



# The True Value of Solar

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## Executive Summary

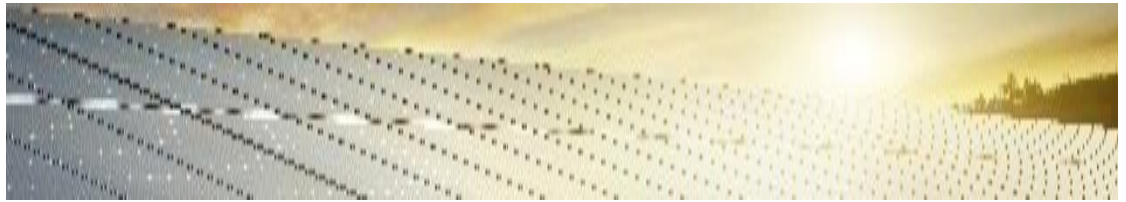
As solar becomes an increasingly significant factor in the generation mix, ICF believes that utilities, investors, and markets are missing out on optimal strategies to price assets, lower costs, and mitigate risks, because they lack a consistent and accurate approach for determining the true value of solar. Current methodologies are all over the map, yielding different outputs based on different inputs, and different assumptions to those inputs. That is why we suggest here an updated, comprehensive methodology that could help all stakeholders expose the benefits and costs and make more informed—and ultimately more beneficial—investments.

This kind of approach will likely become even more important in the years to come. The amount of distributed photovoltaic (DPV) installed behind the meter specifically for residential customers grew 60 percent from 2012 to 2013. ICF forecasts DPV installations to continue to increase to over 27 GW on commercial and residential premises by 2018, representing over 1.8 million locations where DPV will be interconnected to the distribution grid. Utilities, regulators, and the broader solar industry will need to understand how to value this growing factor in the market.

In this paper, we look at the current state of value of solar (VOS) analysis and propose a more holistic methodology that can be consistently applied across various utility service areas. We recommend factors for inclusion and exclusion in the calculation and consider the most appropriate way to construct each variable, keeping in mind our base view that distributed resources need to be evaluated in the same light as other generating resources on the grid, not just a decrement to load.

We recommend the following methodological approaches on potential VOS components:

- **Energy:** avoided generated energy represents the most straight-forward calculation, and while the best way to quantify energy value would be at the margin, a more simplified interim approach may be considered.
- **Avoided/Deferred Generation Capacity:** there needs to be a realistic analysis of the correlation between customer and system peak as well as an analysis of the DPV's generation profile to accurately assign a DPV system capacity credit. The same process should be applied to DPV projects as with central station renewables, with the added complication that penetration rates on distribution system feeders also need to be included.
- **Avoided Transmission and Distribution (T&D) Losses and Capacity:** for the T&D portion of the grid, DPV potentially represents both a benefit and a cost, and both of these impacts need to be included and separately assessed as part of a VOS analysis. This includes careful consideration of where DPV will be deployed versus the loads being served, as well as understanding the different feeder characteristics.
- **Grid Support Services:** based on the high amount of uncertainty on this variable, we believe that Grid Support Services should not be included in a VOS calculation for potential payment but should be reviewed for the potential to determine the mechanisms that may need to be in place to monetize any potential value when the appropriate technology exists.
- **Environmental:** as a generation resource on the grid, DPV should be evaluated in the same way as any other new resource, including central station renewables, in terms of environmental costs and benefits that it confers upon the system. The emissions (in this case CO<sub>2</sub>) values assigned on a \$/ton basis should be similar to those used to evaluate other power generation resources.
- **Financial:** “financial” benefits such as a fuel price hedge, reservation of natural gas pipeline capacity, and/or a market price response are not typically accounted for in utility integrated resource planning (IRP) evaluations of new resources, including central station renewables, or in cost-benefit evaluations of EE measures, and should not be included in VOS analyses.



- **Social:** “social” values are not included in the construction of utility scale conventional or renewable projects and should not be part of VOS analyses.
- **Security:** when DPV is able to isolate from the grid or “island,” it can provide reliability to the owner of the facility. This value, however, does not accrue to society or even the local grid. Security benefits should therefore be explored to value resiliency at specific critical locations, however, they should not yet be included in the VOS calculation until a set and agreed-upon methodology for resiliency is developed.
- **Frequency to Update VOS:** the utility should update the VOST on a locational basis for new installations yearly to address the changing amount of solar or energy use in different areas.

The result of our approach is a general roadmap for achieving a better consensus VOS, though calculations for individual entities would require an analysis tailored to the individual circumstances of their geography, energy market, and physical grid infrastructure.




This new VOS calculation could be an input in calculating the retail credit net energy metering (NEM) subsidy under a Value of Solar Tariff (VOST), and can also help to guide larger investment and market decisions for utilities, regulators, and the broader solar industry, better aligning costs and benefits and mitigating the risks that the rise of solar will bring to the market.

