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BEFORE THE ARIZONA CORPORATION COMMISSION

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

DOCKET NO. E-00000J-14-0023

THE ALLIANCE FOR SOLAR CHOICE (TASC) POST HEARING BRIEF

POST-HEARING BRIEF

OF THE ALLIANCE FOR SOLAR CHOICE

July 20, 2016

Table of Contents

Page

Table of Authorities

Cases **Page**

Statutes

Rules

Constitutional Provisions

The Alliance for Solar Choice ("TASC"), through its undersigned counsel, hereby submits its Post-Hearing Brief.

MEMORANDUM OF POINTS AND AUTHORITIES

I. INTRODUCTION

The goal of this docket is to investigate the benefits and costs of distributed solar generation ("DG") and to create a record that may be accessed for potential use in future dockets wherein the value of solar and the specific valuation method is being dealt with for each utility. With regard to valuing DG, a wide consensus has emerged as to the best practices for performing a benefit-cost analysis.[1] This widely applied framework identifies multiple perspectives that must be analyzed including the perspectives of all integral stakeholders: solar customers/generators, non-participating ratepayers, the utility/electric grid, and society as a whole. Regulators *must* balance all of these perspectives when acting in the public interest.[2] In addition to taking the various stakeholders into account, the Commission should also consider a thorough list of benefits and costs, employ a long-term lifecycle analysis, and consider the excess energy produced and valued via net energy metering ("NEM").[3]

DG is a demand-side resource and should be subjected to the same type of analysis used to assess the cost-effectiveness of other similar demand-side resources like energy efficiency ("EE") and demand response ("DR"). Such a fair evaluation ensures that customer-focused demand-side resources are valued in a manner commensurate with the way utilities evaluate the cost-effectiveness of their own supply-side utility rate base additions. Utilities, however, are eager to thwart the growth of DG by ending NEM and pushing for the adoption of modified rate designs intended to destroy the economic benefit of investing in and adopting DG.

The Commission must be leery of utility-proposed methodologies that exclude or prohibit consideration of benefits of DG by focusing, for example, only on short-term avoided costs or that utilize unjustified comparisons to rates paid for utility scale solar. Arizona utilities have also claimed that the current rate structure causes customers without DG to subsidize DG customers. These claims,

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[1] *See* Beach Direct Test., TASC Ex. 26 at i.
[2] Ariz. Const. art. XV, § 3.
[3] Beach Direct Test., TASC Ex. 26 at i.

however, are based on embedded cost evaluations that exclude the long-term (actual) 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 the actual value of DG and will not lead to the implementation of optimal DG policy.

II. SUMMARY OF ARGUMENT/PROPOSED FINDINGS.

For the reasons set forth below, TASC believes that any "valuation of solar" must accomplish exactly what the term implies, namely, to ensure that the benefits and costs of distributed solar generation are actually accounted for and credited (or debited, as the case may be) in every docket. The Commission should not favor any valuation framework or mechanism purporting to ascertain the value of solar that does not recognize both the full range of benefits of DG, including those benefits currently existing and those that will arise in the future. As discussed in greater detail below, a failure to properly value DG utilizing a long-term, forward-looking, holistic approach will not result in finding the actual value of DG. Utility proposals to use methodologies that by their very nature cannot account for benefits of solar must be rejected.

Simply assigning an arbitrary "zero value" to many of even the undisputed benefits resulting from the adoption of DG or carelessly implementing a utility-scale proxy value in rate cases are surefire ways to undervalue DG. To ensure fair treatment of DG a true valuation methodology must be employed that considers the interests and costs of all those involved with DG, not just the interests of and costs to the utilities.

Although ancillary to the above, this docket also provides the Commission with another opportunity to reiterate its policy in support of full grandfathering of any DG customers in future rate cases. It also provides the Commission with an opportunity to fully voice its continued support for the applicable rules currently in place that set a high bar that utilities must meet to justify differential treatment of DG customers from others as such a burden remains the best means of ensuring that all rates adopted by the Commission are nondiscriminatory.

Note also that, as set forth herein, the Commission must be careful to reject calls from the utilities, RUCO, and and even Staff, that encourage the Commission to go beyond this docket's noticed scope while also exceeding the Commission's rulemaking authority. Calls for a decision that binds future dockets or sets forth guidelines or procedures that must be adhered to in the future are asking the Commission to promulgate or amend administrative rules by improper means and must be rejected.

III. DISCUSSION OF OTHER JURISDICTIONS' ANALYSIS OF THE VALUE OF DG.

Benefit-cost analyses of DG are not new and have been performed across the country. For example, Nevada, California and Mississippi have adopted frameworks that exemplify "best practices" in regards to conducting benefit-cost analyses for DG solar.[4]

The optimal approach is to employ a framework utilizing demand-side analysis that examines "the cost-effectiveness of demand-side programs [such as EE, DR and DG] from a variety of perspectives, including from the viewpoints of the program participant, other ratepayers, the utility, and society as a whole."[5] Not only is such a framework most commonly utilized, but it takes a holistic view of DG by considering the customer's investment; savings and benefits; weighs the benefits of DG for both the utility and society as a whole; measures the impact of DG on other ratepayers; and determines whether the utility's costs are greater than the avoided cost benefits.[6] This demand-side analysis constitutes a comprehensive analysis of all costs and benefits and considers the interests of all parties impacted by DG solar. In other words, this framework is designed to employ methodologies that ascertain the actual value of DG. Most notably, such an approach is utilized in California's Standard Practice Manual, which is widely used across the country as a framework for discussing specific valuation approaches.[7] Such a framework stands in stark contrast to the proposals advanced by the utilities that limit the assessment of benefits to only the short-term avoided costs of DG or make false comparisons of DG to utility-scale generation.

Such comprehensive frameworks are already being utilized across the country. Nevada employed such a demand-side analysis to calculate the benefits and costs of DG going forward from 2014-2016 and concluded that DG was cost-effective even for non-DG customers.[8] California adopted

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[4] Beach Direct Test., TASC Ex. 26 at 3:9-13, 5:14.
[5] *Id.* at 3:13-22.
[6] *Id.* at 4:11 – 5:12.
[7] Kobor Direct Test., Vote Solar Ex. 7 at 18:14-16.
[8] Beach Direct Test., TASC Ex. 26 at 5:18 – 8:5 (also recounting that the Nevada commission ultimately adopted the results of an unrelated short-term cost-benefit study provided by NV Energy to disastrous results for the Nevada DG industry and customers).

a similar framework and is gathering the requisite information to utilize in evaluating its DG and NEM programs and initiatives.[9] Mississippi utilized such an analysis to implement NEM for DG customers and determine a compensation rate for DG customers predicated on the utilities' costs and benefits as calculated in its studies.[10] In fact, state-commissioned independent studies (including the Nevada and Mississippi analyses as well as studies conducted in Maine, Vermont and Minnesota) that have utilized comprehensive frameworks to analyze the full range of benefits and costs of DG have generally concluded that the value of DG solar is well-above retail rates.[11] Evaluating demand-side resources is nothing new and benefit-cost studies are not foreign to the utility regulatory process.

