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BEFORE THE ARIZONA CORPORATION COMMISSION

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TOM FORESE
COMMISSIONER

ANDY TOBIN
COMMISSIONER

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'S (TASC) NOTICE OF SUPPLEMENTAL TESTIMONY OF R. THOMAS BEACH

The Alliance for Solar Choice ("TASC") hereby provides this Notice of Filing Supplemental Testimony of R. Thomas Beach in the above referenced matter.

RESPECTFULLY SUBMITTED this 22nd day of June, 2016.

/s/ Court S. Rich
Court S. Rich
Attorney for The Alliance for Solar Choice

Arizona Corporation Commission
DOCKETED

JUN 22 2016

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DOCKET NO. E-00000J-14-0023

SUPPLEMENTAL TESTIMONY OF R. THOMAS BEACH

Table of Contents

I. INTRODUCTION / QUALIFICATIONS

Q1: Please state for the record your name, position, and business address.

A1: My name is R. Thomas Beach. I am principal consultant of the consulting firm Crossborder Energy. My business address is 2560 Ninth Street, Suite 213A, Berkeley, California 94710.

Q2: Have you previously submitted direct testimony in this docket?

A2: Yes, I have. On February 27 and April 7, 2016, I submitted direct and rebuttal testimony in this docket on behalf of The Alliance for Solar Choice ("TASC"). My experience and qualifications are described in my *curriculum vitae,* which is attached to my direct testimony as **Exhibit 1.**

Q3: You have previously testified under oath in this proceeding. Do you offer this testimony under oath as well?

A3: Yes, I do.

II. PURPOSE

Q4: What is the purpose of this supplemental testimony?

A4: My direct testimony presented TASC's proposal for how the Commission should establish the long-term value of distributed generation (DG) in Arizona, through an analysis of the benefits and costs of DG technologies. My rebuttal testimony responded to the proposals of other parties. This supplemental testimony is provided at the Commission's invitation, and provides a brief summation of TASC's position on benefit/cost analyses, as well as further updates for the record on recent developments relevant to assessing the benefits and costs of renewable DG as an important future electric resource for Arizona.

III. TASC'S POSITION ON BENEFIT/COST ANALYSES OF RENEWABLE DG

Q5: Please briefly summarize TASC's position on the role that benefit/cost studies should play in the evaluation of how to compensate customers for the export of power from renewable DG technologies that customers install with private capital on their own premises.

A5: My direct and rebuttal testimonies in this case propose a benefit-cost methodology for valuing distributed generation (DG) resources that builds upon the widely-used, industry-standard approach to assessing the cost-effectiveness of other types of demand-side resources, such as energy efficiency (EE) and demand response (DR). The primary reason to use a similar approach is so that all types of demand side resources – DG as well as EE and DR – are evaluated on the same basis. Benefit/cost analyses of demand-side resources have long been used to ensure that these customer-focused resources are evaluated in a manner similar to how the cost-effectiveness of supply-side, utility rate base additions are evaluated. The Commission's goal should be to analyze the merits of customer-sited DG in a way that is comparable to how all other long-term resources are evaluated, and that treats all resource options fairly on both the demand- and supply-sides.

Benefit-cost analyses assess the benefits and costs of DG from multiple perspectives, including (1) participating ratepayers who install DG, (2) other non-participating ratepayers, and (3) the utility system and society as a whole. The goal of the regulator should be to balance the interests of all of these stakeholders, who collectively constitute the public interest in the development of renewable DG technologies. In particular, demand-side resources depend on the decisions of customers to make long-term investments to reduce their energy use, shift their loads, or to produce their own generation. As the Commission is well aware, technology has given customers a rapidly increasing ability to produce and to manage their energy use, and customers' interest in doing so is greater than ever. So it is critical to balance the interests of both participating and non-participating ratepayers, and to reach an equitable balance of interests such that, in the future, all Arizona customers can have the option to participate in this revolution in how energy is produced and consumed.

IV. USE OF COST-OF-SERVICE STUDIES

Q6: Why are cost of service studies (COSS) a poor choice to evaluate the value of exports from renewable DG projects?

