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BEFORE THE ARIZONA CORPORATION COMMISSION

DOUG LITTLE - Chairman
BOB STUMP
BOB BURNS
TOM FORESE
ANDY TOBIN

IN THE MATTER OF THE COMMISSION'S INVESTIGATION OF VALUE AND COST OF DISTRIBUTED GENERATION.

Docket No. E-00000J-14-0023

NOTICE OF FILING WRITTEN DIRECT TESTIMONY ON BEHALF OF VOTE SOLAR

Vote Solar, through its undersigned counsel, hereby provides notice that it has this day filed the attached written direct testimony of Briana Kobor and Curt Volkmann.

DATED this 25th day of February, 2016.

By

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ORIGINAL and 13 COPIES of the Foregoing filed this 25th day of February, 2016, with:

Docketing Supervisor
Docket Control
Arizona Corporation Commission
1200 W. Washington
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All Parties of Record

BEFORE THE ARIZONA CORPORATION COMMISSION

IN THE MATTER OF THE COMMISSION'S INVESTIGATION OF VALUE AND COST OF DISTRIBUTED GENERATION.	Docket No. E-00000J-14-0023

DIRECT TESTIMONY AND EXHIBITS OF CURT VOLKMANN

ON BEHALF OF VOTE SOLAR

February 25, 2015

Table of Contents

Table of Exhibits

1 Introduction

Q. Please state your name and business address.

A. My name is Curt Volkmann. My business address is 290 Vine Avenue, Lake Forest, IL.

Q. On whose behalf are you submitting this direct testimony?

A. I am submitting this testimony on behalf of Vote Solar.

Q. What is Vote Solar?

A. Vote Solar is a non-profit grassroots organization working to foster economic opportunity, promote energy independence, and fight climate change by making solar a mainstream energy resource across the United States. Since 2002, Vote Solar has engaged in state, local, and federal advocacy campaigns to remove regulatory barriers and implement key policies needed to bring solar to scale. Vote Solar is not a trade group and does not have corporate members. Vote Solar has approximately 60,000 members nationally and 3,500 in Arizona.

Q. By whom are you employed and in what capacity?

A. I am President and founder of New Energy Advisors, LLC, an independent consulting firm. At New Energy Advisors, I work with local governments and non-profits, such as Vote Solar, on a variety of clean energy issues and opportunities. In addition to this proceeding, I am currently working in California, Minnesota, Illinois, and the Northeast in various regulatory and legislative proceedings related to distributed energy resources.

Q. Please describe your professional background and experience.

A. I have 32 years of experience in the energy and utilities industry. My resume, attached as Exhibit CV-1, provides further detail of my work experience.

Prior to founding New Energy Advisors, LLC, I worked for the Environmental Law & Policy Center ("ELPC") in Chicago as a Clean Energy Specialist. My work at ELPC focused on providing technical advice and expert witness testimony in several renewable energy, energy efficiency, and rate design regulatory proceedings.

Prior to ELPC, I was employed for eighteen years by Accenture, a global management consulting and technology firm. I held several positions at Accenture, including Managing Director in Accenture's Sustainability Services practice, where I oversaw energy efficiency and demand reduction projects for commercial and industrial clients across multiple industries. I was also an Executive Director in Accenture's North America Utilities practice, with client account leadership responsibilities for several gas, electric, and water utilities in the US. In this role, I oversaw several utility cost reduction and smart grid programs.

Prior to Accenture, I worked for the consulting firm UMS Group, where I led multi-utility benchmarking studies examining global best practices in electric transmission and distribution. Participating utilities were from the United States, Canada, Australia, New Zealand, Europe, and Africa.

I also worked for nine years at Pacific Gas and Electric ("PG&E") in various transmission and distribution roles including Distribution Planning Engineer, where I evaluated the impact of demand-side management programs on the deferral of distribution substation upgrades.

Q. Please describe your educational background.

A. I graduated from the University of Illinois at Urbana-Champaign with a Bachelors of Science in Electrical Engineering with a concentration in Power Systems. I also received a Masters of Business Administration from the University of California at Berkeley with a concentration in Finance.

Q. Have you previously testified before the Arizona Corporation Commission (the "Commission")?

A. No.

Q. Have you previously testified before other regulatory commissions?

A. Yes. I have testified before the Illinois Commerce Commission in its investigation into Commonwealth Edison's cost of service in Docket No. 14-0384, Commonwealth Edison's proceeding for approval of its Energy Efficiency and Demand Response Plan in Docket No. 13-0495, and Ameren Illinois' proceeding for approval of its Energy Efficiency and Demand Response Plan in Docket No. 13-0498. I have also testified before the Michigan Public Service Commission in its investigation into the application of Consumers Energy Company to amend its renewable energy plan in Case No. U-17752.

2 Purpose of Testimony and Summary of Recommendations

Q. What is the purpose of your testimony in this proceeding?

A. My testimony serves three objectives. First, I will provide specific responses to a subset of the questions raised in Commissioner Doug Little's letter to interested parties dated December 22, 2015 (the "Guidance Letter"). Second, I will explain why and how solar distributed generation ("DG") and other Distributed Energy Resources ("DERs") can be valuable grid resources, rather than problems that utilities must address.[1] Finally, I will discuss how other jurisdictions are addressing these issues and share emerging best practices.

[1] DERs can include energy efficiency, demand response or direct load control, energy storage, electric vehicles, DG, combined heat and power, or microgrids.

Q. Please summarize your recommendations.

A. I recommend that the Commission:

1) Require utilities to conduct analyses to identify locations on the distribution system where DG solar and other DERs can interconnect with no or minimal integration costs, or where integration costs may be high. I also recommend that the Commission require utilities to publish the results of these analyses in a manner that is easily accessible by customers and DER providers. The results of these analyses will provide key inputs into the integration cost component of DG solar valuation.

2) Modify its interconnection standards to require the deployment of smart inverter functionality for DG solar and storage installations.

3) Adopt a detailed marginal cost of service methodology for both transmission and distribution ("T&D") capacity, reflecting the unique system operating and load characteristics at each location. The methodology should credit DG solar and other DERs for their incremental contributions to T&D capacity relief, even if the utility has not identified an imminent capacity expansion project in the local area.

4) Include the value of avoided water consumption in its DG solar valuation methodology.

5) Explicitly consider the reliability improvement benefits of DG solar and other DERs in the valuation methodology.

6) Initiate changes to traditional utility distribution planning processes to proactively incorporate DG solar and DERs. This should include:

- Increasing transparency regarding the grid's capacity to accommodate DG solar and other DERs, and the locational value of various DER solutions.

- Increasing the transparency of planned capital investments that could be deferred, avoided, or substituted by DER solutions.
- Implementing mechanisms to allow third-party provision of DER solutions as alternatives to traditional distribution capital investment.

7) Establish sufficient flexibility in the DG solar valuation methodology to allow for future inclusion of all DER types and portfolios of DERs.

3 Responses to Questions in the Guidance Letter

Q. What is the focus of this section of your testimony?

A. This section of my testimony will address questions from Commissioner Little in his Guidance Letter from December 22, 2015. Specifically, I will address:

- DER Integration costs (Guidance Letter questions 4, 11, 17, and 20)
- DG intermittency (question 8)
- Coincidence with peak demand (question 9)
- Ability to dispatch (question 10)
- Transmission capacity (questions 15)
- Distribution capacity (question 16)
- Water (question 18)
- Grid security and reliability (question 19)

3.1 DER Integration Costs

Q. Question 4 of Commissioner Little's letter states:

"Does the cost and value of DG solar vary based on the specific customer location? Should this variability be reflected in rates?"

How do you respond?

A. The cost and value of DG solar and other DERs can vary significantly based on location, and this variability should be reflected in rates or other DER compensation mechanisms. I refer to the location-specific net benefits (the sum of all DER location-specific benefits less any associated cost) as Locational Value.

As I will describe below, targeted deployment of DER portfolios, including DG solar, can add significant value by deferring or eliminating the need for more costly traditional capital investment ("Deferral Value"). In these cases, Deferral Value is a significant component of the overall Locational Value of the DER. In other locations with sufficient capacity and no immediate need for system upgrades, there will still be Locational Value (from avoided energy, avoided line losses, etc.), but the Deferral Value from the DER may be less.

Similarly, the costs of DG and DER integration vary by location, based on the DER type and the distribution feeder characteristics at the point of interconnection. Generating-DERs (such as DG solar and storage) inject real power onto a feeder and can negatively impact voltage, depending on the distance from the substation and strength of the circuit at the interconnection location, and may require mitigation measures. Load-DERs (such as energy efficiency, demand response, electric vehicles, and other storage) can have zero cost or may require additional measures to accommodate the increased load on a feeder.

A hosting capacity analysis is a critical and necessary step for identifying the relative costs of DER integration by location on a circuit, and for establishing a foundation for determining the Locational Value of DERs.

Q. What is hosting capacity?

A. The Electric Power Research Institute ("EPRI") defines hosting capacity as the amount of DERs that may be accommodated on a distribution circuit without degrading reliability and power quality.[2] A hosting capacity analysis examines the thermal capacity, voltage, and reliability impacts of various levels of DER deployment for each circuit and subsections of each circuit on a distribution

[2] Elec. Power Research Inst., *The Integrated Grid: A Benefit-Cost Framework* 1-5 (Feb. 2015), *available at* http://goo.gl/cxof7W.

system. Ideally, utilities publish the results of the analysis in a way that makes it easy for customers and DER providers to access the results. For example, the California Distribution Resources Plan ("DRP") proceeding requires each utility to develop an Integration Capacity Analysis (comparable to a hosting capacity analysis), and the investor-owned utilities are publishing the results of the analysis using color-coded maps.[3]

Q. Why is this important?

A. A hosting capacity analysis informs utilities, customers, and other third parties about locations on the distribution system that can accommodate DERs with minimal interconnection costs. Conversely, the analysis also highlights constrained locations on the distribution system that cannot accommodate additional DER without system upgrades. By publicly disclosing the hosting capacity analysis results, along with the underlying data and assumptions, utilities can expedite interconnection processes and enable DER providers to offer innovative alternatives to traditional utility solutions.

Q. How can a hosting capacity analysis expedite interconnection processes?

A. As I explained, hosting capacity defines the quantity of DG solar that a feeder can safely incorporate without requiring modifications to existing infrastructure. Up to this level of penetration, utilities can easily interconnect DG solar systems and the systems should be subject to fast-track approval.

Q. How does a hosting capacity analysis lead to innovative alternatives?

A. Public disclosure of the hosting capacity results, including the nature of the constraints at each location (i.e., thermal, voltage, or system protection), allow customers and DER providers to design solutions that can overcome constraints, increase hosting capacity, and eliminate the need for redundant utility investment.

[3] See, for example, the integration capacity maps for Southern California Edison at http://www.arcgis.com/home/webmap/viewer.html?webmap=e62dfa24128b4329bfc8b27c4526f6b7

For example, a utility's need to install or modify voltage regulation equipment may be eliminated if the DER provider is aware of the constraint and includes smart inverter functionality, as I will explain later.

Q. Question 11 of Commissioner Little's letter states:

"Will the bi-directional energy flow associated with DG solar require modifications or upgrades to the distribution system? How should the cost of these upgrades be considered when determining the cost and value of DG solar? Would the required upgrades vary based on location and penetration of DG solar? Should the costs for DG installations vary based on these factors?"

How do you respond?

A. The interconnection of DG solar may require distribution system modifications, depending on the DG size and the distribution feeder characteristics at the point of interconnection. As I described previously, a hosting capacity analysis can inform utilities, customers, and other third parties about locations on the distribution system that can sufficiently accommodate DERs with no necessary upgrades, and locations where circuit modifications may be required. Any actual costs to accommodate the DG, whether incurred by a utility or by the DER provider, should be included in the determination of Locational Value.

The potential value of hosting capacity analyses is evident from recent experience in California. The California investor-owned utilities have developed initial hosting capacity analyses as part of the DRP proceeding and concluded that, despite increasing levels of DG solar penetration, there is significant capacity to accommodate additional DG with no required upgrades. For example, Southern California Edison ("SCE") found that depending on feeder voltage, existing circuits above 4 kV can accommodate between 2 and 26 MW of additional DG solar without requiring circuit modifications.[4]

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[4] S. Calif. Edison, *Distribution Resources Plan* 38 (July 2015), *available at* http://goo.gl/egrgrd.

Technology and innovation are further eliminating the need for grid modifications to integrate DG solar. For example Hawaii, which has the highest penetrations of solar in the United States, has been able to accommodate rapid growth of DG solar by taking advantage of emerging technologies. In 2015, Hawaiian Electric Company ("HECO") eliminated a backlog of 4,000 customer DG solar interconnection requests and avoided the need to install expensive voltage regulation equipment after collaborating with smart micro-inverter vendor Enphase.[5] HECO's backlog stemmed from its concerns about unacceptable voltage fluctuations on high penetration circuits, but HECO lacked the detailed measurement capability to validate its concern. Enphase's highly-granular voltage and frequency data from its micro-inverters, once shared with HECO, revealed that voltage violations were only a concern on a small percentage of circuits, allowing HECO to proceed with the interconnections.

Q. Question 17 of Commissioner Little's letter states:

"Does the grid itself add value to DG solar? If so, how should the value of the grid be considered when assessing the value and cost of DG solar?"

How do you respond?

A. The grid adds value to DG solar by allowing for exports of energy not consumed locally, and by providing voltage and frequency regulation services. However, as I will explain below, the need for the grid to provide regulation services can be significantly reduced with the widespread adoption of smart inverters.

DG solar and other DERs also add value to the grid by providing flexibility to avoid or delay "lumpy" investments in traditional system capacity upgrades, as I explain in response to Commissioner Little's questions 15 and 16.

[5] Jeff St. John, *How HECO is Using Enphase's Data to Open its Grid to More Solar*, Greentech Media (Apr. 14, 2015), http://www.greentechmedia.com/articles/read/how-heco-is-using-enphase-data-to-open-its-grid-to-more-solar.

Q. Question 20 of Commissioner Little's letter states:

"What, if any, costs are associated with the utility providing voltage support and/or frequency support or other ancillary services in support of DG solar installations?"

How do you respond?

A. Interconnected DG solar may require additional voltage and/or frequency support depending on the size of the DG and the circuit characteristics at the point of interconnection. However, widespread adoption of smart inverters can significantly reduce or eliminate the need for these costs. Additionally, widespread deployment of smart inverter functionality can stabilize the grid as DG solar and DER penetrations increase.

Q. What is a smart inverter?

A. Inverters convert the direct current electricity from DG solar or batteries to alternating current electricity – a necessary requirement for connection to a customer facility or to the grid. Traditional inverters are not capable of handling voltage and frequency fluctuations, and are required by the Institute of Electrical and Electronics Engineers ("IEEE") 1547 standard to disconnect from the grid when these fluctuations occur. Widespread and simultaneous disconnection can worsen grid instability.

Smart inverters have more advanced capabilities and can contribute to the stability of the grid. These capabilities include:

- Maintaining connection to the grid during minor voltage or frequency disturbances.
- Producing or absorbing reactive power, which can help with voltage support.
- Randomized timing of disconnection and reconnection during system disturbances to prevent a large decrease or increase of generation at one time.

- Real-time communications, enabling operator control and management of real/reactive power and voltage.

Q. Are smart inverters in use today?

A. Smart inverters are widely deployed in Europe and to some extent in California, and the technical capabilities of smart inverters I described above exist today. However, current U.S. technical standards that govern the use of inverters do not allow for full utilization of these technical capabilities. Revisions to these standards are in various stages of review and approval.[6] Until the revised standards are finalized, the potential legal liability resulting from an equipment malfunction has inhibited the widespread use of smart inverters.

Q. When will the revised standards be available?

A. It is unclear when the revised standards will be available. However, California has established a multi-stakeholder Smart Inverter Working Group that has led to California Public Utility Commission ("CPUC") approval of some smart inverter functions in its interconnection standards, referred to as Phase 1 of Rule 21. This CPUC approval and adoption of smart inverter functionality is in advance of the revised standards.

Q. Are the Arizona utilities and the Commission aware of the importance of smart inverters?

A. Yes. Arizona Public Service Company ("APS") found in its Flagstaff Community Power project that: "Another cost effective way to maintain feeder voltage profile within limits under high PV penetration levels is the use of reactive power capability of advanced inverters."[7] APS and Salt River Project are deploying

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[6] Specifically, Underwriter Laboratories 1741 and IEEE 1547.

[7] David J. Narang et al., *High Penetration of Photovoltaic Generation Study – Flagstaff Community Power* 48 (Feb. 2015), *available at* http://goo.gl/NWfEhG.

smart inverters in their residential solar pilots to further prove the capabilities of this technology.[8]

An August 2013 letter to the Commission from the Western Electric Industry Leaders ("WEIL") Group, an organization of utility executives including APS CEO Don Brandt, urged widespread adoption of smart inverters.[9] The WEIL letter explains: "[S]mart inverters will play a vital, transformative role. These simple and inexpensive devices can mitigate the voltage drops caused by the fluctuating solar generation, thus preventing potential power quality problems."[10]

Comments in the Commission's Notice of Proposed Rulemaking Regarding Interconnection of Distributed Generation Facilities (Docket No. RE-00000A-07-0609) from the Western Grid Group encouraged the Commission to require smart inverters for DG solar installations.[11]

Q. Please summarize your recommendations for addressing DER integration costs and benefits in the valuation of DG exports.

A. I recommend that the Commission require utilities to conduct hosting capacity analyses ("HCAs") to identify locations on the distribution system where DG solar and other DER can interconnect with no or minimal integration costs, or where integration costs may be high. I also recommend that the Commission require the utilities to publish the results of the analyses in a manner that is easily accessible by customers and DER providers.

The results of the HCAs will provide important inputs into the DG solar valuation framework. Specifically, the integration costs (or lack thereof) calculated for each

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[8] Jeff. St. John, *A State-by-State Snapshot of Utility Smart Solar Inverter Plans*, Greentech Media (Nov. 6, 2015), http://www.greentechmedia.com/articles/read/a-state-by-state-snapshot-of-utility-smart-solar-inverter-plans.

[9] Letter from W. Elec. Indus. Leaders Grp., to Governors, Commissioners, and Legislators (Aug. 7, 2013), *available at* http://goo.gl/2pSZZx.

[10] *Id.* at 1.

[11] Comments of W. Grid Grp., Dkt. No. RE-00000A-07-0609 (July 24, 2015), *available at* http://goo.gl/qTS5PH.

circuit location in the HCAs are inputs into the calculations for determining DG solar costs and benefits at each location.

As I describe above, smart inverters are a key technology for unlocking value from DERs, and DG solar in particular. Smart inverters will improve grid stability, and reduce or eliminate the need for traditional utility investments in reactive power management, voltage, and frequency regulation. I recommend that the Commission modify its interconnection standards to require the deployment of smart inverter functionality for DG solar and storage installations.

Once the Commission adopts a smart inverter requirement, the benefits of avoided voltage or frequency support services will be an additional input into the DG solar valuation methodology.

3.2 Intermittency

Q. Question 8 of Commissioner Little's letter states:

"How does the intermittent nature of DG solar affect its value and costs? Are there technologies that could reduce the intermittency of DG solar? Should those additional costs result in changes to the value and cost of DG solar? Should an 'intermittency factor' be applied to more accurately determine cost and value?"

How do you respond?

A. The intermittent nature and sudden changes in output from DG solar can cause voltage fluctuations on the distribution system. But as I previously explained, smart inverters can alleviate many of the impacts from DG solar intermittency at a significantly lower cost than traditional voltage regulation equipment.
Intermittency is addressed in the valuation of DG exports as described under DER integration costs and benefits above. Any costs associated with additional voltage or frequency support to accommodate DER at a location (as determined by the hosting capacity analysis) can be direct inputs into the cost components of the valuation methodology. Similarly, avoided costs from the deployment of smart inverter functionality with the DER can be direct inputs into the benefits

components of the valuation methodology. There is therefore no need for the Commission to apply an additional "intermittency" factor in the analysis.

3.3 Coincidence with Peak Demand

Q. Question 9 of Commissioner Little's letter states:

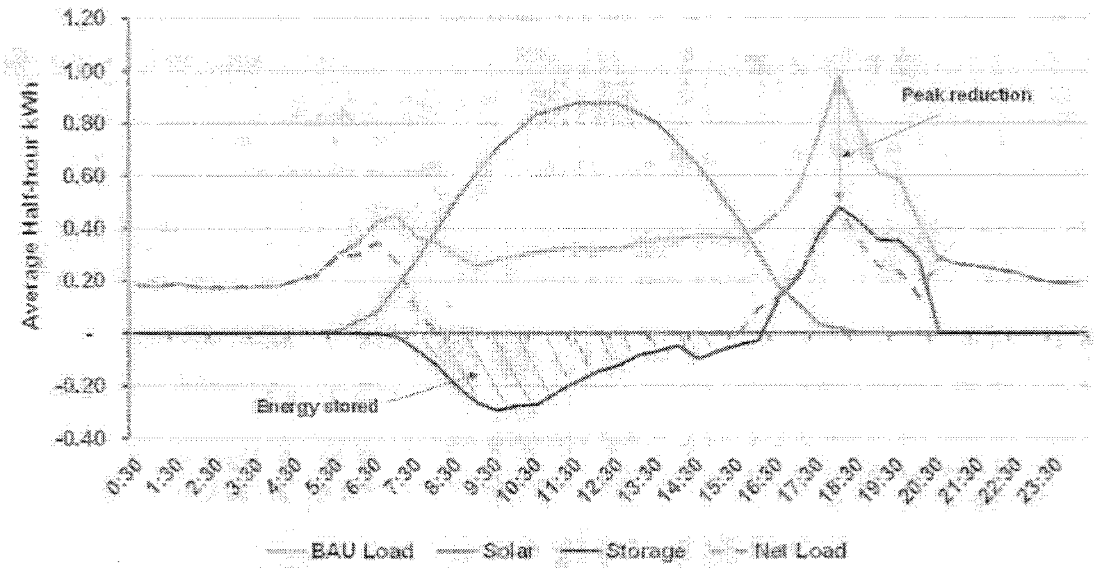
"To what degree is DG solar energy production coincident with peak demand? Does the cost and value of DG solar vary depending on whether or not energy production is coincident with peak demand? Are there policies that the Commission could consider that address this issue?"

How do you respond?

A. A DG solar installation's contribution to the deferral of a planned capacity upgrade (i.e., its Deferral Value) is dependent on its coincidence with the local peak when the system is most constrained. For distribution feeders, these peak periods are typically only a few hours every year, they are not always coincident with the overall system peak, and they are very dependent on the nature of the load (i.e., residential, commercial, or industrial). If the load is primarily commercial, the peak is typically earlier in the day when businesses are open and customers are at work. If the load is primarily residential, the peak is typically later in the day when customers return home and increase their electricity usage.

The output from DG solar also peaks depending on its orientation – the peak output of south-facing panels is earlier in the day than for more west-facing panels. It is therefore possible to strategically deploy and orient DG solar to coincide with system or feeder peaks, but not always. Increasingly, storage combined with DG solar is proving to be an effective way to improve coincidence with local peaks.

The diagram below illustrates how storage can effectively enable DG solar to reduce a local peak demand.[12] The business-as-usual ("BAU") load for this hypothetical customer peaks at around 6:30 pm, while the maximum DG solar output occurs around noon. By directing the DG solar output to charge the storage during the day, then dispatching the storage during peak load periods, the solar PV + storage DER portfolio becomes fully coincident with peak demand and net load decreases.



Q. Is storage cost effective?

A. Energy storage is becoming increasingly cost effective as battery costs decline and as customers are able to monetize the value of storage services. Thermal energy storage technologies, such as those using ice[13] or electric hot water

[12] Lars Karlbom et al., *Why Isn't There More Talk About Network Storage-As-A-Service?*, QSI Online (July 21, 2015), http://www.marchmenthill.com/qsi-online/2015-07-21/why-isnt-there-more-talk-about-network-storage-as-a-service/.

[13] Jeff St. John, *How Solar Power and Ice Energy Can Play Together*, Greentech Media (Aug. 19, 2013), http://www.greentechmedia.com/articles/read/how-sun-power-and-ice-energy-can-play-together.

heaters,[14] are also becoming cost effective solutions for load shifting and peak demand reduction.

Q. What do you recommend?

A. I understand that this docket is primarily focused on establishing a methodology for determining the value of DG solar. However, I encourage the Commission to establish flexibility in the methodology to be able to include the value of multiple DER types and portfolios of DER, such as solar + storage, in the future.

3.4 Ability to Dispatch

Q. Question 10 of Commissioner Little's letter states:

"Is it possible for DG solar to be more dispatchable? How does the ability to dispatch or the lack of ability to dispatch affect the value and cost of DG solar?"

How do you respond?

A. DG solar on its own is non-dispatchable. However, as illustrated above, a solar + storage portfolio can be dispatched in a manner that effectively contributes to a peak load reduction, and can therefore have a Deferral Value.

3.5 Transmission Capacity

Q. Question 15 of Commissioner Little's letter states:

"Does the deployment of DG solar result in changes in the need for transmission capacity? If so, how should those changes be included in the value and cost considerations?"

How do you respond?

A. DG solar and other DERs have the potential to defer or eliminate the need for transmission expansion because they can decrease the peak load at substations

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[14] David Podorson, *Battery Killers: How Water Heaters Have Evolved into Grid-Scale Energy-Storage Devices*, E Source (Sept. 9, 2014), https://www.esource.com/ES-WP-18/GIWHs.

served by the transmission system and provide congestion relief. The extent to which a DER has transmission Deferral Value depends on the coincidence of the DER output with system peak loads.

Q. Are other regulatory commissions addressing issues similar to those in this proceeding, specifically transmission capacity?

A. Yes. New York's Reforming the Energy Vision ("REV") proceeding,[15] and California's Distribution Resources Plan ("DRP") and Integrated Distributed Energy Resource ("IDER") proceedings[16] are addressing similar issues.

Q. How are these other commissions determining the value of transmission capacity deferral?

A. There is no clear consensus in the New York REV and California DRP/IDER proceedings on the preferred way to determine transmission Deferral Value. To determine the value of avoided transmission capacity value beyond that included in avoided generation and avoided energy, New York will use detailed transmission and distribution ("T&D") marginal costs. The utilities have historically used a system average $ per kW value for avoided T&D capacity, but are now required to develop detailed marginal cost of service studies to be included with their initial Distribution System Implementation Plans by June 30, 2016.

The three California investor-owned utilities have proposed different methods for valuing transmission Deferral Value. SCE proposes to calculate the net present value of the capital investment deferral over an identified deferral time-frame, based on the amount of DERs that can reasonably be deployed to address the specified grid need, applied over the timeframe of the deferral.[17] PG&E proposes that the locational impact be the difference between the deferral benefits and the

[15] New York Public Service Commission Case 14-M-0101.

[16] California Public Utilities Commission Rulemaking 14-08-013 and 14-10-003.

[17] S. Calif. Edison, *Distribution Resources Plan*, at 38.

capacity-related costs for interconnecting DERs, less additional benefits of deferring the project.[18] SDG&E proposes to use the cost to install a traditional project to meet a grid need as the T&D capacity value.[19]

Q. What do you recommend?

A. Because transmission and distribution system and load characteristics vary significantly by circuit and location, I recommend that the Commission adopt a detailed marginal cost of service methodology for valuing both transmission and distribution capacity. This approach is data-intensive, but tools are increasingly available to assist with the analysis.[20] I provide a high-level example of this methodology in my response below to the question on distribution capacity.

Q. For DG solar or other DERs to have transmission Deferral Value, is an immediate project addressing a grid capacity shortfall required?

A. No. There will be cases where DG solar or other DERs make small, incremental contributions to increase transmission capacity in areas where no immediate capacity upgrade is planned. I believe this contribution to longer-term capacity relief has value and should be recognized in the valuation methodology.

This approach is similar to how utilities treat avoided generation capacity value. As the Interstate Renewable Energy Council's Regulator Guidebook explains:

> For example, if a utility has ample capacity to meet its reserve margin and its next capacity addition will be a 500 MW CCGT, a utility might argue that incremental additions of 1 MW or 20 MW do not allow them to avoid capacity costs. FERC's regulations recognize that distributed generation provides a more flexible manner to meet growing capacity needs and can allow a utility to

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[18] Pac. Gas & Elec. Co., *Distribution Resources Plan* 70 (July 2015), *available at* http://goo.gl/bNKkCn.

[19] San Diego Gas & Elec. Co., *Distribution Resources Plan* 47 (July 2015), *available at* http://goo.gl/bNKkCn.

[20] *See, e.g.*, Jeff St. John, *Distributed Marginal Price: The New Metric for the Grid Edge?*, Greentech Media (Aug. 21, 2014), http://www.greentechmedia.com/articles/read/distributed-marginal-price-dmp-the-new-metric-for-the-grid-edge.

> defer or avoid the "lumpy" capacity additions. Therefore, it is inappropriate to hold that there is no capacity benefit for deployment of distributed generation in years that come before the time where the "lumpy" capacity investment is required. Distributed generation resources, like other demand-side resources that are continuously pursued to address load growth and to reduce peak demand, provide immediate benefit and a hedge against unexpected outages that could lead to a shortage in capacity. There is, therefore, no good reason to value DSG capacity for its long-term value only in years where it physically displaces the next marginal generating unit.[21]

Q. Please summarize your recommendations for addressing transmission capacity savings in the valuation of DG exports.

A. I recommend that the Commission adopt a detailed marginal cost of service methodology for both transmission and distribution capacity. The methodology should reflect the unique system operating and load characteristics at each location. The methodology should also credit DG solar and DER for incremental contributions to transmission capacity relief, even if the utility has not identified an imminent capacity expansion project in the local area.

3.6 Distribution Capacity

Q. Question 16 of Commissioner Little's letter states:

"Does the deployment of DG solar result in changes in the need for distribution capacity? If so, how should those changes be included in the value and cost considerations?"

How do you respond?

A. DG solar and other DERs can decrease or increase the need for distribution system capacity investments. When strategically deployed, DERs can defer or eliminate the need for traditional investment. Where insufficient hosting capacity exists, feeder upgrades may be required.

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[21] Interstate Renewable Energy Council, Inc., *A Regulator's Guidebook: Calculating the Benefits and Costs of Distributed Solar Generation* 25 (Oct. 2013) (footnotes omitted), *available at* http://goo.gl/SjblOA.

As I described earlier, I recommend that the Commission adopt a detailed marginal cost of service methodology for valuing DER impacts to both transmission and distribution capacity.

The New York REV Benefit Cost Analysis Framework provides the following high-level example using marginal cost data from Con Edison.[22]

EXAMPLE: Battery Energy Storage located at a Con Edison Area Substation

A 1 MW battery with a 5-year service life is attached to an area substation in the Con Edison service territory. The battery is operated to reduce the peak load experienced by the area substation between 6 pm and 8 pm, whereas the system peak generally occurs at 4 pm. What is the value of avoided T&D infrastructure need for 2016?