## The Value of Solar

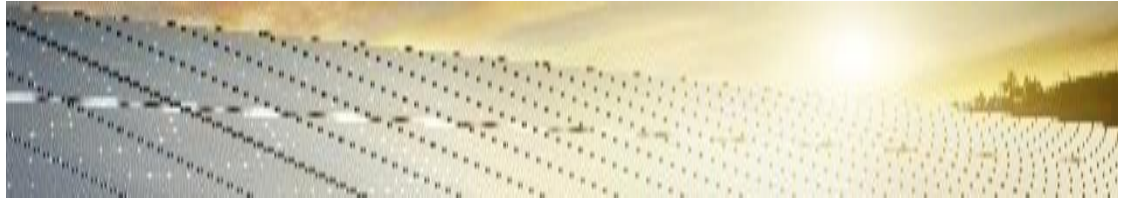
### Value of Solar (VOS) Analysis to Date

Numerous studies have been conducted on VOS, but these have been highly variable in generating estimated value due to the different approaches used to calculate benefits and costs. Despite these variations in values, VOS studies do commonly agree upon the broad categories involved, although not consistently. [Figure 1](#) illustrates the broad categories commonly used in VOS studies extrapolated from the Rocky Mountain Institute’s (RMI) recent 2013 meta-study “A Review of Solar PV Benefit and Cost Studies.” These categories cover most of the tangible and intangible benefits associated with distributed solar.

**Figure 1. Typical Solar PV Benefit and Cost Categories<sup>1</sup>**

	<b>Energy and Capacity</b> <ul style="list-style-type: none"> <li>• Avoided Energy, Losses and Generation Capacity</li> <li>• Avoided T&amp;D losses and capacity</li> </ul>
	<b>Grid Support Services</b> <ul style="list-style-type: none"> <li>• Reactive supply and voltage control, regulation and frequency response, energy and generator imbalance, synchronized and supplemental operating reserves</li> </ul>
	<b>Financial</b> <ul style="list-style-type: none"> <li>• Fuel Price Hedge &amp; Market Price Response</li> </ul>
	<b>Security</b> <ul style="list-style-type: none"> <li>• Reliability, Resiliency</li> </ul>
	<b>Environmental</b> <ul style="list-style-type: none"> <li>• Air emissions, water, and land</li> </ul>
	<b>Social</b> <ul style="list-style-type: none"> <li>• Economic development (jobs, economic activity)</li> </ul>

<sup>1</sup> Derived from RMI “A Review of Solar PV Benefit and Cost Studies” by ICF. [www.rmi.org/Knowledge-Center%2FLibrary%2F2013-13\\_eLabDERCostValue](http://www.rmi.org/Knowledge-Center%2FLibrary%2F2013-13_eLabDERCostValue)

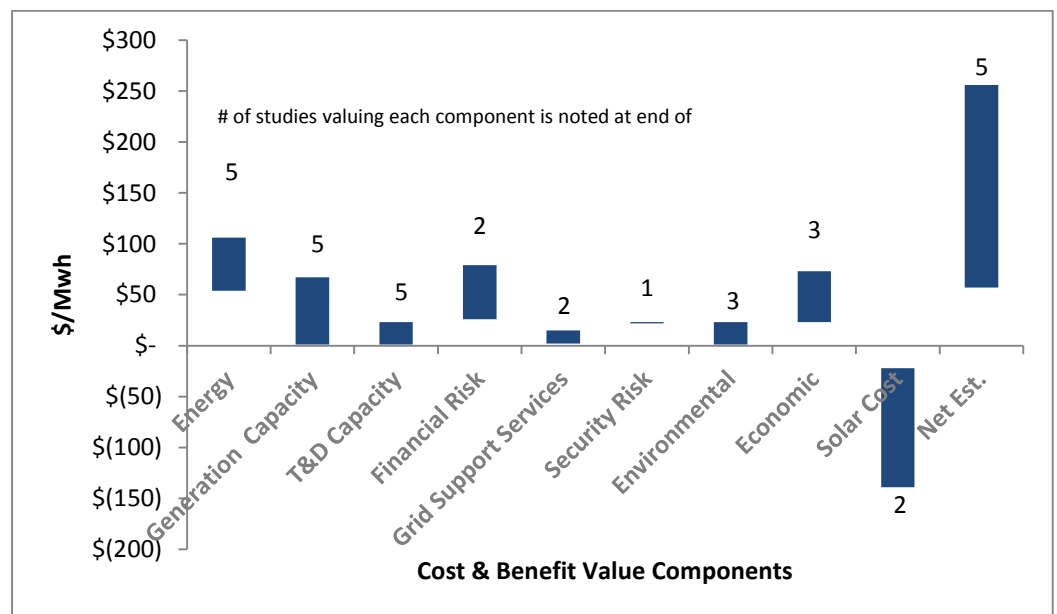


A recent ICF study reviewed five of the VOS studies included in RMI’s analysis and found them lacking in consistency, key value and cost components, and transparency. [Figure 2](#) below shows the wide range of VOS estimates in these studies—from \$50/MWh to over \$250/MWh - as well as the benefit and cost estimates by category.

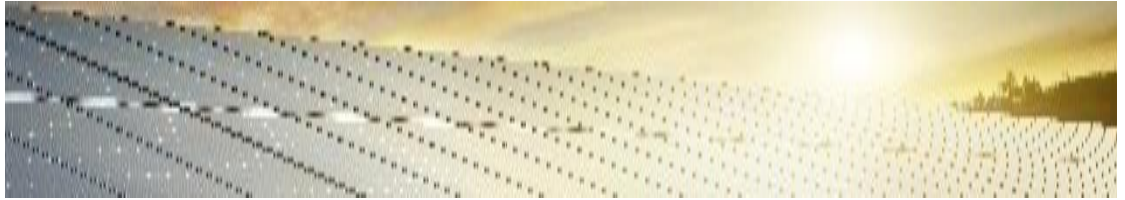
Most of these recent VOS studies also do not capture and consistently value the true cost and benefit of integrating solar DG into the system. Specifically, these studies often overlook the need to maintain reliable electric service to the end-use customer, as well as the fact that the grid is the enabling mechanism for DPV.

