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BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

DOUG LITTLE - Chairman
BOB STUMP
BOB BURNS
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ANDY TOBIN

IN THE MATTER OF THE COMMISSION'S INVESTIGATION OF VALUE AND COST OF DISTRIBUTED GENERATION.	DOCKET NO. E-00000J-14-0023 **STAFF'S INITIAL CLOSING BRIEF**

I. INTRODUCTION.

This case is about the methodologies for determining the cost and value of a solar distributed generation ("DG solar"). The methodologies adopted should be used in electric utility rate cases to help inform the Commission's decision making on related policy and ratemaking issues. The process should provide the Commission with maximum flexibility to address the benefit/cost issues given utility specific circumstances.

II. BACKGROUND.

A. Decision No. 74202.[1]

The Arizona Corporation Commission ("ACC" or "Commission") issued Decision No. 74202 in December 2013. That Decision required that a generic docket be opened to examine the "net metering issue and hold workshops with all stakeholders to help inform future Commission policy on the value that DG installations bring to the grid."[2] Commission Staff opened the instant docket on January 24, 2014.

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[1] Decision No. 74202.
[2] *Id.* at 30.

Commission Decision No. 74202 further ordered that

> the workshops shall investigate the currently non-monetized benefits of DG with the goal of developing a methodology for assigning DG values." The workshops shall be based upon the Commission's determination of the presence of a cost shift from DG customers to non-DG residential customers, and shall provide for the Commission's future full consideration of the net metering cost shift issue, the development of a method(s) by which the value of DG can be considered and balanced in the public interest, and the evaluation of the role and value of the electric grid as it relates to rooftop solar, other forms of distributed generation, and customer-sited technology generally.[3]

The Staff subsequently held workshops on the issues identified by the Commission.

On January 27, 2014 Staff submitted its comments on how to proceed with the generic docket by requesting written comments from the parties as to the relevance and significance of each of the listed categories of DG values, costs, and recommendations of other DG-related issues that should be considered in this docket. In addition, Staff requested substantive comments from all parties regarding the process and methodology for assigning monetary values to DG costs and values.

There were numerous responses from various interested parties on how to proceed and the topics to be covered. At an October 2015 Open Meeting, the Commission ordered that an evidentiary hearing be held in this generic docket covering the value and cost of DG, and cost of service issues related to the provision of service to DG and non-DG customers. A procedural order was issued on December 3, 2015 outlining how to move forward and setting the initial date of the hearing for April 18, 2016.

B. Decision Nos. 62506[4], 63364,[5] and 63486.[6]

The Commission's renewable initiatives go back to 1996 or earlier when the ACC rules provided for a solar portfolio standard, which set a goal of .02 percent from solar energy by 1999 and 1 percent by 2003. Subsequently, the ACC approved an Environmental Portfolio Standard ("EPS') which required regulated utilities to generate 0.4 percent of their power from renewables in 2002,

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[3] In the Matter of Arizona Public Service Company's Application for Approval of Net Metering Cost Shift Solution, Docket No. E-01345A-13-0248, Order, (December 2013).

[4] In the Matter of the Generic Investigation of the Development of a Renewable Portfolio Standard as a Potential Part of the Retail Electric Competition Policy, Docket No. E-00000A-99-0205, Opinion and Order (May 4, 2004).

[5] In the Matter of Commission Consideration and Possible Action on Requests for Rehearing and Reconsideration to Modify Decision No. 63364, adopting the Environmental Portfolio Standard Rules, Docket No. RE-00000C-00-0377 (February 8, 2001).

[6] Docket No. RE-00000C-00-0377 (March 29, 2001).

increasing to 1.1 percent in 2007-2012. Solar power was to make up 50 percent of the total renewables in 2001, increasing to 60 percent in 2004-2012. In 2003, the ACC began its REST rulemaking proceedings.

C. Decision Nos. 68566[7] and 69127.[8]

In Decision No. 68566, the Commission commenced a rulemaking for the adoption of a new Renewable Energy Standard and Tariff. In Decision No. 69127, the Commission adopted a new Renewable Energy Standard and Tariff ("REST") rules, contained at Arizona Administrative Code ("A.A.C.") 14-2-1801 through 1815. The REST rates require regulated utilities to produce at least 15 percent of their retail sales from renewable resources by 2025. R14-2-1805 provides for a Distributed Renewable Energy Requirement. Subpart B provides: that an Affected Utility's Distributed Renewable Energy Requirement shall be calculated each calendar year by applying the following applicable annual percentage to the Affected Utility's Annual Renewable Energy Requirement: (After 2011 - 30%).

D. Decision Nos. 69877[9] and 70567.[10]

In Decision No. 69877, the Commission adopted the Public Utility Regulatory Policies Act of 1978 ("PURPA") standard on net metering. The Commission also ordered the Staff to begin a rulemaking process to draft rules on net metering. In Decision No. 70567, the Commission adopted net metering rules contained at A.A.C. R14-2-2301 through R14-2-2308.

E. Decision No. 71819.[11]

The Commission also has a long history promoting Energy Efficiency ("EE"). Since the mid-1990s, the ACC has approved funding to support utility-sponsored EE initiatives. In 2011, the ACC adopted the Electric Energy Efficiency Rules, which contain requirements for EE and Demand-side management ("DSM") programs and measures. A.A.C. 14-2-2401 through 2419. The rules require

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[7] In the Matter of the Proposed Rulemaking for the Renewable Energy Standard and Tariff Rules, Docket No. RE-00000C-05-0030.

[8] Docket No. RE-00000C-05-0030, Opinion and Order (November 14, 2006).

[9] In the Matter of Net Metering In the Generic Investigation of Distributed Generation, Docket No. E-00000A-99-0431, Order (August 24, 2007).

[10] Docket No. RE-00000C-00-0377 (March 29, 2001).

[11] In the Matter of the Notice of Proposed Rulemaking on Electric Energy Efficiency, Docket No. RE-00000C-09-0427, Opinion and Order (August 10, 2010).

affected utilities to achieve cumulative annual energy savings equivalent to at least 22 percent of the affected utility's retail electric energy sale[s] for 2019.[12]

III. EXECUTIVE SUMMARY.

The following parties offered Value of Solar methodologies for the Commission's consideration in this Docket: Commission Staff, the Residential Utility Consumer Office ("RUCO"), APS, Tucson Electric Power Company ("TEP")/Unisource Electric ("UNSE"), The Alliance for Solar Choice ("TASC") and Vote Solar. All of these methodologies coalesce around a determination of value that is reflected in the "export" rate, or the energy put back on the grid by a DG solar customer, which is now part of the net metering equation. The methodologies are all based upon a formulation of "avoided cost" or an avoided cost proxy. While there are many areas of agreement between the parties; there are just as many areas of disagreement.

Staff has put forth two methodologies for the Commission's consideration, and urges the Commission to adopt both methodologies for consideration in the context of electric utility rate cases. Consideration of both avoided cost results will give the Commission more flexibility in terms of any upcoming policy and ratemaking issues brought before it. The first method proposed by Staff is a traditional avoided cost analysis which can be based upon a long-term or short-term analysis. While Staff witness Solganick favors a shorter term analysis, Staff is not opposed to a long-term analysis as long as caution is taken with respect to the determination of costs and benefits, since in a long-term analysis underlying conditions may change resulting in either overpayments or underpayments in the export rate. The determination of avoided cost can be a complicated undertaking and the methodology adopted needs to be specific in how it is to be calculated and done in a fashion that can be accommodated in the rate case process.

The second methodology proposed by Staff for the determination of avoided cost is the weighted average cost of the utility owned grid-scale solar and the utility's solar Purchase Power Agreements ("PPA"). At Staff's request, both APS and TEP/ UNSE developed spreadsheets for this

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[12] *Id.*

calculation.[13] The methodology produces a reliable reflection of the utility's weighted average avoided grid-scale solar costs.

The other VOS methodologies proposed by the parties include traditional short-term and long-term avoided costs analyses; an adjusted grid scale methodology, and a market based step down methodology. Each of these proposed approaches is addressed in Staff's brief. While no party is recommending that the Commission set any specific rates in this proceeding, Staff does offer what evidence it has to show what the various methodologies would produce in terms of an export rate, for informational purposes only.