In Nevada, the public utilities commission actually deviated from the independent study that was conducted by E3. The final order recognized the categories of long-term benefits of DG discussed herein, but assigned a "zero" valuation to them rather than attempting to analyze, determine, or assign actual values to such benefits. As a result of this short-sighted analysis, Nevada concluded that DG created an unreasonable cost shift and decided to terminate NEM; increase the fixed monthly customer charge for DG customers; and reduce the export rate credited to DG systems from the full retail rate (about 11 cents per kWh for residential customers) to an energy-only avoided cost rate of about 2.6 cents per kWh.[12] Another result of this analysis and subsequent policy changes is that Nevada has seen a layoff of approximately 1,000 DG workers, considerable public outcry, ballot measures, and even litigation.[13] Indeed, the actions of the Nevada Commission are currently being appealed in Nevada courts.[14]

With the exception of Nevada, the aforementioned states all recognized that considering a broad array of costs and benefits as well as accounting for the interests of all parties impacted by DG (not just the traditional utilities) is appropriate for valuing DG. Should Arizona opt for a less-rigorous and comprehensive framework, it stands to bear witness to the destruction of the DG industry and

[9] *Id.* at 8:9-26; Kobor Direct Test., Vote Solar Ex. 7 at 49:1-7.
[10] Beach Direct Test., TASC Ex. 26 at 9:9 – 10:11.
[11] Kobor Direct Test., Vote Solar Ex. 7 at 15:16 – 16:7.
[12] Beach Direct Test., TASC Ex. 26 at 6:20 – 7:22; *accord* Kobor Direct Test., Vote Solar Ex. 7 at 48:7-21.
[13] *Id.* at 7:26 – 8:5.
[14] *Vote Solar v. The Public Utilities Comm'n of Nevada*, No. 16 OC 0052 1B (Nev. Jul. 7, 2016); *The Alliance for Solar Choice v. The Public Utilities Comm'n of Nevada*, No. 16 OC 0072 1B (Nev. Jul. 7, 2016); *see also* Krysti Shallenberger, <u>TASC Sues Nevada PUC To Overturn Net Metering Decision</u>, Utility Dive (Mar. 22, 2016) http://www.utilitydive.com/news/tasc-sues-nevada-puc-to-overturn-net-metering-decision/416087/.

backlash from DG customers whose investments are rendered worthless as occurred in Nevada when it hastily adopted an embedded cost methodology after initially approving of the comprehensive demand-side analysis after careful consideration.[15]

IV. A LONG-TERM AVOIDED COST ANALYSIS MUST BE PROMOTED TO VALUE DG BECAUSE IT IS THE ONLY METHOD THAT ACCURATELY CAPTURES THE FULL BENEFITS OF DG.

A. Guiding Principles for Valuing the Benefits and Costs of DG.

The main tenet of a proper benefit-cost analysis is that DG can be maintained as a "viable economic proposition" for participating solar adopters, the utility grid and society overall, while also keeping rates stable for non-solar customers.[16] Before looking at each of the benefit-cost elements in detail, we address three principles that must be kept in mind when ultimately valuing DG.

First, a DG system should be valued over the long-term and should not be examined as a snapshot in time, which can never properly value benefits that flow over a DG system's life. The benefits and costs of utilizing DG should be calculated over a period that relates to the "useful life" of a DG system, which can be from twenty to thirty years.[17] Therefore, analysis should develop 20+ year levelized benefits and costs for solar DG on the utility system. Doing so enables DG to be treated like a resource and evaluated in the same way that utilities consider the acquisition of other long-term resources. For example, when utilities evaluate the potential acquisition of conventional generation resources, they incorporate the costs to build the plant and its ongoing operations and compare that to either not building the plant or choosing an alternative resource option.[18]

Second, for any analysis of DG valuation, utilities must regularly provide accurate and reliable data not based on proprietary models that cannot be shared. 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.

Finally, the Commission should advocate for a valuation framework that considers a comprehensive list of benefits and costs. The Commission already undertakes a similar benefit-cost

[15] *Id.* at 7:26 – 8:5; Kobor Direct Test., Vote Solar Ex. 7 at 48:7-21.
[16] Beach Direct Test., TASC Ex. 26 at 25:9.
[17] *Id.* at 18:12-21.
[18] *Id.*

analysis when it deliberates the cost-effectiveness of EE and DR programs.[19] For these other demand-side programs, the Commission examines the impacts on utilities, non-participants and society as a whole to determine the tradeoffs. DG, EE and DR are all "small-scale, short lead-time resources."[20] Likewise, the Commission should look at DG's cost-effectiveness including analyzing environmental impacts, improved electric reliability, and improved system operations to the utility in any value analysis.[21]

B. Discussion of each Specific DG Benefit and why it should be Included in a Long-Term Avoided Cost Framework.

1. *Avoided Energy Costs Benefits.*

DG electricity replaces electricity that would have been generated by the utilities and delivered over the utilities' grid. Each kWh of DG offsets the need for a kWh of energy generated by the utility and is a direct benefit of DG. The energy generation savings represent the cost the utility would have incurred if the energy had been produced/procured from another source by the utility. These reductions in costs to the utility include overall fuel and purchased power expenses.[22] Thus, any framework should include fuel savings, the associated heat rate for the generation facility, and related variable costs of operations and maintenance saved by the reductions in generation.[23]

2. *Avoided Line Losses*

The value of avoided energy should also include reductions in transmission line losses.[24] Since DG output is consumed by the neighboring non-DG customer, the utilities avoid line losses of up to 12% that would be incurred if the utility were to send the electricity over the grid to that non-DG customer. Not only does DG avoid direct energy costs but it *also* avoids the additional 12% of generation needed to serve the non-DG customer.[25]

Interestingly in this case, APS, through witness Mr. Brown, makes the unsupported suggestion that there may be no real avoided line loss benefit.[26] It is well accepted that line losses are a real and

[19] *See* A.A.C. R14-2-2412.
[20] Beach Direct Test., TASC Ex. 26 at Ex. 2, p.6 thereto.
[21] A.A.C. R14-2-2412(C).
[22] Albert Direct Test., APS Ex. 5 at 7-8.
[23] Kobor Direct Test., Vote Solar Ex. 7 at 28-29; Beach Direct Test., TASC Ex. 26 at 20, Table 2.
[24] Volkmann Rebuttal Test., Vote Solar Ex. 4 at 16-18.
[25] *Id.*
[26] *See* Brown Direct Test., APS Ex. 8 at 26.

quantifiable benefit and previous APS funded studies even accepted and calculated such line losses.[27] In addition, multiple utilities and experts across the country have agreed with this benefit.[28]

3. *Avoided Utility Generation Capacity Benefits.*

A utility must build generation capacity to meet system peak demand. APS' 2014 IRP filing highlighted that DG, in addition to EE and DR, in APS' service territory is able to "meet APS' resource needs in the near term and will help to defer the need for larger-scale resources in the long-run."[29] In fact, the 2014 IRP shows continued growth both in EE, DR programs and in DG resources between 2014 and 2018, such that new demand-side resources developed in 2014-2018 will contribute *862 MW to meeting APS' peak demands by 2018.*[30] Thus, DG contributed directly to deferring any new power plants until at least 2018. When DG effects the lowering of peak demand on the APS system, it helps avoid generating capacity and even the 15% reserve margin.[31] As a result, DG's value goes beyond its short-term avoided energy costs.