For the majority of the public VOS analysis reviewed here, benefits consistently manifested themselves in avoided energy and capacity purchases as well as transmission and distribution (T&D) impacts. Categories such as financial risk, grid support services and reduced security risk were valued in some, but not in other studies. The difference in estimations and exclusion of value components from multiple VOS studies further emphasizes the need for more consistent methods in valuing solar.

**Figure 2. Recent VOS Studies<sup>2</sup>: Range of VoS Cost and Benefit Price Estimates**



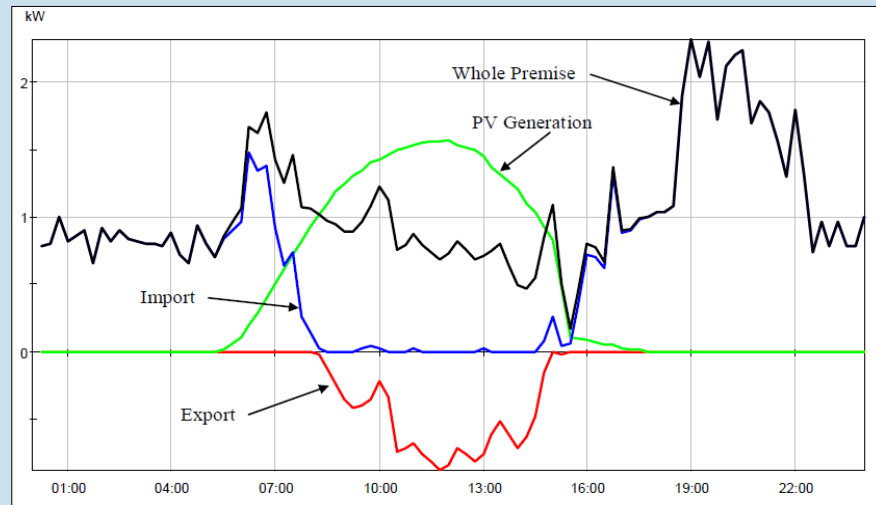
<sup>2</sup> List of Studies Considered: CPRTX - The Value of Distributed Solar Electric Generation to San Antonio. Clean Power Research, 2013; CPRNP - The Value of Distributed Solar Electric Generation to NJ and PA. Clean Power Research, 2012; SAICAZ - 2013 Updated Solar PV Value Report (for Arizona). SAIC, 2013; CBEAZ - Evaluating the Benefits and Costs of Net Energy Metering in CA. Crossborder Energy, 2013; CBECA - Evaluating the Benefits and Costs of Net Energy Metering in AZ. Crossborder Energy, 2013.



### Incompatible Peak Loads

The vast majority of customers who install solar DG will still rely on the grid to absorb the excess generation from solar PV in the middle of the day when the solar system is producing its peak power (and household consumption is typically low). The grid is also needed to reliably and consistently deliver electricity in the evenings when solar generation is non-existent (and when household electricity consumption is typically high). [Figure 3](#) from a residential system in Southern California highlights this challenge.

**Figure 3. Illustrative DPV Generation Profile vs. Customer Load**



Storage is changing this, but very slowly, and it is impractical to expect millions of solar PV deployments to install storage and depart from the grid in the near to mid-term. Emphasis therefore must be placed on the cost of maintaining reliable electric service to all end-use customers. While solar brings incremental value to the system when locational generation is needed, the maintenance of the grid also brings significant value to the end-use customer.

### Our Proposed Approach to VOS

Fully capturing the value of distributed solar generation requires:

1. An analysis of some of the “traditional” components of VOS analysis;
2. Treatment of DPV as a locational generation resource and not as a decrement to load.

The following framework presents an objective overview and methodology for VOS studies that addresses these requirements. It places the critical and material categories previously used in VOS studies into clear definitions and provides a framework to evaluate both the costs and benefits of integrating distributed generation of all types (Solar PV, CHP, storage) onto the grid.

- **Energy.** Avoided generated energy represents the most straight-forward calculation across existing VOS studies. The premise is that energy generated from solar DG installation displaces generation from the grid. Current VOS studies generally assume that solar DG displaces gas-fired combined cycle resources over the daily generation profile of the solar resource. While a more accurate estimate could be obtained using hourly dispatch modeling to determine the marginal resource in each hour, this is a reasonable assumption given the relatively low levels of DPV penetration on the grid. As DPV penetration rates increase, however, a more rigorous analysis involving dispatch modeling may be required in areas where other resources might be displaced.



Overall, while some of the studies we examined identified high avoided energy costs due largely to inflated natural gas price assumptions, there is generally little disagreement about avoided energy costs for VOS.

- **Methodology:** The best way to quantify energy value would be at the margin, to account for the true value of the displaced resource. Therefore, these values are dependent on the time of day and month, the generation fleet and energy costs, assumed load growth, and planned generation. In the interim, a more simplified approach may be considered.

Utilities should ideally develop appropriate time of delivery values for the energy component of supply and consider publishing time of use prices that convert the marginal resources into a time differentiated tariff.

- **Avoided/Deferred Generation Capacity.** Unlike calculating displaced energy from DPV, valuing avoided capacity is both more complicated and often overstated in many existing VOS analyses. Avoided generation capacity is the amount of capacity (MW) that can be deferred due to the DPV installation, and its value hinges on two central factors.

