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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

NOTICE OF FILING REBUTTAL TESTIMONY

Tucson Electric Power Company and UNS Electric, Inc., through undersigned counsel, submit the Rebuttal Testimony of Carmine Tilghman and H. Edwin Overcast.

RESPECTFULLY SUBMITTED this 7th day of April, 2016.

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By ______________________

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Arizona Corporation Commission
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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

Rebuttal Testimony of

Carmine A. Tilghman

on Behalf of

Tucson Electric Power Company

April 7, 2016

TABLE OF CONTENTS

I. INTRODUCTION.

Q. Please state your name and business address.

A. Carmine Tilghman, 88 East Broadway, Tucson, Arizona 85702

Q. What is your position with Tucson Electric Power Company ("TEP" or the "Company")?

A. I am the Senior Director of Energy Supply for Tucson Electric Power Company ("TEP" or "the Company") and UNS Electric ("UNS Electric").

Q. Did you file Direct Testimony in this proceeding?

A. Yes.

Q. On whose behalf are you filing your Rebuttal Testimony in this proceeding?

A. My Rebuttal Testimony is filed on behalf of Tucson Electric Power Company ("TEP") and UNS Electric ("UNSE").

Q. What is the purpose of your Rebuttal Testimony?

A. My testimony will focus on reiterating TEP and UNSE's (collectively the "Companies") position regarding the value of distributed solar and methods on how to calculate that value, as well as refuting a number of claims made by intervening witnesses.

II. COMPANIES' PREFERRED APPROACH TO CALCULATING COST AND VALUE OF DISTRIBUTED GENERATION ("DG").

Q. Please reiterate the Companies' expectation of an outcome for this Value of Solar ("VOS") docket?

A. We would like to see a clear definition and resolution to the following issues:

1. Clearly separating the utility's cost of service from societal and forward-looking benefits associated with solar.
2. Identifying the necessary revenue streams to fairly compensate both the utility and the customer.
3. Establishing an appropriate mechanism or model that provides the correct price signals to allow the market to respond to customer needs and allow technology to advance.

Q. Briefly describe the Companies' position regarding the preferred methods of calculating or assigning a value to DG.

A. As filed in my Direct Testimony, the desired complexity of the solution in this docket should dictate the extent to which the Commission strives for a detailed valuation of the costs and value provided by DG.

Should the Commission seek simplicity and a fair market proxy for the value of DG, it needs look no further than the wholesale solar market. Although there are a few differences between the two products (such as slightly lower distribution losses, loss of control and dispatchability, and interconnection value of 3 phase over single phase systems), the wholesale price still remains a viable proxy to the value of DG. The costs associated with the purchase of DG at this price could be easily recovered through the existing REST mechanisms concerning the calculation of the Market Cost of Comparable

Conventional Generation (MCCCG) and the above market cost (AMCCCG).

Should the Commission choose a more complex model to specifically address individual components associated with DG's value and cost, then the Company fully supports the use of the Value of Solar methodology developed by the Utah Public Service Commission (Docket No. 14-035-114). This model consisted of two primary components:

1) Known and measureable costs and benefits currently collected through rates (rate setting process), such as:
    a. Fuel offset/avoided energy
    b. Losses (energy/line)
    c. Administration and integration costs
    d. Ancillary services
2) External, societal, and future benefits for which a separate revenue stream must be identified (resource planning process), such as:
    a. Avoided generation capacity
    b. Avoided transmission & distribution capacity
    c. Avoided emission costs (CO_2, SO_2, NOX, etc.)
    d. Fuel hedging costs/savings
    e. Additional costs associated with operational compliance – integration costs
    f. Societal benefits

Under this particular model, a blend of historical rates and associated recovery through rate design is coupled with a resource planning value and an "as yet to be determined" source of revenue to pay for this value.

III. RESPONSE TO TASC WITNESS BEACH.

Q. Did you review TASC Witness Beach's testimony?

A. Yes, I did.

Q. Does the Company agree with Mr. Beach's statements and assessments?

A. No. The Company disagrees with the majority of TASC Witness Beach's assumptions, statements, and conclusions. He makes a number of erroneous statements and comments in his testimony.

Q. Do you agree with Mr. Beach's assessment that "to the utility the installation of such a DG system appears no different than if the customer had installed a more efficient air conditioner or simply decided to reduce his power usage in the middle of the day"? (Page 12, lines 26-28)

A. No. What Mr. Beach fails to acknowledge is the difference between supplying a customer's full load through multiple resources (DG and the grid) versus the reduction of load from an efficiency measure. When a customer installs an energy efficiency measure, such as a more efficient air conditioner, the maximum overall load of the customer is reduced. This results in a reduction in demand on the system, both from an operational and a planning perspective. The failure of that air conditioner will not cause an increase in demand on the system, and the Company can reasonably rely on that load reduction for grid management and planning purposes.

However, the installation of a DG system, while reducing the amount of energy taken from the grid by the customer, DOES NOT provide an equal reduction of the customers' overall energy demand, nor does it provide a "one for one" benefit in the demand reduction on the utility's system. For planning purposes, the utility must still be able to supply 100% of the customer's load when the DG system fails to produce. This issue is exacerbated during the winter months, as the customer's peak load is NOT during daylight hours.

Q. Do you agree with Mr. Beach's assertion that DG customers should not be treated differently than customers who employ other methods of cost-savings such as energy efficiency or demand response? (Page 13, lines 26-32)

A. No. As described above, a customer who employs a DG system to reduce their load is, for all intents and purposes, a partial requirements service (PRS) customer and they should be treated as such, with the appropriate demand charges and requirements associated with the applicable PRS tariff. This is especially true based on Mr. Beach's claims that DG exports are "often just 30% to 40%" (page 13, line 26), which establishes the fact, based on Mr. Beach's testimony, that a DG customer relies heavily on the utility to provide supplemental energy services, backup energy services, and ancillary energy services.

Q. Does Mr. Beach's testimony and his claim that the solar customer is not using utility system support the Company's position that the NEM rate should be based on a wholesale rate?

A. Yes. Mr. Beach claims the following (page 1, lines 14-23):

"With exported power, it is not the solar customer who is using the utility system, it is the utility and the solar customer's neighbors, because the title to the exported power transfers to the utility at the solar customer's meter. ***<u>This is no different than when the utility buys power from any other type of generator – the generator is not responsible for and does not have to pay to deliver the power to the utility's customers.</u>*** *<u>(emphasis added)</u> Instead, that delivery service becomes the utility's responsibility when it accepts and takes title to*

the exported power at the generator's meter. As a generator, the only utility costs for which the generator may be responsible are the incremental costs of interconnecting to the utility system to enable the transfer of generation (and these are often paid by the customer-generator)."

Mr. Beach very succinctly highlights that transfer of ownership happens at the meter, and that the customer has ***no responsibility*** for the delivery of that energy to another end user. This is an equivalent wholesale energy transaction, whereby the utility procures energy at a point on its system and is responsible for all costs associated with delivery. Mr. Beach previously notes that most DG customers are "qualifying facilities" under Public Utilities Regulatory Policy Act of 1978 (PURPA), which specifically requires utilities to purchase excess power exported from such systems at a state-regulated price that is based on the utility's avoided costs. (page 13, lines 2-14). Using Mr. Beach's arguments that a DG system is a PURPA facility (a position that the Company agrees with), and that the owner has no responsibility for delivery of energy after the utility takes receipt (a wholesale transaction), then it stands to reason that ALL energy exported from a customers' DG facility should be priced at the utility's avoided cost of energy as required by PURPA.

Q. Do you agree with Mr. Beach's statement that the utility does not incur costs to stand by to serve a solar customer when the solar customer is exporting to the grid?

A. No. Mr. Beach ignores several facts in his analogies, not the least of which is that a typical solar system is installed to help the customer achieve a "net zero" status on an annualized basis. This results in a solar facility size that is typically double the average customer load. Mr. Beach's statement that the loss of a DG facility is an equivalent load fluctuation to a customer who "*may come home unexpectedly in the middle of the day, turn on lights, a computer, and run an appliance, and produce a sudden spike in usage*" is unreasonable and attempts to severely diminish the actual impacts of a DG customer on the grid. The assumption that the sudden loss of 5-10 kW generating system has even remotely the same grid impact as turning on lights, a computer, and an appliance lacks any credible or substantive evidence.

Additionally, Mr. Beach's claims that as "one PV system is being shaded, another will be coming back into full sunlight" further highlights his lack of operational management experience in that Mr. Beach only views the loss and gain of generation systems (assuming they are equivalent) in total to the system load and ignores the dynamic impact to individual substations and feeder circuits.

Q. Under Mr. Beach's section titled, "Exploding Common Myths about Net Metering", he asserts that there is no cost to the utility to "store the excess kWh produced by NEM systems". Do you agree with Mr. Beach's assertion?

A. No. First, the Company is not aware of any widespread "common myth" regarding the actual storing of energy as it pertains to net metering. The Company believes that most entities operating in this industry, particularly as it relates to this docket and the parties participating, are fully aware that electricity is not "stored" per se, for later use. It appears that Mr. Beach has established this "myth" in order to over-dramatize his explanation of how the principles of net-metering actually work.

However, the assumption that there are no costs associated with net metering is inaccurate and fails to acknowledge real-time system operational issues. As Mr. Beach noted previously, the customer bears no responsibility for the movement of that energy once the utility takes ownership at the meter. Distribution wheeling is not free. Losses incurred are not free. Ramping and cycling of power plants is not free. Providing phase balancing and voltage stabilization is not free. The delivery of DG excess energy to the utility creates costs related to these aspects of grid management. All of these costs are borne by the utility and are typically recovered through the volumetric rate design. Net metering allows the DG customer to avoid paying those costs, which are, in fact, paid for by the utility and ultimately by the non-DG ratepayer.