As a general rule, Staff witness Howard Solganick suggests that DG customers be offered "a price [for the export rate] that is understandable, easy to administer, is consistent with the utility's other opportunities to purchase energy with similar characteristics and comports with the utility's responsibility to procure energy at a reasonable price."[14]

IV. DETERMINING THE VALUE OF SOLAR.

A. Net Metering.

Net Metering ("NEM") is a significant part of the Value of Solar debate. As discussed above the Commission adopted net metering rules in 2006 in Decision No. 70567. Those rules are contained at A.A.C. R14-2-2301 *et seq*. As defined by these rules, NEM allows electric utility customers to be compensated for generating their own electric energy from renewable resources, fuel cells, or Combined Heat and Power systems (collectively "distributed generation" or "DG"). If the customer's energy production exceeds the energy supplied by the electric utility during a billing period, the customer's bill for subsequent billing periods is credited for the excess generation. That is, the excess kWh generated during the billing period is used to reduce the kWh billed by the electric utility during subsequent billing periods. Effectively, this credit process compensates the customer (and incents the development of distributed generation) by requiring the electric utility company to

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[13] APS' Response to Staff's Fourth Set of Data Requests, Public Version, Ex. S-5; Spreadsheets, APS 15898 and APS 15913 (Confidential), Ex. S-6; Staff's Exhibits for Hearing June 9, 2016, TEP/UNSE Public Information, Ex. S-9; Staff's Exhibits for Hearing June 9, 2016, TEP/UNSE Confidential/Highly Confidential, Ex. S-10; Staff's Exhibits for Hearing June 13, 2016 TEP/UNSE Confidential/Highly Confidential, Ex. S-12; Staff's Exhibits for Hearing June 13, 2016, APS Confidential and Highly Confidential, Ex. S-13; TEP and UNSE's Joint Supplemental Response to Staff's Third Set of Data Requests, Ex. S-13.

[14] Solganick Direct Test., Ex. S-2 at 19.

acquire the customer's excess generation at the customer's current effective retail rate. In order to prevent abuse of the NEM incentive, the Arizona NEM Rules limit the size of customer DG systems to a maximum of 125 percent of the NEM customer's total connected load.

Once each year (or for a customer's final bill upon discontinuance of service), the electric utility credits the customer for the balance of any remaining excess kWh. The payment for the purchase of these year-end excess kWh is at the electric utility's annual average avoided cost, which is specified on the electric utility's NEM Tariff. A.A.C. R14-2-2302(1) defines avoided cost as "the incremental cost to an Electric Utility for electric energy or capacity or both which, but for the purchase from the NEM facility, such utility would generate itself or purchase from another source."

What distinguishes DG solar from other forms of DSM programs, is the export function where excess power from the facility can flow back to the grid. If the DG solar customer did not export power to the grid, there would be no need for NEM.

Like many state net metering rules, the Arizona rules provide for "banking" or accumulation of credits for excess power. When the meter runs "backwards," the customer receives credit for his generation exports at the retail rate.

The NEM rules were adopted by many states at a time when solar PV was a nascent industry and States wanted to incent its growth and adoption by customers.[15] Now, Arizona and many of these states are grappling with the issue of whether the same level of subsidies are necessary today to the same extent they were 20 years ago and whether net metering should continue to be a significant part of the value equation.

In addition to providing compensation for a wholesale service (exported energy) at a retail rate, net metering's banking and crediting or netting provisions also provide significant subsidies or forms of compensation to NEM customers. This is why Staff witness Solganick recommends that "over the long-term net metering and the banking of excess energy associated with net metering be eliminated and replaced with a direct mechanism for purchasing excess DG energy."[16]

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[15] Decision No. 70567.
[16] Solganick Direct Test., Ex. S-2 at 18.

The current net metering mechanism essentially provides for a 1-for-1 offset, the result of which is to value all excess DG energy, at a utilities retail kWh rate regardless of the time of day or year it is measured. This means that DG energy can be exported during the winter or mid-day when prices are low and then used to offset energy purchases that would otherwise occur during the summer when prices are high.[17] Simply stated, netting provides DG customers with a retail rate offset, and the duration of this netting period (can be seasonal, monthly, daily, annual or instantaneous) can greatly skew the value of excess energy. The longer the netting duration, the more valuable it is to a solar customer and the solar industry. When netting occurs, a utility is unable to account for the energy consumed by the DG customer as well as the energy exported to the grid. The two simply cancel each other out on the customer's bill.

TEP witness Tilghman discussed this disparity in his Direct Testimony:

> This policy [banking], along with a full retail rate credit for excess generation, drives many solar providers to design DG systems to produce as much energy as possible in the non-summer months in order to "get through" the summer months without having to pay for the energy generated and delivered by the utility that was consumed by the customer. The value of energy produced by a solar system between October and May ***is not*** equivalent to the energy consumed by the customer during the summer peak demand moths of June through September.[18]

It is clear that many solar entities that lease or sell systems to customers as well as NEM customers themselves, consider the potential banking and netting effect on the price they pay for energy (which can be considerable) as a significant part of the overall value proposition. TASC witness Beach notes that the typical PV installation, the amount of energy exported to the grid is on average approximately one-third of total PV production.[19]

In order to address some of these issues and other cost shift issues, Staff believes that the concept of net metering needs to transition into a new more simplified billing mechanism which allows for excess DG energy to be purchased from a customer by a utility at an appropriate export rate. Thus, the customer would still be compensated for energy put back on the grid, but at a rate to be determined by the Commission. However, the concepts of banking and netting need to be

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[17] Tilghman Direct at 4-5.
[18] *Id.*
[19] Beach Direct Test., Ex. TASC-26 at 12.

reconsidered as part of the overall value proposition. But, the appropriate place to consider these aspects of Net Metering, are in a rulemaking proceeding or in each utility's rate case.

B. The Avoided Cost Methodology.

All parties in this Docket agree that VOS methodologies should be based upon an avoided cost study or an avoided cost proxy. Avoided cost is defined as the "costs of energy that would have been produced or purchased but for the existence of the DG."[20]

Well recognized categories of costs/benefits have evolved for these studies.[21] One of the most extensive was used by the Public Utilities Commission of Nevada ("PUCN") which found 11 components to the value of DG (based on an adopted stipulation on NEM issues form South Carolina). They included the following avoided cost categories: 1) avoided energy costs, 2) avoided line losses, 3) avoided generation capacity,[22] 4) avoided ancillary services; 5) avoided transmission and distribution capacity, 6) avoided criteria pollutants, 7) avoided CO2 emission costs, 8) fuel hedging, 9) utility integration costs and interconnection costs, 10) utility administration costs;[23] and 11) avoided environmental costs.[24]

This list is consistent with much of the avoided cost discussion in this Docket, although the avoided criteria pollutant and avoided CO2 emission costs are typically included as part of environmental costs. In addition, integration and interconnection costs are sometimes referred to as grid support services.[25] TASC has also included market price mitigation and avoided renewables as additional costs/benefits to consider.[26] In addition, Chairman Little's list includes a cost called utility

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[20] Solganick Direct Test., Ex. S-2 at 10.

[21] These are generally the same categories referenced by Chairman Little in a December 22, 2015 letter to the docket: 1) utility distributed solar costs, including incentive program, system integration cost and utility revenue losses; 2) energy generation savings; 3) generation capacity savings; 4) transmission capacity savings; 4) distribution capacity savings; 6) environmental benefits; and, 7) economic development benefits.

[22] "The utility must build sufficient generation capacity to meet system peak demand, which in Arizona typically occurs in the late afternoon during the summer months. Because system peak demand occurs at a time when solar power is generating, energy for solar DG systems will contribute to meeting system peak. White the 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. because DG can reliably contribute to system peak, it can reduce or delay the need for additional capacity on the system. Kobor Direct Test., Ex. Vote Solar-7 at 29-30.

[23] Customer costs could include: metering and billing; billing (costs of applying bill credits and software changes to accomplish), customer service and interconnection. *See* Solganick Rebuttal Test., Ex. S-3 at 6.

[24] PUCN December 23, 2015 Order in Docket Nos. 15-07-041 and 15-07-042 at 66-67, 95-96; Beach Direct at 7.

[25] Solganick Direct, HS-2 at 13.

[26] Beach Direct Test., Ex. TASC-26 at 21.

distributed solar costs, including incentive programs, system integration costs and utility revenue losses which Staff supports including to the extent not already included.