APS has assigned a capacity value to solar that is far too low in its Cost-of-Service Study ("COSS"), especially given DG's contribution to the top 10-15 percent of APS' top load hours.[32] Further, if customers are incentivized to install west-facing systems, they could be counted on to contribute to a changing mix of resources and an even greater contribution to peak demand.[33]

4. *Avoided Transmission and Distribution Cost Benefits.*

DG provides direct benefits to utilities through the reduction or deferment of new costly transmission and distribution related investments.[34] DG defers or eliminates the need for increased transmission and distribution infrastructure.[35]

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[27] *See* Beach Supplemental Test., at 6-7
[28] *See Id.*
[29] Beach Direct Test., TASC Ex. 26 at Ex. 2, p. 6 thereto.
[30] *Id.* at Ex. 2, p.11-12 and Table 4 thereto.
[31] See *Id.* at 11-13.
[32] *See* Monsen Rebuttal Test., TASC Ex. 29 at 16-18; Beach Rebuttal Test., TASC Ex. 27 at 14-15.
[33] *See* Beach Tr., Vol X at 1853:1-6.
[34] *See* TASC Ex. 19.
[35] *See* Beach Direct Test., TASC Ex. 26 at Ex. 2, p.13-14 thereto; Volkmann Direct Test, Vote Solar Ex. 3 at 16-18.

a) <u>Avoided marginal transmission costs.</u>

Similar to EE and DR, DG slows capacity growth and provides reduced loads which defers or avoids the necessity for new transmission related investments.[36] As a result, DG ultimately provides savings in the form of avoided marginal transmission capacity costs to the utility caused by DG's ability to reduce load growth.[37] This is especially important and beneficial when solar production occurs during peak demand.[38]

In addition, transmission network upgrades can be avoided by DG. This occurs when DG avoids network upgrades to bulk transmission that utilities may have to add to access utility-scale projects that DG can displace.[39]

b) <u>Extended life of distribution and transmission equipment.</u>

DG also reduces wear and tear on the transmission and distribution grid, helping to avoid the replacement of costly infrastructure equipment.[40] The majority of DG output that serves the on-site load will reduce distribution loads because that power will never flow onto the distribution system. Further, exports from DG serve local neighborhoods thus also reducing loads on the entire distribution system. As a result, DG avoids the cost of distribution system expansions or upgrades and extends the life of existing equipment.[41]

c) <u>Additional avoided marginal distribution costs.</u>

It is important to understand that grid modernization projects provide wide ranging benefits in addition to any aimed at integrating distributed energy resources ("DER"), including DG, into the grid.[42] There is significant potential for grid modernization costs to be *reduced* by the smart deployment of DG.[43] A recent study found that DER, including DG, deployed in an intelligent manner can be a least-cost approach to grid modernization.[44] Further, voltage support that can be provided by

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[36] *See* Beach Direct Test., TASC Ex. 26 at Ex. 2, p.13-14 thereto; *See also*, Beach Supplemental Test. At 7:8-21.
[37] *See Id.*
[38] *Id.*
[39] *See* Beach Supplemental Test. at 7:14-17.
[40] *See, e.g.,* TASC Exs. 18 and 20.
[41] *See* Beach Direct Test., TASC Ex. 26 at Ex. 2, p.15 thereto.
[42] *See* Beach Supplemental Test. at 9:20-10:12.
[43] *See Id.* at 10:13-11:6.
[44] *Id.*

smart inverters attached to DG projects can provide a quantifiable benefit on the distribution grid and should be considered in any value analysis.[45]

The utilities' own experts have also acknowledged that there are calculable benefits and impacts that can be realized by utility transmission and distribution systems stemming from DG. TEP and UNSE witness Overcast proposed certain means that could be utilized to set a value for transmission and distribution savings.[46] APS witness Sterling recounted that the Tennessee Valley Authority utilized two models of analysis, both of which found a value in avoided transmission costs.[47] APS witness Albert admitted that even if utility-scale rates were utilized as a proxy for DG value, the rates would need to be adjusted to account for, among other things, the impact of DG on utility transmission systems.[48] In fact, APS witness Snook plainly acknowledged that APS theoretically agrees that DG systems could lead to transmission and distribution savings that could then be calculated and credited (and also stated that APS intended to make such a calculation of such potential savings in its then-upcoming rate case).[49]

With all parties agreeing that there is, at a bare minimum, a potential for savings to the distribution and transmission systems as a result of DG technology, it is imperative that any valuation framework allow for the calculation of and account for such savings. The savings realized to transmission and distribution systems can be monumental. For example, Vote Solar witness Volkmann cited a recent 2016 decision of the California Independent System Operator to cancel $*192 million* worth of planned sub-transmission projects due to load-reducing impacts of DERs, including DG.[50]

Because DG systems can, and have, led to transmission and distribution savings, any valuation framework must necessarily calculate and account for such value. Both New York and California utilities are obligated to calculate and account for transmission and distribution costs and benefits.[51] Arizona cannot, therefore, simply ignore or fail to provide some value for transmission and distribution impacts. Specifically, TASC agrees with Vote Solar that any "methodology should credit DG . . . for

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[45] *See Id.*
[46] Overcast Tr., Vol. V at 1015:13 - 1016:25.
[47] Sterling Tr., Vol. II at 347:24 – 348:6.
[48] Albert Tr., Vol. II at 402:25 – 404:7.
[49] Snook Tr., Vol. I at 110:25 – 111:12, 136:20 – 137:11
[50] Volkmann Tr., Vol. IX at 1620:17 – 1621:8.
[51] Volkmann Direct Test., Vote Solar Ex. 3 at 17-18.

their incremental contributions to [transmission and distribution] capacity relief, even if the utility has not identified an imminent capacity expansion project in the local area."[52]

5. *Fuel hedging Costs Benefits.*

Utilities are exposed to volatile fossil fuel prices. Natural gas has been the most unpredictable fuel source, based on price, and any long-term projections concerning its price have been wrong. The Beach study illustrated this volatility with a plot of historical benchmark Henry Hub gas prices.[53] Renewable generation inevitably reduces the utility's exposure to this volatility. As APS correctly surmised in their 2012 IRP, "renewable resources have the ability to diversify the overall portfolio of resources and provide mitigation against the inherent price volatility risks associated with a natural-gas dominated energy mix."[54] In response to a Vote Solar data request, it was revealed that APS' efforts to hedge fuel averaged $50 million a year based on the utility's gas purchases. These costs, therefore, are added to the costs of the avoided gas burns.[55]

6. *Market Price Mitigation Benefits.*

As renewable generation penetration continues in the APS service territory, it creates a downward trajectory of the region's energy market prices. As renewable generation becomes available to the utility, and its "must-take" position, it displaces the most expensive power that a utility would have otherwise generated or purchased (most likely natural gas on the margin). Accordingly, a utility would not have to shop in the market for electricity and natural gas as often. This is considered to be market price mitigation, a quantifiable benefit of renewable generation.[56] As renewable generation increases, the need for gas-fired generation decreases. The Lawrence Berkeley National Lab estimated that gas-related market mitigation benefits of distributed renewable energy could be about $10 per MWh.[57]

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[52] *Id.* at 4:12-17.
[53] Beach Direct Test., TASC Ex. 26 at Ex. 2, p. 9 thereto.
[54] *Id.* at n.16.
[55] Docket #13-0248, Technical Conferences on DG and NEM.
[56] Beach Direct Test., TASC Ex. 26 at Ex. 2, p.10 thereto.
[57] *Id.* at 11, n.22.

7. *Societal Benefits of DG.*

There are benefits from DG that do not directly impact utility rates, but are conferred on all citizens. For instance, everyone benefits when DG takes the place of conventional fossil fuel generation, which in turn leads to reductions in air pollutants that harm people's health and the environment.