A6: Renewable DG is a long-term resource for Arizona, with an expected useful life of 20-30 years. As a result, the benefits and costs of DG must be assessed over a similar long-run period, just as other types of supply- or demand-side resources are evaluated over their entire expected lives. DG resources should not be evaluated using a COSS that examines utility costs in only a single test year. A COSS is not based on the utility's long-run marginal costs, and thus is likely to underestimate the long-run costs avoided by renewable DG, particularly the avoided capacity costs for generation, transmission, and distribution. Renewable DG installed today will avoid capacity additions that would otherwise occur in the future, outside of the historical test year on which a COSS is based. Regulators do not use COSS to judge the cost-effectiveness of other types of resources and do not even use them to judge utility-owned resources.

Q7: Have there been recent developments in another western state on the use of COSS to evaluate the cost-effectiveness of DG?

A7: Yes. Last December, the Nevada commission based its adverse net metering order only on a COSS submitted by NV Energy.[1] However, at the request of the state legislature, Nevada has now decided that the state should re-do the July 2014 net metering benefit/cost study[2] whose findings the Nevada commission discounted in its December

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[1] *See* the Public Utilities Commission of Nevada (PUCN) December 23, 2015 Order in Dockets Nos. 15-07-041 and 15-07-042 (PUCN December 23 Order), at pp. 40-43.

[2] The PUCN's 2014 net metering study can be found at http://puc.nv.gov/uploadedFiles/pucnvgov/Content/About/Media_Outreach/Announcements/Announcements/E3%20PUCN%20NEM%20Report%202014.pdf.

decision.[3] This study is expected to quantify many of the nine benefits of solar DG that the PUCN acknowledged in its December order but failed to quantify or to consider in its adopted export rate for solar DG.[4]

V. BENEFIT/COST STUDIES ARE NOT RATEMAKING

Q8: Is the purpose of benefit / cost studies of demand-side resources to set rates?

A8: No. The purpose of benefit/cost studies of renewable DG, EE, or DR is not to set rates; it is to determine if these demand-side programs and technologies are cost-effective. Retail rates impact the cost-effectiveness of demand-side resources, because utility bill savings at retail rates are the primary benefit of these resources for the customers who install them, and the primary cost for non-participating ratepayers. As a result, if the conclusion of a benefit/cost study is that rate design changes are necessary to increase the cost-effectiveness of DG resources, then the Commission should first prioritize rate design changes that better align utility rates with costs and that continue to give customers the ability to impact their energy costs by choosing demand-side resources. Such changes include:

1. **Time-of-Use rates** that better reflect how utility costs vary through the day, and
2. **Minimum bills**, which continue to allow the greatest scope for customers to exercise the choice to adopt DG.

The Commission should avoid fixed charges that give the customer no economic signal to use energy wisely, or demand charges that may not be cost-based and that are confusing to and poorly accepted by small customers. The Commission should leave the details of any such rate design changes to specific utility general rate cases where all of the costs and circumstances of the utility can be examined in detail.

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[3] *See* PUCN December 23 Order, at pp. 42. Also PVTech, *"Nevada PUC: Upcoming NEM cost-benefit study 'won't win the day'"* (June 14, 2016), available at http://www.pv-tech.org/news/nevada-puc-upcoming-nem-cost-benefit-study-wont-win-the-day.

[4] *See* PUCN December 23 Order, at pp. 66-67 and 95-96.

VI. EXPORT-ONLY ANALYSIS

Q9: Arizona Public Service's (APS) rebuttal criticized TASC's exemplary benefit-cost study for APS for looking at the entire output of DG facilities, instead of just looking at DG exports.

A9: To be clear, we agree that the focus of the methodology adopted by this proceeding should be the value of exports, because DG customers have a right under PURPA to serve their own on-site loads with their own renewable DG systems, and to export excess energy to the utility. However, as a technical matter of doing the calculations, valuing only the exports is more difficult, because you need to do the analysis on an hourly basis, considering both the hourly DG output and the hourly loads of the DG customer to determine when the exports occur. California and New England have developed models of their long-term, 30-year, hourly avoided cost that are necessary to assess the benefits of DG exports accurately.[5] We suggest that valuing the full output is an easier alternative, and the studies in California that have looked at the value of both exports only and all output have not found a major difference between the two.[6] Mr. Snook's COSS testimony valued all DG output, as did the two prior DG solar cost-effectiveness studies that APS has commissioned, so APS is being inconsistent in making this criticism.[7] In sum, TASC is not opposed to valuing only exports, but the Commission should be aware that it will complicate the analysis, probably for little benefit.