First is the correlation between the host facility’s (and potentially the broader system’s) load profile and that of the DPV resource. This correlation is fundamental to understanding the role of DPV in avoiding the need for new capacity. For example, a DPV generation profile that is fully correlated with the customer’s or system’s load would indicate that 100% of the capacity could be avoided. Anything less than a full correlation would indicate that the capacity value assigned to DPV should be discounted in proportion to the mismatch between the loads.

The second central factor is the relative value of the capacity being avoided. Many markets have traditionally used the Net Cost of New Entry (CONE) values, which is the leveled cost of a new gas unit (typically a simple cycle gas turbine, but potentially a gas combined cycle unit) minus the energy revenues that the unit is expected to see in the market. The higher the energy revenues, the lower the required capacity payment needed to support the capacity value of the unit.

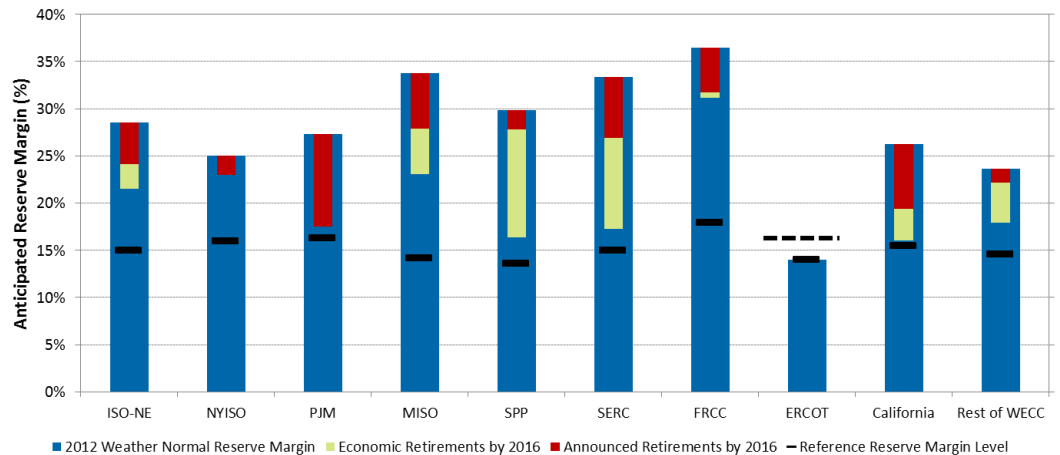
Capacity credit measurements for DPV have ranged widely across previous VOS studies. This capacity credit assigned to DPV is highly dependent upon the correlation between the DPV output and the load of the host facility and the broader wholesale generation system. The majority of previous studies discount the capacity credit assigned to solar DG to account for this correlation, but do not fully reflect the correlation between solar PV generation and load as illustrated in [Figure 3](#) shown earlier.

Some of the recent studies we reviewed applied a capacity credit of over 90 percent, while others provided a capacity credit as low as 21 percent. While this is clearly a location-dependent factor – influenced by solar insolation, typical panel direction, host facility and system load and distribution feeder load profile - such a wide range of capacity credit, particularly with capacity credits of over 90 percent, seems highly improbable. In general, one would expect the capacity correlation to be lower for residential systems, where peak demand typically occurs in the evening hours, when solar insolation has dwindled, and higher for commercial systems, where load is generally more correlated with solar PV generation.

In addition, almost all of the recent studies we examined valued the avoided capacity at full Net Cost of New Entrant (CONE) values – typically at levels of around \$100/kW-yr. This is problematic in two ways. First, most power markets in the US today are generally oversupplied (“long”), due to the remnants of the recession and aggressive and successful EE and DR penetration of the markets. Because of this, assigning the avoided capacity cost at \$100/kW-yr. does not reflect the current market dynamics of similar generating assets. As shown in [Figure 4](#), with the exception of ERCOT, the reserve margin for other regional transmission organizations (RTOs) is easily covered even with announced retirements.



Figure 4. Reserve Margins for Select US ISOs/RTOs



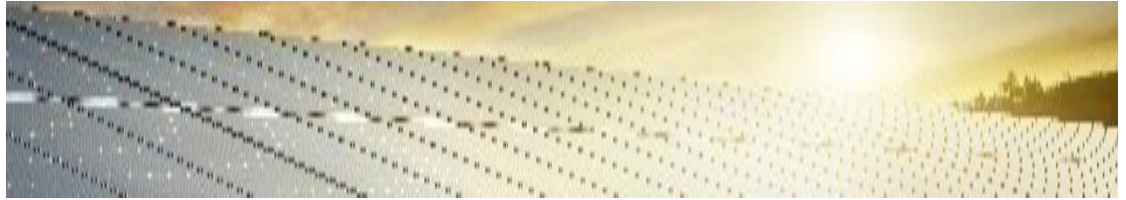
This is further reinforced by the results of the last PJM auction, which saw a significant increase in the RTO price to \$44/kW-yr. – a result that many considered relatively robust in today’s low load growth market, but still significantly lower than the traditional CONE value of \$100/kW-yr. Second, power markets may have entered a new era in which lower CONE prices are the new reality as brownfield sites are redeveloped. When combined with low financing costs and low gas prices (both Henry Hub and delivered), it results in lower capital and energy costs for new gas units, leading to lower CONE values over time.

- **Methodology:** In order to correctly value the avoided capacity benefit of DPV projects, there needs to be a realistic analysis of the correlation between customer and system peak as well as an analysis of the DPV’s generation profile to accurately assign a DPV system capacity credit. RTO’s and ISO’s have been doing this for some time with central station renewable projects. The same process should be applied to DPV projects, with the added complication that penetration rates on distribution system feeders also need to be included.