While parties recognize these categories as being widely accepted in this sort of analysis; some parties take issue with the inclusion of some of these costs in the "avoided cost" calculation for DG solar since they are already accounted for elsewhere such as in the Integrated Resource Planning process.

Another issue subject to extensive debate is whether these costs should be looked at from a short-term versus a long-term perspective. The utilities favor looking at these costs from a short-term perspective because in a typical rate case, costs are looked at using a historical test year[27] Others, including RUCO, Vote Solar and TASC favor a long term analysis which looks at avoided costs over the economic life of a solar system.[28] Vote Solar argues that cost-of-service studies are short-term, single-year snapshots of utility costs which do not account for the long-term benefits of resource supply options like DG export.[29] Vote Solar also points to the IRP process and states that it includes an examination of utility needs and the long-term costs and benefits of various supply options; which are ultimately used to select utility resources that will flow into a rate case.[30] Certainly, a long-term analysis can be used in a VOS study, and in fact the last two studies commissioned by APS utilized a long-term analysis.[31] This is also one of the options put forward by APS witness Albert.[32] Staff suggests that if a long-term approach is used, caution should be exercised in how it is done.[33] For instance, RUCO supports an analysis based upon 20 years but it also takes a less expansive view of costs and benefits and suggests that only easily quantifiable long-term costs and benefits be included.[34]

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[27] Albert Direct Test., Ex. APS-5 at 17.
[28] Kobor Direct Test., Ex. Vote Solar-7 at 23 (over 20-30 years); Huber Direct Test., Ex. RUCO-2 at 13 (over 20 years of energy production); Beach Direct Test., Ex. TASC-26 at 18 (20-30 years).
[29] *Id.*
[30] *Id.*
[31] Albert Direct Test., Ex. APS-5 at 20-21.
[32] Albert Direct Test., Ex. APS-5 at 20.
[33] Solganick Rebuttal Test., Ex. S-3 at 13.
[34] Huber Direct Test., Ex. RUCO-2 at 13.

C. Other Considerations in Determining the Value of Solar.

1. The Value and Role of a VOS Calculation.

All parties to this proceeding recognize that a VOS study is important tool to inform policymaker decision-making on solar policies and the overall value equation. For instance, while APS witness Albert states that retail rates must be based upon actual costs and the application of cost of service principles,[35] he acknowledges that a VOS calculation can play a valuable role for policymakers. It can inform resource planning decisions and can be used to determine how rooftop solar is incentivized.[36] VOS can be considered in determining the amount paid to solar customers who export energy to the grid.[37] It can also be used to establish additional monetary incentives, such as the up-front cash incentive authorized by the Commission in prior years.[38] APS witness Albert acknowledges that it is within the Commission's discretion to choose which methodology to adopt for determining VOS.[39]

Likewise, RUCO witness Huber states that the "value" assigned to DG defines the "range of possible compensation levels for DG (through a combination of rates, incentives, and/or other mechanisms) that can be assumed to be reasonable and in the public interest."[40] How to set rates and whether to compensate DG at the assigned value is a policy decision for the Commission.[41]

This theme is also present in the direct testimony sponsored by TASC witness Beach:

> [T]he goal should be to achieve a reasonable, equitable balance of benefits and costs for all concerned – solar customers, other ratepayers and the utility system as a whole."[42]

Vote Solar recommends that "the result of the DG export valuation be used in the utility's general rate cases to inform DG rate design."[43]

In summary, the VOS determination should be used by the Commission to inform its decision making on related policy and ratemaking issues in an electric utility's rate case.

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[35] Albert Direct Test., Ex. APS-5 at 2.
[36] *Id.*
[37] *Id.*
[38] *Id.*
[39] *Id.* at 3.
[40] Huber Direct Test., Ex. RUCO-2 at 3.
[41] *Id.*
[42] Beach Direct Test., Ex. TASC-26 at 6.
[43] Kobor Direct Test., Ex. Vote Solar-7 at 5.

2. Value From Whose Perspective?

Costs and benefits from DG can be considered from many different perspectives: 1) the DG customer, 2) non-DG customers, 3) the utility; and 4) the economy as a whole.

The parties differ on whose perspective the concept of value should be based. For instance, APS witness Albert would define the term relative to the value that the electric system receives form rooftop solar.[44] APS argues that other purported benefits are hard to quantify and don't result in a direct cost savings to the utility or its customers.[45]

RUCO urges that the Commission consider the cost and benefits of DG from each of the perspectives listed above but states that the Commission, look at "value" primarily from the perspective of the non-DG customers who it states comprise approximately 97% of residential ratepayers.[46] While RUCO acknowledges that the perspectives of the DG-customers, non-DG customers, and the utility also need to be considered.[47] However, RUCO believes that for ratemaking purposes, the perspective of non-DG residential customers needs to dominate the discussion.[48]

Utilities, utility shareholders, solar vendors, regulators, C&I customer and residential customers all have different perspectives and value propositions. Staff believes that it is important for the Commission to consider value from the perspective of all of the utility's customers.[49]

3. Whether to Adopt Tests Used in Other Jurisdictions and Arizona for EE and DSM to Determine Cost Effectiveness of DG Solar.

Closely related to item 2 above, are some parties specific requests that the Commission use a set of standard cost-effectiveness tests that the utility industry developed for demand-side programs.[50] The same issues related to the impacts on the utilities, non-participating ratepayers, and on society as a whole arose when state regulators began to authorize specific EE and DR programs.[51] These tests examine the cost-effectiveness of demand-side programs from a variety of perspectives, including

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[44] Albert Direct Test., Ex. APS-5 at 4.
[45] *Id.*
[46] Huber Direct Test., Ex. RUCO-2 at 1.
[47] *Id.* at 9.
[48] *Id.* at 10.
[49] Solganick Direct Test., Ex. S-2 at 7.
[50] Beach Direct Test., Ex. TASC-26 at 3; Kobor Direct at 4.
[51] Beach Direct Test., Ex. TASC-26 at 3.

from the view points of the program participant, other ratepayers, the utility and society as a whole[52] TASC witness Beach notes that this suite of cost-effectiveness tests is now being applied to NEM and demand-side DG cost/benefit analyses.[53] TASC witness Beach states that evaluating the costs and benefits of all demand-side resources, EE, DR and DG using the same cost-effectiveness framework will help to ensure that all of these resource options are evaluated in a fair and consistent manner.[54]

TASC witness Beach defines the tests as follows. The Participant test is used where a program is set up to attract customers by offering them an economic benefit for their participation – i.e., bill savings and tax benefits which should be comparable to the cost of participating.[55] The Total Resource Cost (TRC) and Societal Tests compare the overall costs of the program to its benefits.[56] The Ratepayer Impact Measure (RIM) looks at the impact on other, non-participating ratepayers.[57]

Vote Solar believes that cost-effectiveness should be examined from the perspective of nonparticipating ratepayers. If, however, the Commission decides to include DG consumed onsite in the evaluation, Vote Solar's recommendation would be to use the Societal Cost Test.[58] However, Vote Solar also points out that the purpose of the cost-effectiveness test is to evaluate the benefits and costs of incentives offered for DSM reductions.[59] In the case of DG, state incentives have been eliminated. Thus, rather than use the Societal Test, Ms. Kobor recommends that the Commission use a modified version of the Ratepayer Impact Measure (RIM) test, plus adders from the Societal Cost Test.[60]

It should be noted that the Commission's EE and DR rules call for utilization of the Societal Test.[61] R14-2-2512 entitled Cost Effectiveness states under subpart A: "An affected utility shall ensure that the incremental benefits to society of the affected utility's overall group of DSM programs exceed the incremental costs to society of the overall group of DSM programs." Subpart B

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[52] *Id.*
[53] *Id.*
[54] Beach Direct Test., Ex. TASC-26 at 3-4.
[55] *Id.* at 4.
[56] *Id.*
[57] *Id.* at 5.
[58] Kobor Direct Test., Ex. Vote Solar-7 at 4.
[59] *Id.* at 9.
[60] Kobor Direct Test., Ex. Vote Solar-7 at 18.
[61] *See* R14-2-2512(B).

provides that the Societal Test shall be used to determine cost-effectiveness.[62] DG solar is not currently subject to this test and enough differentiation has been made by the parties, that the Commission could use either the Societal Test or a different test to consider cost/benefits if it determined appropriate.