Q. Mr. Beach states that customer-generators should not be placed into their own rate class. Do you agree?

A. No. Customer-generators are by definition a Partial Requirements Service customer with distinct loading characteristics on the utility system. Contrary to Mr. Beach's' claims, it not only can, but should be, assumed that DG customers are significantly different than a typical customer. One need only look at the usage profile and additional requirements to serve an exporting DG customer to make that reasonable assumption. At the very least, they should be considered as a unique rate class during the evaluation of DG solar and its value and cost to the system, as is contemplated in the Utah model the Company supports.

Q. Do you agree with Mr. Beach's assertion that any new charge or rate design applicable to net-metered customers' needs to ensure economic viability?

A. No. Ironically, the rooftop solar industry has repeatedly criticized the utility industry as being subsidized, uneconomic, and attempting to stop the more "economic" option of solar. Any rate or charge applied to net metered customers should be based on actual cost to serve and should be compared to other technologies for cost-effectiveness (DG vs. utility scale). If that rate or charge renders DG uneconomic, then it is a policy decision of the Commission to determine if they want to further subsidize the industry in order to make it "economic".

Q. Do you agree with Mr. Beach's assertion that rooftop and utility-scale systems do not provide ratepayers with the same product?

A. No. Mr. Beach's entire argument seems to be based on the delivery point of the solar, and that since a retail customer is "behind-the-meter" it is an equivalent retail product simply because it displaces a ***portion*** of the retail product. This is a common misconception among rooftop industry representatives that solar DG is an equivalent product to grid supplied energy. It is not. It lacks several components of grid supplied energy, not the least of which is the inability to follow a customer's load, provide sufficient starting currents, and other necessary ancillary services that are still provided by the grid.

Additionally, Mr. Beach states that "*a minority of power is exported to the distribution grid, where it immediately serves neighboring loads*". This statement is an inaccurate statement, particularly as it applies to Arizona based utilities. A traditional Arizona-based DG system installed in TEP's service territory from 2013 to present pushed back 47% of the energy generated. While Mr. Beach's comments may be more accurate for older systems that were more expensive and smaller, this data is consistent given the considerable price decline in equipment and the lease model that proliferated in the 2012-2013 timeframe where systems were built to be at close to net-zero as possible to maximize the customer's financial benefit under NEM. And while 47% is technically still a "minority of power", it seems as if Mr. Beach is trying to marginalize the impacts of pushing excess energy back onto the grid.

Mr. Beach's unqualified statement that this energy is immediately consumed by neighboring loads is a common generality that inaccurately reflects distribution loads, and lacks any empirical data proving this statement.

Q. Do you agree with Mr. Beach's assessment regarding the "important policy reasons" why a state should maintain a supportive environment for customer-sited, distributed generation?

A. No. Again, Mr. Beach takes several liberties with his statements in "promoting" customer-sited distribution, specifically:

1. Stating that customers take greater responsibility for their supply of electricity is a misrepresentation of what it means to supply your energy. Mr. Beach ignores that a DG customer not only becomes immune to electricity consumption through utility and non-DG ratepayer borne subsidies under NEM, the customer does not provide all of the necessary components needed for power quality, instead relying heavily on the grid for support services, backup, and supplemental energy while being erroneously told by the rooftop solar industry that they are "self-supplying".

2. Mr. Beach depicts customer-provided capital as being "essential" to the movement of clean resources. However, unregulated expenditures outside the review of the Arizona Corporation Commission fails to protect the Arizona ratepayers from unnecessarily subsidizing one of the least cost-effective clean energy measures. Capital expenditures — and those who would provide the capital — should be subject to the same stringent regulatory oversight as the utility whose system is being impacted, while ensuring that the Commission has the ability to evaluate the prudency of this capital expenditure.

3. Falsely claiming that rooftop solar provides a "competitive alternative" to the utility's delivered power, and that it will spur the utility to cut costs and innovate its offerings. It is disingenuous for an unregulated entity to sell a product that is completely reliant upon the services provided through the regulated utility's infrastructure — an entity who fails to pay for those services and relies on

excessive above-market subsidies to pay for that product — to claim that it is the *utility* that needs to reduce its costs and become more innovative.

4. Mr. Beach's glaring omission that the ability of smart inverters to provide grid services is tied to the ability of being connected to the grid through a communications infrastructure that does not currently exist. Mr. Beach's "representations" of the smart inverter capabilities are little more pre-programmed set-points without effective — and secure — communications with the utility's SCADA system to receive grid management signals. Mr. Beach also erroneously, and without any qualified or fact-based empirical evidence, states that, *"by reducing load on individual circuits, rooftop solar systems reduce thermal stress on distribution equipment, thereby extending its useful life and deferring the need to replace it."*

   Below is a partial list of reports from considerably more qualified entities, all of which identify additional costs and O&M associated with variable generation, which includes rooftop DG.

   1. Western Electricity Coordinating Council's Variable Generation Subcommittee Marketing Workgroup whitepaper – "Electricity Markets and Variable Generation Integration".
   2. Western Electricity Coordinating Council's – "WECC Variable Generation Planning Reference Book: A Guidebook for Including Variable Generation in the Planning Process".
   3. MIT Study on the Future of Solar Energy, specifically Chapter 7 – Integration of Distributed Photovoltaic Generators. https://mitei.mit.edu/futureofsolar

4. North American Electric Reliability Corporation (NERC) Special Report: Accommodating High Levels of Variable Generation, April 2009. http://www.nerc.com/files/IVGTF_Report_041609.pdf

5. Western Wind and Solar Integration Study – "Analysis of Cycling Costs in Western Wind and Solar Integration Study". http://www.nrel.gov/docs/fy12osti/54864.pdf.

6. NREL – "Fundamental Drivers of the Cost and Price of Operating Reserves". http://www.nrel.gov/docs/fy13osti/58491.pdf

7. Intertek APTECH report prepared for NREL and WECC – "Power Plant Cycling Costs".

5. Mr. Beach's attempt to characterize customer response to Nevada's net metering changes as their Commission being disrespectful to a customer's decision to invest in clean energy. As TASC's witness in this proceeding, it appears that TASC is implying that if the Arizona Corporation Commission doesn't continue with the "status quo" there will be a similar result in Arizona.

6. Mr. Beach's repeated mischaracterization that a customer is "self-reliant" and "independent", and that they are somehow identifying with the ideals fostered by our Nation's founding fathers. However, these DG customers remain connected to and dependent on the grid for reliable service, yet apparently expect non-DG customers to pay for the cost of the grid used to serve the DG customers. The Company believes that this type of misinformation and misrepresentation over customer-sited DG is partially responsible for the customer "enragement" in Nevada.

IV. RESPONSE TO VOTE SOLAR WITNESS KOBOR.

Q. Have you reviewed Vote Solar Kobor's testimony?

A. Yes, I have reviewed Ms. Kobor's testimony.

Q. Are there any specific points in which you agree with Ms. Kobor?

A. Yes, there are several points in which I agree with Ms. Kobor. First, I agree with her assessment of the customer's fundamental right to consume as much or as little energy from the utility as the customer chooses, and that such energy reductions should be addressed in a general rate proceedings. This concept is consistent with traditional volumetric rate design; however, this may not be ideal with regards to the appropriate valuation of energy consumed versus the energy pushed onto the grid. TEP and UNSE Witness Overcast provides a more detailed explanation of the Companies' position, as well as a more detailed discussion on buy-all/sell-all and why the need to account for all DG production (including that which is consumed on-site) in the valuation process. Additionally, we agree with the statement that this proceeding should develop a standardized approach and that the DG export valuation could be used in the utility's general rate case to inform DG rate design, as other intervening parties have mentioned.

Q. Are there any specific points in which you disagree with Ms. Kobor?

A. Yes, there are several points in which I disagree with Ms. Kobor, or at least would like to provide additional context to her statements. I will address the points individually.

Q. Ms. Kobor made a recommendation that any utility requesting reform of the existing DG rate structure use an "independent, third-party analysis using the standardized methodology developed in this proceeding". Do you agree with this recommendation?

A. No. The Company supports the development of a standardized methodology that **will** be used in each general rate case proceeding. The Company would support making it a mandatory recalculation during each rate case. As such, the Company should not have to request changes to the DG rate structure.

Additionally, the Company supports the development of a calculable rate methodology based on various supportable inputs. The mechanism for which the variables are derived should be developed in this proceeding. Ms. Kobor's request to have a third-party do the analysis — and then allow for stakeholder input to influence the outcome — implies that this proceeding leaves the parties with a subjective methodology for calculating the rate. As it is contemplated to be calculated in a general rate case, any party who disagree with the calculation performed in each rate case would have an opportunity to make their case for changes during the proceeding. The Company cannot support a methodology that is open to interpretation or based on subjective and biased opinions that are no better than what are arguing over today.

Q. Ms. Kobor has criticized the position that the use of cost-of-service ratemaking and the fact that cost-of-service ratemaking "fails to account to for the range of benefits DG provides". Do you have a response?

A. Yes. Ms. Kobor has mischaracterized the utilities' position. The utilities have consistently stated that the present cost-of-service model used for recovery of utility expenses is not conducive to evaluations based on "value", as value is not a recoverable cost component. The utilities have regularly requested that rate design be modified to allow for the just, fair and reasonable recovery of the utilities expenses, and if the Commission chooses to do so, provide a revenue stream to compensate those DG customers who choose to invest in clean energy resources. Ms. Kobor, as with solar advocates, dances around the subject that it is the utility — and ultimately the ratepayer — that pays for that "value" in the form of higher rates under the current model. Regulated rate design specifically excludes "value" in the utilities rates, and there is no portion of the current electric rate design that a utility recovers that is intended to compensate entities for a "future value."