Actual current and forecast market conditions should also be used to calculate the capacity payment - similar to those used in utility IRP and other market valuation efforts. Over time, markets will start to tighten due mostly to relatively low natural gas prices and environmental capex requirements on units, forcing coal retirements. The subsequent market constriction will eventually make new capacity more attractive, with a premium going to dispatchable and fast-ramp resources to account for the increase in solar resources as the afternoon sun sets.<sup>3</sup> Similar to the energy component of the VOS, utilities should develop annual capacity values to be included in VOS calculations.

- **Avoided Transmission and Distribution (T&D) Losses and Capacity.** The avoided T&D losses and capacity component of the VOS refers to two distinct issues. One is the T&D infrastructure that can be avoided or deferred due to the reduced need to supply a customer that consumes power generated on his or her rooftop. The second is the T&D losses that can be avoided by consuming power adjacent to the point of consumption, as opposed to needing to transmit it long distances from a central generating facility.

<sup>3</sup> See the much publicized “duck curve” at [www.caiso.com/documents/flexible\\_resourceshelp\\_renewables\\_fastfacts.pdf](http://www.caiso.com/documents/flexible_resourceshelp_renewables_fastfacts.pdf)



Many VOS studies assign a material value to the avoided T&D losses associated with generating power at the point of load – much in the way that one would value the avoided T&D value of energy efficiency. Recent studies assign a wide range of values, though there is some debate on a number of them, including:

- If the T&D deferral should be valued on an average versus a marginal basis
- If energy losses should be evaluated, and if so, whether it should be done on a peak versus all-hours basis
- Should transmission and distribution be treated as two distinct systems, or as effectively one

When averaging – either across hours, the T&D system, or both – the benefits of avoided T&D losses may not be accurately depicted, depending on how simple average values are applied. The complexity of the T&D system dictates that any approach must take into account the locational and temporal value of the deferred investment as well as the line losses. This complexity however, needs to be balanced with the feasibility of implementation to provide a practical result. If the solar DG system is generating power in full correlation with host facility load and therefore offsetting all grid purchases, then it may be appropriate to account for avoided T&D losses. If, however, solar generation and host load are only partially correlated, then the avoided T&D losses, like the capacity value, should be prorated accordingly.

The same is true for potential deferred T&D expenditures. If distribution system feeders are indeed unloaded as a result of a high correlation between solar generation and host facility load, and depending on the needs of the area, the VOS should capture that deferred T&D equipment value on a feeder by feeder basis. If profiles do not match or if T&D capacity additions cannot be deferred, then this also needs to be accurately depicted, with little or no value assigned to T&D deferral.

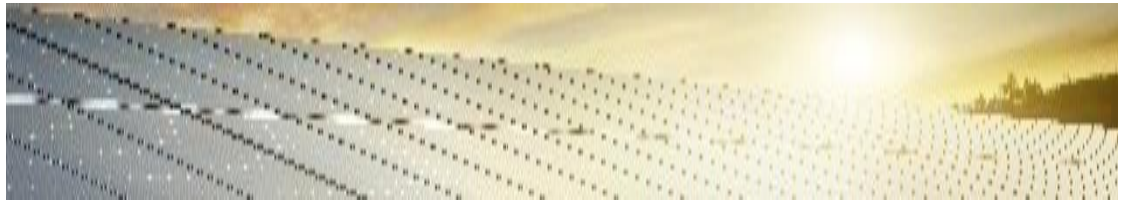
There is also a cost to T&D from DPV. The cost to the grid is the infrastructure and operations that will be necessary to manage the increasing penetration of DPV while maintaining a reliable level of electrical services to the utility customer. These costs may include changes to existing capacitors and load tap changers, additional breakers or reconductoring existing lines. Other costs, while not explicitly T&D, would be any frequency support or load following services to manage the amount of intermittent resources to continue to maintain services.

As solar penetration increases, electricity generated by solar DG may flow back up through the substation onto the bulk power system substation, potentially leading to unintentional islanding of the feeder or segments of the feeder. In essence, the feeder would be energized by the solar facility and not in-control by the utility.<sup>4</sup> Many believe that even if the solar generation and the load at the host facility are not fully correlated (See Figure 4), there will be load in the neighborhood that will absorb the excess generation from that one site. In this context, it is important to evaluate the capacity, load profile of the feeders, the location of load centers, and solar PV along the distribution circuits and not assume generalized concentration levels. PG&E, for example, has found that in areas of their service territory with the highest DG penetration, residential DPV on average exports 50 percent of the power generated to the grid.

- **Methodology:** For the T&D portion of the grid, DPV potentially represents both a benefit and a cost. Both of these impacts need to be included and separately assessed as part of a VOS analysis.

As a benefit, the most straightforward parts of this calculation are the avoided losses of T&D due to the reduction in generation and the need to transport that energy to specific premises or feeders. This benefit is on a marginal basis, not on an average basis. The challenge in accurately quantifying this factor is that losses depend on the location of the DPV generation on the feeder and the impact on off-setting load.

<sup>4</sup> See <http://energy.sandia.gov/wp/wp-content/gallery/uploads/SAND2012-1365-v2.pdf> for a detailed explanation on the causes of feeder unintentional islanding due to solar PV penetrations



DPV may defer construction costs and other capacity upgrades by reducing the overall feeder load. But like avoided losses, this analysis needs to take place on a feeder by feeder basis or, potentially more practically, feeders should be grouped by their load profiles and capacities into prototypical groupings. Once this step has taken place and the feeders have been identified that would benefit from DPV installations, the avoided losses and avoided T&D capital can be calculated and optimized.