Further, as DG deployment increases, demand on water supplies is correspondingly reduced.[58] By siting energy generation upon developed properties as DG does, more land is left available to be utilized for other uses or to be preserved in its natural state.[59] Finally, the jobs created by the burgeoning solar industry also provide a boost to the local economy.

a) Water Savings.

As DG participation grows, the utility needs less water for generation uses. Generating plants primarily use water for cooling purposes. The benefits are easy to ascertain; the less need for water, the less need to worry about its availability. The APS 2012 IRP cited water costs as $1,114 per-acre foot.[60] Studies in California have measured the high costs to retrofit natural gas plants to reduce their water consumption. The Beach Study determined that an avoided cost of $1,660 per acre-foot is a proper value to quantify the water savings from renewable DG, "based on the quantity of water savings from renewable generation that APS stated in table 27 of the 2014 IRP."[61]

b) Reduce Carbon Benefits.

There is a social cost to carbon. It is attributed to greenhouse gas emissions. The Beach study asserted that, "[t]he most prominent and reputable source for estimates of the social cost of carbon is the federal government's Interagency Working Group on the Social Cost of Carbon."[62]

APS witness Albert, in his Direct Testimony, brushed over the environmental attributes of rooftop solar, stating that "the precise benefits attributable to rooftop solar of carbon-free generation are difficult, if not impossible, to quantify."[63] APS witness Brown lamented a "wide variance" in the

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[58] *Id.* at Ex. 2, p. 17 thereto.
[59] *Id.*
[60] *Id.* at Ex. 2, p. 20, n.47, thereto.
[61] *Id.* at 20.
[62] *Id.* at 17, n.33.
[63] Albert Direct Test., APS Ex. 5 at 13:23 – 14:5.

conclusions of VOS studies.[64] But, he cited studies across very different states including Louisiana (as a negative) and Maine (as a positive) as some sort of comparison to justify the futility of determining the value of a resource.[65] However, ratemaking is often about policy decisions based on diverging submissions of evidence. When APS files a rate case, it offers revenue estimates that differ from other parties including RUCO and ACC Staff. Yet, it is safe to assume that Brown would hesitate to describe the revenue requirement portion of ratemaking as "highly subjective and readily manipulative" as he freely characterizes the task with determining the value of solar.[66] In fact, federal government agencies are required to estimate the social cost of carbon in cost-benefit analyses. The Beach study chose a "mid-range real discount rate of 3%" to calculate long-term benefits and costs, as a "conservative assumption."[67]

c) Health Benefits of Reducing Air Pollutants.

Society as a whole benefits when pollutant emissions are lowered, especially in terms of improved human health. The EPA has determined that exposure to particulates cause asthma, and even respiratory illnesses, cancer, and premature death.[68] The Beach study recommended that it was best to "us[e] the health co-benefits from reductions in criteria pollutants that were developed by the EPA in conjunction with the Clean Power Plan. These benefit estimates are recent, as they were developed in 2014 as part of the technical analysis for the proposed rule."[69] Nitrous oxide (NOx) is particularly worrisome. According to the Clean Power Plan, "nitrous oxides react with volatile organic compounds to font ozone, and are also precursors to the connation of particulate matter."

d) Local Economic Benefits.

There are costs uniquely attributable to DG (installation labor, permitting, permit fees, customer acquisition, and marketing) but they occur within the local economy, area and labor market.[70]

[64] Brown Direct Test., APS Ex. 8 at 13:9.
[65] *Id.* at 10 – 11.
[66] *Id.* at 13:4.
[67] Beach Direct Test., TASC Ex. 26 at Ex. 2, p.18 thereto.
[68] *Id* at n.39.
[69] *Id.* at 18.
[70] *Id.* at 20-21.

Meanwhile centralized generating plants are mostly not located in the area where power is purchased and used, thus minimizing its economic benefit within the local community it serves.[71]

8. *Other Policy considerations and Non-Monetary Benefits.*

The Commission should also consider the important non-monetary benefits of DG when evaluating the value of solar. There are many policy-based reasons for the Commission (as well as the State) to continue promoting DG investment. A restrictive framework would curtail these benefits that should be properly accounted for and valued in any framework.[72] These benefits include:

a) New Capital Investments – Each time a customer invests in DG, they are injecting new capital into the power infrastructure and notably, into clean energy sources (with at least some of this clean energy being distributed back into the grid);[73]

b) Future Technologies will only enhance the Value of DG – A restrictive framework would curtail the enhanced value of DG in the future. For example, advanced smart inverters, battery storage and more efficient DG photovoltaic panels will only contribute more to peak demand, grid reliability and capacity.[74] Even APS witness Brown agreed that smart inverters and storage would enhance the value of solar.[75]

c) Competition – DG serves as a competitive alternative to utility power, competition that will only increase with the implementation of customer-sited storage. As DG develops, it may provide a new electric supply with qualities and reliability comparable to that provided by the utilities themselves;[76]

d) High-Tech Synergies – Studies have shown that DG customers are more likely to invest in other energy saving and clean energy technologies once they have invested in DG. Promoting DG has a domino effect of promoting other energy-saving measures as well;[77]

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[71] *Id.*
[72] Beach Tr., Vol. X at 1969:24 – 1970:2.
[73] Beach Direct Test., TASC Ex. 26 at 31:4-8.
[74] *See, e.g.*, Vote Solar Ex. 1; Volkmann Direct Test., Vote Solar Ex. 3 at 9-11; Beach Direct Test., TASC Ex. 26 at 13 – 14.
[75] Brown Tr., Vol VI at 1206:12-25.
[76] Beach Direct Test., TASC Ex. 26 at 31:10-18.
[77] *Id.* at 32:1-12.

e) Self-reliance – DG allows customers to become more independent and self-reliant in the procurement of an essential and necessary commodity.[78]

Although it is difficult to quantify these benefits, as a matter of policy, these outcomes are desirable for both DG customers and society as a whole. Thus, any framework ultimately utilized for calculating the value of solar should include a means for valuing and/or accounting for the above-referenced benefits as well.

C. Summary of DG Benefits to be included in a Valuation Analysis.

Mr. Beach has conducted an illustrative value analysis for APS' service territory[79] that is based on a 20-year levelized cents/kWh value using data directly from APS' 2014 that should be a model to the Commission:[80]

Avoided Costs	**Orientation of DG System**	**Residential Savings**
Energy	All	6.2
Fuel Price hedging	All	0.9
Market price mitigation	All	1.0
Capacity	South	5.0
	West	8.9
Transmission	South	0.9
	West	1.6
Distribution	South	1.5
	West	3.2
Total Direct Benefits	South West Average	15.5 21.8 18.7

[78] *Id.* at 32:36-40.
[79] *See generally,* Beach Direct Test., TASC Ex 26, at Ex. 2 thereto.
[80] *Id.* at 22, Table 11.

Societal		
Carbon	All	3.3
Criteria Pollutants	All	1.1
Water	All	0.2
Local Economic benefit	All	4.7
Total Societal benefits	All	9.3
Total benefits		
Direct and Societal	South	24.8
	West	31.1
	Average	28.0

V. HISTORICAL COST-OF-SERVICE STUDIES CANNOT ACCURATELY REFLECT THE VALUE OF DG BECAUSE THEY ARE ONLY BASED ON EMBEDDED COSTS AND DO NOT CONSIDER REAL LONG-TERM BENEFITS.