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[5] The California avoided cost model, developed by Energy and Environmental Economics (E3) for the California commission, is available at http://www.cpuc.ca.gov/general.aspx?id=5267 and https://ethree.com/public_projects/cpuc4.php. The New England avoided costs for demand-side resources can be found at http://ma-eeac.org/wordpress/wp-content/uploads/2015-Regional-Avoided-Cost-Study-Report1.pdf.

[6] See *California Net Energy Metering Ratepayer Impacts Evaluation* (E3, October 2013). Available at file:///C:/Users/Tom/Downloads/NEMReportWithAppendices%20(1).pdf. Compare Tables 23 and 24 on page 59, which present total levelized avoided costs on a $ per kWh basis, for both an export-only analysis (Table 23) and an all-generation approach (Table 24). The levelized avoided costs from the two approaches are within $0.02 per kWh of each other.

[7] Direct testimony of Leland Snook for APS, at p. 15 ("APS then explicitly credited the customer for: [a]ll their self-provided capacity based on a comparison to the APS-delivered customer load; and, [t]heir entire energy production, including both what the customer consumes on site and what is delivered from the NEM customer to the grid."). Also, R.W. Beck (for APS), *Distributed Renewable Energy Operating*

VII. UTILITY-SCALE SOLAR COMPARED TO ROOFTOP SOLAR

Q10: This case includes comparisons between the costs of utility-scale and rooftop solar systems. Please summarize TASC's views on these comparisons.

A10: Utility-scale solar obviously has lower capital costs, as a result of economies of scale. However, this is not a simple apples-to-apples comparison, because the two types of solar do not provide the same energy product. Rooftop 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.

Q11: What is necessary for a fair comparison between the two resources?

A11: At a minimum one must add to the cost of utility-scale solar the marginal costs associated with delivering this power to the customers that can be served by solar DG located on their own roofs, or in close proximity on the distribution system. The cost categories associated with delivering wholesale power from centralized generators should include line losses, marginal transmission capacity costs, and marginal distribution capacity costs.

Q12: Could you describe your recommendation for calculating avoided line losses on the transmission and distribution system?

A12: Yes. First, with respect to losses, I've used an industry standard approach for quantifying the avoided losses in the benefit/cost study for APS that is attached to my direct testimony; in fact, I used the avoided line loses calculated in the two prior studies of DG benefits that APS commissioned.[8] In this case, APS recommends a radical departure from these established methodologies, and even goes so far as to question whether avoided loss benefits exist at all.[9] It is well accepted among credible industry experts that

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Impacts and Valuation Study (January 2009) and SAIC Energy, Environmental and Infrastructure LLC (for APS), *2013 Updated Solar PV Value Report* (May 2013).

[8] Direct testimony of R. Thomas Beach for TASC, at Exhibit 2 (APS benefit/cost study, at pp.8 and 12), which uses the methodology for avoided line losses that R.W. Beck and SAIC developed in their 2009 and 2013 studies for APS, referenced in footnote 7 above.

[9] Direct testimony of Ashley Brown for APS, at p. 26.

avoided losses are real and easily quantifiable, and can be found in most industry reports that have looked at the value of solar, including those from Duke, Xcel, the National Renewable Energy Lab, and others evaluated in the Rocky Mountain Institute's meta-analysis of 15 DG benefit-cost studies.[10] The fact that APS would suggest that avoided line losses do not exist raises doubts as to the credibility of their recommended methodology.

Q13: What is your recommendation for calculating marginal transmission capacity costs?

A13: There are two potential sources for these added transmission costs. The first is the load-related transmission additions that otherwise would be deferred by the addition of DG. These are the avoided transmission costs analyzed in the benefit/cost study for APS which was attached to my direct testimony.