4. Should the VOS Analysis Apply to the Rate for Self-Consumption As Well.

Most parties would limit the VOS analysis to exports.[63] RUCO urges the Commission to look at both exports and self-consumption in the VOS analysis.[64] RUCO argues that limiting the scope to exports increases the likelihood that there will ultimately be different compensation levels for exports and energy that is self-consumed and that this is problematic for a number of reasons.[65] First, examining exports only would according to RUCO mean that "the Commission would be declaring, by implication, that the prevailing retail rate is an appropriate price for compensating a major portion of a PV system's output," since on-site consumption represents approximately 50% of a system's production on average.[66] RUCO's main concern appears to be that if this is addressed in the utility's rate case, it could adversely affect the non-DG ratepayers.[67] RUCO is also concerned that a pricing differential between self-consumption and exports has no sound economic or technical justification and will be more difficult for the customer to understand.[68]

Staff, in addition to other parties believe the analysis should look at the export side of the equation only.[69] Staff believes that what happens behind the meter is the customer's business. The customer has the right to reduce load by convservation, insulation, high efficiency appliances, storage or the installation of a DG meter[70]. Thus there is no need to include self-consumption in the VOS

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[62] *See* Huber Direct Test., Ex. RUCO-2 at 9 ("...the Commission uses the Societal Cost Test to evaluate the cost-effectiveness of utility DSM portfolio investments. This test takes the perspective of the total economy"). Although RUCO notes that DG and rooftop solar are very different from EE in some respects ad thus a different evaluation approach may be warranted. *Id.* at 10.

[63] *See* Solganick Direct Test., Ex. S-2 at 7; Kobor Direct Test., Ex. Vote Solar-7 at 4.

[64] Huber Direct Test., Ex. RUCO-2 at 15.

[65] Huber Rebuttal Test., Ex. RUCO-3 at 1.

[66] *Id.*

[67] *Id.*

[68] *Id.* at 3-4.

[69] Solganick Direct Test., Ex. S-2 at 7.

[70] *Id.* at 7. Vote Solar Witness Kobor agrees 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." Kobor Direct Test., Ex. Vote Solar-7 at 4.

analysis. Furthermore, Staff views the export rate as more in the nature of a wholesale rate, not a retail rate which would apply to self-consumption.

5. Should the Benefit/Cost Study look at all Customer Classes.

Some parties' proposals in this case focus on the residential class.[71] However, both TASC and Vote Solar propose that the analysis not be limited to the residential class, but should also include the small business, commercial and industrial classes.[72] Vote Solar argues that since Arizona's REST rules provide for specified levels of DG from both residential and commercial customers, commercial customers should be included in any VOS evaluation.[73] Staff agrees that the analysis should look at all of the utility's customers.

D. Staff's Proposals on a Methodology to Determine the Value of Solar.

Staff offered two VOS Methodologies in this case. The first methodology is based upon a traditional avoided cost calculation, with an analysis of all of the factors discussed above. Staff's second methodology for determining an avoided cost for the export rate is based upon the weighted average cost of the utility's solar generation including Purchase Power Agreements ("PPAs") and utility owned grid-scale solar facilities.[74] Staff's recommends that the Commission adopt both of Staff's proposed methodologies for consideration in electric utility rate cases to provide it with maximum flexibility on these issues.[75]

1. Staff's Methodology No. 1: Traditional Avoided Cost Calculation.

Staff's first VOS methodology focuses on a traditional avoided cost determination using the factors discussed above. Staff's Exhibit H-3[76] looks at determining value through avoided cost for many different forms of DG; but only DG solar is being evaluated in this case.

Exhibit HS-2 to Staff witness Solganick's direct testimony, sets out the broad categories of benefits and costs that are considered in an avoided cost determination. They include: 1) Energy and System Losses, 2) Capacity (generation capacity, transmission and distribution capacity and

[71] *See* Solganick Direct Test., Ex. S-2 at 7; Huber Direct at 1.
[72] Kobor Direct at 45; Beach Direct at 17.
[73] *Id.* at 21.
[74] Tr. at 2333 (Broderick).
[75] *Id.* at 2324 (Broderick).
[76] Solganick Direct Test., Ex. S-2.

distributed solar's installed capacity, 3) Grid Support Services (reactive supply and voltage control; regulation and frequency response; energy and generator imbalance; synchronized and supplemental operating reserves; scheduling, forecasting and system control and dispatch); 4) Financial Risk (fuel price hedge; and market price response), 5) Security Risk (reliability and resilience), Environmental (carbon emissions (CO2); criteria air pollutants (SO2, NO2, PM); water and land; and Social (economic development (jobs and tax revenues).

Staff witness Solganick recommends that the Commission utilize an avoided cost methodology that considers the costs/benefits listed above in the following manner: 1) avoided energy costs[77] along with appropriate losses[78] based on an energy loss study performed by the utility which is specific to it and/or its interconnected systems.[79] 2) avoided generating capacity[80] with losses adjusted for geographic location using the demand loss study,[81] 3) avoided transmission and distribution capacity costs[82], with adders for specific geographic areas where a demonstration is made that transmission lines or distribution feeders can be delayed due to solar DG in the area, 4) environmental[83] (would be analyzed, but typically not included because the environmental impacts are already considered in the IRP process); and 5) grid support services.[84][85] The determination of

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[77] Solganick Direct Test., Ex. S-2, HS-2 at 14, defines "Avoided Energy" as the "cost and amount of energy that would have otherwise been generated to meet customer needs, largely driven by the variable cost of the marginal resource that is displaced in addition to the coincidence of solar generation with demand and generation, key drivers of avoided energy cost include (1) fuel price forecast, (2) variable operation & maintenance costs, and (3) heat rate."

[78] Solganick Direct, HS-2 at 14 defines "Energy System Losses" as the compounded value of the additional energy generated by central plants that would otherwise be lost due to inherent inefficiencies (electrical resistance) in delivering energy to the customer via the transmission and distribution system. Since distributed PV generates energy at or near the customer, those losses are avoided. Losses act as a magnifier of value for capacity and environmental benefits, since avoided energy losses result in lower required capacity and lower emissions."

[79] Solgnick Direct at 19.

[80] Solganick Direct, HS-2 at 14, defines "Generation Capacity" as the cost of the amount of central generation capacity that can be deferred or avoided due to the addition of distributed solar. Key drivers of value include (1) distributed PV's effective capacity and 2) system capacity needs.

[81] Solganick Rebuttal Test., Ex. S-3 at 5.

[82] Solganick Direct, HS-2 at 14 defines "Transmission and Distribution Capacity" as the value of the net change in transmission and distribution infrastructure investment due to distributed PV. Benefits occur when distributed PV is able to meet rising demand locally, relieving capacity constraints upstream and deferring or avoiding transmission and distribution upgrades. Costs occur however when additional transmission and distribution investment is needed to support the addition of distributed PV.

[83] Solganick Direct, HS-2 at 7, Environmental is positive when distributed solar results in the reduction of environmental or health impacts that would otherwise have been created. Key drivers include primarily the environmental impacts of the marginal resource being displaced. The components are as follows: carbon, criteria air pollutants, water, land and avoided renewable portfolio standard costs (RPS).

[84] Solganick Direct, HS-2 at 15. "Grid support value" is positive when the net amount and cost of grid support services required to balance supply and demand is less than would otherwise have been required. Grid support services, which encompass more narrowly defined ancillary services (AS), are those services required to enable the reliable operation of

these benefits and costs can be done on either a short-term basis or a long-term basis depending upon the type of analysis the Commission wants undertaken.