It should not be lost on the Commission that, should it determine that a DG customer is to be compensated *today* for a value it provides to other ratepayers in the *future*, there is effectively no savings to the non-DG ratepayers. They are simply paying today what they might be paying in the future under the cost-of-service model, assuming all of the projected assumptions are true.

Additionally, Ms. Kobor argues that the valuation of DG exports should include the long-term costs and benefits, such as was the case in the prudency evaluation of the Company's (TEP) purchase of the Gila River Unit 3. What Ms. Kobor fails to acknowledge is, that while the Company acknowledges the long term benefits of ownership of this facility, it does not — nor has the Commission ever granted — forward looking value on that specific acquisition. The Company justified its purchase through the evaluation of long-term benefits and then includes only the *known and measureable costs* in rates. This is not what the solar industry is proposing. They are proposing to be compensated for projected, assumed, and "as of yet to be realized" savings and subjective environmental values.

Q. Do you agree with Ms. Kobor's generalized statements regarding transmission, generation, and distribution savings, and that it will be more expensive in the long run for society if the Commission adopts a lower value based on cost-of-service structures?

A. No. Ms. Kobor's statements have no basis in fact. Generalized statements such as, "*DG provides significant benefits, including offsetting the need for additional generation, transmission, and distribution infrastructure.*" (Kobor Direct, page 12, lines 26-28) is reflective of someone with limited understanding and knowledge of grid management, utility planning, and operations. Ms. Kobor is not qualified to speak on these issues and does not provide any technical support for her general statements.

Q. Ms. Kobor referenced a report published by the Lawrence Berkeley National Laboratory ("LBNL") (Kobor Direct, page 13), stating an economist's view of how DERs can provide positive benefits to utilities and their customers. Did the report make any assumptions regarding regulatory policy, which may be more relevant to this proceeding?

A. Yes. One of the foundational assumptions of the LBNL analysis stipulated the following:

Continued policy mandates for reliability, safety, universal access and reasonable prices
We also assume that regulators and policymakers will maintain strong policy requirements for continued universal access to electricity service, as well as safety and reliability requirements comparable to those of today, and will continue to seek reasonable prices for customers. As with our other assumptions, we think this is both likely and helpful in focusing the policy analysis regarding appropriate regulatory paradigms for a high DER world.

While LBNL acknowledges that the continued use of policy is necessary to maintain a strong grid, an equally important component to this discussion is their continued reference to "continued universal access to electricity service". LBNL states, "universal access to electricity service at reasonable rates is widely thought to make society more productive and efficient, suggesting positive social externalities for broad-based access to electric service." This positive societal value, while not reflected in the current model for utility rates, could be considered under the context of Chairman Little's request of whether or not the grid provides value to DER's.

Q. Ms. Kobor goes to great lengths to describe the need for the utility to provide transparency in their data, along with decade's worth of projected costs and utility rates, loss calculations, gas projections, and other recommendations. What is the Company's response to Ms. Kobor's recommendations?

A. For the most part, the majority of Ms. Kobor's requested data is already contained and used in calculations through the Company's production models to provide hour by hour cost projections. These calculations are used to calculate annual Market Cost of Comparable Conventional Generation ("MCCCG"), which is the avoided the energy cost. Delivered gas costs and projections are readily available and already used in these calculations, as is generator O&M costs and other variables. Although Ms. Kobor's loss calculation description is somewhat inaccurate, these values can also be determined more accurately through engineering modeling and actual data.

Q. Does the Company agree with Ms. Kobor's other assessment regarding the valuation of environmental attributes, compliance avoidance costs, emissions, water, economic benefits, and grid security?

A. No. Please refer to my direct testimony for more specific responses on these issues.

Q. Have you reviewed the testimony of the other parties?

A. Yes.

Q. Do you have any comments on the testimony of the other parties?

A. Although I do not concur with all of the arguments presented by several of the other parties, I am not providing any additional written comments as TEP and UNSE Witness Overcast sufficiently addresses the other issues.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
DOUG LITTLE - CHAIRMAN
BOB STUMP
BOB BURNS
TOM FORESE
ANDY TOBIN

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

Rebuttal Testimony of

H. Edwin Overcast

on Behalf of

Tucson Electric Power Company and UNS Electric, Inc.

April 7, 2016

TABLE OF CONTENTS

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. H. Edwin Overcast. My business address is P. O. Box 2946, McDonough, Georgia 30253.

Q. HAVE YOU PREVIOUSLY PROVIDED TESTIMONY IN THIS CASE?

A. Yes. I provided direct testimony in this case on behalf of Tucson Electric Power (TEP) and UNS Electric (UNSE) or the Companies collectively.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. My rebuttal testimony addresses a variety of issues raised by other participants' direct testimony in this case. Specifically, I will discuss the numerous problems with the calculation of avoided costs for solar DG and provide an alternative framework for valuing any type of DG that reflects the market value of the particular source of DG. Avoided cost calculations should be consistent with the way other resources are valued in the context of the market. I will also discuss rate design for DG customers, errors made in analysis by solar DG advocates and certain policy issues.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony is organized by sections beginning with this introduction and followed by the following sections:

Section II- Calculating the Value of Solar Based on Avoided Costs;

Section III- Rates for Solar DG Customers;

Section IV- Using Standard Cost Effectiveness Tests to Value Solar DG

Section V- Buy All Sell All Approach Is a Better Option for Matching Solar DG Output and Avoided Costs

Section VI- Services Provided to Solar DG Customers

Section VII- Miscellaneous Issues

Section VIII- Conclusions and Recommendations

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS.

A. I reach a number of conclusions throughout my rebuttal testimony. The most important of those conclusions include:

1. Solar DG is only entitled to short-run avoided energy costs as a measure of energy value.
2. To the extent there are provable avoided capacity costs, those costs should be fixed at the time the solar DG is valued initially.
3. Solar DG customers should be a separate class of service in the cost of service study.
4. Solar DG customers should be billed on three part rates – customer, demand and energy with energy be seasonal TOU based that recover the class revenue requirement.
5. The use of standard practice tests- Participant, Ratepayer Impact, Total Resource Cost and Societal Cost Tests- are screening tools and should not be used to value solar DG.

6. A Buy-All/Sell-All Approach produces the best compliance with cost causation and matching principles of rates.
7. Avoided costs must be based on the actual private costs the utility avoids.

II. CALCULATING THE VALUE OF SOLAR BASED ON AVOIDED COSTS

Q. WHAT IS THE BASIS FOR DETERMINING AVOIDED COSTS FOR SOLAR DG?

A. Section 210 of the Public Utility Regulatory Policies Act (PURPA) of 1978 paragraphs (b) and (d) taken together establish the basis for rules promulgated by the FERC related to the purchase of energy from qualifying facilities including solar DG (CFR Title 18 Chapter I Subchapter K Part 292 ("FERC Rules")) and establish a specific ceiling at a level not to exceed incremental costs of the utility (paragraph (b)) which is further defined in paragraph (d). These same FERC Rules also regulates the rules for rates charged by the utility to these customers. The concept of net metering was added to the PURPA standards for utilities by a subsequent amendment that did not alter the purpose of these standards or the provisions related to avoided costs. This is the basis for determination of avoided costs and all subsequent analysis of avoided costs and changes based on market values are included in the amended regulations. In its rules as set forth in the current amended version and currently effective, the FERC establishes certain requirements for utility purchases. TASC witness Beach refers to the PURPA provisions selectively related only to the obligations related to generation.[1]

[1] TASC Direct at p.13 and 17

It is instructive to note that the utility purchases are for two separate components capacity and energy. These two products are treated differently under PURPA as they should be in this proceeding. The FERC Rules also define avoided costs as "Avoided costs means the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source."[2] Two points are noteworthy namely that capacity and energy are separate products and that avoided costs may be based on purchases from another source as the basis for determining avoided costs. In areas with organized capacity markets such as PJM, NYISO and ISONE the FERC has eliminated the requirement of avoided cost and allowed that to be replaced by a market value. This is consistent with utility proposals to value solar DG capacity based on competitive market transactions for utility scale solar DG. Treating capacity and energy separately is particularly appropriate for the "as available" nature of the energy provided to the utility by solar DG.

This latter observation is important since the avoided costs of energy for TEP and UNSE may be determined by either the lower of cost or market hour by hour. Hence the suggestion by some solar DG advocates that it is permissible to use the "energy cost of the proxy marginal resource"[3] to value avoided energy costs cannot possibly be correct ever. No marginal unit of capacity can be at the margin in all hours of the year nor can even one fuel be at the margin in all hours in an integrated regional market. In addition, the suggestion that solar DG should receive the net present value (NPV) of the

[2] CFR Title 18 Chapter I Subchapter K Part 292, Subpart A, §292.101 Definitions (C), (ii), (6)
[3] See Table 2 of the direct testimony of TASC witness Beach page 20.

energy cost savings as suggested by the solar DG witnesses is inconsistent with the FERC Rules and with the economically proper calculation of avoided costs. As I demonstrate later in my testimony the methods used in IRP proceedings for valuing assets and programs form the basis for planning decisions but not for ratemaking. IRP values are simply tools to choose between alternatives. They do not value assets for cost of service or revenue requirements. No utility is allowed to charge the NPV of energy cost savings as the basis for fuel cost recovery nor is there any regulatory model that uses the levelized carrying charge for capacity as the basis for capacity related revenue requirements. The planning tools allow for an assessment of the relative relationships necessary to choose between alternatives but are not the statutory basis for cost recovery.