The utilities in this docket argue that a single year COSS can accurately reflect the value of DG. This red herring argument is spurious on its face. COSS are based on a single test-year snapshot of *past historical* costs and cannot, by their design, capture the long-term costs and benefits of DG.[81]

Valuation of the costs and benefits of DG based only on the short-term would ignore many significant benefits associated with DG that accrue over the longer term as discussed above.[82] COSS are based on a utility's embedded rather than marginal costs. Thus, a change in the utility's COSS as a result of DG adoption has no direct link to how the company's costs may actually be reduced in the future.[83] COSS cannot evaluate the true long-term benefits of DG over the course of 20 or 25 years. Since a COSS focuses on embedded cost issues, it is not the proper tool for evaluating new generation resources, whether they are traditional utility-scale projects or DG.[84]

[81] Monsen Tr., Vol. X at 2029:3-16.
[82] *Id.* at 2028:1-4.
[83] Beach Rebuttal Test., TASC Ex. 27 at 5:2-15.
[84] Kobor Rebuttal, Vote Solar Ex. 8 at 31:3-18.

Indeed, utilities themselves do not use COSS to analyze the reasonableness of their own long-term resource options. They instead use integrated resource planning.[85] It is standard practice to evaluate the long-term benefits and costs of utility investments, such as power plants and transmission lines.[86] For example, the majority of utility-scale power purchase agreements ("PPA") for renewable generation are 10 to 20-year fixed or escalating contracts and evaluated over their entire life spans.[87] Similarly, COSS are not used by utilities to access the reasonableness or value of other demand-side resources such as EE programs.[88] Despite this, DG is the only resource the utilities argue should be evaluated differently.[89]

DG is also a long-term resource and it would be similarly unreasonable to assess the long-term investment of DG using a one-year snapshot. Rather, a balancing test must be used to assess the long-term benefits and costs from multiple perspectives because DG is an important long-term resource whose economics should be assessed over its full economic life in the same way that other energy resource options are assessed.

Finally, since COSS cannot value the long-term benefits of DG, any reduction in the export rate for DG based only on those studies would be a revenue windfall for the utility because it is selling the energy at the retail rate to non-DG customers.[90]

A. Issues with APS' Cost-of-Service Study.

Initially, APS' COSS is based on a back-end proprietary model that limits full evaluation of its assumptions and inputs.[91] A preliminary analysis, however, reveals that APS' NEM cost-shift claims are based on drastic over-allocation of costs to serve NEM customers.[92] APS has, for example, failed to properly align costs for DG customers based on their delivered load.[93] This alone has caused

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[85] Monsen Tr., Vol. X at 2029:3-16.
[86] Kobor Rebuttal, Vote Solar Ex. 8 at 31:7-9.
[87] *Id.* at 31:19-25.
[88] Beach Tr., Vol. X at 1847:1 – 1849:15; Beach Rebuttal Test., TASC Ex. 27 at 6:1-15.
[89] *Id.*
[90] Kobor Direct Test., Vote Solar Ex. 7 at 22:4-19.
[91] Kobor Rebuttal Test., Vote Solar Ex. 8 at 15:3-14.
[92] Kobor Tr., Vol IX at 1709 – 1711.
[93] Snook Tr., Vol. I at 136:20 – 137:11.

the alleged energy-related demand costs to serve DG customers to be inflated by 28-38% in APS' COSS.[94]

Similarly, APS failed to assign any benefits from DG in its COSS.[95] The credits that APS uses in its COSS to account for the value of solar supplied by NEM customers explicitly omit any potential benefits of solar generation on costs for providing transmission or distribution service.[96] APS also ignores the generation demand reductions associated with NEM deliveries to its distribution grid in its COSS.[97]

B. Issues with TEP/UNSE's Cost-of-Service Study.

TEP/UNSE's COSS suffers from adoption of many of the improperly-utilized methodologies and analyses included in the APS COSS. TEP/UNSE offers little to no explanation of the methodology or meaning of each alleged cost shift category. Again, it improperly allocates costs to NEM customers based on false allocation factors that do not relate to cost causation.[98] The utility conflates the costs and revenues associated with services provided by the utility with compensation paid for energy exports. For example, TEP/UNSE evaluated the actual revenues received from NEM customers, but the cost to serve them was calculated based on TEP's most recent rate case filing that includes a requested $109.5 million non-fuel revenue requirement increase.[99] Thus, the COSS conflates costs because the application is based on a requested increase of over 12% in adjusted test year revenues.[100] Similarly, the utility ignored any long term benefit of DG.[101] The short-term valuation of energy exports appears to be based only on the average marginal cost associated with deliveries to DG customers while the short-term valuation of onsite DG consumption appears to be based on only an avoided fuel cost. Therefore, the utility has failed to even bother considering the long-term benefits of DG, let alone try to analyze them. Correcting this "one way" thinking is of

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[94] Kobor Rebuttal Test., Vote Solar Ex. 8 at 16 – 17 and Table 2.
[95] Snook Tr., Vol. I at 136:20 – 137:11.
[96] Snook Tr., Vol. I at 111:2-12, 133:6-19; Monsen Rebuttal Test., TASC Ex. 29 at 19:21-30.
[97] Beach Rebuttal Test., TASC Ex. 27 at 19-21.
[98] Kobor Tr., Vol IX at 1713 – 1715.
[99] Kobor Rebuttal Test., Vote Solar Ex. 7 at 24, n.52.
[100] *Id.*
[101] Kobor Tr., Vol IX at 1714:19-20.

paramount importance in this docket and a balanced approach should be advocated when considering frameworks for valuing DG.

VI. UTILITY-SCALE SOLAR IS NOT THE SAME AS DG SOLAR AND CANNOT BE USED AS A PROXY PRICE FOR DG.

APS, TEP/UNSE and Staff all argue that utility scale solar can be used as a proxy for DG exports. Grid-scale benchmarking methodology approaches the issue of DG valuation from the utility perspective, making a false comparison between the two resources. The Commission and several other states have already recognized that solar DG and utility-scale solar are not interchangeable resources.[102] As shown below, comparing solar DG and utility-scale solar is largely an "apples to oranges" comparison. In addition, permitting the utilities to select the utility scale projects they use as proxies for setting export reimbursement rates for DG customers would lead to the utilities always imposing the lowest rate possible without regard for the benefits of DG or the investment made by a DG customer. This results in a revenue windfall for the utility because it is selling the exported DG solar energy at the *retail rate* to non-DG customers even though that retail rate includes the costs of services that the utility did not render in delivering that power to that customer.

A. The Market for Utility-Scale and DG are Significantly Different.

A utility-scale developer can choose to develop projects in various locations, can bid into several utility requests for proposals and even sell the power to any interconnecting utility. In contrast, the DG customer can only export power to their utility and only has one possible buyer for that power – their utility provider.[103] The utilities have a monopoly and there is no market to price DG exports for sales to third parties.[104]

The lack of a competitive market for NEM customers' DG exports is illustrated by the fact that the utilities' proposals would also adjust the rate they pay NEM customers every year based on the price of the most recent utility-scale PPA,[105] Utility-scale solar developers are not forced to accept such uncertain and variable prices for the electricity they generate over long term PPAs. Yet DG

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[102] A.A.C. R14-2-1805(B).
[103] Kobor Rebuttal Test., Vote Solar Ex. 7 at 33:1-16.
[104] *Id.*
[105] *Id.* at 31:10-19.

customers would have no choice but to be subject to this highly variable pricing regime under proposals to reset rates over time.