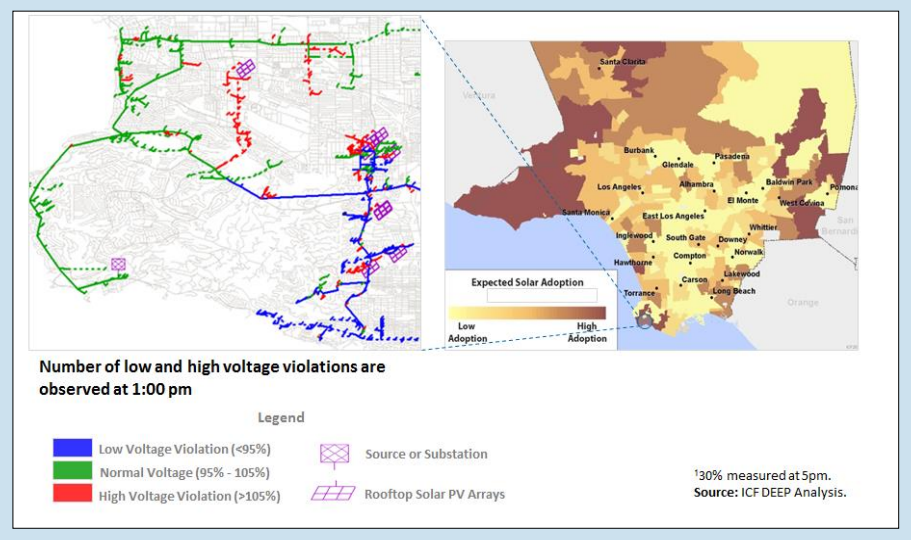
As part of the value analysis, the VOS should also adequately address and explicitly state any T&D costs that will be incurred as a result of DG deployment. Addressing T&D costs involves the same careful analysis of where DPV will be deployed versus the load centers being served, as well as understanding the different feeder characteristics. This means understanding not just the overall penetration levels, but the potential concentration of DPV resources, and assessing and forecasting when they export to the distribution grid. As previously discussed, DPV and other distributed generating assets, while reducing load and creating a T&D benefit, also export to the distribution system. At high enough concentration and penetration levels, DPV energy exports may become problematic in terms of voltage stability if there are not enough loads on the feeder.

To accomplish this valuation, we suggest a systematic review of site-specific DPV analysis to highlight where DPV deployments are most likely to cluster, an analysis of the capacity of those feeders where the solar is located, and a review of the impact on distribution equipment or additional utility monitoring and control equipment to manage the additional distribution assets during low load periods of the day. The practicality of the number of feeders evaluated needs to be accounted for, and it may be most practical to develop prototypical feeder analyses for representative feeder types, customer loads, and DPV penetration levels.

### Example from Los Angeles County

ICF performed an analysis of varying degrees of DPV concentration and penetration levels on a network of distribution feeders in Los Angeles County which demonstrated the importance of understanding the correlation between DPV generation, feeder load and the resulting impact on voltage violations (See [Figure 5](#)).

**Figure 5. Time Series Analysis (Typical Summer Day) with Solar PV at High Load Locations**







## Grid Support Services.

DPV and other forms of distributed generation can provide distribution support services if they have the hardware, software, the excess capacity to provide these services, as well as an ability to react to signals from a distribution management or supervisory control and data acquisition (SCADA) system. For the vast majority of DPV systems this is not the case, and in many instances the international standards (e.g. IEEE 1547) may not allow it. Only a few of the VOS studies ICF examined provided a value to the potential grid support services that DPV can provide either through reduced load (i.e. a reduction in the need for ancillary services) or through smart inverters providing grid support.<sup>5</sup> A recent study from the DOE indicated that based on the intermittency of the solar PV resource and the difficulty in forecasting its availability, additional generating capacity would actually be needed to firm up solar resources<sup>6</sup>. Considering the intermittency of DPV, it is highly unlikely that electric utilities would need to reduce their purchases of ancillary services.

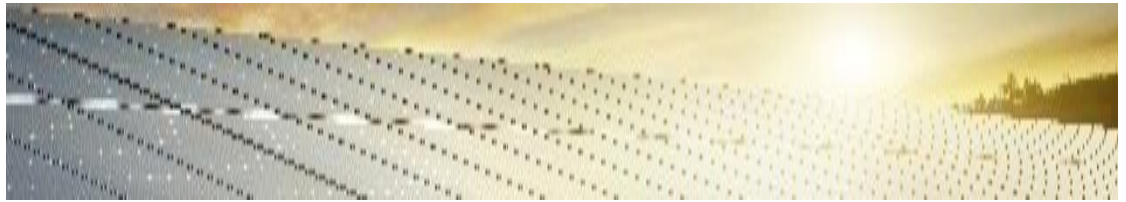
The ability of DPV resources to contribute is still evolving. The vast majority of DPV and their inverters are unable to react autonomously to a grid event (e.g. low voltage ride through) or report when a DPV's inverter reacts to a grid event (e.g. exporting volt-amperes reactive—"vars"), and the ability to monetize the value of these services is still developing. Even the fairly straightforward ability for an inverter to perform a low voltage ride-through and not trip off under low-voltage scenarios is still evolving within the IEEE (e.g. IEEE 1547) standard bodies and regulatory interconnection rules (e.g. Rule 21 in California). Finally, location and distribution feeder characteristics are also drivers of value for any grid support services. As penetration levels increase and managing distributed energy resources like solar PV and storage becomes more integrated, advancements in systems like distributed energy resource management systems (DERMS) will become increasingly important in valuing the costs and benefits of these systems.