Avoided energy costs are typically the most significant component of the avoided cost calculation. An adjustment for losses (since exported DG solar energy is consumed at the same site and the power does not have to travel across the grid) would be included based upon an energy study. APS's estimate is 7% over a year and 12% at the time of peak demand.[86]

To determine the avoided generation capacity costs,[87] assumptions need to be made regarding the generation capacity additions that are reduced or delayed but for the additional DG export capacity.[88] Then, one would need to determine the level of DG export capacity that is expected to contribute to the system peak.[89] A measure of capacity called the "effective load carrying capabilities" ("ELCC") (a method that reflects the capacity value of an intermittent technology) to look at the load carrying capabilities and various peak conditions is typically used."[90] The ELCC will vary depending upon the type of technology used.[91] Storage is the only technology that reduces the intermittency of solar and if used would be included in the ELCC calculation.[92] In effect, the rate should be increased if there is demonstrated or forecast capacity value for generation.[93]

With respect to transmission and distribution, Staff's avoided cost determination requires location specific adders and other adders where value can be shown in certain geographic areas.[94] For instance, with respect to both transmission and distribution, if the deferral or elimination of assets and/or costs can be demonstrated a specific value adder would be appropriate.[95] This could be

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interconnected electric grid systems Grid support services include 1) reactive supply and voltage control, 2) frequency regulation, 3) energy imbalance, 4) operating reserves, 5) scheduling/forecasting.

[85] Solganick Direct, HS-2 at 16 "Security Risk" is defined as positive when grid reliability and resiliency are increased by (10) reducing outages by reducing congestion along the T&D network, (2) reducing large-scale outages by increasing the diversity of the electricity system's generation portfolio with smaller generators that are geographically dispersed, and (3) providing back-up power sources available during outages through the combination of PV, control technologies, inverters and storage.

[86] Solganick Rebuttal Test., Ex. S-3 at 16.

[87] Tilghman Direct at 13. The addition of storage is likely to affect the ELCC.

[88] Kobor Direct at 31.

[89] *Id.*

[90] Solganick Direct Test., Ex. S-2 at 18.

[91] Kobor Direct at 31.

[92] Tilghman Direct at 13.

[93] Solganick Direct Test., Ex. S-2 at 19.

[94] This type of location specific analysis of costs and benefits was one of the methodologies that Commissioner Forese asked parties to examine in a letter to this Docket on January 8, 2016.

[95] Solganick Direct at 19-20.

calculated based upon long-term[96] projections utilizing ELCC to determine when capacity is needed that can be offset.[97] If enough DG can be aggregated in a specific geographic location, to make an incremental difference in feeder or substation enhancements, a value component should be recognized as an adder.[98] This can be calculated long-term based on ELCC, when capacity is needed and can be offset.[99]

Staff witness Solganick recommends that the Commission require use of a feeder focused RFP process to identify geographic areas where additional distributed PV resources may be of value.[100] The RFP process could put a higher value on west facing systems which provide greater production during summer peaking hours.[101] Because the value of DG solar can be reflected in many aspects of a utility's rate design, the Commission could also consider authorizing incentives in specific locations to encourage the deployment of west facing facilities. Geographic components should be treated as separate adders and not accrue to all energy delivered since transmission or distribution asset deferral is location specific.[102]

Another example would be with respect to environmental costs, where the utility receives the Renewable Energy Credit ("REC") when it purchases the excess production, a value component in recognition could be an adder.[103]

Adders would also be appropriate in recognition of the fact that not all DG solar is created equal. Responsive DG, or DG that can be controlled by an entity that is not the owner and/or user (host) of the DG equipment/facility is "responsive" and adds value.[104] Widespread use of smart inverters combined with some centralized control may allow rooftop solar to provide control capabilities similar to utility-scale solar.[105] A third party may aggregate multiple smaller responsive

[96] "Long-term" as referred to in HS-3 refers an impact that is "sufficient in timing and magnitude to change the utility's system plan and eliminate or significantly defer the purchase or construction of generation, transmission and/or distribution facilities." Solganick Direct at 13.
[97] Solganick Rebuttal at 5.
[98] *Id.*
[99] *Id.*
[100] *Id.* at 23-24.
[101] Solganick Rebuttal Test., Ex. S-3 at 20; Tilghman Direct at 4.
[102] Solganick Rebuttal at 3.
[103] *Id.* at 20.
[104] *Id.* at 12.
[105] Solganick Rebuttal at 29.

DG units which would allow the DG to be dispatched to meet common or emergency operating conditions.[106] Storage adds considerable value as well since it addresses intermittency concerns The Commission may ultimately want to incent storage.

Staff is generally opposed to including avoided environmental costs or an adder for economic benefits.[107]

> "Avoided cost values the kWh provided at the costs the utility does not incur (energy if short term and capacity (or some portion) in the longer term). If a generating unit must meet specific environmental standards (NOx, SOx, water usage, maybe carbon) those costs are already included in the costs to construct and/or operate the plant.[108]

Only if the environmental cost is identified in the IRP process and is not already included in utility costs and rates, and is based upon an emerging regulation or results in reductions in emission levels over and above required levels, should this be considered as an avoided cost.[109]

Some parties also support the inclusion of an adder for economic benefits, including TASC and Vote Solar.[110] Staff witness Solganick does not recommend providing a value for societal costs such as local economic development since these costs are very difficult to quantify and are not included in the ratemaking formula for existing generation and other facilities and are not unique or incremental to DG.[111] These costs should be considered "qualitatively" only, and should not be reflected as a quantifiable benefit.

Another avoided cost that TASC, RUCO and Vote Solar support is the fuel hedge value for DG solar.[112] They argue that renewable generation reduces a utility's exposure to fossil fuel price volatility.[113] Staff witness Solganick does not support inclusion of a fuel hedge value to increase the cost of export DG energy, for the following reasons:

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[106] *Id.*; *See also* Solganick Rebuttal at 5.
[107] *See* Solganick Direct at 12.
[108] *Id.*
[109] Solganick Rebuttal at 4.
[110] Kobor Direct at 18; Beach Direct at 8.
[111] Solganick Direct at 20.
[112] Kobor Direct at 14-42; Beach Direct at 9-10; Huber Direct at 18-19.
[113] *See* Beach Direct, Ex. 2 at 9.

> I have seen little evidence that electric utility customers are demanding more reduction in long-term pricing volatility. In competitive supply states residential contracts appear to extend out a few years at most. Utility energy adjustment programs are generally annual or even shorter durations. Staff suggests electric customers do not value a partial fuel price hedge and one should not be applied."

Some solar participants also suggest that reliability of the utility grid is improved due to DG solar. Staff does not believe the record contains sufficient evidence to support this proposition.

Finally, other adders and/or incentives may be appropriate in other instances as well. For instance, water is a scarce resource in the West, and there are oftentimes concerns as to future water shortages in particular areas of the state. Utility thermal generation requires significant amounts of water. While the costs of this should already be reflected in the variable energy costs avoided from DG, concerns about future water shortages may be a policy issue for the Commission to consider.[114] Since DG Solar's water usage is lower on average, the Commission could recognize this in its policy considerations concerning value of solar. The Commission could also use an incentive mechanism for this in particular areas as well.

With respect to "adders", until DG solar penetration (alone or combined with other technologies) is higher, "adders" may be difficult to demonstrate in most areas.

2. Staff's Methodology No. 2: Weighted Average of Utility Owned Solar Facilities and Solar PPAs.

Staff's second methodology for determining avoided cost is to use the weighted average of utility owned solar facilities and PPAs of each individual utility.[115] At the end of April, 2016, Staff propounded a significant amount of discovery to both APS and TEP related to this methodology, which requested information relating to all of their utility owned grid scale solar PV facilities and all of their PPAs for solar PV facilities.[116] That information included the effective date, when the specific generating project started producing energy, what the term of the PPA was, the pricing information related to the PPA, the type of renewable technology, copies of each of the actual

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[114] *See* February 8, 2016 letter from Commissioner Robert L. Burns to the Docket; Accord, Huber Direct at 26.
[115] Tr. at 2332-333.
[116] *See* Staff Ex. 4; *See* also Tr. VII at 1314-318.

contracts, and the actual purchase power agreements. Staff Request 3.2 requested the same type of information, but for solar projects that APS owned.[117]

a. APS Weighted Average Cost of Utility Owned Grid Scale Solar and Solar PPA Resources.