First, consider whether the load reduction of the battery aligns with the cost drivers of the utility equipment which it is connected to. In this instance, operation of the battery does reduce demand during the peak hours experienced by the area substation, but not those of the system as a whole. Further, since the battery is connected directly at the area substation, for simplicity assume its operation does not decrease peak load on Con Edison's primary or secondary distribution feeders. Therefore, only consider the battery's contributions to avoided Area Station and sub-transmission costs.

To determine the value of avoided T&D for the battery, multiply the amount of load reduction caused by the battery by the marginal costs of the equipment that the load is being relieved from; this calculation should be done for the entire service life of the battery (calculations for 2015 and 2016 have been shown as a demonstration).

$$\begin{aligned}\text{Avoided T\&D}_{2015} &= \text{load reduction} * \text{marginal cost}_{2015} \\ &= (-1\ \text{MW}) * \left(\frac{\$43.88}{\text{kW}}\right)\left(\frac{1000\ \text{kW}}{\text{MW}}\right) = \$43{,}880 \\ \text{Avoided T\&D}_{2016} &= \text{load reduction} * \text{marginal cost}_{2016} \\ &= (-1\ \text{MW}) * \left(\frac{\$82.90}{\text{kW}}\right)\left(\frac{1000\ \text{kW}}{\text{MW}}\right) = \$82{,}900\end{aligned}$$

The lifetime Avoided T&D Infrastructure of the battery can then be determined by finding the Net Present Value of the value streams.

[22] Order Establishing the Benefit Cost Analysis Framework, New York PSC Case No. 14-M-0101, at App. C, pp. 9–10 (Jan. 21, 2016), *available at* http://goo.gl/v5pDj5.

Table 2: Illustrative Example of the Avoided T&D Infrastructure Calculation

Year	Marginal Cost	Avoided T&D
2015	$ 43.88	$ 43,880
2016	$ 82.90	$ 82,900
2017	$ 49.68	$ 49,680
2018	$ 127.30	$ 127,300
2019	$ 119.43	$ 119,430
Discount Rate		5%
NPV		**$ 358,205**

Q. To have Deferral Value, does the DER need to directly defer a capital investment?

A. No. As I explained with regard to transmission capacity above, DERs that contribute incremental peak demand reductions or otherwise increase feeder capacity should get credit for the long-term capacity deferral, even if there is no immediate planned project.

Q. Please summarize your recommendations for addressing distribution capacity savings in a valuation of DG exports.

A. As with transmission capacity, I recommend that the Commission adopt a detailed marginal cost of service methodology for distribution capacity. The methodology should reflect the unique system operating and load characteristics at each location. The methodology should also credit DG solar and other DERs for incremental contributions to distribution capacity relief, even if the utility has not identified an imminent capacity expansion project on the interconnected feeder or at the associated substation.

3.7 Water

Q. Question 18 of Commissioner Little's letter states:

"Does the deployment of DG solar result in a reduction in the use of water in electric generation? How should this be considered when determining DG solar value?"

How do you respond?

A. Thermoelectric power generation plants withdraw and consume water for a variety of uses, primarily the condensation or cooling of steam. These plants consume and lose water through evaporation, and the amount of water lost at each facility depends on the generation and cooling technologies utilized at each plant. Arizona power generation facilities consume water from many sources, including the Colorado River (South Point Energy Center), Lake Powell (Navajo Generating Station), and various sources of groundwater and wastewater.

DG solar generation requires no thermoelectric cooling and consumes no water, so each kWh of DG solar serving a customer effectively avoids consumption of water from conventional generation. The Commission acknowledged this in its 2005 APS rate case order stating, "Generation from a solar electric project will add fuel-free, net-plant energy output resulting in environmental benefits and lower energy-specific water usage."[23]

Commissioner Burns emphasized the importance of the energy-water relationship and the water conservation benefits of DG solar in his February 8, 2016 letter to stakeholders in this docket.

The Commission has further demonstrated leadership in recognizing the importance of the energy-water relationship, requiring utilities to report quantities and rates of water consumption in each Integrated Resource Plan ("IRP").[24] In

[23] Decision No. 67744, at 26:18–20 (Apr. 7, 2005).

[24] Decision No. 71722 (June 3, 2010).

response, APS reported average consumption of approximately 400 gallons per MWh in its 2014 IRP.[25] Tucson Electric Power ("TEP") reported a system average of 599 gallons per MWh in its IRP for the same period.[26] In earlier comments in this proceeding, TEP disclosed that its generation fleet consumes, on average, 605 gallons of water per MWh.[27]

In these same IRPs, both APS and TEP acknowledge the important role of renewable energy and other DERs in reducing water consumption. APS stated "due to the energy efficiency and renewable energy resources envisioned in the 2014 Resource Plan, the rate of water usage declines dramatically over the course of the Planning Period."[28] The TEP IRP includes the statement, "TEP plans to continue its development of low cost renewable projects that minimize both water usage and negative impacts to the environment and provide long-term value to TEP's retail customers."[29] TEP and UNS stated in their earlier comments in this docket that "PV systems provide immediate reductions in water use by offsetting energy production from fossil-fueled units."[30]

Q. How can the Commission incorporate the value of reduced water consumption in determining the value of DERs, specifically DG solar?

A. The value of water varies significantly by location. Generally, the value of water in Arizona is high and likely to increase as its population and associated water demand increase. Western Resource Advocates ("WRA") published a report in 2011 providing a methodology for valuing water by examining prices paid for alternative uses to thermoelectric cooling, specifically agriculture, municipal

[25] APS, *2014 Integrated Resource Plan* 119 (Apr. 2014), *available at* https://goo.gl/whtaZa.

[26] TEP, *2014 Integrated Resource Plan* 166 (Apr. 2014), *available at* https://goo.gl/99IVAW.

[27] TEP and UNSE Comments at 6 (Feb. 14, 2014).

[28] APS, *2014 Integrated Resource Plan*, at 119.

[29] TEP, *2014 Integrated Resource Plan*, at 12.

[30] TEP and UNSE Comments at 6 (Feb. 14, 2014).

supply, and environmental uses.[31] The report provides a potential range of value for water in Arizona between $105 and $1,225 per acre-foot per year.[32]

The Commission could determine that prices for agricultural use are the fairest comparison for valuing cooling water consumption. As a proxy for the value of water for agricultural use, water sold by the Central Arizona Project to agricultural customers was $121 per thousand cubic meters in 2014,[33] or $149 per acre-foot.[34]

The Commission could adopt the WRA methodology, an agricultural use comparison, or another approach to determine a dollar value for water in Arizona today and in future years. Because its value is very location-specific, the Commission may determine a different value for water in each utility service territory. Once the Commission establishes a water value, it is straightforward to calculate the associated value of energy from DG solar or other DER by:

- Converting the water value in $/acre-foot to $/gallon (1 acre-foot = 325,851 gallons)
- Multiplying the self-reported water consumption rates of the utilities (in gallons/MWh) by the converted water value ($/gallon)

Q. Can you provide examples?

A. Yes. To illustrate, I will assume that the Commission determines that today's value of water in Arizona is $149/acre-foot per year, which was the price for Central Arizona Project water for agricultural use in 2014. I will also assume for simplicity that the value of water is the same in the APS and TEP service territory. Using the self-reported water consumption rates from each utility:

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[31] W. Res. Advocates, *Every Drop Counts: Valuing the Water Used to Generate Electricity* (2011), *available at* http://goo.gl/Zm6Sye.

[32] *Id.* at 65.

[33] Dennis Wichelns, Org. for Econ. Co-Operation & Dev., *Agricultural Water Pricing: United States* 21 (2010), *available at* http://goo.gl/ABAZF4.

[34] 1,000 cubic meters = 0.811 acre-foot.

- For APS, with 400 gallons per MWh from conventional generation, the value of avoided water consumption from a kWh of DG solar is:

$$\text{Value} = \$149 \times (1/325{,}851) \times 400$$
$$= \$0.183 \text{ per MWh}$$
$$= 0.018 \text{ cents per kWh}$$

- For TEP with 605 gallons per MWh from conventional generation, the value of avoided water consumption from a kWh of DG solar is:

$$\text{Value} = \$149 \times (1/325{,}851) \times 605$$
$$= \$0.277 \text{ per MWh}$$
$$= 0.028 \text{ cents per kWh}$$

Q. Is it worth including these relatively small avoided water consumption values in the DG solar valuation?

A. Yes. The resulting values may be small, but they are not zero. By including the water conservation component in the calculations, the Commission will continue its leadership in acknowledging and spotlighting the significance of the energy-water relationship.

Q. What do you recommend?

A. Because water is, and will increasingly be, a scarce and valuable resource for Arizona, I strongly recommend that the Commission include the value of avoided water consumption in its DER and DG solar valuation methodology. This requires that the Commission:

- Determine a current value for water in Arizona or within each utility's service territory using the WRA methodology or another approach.
- Establish an initial DG solar value of avoided water consumption using the rates reported in the utilities 2014 IRPs .

- Require utilities to explicitly report their current and forecasted average system water consumption rate (gallons per MWh) in each IRP.
- Periodically reassess the value of water in Arizona as new information becomes available.
- After each IRP submission, update the value of avoided water consumption in each service territory and update in the DG solar valuation methodology.

3.8 Grid Security and Reliability

Q. Question 19 of Commissioner Little's letter states:

"Are there disaster recovery or backup benefits associated with the deployment of DG solar? Are they reliable and quantifiable enough to determine tangible benefits that might accrue to the grid?"

How do you respond?

A. Yes, there are disaster-recovery or backup benefits associated with the deployment of DG solar and other DERs. As EPRI explains:

> Properly sited and configured DER can assist in the restoration of service after storm-related outages and power delivery component failures from other causes. Utilities often switch isolated feeder sections to alternate feeds at such times. Occasionally, there is insufficient capacity in the alternate feed to supply the load required to restore service to all consumers on the affected feeder section. The ability to support some of the load from DER output sited on the affected section may improve feeder reliability.
>
> If the DER can operate without the presence of the grid, they can be used to help restore power to sections of the distribution system that are completely isolated from the bulk power system (for example, as a result of storm damage). This is often referred to as a *microgrid* that can provide increased localized grid resiliency.[35]

For locations where DERs lead to avoided service interruptions, utilities could estimate the value of this service by determining the number and duration of

[35] Elec. Power Research Inst., *The Integrated Grid: A Benefit-Cost Framework*, at 4-16 to 4-17.

avoided outages, multiplied by the estimated cost of an interruption.

Q. Can you be more specific?

A. Yes. Utilities often use three metrics to measure and report service reliability: (1) the System Average Interruption Frequency Index ("SAIFI") measures average interruptions per customer, (2) the System Annual Interruption Duration Index ("SAIDI") measures average minutes of interruption per customer, and (3) the Customer Average Interruption Frequency Index ("CAIDI") measures the average minutes per interruption. Utilities can calculate these values for various time periods and at the system level, subsystem or feeder level, or at a very local level.

As I described above, portfolios of DERs, including DG solar, can avoid service interruptions or reduce the duration of an interruption once it occurs. At the time of DER deployment and valuation, distribution planners can estimate the expected reduction in SAIFI, SAIDI, and CAIDI from the DER, much like they do with conventional reliability improvement investments.

The Department of Energy's Interruption Cost Estimate ("ICE") calculator provides a standard way of estimating the dollar value of reliability improvement projects, including DER, for a given improvement in SAIFI, SAIDI, or CAIDI.[36] The ICE calculator provides the present value of reliability improvement, based on the specific customer types on each feeder or area, over the life of an investment.

Q. What do you recommend?

A. I recommend that the Commission explicitly consider the reliability improvement benefits of DG solar and other DERs in the valuation methodology. The approach could include a requirement for the utilities to estimate the expected location-specific SAIFI and SAIDI improvement (if any) for each DG solar or DER

[36] U.S. Dep't of Energy, Interruption Cost Estimate Calculator, http://icecalculator.com/index.html (last visited Feb. 24, 2016).

location, and the conversion to a dollar value using the ICE calculator or other similar reliability calculator.

4 Important Considerations from Other Jurisdictions

Q. You previously mentioned that other commissions are currently addressing issues similar to those in this docket. Are there some common themes in these other proceedings that are relevant to Arizona?

A. Yes. The participants in these other proceedings recognize the potential for DERs to become valuable grid resources and are addressing the need to explicitly incorporate DER capabilities into traditional distribution planning. This includes fundamental changes to traditional planning methodologies, such as developing and publishing hosting capacity analyses. In addition, these other proceedings emphasize the need to analyze and value all DER types and DER portfolios, not just DG solar.

4.1 The Importance of Proactive Planning for DERs

Q. Why is it important to consider changes to traditional distribution planning?

A. Utilities have generally based distribution planning on assumptions of one-way power flow and the need to reliably and safely provide sufficient capacity to meet local peak demand, which may only occur only a few hours each year. Traditional planning models are static, and solutions to address distribution system capacity, voltage, or reliability issues have been almost exclusively limited to traditional utility capital investment. Most utilities have focused on overcoming the perceived challenges of DG solar and DER interconnection, rather than realizing the potential value of full DER integration.

The proliferation of DERs has fundamentally changed the nature of distribution systems, creating new complexities and opportunities for utilities, customers, and other third parties. Distribution planning assumptions and methodologies must therefore change to reflect this new reality. Additionally, DERs can provide significant grid services which, if not explicitly accounted for and incorporated into utility planning, will be underutilized and could lead to redundant utility investments.

Q. What changes to distribution planning are necessary?

A. First, distribution planning tools and methodologies must become more sophisticated to reflect the dynamic nature of DERs. This includes the need for more advanced circuit modeling, load and DER forecasting, and more granular load and voltage monitoring. A recent report by the Solar Electric Power Association and Black & Veatch provides details on the new tools and capabilities required for today's distribution planning functions.[37]

Second, to more fully enable market innovation and customer choice, distribution planning must become a more open and transparent process with utilities proactively seeking opportunities to deploy DERs. This requires closer collaboration within the utility between planning, interconnection, and energy efficiency/demand response functions. It also requires utilities to publicly share information about constraints and opportunities for DER deployment, including historical operational data, grid needs, the value of addressing specific grid needs, and overall grid hosting capacity.

Q. What do you mean by grid needs?

A. A grid need is an existing or anticipated distribution system deficiency, such as a capacity shortfall, violation of voltage limits, poor reliability, or replacement of aging or failing equipment. Grid needs may also include modifications required to increase a distribution circuit's hosting capacity.

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[37] Solar Elec. Power Ass'n and Black & Veatch, *Planning the Distributed Energy Future: Emerging Electric Utility Distribution Planning Practices for Distributed Energy Resources* (Feb. 2016), *available at* https://goo.gl/x1Y8JV.

Q. What other changes to distribution planning have you observed in these other jurisdictions?

A. New York and California also recognize that additional changes are needed to overcome the utility bias for traditional capital investments as preferred solutions to grid needs. This requires new methodologies for determining the Locational Value of DERs and portfolios of DERs at each location on the distribution system, and mechanisms for utilities to procure DERs and fairly recover the costs of the procurement. The New York REV and California DRP/IDER proceedings are exploring ways for distribution utilities to determine DER Locational Value, and to fairly consider and effectively procure DER as alternatives to traditional utility investment.

4.2 The Importance of Valuing All DER Types and DER Portfolios

Q. Why are other jurisdictions considering the value of all DER types and DER portfolios, not just DG solar?

A. The operating characteristics, impact, and value to a distribution system differ between generating-DERs (solar and other DG, CHP, sometimes storage) and load-DERs (energy efficiency, direct load control, EVs, sometimes storage). DERs can work together to shave the peaks and fill in the valleys of a load profile. Demand response/load control can shift load away from peak periods or make load coincident with intermittent generation. Storage absorbs energy from intermittent generation and can discharge to reduce peaks. Energy efficiency can provide targeted energy and demand reductions in specific end-uses. A DER portfolio of renewable generation, storage, demand response/load control, and EE can provide a more reliable and sustained peak demand reduction than any of the resources can provide individually. DER portfolios can therefore be the most reliable and cost-effective alternatives to traditional transmission and distribution capital investment.

Q. Are there any examples of this?

A. Yes, there are several examples demonstrating how portfolios of DERs can reliably and cost-effectively address local load characteristics to reduce peak demands.

In 2013, the Maine Public Utilities Commission established the Boothbay Smart Grid Reliability Pilot project to determine if DERs could effectively avoid the need for rebuilding a transmission line. The pilot sought to reduce 1.8 MW of demand to avoid an $18 million rebuild of a 34.5 kV transmission line in Central Maine Power's service territory. The DERs deployed in the pilot included DG solar, energy efficiency, demand response, energy storage, and back-up generation. Collectively, these DERs have exceeded the demand reduction target. The total cost for the pilot and deployment of the DERs is projected to be one-third the cost of rebuilding the transmission line and will save customers $17.6 million over the 10-year project life.[38]

The State of Rhode Island requires electric utilities to consider DERs or "non-wires alternatives" for certain types of transmission and distribution capital projects. In addition to deploying targeted energy efficiency and demand response measures, National Grid initiated a study to assess the ability of distributed solar to provide 250 kW of reliable load relief during periods of local peak demand in the Tiverton/Little Compton Region.[39] The study found that National Grid could deploy a mix of rooftop and medium-scale solar systems to help defer a multi-million dollar distribution investment. The company has also solicited proposals for development of 140 kW "peak contribution" capacity of medium-scale solar systems for deployment within a specific, load-constrained area of the distribution grid.

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[38] GridSolar, LLC, *Interim Report Boothbay Sub-region Smart Grid Reliability Pilot Project* (March 2014), *available at* http://goo.gl/46zKT1.

[39] R.I. Office of Energy Res., System Reliability Program, http://www.energy.ri.gov/reliability/ (last visited Feb. 24, 2016).

Finally, New York's Consolidated Edison, under the Brooklyn-Queens Demand Management Program, will spend $200 million deploying DERs to reduce 41 MW of customer demand by 2018 and help defer building a $1 billion substation. The program will include many types of DERs including energy efficiency, demand response, DG solar, and distributed storage. Con Edison's benefit-cost analysis shows a $40 million net present value benefit from this approach.[40]

Q. Why is this relevant in this proceeding?

A. I understand that this proceeding is primarily focused on establishing a methodology to inform future rate cases on how to determine the value and cost of DG solar. I encourage the Commission to acknowledge that the full value of DG solar and other DERs is best realized when distribution planning processes proactively and fairly consider DER as alternatives to traditional capital investments.

Q. What do you recommend?

A. In addition to establishing a methodology for valuing DG solar in this proceeding, I recommend that the Commission require modifications to distribution planning processes, including the identification and publication of DER hosting capacity and Locational Value. I also recommend that the Commission establish mechanisms for third-party provision of DER solutions as alternatives to traditional utility investment. Finally, I encourage the Commission to maintain flexibility in developing the DG solar valuation methodology for future accommodation of all DER types and DER portfolios.

[40] Corina Rivera Linares, *New York PSC establishes Con Edison's demand management program in Brooklyn, Queens*, Transmission Hub (Dec. 18, 2014), *available at* http://www.transmissionhub.com/articles/2014/12/new-york-psc-establishes-con-edison-s-demand-management-program-in-brooklyn-queens.html.

5 Summary of Recommendations

Q. Please summarize your recommendations for the Commission

A. I recommend that the Commission:

1) Require utilities to conduct hosting capacity analyses to identify locations on the distribution system where DG solar and other DERs can interconnect with no or minimal integration costs, or where integration costs may be high. I also recommend that the Commission require utilities to publish the results of the analyses for easy access by customers and DER providers. The results of these analyses will provide key inputs into the integration cost component of DG solar valuation.

2) Modify its interconnection standards to require the deployment of smart inverter functionality for DG solar and storage installations.

3) Adopt a detailed marginal cost of service methodology for both transmission and distribution ("T&D") capacity, reflecting the unique system operating and load characteristics at each location. The methodology should also credit DG solar and DER for incremental contributions to T&D capacity relief, even if the utility has not identified an imminent capacity expansion project in the local area.

4) Include the value of avoided water consumption in its DG solar valuation methodology.

5) Explicitly consider the reliability improvement benefits of DG solar and other DERs in the valuation methodology.

6) Initiate changes to traditional utility distribution planning processes to proactively incorporate DG solar and other DERs. This includes:

- Increasing transparency regarding the grid's capacity to accommodate DG solar and other DERs and the locational value of various DER solutions.
- Increasing the transparency of planned capital investments that could be deferred, avoided, or substituted by DER solutions.
- Mechanisms to allow third-party provision of DER solutions as alternatives to traditional distribution capital investment.

7) Establish flexibility in the DG solar valuation methodology to allow for future inclusion of all DER types and portfolios of DERs.

Q. Does this conclude your testimony?

A. Yes.

Exhibit CV-1

Statement of Qualifications

Curt Volkmann

curt@newenergy-advisors.com

Experience

New Energy Advisors, LLC, Strategic Advisory Company, Lake Forest, IL (2015 – present)
President
Advising non-profits and local governments on energy, water and sustainability opportunities

- Advising environmental advocates in various regulatory proceedings related to distributed energy resources
- Led the development of a water and energy community education series for the City of Lake Forest
- Guest lecturer at Chicago-area universities on the topics of energy and sustainability

Environmental Law & Policy Center, Nonprofit Public Interest Advocacy Organization, Chicago, IL (2013 – 2015)
Senior Clean Energy Specialist
Supported advocacy work on various clean energy and transportation policy issues

- Expert witness in several energy efficiency, renewable energy, and rate design regulatory proceedings
- Focused on opportunities to integrate distributed energy resources into electric utility distribution systems

Accenture LLP, Management Consulting and Technology Company, Chicago, IL (1994 – 2013)
Managing Director, North America Strategy and Sustainability (2010 – 2013)
Led the management consulting practice ($260+ million annual sales) focused on energy efficiency and intelligent infrastructure. Clients spanned the chemicals, metals, consumer products, financial services, telecommunications, utilities and federal/state/local government sectors.

- Responsible for sales and project delivery, product/service development, recruiting, alliance management
- Contributed to sales growth of more than 400% in 2 years
- Led creation of Energy Analytics for Cities framework; identified $175 million of energy savings from building retrofits for the City of Chicago
- Frequent speaker and subject-matter expert on the topics of utilities, smart grid, sustainability, clean energy

Partner and Executive Director, North America Utilities Client Group (2000 – 2010)
Managed sales ($10-30 million annually), profitability, and client satisfaction for consulting projects across a portfolio of gas, electric and water utilities. Projects included strategic assessments, smart grid/meter planning, asset management, merger integration, benchmarking, and process improvements.

Senior Manager and Associate Partner, Strategic Services (1994 – 2000)
Led projects involving utility strategic planning, merger integration, cost reduction, and process reengineering

UMS Group, Management Consulting Company, Parsippany, NJ (1993 – 1994)
Senior Associate
Led the Power Delivery consulting practice and benchmarking programs for transmission, distribution and fleet management involving 40+ utilities in 10 countries (in Europe, Africa, North America, Australia/New Zealand)

Pacific Gas and Electric Company, Utility, San Francisco, CA (1984 – 1993)
Electrical Engineer, Operations Planning Consultant, Project Manager

- Assessed impacts to distribution systems from energy efficiency and demand-side management programs
- Modeled impacts of distributed generation on system reliability and safety

Energie- und Verfahrenstechnik (EVT), Power Generation Equipment Manufacturer, Stuttgart, Germany (1983)
Software Developer
Designed steam generating systems for coal-fired power plants

Education

University of California at Berkeley, Haas School of Business
MBA - Concentration in Finance

University of Illinois at Urbana-Champaign
BS - Electrical Engineering, Concentration in Electrical Power Systems

Community Involvement

- Chairman, Lake Forest Collaborative for Environmental Leadership (2012-Present)
- Chairman, City of Lake Forest Parks and Recreation Board (2012-2014)
- Member, City of Lake Forest Municipal Electricity Aggregation Committee (2011-2012)
- Member, City of Lake Forest Environmental Policy Advisory Committee and "Green Team" (2008-2009)
    - Led development of a baseline energy and emissions profile for the City of Lake Forest
- Treasurer, Board Member and Coach; American Youth Soccer Organization (2006-2009)

BEFORE THE ARIZONA CORPORATION COMMISSION

IN THE MATTER OF THE COMMISSION'S INVESTIGATION OF VALUE AND COST OF DISTRIBUTED GENERATION.	Docket No. E-00000J-14-0023

DIRECT TESTIMONY AND EXHIBITS OF BRIANA KOBOR

ON BEHALF OF VOTE SOLAR

FEBRUARY 25, 2016

Table of Contents

List of Tables and Figures

List of Exhibits

1 Introduction

Q. Please state your name and business address.

A. My name is Briana Kobor. My business address is 360 22nd Street, Suite 730, Oakland, CA.

Q. On whose behalf are you submitting this direct testimony?

A. I am submitting this testimony on behalf of Vote Solar.

Q. What is Vote Solar?

A. Vote Solar is a non-profit grassroots organization working to foster economic opportunity, promote energy independence, and fight climate change by making solar a mainstream energy resource across the United States. Since 2002, Vote Solar has engaged in state, local, and federal advocacy campaigns to remove regulatory barriers and implement key policies needed to bring solar to scale. Vote Solar is not a trade group and does not have corporate members. Vote Solar has approximately 60,000 members nationally and 3,500 in Arizona.

Q. By whom are you employed and in what capacity?

A. I serve as Program Director of Distributed Generation ("DG") Regulatory Policy for Vote Solar. I analyze policy initiatives, development, and implementation related to distributed solar generation. I also review regulatory filings, perform technical analyses, and testify in commission proceedings relating to distributed solar generation.

Q. Please describe your education and experience.

A. I have a degree in Environmental Economics and Policy from the University of California, Berkeley, and I have been employed in the utility regulatory industry since 2007. Prior to joining Vote Solar in August 2015, I was employed for eight years by MRW & Associates, LLC ("MRW"), which is a specialized energy consulting firm. At MRW, I focused on electricity and natural gas markets, ratemaking, utility regulation, and energy policy development. I worked with a variety of clients at MRW, including energy policy makers, developers, suppliers, and end-users. My clients included the California Public Utilities Commission, the California Energy Commission, the California Independent System Operator, and several Publicly Owned Utilities. I have experience evaluating utility cost-of-service studies, revenue allocation and ratemaking, wholesale and retail electric rate forecasting, asset valuation, and financial analyses. A summary of my background is attached as Exhibit BK-1.

Q. Have you previously testified before the Arizona Corporation Commission (the "Commission")?

A. Yes. I submitted direct and surrebuttal testimony in Docket No. E-04204A-15-0142, the UNS Electric, Inc. General Rate Case. I am scheduled to testify at the evidentiary hearing in the same docket on March 15, 2016.

Q. Have you previously testified before other regulatory commissions?

A. Yes. I have testified in proceedings before the California Public Utilities Commission. I have testified on behalf of the Coalition for Affordable Streetlights in A.14-06-014, Application of Southern California Edison Company (U338E) to Establish Marginal Costs, Allocate Revenues, Design Rates, and Implement Additional Dynamic Pricing Rates. I have also testified on behalf of the Utility Consumers' Action Network in A.14-11-003, Application of San Diego Gas & Electric Company (U902M) for Authority, Among Other Things, to Increase Rates and Charges for Electric and Gas Service Effective on January 1, 2016.

2 Purpose of Testimony and Summary of Recommendations

Q. What is the purpose of your testimony in this proceeding?

A. My testimony first addresses the role that long-term DG value analysis should have in policy-making and rate-setting. Second, I provide a brief summary of DG valuation in Arizona and examples of DG valuation in other states. Third, I discuss important parameters to consider when determining the most appropriate methodology for analyzing the various categories of costs and benefits that result from DG deployment in Arizona. Fourth, I recommend methodologies specific to each category of costs and benefits that should be assessed in a long-term DG value analysis. Fifth, I provide responses to the specific questions posed by Commissioner Little and Commissioner Stump in this docket. Finally, I offer recommendations for the procedure to develop a robust, standardized methodology for analysis of the long-term costs and benefits of DG, which could inform future solar policy in Arizona.

Q. What is your understanding of how this proceeding could advance the ongoing discussions related to the costs and benefits of solar in Arizona?

A. Considerable tension has built up over DG rate design in Arizona and elsewhere. I believe that developing a robust, standardized approach to evaluating the long-term costs and benefits of DG could inform future policy decisions in a balanced manner. Arizona utilities have claimed that the current rate structure causes customers who do not participate in the net energy metering ("NEM") program (i.e., "non-NEM" customers) to subsidize NEM customers. However, these claims have largely been based on short-term evaluations that inherently exclude many of the long-term value streams that accrue with additional DG deployment. Ignoring long-term benefits, while focusing primarily on short-term costs, will not result in an accurate assessment of optimal DG policy. I commend the Commission for taking up this issue in the present docket. DG is only the first of many new distributed technologies that will change the way customers interact with the grid. Development of a robust, standardized approach for DG can inform future evaluation of other distributed energy resources ("DERs") to help ensure that the transition to the modern grid happens in the most efficient and least-cost manner for all ratepayers.

Q. Please summarize your findings and recommendations.

A. I recommend that this proceeding be used to develop a robust, standardized methodology for DG valuation. In developing this methodology, I recommend that the Commission recognize that every customer should have the right to consume as much or as little electricity from the utility as they wish, regardless of whether they have installed a solar array, invested in energy efficiency measures, or purchased a larger air conditioning unit or electric vehicle. DG only differs from these other examples I mention in its ability to export energy to the electric grid. The individual customer's right to self-consume energy she generates on private property from her own private investment should be maintained. As a result, I recommend that the study of DG costs and benefits focus on evaluation of the energy that is exported from the NEM customer to the utility grid. The methodology defined by this proceeding should seek to answer one fundamental question: whether the price paid for DG exports appropriately reflects the value of the energy provided.

I recommend that the standardized methodology for valuation of DG exports examine cost-effectiveness from the perspective of non-participating ratepayers, including: impact on utility rates, incorporation of environmental impacts, improved electric reliability, and economic development benefits. If the Commission instead decides to evaluate DG consumed onsite in addition to DG exports, my recommendation regarding the appropriate cost test would change. If all DG is to be evaluated, the standardized methodology should examine cost-effectiveness using the Societal Cost Test.

In addition, I recommend that any valuation of DG exports not be limited to a certain customer class, but include valuation of exports from residential, commercial, and industrial classes. I recommend that the standardized methodology for valuation of DG exports focus on current and near-term levels of DG penetration. In addition, I recommend that the capacity benefits associated with DG be evaluated on a continuous basis to capture the unique modulatory and scalability of DG in contrast to traditional utility-scale energy resources.