Those FERC Rules require that "as available purchases"[4] be compensated for energy at the time of purchase. Solar DG is a perfect example of an "as available" resource since the amount delivered to the utility is completely at the discretion of the solar DG customer and the loads placed on DG at the customer premise. Further, solar DG cannot meet the requirements spelled out for different treatment related to a legally enforceable obligation. Among other requirements, the FERC Rules spell is a contract that provides the duration of the contract, the committed capacity and energy pursuant to a schedule, a termination notice requirement and sanctions for non-performance. Solar facilities at end use premises have the first claim on the output and energy is only delivered to the system as it is unused by the premise. Thus under the provisions of the PURPA FERC Rules, there is no option for solar DG customers to have avoided energy

[4] CFR Title 18 Chapter I Subchapter K §292.304 Rates for purchases, (d)

costs based on a levelized long-run avoided energy cost study. Further, since there is no contract between the solar DG customer and the utility that satisfies the requirements under PURPA there is no basis even for long-run avoided capacity costs and in particular no capacity value at the time of system peak since the available kW at the peak for delivery to the utility is zero as a result of load exceeding the DG output. I note that the solar DG advocates all argue that only the delivery energy and capacity should be used to determine the value of solar.

Q. DO YOU AGREE THAT THE VALUE OF SOLAR SHOULD BE BASED SOLELY ON THE ENERGY DELIVERED TO THE UTILITY AS RECOMMENDED BY THE SOLAR WITNESSES?

A. No. Solar DG has a different value when it is based on the total contribution of DG as energy delivered and energy saved. In particular, there are different avoided costs based on the total contribution of solar DG and those should be recognized through the same process that is used for evaluating conservation investments, community solar DG and utility scale solar DG. There is also a different value based on the cost of service analysis used for solar DG customers. "As available" energy has no capacity value simply because no energy is delivered to the system in the peak hour. Looking at the total DG output creates an opportunity for avoided capacity costs based on various measures of peak capacity as I will discuss below. In that case it is possible to determine the avoided capacity value if any based on the long-run avoided capacity costs. There is no reason to use long-run avoided energy costs and pay credits on that basis however.

The reason is straight forward; no power source is allowed to collect the avoided energy costs on a levelized basis over its operating life because that is not consistent with the matching principle of rates. Marginal energy costs are simply a short-run concept and both DG and energy efficiency (EE) investments only save the actual energy costs based on a short-run period. Since these costs are variable in both the short-run and the long run the economically correct price signal is short run marginal costs. If compensation is based on a levelized cost of energy the only thing we know for certain is that that number will be wrong even in the near term for many reasons as I will discuss below. When the energy value is levelized the economics of solar DG investments will produce excess returns over the market value when the levelized value is too high and will produce below market returns when the value is too low. Thus, in a rising fuel cost environment the solar DG customer will see declining benefits relative to the investment and in a declining fuel cost environment will receive windfall profits. I should note that this is not speculation since one needs only to look to the PURPA contracts of the nineteen eighties where actual energy prices were below the levelized costs of energy in the contracts and there was billions of dollars in stranded costs in markets such as New York associated with the buyout of PURPA contracts. Further, IPP contracts for gas fired generation did not value energy at the levelized long-run costs but rather based the energy prices under the contract on a market based index of variable costs. Thus energy costs escalated with the market and the same should be true of the value of solar energy.

Q. FOCUSING ON THE ENERGY COMPONENT SEPARATE FROM THE CAPACITY COMPONENT, WHY IS IT LIKELY THAT A LEVELIZED ENERGY, AVOIDED COST WILL BE WRONG IN BOTH THE NEAR TERM AND THE LONG-TERM?

A. Avoided energy costs are determined in each period by a number of factors that introduce volatility into those costs. Obviously we know that fuel prices are volatile over time and to assure reasonable recovery of those costs by a utility costs are adjusted by a formula rate such as the PPFAC for TEP and UNSE. In the short run, energy costs change with load, fuel prices, forced outage rates, scheduled maintenance and other variables related to near term system dispatch requirements such as unit deratings and ramp rates. In the long-run these costs change based on technology, long-term load and capacity demand growth, significant changes in load shape such as those related to intermittent resources, plus all of the same short-run impacts. As a result, the NPV of energy avoided costs will be higher than actual costs in the near term and below actual costs in the long term unless fuel prices actually fall as a result of technology or other market factors.

Q. WHO IS THE PRIMARY BENEFICIARY OF THE CALCULATION OF ENERGY NPV?

A. The solar installer is the primary beneficiary of calculating an NPV for energy. It allows the solar energy provider to compete against a higher payment for solar DG. This enhances the margin calculation for solar DG installations. Ultimately, the customer has reduced benefits as avoided costs increase above the NPV based payment.

As a result, the customer who expects to save more as energy prices rise actually saves less when energy prices rise above the NPV energy value as they must over time.

Q. HAS THE FERC ADOPTED MARKET BASED ENERGY CHARGES FOR QF'S?

A. Yes. For the competitive markets where hourly prices are based on marginal costs (LMPs), the FERC has determined that QF customers no longer have access to the levelized energy cost component of avoided costs. This is actually the most economically correct way to reflect avoided energy costs in payments to any competitive resource for energy production, since levelized long run energy costs are not consistent with least cost planning or even how energy costs are determined for utility assets. Energy is a short-run concept, while only capacity is a long run concept in valuing utility generation or non-utility generation. In particular, the short-run valuation is consistent with cost causation that is fundamental to the concept of economic costs. Causality asks the simple question of how will cost change with a change in output. There are different answers to this question depending on the change. In any event energy costs change with changes in energy consumption based on the underlying real time mix of fixed resources. An additional kWh of load does not impact costs even in the next week, much less twenty years in the future. For an incremental kW of consumption, there may be only a short-run impact on costs if there is available capacity to serve the load. If the kW increase is a permanent increment of capacity at the time of the planning peak (the planning peak being different for production, transmission and distribution), then that kW may contribute to the need for additional capacity in the future when added with other kW increments. Therefore it is only capacity related avoided costs that have a long-run dimension. Further, that dimension cannot be expressed as a value that should be reflected based on the current increment of capacity alone as that is likely to be zero. Rather, it is expressed as the actual lumpy capacity increment that is avoided or delayed at some point in the future as noted in the FERC Rules. For the current value of an avoided capacity unit, the cost of that capacity per kW installed or the cost per kW of a capacity contract from the market would be discounted to the current period using the utility marginal cost of capital since that would be the cost avoided.

Q. IS THERE CONFUSION ABOUT THE APPROPRIATE DISCOUNT RATE FOR CALCULATING THE NPV OF AVOIDED COSTS?

A. Yes. Determining the correct discount rate is more complicated than it seems because the basic confusion related to determining the discount rate for application in different uses and for different streams of costs or revenues. This distinction is relatively straight forward when we consider the comparison of real and nominal dollars. If the analysis uses real dollars of revenue and costs there is no inflation built into the calculation and the discount rate should be a real discount rate. If inflation is included in costs and revenues the nominal discount rate applies because the nominal rate includes the effect of inflation on the opportunity cost of capital. Properly calculated the real and nominal process should produce the same NPV. Similarly, discount rates may differ based on whether the costs are private costs or social costs.

In the case of utility avoided costs, the costs are private costs and the appropriate discount rate is the utility's long-run marginal cost of capital. This represents the opportunity cost of securing the necessary funds for constructing new plant or the lost opportunity costs from acquiring a capacity in the market. In either case the correct discount rate depends on the risk of the investment that the capital is being used to fund. It is forward looking and bears no relationship to the weighted average cost of capital used to determine revenue requirements. It is also not the societal discount rate as recommended by witness Kobor.[5] It is also not the weighted average cost of capital used by witness Beach in his analysis.[6]

Q. IS THERE ANY CONSENSUS AS TO THE SOCIAL DISCOUNT RATE?

A. No. There is no consistency between the level of social discount rates used by government agencies or those calculated by economists. The values recommended for social discount rates in just a few Federal agencies range from 10% real (OMB) and the CBO uses 2% real discount rate.[7] From a theoretical basis, the concept of a social discount rate should reflect the opportunity cost of capital or the opportunity cost of private consumption as the social discount rate, since the government competes with dollars used to finance private capital or private consumption or both. It is also important to note that these discount rates are real discount rates and cannot be used for discounting nominal dollars.

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[5] Direct Testimony of Briana Kobor, p. 23, l. 18-19

[6] Direct Testimony of B. Thomas Beach, "The Benefits and Costs of Solar Distributed Generation for Arizona Public Service (2016 Update)", p.7

[7] A Student's Guide to Cost Benefit Analysis for Natural Resources: Lesson 6 The Social Discount Rate, http://ag.arizona.edu/classes/rnr485/ch6.htm, p.4

Q. SHOULD AVOIDED COSTS OF DISTRIBUTION PLANT BE INCLUDED IN THE CALCULATION OF SOLAR DG VALUE?

A. Yes to the extent that there are actual avoided costs. In the case of solar deliveries only, it is impossible for DG to avoid any costs because the maximum use of the delivery system occurs at a time when there is no solar diversity and low loads. Further, if you value solar only based on excess generation as suggested by the solar advocates, there is no avoided costs in any event. The proper valuation should be based on the total output of the facility, not just the value of exports. In that case, it is possible that there may be some avoided capacity costs on the distribution system given local conditions. There are no generalized avoided distribution capacity costs as suggested by the solar DG witnesses. To understand the basis for this conclusion one needs only to understand three issues:

1. The planning, design and operation of the distribution system is based on installed capacity for a premise;
2. The fact that marginal cost for an increment of capacity is not the same as for a decrement of capacity; and
3. The investment and capacity of the system are not continuously variable but are lumpy.