Staff Request 3.6 asked APS to build a spreadsheet that had the ability to combine the cost and pricing information for all of the solar projects, including utility owned facilities and PPAs, into a spreadsheet that could then calculate a weighted average overall price or cost for all of the solar projects.[118] The spreadsheet allowed for variance in terms of which projects to include, how far back to go in the analysis i.e., whether the analysis should be limited to a certain number of years,[119] the ability to have the cost represented on either a levelized or non-levelized basis, inclusion or exclusion of Arizona's production tax credit applicable to the first 10 years that the project is in service as well as other variables. At a high level, the response to Staff Data Request 3.6 was intended to provide a per kilowatt hour cost that blends all of APS's grid scale PV facilities.[120] The spreadsheet also has weighting factors built in where the analyst can put more weight on more recent projects or can assign more weight to a larger project that produces more energy.[121]

The levelized versus non-levelized function allows the analyst to see the variance that would result from year to year if a non-levelized annual cost was preferred. Some of the variance may be due to PPAs which contain an escalator over time. Utility owned PV facilities, on the other hand, are going to reflect a higher cost at the beginning of the life of the project because the revenue requirement is higher at the beginning and declines over time as the project is depreciated.[122] In general if you were to use a levelized cost, it is likely to be lower than the yearly or non-levelized cost because the in-service dates of the various facilities or agreements are more recent, so the revenue requirements are still higher than the average over the life of the facility.[123]

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[117] *See* Tr. at 2086.
[118] *Id.*
[119] Currently the spreadsheet is set up to only allow an analysis up to five years. At the hearing, the Company agreed to modify the spreadsheet to allow for consideration of facilities or PPAs spanning a period of time greater than five years. *See* Tr. at 2088-89.
[120] Tr. at 2091.
[121] Tr. at 2089-91.
[122] Tr. at 2102-2012.
[123] Tr. at 2013,

In response to Staff's data requests, APS provided cost per kWh information for its company owned, utility scale solar projects, and for its current PPAs. The owned projects included in APS's analysis were Hyder, Hyder 2, Cotton Center, Paloma, Chino Valley, Foothills, Gila Bend, Luke AFB, Desert Star and Red Rock. Separately, APS provided analysis for six current PPAs. APS's analysis of both owned facilities and PPAs included identification of the year in which the projects came on line (i.e. project "vintage"). The project vintage information is important because it indicates a decrease in costs per kWh from projects of earlier vintage to more recently completed projects.[124] Based on a production weighted average of the entire spectrum of project vintages of company-owned projects, the cost is approximately 10.8 cents per kWh. For PPAs, the weighted average cost is 11.3 cents per kWh. If company-owned and PPA resources are considered together, the weighted average cost is 10.9 cents per kWh.[125]

The vintage data also suggest that as the Company adds newer solar facilities to its portfolio, whether through PPA or utility owned facilities, the weighted average price per kWh will decline.

b. TEP/UNSE Weighted Average Cost of Utility Owned Grid-Scale Solar and Solar PPA Resources.

TEP/UNSE performed an analysis of its solar generation resources, both utility owned and generation procured through PPAs, and calculated a weighted average of the costs of those resource on both a non-levelized and levelized basis as well.

TEP/UNSE provided a similar set of analyses for its company-owned and PPA solar resources as APS. The company-owned facilities included in TEP/UNSE's analysis included Fort Huachuca, Rio Rico, Prairie Fire, La Senita, UASTP1, UASTP II, Springerville 1.8, and White Mountain. TEP/UNSE also provided analysis for 11 current PPAs. Based on a production weighted average of the entire spectrum of project vintages of company-owned projects, the cost is approximately 13.3 cents per kWh. For PPAs the weighted average cost is 10.6 cents per kWh. If company-owned and PPA resources are considered together, the weighted average cost is 11.1 cents per kWh.[126]

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[124] No PPAs or projects that went on line prior to 2008 were requested.
[125] *See* Footnote 11 *infra.*
[126] *Id.*

Staff's weighted average cost methodology is a good alternative to TEP/UNSE's proposed use of the most recent utility scale renewable energy purchased power agreement for either TEP/UNSE; and APS's grid-scale approach, which also relies upon recent PPAs, RFPs or PPAs entered into by other western based electric utilities. Staff's weighted average cost represents the utilities' a reliable avoided cost proxy representing the actual average avoided cost of providing solar generation to their customers.[127]

c. APS's Proposed Short-Term, Long-Term and Grid-Scale Approaches.

APS witness Brad Albert offered three different methodologies which the Commission could use to determine the value of solar.[128] Those methodologies are: short-term avoided cost, 2) long-term avoided cost and 3) adjusted grid scale cost.[129]

1) The short-term avoided cost methodology would set a value for energy based on reported market prices.[130] For instance, meter data could be obtained with production data for residential systems. APS states that during the solar PV production periods, the CAISO energy prices were in the range of 1.0 to 2.5 centers/kwh.[131] According to APS witness Albert, this approach is consistent with the "historic test year" method used in setting utility rates.[132]

The long-term methodology suggested by witness Albert would use as a basis the 2013 SAIC study, modified to reflect updated information regarding system operations that APS obtained since the SAIC was conducted.[133]

The two VOS studies commissioned by APS in the past were long-term avoided cost studies. The first was in 2009 performed by R.W. Beck. The second study commissioned by APS was done in 2013 by SAIC, a successor of R.W. Beck.[134] Both studies are part of this Docket. Both of these studies, according to APS, utilized widely accepted resource planning techniques to assess value.[135]

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[127] Tr. at 2332-333.
[128] Albert Direct at 2.
[129] *Id.*
[130] *Id.*
[131] *Id.* at 18.
[132] *Id.* at 17.
[133] *Id.* at 2.
[134] *Id.* at 21.
[135] *Id.* at 21.

They looked at the following 5 categories: distribution, transmission, generation, fixed O&M and fuel, purchased power, emissions & gas transportation. The differences between the two studies were due to changes in APS's load and resource forecast, fuel prices, market prices, rooftop solar penetration and the cost and timing of APS's need for new generated capacity.[136]

The studies looked at a case with rooftop solar and a case without rooftop solar and compared the two.[137] The difference between the two cases represents the value of rooftop solar from a resource planning perspective.[138] In the R. W. Beck and SAIC studies, APS states that avoided-energy costs constituted between 58% and 90% of the total identified DG value.[139] This is driven by natural gas prices and solar penetration levels.[140] To some extent APS states that the studies showed that installation of rooftop solar could defer future resource additions such as combustion turbines along with their associated transmission, interconnection ad fixed O&M costs. But the value is limited because of the mismatch in the timing of peak rooftop solar production and the peak customer demands on APS's overall system and distribution system.[141]

Neither study found a change in need with respect to distribution or transmission related to solar deployment. However, the studies according to APS did identify that transmission system upgrades needed to support incremental generation-capacity additions (interconnection costs) could be deferred to the extent that rooftop soar defers the need for incremental generation capacity additions.[142]

Grid scale and rooftop solar use the same basic technology – solar photovoltaic (PV). APS's final proposal uses a recent PPA for grid-scale solar as the first step in this methodology. The PPA selected would be based on geography, timing, and other relevant factors. While Staff is unsure if APS utilized this PPA pricing information in its study, in his testimony APS witness Albert referred to publicly available PPA pricing information from a neighboring utility, NV Energy, which recently

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[136] Albert Direct at 26.
[137] Albert Direct at 21.
[138] Albert Direct at 22.
[139] *Id.* at 23.
[140] Albert Direct at 26.
[141] Albert Direct at 23.
[142] Albert Direct at 24-25. With distribution, the value was zero to very small in the first study and in the second study the value was zero.

signed a 20-year PPA with SunPower with an in service date of 2016 for a grid-scale solar PV plant in Nevada with a levelized price of 4.6 cents/kWh. Also referred to was a City of Palo Alto PPA with and in-service date of 2021 for grid-scale solar PV at a levelized price of 3.6 cents/kWh.[143]

It would then be adjusted for recognized differences between grid-scale and rooftop solar.[144] APS's average grid-scale facility is 15-20 MW (15,000 – 20,000 kW) versus the average rooftop solar system which is approximately 7 kW. APS also typically employs tracking technology on its grid-scale systems which maximizes energy production and provides greater capacity contribution at times of peak demand.[145] Grid-scale PV can also be curtailed which increases its value.[146]

APS would cap the result under any of its models at the price paid for a grid-scale solar PPA, with adjustments.[147]

Staff has several concerns with APS's avoided cost proposals. First, Staff does not believe it is appropriate to cap all three approaches at the price paid for a grid-scale solar PPA with adjustments. Staff does not believe that the Company has provided sufficient justification for its position in this regard. In addition, Staff believes it is inappropriate because it does not recognize that there may be geographic value in some cases that would not be accounted for under the Company's proposal to use the grid-scale adjusted price as a cap on avoided cost. Further, the Company did not use its own latest PPA to derive its grid-scale adjusted price. It used the PPA(s) of another western utility. Assuming this is appropriate, Mr. Albert does not give sufficient detail in his testimony how that particular PPA was selected and why it is a good proxy for APS.