Despite wanting to value DG energy utilizing a utility-scale proxy, the utility experts themselves agree that even if utility-scale prices were used as a proxy, there would need to be at least some level of adjustment to account for the different traits and nature of DG exports as compared to utility-scale solar.[106] These "adjustments" would again be subject to manipulation by the utilities. Thus, the only fair value to use for NEM is the actual value realized from the adoption and use of DG, not by utilizing a proxy rate premised on the manipulated costs of utility-scale solar production.

B. DG Solar has Added Value Not Found in Utility-Scale Solar.

The differences between DG and utility-scale are substantive and numerous. Initially, DG solar is a retail product whereas utility-scale produces energy as a wholesale product.[107] When a generation facility is located behind a residential customer's meter, at the point of consumption, it has added benefits that a utility-scale solar facility simply cannot provide. These added benefits that must be accounted for include:

- The majority of the output of a rooftop solar facility provides power directly to end-use retail loads, behind the meter, where it displaces retail power from the utility whereas utility-scale solar power is often delivered over high-voltage transmission systems in competition with other large power sources;[108]
- Avoided costs associated with delivery of the generated electricity from DG systems;[109]
- DG power is delivered to load, whereas utility-scale power is not;[110]
- Local economic and resiliency benefits of local power production via DG systems;[111] and

[106] Albert Tr., Vol. II at 402:25 – 404:7, 408:16-22, 412:24 – 413:11, 440:1; Tilghman Tr., Vol. III at 600:4-21.
[107] Beach Tr., Vol. X at 1855:9-11; *see also* Brown Tr., Vol VI 1202:17-25, 1204:6-24 ("Not the same level of transaction costs for a microtransaction as you do for a macrotransaction.").
[108] Beach Direct Test., TASC Ex. 26 at 29:11-20 (the "minority of power is exported to the distribution grid, where it immediately serves neighboring loads, also displacing retail power from the utility.").
[109] *Id.* at 29:2 – 30:19.
[110] *Id.* at 29:23-24.
[111] *Id.* at 30:17-20.

- More efficient usage of environmental resources via avoidance of biological impacts of the significant land areas and costly transmission facilities required by utility-scale solar projects.[112]

The Commission acknowledged a difference between DG and utility-scale solar by including a DG "carve out" in the REST rules that requires utilities to meet 30% of the overall renewables requirements with DG or other distributed resources and adding additional requirements and safeguards when utilities seek to alter NEM tariffs.[113] If there were no differences between DG and utility-scale renewable resources, the Commission would not have seen fit to treat these resources differently and require the adoption of DG. Given that usage of DG resources are required by the REST rules, the unique societal and environmental benefits of DG must be accounted for when determining value to ensure compliance with these rules.[114] As a result of these added benefits not shared by utility-scale solar, as well as the fact that unlike utility-scale providers, DG customers are limited in both the sale and export of generated power solely to their local utility, utilizing grid-scale proxies to value DG is a false comparison that should be rejected.[115]

For the reasons set out above, RUCO witness Huber is correct when he avers that favorable utility-scale costs should not be used to determine that DG is not cost effective or should not be pursued.[116] In sum, "[r]ooftop solar provides a retail product, while utility-scale solar supplies a wholesale product. The retail, rooftop product has been delivered to load, whereas the wholesale, utility-scale product has not."[117] It is important therefore to ultimately utilize a methodology that recognizes and accounts for these differences[118] when determining the rate to be paid to NEM customers.[119]

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[112] *Id.* at 30:16-23.
[113] A.A.C. R14-2-1805(B), -2305, -2307.
[114] *See generally* Huber Tr., Vol. VIII at 1597:21-23; Beach Tr., Vol. X at 1971; Beach Direct Test., TASC Ex. 26 at 30:2-14.
[115] Kobor Tr., Vol. IX at 1708-09; Kobor Rebuttal Test., Vote Solar Ex. 7 at 32 – 35.
[116] Huber Tr., Vol. VIII at 1538:8-10, 1597:21-23.
[117] Beach Direct Test., TASC Ex. 26 at iv.
[118] *Id.* at 29:28 – 30:23
[119] Although TASC is opposed to the selection of any non-retail rate for the reimbursement of NEM, to the extent the Commission wishes to consider utilizing proxy rates premised on utility-scale power and PPA rates, such a proxy rate should consist of a weighted average of such rates based only on projects or plant in operation at the time the weighted average is determined. Contracts for unbuilt projects must not be considered in any analysis.

VII. RETAIL NEM RATES ARE COST EFFECTIVE AND SHOULD REMAIN INTACT.

The retail rate for NEM is a simple and elegant design of ratemaking. It makes perfect sense for a ratepayer to be paid the same amount for energy he exports as he pays for energy he consumes.

The current export rate, equivalent to the retail rate is, according to Mr. Beach's analysis, a cost-effective method for the Commission to carry out its renewable energy policies and goals. Doing away with the current NEM structure would be akin to the old maxim of "a solution in search of a problem." If the Commission adopted an alternative NEM rate, the Commission would create an unwelcome morass of uncertainty that it would constantly be asking itself to ascertain, determine and finalize. For instance, the Commission might find itself approving one retail rate for a homeowner and a year later, approving a different rate for that homeowner's next door neighbor.

VIII. DG CUSTOMERS ARE NO DIFFERENT FROM OTHER CUSTOMERS AND SHOULD NOT BE IN A SEPARATE RATE CLASS.

To the extent the utilities are arguing that DG customers should be in a separate rate class, such arguments are unsupported and discriminatory against DG customers.

The utilities demonstrate their discriminatory motives toward DG by arguing that DG customers should be put into a separate rate class because they have allegedly different load profiles from the residential class. The same could be said, however, for many other sets of customers that are currently in the residential customer class.[120] Other demand-side technologies can also produce significant changes in customers' load profiles.[121] The utilities ignore that there are significant variations in load shapes, both among customers with similar end uses in their residences and between customers that have installed various load-modifying technologies in their homes.[122] Yet the utilities are insisting that only DG customers be put into a separate rate class.

APS tries to support the utilities' argument through its COSS. APS' COSS is severely flawed as outlined above.[123] APS also used selected examples of customer classes to attempt to demonstrate that loads characteristics of NEM customers are outside the range of load variation that is seen within

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[120] Monsen Rebuttal Test., TASC Ex. 29 at 9:12-28.
[121] *Id.*
[122] *Id.* at 10:1-13.
[123] *Id.* at 14:11 – 28:16.

the residential class.[124] APS only focuses on the average of all of those customers, not *on the range* of loads shown by those customers.[125] As a result, APS' analysis does not provide compelling evidence that NEM customers are even outside of normal variation in loads seen in the residential class. Staff has also already specifically rejected these false arguments and believes there is no justification for breaking DG customers into their own class.[126] The Commission should also recognize these attempts to engage in discriminatory treatment of DG customers and reject them.

IX. GRANDFATHERING.

TASC believes that any changed NEM valuation framework that may ultimately be adopted by the Commission in any other hearing or rulemaking should be applied only to DG customers that sign up for new DG interconnection after the effective date of any Order issued in the utility rate case or rulemaking docket where such changes are ultimately implemented. Currently, DG customers have made long-term and substantial investments in this technology in reliance on the existence of NEM *and* the current rate design. To the extent that such changes negatively impact the DG investment, customers that invested in good faith in such technology (and in many cases, invested in accordance with the public policy implemented by the Commission encouraging DG adoption) should not be penalized.