- **Methodology:** Setting up a framework for DPV providing grid support is critical. In the long term, DPV and other DG assets will replace other utility hardware and grid support services provided by traditional utility owned and controlled distribution assets (e.g. capacitor banks). Open questions still exist across different regions as to who would be responsible for monitoring and controlling the DPV: the local distribution utility, the RTO, an aggregator of grid support services, or a combination of these entities. As previously mentioned, there are also currently no markets or tariffs for these services. Based on the high amount of uncertainty on this variable, we believe that Grid Support Services should not be included in a VOS calculation for potential payment but should be reviewed for the potential to determine the mechanisms that may need to be in place to monetize any potential value when the appropriate technology exists.

- **Environmental:** The deployment of DPV has environmental value as an emissions-free source of generation for the amount of fossil fuel-fired generation it displaces from the grid. Since many VOS analyses assume that the displaced generation is coming from combined cycle gas generation, the avoided emissions are assigned a similar value – generally around 800 to 1000 lb. CO<sub>2</sub>/MWh, depending on the efficiency of the combined cycle unit. Going forward, as central station renewables and DPV penetration on the grid increases, more detailed analysis should be performed to determine the emissions characteristics of the marginal unit being displaced. This unit could be natural gas, coal, wind, hydro or even other renewables.

<sup>5</sup> Smart inverters are AC to DC inverters with enhanced functionality like dynamic reactive power control and low voltage ride through to enhance grid stability, not decrease it. See also <http://www.greentechmedia.com/articles/read/western-utilities-call-for-smart-solar-inverters>

<sup>6</sup> DOE, Sandia Study <http://emp.lbl.gov/sites/all/files/lbnl-6525e.pdf>



The VOS studies evaluated to date use a range of carbon values (\$/ton) to multiply by the avoided emissions rate to generate a \$/MWh value of the CO<sub>2</sub> emissions displaced by the DPV. These range from single digit numbers to well over \$40/ton. In some instances, the suggested values used in previous VOS studies are similar to those used by utilities and Public Utility Commissions to evaluate new resources in utilities' IRPs or to represent other values, including the social cost of carbon. The studies assigning the highest environmental values assumed that existing coal-fired generation will be displaced by solar PV just as much as gas-fired generation. In most cases, however, generation from marginal gas-fired units will be disproportionately displaced. Additionally, VOS studies with the highest value of carbon did not fully account for current market dynamics, regulations, or emission reduction technologies that might occur in the future.

- **Methodology:** As a generation resource on the grid, DPV should be evaluated in the same way as any other new resource, including central station renewables, in terms of environmental costs and benefits that it confers upon the system. The emissions (in this case CO<sub>2</sub>) values assigned on a \$/ton basis should be similar to those used to evaluate other power generation resources. With EPA's proposed Clean Power Plan under Section 111(d) – New Source Performance Standards, all states will need to develop a compliance regime to attain the emission rate targets for existing units as defined by EPA.<sup>7</sup> As the ultimate compliance mechanism will be developed at the state level, and may or may not result in a market-based (i.e., flexible) approach that would result in an explicit value for CO<sub>2</sub>, how these rules are developed and implemented at the state level is clearly going to be a consideration that will need to be taken into account going forward when evaluating any renewable resource, including DPV.

#### RMI Categories Not Included in ICF VOS Methodology

We believe that the below categories listed in the RMI metadata analysis should not be part of a VOS estimate. Below is a description of these categories and our reasoning for exclusion.

- **Financial.** Some VOS analyses assign value to what is termed the "Financial" category of benefits: a fuel price hedge, reservation of natural gas pipeline capacity, and/or a market price response. None of these factors is typically accounted for in utility integrated resource planning (IRP) evaluations of new resources, including central station renewables, or in cost-benefit evaluations of EE measures. While fairly small in the three studies reviewed, as with other energy-based values, these DPV need to be forecasted to increase their predictability, repeatability and value in an IRP.
- **Social.** For social benefits, some studies highlight the positive impact that DPV will bring to the local economy. These values are not included in the construction of utility scale conventional or renewable projects. Job growth and diversifying the work force is important, but placing a value on these factors and compensating an owner of a DPV facility, unless part of a public policy goal to encourage local employment or the installation of solar, should not be part of a VOS. With over 1.8 million behind-the-meter installations forecasted to be installed cumulatively by 2018, distributed Solar PV is no longer an emerging technology. Providing benefits to DPV that are not provided to other central station renewables is inconsistent.
- **Security.** Increased reliability is often touted as a major benefit for DPV adoption in the popular press, but only one of the five studies we reviewed included this measure in its valuation. Like many other distributed resources, when DPV is able to isolate from the grid or "island," it can provide reliability to the owner of the facility. This value, however, does not accrue to society or even the local grid. In the past, large C&I facilities with DPV and other forms of distributed generation have provided support to the local community in the wake of natural disasters. But to date, there is no accurate or consistent way to account for these typically private resources.

<sup>7</sup> The proposed plan was published in the Federal Register on June 18<sup>th</sup>, 2014, and EPA is working to develop a final rule by June 2015. While aspects of the proposed rule will undoubtedly change as it is finalized, it will be the first time that CO<sub>2</sub> emissions from the power sector are regulated under the Clean Air Act.