E. TEP/UNSE Proposed a Grid-Scale PPA Approach and a Traditional Avoided Cost Methodology.

TEP/UNSE propose a new net metering tariff that provides monthly bill credits at what it calls a Renewable Credit Rate ("RCR") for export energy to the grid.[148] TEP/UNSE propose that the RCR would be the equivalent to the most recent utility scale renewable energy PPA connected to either

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[143] Albert Rebuttal at 6.
[144] *Id.* at 9.
[145] Albert Direct at 27.
[146] *Id.*
[147] *Id.*
[148] Tilghman Direct at 3.

TEP's or UNSE's distribution system.[149] TEP/UNSE also want to eliminate the "roll-over" of excess generation to offset future usage as currently prescribed by the Commission's net metering rules.[150]

TEP/UNSE offered a second methodology if the Commission wants a more comprehensive, in-depth analysis to be undertaken. Such an analysis would use a model similar to the one being developed by the Utah Public Service Commission in Docket No. 14-035-114.[151] TEP/UNSE states that this methodology uses two cost of service models to determine "the real impact to rates under the cost of service model, and then allows the Commission to address forward looking and resource planning components separately.

The methodology uses a Counter Factual Cost of Service Study ("CFCOS") that assumes the NEM generation does not exist.[152] An Actual Cost of Service Study ("ACOS")[153] would show actual cost of service including Company provision of NEM net load. According to TEP, these studies allow "the Commission to determine if there is a cost or benefit that should be applied to the DG customer based on known and measurable costs and benefits currently collected through rates." [154] The Utah methodology, according to TEP witness Tilghman also defines "the more subjective costs and savings associated with external, societal, and future benefit for which a separate revenue stream must be identified."[155] TEP states that to the extent the Commission determines a value associated with external, societal and future benefits with a separate value stream, it needs to identify how it would be collected and disbursed if it is not a direct offset to the current cost of service models.[156]

Staff has not had sufficient opportunity to analyze the Utah Commission's models which the Company recommends. To the extent the models incorporate the traditional avoided cost analysis and would allow for either a short-term or long-term view, they may be appropriate for use in Arizona. With respect to TEP/UNSE's PPA proxy approach; Staff agrees with the Companies that such an approach would be less burdensome than an in-depth avoided cost study; and that simplicity

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[149] *Id.*
[150] *Id.*
[151] *Id.* at 6.
[152] *Id.* at 7.
[153] *Id.*
[154] *Id.*
[155] *Id.*
[156] *Id.* at 18.

is an important consideration. However, a single PPA (the most recent) may not be representative of the avoided cost in most instances. Further, the Company provided little information to demonstrate that the PPA is representative of its grid-scale solar PV project costs.

F. RUCO'S Proposed Step Down Approach To Value Of Solar Calculation.

RUCO has essentially put forth two proposals for the Commission's consideration, although its more recent proposal appears to be its preferred option.

In its testimony direct filed on February 26, 2016, RUCO supports use of a long-term avoided cost methodology. RUCO supports measuring benefits and costs over a 20 years of energy production.[157] According to RUCO, the benefits of DG should mainly include the following: 1) avoided energy costs including losses; 2) avoided generation capacity costs including line losses; and 3) avoided transmission system costs and avoided distribution costs.[158]

The primary benefits are those related to the avoided costs associated with energy production and delivery.[159] With respect to fuel savings, RUCO states that future fuel prices should be estimated based on a forward price curve, such as those used in utility IRPs.[160] RUCO witness Huber states that if there are additional fuel savings after the period of the forward price curve, a simple escalation rate can be applied.[161] The actual key inputs and assumptions for calculating each of the benefits on a long-term basis are set forth in a charge on pages 20-21 of Mr. Huber's Direct Testimony.

With respect to transmission, RUCO states that to the extent that DG solar reduces peak load on the transmission system, it may be able to defer the need to build additional transmission lines.[162] Such deferrals are likely to be localized in nature. Transmission savings tied to new generation that is no longer needed is more straightforward.[163] Distribution savings are also tied to the ability of DG to reduce peak load on certain distribution circuits. There may be an opportunity to defer distribution system upgrades on a locational basis.[164]

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[157] Huber Direct at 13.
[158] Huber Direct at 17-19.
[159] *Id.* at 19.
[160] *Id.* at 18.
[161] *Id.*
[162] *Id.* at 19.
[163] *Id.*
[164] *Id.*

RUCO identifies benefits associated with off-system sales as subject to consideration. RUCO also advocates that to the extent that DG solar frees up utility-owned generation capacity, this capacity could be used to sell electricity to other utilities.[165] This benefit should be included in the value of DG calculation. Additionally locational benefits and ancillary service benefits should be recognized when appropriate [166] The example given by RUCO are electric vehicles and the related congestion in the distribution system that DG could help alleviate.[167] Further, to the extent that westward orientation and tracking systems are able to increase the capacity value of distributed solar, these can be included in the determination of value.[168] RUCO witness Huber also notes that the incremental value that storage provides depends on how the stored energy is dispatched.[169] If stored energy is dispatched to increase output during the hours of system peak, then it could increase the value of DG and this should be recognized.[170]

Finally, with respect to economic impacts (secondary impact), RUCO recommends against attempting to quantify benefits/costs related to these larger macroeconomic impacts such as job losses or gains.[171]

RUCO put forward another option in the hearing on June 9, 2016 in response to Staff's weighted average approach.[172] RUCO proposed a solar offer rate with customers given two options: 1.) allow DG Solar to self-consume on whatever plan they choose to utilize but the export rate is fixed on the solar offer rate that declines as more customers come on line or 2.) The entire solar production goes into the solar offer rate. He believes this would give predictability to the customer and resolves the grandfathering issue in a transparent way.[173]

Mr. Huber suggested starting with Staff's weighted average number. At that point you would come up with a step-down schedule from that rate, just like the Commission did with upfront incentives. Mr. Huber states that the proxy could be updated every year or two, and that would be the

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[165] *Id.* at 21.
[166] *Id.*
[167] *Id.*
[168] *Id.* at 22.
[169] *Id.* at 23.
[170] *Id.* at 26.
[171] *Id.*
[172] Tr. at 2154.
[173] *Id.*

cap.[174] As new cheaper utility scale resources come on line, that cap keeps going down. That would be the starting point for the market base step-downs.[175]

Finally Mr. Huber stated that the step downs would be a policy call the Commissioners would make.[176] As the cost to deploy solar reduces your proxy number reduces and so the cap goes down to match the reduction.[177] RUCO witness Huber stated that a megawatt target could also be set, that is linked to the REST compliance plan or not. There are many different ways to determine when and to what extent each stepdown should occur.[178] Staff and the parties were asked to consider this approach in a letter from Commissioner Stump to the Docket on June 13, 2016. Staff does not oppose this approach when coupled with its weighted average approach, however Staff would note that the proposal may be administratively difficult to implement since it appears that many tranches would have to be created as it is implemented. The Companies would have to track these tranches and this may become difficult from both an administrative and billing perspective. Further, Staff's weighted average approach will by itself decline as new projects are added.

G. TASC Proposed Long-Term Avoided Cost Analysis.

TASC witness Beach proposes a benefit/cost methodology for NEM and DG that has four key attributes: 1) it examines and balances the benefits and cots from the multiple perspectives of the key stakeholders; 2) consider a comprehensive list of benefits and costs; 3) use a long-term life-cycle analysis, 4) focus on NEM exports.[179]

Under TASC witness Beach's long-term value of DG analysis,[180] the following avoided cost/benefits would be used: 1) avoided energy, 2) avoided generating capacity, 3) avoided line losses, 4) avoided ancillary services, 5) avoided T&D capacity, 6) avoided environmental costs; 7) avoided carbon emissions, 8) fuel hedge; 9) market price mitigation, 10) avoided renewables, and 11)

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[174] Tr. at 2155.
[175] *Id.*
[176] *Id.*
[177] *Id.*
[178] *Id.*
[179] Beach Direct at i.
[180] *Id.* at 2.

societal benefits.[181] The tables in pages 20 and 21 of his Direct Testimony set forth how each of these variables would be calculated.

