. Distributed PV with smart inverters can deliver CVR benefits on any distribution circuit with voltage regulating equipment, regardless of whether or not a centralized, dynamic voltage control system has been deployed.

Background

As part of their core responsibilities, utilities must supply electricity to customers within established power quality standards. The range of allowable voltages (i.e. 114 to 126 V), an aspect of power quality, is set by American National Standards Institute (ANSI) standards. In practice, utilities over-supply voltage to most customers due to line losses that reduce voltage as electricity flows along distribution circuits. This over-supply of voltage results in excess energy consumption by customers.

A load duration curve is a familiar concept that illustrates a key grid inefficiency related to grid capacity: underutilized capacity is built to meet peak demand that occurs in only a handful of hours per year. Although less well known, a similar inefficiency exists related to customer voltages: higher than necessary voltages are delivered to most customers since no single customer can receive voltage below the ANSI voltage floor. In both cases, the cost of supplying electricity is increased.
To address this voltage delivery inefficiency, utilities are increasingly deploying conservation voltage reduction (CVR) programs. CVR is a demand reduction and energy efficiency technique that flattens and reduces distribution voltage profiles in order to achieve a corresponding reduction in energy consumption and greenhouse gas emissions. A 1% reduction in distribution service voltage can drive a 0.4% to 1% reduction in energy consumption. CVR programs typically save 0.5 to 4% of energy consumption on individual circuits, and are often implemented on a large portion of a utility’s distribution grid.

Distributed PV and smart inverters can enable greater savings from utility CVR programs because those programs typically only control utility-owned distribution voltage regulating equipment. Such utility equipment affects all customers downstream of any specific device; therefore, CVR benefits in practice are limited by the lowest customer voltage in any utility voltage regulation zone (often a portion of a distribution circuit) since dropping the voltage any further would violate ANSI voltage standards for that customer. Because distributed PV with smart inverters can increase or decrease the voltage at any individual customer location, these resources can be used to more granularly control customer voltages.

**How CVR + Distributed PV with Smart Inverters Creates Benefits**

Typical distribution capacity planning studies do not consider the effects of the secondary distribution system, or secondary voltage drop – the portion of the distribution grid consisting of the power lines and pole top transformers that connect a customer’s meter to the utility’s primary distribution system. However, incorporating these details is critical to capturing the technical potential of CVR since secondary voltage drop is a limiting factor for utility voltage reduction strategies today. Within a voltage regulation zone, if the lowest customer voltages on the secondary distribution system were to be increased by one volt, the entire voltage regulation zone could then be subsequently lowered another volt. Therefore, the benefit of addressing the secondary voltage drop is significant.

The CVR concept is demonstrated in the figure below, where three voltage profiles are shown along a typical distribution circuit, from substation to end customers. The solid lines depict the primary voltage drop, while the dashed lines represent the secondary voltage drop. The reduction in voltage between the gray and green lines represents the voltage reduction that can be achieved solely by controlling utility-owned voltage regulating equipment within a traditional CVR scheme. However, potential voltage reduction is limited by the customer voltage at the end of the line, which in this example is already at the lowest permissible voltage according to ANSI standards. By installing distributed PV with smart inverters at this customer site, the secondary voltage drop is decreased and voltage is subsequently increased, which is evident in the reduced slope of the secondary voltage drop. This allows the overall voltage profile in yellow to be further reduced, increasing efficiency savings.

**DERs control voltage locally and enable increased CVR benefits**

While individual customer voltages vary within the allowable ANSI voltage band of 114 V to 126 V, suppose the average customer voltage is 120 V in the utility CVR example above (i.e. green line). In this case, a single customer receiving service at the voltage floor of 114 V prevents further savings through additional voltage reductions. To remove this inefficiency, deploying rooftop solar PV with a smart inverter at the limiting customer site can increase their voltage from 114 V to 115 V. Subsequently, the overall circuit voltage could also be lowered by a volt, delivering voltage to all customers at 119 V. Therefore, in this example, efficiency savings on the entire circuit are unlocked by installing a single rooftop PV system.
Benefits Calculation Methodology

The following methodology for determining the CVR benefits of distributed PV with smart inverters focuses on inverter contributions at the secondary (low voltage) level. This methodology quantifies the benefit from increasing the voltages of a subset of customers through targeted deployment of distributed PV with smart inverters in order to enable the subsequent decrease of voltages to all other customers on the circuit, resulting in energy efficiency savings. This methodology does not evaluate the incremental benefits to the primary (medium voltage) system due to the complexity introduced in modeling such benefits. Primary system benefits could be modeled if circuit model, equipment, and loading data were available.