These three facts taken individually have implications for the possibility that solar DG avoids distribution capacity costs in general.

Since the local facilities are designed based on connected load, the addition of DG would not require a change in the capacity of local facilities except in the event that all of the customers connected to a given transformer installed solar DG. In that event the export function would require **more** local capacity not less; in fact my direct testimony (pages 16-17 and the class NCP value in the base cost study and the solar class study for solar DG customers) shows that for TEP the solar class NCP for exports is greater than for imports. The reduction in local demand at the NCP peak would only result in a smaller transformer replacing a larger transformer at the end of the transformers useful life under the condition that solar DG for the customers on the transformer could reduce the NCP loading by about 2 kW per customer served on the typical residential transformer since transformer sizing as noted above is not continuous.

In any event, to reach this level of NCP peak load reduction would require too much capacity for export to be served by the next smallest transformer size. There is no way to free-up enough local capacity to avoid distribution costs locally.

The fact that marginal costs for increments and decrements of capacity are not equal is also an issue with respect to avoided capacity costs for distribution facilities. Given the sunk cost nature of capacity investments and the lumpiness of capacity for distribution equipment, there is no likelihood that adding solar DG would avoid any distribution costs and conversely, a decrement of load would not eliminate any cost in the short run. However, the marginal cost of adding capacity to the delivery system is likely to be positive as it relates to changes resulting from customer additions (extending the system to attach new customers adds at least the minimum system components that includes capacity for delivery) and from capacity additions when the minimum system is inadequate to serve the load. Thus when calculating marginal cost of growth in capacity on the distribution system the result is a number substantially greater than the avoided distribution costs associated with a load decrement.

Q. DO SOLAR ADVOCATES RECOGNIZE THE DIFFERENCE BETWEEN AN INCREMENT OF CAPACITY AND A DECREMENT OF CAPACITY?

A. No. Both VS witness Volkmann and TASC witness Beach recommend the use of a marginal cost analysis as the basis for assigning avoided distribution and transmission cost to solar DG. Witness Volkmann recognizes that DG and other DER resources may cause an increase in distribution costs.[8] However, he calls for a marginal cost study to determine avoided costs. TASC witness Beach uses a regression analysis of historic costs as the basis for determining marginal T&D costs which he equates to avoided T&D capacity costs. Neither approach is correct because it relies on the incorrect assumption that the marginal costs associated with a load increment are equivalent to the avoided cost of a potential load decrement. I use the term potential load because as I have shown in my direct testimony the maximum demand on the delivery system does not occur because of load but because of reverse power flows for delivery to the system. In that event witness Volkmann is correct that under the concept of cost causation solar DG customers cause more costs rather than avoiding any costs.

[8] For example the use of storage heating in Europe has caused a significant shift in the distribution system peak as storage units begin the heating cycle at the end of the on-peak period. During cold weather, there is no natural diversity and the need to store adequate heat for the next on-peak period results in higher charging kW then the required heating kW absent storage. The same phenomenon would occur for storage cooling and storage water heating. The diversified off-peak demand for storage water heating is over three times the winter coincident peak demand and more than that for the summer NCP demand.

Q. WHY IS THE USE OF REGRESSION ANALYSIS BY WITNESS BEACH INCORRECT?

A. The methodology of regression analysis cannot produce reasonable results for a number of reasons. First, the implicit assumption in his analysis is that all new dollars invested in a distribution or transmission plant account are growth related. That is an incorrect assumption. Many of these dollars are related to serving existing load where existing infrastructure must be replaced to maintain the same level of service. New dollars will be greater than the depreciated value of the assets removed. So the growth of rate base is not related to load growth alone. The same logic also tells us that not all of the increases in O&M expenses for T&D are related to growth. In fact, most are not growth related at all. Second, the assumption that growth in T&D investment is related to system peak growth is also incorrect. It is not coincident peak that causes all T&D investment. That would only be true if all of the T&D assets reached their maximum capacity at the same hour as the coincident peak load — a proposition we know is false. Using the system peak to calculate the growth in T&D capacity results in a higher avoided cost per kW and inflates avoided costs for capacity. Third, using sunk costs to estimate marginal costs is inconsistent with the concept of marginal costs, which is inherently forward looking not backward looking as the historic regression analysis used by witness Beach. Witness Beach fails to recognize that those sunk costs from FERC Form 1 that are part of revenue requirements may bear no relationship to the actual marginal cost going forward because of changes in technology, changes in the relative cost of inputs and economies of scale. Fourth, the regression analysis cannot address the issue that plant additions are not designed to simply meet the current load requirements but to be able to meet load over the useful life of the asset. New assets are lumpy additions. For that reason alone the use of measured growth rather than capacity growth overstates marginal costs. A simple example will illustrate this concept. When a residential subdivision is wired for electric service, transformers are installed based on the underlying buildout of homes. Not all homes are added in the same year so there is a mismatch between load and capacity that is resolved over time but not in one year.

Q. WHAT IS THE RELEVANCE OF LUMPY ADDITIONS TO THE CALCULATION OF AVOIDED COSTS?

A. Although the solar advocates recognize the issue of lumpy additions they do not properly address the implications for the calculation of avoided costs. Instead, witness Volkmann opines that "The methodology should also credit DG solar and other DERs for incremental contributions to distribution capacity relief, even if the utility has not identified an imminent capacity expansion project on the interconnected feeder or at the associated substation."[9] Simply put, in the absence of a need for marginal capacity, there is no value to any incremental contribution to capacity relief and any attempt to place such a value is misplaced and results in an over-estimate of the value of solar that greatly exceeds any reasonable level of avoided costs if any. There is no basis for assuming or concluding that solar DG ever saves any dollars of distribution costs except on specific circuits with unanticipated high load growth where there is sufficient aggregate solar DG to allow for capacity deferral without creating a new peak period for the circuit resulting from excess delivery causing the circuit peak. In part, this is because the absence of any need to add capacity on a circuit, feeder or substation means

[9] Volkmann Direct p. 21

that the solar DG customer does not save the utility any costs (and may increase the costs) so that any compensation for a cost not actually avoided is a direct subsidy in the current period and continues to be a subsidy potentially over the whole life of the DG facility given the average life of distribution assets. Recognizing the lumpy nature of utility assets must necessarily alter both the calculation of avoided costs and the localized nature of distribution investments.

To calculate the avoided costs for distribution the first necessary condition is that there is a capacity constraint on the particular local distribution facilities where the solar DG is to be connected. Second, the solar DG must be able to result in one of three outcomes:

1. Avoid the capacity addition in total;
2. Delay the capacity addition for some period; or
3. Reduce the current level of investment in those local facilities.

If solar DG eliminates the need for capacity the avoided cost per kW is the levelized annual carrying charge rate applicable to the avoided capital costs of the facility avoided. If the solar DG delays the capacity upgrade, the avoided costs is the NPV of the differences in the levelized payments for the current installation and the levelized payments for the future installation. Finally, if the solar DG permits a smaller investment the value of the DG is the NPV of the differences in the levelized costs of the two different projects. The value of solar DG is far less than the marginal cost of distribution capacity in general except for the case where solar DG eliminates the need for the capacity upgrade in total by freeing up capacity in a sufficient quantity to address the capacity requirements over the remaining life of the existing assets. It is far more likely given the lumpy nature of investments that the avoided cost would be based on either a deferral value or a replacement value.

Table 1 below provides perspective on the avoided costs associated with the more likely option to down size a transformer.

Table 1

Avoided Transformer Costs

kVa		Levelized Carrying Charge Rate 11.55%			1752	kWh per kW
	Under Ground	Annual carrying costs	Difference	Difference per kW	Cents per kWh @20% Capacity Factor	
25	$3,800	$439	$46	$1.85	$0.0011	
50	$4,200	$485	$35	$0.69	$0.0004	
75	$4,500	$520	$0			
100	$4,500	$520				
150						
167	$5,000	$578	$58	$0.35	$0.0002	
225						
250	$6,500	$751	$173	$0.69	$0.0004	

As the table illustrates the value of a smaller size transformer, assuming that solar DG would permit that downsizing of a transformer is measured in a fraction of a cent per kWh produced by solar DG. Similarly, a delay of say five years would also result in a fraction of a cent per kWh produced by solar DG. These values are nowhere near the values calculated by TASC which range from $0.015-$0.032 per kWh for residential customers. There is virtually no reason to assume that other distribution facilities such as conductor and poles would be changed out as a result of solar DG. The multiple errors in the TASC analysis make these estimates incorrect and inconsistent with properly calculated avoided costs. Simply put, there is no rationale for a system wide avoided distribution cost calculation, which implicitly assumes that every circuit has no capacity to accommodate load growth. Further, if one assumes that there is no capacity on any conductor we would see the need to reconductor the system on a continuous basis when customers were added to a circuit or a feeder.

Q. HOW SHOULD THE FORECAST OF AVOIDED CAPACITY REQUIREMENTS BE DETERMINED?

A. The forecast should include not only load growth but also the projected growth in solar DG penetration as well other DG options, DER and DSM over the period for which avoided capacity costs are calculated. Essentially avoided costs are based on the full utility planning models. This process is not the one recommended by witness Kobor who states "The valuation of DG exports will be most relevant if it examines current and/or near-term expected penetration levels on the utility's system."[10] Such a recommendation is not surprising since it results in over valuing both the capacity and energy benefits of solar DG. However, it is not part of the utility plan to ignore trends that impact capacity requirements either positively or negatively.