I additionally recommend that the full range of costs and benefits be quantified and included in the standard DG valuation methodology. These costs and benefits include: (1) utility distributed solar costs, (2) energy generation savings, (3) generation capacity savings, (4) transmission capacity savings, (5) distribution capacity savings, (6) environmental benefits, (7) economic development benefits, and (8) grid security benefits. My testimony includes detailed recommendations on the methodology to quantify each of these categories of costs and benefits.

Finally, I recommend that the Commission require any utility requesting reform of the existing rate structure for DG to provide the necessary data for an independent, third-party analysis using the standardized methodology developed in this proceeding. The Commission should develop a stakeholder process that would allow interested parties to provide input on the independent, third-party DG export valuation. The utility should provide funding for the independent, third-party analysis that would be recoverable in rates. Because this expense would be directly related to DG, it would be appropriate to include costs of this analysis as a cost to be evaluated in the context of the DG valuation study. I recommend that the results of the DG export valuation be used in the utility's general rate case proceeding to inform DG rate design.

3 How a Full DG Value Analysis Impacts Ratemaking and Policy

Q. Please explain the relationship between DG and the utility system.

A. Customers who install DG under the NEM program install small power plants on their own properties. Rooftop solar panels comprise the vast majority of DG in Arizona, although some customers have installed wind generators as well. Customers that install DG, or "participating customers," use their small power plants to supply a portion of their own electricity needs and feed the excess energy, called "exports," into the utility distribution system. In addition to benefiting the participating customer, this private investment in energy infrastructure provides a number of benefits to utilities, other customers, and the public. The benefits of DG include environmental benefits, economic benefits, reliability benefits, and a reduced need for the utility to build new power plants and infrastructure.

Q. What is net metering?

A. Net metering is the process by which DG owners are compensated for the energy produced by their generating asset. Net metering is codified in Arizona law.[1] Under net metering, the participating customers self-consume the energy they generate. When the participating customer's energy usage is more than their DG system can supply, the utility grid supplies the customer with the balance of the needed energy. Conversely, when the energy generated by the DG system exceeds the participating customer's usage, that energy is exported to the utility distribution system.

Net metering provides a simple and easily understood means of valuing the energy exports from rooftop solar and compensating the participating customers who have invested private funds in an electricity system asset. Under net metering, a participating customer has the right to a one-to-one offset for the

[1] A.A.C. R14-2-1801(M).

excess energy produced by their rooftop solar system.[2] Both the customer's energy purchases from the utility and the excess energy they send to the grid are valued at the full retail rate per kilowatt-hour ("kWh"). This system has been adopted in most states around the country, and while this process involves an inherent approximation of the value of exports, the approximation is logical and easily understood by customers.

Q. Under net metering, where does the excess energy exported to the utility system go?

Exported energy will flow from the DG system to the nearest load.[3] The nearby customer will pay the utility the full retail rate for the energy they consume from their neighbor's DG system. Thus, the utility is both crediting the participating customer for the energy at the retail rate and receiving payment for that energy from the other customer at the retail rate.

Q. Does net metering require utilities to "bank" the participating customers' excess energy?

No. Utilities often refer to the need to "bank" excess energy on the system, but such a characterization is misleading. The utility is not required to take any active role in physically "banking" kWh, and only a minimal portion of the utility distribution system is used to carry DG exports. Rather, the entire transaction typically takes place on a single circuit and the utility only sees the transaction as a reduction in load on the circuit.

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[2] *Id.*

[3] R. Thomas Beach & Patrick G. McGuire, *Evaluating the Benefits and Costs of Net Energy Metering in California*, Crossborder Energy, 9 (Jan. 2013), http://votesolar.org/wp-content/uploads/2013/01/Crossborder-Energy-CA-Net-Metering-Cost-Benefit-Jan-2013-final.pdf.

Q. What is a DG value analysis and why is it important?

A. When private citizens make investments in energy infrastructure that serves their own needs and the needs of nearby customers, those investments result in a number of benefits and costs. A DG value analysis attempts to quantify those benefits and costs, and can be used to evaluate the appropriate rate treatment for DG on a utility's system. A proper assessment of the value of DG on the system must include the full range of long-term benefits and costs that result from the private customer's investment. DG value analyses are inherently system specific and may furnish different results for different utilities. If a robust and reliable DG analysis is completed, it can provide a useful tool for decision makers to evaluate the appropriateness of different rate treatments for DG. A robust and reliable DG analysis can assist decision makers in evaluating whether the current NEM structure, including compensation for NEM exports at the retail rate, provides a reasonable approximation of the value of DG to non-participating ratepayers.

The remainder of this testimony will address the appropriate methodology for undertaking a complete and robust DG value analysis that can be used to inform future DG policy.

3.1 Only DG exports are germane to the value discussion

Q. Should the DG value analysis extend to the value of the DG that is consumed onsite by the participating customer?

A. No. The methodology defined by this proceeding should seek to answer one fundamental question: whether the price paid for DG exports appropriately reflects the value of the energy provided. While there are certainly benefits and costs associated with self-consumption of DG, these benefits and costs accrue to the participating customer and should not be considered in an assessment of the value of DG to non-participating ratepayers. Every customer has the individual right to choose how much energy to consume or not consume from the utility, regardless of whether they modify their consumption through DG, conservation, or by buying an electric car or installing a bigger AC unit.

The right to consume self-generated electricity is reflected in the Public Utility Regulatory Policy Act ("PURPA") and other laws and regulations. Customers should not be discriminated against for the technological choices they make regarding their personal energy consumption. The only thing that differentiates customers who install DG from customers who employ other forms of technology that change consumption patterns is the fact that DG systems can export energy to the grid, which will be consumed by neighboring customers. As discussed above, current Arizona law dictates that when exports are fed to the grid, the utility must compensate the participating customer for that energy at the full retail rate.

To the extent that a reduction in consumption from DG may affect fixed cost recovery by the utility, that issue is best addressed through a general rate case. In a rate case, any reduction in consumption due to DG can be considered on equal footing with other drivers of reduced consumption, such as energy efficiency, economic recession, seasonal or vacant homes, etc.

Q. Does the Commission evaluate the value of reductions in consumption from other programs, such as Demand Side Management ("DSM") programs?

A. Yes, the Commission does employ cost-effectiveness tests to examine the value of reductions in consumption from DSM programs. However, the purpose of that review is to evaluate the benefits and costs of incentives offered for DSM reductions. The DSM program is thus distinct from DG, as state incentives for DG have been phased out. The question of behind-the-meter consumption of self-generated electricity should be recognized as a personal choice available to Arizonans. The discussion should thus be limited to valuation of exports to answer the fundamental question at hand, which is whether the price paid for DG exports appropriately reflects the value of the energy provided.

3.2 The relationship between this proceeding and cost-of-service ratemaking

Q. How does an assessment of the value of DG exports relate to cost-of-service ratemaking?

A. Cost-of-service ratemaking is used for setting rates in each utility's general rate case. This approach is based on a test year, which is essentially a one-year snapshot of utility costs. Cost-of-service ratemaking focuses on current utility costs and does not account for the long-term benefits of resource supply options, like DG exports. The appropriate rate treatment for DG has caused significant controversy in Arizona in recent years, due in part to the difficulties in properly assessing the value of DG in a cost-of-service ratemaking proceeding. Utilities have claimed that DG causes a cost shift on non-participating customers. However, these claims often fail to account for the full range of benefits DG provides. Instead, the utilities' claims are largely based on results from utility cost-of-service studies, which are ill-suited to value such long-term benefits and assets.

Q. How should the valuation of DG exports be approached?

A. When discussing the appropriate means for valuation of DG exports, it is helpful to consider how other supply resources are evaluated. Utilities evaluate various supply resources through the Integrated Resource Plan ("IRP") process. This process includes an examination of utility needs and the long-term costs and benefits of various supply options. It is common practice to build or acquire power plants in the near-term, paying a large amount of fixed costs upfront. Utilities – or, more accurately, the utility's ratepayers – pay these large upfront fixed costs with the expectation that in the future, there will be a benefit from this investment.

This practice is exemplified by the 2015 acquisition of natural gas combined cycle capacity from the Gila River Power Station by Tucson Electric Power Company

("TEP") and UNS Electric, Inc. ("UNSE"). TEP's IRP explains that the utilities acquired Gila River to add capacity that would otherwise be lost by 2018 due to coal capacity reductions.[4] UNSE's most recent general rate case application describes the long-term benefits of the Gila River acquisition as a rationale for Commission approval of rate recovery. UNSE states:

> Ownership of Gila River provides numerous benefits to UNS Electric's customers, the most significant being long-term rate stability through the use of a highly efficient, combined cycle natural gas plant. [...] ownership of Gila River reduces the Company's reliance on the wholesale power markets, thus reducing risk to UNS Electric's customers by minimizing unpredictable swings in wholesale market costs.[5]

Resources, like Gila River, are selected through the IRP process based on long-term costs and benefits, rather than needs specific to the test period. Similarly, value of DG exports must take into account the costs and benefits over the resource's useful life, not a single-year snapshot.

Q. Does a cost-of-service study provide the costs of DG that should be evaluated in an analysis of the value of DG exports?

A. No. That is an important distinction to make. Cost-of-service studies are short-term, single-year snapshots of utility costs and are used to develop revenue allocation and rate design. The costs referred to in the context of valuation of DG exports are the long-term costs that result from additional DG deployment. These costs are described in further detail below, but most of these costs are related to the price non-participating ratepayers pay for exported DG over the useful life of the asset.

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[4] TEP IRP at 15, 2013-2014 Resource Planning and Procurement, No. E-00000V-13-0070 (Ariz. Corp. Comm'n Apr. 1, 2014), Barcode No. 0000152206.
[5] UNSE Application at 6:26-7:10, UNSE General Rate Case, No. E-04204A-15-0142 (Ariz. Corp. Comm'n May 5, 2015), Barcode No. 0000161983.

3.3 Potential outcomes and implications of this proceeding

Q. If rates are set through cost-of-service ratemaking, how could decision makers use the results of the analysis guided by this proceeding?

A. If this proceeding results in the development of a robust, standardized methodology for analysis of the value of DG exports, it would make significant progress in easing the tension that has developed over solar rate design in Arizona. This tension has built up in part because cost-of-service ratemaking, by design, does not capture the long-term benefits of a resource like DG. Results from a robust valuation of DG exports will be able to tell the Commission whether the long-term impacts of the NEM policy result in net benefits or net costs, and thus whether DG exports are properly valued under net metering. If the long-term analysis of DG results in net benefits, the Commission should continue to run net metering programs at the full retail rate. Conversely, if a robust valuation of DG exports shows that net value of DG is a net cost, then the Commission can consider whether it would be appropriate to modify the NEM rules and develop an alternative export rate.

Absent a robust and reliable value of solar analysis, the utilities will continue to ask for rate modifications based on the short-term cost-of-service cost shift argument. If the Commission approves this short-term view without considering the long-term benefits, the result will be more expensive for all ratepayers and for society.

Q. Why would it be more expensive for ratepayers and society to consider only the short-term picture captured by a cost-of-service study?

A. If DG provides net benefits but the Commission approves rates based on cost-of-service ratemaking, the Commission may leave those benefits on the table based on an unreasonably narrow view of DG's costs and benefits. DG provides significant benefits, including offsetting the need for additional generation, transmission, and distribution infrastructure. DG also provides a number of environmental and economic development benefits that should not be ignored simply because they do not fit the historical mold of cost-of-service ratemaking.

The fundamental operation of the distribution grid is changing with the increasing availability of new technologies like DG, energy storage, demand response, and electric vehicles. If utilities continue to ignore the fact that DG and other DERs have the real potential to offset the need for additional generation, transmission, and distribution infrastructure, the result will be less efficient and more costly for all ratepayers. In a recent report from the Lawrence Berkeley National Laboratory ("LBNL"), economists found that "DERs will not only improve customers' energy costs, resilience and power quality, they can help utilities avoid risky capital expenditures and operate their systems more efficiently. By facilitating DERs, utilities can both lower their costs and increase the benefits they can offer customers who deploy DERs . . . ."[6]

DG is only the first of many DERs to force utilities to confront these issues. The transition to the modern grid is already happening and will continue to accelerate as prices for photovoltaic generators, distributed energy storage, electric vehicles, and other technologies continue to decrease. As we look to greater deployment of increasingly complex technologies, the task at hand in this proceeding becomes even more important. Now is the time to standardize the way of valuing DG and to support future valuation of other DERs. Vote Solar commends the Commission for taking up this important issue in this docket.

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[6] *See* Steve Corneli and Steve Kihm, *Electric Industry Structure and Regulatory Responses in a High Distributed Energy Resources Future*, Lawrence Berkeley Nat'l Lab., 1 (Nov. 2015), https://emp.lbl.gov/sites/all/files/lbnl-1003823.pdf.

4 History of Solar Cost-Benefit Analysis in Arizona

Q. Have distributed solar cost-benefit analyses been completed for any regulated Arizona utilities in the past?

A. Yes. A series of cost-benefit analyses have addressed the value of distributed solar energy on the Arizona Public Service Company ("APS") system. To my knowledge, no public studies have examined the value of distributed solar energy on the TEP or UNSE systems.

Q. What were the results of the APS analyses?

A. The results were extremely mixed. The first analysis was commissioned by APS and completed in 2009 by consultant R.W. Beck.[7] In 2013, APS commissioned an update to the 2009 study which was completed by SAIC, the company that had acquired R.W. Beck.[8] Also in 2013, Crossborder Energy completed an alternative cost-benefit analysis commissioned by the solar industry.[9] Each of these studies developed significantly different results, which are summarized in Table 1 below.

[7] R.W. Beck, *Distributed Renewable Energy Operating Impacts and Valuation Study*, R.W. Beck (Jan. 2009), http://files.meetup.com/1073632/RW-Beck-Report.pdf (R.W. Beck Report).
[8] SAIC, *2013 Updated Solar PV Value Report*. SAIC (May 10, 2013), https://www.azenergyfuture.com/getmedia/77708c68-7ca6-45c1-a46f-84382531bae3/2013_updated_solar_pv_value_report.pdf/?ext=.pdf ("SAIC Report").
[9] R. Thomas Beach & Patrick G. McGuire, *The Benefits and Costs of Solar Distributed Generation for Arizona Public Service*, Crossborder Energy (May 8, 2013), https://www.seia.org/sites/default/files/resources/AZ-Distributed-Generation.pdf.

Table 1: Results of Existing APS DG Solar Valuation Studies

Study Author and Year	Present Value of Distributed Solar (¢/kWh)
RW Beck, 2009	7.91 to 14.11
SAIC, 2013	3.56
Crossborder Energy, 2013	21.5 to 23.7

As Table 1 shows, the results from the three studies of APS's territory are very different. The first APS-commissioned study found that distributed solar had a value of roughly 8-14¢/kWh. Three years later, APS commissioned an update to that study, which found that values were less than half of the lower range of the original estimate. Meanwhile, a solar industry-sponsored study that relied on much of the same data as the APS update found values to be roughly double the original 2009 estimate. Such a large variation in results can be problematic for policy makers to use as a basis for decision-making.

The experience with distributed solar valuation analyses in APS territory illustrates the need for Commission guidance regarding the appropriate methodology for developing a comprehensive assessment of the full range of costs and benefits from distributed solar generation.

Q. Have any other states commissioned their own value of distributed solar analyses?

A. Yes. A number of notable studies have been sponsored by independent state entities. Each of these studies concluded that the benefits distributed solar generation provides to the utility exceed the costs. Table 2 below summarizes the results of recent studies performed by or for state governments.

Table 2: Recent Distributed Solar Valuation Studies

State	Date	Sponsor	Resulting Value
ME	Mar-2015	Legislature	33.7¢/kWh levelized[10]
VT	Nov-2014	Legislature	23.7¢/kWh levelized[11]
MS	Sep-2014	PSC	17.0¢/kWh levelized[12]
NV	Jul-2014	PUC	18.5¢/kWh levelized[13]
MN	Jan-2014	Dep't of Commerce	14.5¢/kWh levelized[14]

As the studies in Table 2 demonstrate, state-sponsored studies have found that the benefits of solar can be as high as 25-30¢/kWh in some jurisdictions. While each of these studies employed different variations in methodology, the results of these studies indicate that a good faith undertaking to capture the full range of benefits of distributed solar generation may result in a valuation of solar above the retail rate.

[10] Clean Power Research, LLC, *Maine Distributed Solar Valuation Study*, Me. Pub. Util. Comm'n, 6 (Mar. 1, 2015), http://www.ripuc.org/eventsactions/docket/4568-WED-Ex6-MaineSolarReport(11-23-15).pdf.

[11] Pub. Serv. Dep't, *Evaluation of Net Metering in Vermont Conducted Pursuant to Act 99 of 2014*, 17 (Nov. 7, 2014), http://psb.vermont.gov/sites/psb/files/Act%2099%20NM%20Study%20Revised%20v1.pdf.

[12] Elizabeth A. Stanton, et al., *Net Metering in Mississippi: Costs, Benefits, and Policy Considerations*, Synapse Energy Econ., Inc., 43 (Sep. 19, 2014), http://www.synapse-energy.com/sites/default/files/Net%20Metering%20in%20Mississippi.pdf.

[13] Energy and Envtl. Econ., *Nevada Net Energy Metering Impacts Evaluation*, Energy and Envtl. Econ., 93 (July 2014), http://puc.nv.gov/uploadedFiles/pucnvgov/Content/About/Media_Outreach/Announcements/Announcements/E3%20PUCN%20NEM%20Report%202014.pdf?pdf=Net-Metering-Study ("E3 Report").

[14] Peter Fairly, *Minnesota Finds Net Metering Undervalues Rooftop Solar*, IEEE Spectrum (Mar. 24, 2014), http://spectrum.ieee.org/energywise/green-tech/solar/minnesota-finds-net-metering-undervalues-rooftop-solar.

5 General Methodological Approach to Valuation of DG Exports

Q. Are there any independent reports that the Commission should look to for guidance regarding the appropriate methodology for valuing distributed generation?

A. Yes. The Interstate Renewable Energy Council ("IREC") has developed a useful guidebook on calculating the costs and benefits of distributed solar generation that can inform the Commission's process. This guidebook is attached as Exhibit BK-2. The guidebook builds on experiences throughout the country to propose a standardized and reliable approach to the analysis. Many of my recommendations in this testimony are informed by the IREC guidebook, and I recommend that the Commission adopt the guidebook's approach in Arizona.

Q. Do you have any recommendations regarding the general methodological approach for valuation of DG exports?

A. Yes. A number of factors are important to consider regarding the general methodological approach for valuing DG exports. These include the following recommendations, which are each addressed below:

- Use an appropriate cost-effectiveness test;
- Analyze all distributed solar generation, both residential and commercial/industrial;
- Require utilities to provide sufficient and reliable data;
- Use an appropriate timeframe that analyzes value over the life of a DG system;
- Use an appropriate discount rate;
- Use a realistic near-term forecast of DG penetration;
- Analyze capacity benefits on a continuous basis.

5.1 Use an appropriate cost-effectiveness test

Q. Do you have any recommendations regarding the cost-effectiveness test to be used in the analysis?

A. Yes. A fundamental component of the analysis is from whose perspective the costs and benefits of DG should be measured. As discussed above, the analysis should ultimately seek to answer the question of whether the price paid for DG exports appropriately reflects the value of the energy provided. To this end, it is most reasonable to examine whether non-participating customers are paying a fair price for DG exports, based on the value of DG to the non-participating ratepayer, including impact on utility rates and incorporation of environmental, economic development, and grid reliability benefits. If the Commission instead decides to evaluate DG consumed onsite in addition to DG exports, I recommend that the Commission evaluate DG from a societal impact perspective.

California has developed a "Standard Practice Manual" for examining the cost-effectiveness of demand-side programs; this manual is widely used across the country as a framework for discussing specific valuation approaches.[15] While the cost-effectiveness measure I advocate for in evaluating the value of DG exports is not directly defined in the Standard Practice Manual, it could be considered a modified version of the Ratepayer Impact Measure ("RIM") test, plus adders from the Societal Cost Test ("societal adders"). The RIM test would capture the impact of DG exports on utility rates and the societal adders would allow for necessary incorporation of other benefits.

[15] Cal. Pub. Util. Comm'n, *California Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects*, Cal. Pub. Util. Comm'n (Oct. 2001), http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=7741 ("SPM").

The RIM test is defined in the Standard Practice Manual as follows:

> The Ratepayer Impact Measure (RIM) test measures what happens to customer bills or rates due to changes in utility revenues and operating costs caused by the program. Rates will go down if the change in revenues from the program is greater than the change in utility costs. Conversely, rates or bills will go up if revenues collected after program implementation are less than the total costs incurred by the utility in implementing the program. This test indicates the direction and magnitude of the expected change in customer bills or rate levels.[16]

In Commissioner Little's letter to the parties in this docket, he asked questions about whether or not the cost of photovoltaic ("PV") panels should be considered in the analysis.[17] Examining the value of DG exports from the perspective of non-participating ratepayers excludes the cost of PV panels from the equation. The question is whether the price paid by non-participating customers is fair, given the value they receive from DG systems' exported energy. The goal of this process is to develop a framework to ensure that an appropriate price signal is sent to customers to help them decide whether or not to install DG. The price of PV panels will likely weigh heavily into that equation, but the economics for the customer who installs solar do not impact the value of the exports to his/her neighbors.

Q. What are the societal adders that you recommend be included in the analysis?

A. The RIM test defined in the Standard Practice Manual takes a very narrow look at the impact a program will have on utility rates. This approach does not include a number of other very real benefits that will accrue to non-participating ratepayers and to society in general. These benefits include environmental impacts, improved electric reliability, improved system operations, and economic development benefits. I recommend that the Commission consider these benefits, in addition to the standard RIM test categories, when valuing the costs and benefits of DG exports.

[16] *Id.* at 13.

[17] Commissioner Little's Letter to the Parties at Question Nos. 2 and 3, Dec. 22, 2015.

Q. Has the Commission ever taken these types of societal adders into account when evaluating the cost-effectiveness of its programs?

A. Yes. Commission rules regarding cost-effectiveness testing for DSM programs require that the societal test be used to determine cost-effectiveness.[18] Moreover, the rules specifically address the inclusion of environmental impacts, improved electric reliability, and improved system operations.[19]

Q. If Commission rules require use of the Societal Cost Test for DSM programs, should the Societal Cost Test be used for DG exports?

A. As I have discussed above, the cost-effectiveness evaluation for DSM is used to inform the level of incentives for programs that result in reductions in customer consumption. I recommend that the methodology developed in this docket be limited to an analysis of the value of DG exports, which is different than DSM, because it excludes the energy consumed onsite by the customer who has installed a DG system. Valuation of the DG exports should only be examined from the perspective of the non-participating ratepayer, including impact on utility rates and incorporation of environmental, economic development, and grid reliability benefits.

Q. Does your recommendation for the cost-effectiveness test change if the Commission decides to examine the costs and benefits of both the DG that is consumed onsite and the DG that is exported to the grid?

A. Yes. While I strongly recommend that the Commission develop a methodology to value only DG exports, if the Commission decides to additionally value the DG that is consumed onsite, the modified RIM test with societal adders would no longer be the appropriate cost-effectiveness test for the analysis. If the Commission elects to examine the value of onsite DG consumption, the most appropriate cost-effectiveness test would be the Societal Cost Test consistent with

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[18] A.A.C. R14-2-2412(B).
[19] *Id.* at (C).

the Commission's approach for valuation of DSM programs. This test would take into account the benefits that accrue to the participating customers, in addition to the benefits that accrue to non-participating ratepayers.

5.2 Analyze all distributed solar generation, both residential and commercial/industrial

Q. Do you have any recommendations regarding the type of DG that should be considered in the analysis?

A. Yes. In order to capture the full range of costs and benefits of DG, it is crucial that the analysis be comprehensive and not limited to DG within a specific customer class. In other words, attempts to limit the analysis to an examination of the costs and benefits of residential DG ignores the costs and benefits of commercial and industrial DG. This is because residential customers have a much larger portion of their costs recovered through the volumetric portion of their rate, and thus receive a higher per kWh credit for their DG exports. Commercial and industrial customers generally have demand charges in their rates that reduce the volumetric rate, dampening the price signal for energy from the DG system. The result is that the net benefits per kWh of DG may be smaller for residential customers than for commercial and industrial customers, where the benefits more clearly outweigh the costs.

Commission policy addresses both residential and commercial/industrial DG, and therefore it is prudent that both be considered in this docket. Arizona's RES rules call for specified levels of DG from both residential and commercial sectors.[20] In order to gain a full understanding of the value of DG exports, all rate classes must be considered.

[20] A.A.C. R14-2-1805(D).

5.3 Require utilities to provide sufficient and reliable data

Q. Do you have any recommendations regarding data from the utilities for the valuation of distributed solar generation?

A. Yes. Many aspects of this analysis require data that can only be supplied by the utilities. In order to complete a reliable and comprehensive analysis, the utilities must provide stakeholders with access to that data for review. The necessary data include customer usage and distributed solar generation data from the utilities' existing NEM and non-NEM customers, a reliable and transparent forecast of future utility rates, hosting capacity analyses, and inputs required for a detailed marginal cost study valuing transmission and distribution capacity.

This issue is of the utmost importance for ensuring that the valuation can provide a credible basis for decision-making. To the extent that the utilities may seek to modify existing NEM structures, they have the burden of proof regarding new or additional charges.[21] In its current rate case, UNSE has proposed wide-sweeping changes to net metering rates, but has not provided intervenors with actual data on the consumption patterns of customers on their system with distributed solar.[22] This lack of cooperation and critical data makes a reliable assessment difficult. The Commission should require the utilities to produce needed data as a precursor to asking for reform of existing rate structures.

5.4 Use an appropriate timeframe that analyzes costs and benefits over the useful life of a DG system

Q. Do you have any recommendations regarding the time scale of the analysis?

A. Yes. I support Commissioner Little's guidance indicating that the analysis should examine the levelized costs and benefits of DG over the economic life of the

[21] A.A.C. R14-2-2305.

[22] *See* Direct Test. and Exs. of Briana Kobor at 47-50, UNSE General Rate Case, No. E-04204A-15-0142 (Ariz. Corp. Comm'n Dec. 9, 2015).

system.[23] This is generally considered to be twenty to thirty years. This approach is inherently distinct from cost-of-service ratemaking, which looks at a single test year and is consistent with the methodologies used for evaluating other generation technologies.

5.5 Use an appropriate discount rate

Q. Do you have any recommendations regarding the discount rate to be used in the analysis?

A. Yes. The chosen discount rate is a crucial assumption in a levelized cost analysis. The discount rate is used to quantify the time value of money by looking at how the value of costs and benefits change over the time period of the analysis, which in this case should be twenty to thirty years. Utilities generally advocate using a discount rate related to their weighted average cost of capital ("WACC") for all costs and benefits included in the value-of-solar analysis. Utility WACC, which is generally in the range of 6-9%, may undervalue future benefits and costs of distributed solar generation from the perspective of non-NEM ratepayers. To the extent that the costs and benefits are being examined from the perspective of non-participating ratepayers, the discount rate employed should be reflective of the time value of money for these ratepayers. For this purpose, it is reasonable to use a societal discount rate similar to inflation, rather than the utility WACC. While I recommend that the Commission apply a societal discount rate to all the categories of benefits and costs, at a minimum the societal discount rate should be applied to the categories that are separate from utility costs, including environmental benefits, economic development benefits, and grid security.

[23] Little Letter at 2.

5.6 Use a realistic near-term forecast of DG penetration

Q. Do you have any recommendations regarding the level of DG penetration to be considered in the analysis?

A. Yes. The amount of DG on a utility's system can significantly impact the costs and benefits of DG, and the cost/benefit equation can therefore change as DG penetration levels increase. The valuation of DG exports will be most relevant if it examines current and/or near-term expected penetration levels on the utility's system. The Commission can additionally consider requiring that the valuation of DG exports be revisited when DG penetration reaches a certain point.

While the utilities have claimed that DG causes significant grid impacts, the impacts are likely minimal at current penetration levels.[24] While Arizona is a leading solar state, DG still accounts for only a small proportion of total energy supplied by the utilities. While it can be informative to examine the value of DG exports at higher levels of penetration, the economics of DG at high penetration levels does not impact the economics of DG at current and near-term levels, and therefore should not influence current policy. For purposes of this analysis, I recommend DG exports be evaluated at penetration levels expected to occur in the next one to three years and that valuation be revisited periodically as the market grows.

[24] *See* Direct Testimony and Exhibits of Curt Volkmann on behalf of Vote Solar at 8:24-9:15, Feb. 25, 2016 (discussing integration costs).

5.7 Analyze capacity benefits on a continuous basis

Q. Do you have any recommendations regarding the general approach to valuing the capacity benefits of DG exports?

A. Yes. Valuing the capacity benefits of DG requires an analysis of avoided generation, transmission, and distribution capacity. These capacity benefits should be evaluated on a continuous basis. Like the tension between using a single-year snapshot for rate setting based on cost-of-service and the need to consider long-term benefits of DG, the unique benefits associated with the modularity of DG additions do not fit the mold of traditional utility resource planning. Utility planning models typically forecast capacity that will be needed to meet increasing demand in large, "lumpy" increments, but the modularity and scalability of DG has the potential to offset or delay the need for forecasted capacity additions. Moreover, FERC regulations recognize that DG may impact future capacity needs by leading to smaller needed increments and shorter lead times.[25]

It is vital that the Commission recognize that the appropriate means for valuing avoided capacity costs related to DG exports is on a continuous basis that recognizes the modularity of DG additions and does not simply try to fit DG into the traditional planning model that cannot, by design, properly account for its benefits.

6 Recommended Approach to Valuation of DG

Q. How have you organized your testimony regarding your recommended approach to valuation of DG?

A. I describe below my recommendations for valuation of DG based on the seven core cost categories identified by Commissioner Little in his letter dated December 22, 2015. In addition to these seven categories, I also discuss

[25] 18 C.F.R. 292.304(e)(2)(vii) (2015).

recommendations for including DG benefits related to grid security. The categories to be covered in this section are listed below:

1. Utility Distributed Solar Costs;
2. Energy Generation Savings;
3. Generation Capacity Savings;
4. Transmission Capacity Savings;
5. Distribution Capacity Savings;
6. Environmental Benefits;
7. Economic Development Benefits; and
8. Grid Security Benefits

The appropriate methodology for valuing integration costs (a subset of utility distributed solar costs), transmission capacity savings, distribution capacity savings, water usage impacts (a subset of environmental benefits), and grid security benefits is covered in detail in the direct testimony of Curt Volkmann, filed in this docket on behalf of Vote Solar. In the sections below, I refer to Mr. Volkmann's testimony on these topics.