A detailed methodology and accompanying calculator are provided to facilitate replication of the benefits described herein. The calculator can be applied to any distribution circuit, and can be found at www.solarcity.com/gridx.

Modeling Secondary Voltage Drop

Secondary voltage drop is a function of net load and the impedance of the service transformer and secondary line. To represent a typical secondary system, a simplified secondary model was utilized that consisted of typical pole top transformer, secondary conductor, and customer loads. For simplicity, all load is modeled as connected at a single location at the end of the secondary line. Consistent with the IEEE 8500-Node Test Feeder, the secondary system, and therefore the impedance, consists of a 25 kVA transformer and 50 feet of 4/0 Al secondary conductor. The single line diagram of this typical secondary system is depicted in the figure below.

Equation 1 below shows how the secondary voltage drop is calculated, which is the difference of voltage magnitude between the primary side of the service transformer and the customer’s meter. The voltage at the primary side of the transformer can be derived using the transformer load and secondary impedance, as seen in Equation 2. The voltage at the meter is used as reference and is fixed to a nominal value, 120∠0° V, as shown in Equation 3. The difference in magnitudes between these two voltages equals the voltage drop across the secondary system (Equation 1).

\[
V_D = |V_{pri}∠\theta_{pri}| - |V_{mtr}∠\theta_{mtr}|
\]

Where:

\[
V_{pri}∠\theta_{pri} = \left(\frac{\text{Transformer Net Load}}{\text{Secondary Impedance}}\right) * \left(\frac{Z_{xf}∠\theta_{xf} + Z_{line}∠\theta_{line}}{1}\right) + V_{mtr}∠\theta_{mtr}
\]

\[
V_{mtr}∠\theta_{mtr} = 120∠0^\circ V
\]

Modelling PV with Smart Inverter Capability

The voltage drop reduction of PV with smart inverters is a function of both the underlying PV generation as well as the reactive power capability of the smart inverter. Therefore, their combined impact on the secondary voltage drop must be modeled. To do so, PV production data from the National Renewable Energy Lab’s (NREL) PVWatts® Calculator is applied to an archetypal 5 kVA smart inverter. Inverter reactive power capability is activated for all hours of the day, but the smart inverter is assumed to maintain an active power priority because the economic value of active power is generally greater than reactive power (note: in geographies or times of day when reactive power is more valuable, this prioritization can be removed). Therefore, the amount of reactive power available per inverter is limited by the coincident apparent power generation. For example, at night when the PV is not generating, the smart inverter is capable of supplying the full 5 kVAR. However, during peak PV generation, the smart inverter is not capable of supplying any VARS. Since both active and reactive power enable a reduction in secondary voltage drop, any combination of active and reactive power output provides benefits.
A negative secondary voltage drop (i.e. voltage rise) can occur due to reverse power flows from PV back-feeding onto the primary, or excessive reactive power support during low loading conditions. While voltage rises can occur in practice, overall CVR benefits would be limited by the customer with the next lowest voltage. Therefore, secondary voltage drops are assumed to be able to be reduced to zero, but no incremental benefits are attributed to voltage rises on the secondary.

**Relating Voltage Reduction to Energy Reduction**

Equation 4 details how the incremental CVR energy savings ($/kWh) are calculated for each voltage regulation zone.

\[
\left( \frac{\$}{kW\cdot h} \right)_{\text{Energy}} = \frac{\sum_{t=1}^{8760} \left[ \frac{V_{D_{\text{noPV}}}-V_{D_{PV}}}{V_{\text{Base}}} \right] C_{\text{Targeted}} \left( 1 - \frac{\%_{\text{Targeted}}}{\%_{\text{TotalCustomers}}} \right) E_{\text{AnnualProducedByPV/Customer}}}{\%_{\text{Targeted}} \cdot \text{TotalCustomers}}
\]  

(4)

The difference in the secondary voltage drop with and without PV \((V_{D_{\text{noPV}}} - V_{D_{PV}})\) is calculated for each hour over the course of one year (8760 hours) using Equations 1-3 above. The change in voltage drop after PV is deployed is then converted to a percentage by dividing by the nominal voltage at the customer meter (i.e. 120 V).