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[10] Kobor Direct at p. 24

Q. FROM AN AVOIDED COST PERSPECTIVE HOW DOES THE FACT THAT SOLAR DG IS NON-FIRM, NO TERM COMMITMENT AND NON-DISPATCHABLE IMPACT AVOIDED COSTS TO VALUE SOLAR DG?

A. Each of these three characteristics reduces both the capacity and the energy value as compared to the utility avoided cost unit such as a combustion turbine or even a utility scale solar DG unit. These factors are specifically itemized in PART 292—REGULATIONS UNDER SECTIONS 201 AND 210 OF THE PUBLIC UTILITY REGULATORY POLICIES ACT OF 1978 WITH REGARD TO SMALL POWER PRODUCTION AND COGENERATION issued by the FERC Rules current as of March 16, 2016. §292.304 provide detailed requirements for a utility to purchase energy and capacity from QF facilities including solar DG.

Non-Firm Sales

Non-firm sales are functionally "as available sales" as defined by the FERC Rule. This means that the owner of the QF decides when energy will be delivered to the utility. In the case of solar DG the deliveries are first used to serve the customers own load and to export energy when net of load is less than the production from the facility. Simply, the utility can never be sure when energy will be delivered to its system since the customer always has the first call on the production capacity of its unit.

Moreover, that capacity varies with factors that neither the solar DG owner nor the utility control such as cloud cover or ambient temperature impacts that raise or lower available capacity relative to the kW nameplate capacity.

No Contract Term Commitment

The only basis for choosing a payment other than the avoided costs at the "time of delivery"[11] is for the customer to have a contract for energy or capacity that is "pursuant to a legally enforceable obligation for the delivery of energy or capacity over a specified term."[12] That legally enforceable obligation is defined in the regulations as "The terms of any contract or other legally enforceable obligation, including the duration of the obligation, termination notice requirement and sanctions for noncompliance."[13] That is certainly not applicable to Solar DG.

Performance Obligations

As I mentioned earlier, the ISO-New England recognizes the very different service characteristics of the capacity product from the energy product; and in fact, has recently modified its capacity market rules to introduce specific performance obligations on generators receiving capacity payments. This is an example of the quid pro quo that must be established for a true capacity resource. DG capacity by its nature cannot be associated with specific performance obligations and from a utility planning perspective cannot be viewed as a capacity resource particularly when the peak hour is shifting later in the evening.

Non-Dispatchability

The regulations also note that the ability of the utility to dispatch the QF facility is a determining factor for avoided costs.[14] This creates value from the utility to take

[11] §292.304 Rates (d) (1)
[12] §292.304 Rates (d) (2)
[13] §292.304 Rates (e) (2) (iii)
[14] §292.304 Rates (e) (2) (i)

advantage of low or negative prices in the market place rather than pay the fixed rate for solar DG energy delivered when lower cost alternatives are available for customers.

Q. DOES THE FERC RULE REQUIRE THAT A UTILITY CONSIDER THE AGGREGATE VALUE OF CAPACITY OR ENERGY?

A. Yes. The FERC Rules also require that the utility use the aggregate value of any capacity or energy in calculating the avoided costs.[15] That aggregate value is reflected in the avoided cost analysis used by utilities as it applies to avoided energy costs and capacity cost for generation. A different aggregate concept must be used for transmission and distribution since those costs are only avoided related to a particular transmission delivery node and for individual substations, feeders and circuits. The logic for this conclusion is that solar DG located in one delivery node portion of the transmission system cannot save costs for capacity for any other delivery node. The same is true for calculating avoided distribution costs by the systems basic components-substations, feeders, circuits and transformers.

The regulations also require that the smaller capacity increments and shorter lead times also be considered. This point may have positive value for specific circuits and feeders if capacity is constrained but may have no value if the aggregate capacity is too small to impact the capacity requirements of local facilities. As noted above the fundamental problem of lumpy capacity additions causes the solar DG to be unlikely to reduce costs for distribution capacity because in order to reduce capacity requirements for local facilities the aggregate solar DG on the system must be large relative to the size of the facilities loads. If it reduces peak loads sufficiently at the time of class NCP to save

[15] FERC Rule §292.304 Rates for purchases, (e), (2), (vi)

distribution capacity it is likely that the load at the time of maximum output to the system will be too large to allow for smaller equipment.[16] The modularity of solar DG has no value as it relates distribution beyond specific circuit requirements that cannot be incorporated in the general value of solar DG but must be evaluated for each circuit or feeder on the system.

Q. IS VALUING SOLAR DG THE SAME AS DETERMINING THE AVOIDED COST PAYMENTS UTILTIES SHOULD PAY FOR EXCESS SOLAR EXCESS DG ENERGY?

A. No. Given the specific nature of solar DG as an intermittent resource, with excess delivery to the system on an as available basis, with no contractual commitment to deliver (and no penalties for failure to deliver) and non-dispatchable capacity there is no justification for any payment above the avoided cost at the time the power is delivered to the system for excess generation. Any capacity value based on actual, quantifiable avoided capacity costs should be treated separately from the compensation for energy; should be an annual payment; and should be performance based so that if the facility is out of service during peak periods or is not maintained over the life, capacity payments would be reduced.

Moreover, solar DG may be valued in the context of IRP just like any other generation source. That value may include all of the marginal Pareto-relevant externalities as part

[16] The math for this conclusion is straight forward. To replace a 50 kVa transformer with a 25 kVa transformer one needs to reduce load by 25 kVa or 5 kVa for five customers. At the class NCP this would mean that each customer would need at least 25 kVa of capacity because of the peak afternoon output of 20% of capacity. Even with only one 25 kVa solar DG facility the output in a low load period would exceed the transformer loading so there would be no way to reduce the size of the transformer.

of the value.[17] Avoided costs are defined in the FERC Rules as "the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source."[18] To the extent that externalities have not been internalized through law or regulation those costs are not avoidable. The FERC regulation also states that the regulation does not require a utility to pay more than avoided costs under the regulation.[19] This means that the inclusion of externalities not yet internalized such as carbon costs is not permitted under the FERC regulation as part of avoided costs. That same position is consistent with economic theory and coincides with the views of AIC witness O'Sheasy (who points out the inequity and inefficiency associated with including the externalities in the avoided costs), APS witness Brown (who points out the inefficiency and incorrect logic associated with the treatment of externalities not otherwise internalized), and Staff witness Solganick (who points to external costs already included in the actual avoided costs).

III. RATES FOR SOLAR DG CUSTOMERS

Q. HOW SHOULD RATES BE DETERMINED FOR SOLAR DG CUSTOMERS?

A. Rates should be designed to reflect cost causation. This requires that solar DG customers' rates are fully unbundled, three-part rates with seasonal and TOU features

[17] The definition of a Pareto-relevant externality is an externality where the extent of the activity may be modified in a way that the "externally effected party A, can be made better off without the acting party, B being made worse off." See "Externality" by James M. Buchanan and Wm. Craig Stubblebine in Economica, N. S. 29(1962) pp 371-384

[18] §292.101 (C) (6)

[19] §292.304 (a) (2)

for energy and demand. No other rate design option will adequately track cost causation and match costs to rates paid on a real time basis. As a policy matter, this is a critical component for equitable treatment of all customers. This policy is explained in detail in my Direct Testimony at pages 9-16 and I will not repeat that discussion here. In addition, I have provided a response to VS 1.11 that provides citations to both the Supreme Court decisions and the D.C. Circuit and 7th Circuit decisions that support these rate propositions.

I also find further support in the FERC Rules implementing PURPA requirements for QFs that state that the requirements for rates to sell power to QFs. Specifically the FERC regulations state that "Rates for sales which are based on accurate data and *consistent system wide costing principles* shall not be considered to discriminate against any qualifying facility to the extent that such rates apply to the utility's other customers with similar load or other cost related characteristics."[20] (Emphasis added.)

The FERC recognizes that partial requirements customers differ from full requirements customers and as a result require service not required by other customers. In particular these services include supplemental power and back-up power on a firm basis.[21] Both of these services are defined in the regulation and are the same services that utilities supply to solar DG customers when the utility delivers energy and capacity to those customers.

[20] §292.305 (a) (2)
[21] §292.305 (b) (i) and (ii)

Q. DO SOLAR INTERVENERS OPPOSE THIS TREATMENT?

A. Yes. The solar DG advocates support TOU energy rates and a minimum bill and oppose fixed charges such as cost-based customer charges and demand charges.[22] While TOU based energy charges provide an improvement in price signals for the energy component of cost and the value of energy delivered based on seasonal and diurnal cost variation, they do nothing to address cost causation related to demand. Continuation of the rates advocated by solar DG interests will artificially enhance the development of solar DG through shifting costs to non-participant customers as demonstrated by the counterfactual cost of service study in my direct testimony that fully complies with the FERC requirement that consistent system wide cost principles are applied. Application of those same principles also demonstrate that the solar customers are properly included in their own cost study as demonstrated by the separate solar class cost study filed in my direct testimony.