6.1 Utility distributed solar costs

Q. Please describe the utility distributed solar costs that result from DG exports.

A. There are two categories of utility costs resulting from DG exports that should be included in the DG value analysis: (1) cost to provide participating ratepayers with credits for exported generation, and (2) net integration costs.

The cost incurred to provide participating ratepayers with credits for exported generation is by far the largest cost to be assessed. Under the NEM program, participating ratepayers are credited for the kWh they export to the grid on a one-to-one basis with the kWh they take from the grid. This means that exports are valued at the full volumetric retail rate.

Q. What methodology do you recommend for valuation of utility distributed solar costs?

A. In order to quantify the levelized costs per kWh of DG export credits, the analysis must include a forecast of utility rates over the twenty- to thirty-year timeframe of the analysis. This is an instance where it will be necessary for utilities to provide reliable and transparent data from their own systems. Utilities should provide data on the current price paid to customers for their DG exports by customer class, in addition to the utility's forecast of how those prices are expected to change over the timeframe of the analysis. Interested parties should assess the reasonableness of the utility's assumed rate escalations prior to inclusion in the DG valuation.

It should be noted that the cost for DG is a direct function of the volumetric portion of the retail rate by customer class. To the extent that significant changes in rate design are expected—such as movement toward time-varying rates or rates that include a demand charge—it would be critical to consider the impacts those changes may have on the price paid for DG exports. In the event of uncertainty over future rate design, a scenario analysis that addresses various potential rate design structures may help the Commission determine the impact of rate design changes on the value and cost of DG exports.

Integration costs and benefits are discussed in detail in the testimony of Mr. Volkmann. Mr. Volkmann recommends that hosting capacity analyses specific to each utility system be developed to assess the locational-specific costs of DG additions. I support Mr. Volkmann's recommendation.

6.2 Energy generation savings

Q. Please describe the energy generation savings that result from DG exports.

A. When participating customers install DG capacity that exports energy to nearby customers, the exported energy replaces energy that would have been generated by central station power plants and delivered over the utility's transmission and distribution system to the end-use customer. Each kWh of DG exports offsets the need for a kWh of energy generated at the marginal generation plant. The cost that would have been incurred to produce the offset kWh of energy can be considered energy generation savings.

Q. What methodology do you recommend for valuation of energy generation savings?

A. Energy generation savings should be valued by estimating the cost to produce the energy that would be offset by additional DG exports. The type of resource that will be offset by additional DG exports will depend on the individual utility and the timing and seasonality of DG exports. As a result, it will be necessary for the utilities to supply data on the current export profile of their NEM customers, which can be used to develop assumptions about the marginal generator that would serve various portions of the load expected to be served by additional DG exports.

Once the type of marginal generator or generators is identified, it will be necessary to determine the avoided cost of energy from these plants. Avoided cost of energy from a natural gas-fired plant is a function of three key inputs: (1) natural gas price, (2) heat rate, and (3) variable costs of operations and maintenance ("O&M").

While there is considerable uncertainty regarding the price of natural gas over the next twenty to thirty years, it is reasonable to develop a projection of future prices based on available information from the commodity futures trading market. I recommend that a natural gas price forecast be developed by examining available NYMEX futures trading data and extrapolating longer-term values based on publicly available forecasts, such as the twenty-five-year forecast developed by the Energy Information Administration ("EIA").[26] Market center prices would need to be converted to local burnertip prices by using futures data on basis swaps

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[26] EIA, *Annual Energy Outlook 2015* (Apr. 2015), http://www.eia.gov/forecasts/aeo/.

prices, as well as estimated costs to bring the gas to generators over the local gas transportation system. Developing a forecast of long-term natural gas prices is an exercise that brings significant uncertainty to the analysis. As a result, it would be reasonable to include sensitivity analyses based on higher- and lower-than projected natural gas prices to assess how this uncertainty may impact the overall DG value analysis.

The heat rate assumption is specific to the type of plant and should reflect expected average heat rate, including accounting for long-term heat rate degradation that may occur over the period of the analysis. In addition, a reliable estimate of variable O&M must be developed and forecasted over the period of the analysis.

Because DG exports offset the need for energy at or near customer load, the calculation of energy generation savings must also include avoided line losses associated with delivering electricity from a central station generator to customer load. Line losses vary by utility and are typically about 7%, though they may be higher during periods of congestion.[27] Because line losses may vary by season and time of day, it is important that marginal line losses expected during the periods of DG exports be used to estimate the avoided line losses from DG. Because DG exports are expected to occur during heavier loading periods, estimating avoided line losses using average line loss figures would likely undervalue the benefit from DG exports. Avoided line losses must also be accounted for in the calculation of generation, transmission, and distribution capacity savings.

6.3 Generation capacity savings

Q. Please describe the generation capacity savings that result from DG exports.

A. The utility must build sufficient generation capacity to meet system peak demand, which in Arizona typically occurs in the late afternoon during the summer

[27] Ex. BK-2 at 23 of 46.

months. Because system peak demand occurs at a time when solar power is generating, energy from solar DG systems will contribute to meeting system peak. While individual DG systems may not be able to provide dependable peak capacity due to the potential for passing clouds to temporarily reduce generation, geographically diverse groups of DG systems can reliably contribute to peak capacity. This fact is widely recognized by the utilities in their IRPs, which include estimates of the levels of DG that can be expected to contribute to system peak. For example, the 2020 peak capacity assumptions from DG for APS, TEP, and UNSE are summarized in Table 3 below.

Table 3: Forecasted DG Peak Capacity Contribution, 2020[28]

Utility	Peak Capacity Contribution
APS	119 MW
TEP	41 MW
UNSE	8 MW

Because DG can reliably contribute to system peak, it can reduce or delay the need for additional capacity on the system. Delaying and/or offsetting the need for additional generation capacity will result in savings that can be attributed to DG.

Q. What methodology do you recommend for valuation of generation capacity savings?

A. As described above, evaluation of DG capacity savings from generation, transmission, and distribution must take into account the modularity of DG additions. Moreover, it must evaluate savings on a continuous basis, not based on large tranches of "lumpy" additions, as done in the R.W. Beck and SAIC reports for APS's system.

An appropriate analysis would examine the marginal benefit of additional DG capacity to delay or offset the need for future generation capacity additions. In

[28] APS IRP at 300, 2013-2014 Resource Planning and Procurement, No. E-00000V-13-0070 (Ariz. Corp. Comm'n Apr. 1, 2014), Barcode No. 0000152210; TEP IRP at 28; UNSE IRP at 20.

order to quantify this benefit, assumptions must be made regarding the generation capacity additions that would be needed but for the additional DG export capacity. Capacity cost from a new generator can be estimated by developing assumptions for capital costs, fixed O&M, and gen-tie transmission costs to develop an estimate of the $/kW of installed capacity.

Once the cost of new installed capacity is developed, the analyst must determine the level of DG export capacity that is expected to contribute to the system peak. Such a calculation may be completed using an assessment of the effective load-carrying capacity ("ELCC"). ELCC is a statistical measure of capacity that can be relied on by the utility to meet load that accounts for the intermittency associated with solar DG. The ELCC measures the load increase that the system would be able to carry while maintaining the designated reliability criteria.[29] ELCC can vary by technology. For example, single-axis tracking PV has a higher estimated ELCC than fixed-array PV. In developing the assumptions for ELCC of DG exports, it will be necessary to evaluate the expected technology of future DG additions.

With these assumptions in place, calculating the generation capacity savings of DG is a relatively simple undertaking. As discussed above, under energy generation savings, marginal avoided line losses associated with DG capacity located at or near load must be accounted for by applying an adder to the expected cost of new generation capacity. In addition, utilities are required to maintain certain levels of capacity reserve margins (e.g., 15% above peak load) to ensure reliability in the event of extreme load circumstances or unexpected outages of transmission or generation infrastructure. Dependable DG capacity will reduce the need for additional capacity to meet the reliability criteria. This reduction in needed reserves should be accounted for by developing an adder to be multiplied by the cost of new generation capacity. The resulting value is then multiplied by the ELCC to determine the generation capacity savings attributable to DG.

[29] Ex. BK-2 at 24-25 of 46.

6.4 Transmission capacity savings

Q. What do you recommend regarding assessment of transmission capacity savings?

A. Assessment of transmission capacity savings associated with DG is discussed in detail in the testimony of Mr. Volkmann. Mr. Volkmann recommends that the Commission adopt a detailed marginal cost-of-service methodology that would allow for quantification of the transmission capacity deferral benefits associated with DG. This methodology would recognize the unique benefits associated with the modularity and scalability of DG and would not be constrained by assessment of only large, "lumpy" capital projects. I support Mr. Volkmann's recommendation.

6.5 Distribution capacity savings

Q. What do you recommend regarding assessment of distribution capacity savings?

A. Assessment of distribution capacity savings associated with DG is discussed in detail in the testimony of Mr. Volkmann. Like his recommendation for evaluating transmission capacity savings, Mr. Volkmann recommends that the Commission adopt a detailed marginal cost-of-service methodology that would allow for quantification of the distribution capacity deferral benefits associated with DG. This methodology would recognize the unique benefits associated with the modularity and scalability of DG and would not be constrained by assessment of only large, "lumpy" capital projects. I support Mr. Volkmann's recommendation.

6.6 Environmental benefits

Q. Please describe the environmental benefits that result from DG exports.

A. Unlike the conventional generation that it is expected to offset, solar DG provides clean, carbon-free renewable energy. Solar DG also uses minimal amounts of water when compared to conventional generation. The categories of environmental benefits that occur as a result of DG exports include avoided utility compliance costs, avoided carbon emissions benefits, benefits related to avoided emissions other than carbon, and benefits related to water conservation. Each category warrants separate consideration and quantification in an analysis of the value of DG exports.

Q. What methodology do you recommend for valuation of avoided utility compliance costs?

A. Valuation of avoided utility compliance costs should account for the reduction in needed renewable procurement attributable to additional DG. Arizona's Renewable Energy Standard ("RES") rules require utilities to procure certain levels of renewable generation: 10% of sales by 2020 and 15% of sales by 2025.[30] Because increases in DG capacity will result in reductions in sales from the utility, DG will reduce the total amount of renewable energy that must be procured to comply with the RES rules. This will produce savings commensurate with average renewable energy cost premiums compared with the cost of conventional energy. The renewable energy cost premium can be evaluated by comparing the levelized cost of energy from conventional and renewable generation.

Q. What methodology do you recommend for valuation of avoided carbon emissions benefits?

A. The value of avoided carbon emissions benefits should be taken into account when examining the environmental benefits of DG. The value of avoided carbon emissions attributable to DG has been widely recognized in past DG valuation studies in Arizona and elsewhere. For example, both APS-sponsored DG valuation reports included a measure of carbon benefits.[31] Moreover, last year EPA finalized regulations limiting carbon emissions from coal- and gas-fired

[30] A.A.C. R14-2-1804(B).
[31] R.W. Beck Report at 6-19; SAIC Report at 1-3.

power plants, which will require carbon reductions from Arizona's power sector. The White House has developed a standard method for evaluating avoided carbon benefits known as the social cost of carbon ("SCC").[32] I recommend that the SCC value related to emissions reductions from additional DG exports be used to estimate avoided carbon emissions benefits.

Q. What methodology do you recommend for valuation of benefits related to avoided emissions other than carbon?

A. DG will also reduce emissions of criteria air pollutants, including sulfur oxides ("SO_x"), nitrogen oxides ("NO_x"), and particulate matter. While the cost of compliance with pollution regulation is likely to be rolled into the estimate of avoided energy costs, regulations still allow some level of pollution that has been widely acknowledged to result in impacts to public health.[33] Additional consideration should be given to the value of avoiding air pollution from a societal perspective. EPA has estimated social costs of major pollutants, and I recommend that these estimates be netted against the level of compliance costs embedded in avoided energy costs in order to assess the total additional environmental benefit of DG from reduced air pollution.[34]

Q. What methodology do you recommend for valuation of benefits related to water conservation?

As Commissioner Burns described in his letter to this docket dated February 8, 2016, strong consideration should be given to the water-energy nexus in the context

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[32] Interagency Working Group on Social Cost of Carbon, *Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis*, U.S. Gov't (May 2013), https://www.whitehouse.gov/sites/default/files/omb/inforeg/scc-tsd-final-july-2015.pdf.
[33] Ex. BK-2 at 34 of 46.
[34] *See* U.S. Envtl. Prot. Agency, *Regulatory Impact Analysis for the Proposed Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants* at Chapter 4: Estimated Climate Benefits and Human Health Co-Benefits, U.S. Gov't (June 2014), http://www3.epa.gov/ttnecas1/regdata/RIAs/111dproposalRIAfinal0602.pdf.

of energy planning decisions in Arizona.[35] A full discussion of the water-energy nexus is provided in Mr. Volkmann's testimony. Mr. Volkmann recommends that the Commission include a value for avoided water consumption in its valuation of the costs and benefits of DG. I support Mr. Volkmann's recommendation.

6.7 Economic development benefits

Q. Please describe the economic development benefits that result from DG exports.

A. Installation of rooftop DG solar systems requires a robust local workforce that includes installers, manufacturers, sales associates, and distribution workers. Increases in jobs provide stimulation to local economies and greater tax revenue to state and local jurisdictions. It has been found that solar PV creates more jobs per megawatt-hour ("MWh") than other energy sources, implying that additional DG capacity is likely to garner economic benefits.[36]

Q. What methodology do you recommend for valuation of economic development benefits?

A. A number of methodologies exist for quantifying the economic impact of additional jobs that would be created with additional DG capacity. Economic input-output analysis that would examine the potential multiplier affect associated with DG-related jobs is one such possible methodology. Other options include quantification of tax enhancement value resulting from increased employment.

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[35] Letter from Commissioner Robert L. Burns at 1, Feb. 8, 2016.

[36] Daniel M. Kammen et al., *Putting Renewables to Work: How Many Jobs Can the Clean Energy Industry Generate?*, Renewable and Appropriate Energy Lab., 2 (Jan. 31, 2006), http://rael.berkeley.edu/old_drupal/sites/default/files/very-old-site/renewables.jobs.2006.pdf.

6.8 Grid security benefits

Q. What do you recommend regarding assessment of grid security benefits?

A. Assessment of grid security benefits associated with DG is discussed in detail in the testimony of Mr. Volkmann. Mr. Volkmann recommends that the Commission explicitly consider the reliability improvement benefits associated with DG in its valuation methodology and provides an example of how those benefits may be quantified. I support Mr. Volkmann's recommendation.

7 Response to Questions Raised by Commissioner Little in His December 22, 2015 Letter

Q. Please address the specific questions raised by Commissioner Little in his December 22, 2015 letter.

A. Answers to each of Commissioner Little's questions are provided below:

1. **How was the value and cost of solar considered in the development of the current net metering tariffs?**

The current net metering tariffs were developed as part of the Commission's RES rules to promote development of renewable DG. In developing the tariffs, it was recognized that retail rate compensation provides a reasonable approximation of the value and cost of DG for purposes of tariff design. In Decision No. 69127 approving the RES rules, the Commission stated:

> [C]ustomers who pay capital costs to install distributed generation, benefit not only themselves, but the system by not contributing to overloading of transmission lines, overheating of distribution lines, wear and stress on substations and transformers, and the need for utilities to procure or generate the most expensive peaking power during peak load times, and utility

customers who do not install distributed generation will therefore receive a benefit from distributed generation.[37]

2. Over the past several years the cost of PV panels has declined significantly. Does the declining cost of panels affect the value proposition? If so, how?

The answer to this question depends on the perspective from which the value proposition is examined. As described in this testimony, I recommend that the question the Commission should seek to answer is whether non-participating ratepayers are paying the right amount for the DG exports they receive. This means that the analysis should be limited to DG exports and should be evaluated from a non-participating ratepayer perspective, including impact on utility rates and incorporation of environmental impacts, improved electric reliability, and economic development benefits. Non-participating ratepayers will be indifferent as to whether the NEM customer next door spent $10,000 or $100,000 on his/her solar installation; what is important to them is whether the price paid for the exports is commensurate with the value received. As a result, the declining cost of PV panels would be irrelevant to the analysis.

3. Is it appropriate to factor the cost of the panels into the reimbursement rate for net metering? If so, how?

No. The cost of panels relative to the rate provided for solar DG exports will factor into the participating customer's decision to install DG, but is irrelevant to the core issue in this proceeding: development of a robust and standardized methodology to inform whether the price paid for DG exports appropriately reflects the value of the energy provided.

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[37] Decision No. 69127 at Appendix B p. 6, Proposed Rulemaking for the Renewable Energy Standard and Tariff Rules, No. RE-00000C-05-0030 (Ariz. Corp. Comm'n, Nov. 14, 2006), Barcode No. 0000063561.

4. **Does the cost and value of DG solar vary based on the specific customer location? Should this variability be reflected in rates?**

There is some variation in the distribution-related value and costs of DG solar depending on location. Please see Mr. Volkmann's testimony for a full discussion.

5. **How does the cost and value of DG solar vary based on the orientation of the panels? How would the installation of single or dual access trackers change the output or efficiency of the DG solar system? Should this variability be reflected in rates?**

There will be some variation in the avoided-energy benefit and avoided-generation, -distribution, and -transmission capacity benefit based on the orientation and technology of the DG solar system. The valuation of DG exports can take this into account by assessing how these benefits may change if differing PV orientation and technologies are deployed in the future. To the extent that westward panel orientation and/or tracking systems may result in a larger net benefit, the Commission could consider adoption of rates that vary based on time of day ("TOU rates") to incent customers to install DG systems to maximize production during the peak period.

6. **How is the value and cost of DG solar affected when coupled with some type of storage? Should deployment of storage technologies be encouraged? If so, how?**

Storage has the potential to impact customer load profiles for customers who employ DG solar. The way in which storage would impact the value and cost of DG solar is highly dependent on rate design. If customers are fairly compensated for the energy from their DG systems, storage may incent them to maximize benefits to the grid. In contrast, if rates are designed such that customers do not receive a fair value for the energy from their DG systems, storage may enable them to minimize grid usage or defect from the grid entirely. Storage has a large potential to enable more efficient usage of the utility grid, bringing huge cost savings to all customers. The Commission should encourage deployment of storage technologies with rate designs that capture the costs and benefits that storage can provide to the grid.

7. How does the value and cost of DG solar compare to the value and cost of community scale and utility scale solar? How do the value and costs of DG solar compare to that of wind or other renewable resources? How does the value and cost of DG solar compare to that of energy efficiency?

There are numerous factors that would need to be taken into consideration to appropriately compare the value and cost of DG solar with community- and utility-scale solar, other renewables, and efficiency. An important first step in any comparison would be to develop a robust methodology for fully valuing each resource. Until such a methodology is used to analyze the value of specific resources, it is difficult to compare the value and cost of these different resources.

8. How does the intermittent nature of DG solar affect its value and costs? Are there technologies that could reduce the intermittency of DG solar? Should those additional costs result in changes to the value and cost of DG solar? Should an "intermittency factor" be applied to more accurately determine cost and value?

Intermittency affects the dependable peak capacity contribution of DG solar. This is accounted for in the estimation of avoided generation capacity costs through an evaluation of the ELCC of DG solar. There is no need for an additional "intermittency factor," as this phenomenon should be fully captured by the ELCC.

Mr. Volkmann's testimony includes additional discussion of intermittency impacts in relation to grid integration.

9. To what degree is DG solar energy production coincident with peak demand? Does the cost and value of DG solar vary depending on whether or not energy production is coincident with peak demand? Are there policies that the Commission could consider that address this issue?

Peak demand typically occurs in the afternoon during the summer, when solar provides energy and capacity. Valuation of avoided energy, generation capacity, distribution capacity, and transmission capacity costs vary based on peak demand coincidence; the methodology outlined in this testimony takes each of these factors into account. To the extent the Commission wishes to incent greater peak coincidence from DG solar, TOU rates that value energy higher during peak hours should be considered.

Mr. Volkmann's testimony includes additional discussion of peak coincidence of DG.

10. Is it possible for DG solar to be more dispatchable? How does the ability to dispatch or the lack of ability to dispatch affect the value and cost of DG solar?

Please refer to Mr. Volkmann's testimony for a full discussion.

11. Will the bi-directional energy flow associated with DG solar require modifications or upgrades to the distribution system? How should the cost of these upgrades be considered when determining the cost and value of DG solar? Would the required upgrades vary based on location and penetration of DG solar? Should the costs for DG installations vary based on these factors?

Please refer to Mr. Volkmann's testimony for a full discussion.

12. How much should secondary economic impacts of DG solar deployment be considered in the value and cost considerations? Do investments in other types of generation technology have similar, greater or lesser secondary economic impacts? If so, how?

It has been found that solar PV creates roughly seven to eleven times more jobs per MWh than gas- or coal-fired generation.[38] Secondary economic impacts of additional DG solar deployment should be considered in the valuation study through economic input-output modeling or quantification of tax enhancement value resulting from increased employment.

13. How does the value and cost of DG solar change as penetration levels rise? How should this be considered in rate making and resource planning contexts?

As penetration levels rise, the value and cost of DG solar may change in several ways. Large-scale deployment of solar may depress market prices for conventional energy, and large amounts of DG solar may shift the system peak. In this proceeding, it is most useful to consider the value and cost of solar based on current and near-term projected penetration levels, and to consider revisiting the analysis periodically as penetration levels increase.

14. Should the fuel cost savings to the utility associated with DG solar be considered in the value and cost determination? If so, how do we deal with the uncertainty of future fuel prices?

Yes. Dealing with fuel price uncertainty is an inherent issue in any long-term energy resource evaluation, but the uncertainty in fuel prices does not negate the very real avoided energy costs associated with DG solar. In fact, DG solar provides the additional benefit of shielding consumers from the uncertainty inherent in fuel market pricing. As discussed in detail Section 6.2 of this

[38] Kammen et al., *Putting Renewables to Work*, Renewable and Appropriate Energy Lab., http://rael.berkeley.edu/old_drupal/sites/default/files/very-old-site/renewables.jobs.2006.pdf.

testimony, fuel price uncertainty can be addressed by looking at available forward market data and evaluating scenarios in which fuel prices are higher than and lower than expected.

15. Does the deployment of DG solar result in changes in the need for transmission capacity? If so, how should those changes be included in the value and cost considerations?

Please refer to Mr. Volkmann's testimony for a full discussion.

16. Does the deployment of DG solar result in changes in the need for distribution capacity? If so, how should those changes be included in the value and cost considerations?

Please refer to Mr. Volkmann's testimony for a full discussion.

17. Does the grid itself add value to DG solar? If so, how should the value of the grid be considered when assessing the value and cost of DG solar?

Please refer to Mr. Volkmann's testimony for a full discussion.

18. Does the deployment of DG solar result in a reduction in the use of water in electric generation? How should this be considered when determining DG solar value?

Please refer to Mr. Volkmann's testimony for a full discussion.

19. Are there disaster recovery or backup benefits associated with the deployment of DG solar? Are they reliable and quantifiable enough to determine tangible benefits that might accrue to the grid?

Please refer to Mr. Volkmann's testimony for a full discussion.

20. What, if any, costs are associated with the utility providing voltage support and/or frequency support or other ancillary services in support of DG solar installations?

Please refer to Mr. Volkmann's testimony for a full discussion.

8 Response to Questions Raised by Commissioner Stump in His February 19, 2016 Letter

Q. Please address the specific questions raised by Commissioner Stump in his February 19, 2016 letter.

A. Answers to each of Commissioner Stump's questions are provided below:

1. The Commission's May 7, 2014 Workshop on the Value and Cost of Distributed Generation included debate on whether a remote solar generation station should receive equal treatment with rooftop solar, with regard to calculating the value of solar. What are the parties' thoughts?

This is discussed in response to Commissioner Little's question number 7 on page 39 of this testimony. In addition, there are a number of differences between utility-scale solar generation and DG that would need to be taken into account in order to compare resource costs and benefits. Namely, DG may have additional benefits associated with avoided line losses and capacity benefits resulting from geographic diversity.

2. Why argue that a value-of-solar proceeding is important only for resource-planning purposes, given that discussions about cost-shifts are informed by discussions on the value of DG?

Vote Solar believes that the tension that has built up over solar rate design in Arizona is in part a function of the disconnect between short-term cost-of-service ratemaking and accounting for long-term benefits of DG. Utilities in Arizona have alleged that DG is causing a cost-shift, but these analyses are largely based on short-term evaluations that, by design, cannot fully account for the long-term benefits associated with DG. Robust valuation of DG exports can help to inform cost-of service ratemaking, as discussed in Section 3.3 of this testimony.

3. In 2014, lost fixed costs associated with EE programs amounted to $24.1 million out of $34.5 million in total cost shifts. Do recoverable EE lost fixed costs constitute a greater proportion of the total lost fixed cost revenue at hand? Discuss how value-of-solar discussions are informed by comparing the impacts of solar versus EE on the grid. Is the per-customer shift larger for solar versus EE customers? Why is the greater customer accessibility of EE programs relevant to this discussion? How does the average DG user's demand curve differ from an EE user, and describe its effect on the grid, given that the EE user is not in need of backup power, unlike the solar DG user.

Please refer to the response to Commissioner Little's question number 7 on page 39 of this testimony.

4. How do we calculate regressive social costs into the value of solar, given that non-solar utility customers subsidize solar customers?

It is Vote Solar's contention that it has not been established whether non-NEM customers subsidize NEM customers under the current rate structure. The Commission's findings have been limited by focus on short-term cost-of-service-based analysis and have not fully evaluated the long-term value and cost of DG exports. Vote Solar is hopeful that this proceeding may inform a robust, standardized methodology for evaluation of the long-term costs and benefits attributable to DG that may enable the Commission to better evaluate whether any cost shifts may occur as a result of DG in Arizona.

5. Are solar DG users being overcompensated or undercompensated for remitting excess solar power to the utility at the retail rate?

This is the central question to be answered by the methodology developed in this proceeding. Vote Solar is hopeful that a robust long-term evaluation of the costs and benefits attributable to DG exports will be able to answer this question.

6. To what degree do intermittency and non-dispatchability affect the value of solar?

Please see response to Commissioner Little's question number 8 on page 39 of this testimony.

7. How will increases in productivity be incentivized once the value of solar is estimated? In addition to the declining cost of panels, is it appropriate to factor relatively high U.S. installation costs into a value-of-solar determination?

Please see response to Commissioner Little's question numbers 2 and 3 on page 37 of this testimony.

8. In value-of-solar discussions, are we attributing a unique value to DG, which other power sources also have? In other words, are there alternatives to DG that may be more efficient in reaching the same desired outcome of reducing carbon dioxide emissions at lower instillation costs? How does the cost and value of DG compare with alternative renewable resources? In pursuing DG, what alternative forms of renewable energy are we displacing? How does the cost and value of DG compare with that of utility-scale and community-scale solar? Is DG as efficient as alternative forms of solar? Is the value of solar lessened for DG versus utility-scale or community-scale solar?

Please refer to the response to Commissioner Little's question number 7 on page 39 of this testimony.

9. How should we go about attempting to quantify largely externalized and unmonetized factors, such as projected financial, energy security, social, and environmental benefits? How are long-term forecasts accurately incorporated into present value-of-solar calculations?

Renewable DG assets provide a number of quantifiable environmental benefits, economic benefits, and benefits to grid security and reliability. Recommended methodologies for calculating each of these factors are provided in Section 6 of this testimony.

10. Despite recognized advantages, a number of states are reexamining their traditional net metering policies and underlying rate designs. The increasingly pervasive review of conventional net metering policies by states is attributable to a multitude of trends, including decreasing solar rebate incentives, rapid encroachment of renewable portfolio standards, the realization of net metering caps, as well as raised public awareness surrounding prospective cost-shift concerns.

For instance, the Hawaii Public Utilities Commission brought an end to the state's net metering program when it cut payments to new solar customers by approximately half the going rate. Nevada alternatively reduced payments to existing solar customers from the retail to the wholesale rate and raised customers' fixed charges to cover the cost of using the grid. Moreover, the California Public Utilities Commission recently approved a NEM 2.0 successor tariff, which effectively preserves retail rate payments for residential DG systems while imposing new interconnection fees, non-bypassable charges, and a shift to time-of-use rates for DG customers.

a. Given this context, how did Hawaii, Nevada, and California value the costs and benefits of net-metered solar?

b. What analyses on the cost of solar did these states use when they changed their net metering policies in light of an acknowledged cost-

shift? Did such analyses adequately account for the costs associated with redesigning and maintaining the distribution system to accommodate DG?

c. How would a value-of-solar methodology facilitate the successful implementation of similar updated policies in Arizona?

Quantification of the value and costs of DG is an inherently context-specific exercise and caution should be taken in extrapolating findings from one utility service territory to another. As a result, we recommend that a robust, long-term evaluation of the costs and benefits attributable to DG exports be completed specific to any utility requesting modification to the existing NEM structure. Notwithstanding the need for system-specific analysis, there are several lessons that can be learned from the experience in other jurisdictions.

In reference to Hawaii, it is important to consider that the penetration levels of DG on Hawaii's isolated island systems are vastly larger than DG penetration in Arizona. In fact, DG currently accounts for as much as 30-53% of system peak on Hawaii systems.[39] The experience in Hawaii highlights the strength of the NEM policy, which was kept in place until DG penetration reached much higher levels of penetration than is expected in Arizona. The Hawaii Public Utilities Commission's order states the following:

> The commission has determined that DER policies and programs in Hawaii must evolve to meet changing customer and utility system needs. This is in sharp contrast to the attempts in other states to alter or limit net metering *before* customer sited renewables have had the opportunity to scale or have resulted in significant technical integration challenges. The NEM program has fulfilled its core objective of providing a simple and effective tool to jumpstart the adoption of distributed renewable energy. As a corollary, this policy also moved the DER industry in Hawaii past the early stages of development. Hawaii's electric utilities and the DER industry are now adapting to technical challenges not yet experienced in

[39] Decision and Order No. 33258 at 160, Instituting a Proceeding to Investigate Distributed Energy Res. Policies, No. 2014-0192 (Haw. Pub. Util. Comm'n, Oct. 12, 2015).