The percent reduction in energy for a voltage regulation zone is then determined by multiplying the percent reduction in voltage by the relevant CVR factor. The CVR factor of a load is the change in energy that results from a corresponding change in voltage. For example, if a load has a CVR factor of one, then a 1\% reduction in voltage would result in a 1\% reduction in energy. In this analysis, a CVR factor of 0.8 is used, which has been found to be representative of typical distribution circuits.\(^3\)

Percent reduction in energy for the entire circuit is then determined by multiplying the voltage drop and CVR factor by the percentage of customers that are having their voltage reduced. In this case, the customers who are experiencing the voltage reduction are those without PV installations \((1 - \%_{\text{Targeted}})\). Those customers with PV installations will receive the same voltage before and after the CVR scheme is in place, since the PV will raise their voltage while the CVR scheme will then lower it to its previous value. Equation 4 assumes that all customers have the same net load. In other words, 1\% of customers consume 1\% of the circuit load.

**Targeting Customer PV Deployments**

An Electric Power Research Institute (EPRI) analysis found that 90\% of the secondary voltage drops were less than 2 V (on a 120 V base), but that 1\% of voltage drops were greater than 4.2 V.\(^3\) This finding indicates that a small minority of customers experience outsized secondary voltage drops. Therefore, incremental CVR benefits could be unlocked if voltages at that small minority of customer sites could be raised, allowing for all customer voltages along the circuit to be subsequently lowered.

Voltage data from SolarCity customers offers a corroborating insight: that a small percentage of customers receive voltages at the low end of the ANSI voltage range. The baseline scenario in the figure below shows a histogram of voltages from 18,000 SolarCity customers at 5 PM on a particular day. PV production at 5 PM is low enough that these readings approximate voltages at customer sites without PV. In this data set, 1\% of the customers receive power within the lowest 3 V of the ANSI range: from 114 V to 117 V. A similar distribution was found for voltages at 7 AM. If voltages at these 1\% of customers could be raised, then significant energy efficiency benefits can be achieved by subsequently lowering all customer voltages on the circuit. Targeting PV deployments with smart inverters at these 1\% of customers could achieve this goal.

![Baseline Voltage Distribution](image-url)

*Residential Voltage Distributions based on 18,000 SolarCity Customer Voltages*
While this data suggests that increased CVR savings could be unlocked by siting PV at as few as 1% of customers, this analysis assumes that PV installations are deployed across 3% of total customers in order to account for the possibility that the lowest voltage customers may change throughout the day. This analysis also conservatively assumes that the lowest voltage customers are dispersed across the circuit on different secondary systems. In practice, if multiple low voltage customers were on the same secondary system, fewer PV systems would be required to achieve the same CVR benefit.

The figures below illustrate the impact that a targeted deployment of PV with smart inverters can have on customer voltages across a circuit. In the base benefits case, the lowest voltage customers are shifted up by 1 V, allowing the median service voltage to subsequently drop by 1 V from 122 V to 121 V for the remaining customers. In the high benefits case, the lowest voltage customers are shifted up by 3 V, allowing the median service voltage to subsequently drop to 119 V. This high benefits case is achievable if more than one low voltage customer occurs per transformer.

Quantifying Incremental CVR Benefits

After determining the percent reduction in energy, total financial savings in the numerator of Equation 4 are determined by multiplying the percent reduction in energy by the cost of energy in the voltage regulation zone. $/kWh benefits are calculated by dividing this number by the estimated annual energy production from all of the targeted systems. Equation 5 shows an annotated version of the energy benefits calculation highlighting where the change in voltage, reduction in energy, energy costs, and annual energy production are calculated.

$$\left( \frac{\$}{kWh} \right)_{Energy} = \sum_{i=1}^{8760} \left[ \frac{\% \text{ Change in Voltage}}{V_{Base}} \right] \left[ CVR_i \left( 1 - \% \text{Targeted} \right) \right] \left[ Utility \ CVR \ Energy \ Cost \right] \left[ E_{PV \ Annual \ Produced \ By \ PV \ System \ / \ Customer} \right] \left[ \% \text{Targeted} \right] \left[ n_{Total \ Customers} \right] \left[ \frac{Annual \ Energy \ Production \ of \ all \ Targeted \ PV \ Systems}{8760} \right]$$

After determining the savings attributed to energy, the savings attributed to capacity can be similarly found by taking the demand reduction at peak and multiplying it by the distribution marginal cost of capacity (DMC) as seen in Equation 6.
\[
\left( \frac{\$}{kWh} \right)_{\text{Capacity}} = \left[ \frac{V_{\text{D, noPV}} - V_{\text{PV}}}{V_{\text{Base}}} \right] C_{\text{VR}} (1 - \%_{\text{Targeted}}) P_{\text{Regulation Zone}} D_{\text{MC}} \left( \frac{1}{E_{\text{Annual Produced by PV/Customer}} \%_{\text{Targeted}} n_{\text{Total Customers}}} \right)
\]