The Commission itself already recognized that grandfathering is the proper approach when dealing with decisions impacting DG. In 2013, Staff recommended to the Commission that "any consideration of grandfathering existing NEM situations to existing NEM customers should view the grandfathering as pertaining to the DG system and premises where the DG system is sited (in other words, 'runs with the land'), versus a 'right' that resides with a specific customer."[127] Consequently, the Commission decided that, "[r]esidential customers who either have a DG system installed on their homes now, or who submit an application and a signed contract with a solar installer to APS . . . shall

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[124] *Id.* at 9:22-28.
[125] *Id.*
[126] *See* Solganick Tr., Vol VII at 1371:7-20 (Q. Would you agree that the characteristics of rooftop solar customers as they relate to service load and costs from the utility perspective justify putting them into a separate rate class? A. No.); *see also* Direct Testimony of Thomas M. Broderick, Docket No. E-04204A-15-0142, December 9, 2015 at 6-7; Direct Testimony of Eric Van Epps, Docket No. E-01575A-15-0312, March 18, 2016 at 2.
[127] Corporation Decision # 74202 at 11:23-26.

have their system grandfathered under the current NEM policies . . . ."[128] Similarly, at least two commissioners, Commissioners Little and Bob Burns, have indicated disapproval of any attempts to circumvent grandfathering with retroactive ratemaking when such an order would impact DG customers.[129]

Maintaining full retail rate compensation for existing NEM customers and their current rate design by way of grandfathering such existing customers under the currently-existing tariffs is the proper means to proceed herein.[130] Even the utilities appear to recognize that full grandfathering should apply to any decisions issued or changes ordered in this docket.[131] The Commission should act accordingly in grandfathering all currently-existing DG customers under the current regulatory scheme.

X. THIS DOCKET IS FOR THE PURPOSE OF INFORMING POTENTIAL FUTURE COMMISSION POLICY AND INVESTIGATING BENEFITS DERIVED FROM SOLAR AND CANNOT END INDIVIDUALIZED ANALYSIS IN RATE CASES.

A. Establishing a Binding Methodology Would Go Beyond the Scope of this Hearing as Set Forth in the Official Notice.

It is important for the parties and the Commission to maintain a clear understanding of the purpose and the permitted scope of this proceeding. In the December 3, 2015, Procedural Order setting this matter for hearing, the Commission required utilities to publish public notice of the hearing to be held in this matter (the "Hearing Notice"). The Hearing Notice provided the public with notice that a "generic evidentiary hearing" was being convened and was "intended to produce a factual record that will be available for the Commission to use in future proceedings for all Arizona electric public service corporations."[132] Notably, the Hearing Notice said nothing about the potential for this docket to establish a methodology for use in other dockets or find a value of solar. In fact, the Hearing Notice

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[128] *Id.* at 24:17-19.
[129] ACC hearing for Commission Docket No. E-01933A-15-0100, video at 4:11:55 - 4:13:03.
[130] Kobor Tr., Vol. IX at 1820:22 – 1822:3.
[131] Tilghman Tr., Vol. IV at 784:6 – 785:17, 786:10-15; Overcast Tr., Vol. V at 1006:5-23.
[132] Commission Docket No. E-00000J-14-0023, "Procedural Order," at 5:5-8 (Dec. 03, 2015).

did not indicate that anything about this proceeding would be binding or conclusive in future rate cases.[133]

The Hearing Notice set the boundaries for Commission action that can be taken.[134] It is therefore clear that the Commission cannot implement a binding methodology or make decisions that are dispositive in future rate cases as part of this proceeding.

B. At Most, the Commission May Issue an Advisory Statement as to the Valuation of DG that may be Considered, But is Not Binding Upon, Future Rate Cases.

It appears that certain parties, notably Commission Staff, believe that the purpose of the docket should be to adopt a definitive framework for valuing DG that essentially would be utilized in every docket going forward as the sole means of valuation of DG. While this outcome is outside the bounds of the Hearing Notice, for the additional reasons set forth below, such a "plug and play" methodology cannot be promulgated herein to bind all parties going forward. Instead, all parties must still comply with the currently-enacted and binding NEM rules (especially the rules mandating adoption of non-discriminatory rates and requiring DG-specific benefit/cost analyses to justify the adoption of differential DG rates or charges[135]) and at most, any framework advocated for herein must be treated as advisory only and merely as information that may be considered when valuing DG in any particular rate case.

This proceeding was initiated as a result of APS' 2013 application to attempt to redress alleged cost-shifts that it claimed were the result of the current NEM rules and the proliferation of DG systems

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[133] *George v. Ariz. Corp. Comm'n*, 83 Ariz. 387, 390-91, 322 P.2d 369, 371 (1958) ("This court has held flatly that rules and regulations prescribing methods of procedure of an administrative board or commission,-and specifically the Corporation Commission,-have the effect of law, are binding on the board or commission, and must be followed by it so long as they are in force and effect."); *accord Clay v. Ariz. Interscholastic Ass'n, Inc.*, 161 Ariz. 474, 476, 779 P.2d 349, 351 (1989); *see also* A.R.S. § 41-1021 (setting forth the notice and docket requirements to be followed when engaged in rulemaking).

[134] *See* A.R.S. §§ 38-431.02 (open meeting laws limit public bodies to consideration of or taking binding action on only those issues that have been previously noticed); 41-1021, -1022, and -1023 (setting forth specific notice and public participation requirements to engage in rule making); A.A.C. R14-3-103, -105, and -109 (setting forth specific notice and participation requirements to engage in Commission hearings). *See also Matter of Rights to Use of Gila River*, 171 Ariz. 230, 237-38, 830 P.2d 442, 449-50 (1992) ("The issue of notice for due process purposes is not merely a question of the mode of notification employed. Due process also requires that the notice be of such nature as reasonably to convey the required information. That is, the content of the notice must be sufficient to apprise interested parties of the pendency of the action and to make them aware of the opportunity to present their objections." (Internal quotations omitted)); *Iphaar v. Indus. Comm'n of Ariz.*, 171 Ariz. 423, 426, 831 P.2d 422, 425 (App. 1992) ("The elements of procedural due process are notice and an opportunity to be heard." (Internal quotations omitted)).

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

within its service territory.[136] Therein, Commission Staff opined that before any reasonable action could be taken to redress these alleged cost shifts, the Commission should initiate an effort "to investigate the value of DG [including the non-monetary benefits of DG] and hold workshop meetings to obtain stakeholder input."[137] Ultimately, the administrative law judge agreed, ordering the Commission to "open a generic docket on 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."[138] The scope of this docket was confirmed when Steven Olea, then-director of the Commission's utilities division, requested the opening of a generic docket "for the purposes of gathering [s]takeholder input and to help inform future Commission policy on the value and costs that Distributed Generation brings to the grid."[139] As discussed in greater detail above, this docket's Procedural Order then formally adopted this limited scope and noticed that to the public.[140]

The establishment of a final and binding decision on all parties going forward was never contemplated at any phase of the creation of this docket. Instead, this proceeding has always been conceived of as an "investigation" that could be used, eventually, to inform individual utility rate cases. But it has never been stated (nor has any docket or notice provided for) a binding and all-encompassing outcome to be derived from this docket.