> other jurisdictions, while developing advanced solutions that, in some cases, have not yet been tested in operating power systems.[40]

In addition, even with such large levels of DG penetration, Hawaii has continued to embrace solar development. The state recently passed legislation directing the utilities to generate 100% renewable power by 2045 and to promote deployment of additional distributed PV through community solar projects.[41]

Additional lessons can be learned from the recent developments in Nevada. In 2014, the Public Utilities Commission of Nevada ("PUCN") commissioned a study to evaluate the long-term costs and benefits of DG. A stakeholder process was convened to select an independent, third-party to complete the analysis and the results indicated that long-term benefits attributable to the NEM program exceeded costs, benefitting Nevada ratepayers by a total of $36 million.[42] Despite these findings, the PUCN recently approved a proposal to single out NEM customers for punitive rate treatment.[43] This approval was based only on a short-term evaluation of utility cost-of-service, and failed to take into account any long-term benefits attributable to DG. In addition, Vote Solar contends that the utility-sponsored cost-of-service study presented in the docket was flawed and should not have been relied on. It is notable that the PUCN decision on NEM changes has caused significant controversy and economic impacts in the state of Nevada. As a result of the PUCN decision, major solar companies have eliminated jobs in Nevada, putting hundreds of people out of work.[44]

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[40] *Id.* at 161-162 (emphasis added).
[41] *Governor Ige Signs Bill Setting 100 Percent Renewable Energy Goal in Power Sector*, Governor of the State of Haw. (June 8, 2015), http://governor.hawaii.gov/newsroom/press-release-governor-ige-signs-bill-setting-100-percent-renewable-energy-goal-in-power-sector/.
[42] E3 Report at 93.
[43] Order, Application of NV Energy for approval of a cost-of-service study and net metering tariffs, Nos. 15-07041 and 15-07042 (Nev. Pub. Util. Comm'n, Dec. 23, 2015).
[44] Sean Whaley, *Utility regulators reject call to delay new rooftop-solar rates*, Las Vegas Review-Journal (Jan. 13, 2016, 10:52 AM), http://www.reviewjournal.com/business/energy/utility-regulators-reject-call-delay-new-rooftop-solar-rates.

Finally, the California process included evaluation of the long-term costs and benefits of solar DG through a publicly-vetted process that allowed stakeholders to suggest appropriate modifications and inputs to the valuation tool. Based on the evidence developed in the proceeding, the California Public Utilities Commission determined that it was appropriate to continue full retail-rate net metering for DG in California.[45] In addition, California has taken the lead in planning for DERs through various processes discussed in detail in the testimony of Mr. Volkmann.

9 Recommendations

Q. Please summarize your recommendations.

A. I recommend the following:

- The Commission should develop a robust, standardized methodology for valuation of DG that can be employed to develop specific findings for each Arizona utility.
- Because customers have the right to self-consume the energy they generate on their own private property as a result of private investments, DG valuation studies should be limited to DG exports.
- This proceeding should seek to answer the question of whether the price paid for DG exports appropriately reflects the value of the energy provided.
- The standard methodology should include the following requirements:
    - If only DG exports are evaluated: use a modified RIM test plus societal adders;
    - If DG consumed onsite is evaluated in addition to DG exports: use the Societal Cost Test;
    - Examination of commercial and industrial DG, in addition to residential DG;

[45] Decision 16-01-044 Adopting Successor to Net Energy Metering Tariff, Rulemaking to Develop a Successor to Existing Net Energy Metering Tariffs, Rulemaking 14-07-002 (Cal. Pub. Util. Comm'n, Feb. 5, 2016), http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M158/K285/158285436.pdf.

- Analysis on the basis of levelized cost of electricity as examined over useful life of a DG system;
- Use of appropriate discount rate to reflect non-participating ratepayer perspective;
- Use of realistic near-term forecast of DG penetration;
- Analysis of capacity benefits on a continuous basis to capture modularity unique to DG;
- Inclusion of full accounting of utility distributed solar costs, energy generation savings, generation capacity savings, transmission capacity savings, distribution capacity savings, environmental benefits, economic development benefits, and grid security benefits.

Q. How should this analysis be used by the Commission and utilities?

A. I recommend that the Commission require that any utility seeking reform of the existing rate structure for DG provide necessary data for an independent, third-party to complete a full long-term evaluation of the costs and benefits of DG exports. This independent analysis should be specific to the utility's system, using the standardized methodology developed in this proceeding. The Commission should also develop a stakeholder process to allow interested parties to provide input on the independent, third-party DG export valuation. I recommend that the results of the DG export valuation be used in the utility's general rate case proceeding to inform DG rate design.

Q. Who would pay for the independent, third-party analysis?

A. The utility should provide funding for the independent, third-party analysis that would be recoverable in rates. Because this expense would be directly related to DG, it would be appropriate to include costs of this analysis as a cost to be evaluated in the context of the DG valuation study.

Q. Does this conclude your testimony?

A. Yes, it does.

Exhibit BK-1

Statement of Qualifications

Briana Kobor
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PROFESSIONAL EMPLOYMENT

Program Director – DG Regulatory Policy, Vote Solar
August 2015-present

- Analyze policy initiatives, development, and implementation related to distributed solar generation
- Review regulatory filings, perform technical analyses, and testify in commission proceedings relating to distributed solar generation

Senior Associate, MRW & Associates
April 2007-August 2015

- Develop and sponsor expert witness testimony for numerous clients to assist intervention in the utility regulatory process including investor-owned utility general rate cases, policy rulemakings, utility applications for power plant and transmission development, and other rate-related proceedings
- Represent clients at regulatory workshops, hearings and settlement discussions
- Perform in-depth quantitative analysis of utility models and testimony in support of general rate case and other regulatory proceedings
- Conduct extensive analysis of energy policy, regulation, economics, and emerging energy trends
- Build and maintain spreadsheet models to forecast utility rates and rate components tailored to client needs
- Create analytical models to assess generator production, profitability and electricity costs under a variety of regulatory and market scenarios and conduct pro forma analyses and technical assessments of infrastructure development in support of business decisions
- Provide analyses to investors and developers on the impact of laws, regulations, and procurement practices on potential sales of generation in various markets, assess current procurement progress, estimate pricing expectations for power sales, identify potential considerations that affect the marketability of project generation
- Provide policy recommendations to the State of California regarding greenhouse gas reduction, nuclear power generation and natural gas storage

EDUCATION

University of California, Berkeley
Bachelor's of Science with Honors, Environmental Economics and Policy

PREPARED TESTIMONY

- CPUC Application A.14-06-014
  Testimony of Briana Kobor on behalf of the Coalition for Affordable Streetlights Concerning SCE's Proposed Street Light Rates. March 13, 2015.
- CPUC Application A.14-11-003
  Testimony of Briana Kobor on Behalf of the Utility Consumers' Action Network Concerning Sempra's Revenue Requirement Proposals for San Diego Gas & Electric and SoCalGas. May 15, 2015.

- ACC Docket No. E-04204A-15-0142
  UNS Electric, Inc. General Rate Case
  Direct Testimony and Exhibits of Briana Kobor on Behalf of Vote Solar. December 9, 2015.
- ACC Docket No. E-04204A-15-0142
  UNS Electric, Inc. General Rate Case
  Surrebuttal Testimony and Exhibits of Briana Kobor on Behalf of Vote Solar. February 23, 2016.

SELECTED PUBLICATIONS AND PRESENTATIONS

- Kobor, Briana. Rate Design to Support the Distributed Energy Future. Arizona Energy at the Crossroads Conference. November 2015.
- Monsen, Bill and Kobor, Briana. California Rules Worry Out-of-State Generators. Project Finance Newswire, Chadbourne & Parke. May 2012.
- McClary, Steven C., Heather L. Mehta, Robert B. Weisenmiller, Mark E. Fulmer and Briana S. Kobor (MRW & Associates). 2009. Framework for Evaluating Greenhouse Gas Implications of Natural Gas-Fired Power Plants in California. California Energy Commission. CEC-700-2009-009.
- Mehta, Heather, Kobor, Briana, & Weisenmiller, Robert. California Plans a Carbon Diet. Project Finance Newswire, Chadbourne & Parke. January 2009.

Exhibit BK-2

IREC Report

October 13

A REGULATOR'S GUIDEBOOK: Calculating the Benefits and Costs of Distributed Solar Generation

Interstate Renewable Energy Council, Inc.

IREC

About the Authors

Interstate Renewable Energy Council

Jason B. Keyes, Partner, Keyes, Fox & Wiedman, LLP. Mr. Keyes has represented the Interstate Renewable Energy Council in state utility commission rulemakings regarding net energy metering for the past six years. Prior to becoming an attorney, he managed government contracts for a solar energy R&D company and developed load forecasts and related portions of integrated resource plans at a large electric utility. Mr. Keyes can be reached at jkeyes@kfwlaw.com.

Rábago Energy LLC.

Karl R. Rábago, Principal. Mr. Rábago is an attorney with more than 20 years experience in utility regulation and clean energy, including as a former utility executive with Austin Energy and the AES Corporation, Commissioner for the Texas Public Utility Commission, and Deputy Assistant Secretary for the U.S. Department of Energy. Mr. Rábago can be reached at karl@rabagoenergy.com.

Executive Summary

As distributed solar generation ("DSG") system prices continue to fall and this energy resource becomes more accessible thanks to financing options and regulatory programs, regulators, utilities and other stakeholders are increasingly interested in investigating DSG benefits and costs. Understandably, regulators seek to understand whether policies, such as net energy metering ("NEM"), put in place to encourage adoption of DSG are appropriate and cost-effective. This paper first offers lessons learned from the 16 regional and utility-specific DSG studies summarized in a recent review by the Rocky Mountain Institute ("RMI"),[1] and then proposes a standardized valuation methodology for public utility commissions to consider implementing in future studies.

As RMI's meta-study shows, recent DSG studies have varied widely due to differences in study assumptions, key parameters, and methodologies. A stark example came to light in early 2013 in Arizona, where two DSG benefit and cost studies were released in consecutive order by that State's largest utility and then by the solar industry. The utility-funded study showed a net solar value of less than four cents per kilowatt-hour ("kWh"), while the industry-funded study found a value in excess of 21 cents per kWh. A standard methodology would be helpful as legislators, regulators and the public attempt to determine whether to curtail or expand DSG policies.

Valuations vary by utility, but the authors contend that valuation methodologies should not. The authors suggest standardized approaches for the various benefits and costs, and explain how to calculate them regardless of the structure of the program or rate in which this valuation is used. Whether considering net NEM, value of solar tariffs, fixed-rate feed-in tariffs, or incentive programs, parties will always want to determine the value provided by DSG. The authors seek to fill that need, without endorsing any particular DSG policy in this paper.

Major Conclusions

Three conclusions stand out based on their potential to impact valuations:

- DSG primarily offsets combined-cycle natural gas facilities, which should be reflected in avoided energy costs.
- DSG installations are predictable and should be included in utility forecasts of capacity needs, so DSG should be credited with a capacity value upon interconnection.
- The societal benefits of DSG policies, such as job growth, health benefits and environmental benefits, should be included in valuations, as these were typically among the reasons for policy enactment in the first place.

[1] *A Review of Solar PV Benefit & Cost Studies* (RMI), July 2013 ("RMI 2013 Study"), *available at* http://www.rmi.org/elab_empower.

I. Introduction

There is an acute need for a standardized approach to distributed solar generation ("DSG") benefit and cost studies. In the first half of 2013, a steady flow of reports, news stories, workshops and conference panels have discussed whether to reform or repeal net energy metering ("NEM"), which is the bill credit arrangement that allows solar customers to receive full credit on their energy bills for any power they deliver to the grid.[2] The calls for change are founded on the claim that NEM customers who "zero out" their utility bill must not be paying their fair share for the utility infrastructure that they are using, and that those costs must have shifted to other, non-solar customers. Only a thorough benefit and cost analysis can provide regulators with an answer to whether this claim is valid in a given utility service area. As the simplicity and certainty of NEM have made it the vehicle for nearly all of the 400,000+ customer-sited solar arrays installed in the United States,[3] changes to such a successful policy should only be made based on careful analysis. This is especially so in light of a body of studies finding that solar customers may actually be subsidizing utilities and other customers.

The topic of NEM impacts on utility economics and on rates for non-solar customers seems to have risen to the top of utility priorities with the publication of an industry trade group report in January 2013 calling NEM "the largest near-term threat to the utility model."[4] Extrapolating from the current NEM penetration of just over 0.1% of U.S. energy generation to very high market penetration assumptions (e.g., if "everyone goes solar"), some have speculated that unchecked NEM growth will lead to a "utility death spiral." One Wall Street rating agency questioned the value of utility stocks in light of the continued success of NEM programs, claiming that it was "a scheme similar to net metering that led to the destabilization of the power markets in Spain in late 2008."[5]

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[2] NEM allows utility customers with renewable energy generators to offset part or all of their electric load, both at the time of generation and through kWh credits for any excess generation. This enables customers with solar arrays to take credit at night for excess energy generated during the day, for instance. Forty-three states have implemented NEM (*see* www.freeingthegrid.org for details on state NEM policies).

[3] Larry Sherwood, *U.S. Solar Market Trends 2012* (Interstate Renewable Energy Council), at p. 5 (316,000 photovoltaic installations connected to the grid at year-end 2012, with 95,000 in 2012 alone), July 2013, *available at* http://www.irecusa.org/wp-content/uploads/2013/07/Solar-Report-Final-July-2013-1.pdf. Forecasts for 2013 installations surpass 2012. *See, e.g., U.S. Solar Market Insight Report Q1 2013*, Greentech Media, Executive Summary, at p. 14, June 2013, *available at* http://www.greentechmedia.com/research/ussmi.

[4] Peter Kind, *Disruptive Challenges: Financial Implications and Strategic Responses to a Changing Retail Electric Business* (Edison Electric Institute), at p. 4, Jan. 2013.

[5] *Solar Panels Cast Shadow on U.S. Utility Rate Design* (FitchRatings), July 17, 2013, *available at* http://www.fitchratings.com/gws/en/fitchwire/fitchwirearticle/Solar-Panels-Cast?pr_id=796776. The piece was wrong on its facts. The Spanish model used a feed-in tariff ("FIT") based on solar energy costs and set at over US $0.60/kWh, leading to a massive build-out in a single year when solar prices dipped below the FIT rates. See *Spain's Solar Market Crash Offers a Cautionary Tale About Feed-In Tariffs*, N.Y. Times, Aug. 18, 2009, *available at* http://www.nytimes.com/gwire/2009/08/18/18greenwire-spains-solar-market-crash-offers-a-cautionary-88308.html?pagewanted=all (for up to 44 eurocent incentives, and using 0.711 average euro to U.S. dollar exchange rate in 2008, per IRS tables).

Numerous trade and industry publications have joined the chorus, with little indication that the rhetoric will abate anytime soon.[6]

DSG benefit and cost studies are important beyond the context of NEM. To address concerns about the cost-effectiveness of NEM, Austin Energy implemented the first Value of Solar Tariff ("VOST") in 2012, which is now under consideration in other jurisdictions. Under the Austin Energy approach, all of the customer's energy needs are provided by the utility, just as they would be if the customer did not have DSG, and the utility credits the residential solar customer for the value of all of the energy produced by the customer's solar array.[7] Though intended to offer a new approach to address the valuation issue, Austin Energy's VOST did little to quell the larger debate; indeed, this new policy highlights the fact that valuation is the key issue for any solar policy—NEM, VOST or otherwise.

Austin Energy's VOST rate, as initially calculated, was about three cents higher than retail rates, giving customers an even greater return than the NEM policy that the VOST replaced. However, as with NEM, discussions about "value of solar" rates have now turned to how to calculate the benefits of customer-generated energy. Claiming the use of their own VOST approach, City Public Service, the municipal utility serving San Antonio, Texas (just 80 miles from Austin) used an undisclosed, annualized value approach to conclude that the value of customer-sited energy from solar arrays was roughly half of the retail rate. A competing study for San Antonio, sponsored by Solar San Antonio and using publicly available data, showed twice that value.[8] As with NEM, the VOST approach is still subject to significant variation in valuation methodologies.

In early 2013, competing studies looking at DSG values for Arizona Public Service ("APS") kept the debate over valuation raging. APS funded a study that concluded DSG value was only 3.56 cents per kilowatt-hour ("kWh"), based on the present value of a kWh from DSG in the year 2025. Subsequently, APS filed an application to either change the rate schedule available to NEM customers or switch to a Feed-In Tariff ("FiT"), with both approaches relying on valuation in the range of 4 to 5.5 cents per kWh. At the same time, a solar industry-sponsored study found a 21 to 24 cent range for the value of each kWh of DSG, far exceeding costs, which it found to be in the range of 14 to 16 cents per kWh.[9] The lack of a consistent study approach drives the disparity in results.

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[6] See David Roberts, *Solar panels could destroy U.S. utilities, according to U.S. utilities*, Grist, April 2013, *available at* http://grist.org/climate-energy/solar-panels-could-destroy-u-s-utilities-according-to-u-s-utilities/; Herman Trabish, *Solar's Net Metering Under Attack*, GreenTech Media, May 2012, *available at* http://www.greentechmedia.com/articles/read/solars-net-metering-under-attack.

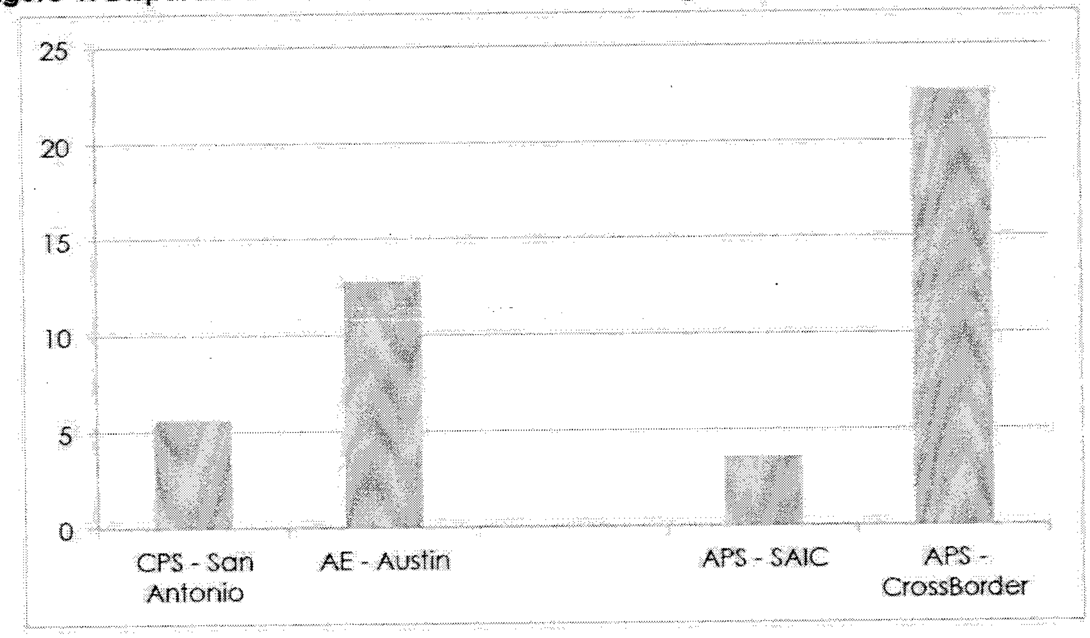
[7] See Austin Energy's Residential Solar Tariff, *available at* www.austinenergy.com/About%20Us/Rates/pdfs/Residential/ResidentialSolar.pdf (last accessed September 9, 2013).

[8] See N. Jones and B. Norris, *The Value of Distributed Solar Electric Generation to San Antonio*, March 2013 ("San Antonio Study"), *available at* www.solarsanantonio.org/wp-content/uploads/2013/04/Value-of-Solar-at-San-Antonio-03-13-2013.pdf.

[9] Arizona Corporation Commission Docket No. E-01345A-13-0248 regarding NEM valuation opened with APS's application in July, 2013, and is available at http://edocket.azcc.gov/. The May 2013 APS study prepared by SAIC is available at http://www.solarfuturearizona.com/2013SolarValueStudy.pdf. The May 2013 solar industry-sponsored study prepared by Crossborder Energy is available at http://www.solarfuturearizona.com/TheBenefitsandCostsofSolarDistributedGenerationforAPS.pdf.

Figure 1 displays the 150% difference between the Austin Energy and San Antonio City Public Service DSG valuations, alongside the 6X difference in values found in the two APS studies.

Figure 1: Disparate DSG Valuations in Texas Studies (cents/kWh).



The figure above shows that Austin Energy's latest valuation of 12.8 cents per kWh is 150% greater the 5.1 cent valuation by City Public Service in San Antonio, just 80 miles away. Even more dramatic is the difference in DSG values for APS, with 3.56 cents by the utility consultant and a range of 21.5 to 23.7 cents by the solar industry consultant.

Overview of a proposed standardized approach. This paper explains how to calculate the benefits and costs of DSG, regardless of the structure of the program or rate in which this valuation is used. Whether considering NEM, VOST, FiTs or incentive programs, parties will always want to understand DSG value. Indeed, accuracy in resource and energy valuation is the cornerstone of sound utility ratemaking and a critical element of economic efficiency. Fortunately, at least 16 studies of individual utilities or regions have been performed over the past several years, providing a backdrop for the types of benefits and costs to consider. While the variation in the purposes, assumptions and approaches in these studies has been wide, the body of published work is sufficient to draw some conclusions about best practices via a meta-analysis.

Rocky Mountain Institute ("RMI"), a Colorado-based not-for-profit research organization, looked at these 16 studies and summarized the range of valuations for each benefit and cost category in *A Review of Solar PV Benefit and Cost Studies* ("RMI 2013 Study"), providing a very useful tool for regulators determining whether a new study has considered all of the relevant benefits and costs. As well, an IREC-led report in early 2012 summarized these key benefits and costs and provided a generalized, high-level approach for their inclusion in any study ("Solar ABCs Report").[10] Together, the Solar ABCs Report and the RMI 2013 Study provide a detailed summation of efforts to date to assess the net benefits and costs of DSG.

This paper discusses various studies, but does not attempt to replicate RMI's thorough meta-analysis. Rather, this paper proposes *how* each benefit should be calculated and *why*. To assist state utility commissions and other regulators as they consider DSG valuation studies and the fate of NEM, VOST, or other programs or rate designs, we offer a set of recommended best practices regulators can use to ensure that a DSG benefit and cost study accurately measures the net impact of DSG.[11]

This paper synthesizes the prevalent and preferred methods of quantifying the categories of benefits and costs of DSG. One point of agreement is that DSG-related energy benefits are well accepted and are typically employed in cost-effectiveness testing, as well as in avoided cost calculations. Additional benefits and costs, related to capacity, transmission and distribution ("T&D") costs, line losses, ancillary services, fuel price impacts, market price impacts, environmental compliance costs, and administrative expenses are less uniformly treated in regulation and in the literature, and are addressed here in an effort to establish more commonality in approach. The quantification of societal benefits (beyond utility compliance costs) is also addressed. While typically not quantified in cost-effectiveness tests, these benefits—especially as related to evaluation of the risk associated with alternate resources—also merit more uniform treatment.

Organizationally, this paper covers the types of studies undertaken in relation to DSG valuation and overarching issues in DSG valuation studies, followed by the benefits and costs considered in various studies, the rationale for them, and the authors' recommendations on how to approach them.

> *The premise of this paper is that while calculated values will differ from one utility to the next, the approach used to calculate the benefits and costs of distributed solar generation should be uniform.*

II. DSG Benefit and Cost Studies

A history of DSG benefit and cost studies. There have been an increasing number of studies conducted and published over the past 10-15 years addressing the value of DSG and other distributed energy resources. The first comprehensive effort to

[10] J. Keyes and J. Wiedman, *A Generalized Approach to Assessing the Rate Impacts of Net Energy Metering* (Solar America Board of Codes and Standards), January 2012 ("SolarABCs Report"), *available at* www.solarabcs.org/about/publications/reports/rateimpact.

[11] In addition, the Interstate Renewable Energy Council, Inc. ("IREC") is proactively working with state utility commissions to ask these questions before studies are undertaken, with the expectation that having clarified the assumptions, commissioners will be more confident in the results.

characterize the value of distributed energy resources was *Small Is Profitable: The Hidden Economic Benefits of Making Electrical Resources the Right Size*, published by RMI in 2002. Drawing from hundreds of sources, pilot project reports, and studies, *Small Is Profitable* set the stage for more specific technology-based studies, including the NEM cost-benefit studies and solar valuation studies that followed. Studies specific to DSG systems have appeared with increasing frequency since the Vote Solar Initiative published Ed Smeloff's *Quantifying the Benefits of Solar Power for California* in 2005 and Clean Power Research ("CPR") published its evaluation of *The Value of Solar to Austin Energy and the City of Austin* in 2006.

The reasons behind the appearance of these studies are several. DSG represents an increasingly affordable, interconnected form of distributed generation, creating the potential for significant penetration of small-scale generation into grids generally built around a central station model. In addition, economic and policy pressure on rebates and other mechanisms to foster DSG penetration has increased interest in improving understanding of the DSG value proposition. Utilities, policymakers, regulators, advocates, and service and hardware providers share a common interest in understanding what benefits and costs might be associated with such increased deployment of DSG, and whether net benefits outweigh net costs under a variety of deployment and analysis scenarios.

Many recent DSG valuation studies have been cost-effectiveness analyses of NEM policies for a given utility or group of utilities. NEM has proven to be one of the major drivers of distributed generation in the United States; 43 states and the District of Columbia feature some form of NEM.[12] The success of NEM as a policy to drive distributed generation market growth has caused several states to examine the impact that the policy has on other non-participating ratepayers. Efforts are currently underway in California, Arizona, Hawaii, Colorado, Nevada, North Carolina and Georgia to quantify the benefits and costs of the policy in order to inform the appropriate level of support for distributed energy generation, particularly rooftop solar photovoltaic ("PV") generation. Other states may follow soon, even those with relatively few DSG installations; for example, the Louisiana Public Service Commission indicated that it would launch a cost-benefit analysis for net-metered systems.

Another major use for DSG value analysis is in resource planning and other regulatory proceedings. In December 2012, Lawrence Berkeley National Laboratory ("LBNL") published a review of how several utilities account for solar resources in *An Evaluation of Solar Valuation Methods Used in Utility Planning and Procurement Processes.*[13] At this writing, Integrated Resource Plan ("IRP"), avoided cost, or renewable plan dockets are, or soon will be, underway at several utilities[14] where the value of DSG is directly at issue. In addition, the state of Minnesota has recently adopted legislation that establishes a

[12] *See* Database of State Incentives for Renewables and Energy Efficiency ("DSIRE"): Summary Maps – Net Metering Policies, *available at* www.dsireusa.org (last accessed Aug. 18. 2013).

[13] Andrew Mills & Ryan Wiser, *An Evaluation of Solar Valuation Methods Used in Utility Planning and Procurement Processes* (Lawrence Berkeley National Laboratory), LBNL-5933E, December 2012 ("LBNL Utility Solar Study 2012"), *available at* http://emp.lbl.gov/publications/evaluation-solar-valuation-methods-used-utility-planning-and-procurement-processes.

[14] *See, e.g.,* Georgia Public Service Commission Docket No. 36989 (Georgia Power Rate Case); North Carolina Utilities Commission Docket No. E-100, Sub 136 (Biennial Avoided Cost); Colorado Public Utilities Commission Docket No. 13A-0836E (Public Service Company Compliance Plan).

Value of Solar rate for DSG.[15] The authors anticipate that additional valuation studies will result from one or more of these proceedings.

As of this writing, relatively few jurisdictions have conducted full cost-effectiveness studies for DSG and fewer still provide sufficient detail to guide development of a common methodology. CPR's Austin Energy study, updated in 2012, established an approach that has been applied in other regions, including a recent study on the value of DSG in Pennsylvania and New Jersey.[16] The California Public Utilities Commission ("CPUC") and APS commissioned comprehensive studies in 2009; both commissioned revised studies in 2013.[17] In January 2013, Vermont's Public Service Department[18] completed a cost-benefit analysis of NEM policy.

While not identical in structure, these works typify the recent reports and illustrate some commonalities in approaching the valuation of distributed energy. NEM-specific studies include the 2009 California Energy and Environmental Economics ("E3") Study, Crossborder Energy's 2013 updated look at that E3 study,[19] Crossborder Energy's 2013 analysis of DSG cost-effectiveness in Arizona,[20] and the Public Service Department's own analysis for Vermont.

As noted earlier, this paper complements IREC's recent publication, *A Generalized Approach to Assessing the Rate Impacts of Net Energy Metering*.[21] That paper reviews the DSG valuation studies that had been published to date and provides general approaches to calculating the widely recognized categories of benefits and costs that are relevant to the consideration of the cost-effectiveness of VOST, NEM, and other policy mechanisms impacting DSG. The intent of this examination is to dive deeper, find more common ground for discussion and foster greater consistency in how these values are determined across jurisdictions.

Also as noted earlier, this paper benefits from analysis recently published by RMI, entitled *A Review of Solar PV Benefit and cost Studies*.[22] That report reviews 16 studies in a meta-analysis that examines methodologies and assumptions in great detail. Figure 2 is from that study, and characterizes the differences and similarities in the studies. As

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[15] Minn. Stat. § 216B.164, subd. 10 (2013): Chapter 85--H.F. No. 729, Article 9, Distributed Generation, Section 10.

[16] Richard Perez, Thomas Hoff, and Benjamin Norris, *The Value of Distributed Solar Electric Generation to New Jersey and Pennsylvania*, 2012 ("CPR 2012 MSEIA Study"), *available at* http://communitypowernetwork.com/sites/default/files/MSEIA-Final-Benefits-of-Solar-Report-2012-11-01.pdf.

[17] APS studies: *Distributed Renewable Energy Operating Impacts and Valuation Study*, RW Beck, Jan. 2009, available at http://www.solarfuturearizona.com/SolarDEStudy.pdf; *2013 Updated Solar PV Value Report*, SAIC, May 2013, available at http://www.solarfuturearizona.com/2013SolarValueStudy.pdf.
CPUC studies conducted by Energy and Environment Economics ("E3"): http://www.cpuc.ca.gov/PUC/energy/Solar/nem_cost_effectiveness_evaluation.htm.

[18] *Evaluation of Net Metering in Vermont Conducted Pursuant to Act 125 of 2012*, January 15, 2013 ("Vermont Study"), *available at* www.leg.state.vt.us/reports/2013ExternalReports/285580.pdf.

[19] Thomas Beach and Patrick McGuire, *Evaluating the Benefits and Costs of Net Energy Metering in California* (Vote Solar Initiative), 2013 ("Crossborder 2013 California Study"), *available at* http://www.seia.org/research-resources/evaluating-benefits-costs-net-energy-metering-california.