Total financial savings are determined by adding equations 5 and 6.

\[
\left( \frac{\$}{kWh} \right)_{\text{Total}} = \left( \frac{\$}{kWh} \right)_{\text{Energy}} + \left( \frac{\$}{kWh} \right)_{\text{Capacity}}
\]

**Case Study**

The previous section describes a methodological approach to quantify the benefits of integrating PV with smart inverters into utility CVR programs. In this section, the methodology is performed on a realistic case study of a 30 MVA substation in Southern California Edison’s territory. In this case, a 30 MVA utility substation loading profile is synthesized from an aggregation of SolarCity residential loads for a year within Southern California Edison’s (SCE) service territory. This proxy load profile is necessary because the utility data is generally not publicly available.

The results of these calculations can be articulated through a variety of perspectives and scopes, but this paper focuses on the relationship between incremental energy efficiency savings (\$/year) unlocked by smart inverters and the corresponding PV production (kWh), yielding a $/kWh benefit. The table below summarizes the incremental energy and capacity savings that can be delivered by PV with smart inverters in the substation case study analyzed. Energy consumption and peak demand is reduced by approximately 0.4% per year, avoiding 350,412 kWh of incremental energy and 128 kW of capacity per year for the substation modeled.

**System Benefits of PV with Smart Inverters in Utility CVR Schemes**

<table>
<thead>
<tr>
<th>Energy Efficiency</th>
<th>Demand Reduction</th>
</tr>
</thead>
<tbody>
<tr>
<td>Absolute Reduction</td>
<td>350,412 kWh/yr</td>
</tr>
<tr>
<td>% Difference</td>
<td>0.38%</td>
</tr>
<tr>
<td>Avoided Cost Value</td>
<td>$39/MWh</td>
</tr>
<tr>
<td>Annual Value</td>
<td>$14,613</td>
</tr>
</tbody>
</table>

The financial impact of these results can be measured by considering the value of the consumption and capacity reductions. Based on hourly energy costs from 2012-2015 in SCE territory,\(^7\) the value of these energy reductions avoids bulk system energy consumption at a weighted average cost of $39/MWh, yielding an annual energy benefit of $14,613. While the energy reductions also result in lower greenhouse gas emissions, the marginal cost of AB32 emission permits is assumed to be adequately captured in the avoided locational marginal prices (LMP). On the capacity side, assuming SCE’s own marginal distribution capacity value of $53/kW-year,\(^7\) 128 kW in peak demand reduction generates benefits of $6,798 per year. In sum, the incremental energy efficiency and capacity benefits total $21,411 per year.

These benefits are enabled by the PV systems with smart inverters. A critical assumption identified in the methodology is the quantity of systems needed on the substation circuit to materially address the secondary voltage drop, which is a function of the feeder’s underlying composition and voltage dispersion. In the **base** scenario, the 3% of customers with the lowest voltages are targeted with PV systems to reduce the secondary voltage drop by 1 V, yielding a 1.0 $/kWh benefit ratio. In the **high** benefits case, the same 3% of customers reduces the secondary voltage drop by 3 V, which yields a benefit ratio of 2.9 $/kWh. While SolarCity’s voltage data suggests the **high** benefits case is realistic, the **base** case assumes a more conservative 1 V circuit voltage reduction. Specific results would vary by geography, circuit, and voltage regulation zone.
Efficiency Benefits of Smart Inverters in Utility CVR Programs

As stated previously, these technical benefits can be seen at penetrations as high as 10% of customers. However, if PV penetrations higher than 3% of customers are seen on a distribution circuit, this methodology will begin to underestimate the economic benefit per kWh, as the kWh produced in the denominator of the equation increase while the CVR benefits in the numerator remain relatively the same. Therefore, analysis at these higher penetration levels should incorporate benefits at the primary level, including voltage profile flattening and distribution line loss reduction. Further analysis at these penetration levels will require detailed circuit models and operational data for the utility’s distribution system.

Realizing Voltage Benefits of Smart Inverters

Realizing smart inverter benefits in CVR programs is a relatively straightforward and low-cost opportunity to unlock energy efficiency savings, particularly in areas where smart meters are deployed that are capable of providing voltage data. Proactive voltage analysis by utility engineers and simple changes to the interconnection process could leverage the unique capabilities of smart inverters to address voltage inefficiencies deep in the distribution system.