Q. HAVE SOLAR INTERVENORS PROVIDED ANY EVIDENCE TO SUPPORT THEIR ARGUMENTS ABOUT COST CAUSATION AND RATE DESIGN?

A. No. Aside from an assertion that "Cost studies adopted by the California PUC have demonstrated that demand charge structures actually overcharge solar customers relative to the costs that they impose on the system, and undervalue the peaking capacity that solar DG provides,"[23] there has been no attempt to develop a fully unbundled cost study that applies system wide cost causation factors. Further, it is not

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[22] TASC at p. iv, p. 25 where TASC suggests the standard for DG rates is that the ensure "DG will remain a viable economic proposition for participating ratepayers", p. 26-28, Vote Solar (Kobor) at p. 28 (supporting TOU energy rates), p. 40

[23] Beach Direct at pp. 25-26

possible that unbundled demand charge structures overcharge solar customers particularly when these charges are based on costs caused by the solar class of residential customers.[24]

Further, the Vote Solar view of the cost of service study as expressed by witness Kobor confuses value and costs and misstates the basis for a test year cost of service analysis. The confusion in the testimony of witness Kobor is the basis for concluding that a cost of service study is "ill-suited to value such long-term benefits and assets." Value must be based on either cost or market. In ratemaking it is the cost that is reflected. The costs of long-term benefits and assets are included in the cost of service study based on the recovery of depreciation expense over the life of the asset and the return earned on the undepreciated asset based on market costs. These costs are only included so long as the costs were prudently incurred and the plant is used and useful.

Inclusion of solar DG as a long term asset is inconsistent with the FERC regulations associated with "as available" QF generation and on that basis has no capacity value since the solar DG customers are net users of the system at the time of the system peak production, transmission and distribution capacity. That conclusion as discussed above is consistent with the view of treating excess generation separate from the generation used to meet the customers' energy demand in real time.

[24] The same conclusion would apply to commercial customers as well so long as the demand charges are based on costs and have not been altered for some policy reason so that they no longer reflect costs.

As I have discussed above, I do not support this view of solar DG generation and thus allow for some possibility that in total solar DG capacity may have an avoided capacity cost component. In the context of the cost of service studies I have filed, there is an explicit value for solar DG capacity that may be determined from the unbundled costs. In this case, the value attributed to solar DG for production capacity is the difference between the counterfactual revenue requirement for generation (procurement demand in the cost study) and the same revenue requirement in the solar class case. That difference is the credit that accrues to solar DG based on the earned return in the TEP test year and amounts to a little over $1.5 million dollars. That value translates to almost $25 per kW of installed capacity and almost $142 per kW for the solar customers' contribution to peak load at the system peak hour in June at 5PM.[25] A cost of $142 per kW is well above the avoided capacity costs since the only additional planned capacity for the system would potentially be fast start CTs to respond to intermittent DG output on the system. This can hardly be characterized as the cost study being unable to reflect long term benefits. As an additional note, this amount would increase in a rate case context because the filed analysis only reflects the actual earned return not the allowed return.

It is certainly true that this per kW value is well above any production avoided costs in the current period and would not be inconsistent with The EIA capital cost data for an advanced combustion turbine as reported in the Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants published in April of 2013. That study

[25] Calculated as 17.4% of capacity times 61,277.33 kW solar installed or 10,681 kW CP production divided into $1.5 million dollars.

reports the cost of this facility at $660 per kW with fixed O&M at $7.04 per kW per year. If the cost of that plant is escalated at three percent per year, the 2016 capital cost would be $743 per kW installed. From this information, it is possible to see that the $ per kW is equivalent to an 11.7 percent levelized annual carrying charge rate.[26] Given the current capital structure for TEP, the 18.2% levelized carrying charge rate would require an authorized return of almost 21.5% on common equity to justify a $142 credit. Thus the avoided cost implicit in the cost study far exceeds avoided costs even if there was an immediate need for capacity and there is not. It is also likely that the actual avoided cost for capacity in the current market for power is less than the avoided cost for the least cost gas turbine because the capacity market is competitive and even for solar would be based on the option of a utility scale facility and be less than $142 per kW as well.

Q. PLEASE EXPLAIN WHAT THE DIFFERENCES IN REVENUE REQUIREMENT FOR PROCUREMENT DEMAND MEANS IN THE CONTEXT OF A RATE CASE.

A. In simplest terms, the difference between the counterfactual cost production revenue requirements and the solar class cost study production revenue requirements measures the allocated cost difference that provides a production credit to solar DG customers who would be on rates developed to reflect the solar DG class revenue requirements. The notion that cost of service studies do not provide any credit for solar DG customers is simply incorrect. Further, the fact that this credit is larger than avoided costs means

[26] Calculated as $660*(1.03^4) = $743, the required carrying charge is calculated as ($142-$7.04)/$743= 11.7%

that this study provided an additional subsidy for solar DG and does not over allocate costs to the solar DG class.

Q. IS IT UNUSUAL THAT THE IMPLIED CAPACITY CREDIT IN A COST OF SERVICE STUDY WOULD BE MORE THAN AVOIDED COSTS FOR GENERATION?

A. No. The cost of service study allocates the total system generation capacity costs. That cost includes much more than the cost of combustion turbines. Other units have much higher costs per kW than the least cost combustion turbine that represents the maximum avoided capacity cost per kW. It would not be uncommon for this cost to be a multiple of avoided costs when new capacity has been recently added to rate base. Thus the claim that the cost of service study does not credit solar DG for avoided capacity is simply false. In this case it results in a much higher credit than avoided costs. Thus we can conclude with certainty that no avoided production capacity needs to be credited to the excess generation from solar DG customers.

Q. IS IT FAIR TO CONCLUDE THAT A THREE PART, UNBUNDLED RATE RESULTING FROM THE FILED COST STUDY THAT TREATS SOLAR DG CUSTOMERS AS A SEPARATE CLASS OF CUSTOMERS IS A JUST AND REASONABLE RATE AND CONSISTENT WITH THE REQUIREMENTS OF PURPA AS CODIFIED IN THE FERC RULES?

A. Yes. Any other rate design such as those recommended by solar DG interests cannot result in just and reasonable rates for all customers and would actually result in the undue discrimination claimed by solar DG advocates as an argument against both separate rate class treatment and three part rates.

Q. DOES THIS MEAN THAT THE ARGUMENT RAISED BY SOLAR ADVOCATES THAT DG CUSTOMERS ARE JUST LIKE OTHER LOW USE RESIDENTIAL CUSTOMERS IS INCORRECT?

A. Yes. Solar DG customers actually use the system in very different ways than other low use customers. First, solar DG customers have much lower load factors than other low use full requirements customers. Consider for a moment a customer that installs sufficient solar DG to produce an annual bill of zero kWh under net metering. That customer still uses the system at night and even during the peak load hours of the day. Further, the customer uses the system at the time of the system peak hour. From these observations we know that the annual load factor based on coincident peak demand, class NCP demand and customer NCP demand of such a solar customer is zero even without knowing the demands in each of those periods. The reason is that average demand is zero because of the zero annual kWh bill. Even if we assume that the bill is for a modest level of net kWh typical of a small user, the load factor will be much lower for a solar DG because of the higher demand of these customers and in particular the higher demand requirements for the distribution system. The cost studies filed in my direct testimony demonstrate conclusively that solar DG customers have higher demand costs than residential customers and that if one were to use kWh charges to recover those cost the solar DG customers would require energy charges over twice those of full requirements customers. That fact alone indicates the absence of homogeneity for solar

DG customers with the residential class. It also shows why two-part rates that recover fixed costs in energy charges cannot possibly track costs and result in rates favor the solar DG customers through intraclass subsidies under the current rates used by the Commission.

IV. USING STANDARD COST EFFECTIVENESS TESTS TO VALUE SOLAR DG

Q. SEVERAL WITNESSES SUGGEST THE USE OF THE STANDARD COST EFFECTIVENESS TESTS USED TO EVALUATE PROGRAMS FOR IRP FILINGS AS A BASIS FOR VALUING SOLAR DG. PLEASE DESCRIBE THE COMMONLY USED TESTS.

A. Beginning in the early 1980s the California Standard Practice Manual was adopted to test conservation and energy efficiency programs. That manual was modified in the late 1980s to adopt four tests — the Participant Test, the Ratepayer Impact Test, the Total Resource Cost Test and the Societal Cost Test. The manual then specifies the components of each test. These tests are designed not to determine the value of a measure but the cost effectiveness of the various measures. Cost effectiveness is not a measure of value but is rather a screen designed to determine if a particular program produces net benefits as applicable for each test. The value of solar in the regulatory environment must be either based on the cost of service or the market value and neither of these values result from these standard tests.

Q. WHY ARE THESE TESTS NOT USEFUL IN DETERMINING THE VALUE OF SOLAR?

A. These tests were designed only to value a reduction in the kWh use over the life of an asset that has a continuous impact that is the same over time and do not include a value for the generation sent back to the system. They were also designed to reflect broad based programs that only change the pattern of load by reducing load in specific hours across the system and increase the system requirements at other hours. They are not designed to value an intermittent resource with declining output and an "as available" production resource. Further, these screening tests are not designed to value an asset across the spectrum of utility functions using different definitions of demand- CP, NCP and customer NCP. Typically the tests used for EE and DSM have the same impact on all measures on demand and that may be zero for demand in some cases. Solar DG has both positive and negative capacity impacts. It also has both positive and negative impacts on avoided energy costs as well. With these varied impacts, none of the standard tests used to evaluate EE and DSM are designed to fully develop the value of solar.