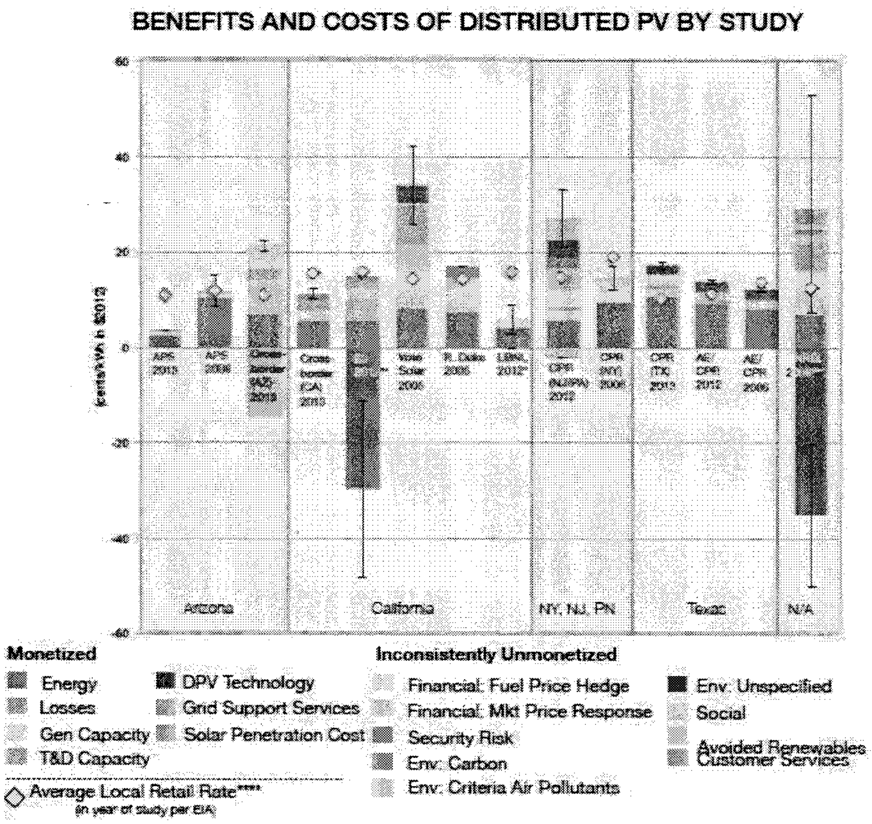
[20] Thomas Beach and Patrick McGuire, *The Benefits and Costs of Solar Distributed Generation for Arizona Public Service* (Vote Solar Initiative), at p.12, 2013 ("Crossborder 2013 Arizona Study"), *available at* http://www.solarfuturearizona.com/TheBenefitsandCostsofSolarDistributedGenerationforAPS.pdf.

[21] *See* SolarABCs Report, *supra*, footnote 10.

[22] See RMI 2013 Study, *supra*, footnote 1.

well as considering benefits and costs the RMI 2013 Study points out that the various studies differ significantly in the amount of DSG penetration considered, which can drastically impact values. Another important differentiator is whether the studies are based on high-level, often secondary, review of benefits and costs, or whether they rely on more granular and detailed modeling of impacts.[23]

Figure 2: Rocky Mountain Institute Summary of DSG Benefits and Costs



The RMI 2013 Study figure is reprinted here to make three important points. First and foremost, the calculated benefits often exceed residential retail rates, shown in the figure with diamonds, implying that NEM would not entail a subsidy flowing from non-solar to solar customers. Second, commercial customers almost always have unbundled rates and NEM has minimal impact on their demand charges because they still have demand after the sun sets. That means that DSG benefits compared to commercial customer energy rates would be strongly positive based on almost all of these studies. And third, costs are accounted for in varying ways: three studies show costs including lost retail rate payments, with large bars below the zero line indicating total costs, one shows costs other than retail rate payments (CPR NJ/PA), and the rest include costs as a deduction within the benefits calculation. As an overarching point,

[23] *Id.* at p. 21.

the RMI 2013 Study figure confirms that there is no single standard DSG valuation methodology today.

Types of Studies. Distributed solar valuation requires quantitative analysis of a wide range of data in an organized way. Fortunately, there are abundant existing approaches that can contribute to estimation of DSG value. This section briefly introduces the two major types of studies that underlie DSG valuation. The first category of studies is input and production cost models. These have general application in the utility industry in the comparison of resource alternatives. The second category, DSG-specific studies, includes three sub-types, depending on the purpose for which the study was conducted. In practice, most DSG-specific studies rely on inputs from input and production cost models.

A. Input and Production Cost Models

Utility planners and industry experts rely on a wide range of models and analytical tools for calculating costs associated with generation and systems. Power flow, dispatch, and planning models all provide input to the financial models used to evaluate DSG cost effectiveness and value. While detailed treatment of the utility models providing input to the DSG models is beyond the scope of this paper, they impact the DSG models and need to be understood. Often, these utility models are deemed proprietary, creating "black box" solutions regarding what generation is needed and when. Among the most critical decisions made at this juncture is whether the generation that will be offset by DSG is a relatively efficient natural gas combined-cycle combustion turbine ("CCGT")or a less efficient single cycle "peaker" plant running on natural gas, or some combination of the two.

As most of the gas-fired energy delivered by utilities comes from CCGTs, and peakers will still be needed to handle changes in load, models should reflect that DSG is primarily offsetting CCGTs. However, the APS 2013 study is an example in which the input model results are confounding, and there is no way to review the black box solution. Oddly, APS found that baseload coal would be displaced for part of the year. We believe that such an example deserves more careful study; it is a nearly universal truth that coal plants are run as much as possible. While many coal plants have been shut down in the past decade, those that remain are typically only curtailed for maintenance. Regulators should consider whether input assumptions such as coal or nuclear displacement are reasonable, particularly if the results are based on proprietary, opaque modeling.

Capacity needs in planning models are typically forecasted several years in the future and, because of the legacy of the central station utility plant paradigm, in large increments of capacity. These so-called "lumpy" capacity investments generally overshoot capacity requirements in order to ensure resource adequacy in the face of multi-year development lead times. As a result, the opportunity for DSG to provide useful capacity is generally seen as too little and too early. For example, a typical utility resource plan might state that capacity is adequate until the year 2018, at which time the company forecasts a need for an additional 200 megawatts ("MW") of generation capacity. In such a situation, traditional resource planning and avoided cost estimates assign no capacity value to DSG installed on customer roofs before 2018, and none in

2018 unless the systems provide the equivalent to 200 MW of capacity. This ignores the benefit of DSG's modularity—the utility does not need 200 MW in 2018, at that point it only starts to need more than it already has available. DSG can provide for that capacity through incremental installations starting in 2018. Likewise, if the utility has projects under development prior to 2018, it could have deferred or avoided some of that need if it had accurately predicted and valued DSG installations.

Today, many input and production cost planning models include the opportunity to adjust assumptions about customer adoption of DSG (and energy efficiency), which assume that those resources are going to play a role in the utility's near term capacity requirements. With these adjustments, the in-service requirement date can possibly be deferred, generating both energy and capacity savings attributable to the distributed resources. Accordingly, models that do not address DSG installations are inadequate and could lead to costly overbuilding and, given planning and construction lead times associated with large plants, premature expenditure of development costs.

B. DSG-Specific Studies

DSG-specific studies often start with inputs from the models just described. These studies are themselves usually of three types:

Studies of studies. Like this white paper, these studies start with work conducted by one or more experts and organize the information and data in a form that addresses questions of interest. In some cases, the authors report the results and the source conditions for the data. In others, study authors attempt to adjust the results for different local conditions. The RMI 2013 Study on solar PV reports the results of 16 different studies spanning some eight years. These studies provide useful introductions to the emerging discipline and demonstrate the ways in which differences in assumptions, methodologies, and underlying data can impact outcomes. In addition, when adjusting for outlier conditions, the studies can demonstrate where there exists relatively strong coherence in approach and results.

Cost-Benefit Analysis studies. Cost-benefit studies focus on using avoided cost methodologies and cost-benefit test approaches to review large-scale DSG initiatives and programs. They seek to answer the question of whether total costs or total benefits are greater over a specified period of time. For these studies, forward-looking cost estimates for DSG interconnection, lost revenues, avoided RPS costs, and incentive programs are important inputs. The best-known examples of this study approach were conducted by E3, reviewing the California Solar Initiative and NEM programs, and those by Crossborder Energy, reviewing the E3 reports. Most of the studies reviewed by the RMI 2013 Study are of this sort. There are several cost-benefit analysis varietals, as described in the California Standard Practice Manual and summarized in the box below.

Value of Solar studies. Smeloff and CPR pioneered the "value of solar" genre of study. As the name implies, this study approach focuses on using avoided cost and financial analysis methods in discerning the future investment value of distributed solar to the utility, ratepayers, and society. Generally, these evaluations ignore utility lost revenues, instead focusing on valuation that can be used in designing and setting incentive levels, program limits, and other features of utility DSG programs. The studies stop short of rate or tariff design features, and as a result, do not typically address lost revenue issues. Perhaps best known is the Austin Energy Value of Solar study conducted by CPR in 2006 and updated in 2012.[24]

With reference to the California Standard Practice Manual study descriptions summarized in the prior box, the type of test that the authors suggest in this paper is a blend of the Ratepayer Impact Measure ("RIM") and Societal Cost Test ("SCT") approaches. The RIM test addresses the impact on non-participating ratepayers in terms of how benefits and costs impact the utility and are passed along to those ratepayers. That necessarily does not account for the participating ratepayers' outlay for DSG systems, nor should it. The SCT approach looks at whether it is a good idea for society as a whole to pursue a policy, and includes participating ratepayers' investment in DSG systems. The authors contend that the participants' investment is outside of the scope of the appropriate investigation. The goal should be to determine whether non-participants have a net benefit from the installation of DSG systems. As the job creation, health and environmental benefits accrue to non-participants just as much as they accrue to participants, there is no apparent reason why societal benefits should not be included. In its consideration of benefits, this approach aligns with the VOST methodology which aims to include all benefits that can reasonably be quantified and assigned to utility operations.

Utilities often object, stating that valuing societal benefits conflates customers with citizens, and note that utility rates must be based on costs directly impacting utilities. By this line of reasoning, job creation and health benefits may be the basis of legislative policies supportive of DSG, but should not be considered when developing DSG tariffs. We are reluctant to accept an artificial division between citizens and utility customers; the overlap is complete for most benefits and costs. Moreover, a major reason for establishing NEM, VOST or other DSG programs is primarily related to the same broad societal benefits that drive utility regulatory systems—economic efficiency, and rates and services in the public interest—so those benefits should be considered in any programmatic or policy analysis.

Recommendation: Use a blend of the Ratepayer Impact Measure ("RIM") and Societal Cost Test ("SCT") Cost-Benefit Tests

24 Author K. Rábago, while at Austin Energy, helped establish the nations' first VOST. *See* K. Rábago, *The Value of Solar Rate: Designing an Improved Residential Solar Tariff*, Solar Industry, at p. 20, Feb. 2013, *available at* http://solarindustrymag.com/digitaleditions/Main.php?MagID=3&MagNo=59.

Cost-Benefit Tests

The California Standard Practice Manual is used for economic analysis of demand-side management ("DSM") programs in California. The cost-benefit tests in the Standard Practice Manual have also been used to evaluate DSG value, most notably in California, where the tests have been applied to a review of the cost effectiveness of the California Solar Initiative. The various tests differ in the perspective from which cost effectiveness is assessed.

- ***Participant Cost Test* ("PCT").** Measures benefits and costs to program participants.
- ***Ratepayer Impact Measure ("RIM") Test.*** Measures changes in electric service rates due to changes in utility revenues and costs resulting from the assessed program.
- ***Program Administrator Cost Test ("PACT").*** Measures the benefits and costs to the program administrator, without consideration of the effect on actual revenues. This test differs from the RIM test in that it considers only the revenue requirement, ignoring changes in revenue collection, typically called "lost revenues."
- ***Total Resources Cost Test ("TRC").*** Measures the total net economic effects of the program, including both participants' and program administrator's benefits and costs, without regard to who incurs the costs or receives the benefits. For a utility-specific program, the test can be thought of as measuring the overall economic welfare over the entire utility service territory.
- ***Societal Cost Test ("SCT").*** The SCT is similar to the TRC, but broadens the universe of affected individuals to society as a whole, rather than just those in the program administrator territory. The SCT is also a vehicle for consideration of non-monetized externalities, such as induced economic development effects, which are not considered in the TRC.

III. Key Structural Issues for DSG Benefit and Cost Studies

Underlying study assumptions and major study components. The evaluation of the cost-effectiveness of a given DSG policy, particularly NEM, is a complex undertaking with many potential moving parts. Before delving into the specific benefits and costs, it is important to recognize that the ultimate outcome of the analysis is highly dependent on the base financial and framework assumptions that go into the effort. Much of the work involves forecasting—estimating the future benefits and costs, performance, and cumulative impacts associated with increasing penetration of distributed generation into the electric grid. It is important to develop a common set of base assumptions that reflect the resource being studied and to be as transparent as possible about these assumptions when reporting the results of the analysis. At the outset of a study, it is important to define these structural parameters. Below we present key questions for regulators to explore at the onset of a study:

Q1: WHAT DISCOUNT RATE WILL BE USED?

The discount rate should reflect how society evaluates costs over time. Utilities use a discount rate based on the time value of money, using the rate of return available for investments with similarly low risk, now in the 6% to 9% range. However, society may prefer the use of a lower discount rate, closer to the rate of inflation. The difference is important. High discount rates improve the evaluation of resources with continuously escalating or high end-of-life costs. For instance, an 8% discount rate may favor a natural gas generator because much of the cost (the fuel, operation and maintenance) to run the generator is incurred over the life of the generator, while the cost of DSG is almost entirely at the front end. A low discount rate improves the valuation of resources with high initial costs and low or zero end-of-life costs. The same analysis based on a 3% inflation rate may favor DSG resources, as there are no fuel costs over time and the operations and maintenance ("O&M") costs are low because there are fewer or no moving parts. While the utility's discount rate is appropriate when considering utility procurement because those funds could be invested elsewhere at competitive rates, the utility is not procuring the DSG resources in the case of NEM, VOST or FiT arrangements. It is worth questioning whether the future benefits of DSG resources should be heavily discounted, based on the utility's cost of capital, when the customer (or a third party owning a system at the customer's site) is making the investment. As utility valuation techniques improve, is it reasonable to discount future benefits and costs by the inflation rate rather than the utility's cost of capital.

Recommendation: We recommend using a lower discount rate for DSG than a typical utility discount rate to account for differences in DSG economics.

Q2: WHAT IS BEING CONSIDERED – ALL GENERATION OR EXPORTS ONLY?

Under NEM, utility customers can take advantage of a federal law[25] allowing for on-site generation to offset consumption, with the opportunity to sell excess generation to the utility at the utility's avoided cost. Because the customer has a right to avoid any and all consumption from the utility, studies of NEM cost-effectiveness will often look only at the utility cost associated with exports to the grid. The assumption under NEM is effectively that at or below the total consumption level, the value of offset consumption is the retail rate. This valuation is supported by the concept behind cost-of-service rate regulation—that the retail rate is the accumulation of costs to generate and deliver energy for the customer.[26] Note that to the extent that NEM benefits are calculated to

[25] *See* Public Utility Regulatory Policies Act ("PURPA"), 16 U.S.C. *et seq.*
[26] VOST studies, on the other hand, presume a difference between the value of generation at or near the point of consumption and the level of the rate. That is, the customer with DSG may well be generating electricity of greater value than that being provided by the utility.

outweigh costs, consideration of all generation amplifies the calculated net benefit. However, if NEM costs outweigh benefits, the opposite is true.

Recommendation: We recommend assessing only DSG exports to the grid.

Q3: OVER WHAT TIMEFRAME WILL THE STUDY EXAMINE THE BENEFITS AND COSTS OF DSG?

Utility planners routinely consider the lifecycle benefits and costs of traditional utility generators, typically over a period in excess of 30 years. Solar arrays have no moving parts and are generally expected to last for at least 30 years, with much less maintenance than fossil-fired generation. Solar module warranties are typically for 25 years, and many of the earliest modules from the 1960s and 1970s are still operational, indicating that modules in production today should last for at least 30 years. This useful life assumption creates some data challenges, as utilities often plan over shorter time horizons (10-20 years) in terms of estimating load growth and the resources necessary to meet that load. As described below, methods can be used to estimate the value in future years that interpolate between current market prices or knowledge, and the most forward market price available or data that can accurately be estimated, just as planners do for fossil-fired generators that are expected to last for decades.

Recommendation: We suggest that the most appropriate timeframe for evaluating DSG and related policy is 30 years, as that matches the currently anticipated life span of the technology.

Q4: WHAT DOES UTILITY LOAD LOOK LIKE IN THE FUTURE?

Key to determining the value of DSG is a reasonable expectation of what customer loads will look like in the future, as much of the value of distributed resources derives from the utility's ability to plan around customer-owned generation. Other DSG rate or program options involving sale of all output to the utility do not reduce utility loads, as customer facilities contribute to the available capacity of utility resources as small contracted generators.

Recommendation: Given that NEM resources are interconnected behind customer meters, and result in lower utility loads, we recommend that the assigned capacity value of the distributed systems reflect the fact that the utility can plan for lower loads than it otherwise would have.

Q5: WHAT LEVEL OF MARKET PENETRATION FOR DSG IS ASSUMED IN THE FUTURE?

Many benefits and costs are sensitive to how much customer-owned generation capacity is on the grid. Most studies assume current, low penetration rates. Several of the studies consider higher penetration levels, as well, typically out to 15% or 20% of peak load, with some outlier studies looking at 30% and 40% penetration levels. In a high-penetration scenario, the utility may face higher integration expenses that might undermine the specific infrastructure benefits of distributed generation. Studies that address the issue often find that marginal capacity benefits decline with high penetration.

On the other hand, some studies such as those by APS, conclude that capacity benefits are dependent on having enough DSG to offset the next natural gas generator, and therefore that there are no capacity benefits in low-penetration scenarios. Market penetration estimates should also be reasonable in light of current supply chain capacity and local market conditions. Generally, the most important penetration level to consider for policy purposes is the next increment. If a utility currently has 0.1% of its needs met by DSG and a study shows that growth to 5% is cost-effective, but growth to 40% is not, then it would be economically efficient to allow the program to grow to 5% and then be reevaluated.

Recommendation: We recommend the establishment of an expected level of DSG penetration, and the development of low and high sensitivities to consider the full range of future impacts.

Q6: WHAT MODELS ARE USED TO PROVIDE ANALYTICAL INPUTS?
Analysts have used a wide variety of tools to calculate the benefits and costs of DSG. There is almost no commonality at the model level, even though many of the analyses address similar or identical issues. Several studies use some version of investment and dispatch models in order to determine which resources are displaced by solar and the resulting impacts. As noted earlier, utility DSG studies have often relied on proprietary models for these inputs. The fact that CPR and Professor Richard Perez[27] have published a number of studies creates some commonality among those studies, but over time, even the CPR approaches have evolved as tools have been improved.

Recommendation: We suggest that transparent input models accessible to all stakeholders are the proper foundation for confidence and utility of DSG studies. If necessary, non-disclosure agreements can be used to overcome data sharing sensitivities.

Q7: WHAT GEOGRAPHIC BOUNDARIES ARE ASSUMED IN THE ANALYSIS?
Value of solar analysis is heavily influenced by local resource and market conditions. Most published studies are geographically scoped at the state, service territory, or interconnected region level. Given its leadership in solar deployment, California also leads as the subject of studies and as a data source. Some studies relating to economic development and environmental impacts use a national and regional scope.

Recommendation: We suggest that it is important to account for the range in local values that characterize the broader geographical area selected for the study. In some cases, quantification according to similar geographical sub-regions may be appropriate.

Q8: WHAT SYSTEM BOUNDARIES ARE ASSUMED?
The majority of studies consider benefits and costs in the generation, transmission, and distribution portions of the system. Of the studies that consider environmental impacts,

[27] Richard Perez is a Research Professor at the University at Albany-SUNY.

most only look at avoided utility environmental compliance costs at the generation level.

Recommendation: We recommend considering impacts associated with adjacent utility systems, especially at higher (above 10%) penetration levels of DSG.[28]

Q9: FROM WHOSE PERSPECTIVE ARE BENEFITS AND COSTS MEASURED?

Nearly all the studies consider impacts from the perspective of the utility and ratepayers. Several also consider customer and societal benefit and costs. Cost-benefit studies apply California Standard Practice Manual tests for Demand Side Management, discussed earlier.

Recommendation: We suggest that rate impacts and societal benefits and costs should be assessed.

Q10: ARE BENEFITS AND COSTS ESTIMATED ON AN ANNUALIZED OR LEVELIZED BASIS?

When a DSG system is installed, it is like commissioning a 30-year power plant that will, if properly maintained, produce energy and other benefits during that entire period. Several studies look at snapshots of benefits and costs in a given year, which fails to answer the basic question of whether DSG is cost-effective over its lifetime. Levelization involves calculating the stream of benefits and costs over an extended period and discounting to a single present value. Such levelized estimates are routinely used by utilities in evaluating alternative and competing resource options. As such, levelization of the entire stream of benefits and costs is appropriate.

Recommendation: We recommend use of a levelized approach to estimating benefits and costs over the entire DSG life of 30 years.

Q11: WHAT DATA AND DATA SOURCES ARE USED?

As the number of solar valuation studies has increased, so has the frequency with which newer studies cite data provided in prior studies. There are two reasons behind this trend, cost and availability of data, which we discuss in detail below.

As with any modeling exercise, models are only as good as the data fed into them. The ability to precisely calculate the benefits of DSG often rests on the availability and granularity of utility operational and cost data. More granular data yields more reliable analysis about the impacts of DSG deployment and operation.

Calculating many of the benefit and cost categories requires that analysts address utility-specific or regional conditions that can vary significantly from utility to utility, even within the same state. In addition, the availability of the type of granular data needed

[28] Mills and Wiser point out that consideration of inter-system sales of capacity or renewable energy credits could mitigate reductions in incremental solar value that could accompany high penetration rates. *See* A. Mills & R. Wiser, *An Evaluation of Solar Valuation Methods Used in Utility Planning and Procurement Processes* (Lawrence Berkeley National Laboratory), LBNL-5933E, at p. 23, December 2012, *available at* http://emp.lbl.gov/publications/evaluation-solar-valuation-methods-used-utility-planning-and-procurement-processes.

to accurately project location and time-specific benefits varies from one utility to the next. Much of the data needed to quantify the benefits of DSG resides with utilities.

Fortunately, additional data, such as energy market prices, is often publicly available, or can be released by the utility without proprietary concerns. In some limited cases, the utility may have proprietary, competitive, or other concerns with plant- or contract-specific information. And in some cases, the form and format of utility data may require adjustments.

These problems are not insurmountable. Utility general rate cases and regulatory filings with the Federal Energy Regulatory Commission ("FERC") are good sources for data relevant to utility peak demand and for the components of cost of service, including transmission costs, line loss factors, O&M costs, and costs of specific distribution upgrades or investments, among other cost categories. Additionally, the federal Energy Information Administration ("EIA") and various state agencies compile utility cost data that can be used as a reference to determine heat rates, the costs of O&M associated with various plants, and the overall capital cost of new construction of generating capacity.[29]

Recommendation: Require that utilities provide the following data sets, both current information and projected data for 30 years[30]:

1) The five or ten-year forward price of natural gas, the most likely fuel for marginal generation, along with longer-term projections in line with the life of the DSG.
2) Hourly load shapes, broken down by customer class to analyze the intra-class and inter-class impacts of NEM policy.
3) Hourly production profiles for NEM generators. The use of time-correlated solar data is important to correctly assess the match of solar output with system loads. In the case of solar PV, this could vary according to the orientation of the system. For example, while south-facing systems may have greater overall output, west or southwest facing systems may produce more overall value with fewer kWh because of peak production occurring later in the day than a south-facing system.
4) Line losses based on hourly load data, so that marginal avoided line losses due to DSG can be calculated.
5) Both the initial capital cost and the fixed and variable O&M costs for the utility's marginal generation unit.
6) Distribution planning costs that identify the capital and O&M cost (fixed and variable) of constructing and operating distribution upgrades that are necessary to meet load growth.
7) Hourly load data for individual distribution circuits, particularly those with current or expected higher than average penetrations of DSG, in order to capture the potential for avoiding or deferring circuit upgrades.

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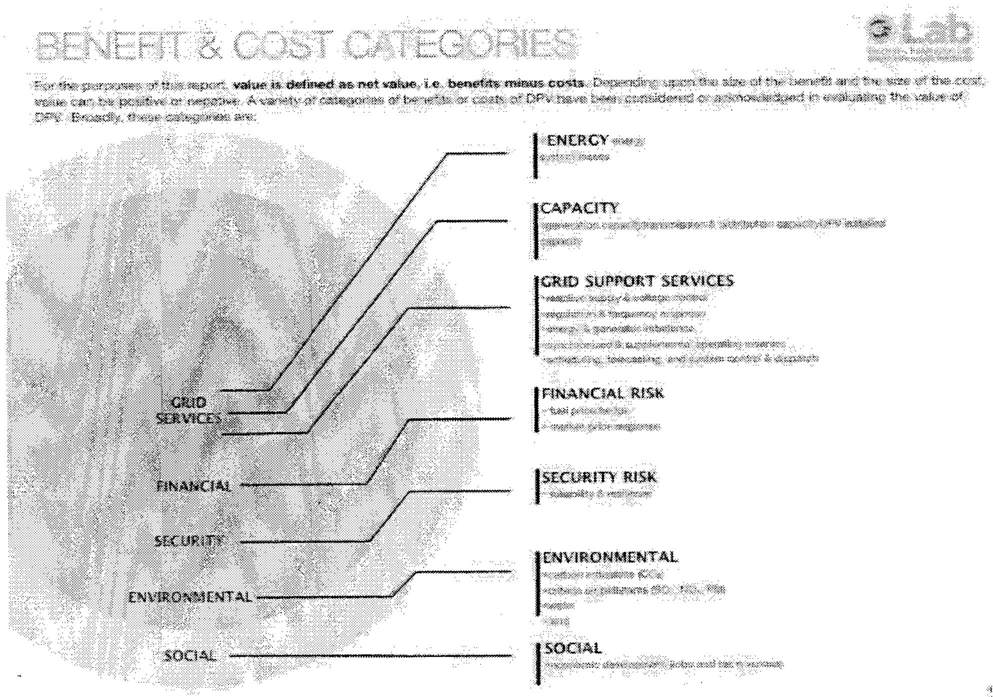
[29] *See Updated Capital Cost Estimates for Electricity Generation Plants* (EIA), November 2012, *available at* http://www.eia.gov/oiaf/beck_plantcosts/pdf/updatedplantcosts.pdf (providing estimate of capital cost, fixed O&M, and variable O&M for generation plants with various technical characteristics).
[30] Note: Where a utility or jurisdiction does not regularly collect some portion of this data, there may be methods to estimate a reasonable value to assign to DSG.

IV. Recommendations for Calculating the Benefits of DSG

Benefits of DSG get categorized and ordered in various ways from study to study, typically based on the relative magnitude of the benefits. The RMI 2013 Study is structured around a list of "services," encompassing flows of benefits and costs to and from solar PV. That list is replicated here in an effort to coordinate with that study.[31] The RMI services categories are depicted in the graphic below.

Figure 3: Rocky Mountain Institute Summary of DSG Benefits



While replicating the RMI services categories, we have subdivided them in recognition that the divide between utility avoided costs and other societal benefits is not clear from the list above. For instance, utilities can avoid certain environmental compliance costs, which are direct utility avoided costs, while other environmental benefits inure to society more generally. As another example, reliability or resiliency is only a utility avoided cost to the extent that the utility was going to take some other measures to achieve the levels enabled by DSG. If DSG enables higher reliability than would have otherwise been achieved, that is undoubtedly a benefit, though it is most notably realized by utility customers when a storm event does not cause a major service interruption, which may occur once in a decade. As a further example, market price

[31] *See* RMI 2013 Study.

response benefits can be felt by the utility itself but will also extend to citizens who are customers of nearby utilities.

To track utility avoided costs and societal benefits separately, separate subsections are provided below, with the final three RMI environmental and social benefit categories covered after utility avoided costs. We note where some categories listed under utility avoided costs have societal benefits as well, and we separately create an environment category under utility avoided costs to capture utility avoided environmental compliance costs.

Calculating Utility Avoided Costs

1. <u>Avoided energy benefits</u>

To determine the value of avoided generation costs, the first step is to identify the marginal generation displaced. In most instances, the next marginal generator will be a natural gas-fired simple-cycle combustion turbine ("CT") or a more efficient CCGT. Avoiding the operation of that marginal generating facility to produce the next increment of electricity means that the solar generator allows the utility to avoid both variable O&M activities (i.e., those activities and expenses that vary with the volume of output of the CT or CCGT plant) and the fuel that would be consumed to produce that next unit at the time that the customer-generator allows the utility to avoid that operation.

To calculate the avoided generation cost over the life of the DSG system—assumed throughout this paper to be 30 years—the calculation must estimate the market price of energy throughout that time span. Given the limitations on the availability of data, including the future price of a historically volatile commodity like natural gas, many studies have used interpolation and extrapolation to estimate gas prices in the 30 year horizon by taking the readily attainable current market price for natural gas and referencing it against the most forward natural gas price available.

Additionally, the calculation of avoided generation costs over time must account for degradation in the marginal generation plant and adjust expected heat rates (i.e., the measure of efficiency by which a unit creates electricity by burning fuel for heat to power a turbine). Over time, the marginal generation plant will become less efficient and require incrementally more fuel to reach the same production levels. Production cost modeling enables the utility to cumulate value of avoided costs throughout the useful life of the solar generating system. However, due to built in constraints or other issues, such modeling can produce results that are illogical, as has been seen in Arizona (baseload coal generation displaced by DSG) and Colorado (high cost of frequent unit startups reducing energy benefits).

A standard approach to determining the value of avoided generation over the life of a DSG system is to develop: (1) an hourly market price shape for each month and (2) a forecast of annual average market prices into the future.[32] One way to forecast the annual market prices, with less reliance on forward market prices, is to project the rolled-in costs of the marginal generation unit, accounting for variable O&M and

[32] E3 Study, Appendix A at pp.10-11.

Comparison with PURPA Avoided Cost Calculations

Value of solar analysis literature is complemented by other studies and reports related to the issue. These include studies relating to avoided cost methodologies under the Public Utility Regulatory Policies Act of 1978 ("PURPA"), and those addressing utility resource planning evaluation of distributed resources.

Because both the cost-benefit and value-of-solar approaches start with avoided cost calculations, publications and processes used in conducting such calculations are informative in establishing the costs and benefits of DSG. State utility commissions and public utility regulators have approached PURPA valuation of avoided costs quite differently, and FERC has rarely constrained the approach selected. Rather than attempt to discern a consensus approach, a more fruitful approach is to consider what PURPA allows.

IREC recently published a paper to do this, cataloguing the kinds of DSG-related avoided cost calculations that could improve understanding of DSG value, and citing most of the utility avoided costs discussed in this paper.