In addition to the avoided marginal transmission costs that result from DG's ability to reduce load growth, the second source of transmission costs that DG can avoid are the network upgrades to the bulk transmission that utilities may have to add to access the areas in which utility-scale solar projects are located. These are ratepayer-funded transmission costs that are beyond the interconnection costs paid for by the utility-scale projects themselves. These costs can be significant if utility-scale solar is sited at a significant distance from load centers and requires bulk transmission additions or upgrades.

Q14: Do you have any examples of such added bulk transmission costs to deliver utility-scale renewables?

A14: Yes. As one example, the 2015 study of a 50% Renewable Portfolio Standard (RPS) in California by Energy and Environmental Economics assumes the following costs (in cents per kWh) for incremental transmission to deliver new renewable generation,

[10] See Rocky Mountain Institute (RMI), *A Review of Solar PV Benefit and Cost Studies* (July 2013), at pp. 14 and 27-28, available at http://www.rmi.org/Knowledge-Center%2FLibrary%2F2013-13_eLabDERCostValue.

beyond the renewables already under contract to meet California's 33% by 2020 RPS goal:[11]

Table 1: *California RPS Transmission Costs (cents per kWh)*

Resource	Transmission Cost (c/kWh)
Out-of-state renewables	4.6
In-state renewables	3.4
Small-scale solar	2.1

These significant transmission costs reflect the large distances in the U.S. West and the relatively remote locations of the best renewable resource areas in the West. Other studies – for example, the 2014 study of integrating large amounts of renewables into the PJM Interconnection[12] – have estimated lower incremental transmission costs. The PJM study estimated incremental transmission expansion costs averaging 0.5 cents per kWh in the scenarios with 30% penetration of renewables.

Available data from Colorado falls between the California and PJM studies. The studies required by Colorado's SB 100 legislation provide limited data on the costs of incremental transmission to access utility-scale renewables. This information is presented in **Table 3** based on reported capital costs and capacities for these projects. The capital costs for these projects are converted to cents per kWh assuming a 7.4% levelized carrying charge for transmission and that wind and solar resources operate at 35% and 20% capacity factors, respectively.

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[11] E3, *Investigating a Higher Renewables Portfolio Standard in California* (January 2014), at p. 58 and Tables 10 and 29, available at https://www.ethree.com/public_projects/renewables_portfolio_standard.php.

[12] GE Energy Consulting, "PJM Renewable Integration Study" (March 2014), at Table 7. Available at http://pjm.com/~/media/committees-groups/task-forces/irtf/postings/pris-executive-summary.ashx.

Table 2: *Colorado Renewables Transmission Costs (cents per kWh)*

Line	Capacity / Resource	Status	Cost (c/kWh)
Pawnee-Smoky Hill	500 MW / wind	Built	1.3
Lamar-Front Range	900 MW / wind	Planned	1.3
San Luis-Comanche	1,400 MW / solar	Cancelled	1.2

Further, utility-scale solar has significantly greater land use impacts (and the associated permitting risks) than DG solar, which can use the already-built environment (e.g. rooftops and parking lots).

Q15: And what is your recommendation for calculating marginal distribution costs?

A15: My testimony and the accompanying benefit / cost study for APS discuss and quantify the benefits of DG in reducing distribution line losses and deferring distribution capacity additions. However, recent work has also quantified additional elements of the value that DG can provide to the distribution system.

Q16: Please update the Commission on recent work on analyzing and quantifying these additional benefits of DG to the distribution system.

A16: First, it is important to recognize that integrating DG into the distribution system will take place in the context of many initiatives that are underway across the U.S. to modernize the electric grid and to expand its capabilities to handle a wide variety of new distributed energy loads & resources – new DR programs such as programmable thermostats, electric vehicle charging, and distributed storage, for example. Integrating DG is just one of the many significant benefits of **grid modernization**, which also include:

1. Reducing the frequency and effects of outages, by allowing greater visibility for system operators into local grid conditions and reducing response times to customer outages;

2. Optimizing demand to reduce system and customer costs;

3. Improving utility workforce and asset management, such as reduced costs for distribution maintenance;

4. Development of a charging infrastructure for electric vehicles;

5. Opportunities to reduce stationary source air emissions through further electrification of buildings and industrial processes; and

6. Allowing deployment of distributed storage, which in turn has numerous potential benefit streams – energy arbitrage, capacity deferral, ancillary services, enhanced reliability and resiliency, and power quality.