Dynamic, centrally controlled CVR schemes are often thought to be a prerequisite to utilizing distributed PV to achieve CVR benefits. However, this is not the case. While dynamic CVR control systems can unlock additional efficiency savings, CVR benefits are achievable with open-looped control methods that use existing utility equipment, often only requiring easily administered device settings changes.\(^1\,3\,8\) For example, the California Public Utilities Commission (CPUC) required their regulated utilities to implement CVR programs to avoid capacity shortages in 1976, a time when dynamic CVR control systems did not exist.\(^9\) Capturing CVR benefits therefore does not require significant investment by the utilities, and distributed PV with smart inverters can deliver CVR benefits on any circuit today, regardless of whether or not a dynamic, centrally controlled system has been implemented.

Conclusion

This method uses a simplified secondary model to estimate the reduction in voltage drop and proprietary voltage data to determine the percentage of customers to target to unlock additional CVR savings. The typical economic benefit is 1.0 c/kWh of PV production, which can increase the benefits of utility CVR programs by at least 10%, generating incremental savings of 0.4% to a typical 3% utility CVR energy savings rate.\(^7\) In a highly targeted scenario, these savings could be as high as 2.9 c/kWh of PV production. These enhanced benefits suggest that all ratepayers – solar and non-solar customers – would benefit if their utility proactively integrated PV with smart inverters into their CVR schemes.

A detailed methodology and accompanying calculator are provided to facilitate replication of the quantified benefits and to stimulate discussion. The calculator can be applied to any distribution circuit, and can be found at www.solarcity.com/gridx. Readers are encouraged to contact GridX@solarcity.com with any questions or comments.
Appendix 1 - Methodological Critiques

When performing analyses to make general statements and rules-of-thumb regarding the electric distribution system, a common critique is that every circuit is unique and all results depend on the characteristics of the circuit in question. While this critique is reasonable, the use of methodological simplifications and assumptions are routine in order to practically quantify and generalize results. A few of the key assumptions and simplifications are highlighted below, which potential critiques identified. Whenever possible, justification is provided for chosen methodologies and assumptions.

To quantify typical benefits on a sample distribution circuit, a simplified distribution secondary model was modelled based on the IEEE 8500-Note Test Feeder consisting of all load connected to a single tap off of a secondary transformer. In reality, the secondary system would be more complex, and a more exhaustive approach would be to model the actual secondary system in question. However, EPRI states that most utilities “do not model into the secondary system...and secondary conductor sizing and circuit connectivity are often not known or have errors.” Therefore, this simplified approach is used. More accuracy in the underlying secondary model would likely increase the potential voltage drop and therefore increase benefits.

Another key assumption is the percentage of customers necessary to target in order to unlock increased CVR benefits. This benefits calculation methodology assumes 3% of customers must be targeted, based on current distributed PV penetration in California and by sampling SolarCity inverter voltage data. This sampling was done at sunrise and sunset, low solar production times of day in order to capture voltage not being influenced by the generation. Since evening peak typically occurs after the sun sets, these results suggest that the 3% could be even lower at evening peak. This assumption is similar to that used in EPRI’s evaluation of the topic. Access to detailed customer voltage profiles would help refine these assumptions.

A key technical assumption is how significantly circuit voltage profiles could be lowered. Mechanically switched, voltage regulating equipment can typically only adjust voltage in 0.625% increments, implying that a secondary voltage drop would be enough to trigger a voltage regulator band. In reality, EPRI states that most utilities “do not model into the secondary system...and secondary conductor sizing and circuit connectivity are often not known or have errors.” Therefore, this simplified approach is used. More accuracy in the underlying secondary model would likely increase the potential voltage drop and therefore increase benefits.

The calculations in this paper provide an estimate of value under the methodology and assumptions described. Access to utility distribution data would enable a more refined benefits calculation, and would also enable quantification of additional benefits to the primary distribution system.

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4 “The IEEE 8500-Node Test Feeder”, Arritt and Dugan, Electric Power Research Institute (EPRI), 2010
6 Prices were averaged based on hourly day-ahead LMP prices in the SCE DLAP for Jan 1, 2012 to December 31, 2015
7 See SCE fillings in California Public Utilities Commission Proceed on Net Energy Metering Successor Tariff. SCE’s assumption for Marginal Distribution Avoided Cost of Capacity was $53/kw-year, which is 55% lower than SCE’s marginal distribution cost of capacity ($118/kw-year) used in rate case filings. To be conservative, the authors use SCE’s assumption of $53/kw-year provided to the NEM 2.0 proceeding.
10 “2017 General Rate Case Phase 1 Application 15-09-001 Data Response to PG&E Data Request No. ORA_185-Q20”, Dasso, Pacific Gas & Electric (PG&E), March 2016.