See the full report:
http://www.irecusa.org/wp-content/uploads/2013/05/Unlocking-DG-Value.pdf

degradation of heat rate efficiency in future years. This method still relies on forecasts of natural gas prices in future years, but provides more certainty for variable O&M costs.[33]

In the Vermont study, the Public Service Department assumed that the New England Independent System Operator ("ISO-NE") wholesale market would provide the marginal generation price for energy displaced by solar generation. To account for the high correlation of solar PV with system peak, and therefore the offset of higher value generation, the Department created a hypothetical avoided cost for 2011 using real output data that was matched with actual hourly market data from the ISO-NE market.[34] This adjusted hourly market price was then scaled to future years by utilizing an energy price forecast, based on the forward market energy prices for the first five years and for the forward natural gas prices for years five to ten.[35] Prices for years after year ten were based on an extrapolation of the market prices for electricity and natural gas for years one through ten.

As CPR observes, there are inherent shortcomings in relying on future market prices for marginal generation decades into the future.[36] A more straightforward method would be to "explicitly specify the marginal generator and then to calculate the cost of the generation from this unit."[37] In this way the avoided fuel and O&M cost savings are roughly equivalent to capturing the future wholesale price. Of course, this approach still relies on forward projections in the natural gas market.

[33] CPR 2012 MSEIA Study at pp. 28-29.
[34] Vermont Study at p. 16.
[35] *Id.*
[36] CPR 2012 MSEIA Study at pp. 28-29.
[37] *Id.* at p. 29.

2. Calculating system losses

DSG sited at or near load avoids the inefficiencies associated with delivering power over great distances to the end-use customer due to electric resistance and conversion losses. When a DSG customer does not consume all output as it is being produced, the excess is exported to the grid and consumed by neighboring customers on the same circuit, with minimal losses in comparison to electricity generated by and delivered from a utility's centralized but distant plant. Without DSG and its local load reduction impact, utilities are forced to generate additional electricity to compensate for line losses, decreasing the economic efficiency of each unit of electricity that is delivered.

Including avoided line losses as a benefit is relatively straightforward and should be non-controversial. For instance, FERC's regulations implementing PURPA recognize that distributed generation can account for avoided line losses.[38] This benefit exists for all types of DG technologies and, to some extent, in all locations. Typically, average line losses are in the range of 7%, and higher during heavier load periods, which can correlate with high irradiance periods for many utilities.[39] Additional losses termed "lost and unaccounted for energy" are also likely associated with T&D functions and, with further research, may also be avoided by DSG.[40]

Average line loss is often used as the primary approach to adjusting energy and capacity-related benefits. However, because line losses are not uniform across the year or day, the use of average losses ignores significant value because it fails to quantify the "true reduction in losses on a marginal basis."[41] Considering losses on a marginal basis is more accurate and should be standard practice as it reflects the likely correlation of solar PV to heavy loading periods where congestion and transformer thermal conditions tend to exacerbate losses. In its Austin Energy study, CPR evaluated marginal T&D losses at times of seasonable peak demand using load flow analysis. CPR decided to average the marginal energy losses on the distribution system, for purposes of the study, and added marginal transmission losses in order to report hourly marginal loss savings due to solar generation. According to one APS study, the degree of line losses may decrease as penetration increases.[42]

As with the effect of reducing market prices by reducing load at times of peak demand, and therefore reducing marginal wholesale prices (see below), DSG-induced reduction of losses at times of peak load has a spillover effect. The ability of customers to serve on-site load without use of the distribution system reduces transformer

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[38] *See* FERC Order No. 69, 45 Fed. Reg. 12214 at 12227.("If the load served by the [QF] is closer to the [QF] than it is to the utility, it is possible that there may be net savings resulting from reduced line losses. In such cases, the rates should be adjusted upwards.").

[39] For example, the E3 study assumes an average loss factor of 1.073, which indicates that 7.3% more energy is supplied to the grid than is ultimately delivered and metered by the end-use customers. In contrast, Vermont's study noted that the Department's energy efficiency screening tool concluded that typical marginal line losses are about 9%. Vermont Study at p.17.

[40] *See, e.g.,* A. Lovins *et al.*, Small Is Profitable: The Hidden Economic Benefits of Making Electrical Resources the Right Size, Rocky Mountain Institute, at p. 212, August 2002; U.S. Energy Information Administration's Annual Energy Review, *available at* http://www.eia.gov/totalenergy/data/annual/diagram5.cfm.

[41] CPR 2012 MSEIA Study at p. 27.

[42] *Distributed Renewable Energy Operating Impacts and Valuation Study, R. W. Beck for Arizona Public Service, Jan. 2009, at p. 4-7 and Table 4-3. (Finding that a "law of diminishing returns" applies to solar distributed energy installations.) Available at:* http://www.solarfuturearizona.com/SolarDEStudy.pdf.

overheating, a major driver of transformer wear and tear, and in turn allows customers to receive power from utility generators at lower marginal loss rates. Without on- or near-peak DSG, all customers would face higher marginal loss rates with the contribution to thermal transformer conditions caused by all customers seeking grid delivered power for all on-site needs at times of peak load.

With consideration of the line losses avoided in relation to both the energy that did not have to be delivered due to DSG, and the marginal improvement in line losses to deliver power for the rest of utility's customers' needs, the appropriate methodology developed by CPR is to look at total line losses without DSG and total line losses with DSG. In practice this can equal 15-20% of the energy value.

Separately, line losses figure into capacity value as well, as a peak demand reduction of 100 MW means in turn that a generation capacity of more than 100 MW is avoided. This aspect of avoided line losses should be included with generation and T&D capacity benefits, discussed below.

3. *Calculating generation capacity*

Determining the capacity benefits of intermittent, renewable generation is a more complex undertaking than analyzing energy value, but there is a demonstrated capacity value for DSG systems. Capacity value of generation exists where a utility can count on generation to meet its peak demand and thereby avoid purchasing additional capacity to generate and deliver electricity to meet that peak demand.

While individual DSG systems (without energy storage) provide little firm capacity value to a utility given the potential for cloud cover, there is compelling research supporting the consideration of the aggregate value of DSG systems in determining capacity value. A recent study by LBNL demonstrates that geographic diversity tends to smooth the variability of solar generation output, making it more dependable as a capacity resource.[43] As well, FERC considered the fact that distributed solar and wind should produce some capacity value when considered in the aggregate when it was developing its avoided cost pricing regulations.[44] Capacity value for DSG systems should look to the characteristics of all DSG generators in the aggregate, including the smoothing benefits of geographic diversity.

Solving for Intermittency. CPR developed the most prominent and widely used method to address the intermittency of DSG technologies. This method recognizes a capacity value for intermittent, non-dispatchable resources, and is referred to the as the "effective load carrying capability" ("ELCC"). ELCC is a statistical measure of capacity that is "effectively" available to a utility to meet load. "The ELCC of a generating unit in a utility grid is defined as the load increase (MW) that the system can carry while

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[43] *See* Andrew Mills and Ryan Wiser, *Implications of Wide-Area Geographic Diversity for Short-Term Variability of Solar Power* (Lawrence Berkeley National Laboratory), LBNL-3884E, September 2010.
[44] FERC Order No. 69, 45 Fed. Reg. 12214 at 12227 ("In some instances, the small amounts of capacity provided from [QFs] taken individually might not enable a purchasing utility to defer or avoid scheduled capacity additions. The aggregate capability of such purchases may, however, be sufficient to permit the deferral or avoidance of a capacity addition. Moreover, while an individual [QF] may not provide the equivalent of firm power to the electric utility, the diversity of these facilities may collectively comprise the equivalent of capacity.").

maintaining the designated reliability criteria (e.g., constant loss of load probability)."[45] In this way, ELCC provides a reliable statistical method to project the capacity value of intermittent resources.

On the other hand, the ELCC method can be data intensive and complex to some stakeholders. Simpler methods may also yield reasonable results. For example, an alternate method, based on the utility's load duration curve, looks at the solar capacity available for the highest load hours, usually the top 50 hours.

Implemented in a rate, a capacity credit for DSG denominated in kWh represents the best approach. This ensures that DSG only receives capacity credit for actual generation.

Valuing Small, Distributed Capacity Additions. An often controversial issue in determining avoided capacity value is the fact that distributed generation provides small, incremental additions and utility resource planning typically adds capacity in large, or "lumpy," blocks of capacity additions. For example, if a utility has ample capacity to meet its reserve margin and its next capacity addition will be a 500 MW CCGT, a utility might argue that incremental additions of 1 MW or 20 MW do not allow them to avoid capacity costs. FERC's regulations recognize that distributed generation provides a more flexible manner to meet growing capacity needs and can allow a utility to defer or avoid the "lumpy" capacity additions.[46] Therefore, it is inappropriate to hold that there is no capacity benefit for deployment of distributed generation in years that come before the time where the "lumpy" capacity investment is required. Distributed generation resources, like other demand-side resources that are continuously pursued to address load growth and to reduce peak demand, provide immediate benefit and a hedge against unexpected outages that could lead to a shortage in capacity. There is, therefore, no good reason to value DSG capacity for its long-term value only in years where it physically displaces the next marginal generating unit.

One solution around the valuation of incremental capacity additions versus lumpy additions that would follow more traditional utility planning is laid out in Crossborder Energy's 2013 update to the 2009 E3 Net Metering Cost-effectiveness study for California. In the E3 study, a mix of short-run and long-run avoided capacity costs are applied to renewable generators based on the fact that additional capacity would not be required until a certain year, called the "Resource Balance Year" in the E3 study. Crossborder's update recognizes the incremental value of small capacity additions for the years leading up to the Resource Balance Year and uses a long-run capacity value methodology for the life of the distributed generation system.[47] In other words, utilities are responsible for predicting load growth and planning accordingly, so the full penetration of DSG installations should already be built into their plans, reflecting the incremental capacity benefits these systems provide.

Adding It All Together: Determining the capacity credit for DSG systems. There are two basic approaches taken to determine capacity credit: (1) determine the market value

[45] CPR 2012 MSEIA Study at pp. 32-33.
[46] 18 C.F.R. 292.304(e)(2)(vii) (providing that avoided cost may value "the smaller increments and shorter lead times available with additions of capacity from qualifying facilities").
[47] Crossborder 2012 California Study, Appendix B.1.

of avoided capacity; or (2) estimate the marginal costs of operating the marginal generator, typically a CCGT.[48] For the same reasons that it is less than ideal to rely solely on the future projected market price for energy, it is also unreliable to credit DSG based on the projected future capacity market. The preferred approach is to determine the capacity credit by looking at the capital and O&M costs of the marginal generator.[49]

The resulting value is often termed a capacity credit—a credit for the utility capacity avoided by DSG. It is important to recognize that this credit is different from the "capacity value" of DSG. Capacity value is a term for the percentage of energy delivered as a fraction of what would be delivered if the DSG unit was always working at its rated capacity, that is, as if the sun were directly overhead with no clouds and the temperature was a constant 72 degrees at all times. Capacity value is typically in the range of 15-25% in the United States, depending on location. Because DSG generates electricity during daylight hours, often with high coincidence with peak demand periods, it earns a capacity credit based on the higher value of its generation during the hours in which it operates—a higher amount than simple capacity value. Alternatively, for a utility with an early evening peak or a winter peak, the capacity credit may be based on a lower percentage of its rated capacity than the capacity value.

Once the ELCC is determined for DSG resources for a given utility, the calculation of generation capacity is straightforward. The capacity credit for a DSG system is "the capital cost ($/MW) of the displaced unit times the effective capacity provided by PV."[50] Inherent in the ELCC calculation are the line losses associated with capacity, as discussed earlier.

4. *Calculating transmission and distribution capacity*

Distributed solar generation, by its nature, is usually located in close proximity to load on the distribution system, which may help reduce congestion and wear and tear on T&D resources. These benefits can reduce, defer, or avoid operating expenses and capital investments. Tactical and strategic targeting of distributed solar resources could increase this value.

The ability of DSG systems to yield T&D benefits is location-specific and also depends on the extent to which system output correlates to cost-causing local load conditions, especially before and during peak load periods. Utilities undertake system resource planning (i.e., planning for upgrades or additions to T&D capacity) to meet peak load conditions, so the correlation of DSG output to peak load conditions is important to understand. On the distribution system, unlike the bulk transmission system, this is a more difficult undertaking because local cost-causing load conditions (i.e., the timing, duration, and ramping rates associated with peak load on a given circuit) will vary according to a number of factors. These factors include customer mix, weather conditions, system age and condition, and others. As a simple example, a circuit that carries predominantly single-family residential load is likely to rise relatively smoothly to a peak in early evening, when solar PV output is waning. A circuit primarily serving

[48] CPR 2012 MSEIA Study at p. 32.
[49] *Id.* at pp. 32-33.
[50] *Id.*

commercial customers in a downtown setting will typically peak in the early afternoon. All other things being equal, DSG systems on circuits primarily serving commercial customers are more likely to avoid distribution capacity costs.

It is also important to consider system-wide T&D impacts. Transmission lines, and to an extent, substations, serve enough of a cross-section of the customer base to peak at approximately the same time as the utility as a whole. DSG coincidence with system peak means that DSG, even located on residential circuits, contributes to reduced demand at the substation level and above. Based on interconnection procedures, DSG systems in the aggregate on a circuit do not produce enough to export power off of the circuit; they simply reduce the need for service to the circuit. The avoided need for transmission infrastructure creates an avoided cost value to a utility and should be reflected as a benefit for DSG systems. Combining any granular distribution value with avoided, peak-related transmission costs, all DSG may demonstrate significant T&D value in allowing the utility to defer upgrades or avoid capital investments.

Estimating T&D Capacity Value. To determine the ability of DSG systems to defer T&D upgrades or capacity additions, it is critical to have current information on the system planning activities of utilities, and to periodically update that information. Often, the cost information is obtainable through rate case proceedings, where the utility ultimately seeks to include the upgrade or capital project in rate base. To make use of any cost data, however, it is important to have a sufficient amount of hourly data on both load and solar resource profiles. Much of the relevant information is also contained in utility maintenance cost data, grid upgrade and replacement plans, and capital investment plans. Beyond the planning horizon, expense and investment trends must be extrapolated to match the expected useful generating life of DSG.

With the data in hand, T&D capacity savings potential can be determined in a two-step process.[51] As described by CPR, "The first step is to perform an economic screening of all areas to determine the expansion plan costs and load growth rates for each planning area. The second step is to perform a technical load-matching analysis for the most promising locations."

For solar PV profiles, output can be estimated at particular places using irradiance data and various methods of estimating the output profile.[52] By looking at the load profile for a year, it is possible to isolate peak days at the circuit or substation level and calculate a capacity credit by measuring the net load with solar PV production. By reducing absolute peak load, DSG systems may allow a utility to avoid overloading transformers, substations or other distribution system components and, thereby, to defer expensive capital upgrades.

To determine deferral value, it is necessary to monetize the length of time that DSG allows a utility to defer a capital upgrade. Deferring an upgrade allows a utility to avoid the carrying cost or the cost of ownership of an asset and defers substantial expenditures that may be, at least to some extent, debt financed. Generally, the

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[51] *Id.* at p. 33 (citing T. E. Hoff, *Identifying Distributed Generation and Demand Side Management Investment Opportunities*, Energy Journal: 17(4), 1996).

[52] M. Ralph, A. Ellis, D. Borneo, G. Corey, and S. Baldwin, *Transmission and Distribution Deferment Using PV and Energy Storage*, published in Photovoltaic Specialists Conference (PVSC), 2011 37th IEEE, June 2011, *available at* http://energy.sandia.gov/wp/wp-content/gallery/uploads/TransandDistDeferment.pdf.

avoided capital is multiplied by the utility's weighted average cost of capital or authorized rate of return to determine the value of deferring that investment.[53] However, as noted earlier, a lower discount rate could be used. For instance, the avoidance of a million dollar transmission upgrade five years from now—for a utility with a 7% discount rate—is arguably worth that amount divided by (1.07)^5, or approximately $713,000. From the ratepayers' perspective, avoiding the million dollar upgrade in five years might be worth more; based on an estimated inflation rate of 3%, the value would be $862,000.

System-Wide Marginal Transmission and Distribution Costs. When conducting a statewide or utility-wide analysis, it may be difficult to hone in on specific locations to determine the ability of DSG systems to enable deferment or avoidance of system upgrade activity. In some cases, distribution deferral value manifests in changes in distribution load projection profiles and should be calculated as the difference in what would have happened without the DSG. E3's approach to valuing avoided T&D takes a broader look at the ability to avoid costs and estimates T&D avoided costs in a similar manner to other demand-side programs, such as energy efficiency. E3's avoided cost methodology develops "allocators" to assign capacity value to specific hours in the year and then allocates estimates of marginal T&D costs to hours. E3 acknowledges that it lacks sufficient data to base its allocators on local loads and that, ideally, "T&D allocators would be based upon local loads, and T&D costs would be allocated to the hours with the highest loads."[54]

E3 determined that temperature data, which is available in a more granular form for specific locations in the many climate zones of California's major utilities, would be a suitable proxy method for allocating T&D costs. After determining these allocators and assigning them to specific hours, E3 determined the marginal distribution costs by climate zone, using a load-weighted average. Since marginal transmission costs are specific to each utility, those are added to the marginal distribution costs to arrive at the overall marginal T&D for a specific climate zone. This approach lacks the potential for capturing high-value, location-specific deferral potential, but it does approximate some value without requiring extensive project planning cost and load data for specific feeders, circuits, and substations. E3's methodology may be suitable in circumstances where there is limited local load data to develop what E3 described as an "ideal" methodology, but it does come with drawbacks. For example, allocating costs to certain hours by temperature may not correlate to peak conditions in certain locations.

Alternative Approaches to T&D Valuation. Clean Power Research also approached T&D value broadly in its study of Pennsylvania and New Jersey, taking utility-wide average loads in a conservative approach to valuation. CPR's Pennsylvania and New Jersey report notes that T&D value may vary widely from one feeder to another and that "it would be advisable to . . . systematically identify the highest value areas."[55]

Where information on specific upgrade projects is known, and there is sufficiently detailed local load data, a more detailed analysis of deferral potential should yield far more accurate results that better reflect the T&D value of DSG. For example, CPR was

[53] *Id.*
[54] E3 Study, Appendix A at p. 16.
[55] CPR 2012 MSEIA Study at p. 20.

ablle to take a more granular and area-specific look at T&D deferral values of DSG in its Austin Energy study, where it had specific distribution system costs for discrete sections of the city's distribution system.[56]

In Vermont, the Public Service Department took a reliability-focused approach. Noting that T&D upgrades are driven by reliability concerns, the Department determined that the "critical value is how much generation the grid can rely on seeing at peak times." To capture this benefit, the Department calculated a "reliability" peak coincidence value by calculating the average generator performance of illustrative generators for June, July and August afternoons.[57] The resulting number reflects the percentage of a system's nameplate capacity that is assumed to be available coincident with peak, as if it is "always running or perfectly dispatchable."[58] Accordingly, the generation system receives the same treatment as firm capacity in terms of value for providing T&D upgrade deferrals at that coincident level of output.

The risk of the Vermont approach is that it may overstate the ability of certain generators to provide actual deferral of T&D upgrades, since system planners often require absolute assurance that they could meet load in the event that a particular distributed generation unit went down. Another apparent weakness of this approach is the inability to target or identify location-specific values in the dynamic, granular nature of the distribution system.

T&D Capacity Value Summary. Distributed solar systems provide energy at or near the point of energy consumption. When they are generating, the loads they serve are therefore are less dependent on T&D services than other loads. In addition, because DSG provides energy in coincidence with a key driver of consumption—solar insolation—these resources can reduce wear and tear. Calculating the T&D benefits of DSG requires data that allows estimation of marginal T&D energy and capacity related costs. Ideally, utilities will collect location-specific data that can support individualized assessment of DSG system value. In the absence of such data, system-wide estimations of T&D offset and deferral value can be used with reasonable confidence.

5. Calculating grid support (ancillary) services

Grid support services, also referred to as ancillary services in many studies, include VAR support, and voltage ride-through. Existing studies often include estimates of ancillary services benefits as well as costs associated with DSG, as reported in the RMI 2013 Study. Costs, also called grid integration costs, are discussed below.

Currently, DSG systems utilize inverters to change direct current to alternating current with output at a set voltage and without VAR output, and with the presumed functionality of disconnecting in the event of circuit voltage above or below set limits. This disconnection feature has become a concern, as a voltage dip with the loss of a major utility generator could lead to thousands of inverters disconnecting DSG systems, reducing voltage inputs and exacerbating the problem. In practice, inverters could be

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[57] Vermont Study at p. 19 (The Department looked at ten two-axis tracking solar PV systems, four fixed solar PV systems, and two small wind generators.).
[58] *Id.* at p. 19.

much more functional or "smart"; indeed Germany is in the process of changing out hundreds of thousands of inverters to achieve added functionality.

Because U.S. electrical codes generally preclude inverters that provide ancillary services, many valuation studies have concluded that no ancillary service value should be calculated. While that approach had some merit in the past, when more versatile inverters where generally unavailable and regulatory change seemed far off, the present circumstances warrant a near-term recognition of ancillary services value. With proof of the viability of advanced inverters, it is highly likely that advanced inverters will be standard in the next few years, and ancillary services will be provided by DSG.

A group of Western utilities and transmission planners recently issued a joint letter on the issue of advanced inverters, calling for the deployment as soon as feasible to avoid the sort of cascading problem described above, which could lead to system-wide blackouts.[59] With the utilities themselves calling for advanced inverter deployment, and costs expected to be only $150 more than current inverters, there will be good reason to collect the data and develop the techniques to quantify ancillary services benefits of DSG. Modeling these ancillary services is important to inform policy decisions such as whether to require such technology as a condition of interconnection, and under what circumstances.

6. Calculating financial services: fuel price hedge[60]

DSG provides a fuel cost price hedge benefit by reducing reliance on fuel sources that are susceptible to shortages and market price volatility. In addition DSG provides a hedge against uncertainty regarding future regulation of greenhouse gas and other emissions, which also impact fuel prices. DSG customer exports help hedge against these price increases by reducing the volatility risk associated with base fuel prices—effectively blending price stability into the total utility portfolio.

The ideal method to capture the risk premium of natural gas uncertainty is to consider the difference between an investment with "substantial fuel price uncertainty" and one where the uncertainty or risk has been removed, such as through a hypothetical 30-year fixed price gas contract. As CPR explains, a utility could quantitatively set aside the entire fuel cost obligation up front, investing the dollars into a risk free instrument while entering into natural gas futures contracts for future gas needs.[61] Performing this calculation for each year that DSG operates isolates the risk premium and provides the value of the price hedge of avoiding purchases involving that risk premium.

Interestingly, utilities often used to hedge against fuel price volatility, but do less such hedging now. That leads some utilities to conclude that since the fuel price hedge benefit is not avoiding a utility cost, it should not be included. In practice, the risk of fuel price volatility is falling on customers even if the utility is not mitigating the risk. Reducing that risk has value to utility customers, even if the utility would not otherwise protect against it.

[59] See L. Vestal, *Utility Brass Call for Smart-Inverter Requirement on Solar Installations*, California Energy Markets No. 1244, at p. 10, August 11, 2013.
[60] Clean Power Research now uses the term "Fuel Price Guarantee" in order to distinguish this benefit from traditional utility fuel price hedging actions.
[61] CPR 2012 MSEIA Study at p. 31.

7. *Calculating financial services: market price response*

Another portfolio benefit of DSG is measured in reductions to market prices for energy and capacity. By reducing demand during peak hours, when the price of electricity is at its highest, DSG reduces the overall load on utility systems and reduces the amount of energy and capacity purchased on the market. In this way, DSG reduces the cost of wholesale energy and capacity to all ratepayers.[62] This benefit is not captured by E3's methodology; it is reflected in CPR's most recent Pennsylvania and New Jersey study, where it is illustrated and explained in much greater detail.[63]

The premise of this benefit is that total expenditures on energy and capacity are less with DSG generation than without. The total expenditure, as CPR explains, is the current price of power times the current load at any given point in time. Because the amount of load affects the price of power, a reduced load condition, such as occurs as a result of DSG generation, reduces the market price of all other power purchases at those times.[64] While this change in market price is incrementally small, it represents a potentially significant system-wide benefit. This means that all customers, including non-solar customers, enjoy the benefit of lower prices during these reduced load conditions. As CPR notes, however, the reduction in price cannot be directly measured, as it is based on a hypothetical of what the price would have been without the load reduction, and must be modeled. The total value of market price reductions is the total cost savings calculated by summing the savings over all time periods during which DSG operates.[65] A similar analysis for capacity market prices can be conducted as well.

8. *Calculating security services: reliability and resiliency*

Particularly with the extended blackouts from Hurricane Sandy in 2012, a value is being attributed to added reliability and resiliency due to DSG, at both the grid and the individual customer levels. For grid benefits, this value in particular is difficult to quantify; it depends on the assumed risk of extended blackouts, the assumed cost to strengthen the grid to avoid that risk, and the assumed ability of DSG to strengthen the grid. With utility generation and T&D out of service, DSG can only do so much, and storm conditions often occur during periods of limited sunshine, so it is particularly hard to determine what DSG can do in this regard.

The ancillary services benefit discussed earlier is closely related to this benefit when considering the potential for the grid as a whole to continue operation. Even at the level of a circuit outage, the ancillary services benefit is capturing the value of providing VAR support and voltage ride-through. Arguably, the ancillary services benefit captures this level of grid support.

On the other hand, CPR noted in its first Austin Energy study that reliability and resiliency are very real DSG benefits at the individual customer level. The hospital with traditional backup generation powers up during an outage, and can be supported during a prolonged outage by the addition of DSG. Instead of relying entirely on the traditional generation and a substantial fuel supply, it can get by with less fuel. Likewise the

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[62] *Id.* at 15.
[63] *Id.* at pp. 33-43.
[64] CPR 2012 MSEIA Study at p. 34.
[65] *Id.* at p. 36.

residential customer with a medical condition requiring certainty can rely on DSG plus battery storage rather than a generator.

To the extent that utilities have an obligation to provided heightened reliability to vulnerable customers, DSG can be counted as avoiding those utility costs. On a larger scale, to the extent that customers enjoy greater reliability than the utility would otherwise provide, that is a benefit to participating customers that can be included.

9. *Calculating environmental services*

A. Utility avoided compliance costs. The cost of complying with regulatory and statutory environmental requirements is a real operating expense of a generating plant and should be included in the avoided cost of generation. This avoided cost typically is included in the studies as a direct utility cost. In the CPUC's 2010 CSI Impact Evaluation report, conducted by Itron, the CSI general market program and the Self-Generation Incentive Program ("SGIP") were estimated to be responsible for reducing over 400,000 tons of CO_2 emissions in 2010. Additionally, the report estimated that the CSI general market program and the SGIP provided over 52,000 pounds of PM_{10} and over 92,000 pounds of NOx emissions reductions in 2010.[66] These reductions can be quantified and calculated against the market price for the relative compliance instrument. To the extent these values are fully reflected in the cost of the avoided energy, they should not be counted again in a DSG valuation analysis. It is important to account for only residual environmental compliance costs in estimating the benefit of DSG.

While certain emissions credit markets will be geographically tied to a small area with no established compliance market, the markets for NOx, SOx, and CO_2 are more readily identified and quantified with publicly available sources. Accordingly, any study of DSG should include the value of avoided compliance costs reflected in air emissions, land use, and any consumption and discharge costs associated with water.

Likewise, utilities in states with Renewable Portfolio Standards ("RPS") avoid RPS compliance costs due to DSG. For example, if a utility must comply with a 20% RPS and has a billion megawatt hours ("MWh") of annual load, it has to secure 200 million MWh of renewable generation. If instead, 100 million MWh is generated by DSG facilities, the utility's annual load is reduced by that amount and its RPS compliance obligation is reduced by 20 million MWh. The utility's cost of procuring those 20 million MWh should be considered, to the extent that the procurement is greater than the utility's avoided natural gas energy and capacity costs already attributed to those 20 million MWh.

Quantification of societal benefits is particularly difficult and controversial. Regarding environmental benefits, avoided utility compliance costs capture what society has decided are the proper tradeoffs of electricity generation for pollution, but society recognizes additional value related to not generating electricity from fossil generation in the first place. If DSG within a given utility service territory avoids a 100 million MWh of gas-fired generation, the utility avoids paying for the required clean up the emissions

[66] *California Solar Initiative 2010 Impact Evaluation* (California Public Utilities Commission), prepared by Itron, at p. ES-2, 2011, *available at* http://www.cpuc.ca.gov/NR/rdonlyres/E2E189A8-5494-45A1-ACF2-5F48D36A9CA7/0/CSI_2010_Impact_Eval_RevisedFinal.pdf.

that never occurred. However, had the utility generated those 100 million MWh, millions of pounds of pollutants would have gotten past the required emissions controls, and not emitting all of those pollutants is a significant benefit to the society.

While most utility avoided costs benefit the utility's ratepayers directly, societal benefits tend to be spread beyond the utility's customers. Job creation can be expected to center in the utility's service territory, but will also lead to jobs in adjoining service territories. Emissions benefits are even more dispersed. The benefits are regional or global, with utility generation often far removed from utility customers. This is the traditional "tragedy of the commons[67]" problem, but on a global scale. As with the problem of colonial farmers not having an incentive to care for the commons on which their cows grazed, utilities use the environment but have no incentive to care for it beyond what is legally required. By recognizing the value of not emitting pollutants in a DSG valuation study, analysts capture this value that utilities would otherwise ignore. To say that this benefit is realized by society, but somehow not by utility customers, is to ignore the reality that society is made up of utility customers.

Again, we use the benefits categories outlined in the RMI 2013 Study, of which the last three address societal benefits and are listed here.

B. Carbon. The RMI 2013 Study breaks out carbon as a separate avoided cost, based on the significant uncertainty of carbon regulation. On the one hand, carbon markets and restrictions on carbon emissions have been frequently discussed, and tied to climate change. On the other hand, almost no carbon restrictions are currently in place, despite all of the discussion. Studies now five years old that presumed carbon costs by 2013 have been proven wrong. However, with the establishment of a carbon market in California, and the continuation of carbon markets in Europe, the likelihood of carbon costs throughout the U.S. is well beyond zero.

Even in the absence of a carbon market or carbon restrictions, the benefits of not emitting carbon are considered to be real by many people. While some have touted the benefits of carbon for plant life, the widespread view appears to be that emitting more carbon has a negative impact. One way to approach this is to consider what customers are willing to pay for reduced emissions of both carbon and other matter. For instance, Austin Energy uses the premium value for their GreenChoice® green power product in the absence of compliance cost information in its Value of Solar rate.

Another carbon valuation option is to use the added utility cost to comply with RPS targets. The argument for this approach is that if society has determined that a 20% RPS is appropriate, and renewable energy costs an extra $10 per MWH to procure, then it would presumably value additional avoided emissions (both carbon and other matter) at the same rate. However, RPS systems are compliance systems that integrate price impact controls, credit trading schemes, and other features that impact compliance certificate prices without direct relationship to the value of associated emissions reductions. Caution should be used in applying a regulatory system designed to minimize the cost of compliance with an effort to accurately value benefits net of costs.