Central station and large generating assets should coordinate with one another through an RTO and distribution utility in order to provide optimal grid resiliency. In contrast, it has been suggested that DPV should provide a degree of resiliency to the grid by diversifying the generating assets in terms of supply and location; however, DPVs have neither the scale nor the communication infrastructure to coordinate and provide resiliency value. DPV's impact on reliability and resiliency is evolving as utility communication to these assets improves, and as strategies to recover costs or monetize the value of DPV to distribution feeders, community and utilities are developed. These values will be realized and likely maximized by the utility in determining appropriate locations and services.

Individually-owned systems that can be islanded have a value, but the value accrues to the owner of the system, and therefore it should not be part of a VOS calculation. If DPVs are able to be controlled and managed by the electric utility—along with other grid stabilizing equipment on a feeder basis similar to a micro grid—then there is locational value. This should be estimated and included in a VOS analysis as a resource that is rarely used but, when it is, brings significant value.

### Frequency to Update VOS:

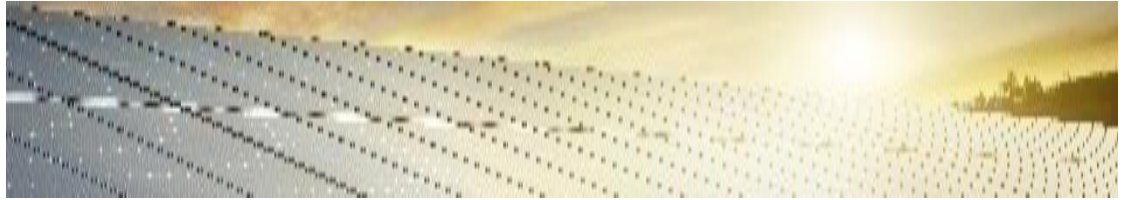
One very clear item missing from reviewed VOS studies is the suggested frequency to update a VOS for existing and new systems. Minnesota reviewed this concept and determined that the value of solar tariff for existing systems is the life of the solar PV system, or approximately 20 years. The VOS tariff for new systems however, would be updated annually.<sup>8</sup> Conversely, Austin Electric has established an effective annual updating process for their VOST for both existing and new DPV systems.

The VOS will evolve over time as the penetration of DPV systems increases and managed load and eventually storage becomes more widely dispersed and integrated with DPV. If the electricity generated by a rooftop DPV system is fully consumed on-site and that household or business never exports energy, then the avoided cost of electricity from the grid is a straightforward means to recoup the customer's investment. However, as DPV-generated power is exported to the grid, the avoided cost of electricity becomes less relevant and there is a need to more comprehensively understand the benefits as well as the cost of the electricity generated by the DPV system. We believe that the methodology outlined above goes a long way to providing a comprehensive and objective framework. However, based on adoption patterns, the utility should update the VOST on a locational basis for new installations yearly to address the changing amount of solar or energy use in different areas.

Updating the VOS will require that the utilities understand in advance different DPV adoption scenarios for specific feeders and communicate these scenarios effectively to the installation community. California is attempting to do this through language in AB327, a bill that was signed into law in the fall of 2013. In the law, language specified that the utilities are required by July 1, 2015 to develop a distribution resource plan to identify "*...optimal locations for the deployment of distributed resources...this evaluation shall be based on reductions or increases in local generation capacity needs, avoided or increased investments in distribution infrastructure...or costs to the ratepayers of the electrical corporation.*"

Many of the same variables we believe should be included in a VOS, but in the case of California AB327, these values become part of a distribution resource plan that is made available and updated on a periodic basis to reflect the changing landscape of distributed generation installation.

<sup>8</sup> <http://mn.gov/commerce/energy/images/MN-VOS-Methodology-FINAL.pdf>, page 6.



## Conclusion

In order to get the Value of Solar “right,” a consistent and comprehensive methodology is needed for calculating avoided generated energy, avoided generation capacity, T&D losses and capacity deferrals, grid support services, and environmental values. VOSTs should be updated periodically to reflect existing and new systems. Furthermore, DPV must be treated not simply as a decrement to the system, but as a system resource. Customers who have installed DPV should be viewed as contributing generation to the grid at time of export and also as retail customers when they are not exporting during the majority of the year.

Traditional evaluation parameters such as those applied to central station resources, including renewables, should be applied. Avoided generation, capacity, and T&D should be correctly accounted for within the system at the location of the asset, and not just from aggregated and isolated distribution perspectives. This is increasingly important as distributed generation of all types continues to deliver costs and value to the grid based on the locational nature of the distribution feeder and its segments. Environmental benefits also need to be included in VOS calculation using the marginal resource avoided, which may be a gas fired simple cycle or combined cycle combustion turbine, but could also be any type of generating unit . Therefore, an analysis of the utility’s energy supply should be prepared and reviewed.

Values that should not be part of a VOS calculation are those that would not be considered part of the valuation of a generation asset or those that are not yet available in the market – specifically financial hedging and societal benefits. Security benefits should be explored to value resiliency at specific critical societal locations. However, they should not yet be included in the VOS calculation until a set and agreed-upon methodology for resiliency is developed. Grid support services should be included once technologies and a means to actively coordinate with distributed generators like DPV has been established consistently.

A VOS approach moves beyond NEM and makes much more sense, but studies to date have often been less rigorous and thorough, ignoring the infrastructure that needs to be in place to manage the DPV and capture the value. A strong VOS approach, in which the real costs and benefits to the system are accurately portrayed and valued, is not only a useful tool for integrating increasing amounts of DPV onto the grid, but will be critical for utilities, regulators, and other stakeholders to make rational planning and risk management decisions.

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