Mr. Beach attached an updated cost/benefit study called the Cross Border study which he states demonstrates that 1) solar DG is a cost-effective resource for APS using the Total Resource Cost and Societal Tests; 2) that there is a balance between the costs and benefits of residential DG for both participants and non-participants under the Participant and Ratepayer Impact Measure tests, 3) the benefits of DG significantly exceed the costs in the commercial market; 4) the benefits of solar DG in APS's service territory are higher for west-facing systems and 5) there are lower costs of solar DG to non-participants under APS's existing residential TOU rates.[182] Benefits of solar DG in APS's service territory are higher for west-facing systems.[183]

The updated study shows average total direct benefits of 18.7 cents per kWh and 28.0 cents per kWh when societal benefits are included.[184]

H. Vote Solar Proposed Long-Term Avoided Cost Analysis.

Vote Solar proposes a long-term avoided cost evaluation which quantifies the full range of cost and benefits included in the standard valuation methodology.[185] The 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.[186]

The Vote Solar proposal is interesting in that it recommends that capacity benefits be evaluated on a "continuous" basis, because of the unique benefits associated with the modularity of DG additions.[187] She points out that "[u]tility 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."[188]

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[181] *Id.* at 20-21.
[182] *Id.* at 24.
[183] *Id.* at ii.
[184] *Id.*, Ex. 2, The Benefits and Costs of Solar Distributed Generation for Arizona Public Service (2016 Update) by Cross Border Energy at 22.
[185] Kobor Direct at 5.
[186] *Id.*
[187] *Id.* at 25.
[188] *Id.* at 25.

Additionally, Vote Solar's analysis with respect to transmission and distribution avoided costs would likewise look at the unique benefits associated with modularity and scalability of DG.[189] Other than this difference, Staff does not believe that their long-term avoided cost methodology differs significantly from those discussed above.

Vote Solar testimony also depicts the range of results from several other state studies and from the APS's long-term studies including the most recent update.[190]

V. COST METHODOLOGIES.

Both APS and TEP submitted cost of service studies in this proceeding which they state show a substantial cost shift from NEM to non-NEM customers. APS' embedded COSS used data from the twelve-month period ending December 31, 2014.[191]

APS witness Snook claims that APS's study demonstrates that residential rooftop solar customers, on energy based rates pay only 36% of the cost to serve them.[192] In contrast, NEM customers on demand rates pay approximately 72% of the cost to serve them.[193] APS further claims that the typical residential customer (without solar) pays 86% to 91% of the cost to provide them service.[194] APS states that this equates to approximately $67 per month for solar customers on energy rates and $29 per month per customers on demand rates will be shifted to residential customers without solar. Witness Snook states that the typical residential solar customer still needs about 81% of the capacity they used before they adopted solar and 30% of the energy.[195]

TEP, on the other hand, used models similar to the models used by the Utah Commission to determine its costs associated with DG solar compared to non-DG customers.

Staff is concerned with the parties inability to conduct a thorough review of the models, in particular the APS model, because the model is proprietary and the model's vendor will not agree to

[189] Kobor Direct at 32.
[190] *See* Kobor Direct at 16 and 15, respectively.
[191] Snook Direct at 8.
[192] *Id.* at 3.
[193] *Id.*
[194] *Id.*
[195] *Id.*

its use in this proceeding.[196] Vote Solar witness Kobor claims she was only able to do a limited review of the results of the model. She further stated that without the model she was unable to evaluate how its results would change if the assumptions were modified.[197] Ms. Kobor also states that she found significant flaws that overinflate the costs allocated to NEM customers.

Because of these limitations, Ms. Kobor states that she cannot find that there is sufficient evidence in this proceeding to support the alleged cost shift calculation put forth by APS.

She also states that her ability to review the TEP/UNSE COSS evidence has been even more limited. TEP/UNSE has presented evidence form three TEP-related cost of service studies in this docket but failed to provide Vote Solar with timely access to working COSS models or functioning work papers that would allow for an evaluation of the methodologies and assumptions therein. As a result her ability to review the reasonableness of the COSS-based evidence including TEP/UNSE's claim that NEM customers shift $874-967 per year to non-NEM customers has been extremely limited.

TASC lodged a similar complaint about the models particularly the APS model regarding the fact that they were not able to access, manipulate, test or work with it.[198] According to Mr. Snook's testimony APS previously used a Microsoft Excel based model which APS would provide upon a discovery request.[199] With the current model, Vote Solar indicated that they contacted the software provider Utilities International on how much it would cost to purchase the software needed to interact with the model and were told it would be around $250,000.[200]

APS stated that it provided the parties with the full output of the model and all of the inputs used to obtain those outputs.[201] APS does not believe that anyone is limited by the model change because they provided "…all of the information necessary for a cost of service expert to take that information and replicate the analysis."[202] Further, according to Mr. Snook any party could have

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[196] Staff asked APS to talk to its vendor to see if it would make the model available for purposes of the Commission's administrative proceeding. APS informed Staff that the vendor would not agree to make the model available.
[197] Kobor Rebuttal at 3.
[198] *Id.* at 88.
[199] *Id.* at 127.
[200] *Id.* at 129.
[201] *Id.* at 115.
[202] *Id.* at 127–28.

used that information and replicated the analysis either through a different cost of service tool, a spreadsheet model or with the Utilities International model.[203]

APS contended that the only substantive difference from the information it provided in the case and under the previous model is that the output is not linked up with the input.[204] Additionally the software was not able to output a version of the model to Excel that has the inputs linked to the outputs.[205] Mr. Snook stated that APS had decided to switch to the new model back in 2012 and that decision was not made with this case in mind but was the result of its evaluation of various cost of service model tools.[206] It was also in an effort to prevent any issues with the spreadsheet model running afoul of Sarbanes-Oxley controls.[207]

In response, Vote Solar witness Kobor stated that she attempted to utilize the spreadsheets provided by APS but stated it would have required a significant amount of effort that may not have even been completed by the time the hearing occurred.[208] In support, Ms. Kobor presented Vote Solar-Exhibit 9 as a representation of the model spreadsheet provided. It was one tab of a 157 tab spreadsheet that had over 4000 rows in a single column.[209] She further testified that the density of this data provided such a barrier that she would consider it a "Black Box" model.[210]

Staff had asked Mr. Snook during the hearing if there was a way for APS to get Utilities International to make the links available for specific regulatory proceedings aside from the two unlinked input and output files. APS indicated that they would check with Utilities International and report back on the result but were unable to predict what that result might be.[211] Staff believes that any efforts to provide more transparency on the models provided by the utilities will help not only with this hearing but future hearings where there may be questions on the Cost of Service and parties abilities to interact with those models.

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[203] *Id.* at 115.
[204] *Id.* at 128.
[205] *Tr.* at 291.
[206] *Tr.* at 114.
[207] *Id.* at 158.
[208] *Tr.* at 1711.
[209] *Id.*
[210] *Id.* at 1712.
[211] *Tr.* at 294-95.

TEP has classified its model was confidential however, they were willing to provide access to the model if the reviewer was willing to be subject to a non-disclosure agreement.

Staff believes that since APS's underlying model is proprietary, APS should make a spreadsheet available with inputs linked to output so that all parties have access to a workable model that they can vary the inputs in support of their position. Staff believes that APS could request funding for this in an upcoming rate case. Staff agrees with the RUCO guidelines on these issues contained in Mr. Huber's Direct Testimony. The methodology used by the Commission should: 1) be transparent in that all Inputs, assumptions, and calculations should be clearly described and explained, 2) accessible i.e., the cost-benefit calculation should be made available to the public in the form of an electronic spreadsheet that is published on the Commission's web-site, and 3) there is an ability to change inputs and assumptions used in the calculation which are likely to change over time.

VI. CONCLUSION.

Staff recommends that the Hearing Division adopt both of Staff's proposed methodologies in this case for use in future electric utility rate cases to inform the Commission's decision-making in those cases on related policy and ratemaking issues. Staff also recommends that the Hearing Division adopt Staff's other recommendations contained herein.

RESPECTFULLY SUBMITTED this 21st day of July 2016.

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