As a result, states have recognized that there can be many reasons to modernize the grid, and many benefits from doing so that would be realized even if DG did not exist.[13] Moreover, there is significant potential for the intelligent deployment of DG to reduce the costs associated with grid modernization. Solar City recently released an important white paper, *A Pathway to a Distributed Grid*, which quantifies the net benefits of distributed energy resources ("DER") – including both DG and other distributed resources such as smart inverters, storage, energy efficiency, and controllable loads – and shows that they are a cost-effective, least-cost approach to grid modernization. This study reviews the recent grid modernization proposal of Southern California Edison, and concludes that only 25% of the proposed investments are related to DER integration. The other 75% are intended to realize the other benefits listed above.[14]

Other recent work has quantified the benefits of DG in providing **voltage support** on the distribution system. American National Standards Institute (ANSI) standards require utilities to supply power to all customers within industry-standards power quality standards, including within a range of allowable voltages. Utilities today use Conservation Voltage Reduction (CVR) programs to achieve lower and more uniform voltages for all customers. CVR program save energy by reducing voltages to customers who would otherwise be oversupplied with voltage in order to ensure that customers at the end of the circuit have adequate voltages. Smart inverters can regulate voltages at

[13] *See*, for example, *Investigation by the Department of Public Utilities Upon its Own Motion into Modernization of the Electric Grid*, Massachusetts Department of Public Utilities ("DPU") order D.P.U. 12-76-B, at pp. 7-15 (Jun. 12, 2014).

[14] This Solar City white paper is available at http://www.solarcity.com/sites/default/files/SolarCity_Distributed_Grid-021016.pdf.

their location; thus, they can be used as part of a CVR program to produce lower and more consistent voltages on the distribution system, thus yielding energy savings for customers. Based on an analysis from SolarCity using the results of its smart inverter field demonstration projects, smart inverters used for CVR can produce an incremental 0.4% energy consumption savings, with the associated greenhouse gas emissions reductions.[15] This benefit was not included in our benefit/cost study for APS.

Q17: Is there a basic conceptual issue with assuming that utility-scale solar would replace rooftop solar if less of the latter is installed by customers?

A17: Yes, there is. There is nothing in APS's 2014 IRP or draft 2017 IRP which indicates that rooftop and utility-scale solar are substitutes for each other. So, if APS installs less rooftop solar, it is not committed to installing more utility-scale solar, or vice versa. APS's own testimony assumes that the output from DG solar avoids APS's marginal fuel costs, which are natural gas.[16] There is no Renewable Energy Standard requirement which requires the substitution of utility-scale for rooftop solar, as APS is in compliance with the RES goals. These resources are treated differently in their value for RES compliance, and rooftop solar provides additional benefits to the local environment and economy. Finally, there are important policy reasons to treat rooftop solar equitably, so that consumers continue to have the freedom to exercise a competitive choice and to become more engaged and self-reliant in providing for their energy needs. The full benefits of enhanced customer choice, engagement, and self-reliance will not be realized if all solar energy is supplied through utility-scale projects.

Q18: Does this conclude your prepared supplemental testimony?

A18: Yes, it does.

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[15] Based on an analysis of SolarCity field demonstration project that utilized 150 distributed smart inverters to provide reactive power and voltage support in collaboration with an investor-owned utility (2016), as reported in a white paper from Solar City Grid Engineering and the Natural Resources Defense Council, *Distributed Energy Resources in Nevada: Quantifying the net benefits of distributed energy resources* (May 2016), available at. http://www.solarcity.com/sites/default/files/SolarCity-Distributed_Energy_Resources_in_Nevada.pdf.

[16] Direct testimony of Leland Snook for APS, at p. 17 ("The method described above uses the filed avoided fuel costs for all kWh produced by the rooftop solar system.").