The sole means the Commission has to adopt non-ratemaking policies or methodologies (including the issues presented here) is through the rulemaking process as set forth in the Administrative Procedure Act (the "APA").[141] A rule is defined as "an agency *statement of general applicability that implements, interprets or prescribes law or policy, or describes the procedure or practice requirements of an agency*. [The term "Rule" also] includes prescribing fees or the amendment or repeal of a prior rule but does not include intra-agency memoranda that are not

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[136] Commission Decision No. 74202, pp. 2-3.
[137] *Id.* at 14.
[138] *Id.* at 30.
[139] Commission Docket No. E-00000J-14-0023, "Memorandum" (Jan. 24, 2014).
[140] Commission Docket No. E-00000J-14-0023, "Procedural Order," p. 1 (Dec. 03, 2015).
[141] A.R.S. §§ 41-1001(1), -1002(A); *see also Phelps Dodge Corp. v. Ariz. Elec. Power Co-op., Inc.*, 207 Ariz. 95, 115-17, ¶¶ 78-91, 83 P.3d 573, 593-95 (App. 2004), *as amended on denial of reconsideration* (Mar. 15, 2004) (stating that Commission rules, other than those rules related to the Commission's ratemaking powers, are subject to APA regulations); *accord U S W. Communications, Inc. v. Ariz. Corp. Comm'n*, 197 Ariz. 16, 24, ¶¶ 29-32, 3 P.3d 936, 944 (App. 1999).

delegation agreements."[142] If a methodology were to be adopted that were to be utilized in every subsequent rate case as the sole or determining factor for valuing solar, such a methodology would constitute a Rule.[143] Indeed, when the Commission initially adopted the current NEM rules, it did so via compliance with the APA rulemaking process.[144]

Amongst other things, the APA requires issuance of notice of the rulemaking process, a separate rulemaking docket to be initiated, and for the proposed rules to be reviewed by the Attorney General's Office.[145] Rules may not be adopted if an agency does not substantially comply with the laws in place for adopting such rules.[146] In this instant case, the Commission has not opted to engage in rule making. It neither opened the requisite docket nor issued the mandated notice to allow for the adoption of new rules. Nor does it appear that the Commission intends to submit any orders or decisions to the Attorney General for review. If anything, the testimony and evidence presented in this case is, as the Commission itself stated, intended only for use in potential future policy decisions. Because the Commission is not engaging in rule making, no framework or decision in this case may be generally applied to all dockets moving forward. Nor may any decisions or methodologies be used to interpret or prescribe a universal law, policy, procedure, or practice requirement to be used whenever engaged in valuing solar.[147]

At most, the Commission may issue a substantive policy statement. Such statements are defined as "a written expression which informs the general public of an agency's current approach to, or opinion of, the requirements of the federal or state constitution, federal or state statute, administrative rule or regulation, or final judgment of a court of competent jurisdiction, including, where appropriate, the agency's current practice, procedure or method of action based upon that

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[142] A.R.S. § 41-1001(19); *see also* 41-1001(10) (defining what constitutes a "final rule").
[143] *See Arizona State Univ. ex rel. Ariz. Bd. of Regents v. Ariz. State Ret. Sys.*, 237 Ariz. 246, 250-51, ¶¶ 14-17, 349 P.3d 220, 224-25 (App. 2015); *Duke Energy Arlington Valley, LLC v. Ariz. Dept. of Revenue*, 219 Ariz. 76, 79-80, ¶¶ 14-15, 193 P.3d 330, 333-34 (App. 2008).
[144] Commission Decision No. 69877, p. 7 (ordering that "Staff is to begin a rulemaking process to draft rules on net metering."); Commission Docket No. RE-00000A-07-0608, "Notice of Filing" (May 30, 2008) (giving the requisite notice of the initiation of the rulemaking process to adopt proposed NEM rules in accordance with the APA).
[145] A.R.S. §§ 41-1021, -1044(A).
[146] A.R.S. § 41-1030; *accord Cochise County v. Ariz. Health Care Cost Containment Sys.*, 170 Ariz. 443, 445, 825 P.2d 968, 970 (App. 1991) ("In order for a rule to be effective, it must be enacted in accordance with the provisions of the APA.").
[147] *Arizona State Univ.*, 237 Ariz. at 250, ¶ 16, 349 P.3d at 224.

approach or opinion."[148] Notably, a "*substantive policy statement is advisory only.* A substantive policy statement . . . *does not impose additional requirements* or penalties on regulated parties, confidential information *or rules* made in accordance with this chapter."[149] (Emphases added). Arizona courts have strictly construed the advisory nature of such opinions. Such statements may only be utilized as "an element to aid in the determination of the statutorily mandated valuation," not as a generally applicable formula that must be utilized by Commission to reach a decision.[150] Courts have also recognized that administrative law judges may not rely on policy statements alone to reach a decision in administrative hearings.[151] Further, when courts have determined that substantive policy statements effectively function as rules, the statements themselves are declared void (as such statements were not adopted in compliance with the APA).[152]

In sum, the only legal outcome for this docket includes: (1) the use of the evidence herein to bear on a future rule making; and/or (2) the adoption of an advisory substantive policy statement. Should the Commission decide upon a framework for valuing DG in this case, such framework may only be used in future utility rate cases whereby the methodologies, the assumptions used, and the methods of calculation must all be open to review and subject to debate as if not previously considered. To hold otherwise would be a violation of the APA rule making requirements. Further, this docket may not serve to circumvent, repeal, or amend the rules currently governing NEM, which must still be complied with in all rate cases going forward.

XI. <u>CONCLUSION.</u>

DG technology has evolved, and will continue evolving, in new and exciting ways so long as customers are allowed to benefit from investment in clean and self-reliant energy technologies such as DG solar. Although the utilities have a stake in the outcome of this docket, so too do both current and potential DG customers and society as a whole.

For the reasons stated above, the following actions should be taken:

(1) The Commission should advocate for use of a framework that incorporates a

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[148] A.R.S. § 41-1001(22).

[149] *Id.*; *Holsum Bakery v. Indus. Comm'n of Ariz.*, 191 Ariz. 255, 257, 955 P.2d 11, 13 (App. 1997).

[150] *Duke Energy*, 219 Ariz. at 79-80, ¶¶ 14-15, 193 P.3d at 333-34.

[151] *Holsum Bakery*, 191 Ariz. at 257, 955 P.2d at 13.

[152] *Arizona State Univ.*, 237 Ariz. at 250-51, ¶¶ 14-17, 349 P.3d at 224-25.

methodology premised on the long-term avoided costs of DG;

(2) The Commission should place no weight on the COSS provided in this docket;

(3) Such framework should also include a methodology that analyzes and accounts for the non-economic and societal benefits the Commission determines are created via the adoption of DG;

(4) This docket should reject proposals to set compensation rates premised on a proxy rate set by utility-scale solar rates;

(5) Current NEM Rules should remain in force;

(6) This docket should not recognize or provide for the creation of a wholly new class for DG residential customers;

(7) Regardless of any action taken in this docket, the Commission should recognize the right of all DG customers that have submitted interconnection applications for DG systems prior to any final Order issued in any rate case where changes to NEM or rate design are considered be fully grandfathered and continue to utilize currently-implemented rate design and NEM and be subject to currently-existing rules and regulations impacting DG;

(8) The Commission should issue an Order acknowledging that any action taken herein is advisory or informational only and the specific elements of any methodology utilized in future rate cases will be subject to review in each individual rate case and that the ultimate applicability of any value determined in a rate case can be acknowledged in rates in various ways to be determined separately in each utility rate case.

RESPECTFULLY SUBMITTED this 20th day of July, 2016.

/s/Court S. Rich
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