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[67] G. Hardin, "The Tragedy of the Commons," Science 13 December 1968: 1243-1248. Available at: http://www.sciencemag.org/content/162/3859/1243.full?sid=f031fb58-2f56-4c25-ac0e-d802771c92ef

Where a state has a RPS mandate for its utilities, DSG provides a dual benefit. First, it lowers the number of retail sales that comprise the compliance baseline. Second, it results in the export of 100% renewable generation to the grid to offset some mix of renewable and fossil-fuel generation being produced to meet customer load.[68] The first benefit was discussed above, under avoided utility compliance costs. The second benefit accounts for the fact that energy exports from DSG are 100% renewable generation and arguably should be valued at 100% of the RPS value for purposes of a cost-benefit study.[69]

Another way to look at this is to say that all exports from a DSG system should receive the value of a market-priced renewable energy certificate, even where such a generator cannot easily create a tradable certificate.[70] This is justified because DSG exports help meet other customers' load on the utility's grid with 100% renewable energy and displace grid delivered electricity, which is only partially renewable. If a state has an RPS of 33% renewables, as does California, then DSG exports give rise to at least a 67% improvement in the renewable component of electricity.[71]

C. Airborne Emissions Other than Carbon and Health Benefits. Exceeding utility compliance with air regulations can be taken into account in a manner akin to that described for valuation of avoided carbon emissions. The public health impacts of fossil fuel generation have been well documented, though not well reflected in electricity pricing. In particular, air pollution can increase the severity of asthma attacks and other respiratory illnesses in vulnerable populations living in close proximity to fossil fuel-fired plants. Impacts on crops and forest lands have also been documented.

DSG reduces fossil fuel generation, especially from less efficient peaker plants and potentially from thermal plants that emit higher levels of pollution during startup operations. We are not aware of a dominant methodology, but note that public health literature will continue to grow in the area of recognizing and quantifying the public health impacts of electric generation, including health impacts related to climate change. Valuing emissions of carbon and other matter based on green energy pricing programs or RPS compliance costs, as described earlier, is an effective way to capture this benefit. Even outside of states with such programs, the value of reduced emissions is not zero; the value ascribed by nearby states with programs could serve as a proxy.

D. Avoided Water Pollution and Conservation Benefits. The utility industry uses and consumes a substantial portion of the nation's freshwater supplies for thermoelectric generation.[72] The benefit of not using the water for fossil-fuel generation should be

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[68] A third benefit associated with reducing overall market costs for renewable energy certificates may also manifest with increased DSG penetration.
[69] Crossborder 2013 California Study at pp.18-21.
[70] For example, owners of California NEM systems rarely bother to establish RECs related to their output given required documentation, and the treatment of RECs from NEM systems in a lower value "bucket" than RECs from systems with in-state wholesale sales to utilities.
[71] Crossborder 2013 California Study at p. 18.
[72] *How It Works: Water for Energy* (Union of Concerned Scientists), July 2013, *available at* http://www.ucsusa.org/clean_energy/our-energy-choices/energy-and-water-use/water-energy-electricity-overview.html.

based on the value of the water to society, that is, the value of conserving water for other beneficial uses.

Valuing water is intrinsically difficult. The tangle of water rights laws among the states complicate the determination of water value. To the extent that utilities have specific contracts for delivery or withdrawal of water to serve particular plants, it is likely that those expenses are already captured as an operating expense of the plant, but those are often at historic, ultra-low rates. Where a plant uses potable water, the value should be based on what society is willing to pay for that water. Likewise, where a plant is using non-potable, reclaimed water for cooling purposes, the appropriate value might be the price that someone would pay for an alternate use, such as irrigation.

The value to society of conserving water, which is of growing importance in water constrained regions of the country, is not adequately captured by the contract price for water or in the retail price that one would pay for an alternate use. We are not aware of a dominant methodology for measuring the conservation value of water, but this value should be considered as utilities consume a tremendous amount of water each year and will be increasingly competing for finite water resources. Avoiding the increased risk associated with maintaining secure, reliable, and affordable supplies of water is a benefit that DSG, with its 30-year expected operating life, delivers to all customers of the utility system.

10. <u>Calculating social services: economic development</u>

Installation and construction associated with onsite generation facilities is inherently local in nature, as contractors or installers must be within reasonably close geographic proximity to economically install a system and be present for building inspections. Accordingly, the solar industry creates local jobs and generates revenue locally. Economic activity associated with the growing rooftop solar industry creates additional tax revenue at the state and local levels as installers purchase supplies, goods and other related services subject to state and local sales tax, and pay payroll taxes. Locally spent dollars displace those frequently sent out of state for fuel and other supplies.

Taking a conservative approach, CPR's Pennsylvania and New Jersey study focused solely on tax enhancement value, which derives from the jobs created by the PV industry in those states. CPR used representative job creation numbers from previous studies in Ontario and Germany that quantify the number of jobs created by installing a unit of solar PV. CPR used assumptions that construction of solar PV involves a higher concentration of locally traceable jobs than construction of a centralized CCGT plant and determined the net local benefit of a solar project on the economy.

There remains a legitimate regulatory policy question of whether economic development benefits should be considered in calculating the value of DSG for use in setting electricity rates, or avoided cost calculations, even though there is a long history of economic development factors influencing commercial rates and line-extension fees. In any event, the economic development and tax base benefits of DSG deployment and operation should be consider when evaluating the societal cost-effectiveness of the technology and policies to support it.

Checklist of Key Requirements for a Thorough Evaluation of DSG Benefits

- ☑ **Energy benefits should be based on the utility not running a CT or a CCGT.** It is highly unlikely that DSG will offset coal or nuclear generation. Some combination of intermediate and peaking natural gas generation, with widely accepted natural gas price forecasts, should establish the energy value.
- ☑ **Line losses should be based on marginal losses.** Losses are related to load and DSG lowers circuit loads, which in turn lowers losses for utility service to other customers. Average line losses do not capture all of the loss savings; any study needs to capture both the losses related to the energy not delivered to the customer and the reduced losses to serve customers who do not have DSG.
- ☑ **Generation capacity benefits should be evaluated from day one.** DSG should be credited for capacity based on its Effective Load Carrying Capacity ("ELCC") from the day it is installed. If the utility has adequate capacity already, it may not have taken into account DSG penetration in its planning and overbuilt other generation; the DSG units that are actually operating during utility peaks should be credited with capacity value rather than a plant that is never deployed.
- ☑ **T&D capacity benefits should be assessed.** If the utility has any transmission plans, then DSG is helping to defer a major expense and should be included. On distribution circuits, watch for a focus on circuits serving residential customers, which tend to peak in the early evening when solar energy is minimal. Circuits serving commercial customers tend to peak during the early afternoon on sunny days, and a capacity value should be recognized for them in the form of avoided or deferred investment costs.
- ☑ **Ancillary services should be evaluated.** Inverters that can provide grid support are being mass-produced, and utility CEOs in the United States are calling for their use; ancillary services will almost certainly be available in the near future. Modeling the costs and benefits of ancillary services can also inform policy decisions like those related to interconnection technology requirements, and provides a hedging benefit.
- ☑ **A fuel price hedge value should be included.** In the past, utilities regularly bought natural gas futures contracts or secured long-term contracts to avoid price volatility. The fact that this is rarely done now and the customer is bearing the price volatility risk does not diminish the fact that adding solar generation reduces the reliance on fuels and provides a hedging benefit.
- ☑ **A market price response should be included.** DSG reduces the utility's demand for energy and capacity from the marketplace, and reducing demand lowers market prices. That means that the utility can purchase for less, saving money.
- ☑ **Grid reliability and resiliency benefits should be assessed.** Blackouts cause widespread economic losses that can be avoided in some situations with DSG. As well, customers who need more reliable service than average can be served with a combination of DSG, storage and generation that is less expensive than the otherwise necessary standby generator.
- ☑ **The utility's avoided environmental compliance costs should be evaluated.** DSG leads to less utility generation, and lower emissions of NOx, SOx and particulates, lowering the utilities costs to capture those pollutants.
- ☑ **Societal benefits should be assessed.** DSG policies were implemented on the basis of environmental, health and economic benefits, and should not be ignored or not quantified.

V. Recommendations for Calculating the Costs of DSG

Distributed solar generation comes with a variety of costs. These include the costs for the purchase and installation of the DSG equipment, the costs associated with interconnecting DSG to the electric grid, the costs of incentives, the cost associated with administration and billing, and indirect costs associated with lost revenues and other system-wide impacts. As with cost of service regulation in general, the important principles of cost causation and cost allocation are critical in dealing with DSG costs as well.

DSG cost estimation depends on the perspective from which one seeks to examine policies. Some costs, depending on perspective, should not be treated as costs in a DSG valuation study at all. For example, the cost of a DSG system net of incentives and compensation that the individual solar customer ultimately bears—the net investment cost, does not impact other customers. Whether a customer pays $100,000 or $20,000 for a five kilowatt ("kW") DSG system, the avoided utility costs and the societal benefits are unchanged.

In general, solar valuation studies address costs in varying degrees according to the aim of the individual study. A convenient way to characterize solar costs is according to who bears them. Costs relevant to determining value or cost effectiveness can generally be grouped into three categories:

1. Customer Costs—Customer costs are costs incurred by or accruing to the customers who use DSG. These include purchase and installation costs, insurance costs, maintenance costs, and inverter replacement, all net of incentives or payments received.
2. Utility and Ratepayer Costs—Utility and ratepayer costs are costs incurred by the utility and ratepayers due to the operation of DSG systems in the utility grid. These include integration and ancillary services costs, billing and metering costs, administration costs, and rebate and incentive expenses. In NEM valuation studies, utility lost revenues are potentially a significant utility cost, under the assumption that there are no other mechanisms to adjust for these losses.[73]
3. Decline in Value for Incremental Solar Additions at High Market Penetration—A number of studies also identify modeled impacts associated with significant penetration of solar on the utility system. Most studies characterize low penetration as less than 5% of peak demand or total energy met by solar generation, and characterize high penetration as 10%-15% or more. These

[73] Lost revenues arise when market penetration of consumption-reducing measures like energy efficiency and distributed generation have sales impacts that exceed those forecasted in the last rate-setting procedure, and only last until the next rate-setting, when a true-up can occur. Between rate cases, trackers or other mechanisms to mitigate impacts of regulatory lag can also be installed. Valuation studies themselves do not dictate whether lost revenues occur or are recovered. This is a function of tariff design. In some jurisdictions, for example, stand-by charges are used to adjust for revenue losses under NEM. In others, Buy All-Sell All arrangements or Net Billing models are used.

impacts can be accounted for as a cost or as an adjustment to value credit for solar energy when long-term impacts are considered.

When evaluating the cost-effectiveness of NEM, most utilities have access to cost-of-service data that can measure energy-related impacts. As noted earlier, the most direct and obvious source of potential cost or benefit of NEM policy is the mechanism that sets NEM customers apart from general ratepayers—the ability to use electricity not consumed instantaneously (i.e., exported energy) against future purchases of electricity in the form of a kWh or monetary bill credit. The value that customers derive from these bill credits is solely assignable to NEM as a policy, as distinguished from changes in behind-the-meter consumption that could occur under PURPA, in the absence of NEM policy. Accordingly, it is only appropriate to examine the net value of exports, and not behind the meter consumption, as a cost to non-participating ratepayers. It is also appropriate to note that NEM export costs are likely different depending on the class of customer generating excess solar energy. The good news is that the easy starting point for calculating NEM export energy costs is the monthly sum of the bill credits appearing on the customer bill, already adjusted by customer class. These credit costs can then be netted against the value of avoided produced or purchased energy.

1. Recommendations for calculating customer costs

Most value of solar studies focus on utility, ratepayer, and society costs, but not private costs. Therefore, these studies do not address customer investments or expenses in DSG. On the other hand, these costs are part of the total cost effectiveness of solar and have been addressed in broader societal perspective studies or in evaluating cost effectiveness for a solar incentive program. NEM and VOST programs are not intended to be incentive programs, but rather to fairly compensate customers for DSG.

When customer costs are included for a broader societal test, a major challenge in evaluating forward-looking solar customer costs associated with a long-term policy relates to accurately predicting the market prices for solar systems and installation as well as maintenance costs.

Regarding customer O&M costs, NREL has estimated costs between 0.05 and 0.15 cents per kWh.[74] E3 estimates customer O&M costs at $20 per kW with an escalator of .02% per year, factors inverter replacement at $25 per kW, once every 10 years, and estimates insurance expenses at $20 per kW, escalating at .02% per year.[75] Together, these O&M costs are fractions of a cent when converted to kWh, in line with the NREL estimate.

As noted, customer costs are rarely relevant to DSG policy valuation studies. The relevant question when evaluating DSG programs is what the net effect is on other utility customers.

2. Recommendations for calculating utility costs

[74] *Photovoltaics Value Analysis* (National Renewable Energy Laboratory), February 2008, *available at* http://www.nrel.gov/analysis/pdfs/42303.pdf.

[75] *Technical Potential for Local Distributed Photovoltaics in California: Preliminary Assessment* (Energy & Environmental Economics, Inc.), March 2012 ("E3 Technical Potential Study 2012"), *available at* http://www.cpuc.ca.gov/NR/rdonlyres/8A822C08-A56C-4674-A5D2-099E48B41160/0/LDPVPotentialReportMarch2012.pdf.

The most significant utility cost for NEM program valuation purposes is avoided revenue. A customer who used to pay $1000 per year to her utility and then installed a NEM system and cut her bills to only $200 per year is seen as costing the utility $800 of lost revenue. Again, to the extent that the customer could install the same system under PURPA and reduce her bill to $300 per year, the net cost of the NEM program would only be $100, representing the extra savings that she realized due to the NEM program. For a VOST program, the intent is to determine the value of the benefits and credit that amount to customers for all generation. In effect, the cost of the program is automatically equated to the benefits of the program, net of charges for consumption or network services.

The second largest utility or societal cost of DSG programs is the cost of incentives, though this cost is declining rapidly. Incentive costs are direct costs when the utility provides the funding from ratepayers, but are indirect when considering taxpayer-funded incentives. While incentive costs are real, they are primarily justified on market-stimulation bases, and scheduled to expire in a matter of years. Given that independent rationale for incentives, incentive costs are generally not included in DSG valuations. As the installed cost of DSG has declined, the need for incentives and rebates has diminished, with the California market reaching the end of its state incentive program almost entirely, and federal incentives slated to end in 2016.

Integration costs are the third most important utility cost for NEM programs, and the leading factor for value of solar studies addressing utility costs. Integration costs include the direct costs associated with administration of utility functions associated with distributed solar systems, rebates and incentives, and other administrative tasks. Direct costs can be addressed as a cost or as a decrement to the benefits of DSG, since these costs enable the benefits.

Reports of utility costs vary most significantly with the assumed solar penetration rate used in the study. Integration costs are variously labeled as "integration costs," "grid support expenses," or "benefits overhead." Estimates of these costs range from 0.1 to 1 cent per kWh in studies that attempt to account for increased variability in the overall generation mix and resulting increases in ancillary services costs starting from very low solar penetration rates. Solar integration costs for a 15% market penetration level were estimated at 2.2 to 2.3 cents per kWh by Perez and Hoff, based on an analysis that focuses on the need and cost of storage to complement solar intermittency in order to provide firm capacity.[76] Navigant and Sandia performed an assessment of high penetration of utility scale solar in 2011 and estimated integration costs associated with increasing production to account for solar variability at between 0.31 cents for low penetration and 0.82 cents for higher penetration of roughly one gigawatt of installed solar.[77]

In states like California, where utilities are prohibited from charging solar customers for interconnection costs or upgrades, interconnection costs may be a substantial source of costs directly assignable to a DSG program. Where this is the case, it is necessary to have real, disaggregated data that tracks the exact interconnection costs of DSG. In

[76] CPR 2012 MSEIA Study at p. 47.
[77] *Large Scale PV Integration Study* (Navigant), July 2011, *available at* http://www.navigant.com/insights/library/energy/2011/large-scale-pv-integration-study/.

the E3 study, for example, utilities did not have sufficient detail on interconnection costs in 2009 to provide a clear or transparent picture on the extent of those costs, or whether the costs incurred were reasonable and not blended in with other upgrades that would have occurred without the solar generator's interconnection. Interconnection costs should, in theory, be clearly identifiable through utility-provided data. In analyzing the value of distributed solar, these costs should also be amortized against the useful life of the measures.

In states where customers are responsible for interconnection costs and upgrades, however, this would not be a cost assignable to DSG policy. As with other customer costs, this is not a cost borne by the utility and should not be factored into an evaluation of the impact of a DSG policy on other customers.

Experience and more sophisticated modeling will be required to understand the shape and ultimate level of the integration cost curve. While integration costs are likely low at low market penetration levels, they are also likely to increase with market penetration. But these increases may decline as solar systems become more widely dispersed and as utilities begin targeting deployment to high-value locations within the grid. In addition, increased deployment of other distributed technologies, such as electric vehicles, distributed storage, load control, and smart grid technologies will impact the costs associated with larger scale DSG deployment.

The billing and administration costs associated with DSG encompass the one-time setup expenses of processing and verifying applications and the ongoing expense of administering unique features of solar customer bills. In states with modest numbers of solar customers, it is not uncommon to manually adjust solar customer bills, with associated incremental costs. Depending on the utility's accounting practices and billing capabilities, solar-specific billings cost should be relatively easily segregated and allocated. In states with automated processes, the ongoing incremental costs of administering solar customer accounts should be, as was determined in the Vermont study, nearly zero.[78]

In some cases, utilities will incur costs directly associated with DSG that are not fairly assignable to DSG policy. For example, in Texas, renewable energy generators under one MW are classed as "microgenerators," subject to registration and reporting requirements under the state's renewable energy portfolio standard law.[79] To the extent that the utility acts as a program manager and aggregator of renewable energy certificates assigned by solar generators, these costs are not fairly assigned to NEM or other solar promotional program unless also offset by the value of the assigned certificates.

3. Recommendations for calculating decline in value for incremental solar additions at high market penetration

The incremental positive value of additional solar deployment within a particular utility service territory is anticipated to decline as solar penetration levels increase. There are two major drivers of these impacts, which are not technically costs, but actually

[78] Vermont Study at p. 15.

[79] *See* 16 Tex. Admin. Code 15, *available at* http://www.puc.texas.gov/agency/rulesnlaws/subrules/electric/25.173/25.173.pdf.

decrement adjustments that impact value of solar in the context of expanding markets and higher solar penetration.

These impacts address the value of additional deployments and not past installations, and not replacement installations. The two major drivers are the expected reduction in capacity credit for solar and reduced peak energy value as market penetration increases. Capacity credits for solar are typically higher than capacity factor due to good solar coincidence with peak demand periods. However, as more solar is added to a system, the difference between peak and non-peak demand dissipates. Without storage, solar has a limited ability to reduce a system peak that is essentially shifted forward into evening hours. As a result, the incremental capacity benefit of solar is reduced for incremental additions as penetration increases. This impact could reduce capacity credit by 20-40% as penetration rates approach 15%.[80]

To the extent that solar energy is generated at periods of high utility cost, it provides great value. As the penetration rate of solar increases, peak market prices are likely suppressed, reducing the value of incremental solar energy. E3 estimated the reduced energy value at 15% over ten years in a study for California.[81]

Much work is needed in measuring and modeling the impact of high penetrations of DSG to address exactly how much DSG creates high penetration impacts, and inserting this clarity in valuation and cost effectiveness studies. Most states receive less than 0.5% of peak energy from distributed solar generation, while most studies looking at high penetration model levels at 10-15%. As noted earlier, the most relevant costs to consider are those that will occur at more modest penetrations. For example, if capacity benefits decline significantly at higher penetrations, that does not justify finding low capacity benefits at early stages.

Other important issues to be addressed include the impacts of different assumptions regarding geographic region, system size, and long-term changes in energy demand. It is important to note that both the capacity credit and energy value deterioration could be mitigated through consideration of energy sales from areas of high solar penetration to areas of lower penetration. For example, utilities facing near term surplus capacity situations could incur short-term lost revenues that could be mitigated over the period that solar systems operate, creating the potential for net benefits over that longer term.

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[80] *See* LBNL Utility Solar Study 2012, *supra*, footnote 13.

[81] *See* E3 Technical Potential Study 2012, *supra*, footnote 74.

Checklist of Key Requirements for a Thorough Evaluation of DSG Costs

- ☑ **Is lost revenue or utility costs the basis of the study?** For NEM studies, lost revenue is the standard (what the DSG customer would have otherwise paid the utility). For other studies and even some NEM studies, the cost to serve the DSG customer is addressed instead, which should lead to an inquiry in particular regarding allocation of capacity costs.
- ☑ **Assumptions about administrative costs must reflect an industrywide move towards automation.** With higher penetration, costs per DSG customer tend to decline, so administrative costs should assume automation of processes.
- ☑ **Interconnection costs should not be included.** If the DSG customer pays for the interconnection, this should not be included as a cost to the utility. As well, the utility's interconnection costs should be compared to national averages to determine whether they are reasonable.
- ☑ **Integration costs should not be based on unrealistic future penetration levels.** Studies tend to find minimal grid upgrade requirements at DSG penetrations below a few percent. Looking ahead to what the grid might need to accommodate 50% penetration unnecessarily adds costs that are not actually being incurred.

VI. Conclusion

Valuations vary by utility, but valuation methodologies should not. In this report IREC and Rabago Consulting LCC suggests a standardized approach for calculating DSG benefits and costs that we hope proves helpful to regulators as they embark on commissioning or reviewing valuation studies. Please see the mini-guide at the end of this report for a quick reference guide to the recommendations in this report.

IREC

REGULATOR'S MINI-GUIDEBOOK

Calculating the Benefits and Costs of Distributed Solar Generation

Valuations vary by utility, but valuation methodologies should not. IREC and Rábago Energy LLC suggest a standardized approach for calculating DSG benefits and costs in the white paper "A REGULATOR'S GUIDEBOOK: Calculating the Benefits and Costs of Distributed Solar Generation." We hope that this paper proves helpful to regulators as they embark on commissioning or reviewing valuation studies. Below is a high-level summary of the recommendations in the white paper. Please see the full report for more detail per section.

A. KEY QUESTIONS TO ASK AT THE ONSET OF A STUDY

Q1: WHAT DISCOUNT RATE WILL BE USED?

Recommendation: We recommend using a lower discount rate for DSG than a typical utility discount rate to account for differences in DSG economics.

Q2: WHAT IS BEING CONSIDERED – ALL GENERATION OR EXPORTS ONLY?

Recommendation: We recommend assessing only DSG exports to the grid.

Q3: OVER WHAT TIMEFRAME WILL THE STUDY EXAMINE THE BENEFITS AND COSTS OF DSG?

Recommendation: Expect DSG to last for thirty years, as that matches the life span of the technology given historical performance and product warranties. Interpolate between current market prices (or knowledge) and the most forward market price available or data that can accurately be estimated, just as planners do for fossil-fired generators that are expected to last for decades.

Q4: WHAT DOES UTILITY LOAD LOOK LIKE IN THE FUTURE?

Recommendation: Given that NEM resources are interconnected behind customer meters, and result in lower utility loads, the utility can plan for lower loads than it otherwise would have. In contrast, other DSG rate or program options involving sale of all output to the utility do not reduce utility loads, but rather the customer facilities contribute to the available capacity of utility resources.

Q5: WHAT LEVEL OF MARKET PENETRATION FOR DSG IS ASSUMED IN THE FUTURE?

Recommendation: The most important penetration level to consider for policy purposes is the next increment: what is likely to happen in the next three to five years. If a utility currently has 0.1% of its needs met by DSG, consideration of whether growth to 1% or even 5% is cost-effective is relevant, but consideration of whether higher penetrations are cost-effective can be considered at a future date.

Q6: WHAT MODELS ARE USED TO PROVIDE ANALYTICAL INPUTS?

Recommendation: Transparent input models that all stakeholders can access will establish a foundation for greater confidence in the results of the DSG studies. When needed, the use of non-disclosure agreements can be used to overcome data sharing sensitivities.

Q7: WHAT GEOGRAPHIC BOUNDARIES ARE ASSUMED IN THE ANALYSIS?

Recommendation: It is important to account for the range in local values that characterize the broader geographical area selected for the study. In some cases, quantification according to similar geographical sub-regions may be appropriate.

Q8: WHAT SYSTEM BOUNDARIES ARE ASSUMED?

Recommendation: It may also be appropriate to consider impacts associated with adjacent utility systems, especially at higher (above 10%) penetration levels of DSG. [82]

Q9: FROM WHOSE PERSPECTIVE ARE BENEFITS AND COSTS MEASURED?

Recommendation: We recommend that ratepayer and societal benefits and costs should be assessed.

Q10: ARE BENEFITS AND COSTS ESTIMATED ON AN ANNUALIZED OR LEVELIZED BASIS?

Recommendation: We recommend use of a levelized approach to estimating benefits and costs over the full assumed DSG life of 30 years. Levelization involves calculating the stream of benefits and costs over an extended period and discounting to a single present value. Such levelized estimates are routinely used by utilities in evaluating alternative and competing resource options.

B. DATA SETS NEEDED FROM UTILITIES

- ☑ The five or ten-year forward price of natural gas, the most likely fuel for marginal generation, along with longer-term projections in line with the life of the DSG
- ☑ Hourly load shapes, broken down by customer class to analyze the intra-class and inter-class impacts of NEM policy
- ☑ Hourly production profiles for NEM generators, including south-facing and west-facing arrays
- ☑ Line losses based on hourly load data, so that marginal avoided line losses due to DSG can be calculated
- ☑ Both the initial capital cost and the fixed and variable O&M costs for the utility's marginal generation unit

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[82] Mills and Wiser point out that consideration of inter-system sales of capacity or renewable energy credits could mitigate reductions in incremental solar value that could accompany high penetration rates. *See* A. Mills & R. Wiser, *An Evaluation of Solar Valuation Methods Used in Utility Planning and Procurement Processes* (Lawrence Berkeley National Laboratory), LBNL-5933E, at p. 23, December 2012 (nt Processes energy credits could *available at* http://emp.lbl.gov/publications/evaluation-solar-valuation-methods-used-utility-planning-and-procurement-processes.

☑ Distribution planning costs that identify the capital and O&M cost (fixed and variable) of constructing and operating distribution upgrades that are necessary to meet load growth

☑ Hourly load data for individual distribution circuits, particularly those with current or expected higher than average penetrations of DSG, in order to capture the potential for avoiding or deferring circuit upgrades

Note: where a utility or jurisdiction does not regularly collect some portion of this data, there may be methods to estimate a reasonable value to assign to DSG.

C. RECOMMENDATIONS FOR ASSESSING BENEFITS

1. **The following benefits should be assessed:**

    1. Energy
    2. System Losses
    3. Generation Capacity
    4. Transmission and Distribution Capacity
    5. Grid Support Services
    6. Financial: Fuel Price Hedge
    7. Financial: Market Price Response
    8. Security: Reliability and Resiliency
    9. Environment: Carbon& Other Factors
    10. Social: Economic Development

2. **Energy benefits should be based on the utility not running a CT or a CCGT.** It is highly unlikely that DSG will offset coal or nuclear generation. Some combination of intermediate and peaking natural gas generation, with widely accepted natural gas price forecasts, should establish the energy value.

3. **Line losses should be based on marginal losses.** Losses are related to load and DSG lowers circuit loads, which in turn lowers losses for utility service to other customers. Average line losses do not capture all of the loss savings; any study needs to capture both the losses related to the energy not delivered to the customer and the reduced losses to serve customers who do not have DSG.

4. **Generation capacity benefits should be evaluated from day one.** DSG should be credited for capacity based on its Effective Load Carrying Capacity ("ELCC") from the day it is installed. If the utility has adequate capacity already, it may not have taken into account DSG penetration in its planning and overbuilt other generation; the DSG units that are actually operating during utility peaks should be credited with capacity value rather than a plant that is never deployed.

5. **T&D capacity benefits should be assessed.** If the utility has any transmission plans, then DSG is helping to defer a major expense and should be included. On distribution circuits, watch for a focus on circuits serving residential customers, which tend to peak in the early evening when solar energy is minimal. Circuits serving commercial customers tend to peak during the early afternoon on sunny days, and a capacity value should be recognized for them in the form of avoided or deferred investment costs.

6. **Ancillary services should be evaluated.** Inverters that can provide grid support are being mass-produced, and utility CEOs in the United States are calling for

their use; ancillary services will almost certainly be available in the near future. Modeling the benefits and costs of ancillary services can also inform policy decisions like those related to interconnection technology requirements.

7. **A fuel price hedge value should be included.** In the past, utilities regularly bought natural gas futures contracts or secured long-term contracts to avoid price volatility. The fact that this is rarely done now and that the customer is bearing the price volatility risk does not diminish the fact that adding solar generation reduces the reliance on fuels and provides a hedging benefit.
8. **A market price response should be included.** DSG reduces the utility's demand for energy and capacity from the marketplace, and reducing demand lowers market prices. That means that the utility can purchase these services for less, saving money.
9. **Grid reliability and resiliency benefits should be assessed.** Blackouts cause widespread economic losses that can be reduced or avoided in some situations with DSG. As well, customers who need more reliable service than average can be served with a combination of DSG, storage and generation that is less expensive than the otherwise necessary standby generator.
10. **The utility's avoided environmental compliance and residual environmental costs should be evaluated.** DSG leads to less utility generation, and lower emissions of NOx, SOx and particulates, lowering the utilities costs to capture or control those pollutants.
11. **Societal benefits should be assessed.** DSG policies were implemented on the basis of environmental, health and economic benefits, which should not be ignored and should be quantified.

D. RECOMMENDATIONS FOR ASSESSING COSTS

1. **Determine whether lost revenue or utility costs are the basis of the study.** For NEM studies, lost revenue is the standard (what the DSG customer would have otherwise paid the utility). For other studies and even some NEM studies, the cost to serve the DSG customer is addressed instead, which should lead to an inquiry in particular regarding allocation of capacity costs.
2. **Assumptions about administrative costs should reflect an industry-wide move towards automation.** With higher penetration, costs per DSG customer tend to decline, so administrative costs should assume automation of processes.
3. **Interconnection costs should not be included.** If the DSG customer pays for the interconnection, this should not be included as a cost to the utility. As well, the utility's interconnection costs should be compared to national averages to determine whether they are reasonable.
4. **Integration costs should not be based on unrealistic future penetration levels.** Studies tend to find minimal grid upgrade requirements at DSG penetrations below a few percent. Looking ahead to what the grid might need to accommodate 50% penetration unnecessarily adds costs that are not actually being incurred.