Q. IS THERE A RATE CASE METHOD FOR DETERMINING THE EQUIVALENT OF THE RATE PAYER IMPACT MEASURE?

A. Yes. The costs studies filed with my direct testimony demonstrate the ratepayer impacts in a direct calculation based on the differences in the allocated costs for residential solar DG customers and all other full requirements customers. This is especially true when the base rate revenue is added to the cost studies. It is possible to determine the precise level of costs shifted from solar DG customers to the full requirements customers as I have discussed above. Essentially, the total impact of net metering with banking is the sum of base costs shifted as well as the energy cost shifts. The evidence shows that the full requirements customers are subsidizing the solar DG customers and that the equivalent of the RIM test would not pass this screening analysis under the current base rate design with current net metering policy. As a result, the current arrangement does not meet the purpose of PURPA that requires equitable rate treatment for customers. That treatment would be fair and equitable if solar DG customers are allocated revenue requirement based on the cost study where the solar customers are treated as a separate class for cost causation and rates were designed to recover the fully allocated costs based on the same percentage of costs paid by residential customers as a whole. In turn, those revenue requirements would be recovered in a multi-part rate including customer, demand, and TOU energy charges.

V. BUY-ALL/SELL-ALL APPROACH IS A BETTER OPTION FOR MATCHING SOLAR DG OUTPUT AND AVOIDED COSTS

Q. WHAT IS A BUY-ALL/SELL ALL APPROACH?

A. A Buy-All/Sell-All approach is the type of rate mechanisms contemplated in §292.304 (c) Rates for Purchases in the FERC PURPA regulations. In this section, the FERC mandates standard rates for purchase for QFs smaller than 100 kW. In particular, the regulations recognize that such rates may vary among technologies. By buying all the output from the solar DG facility at buy-all rate and requiring customers to buy all of their energy from the utility at Commission approved rates both the principle of cost causation and the matching principle are satisfied. Customers receive the actual value of their generation as a credit calculated under the buy-all values that can easily reflect the value of energy and capacity separately. As discussed in detail above, the energy value would be based on short-run marginal cost and any capacity value could be fixed for a period based on a long-term avoided cost on an annual basis. Absent a contractual commitment it is not reasonable to pay a fixed cost over the entire life of solar DG.

Q. WILL USE OF BUY-ALL/SELL-ALL APPROACH BE MORE CONSISTENT WITH JUST AND REASONABLE RATES THAT ARE FAIR TO CUSTOMERS AS REQUIRED BY PURPA? PLEASE EXPLAIN.

A. Yes. By purchasing all output and valuing that output at avoided costs, customers will make better decisions related to the installed kW of the unit because the advantage of using high cost peak period energy and returning that energy at lower load and lower marginal cost periods will no longer be the same. This may also avoid the significant distribution system impact associated with delivery of excess kWh during low load periods. Under the current arrangement the incentive to zero out kWh use result in oversizing the solar DG kW by the amount calculated as DG capacity factor (about 20%) divided into the customers annual load factor. The resulting percentage is the amount needed to zero out kWh. Based on available load factor data, the capacity for solar DG is from 50% to 100% of maximum demand based on load factors between 30% and 40%. By sending the time varying price signal for energy, panel orientation will likely change to maximize on-peak kWh production. The result will be more efficient and more economic solar DG contributions to the grid.

The payments under the sell-all approach will be based on actual marginal costs avoided. This alone will eliminate the subsidy associated with costs not actually avoided by solar DG. Under the current system of two-part rates with customer charges below customer costs, there is a significant subsidy for solar DG that exceeds avoided costs as shown by the cost studies in my direct testimony. The use of a buy-all rate would be directly based on avoided costs just as required by the PURPA regulations while all use by solar DG customers would be billed on a three part rate that recovers the class cost for solar DG customers.

VI. <u>SERVICES PROVIDED TO SOLAR DG CUSTOMERS</u>

Q. ARE THERE DIFFERENT VIEWS ABOUT THE SERVICES PROVIDED TO SOLAR DG CUSTOMERS?

A. Yes. Solar advocates make a number of claims about the services provided by the utility to solar DG customers. For example, TASC witness Beach denies that under net metering with banking that the utility provides a storage service even going so far as to call the storage concept a myth.[27] Witness Beach also recognizes ancillary services as an avoided cost but does not recognize the possibility that solar DG may require these same ancillary services thus causing these costs. TASC witness Beach also denies that solar DG customers require standby services. The solar advocates also fail to recognize

[27] Beach Testimony at p. 17

that all customers with generation are partial requirements customers that require, indeed select, a different set of services than full requirements customers.

Q. ON WHAT BASIS DO YOU CONCLUDE THAT SOLAR CUSTOMERS REQUIRE STANDBY SERVICE?

A. Standby service (sometimes also called breakdown service historically) is not a new or novel concept. Indeed the very origin of the concept has always been a service provided to customers with their own generation who desire to insure continuous service when that generation fails to operate. Solar DG customers require this service in a number of circumstances such as cloud cover, mechanical malfunction and outages resulting from automatic control equipment protecting the system.

The FERC Rules implementing PURPA contain §292.305 Rates for sales to qualifying facilities. That section defines four services that utilities potentially provide to solar DG QFs. Two of those services are relevant in the context of serving solar DG customers- supplemental service and back-up service (also known as standby service). There is no question that solar DG customers require both of these services. Supplemental power defined as "electric energy or capacity supplied by an electric utility, regularly used by a qualifying facility in addition to that which the facility generates itself."[28] Back-up power means "electric energy or capacity supplied by an electric utility to replace energy ordinarily generated by a facility's own generation equipment during an unscheduled outage of the facility."[29] Despite the claim by witness Beach that this is an

[28] §292.101 Definitions, (b) (8)
[29] §292.101 Definitions, (b) (9)

identical service provided to a regular customer who changes the normal usage pattern to increase load in a low load period, that claim is incorrect because that random event is accounted for by the fact that the system deals with the issue based on the diversity of thousands of customers. Solar DG customers' loads are impacted by the effects that are common for all customers in a geographic area resulting in no diversity of the impact. It is this absence of any diversity related to production that distinguishes the solar intermittency from customers who use power in different patterns from the average for the population. Further, when the load is low as in the case that witness Beach describes at pages 15 and 16 of direct testimony, the added load is very small from the change that includes lights, computer and a small appliance. The solar load change in the same period is multiples of the change in load because it goes from full to zero output along with every other solar DG customer served on that same circuit causing voltage to drop significantly as the utility service is called on to meet all the loads previously served by solar DG. This is truly a standby service.

Q. DOES THE UTILITY PROVIDE A VIRTUAL STORAGE SERVICE FOR SOLAR DG UNDER THE BANKING PROVISION?

A. Yes. The concept of banking has its origins in the nomination and delivery of natural gas to end use customers. The daily nominations for customers seldom matched the actual daily gas consumed. Customers were allowed to address this mismatch on a daily basis through a separate banking service. Under that service, excess deliveries were credited to the account of the customer to offset the under deliveries that occurred on another day. At the end of the month, the bank was cashed out. This banking service was often referred to as a storage service even though no physical storage was used. The virtual storage used by solar DG customers is when one or more kWhs are recorded to the account of a customer and become available for later use on a one for one basis for power delivered by the utility to the customer. (I will not discuss the storage arbitrage issue or the facts that there are losses associated with both the delivery to the utility and the delivery back to the customer as these topics are covered in my direct testimony.) The virtual storage concept is also used within a month when excess generation during the high production hours is used in the nighttime hours to offset the current bill. This is equivalent of a daily balancing concept with supplemental daily service provided by the utility when the customer has a non-positive storage balance for the month.

To claim that the banking provision is not storage is to deny the physical reality of the service. A kwh is delivered physically from solar DG to the utility as recorded by the meter turning backward and that kWh is physically delivered back to the solar DG customer from a utility owned resource when the meter turns forward to record the utility delivery.

Q. DO SOLAR DG CUSTOMERS REQUIRE ANCILLARY SERVICES?

A. Yes. In particular solar DG typically requires reactive power, voltage control, frequency control, spinning reserves and operating reserves. These services are not free and the added cost for these services that result from current installations of solar DG should properly be paid by the solar DG class. The requirement for these services arises with current technology because inverters in the typical solar DG installation do not provide ancillary services but do use them. As the penetration of solar DG increases, the requirement for both spinning and operating reserves increases in large part due to the combination of intermittency and the absence of diversity related to solar insolation. The TEP OATT spells out the cost of these services in various schedules of the tariff.

Q. HAVE YOU EXPLAINED THE CONCEPTS OF FULL AND PARTIAL REQUIREMENTS CUSTOMERS IN THIS CASE?

A. Yes. I have provided a full explanation of these services in my direct testimony at pages 11-16. I will not repeat that discussion here, except to note that these partial requirements solar DG customers must be treated as a separate class of service in order to have just and reasonable rates that are non-discriminatory. TASC witness Beach has provided no evidence to support his views on appropriate rates for solar DG customers.

VII. MISCELLANEOUS ISSUES

Q. TASC WITNESS BEACH STATES AT PAGE 14 THAT THE EXPORT COST OF POWER IS THE UTILITY COST. PLEASE COMMENT.

A. There is no suggestion that the cost of the physical export of power be charged an export rate. As for cost causation, the facilities serving the solar DG customer must be designed for the greater of the customer peak load or the customer peak delivery. In this case the peak delivery is greater than the peak load by almost two to one. Witness Beach acknowledges that the customer generator is responsible for interconnection costs and the allocation of costs based on solar DG class NCP is fully consistent with cost causation and witness Beach's view of cost responsibility. Similarly, it should be directly recognized that the actual kWh delivered to the system is less than the metered kWh delivered to the utility as a result of losses. Since the utility is providing the delivery service the number of kWhs should be reduced by losses to reflect the actual kWhs available for delivery. This is common practice in the electric industry to reduce the number of kWhs delivered to the system by the difference in losses between the receipt point and the delivery point or points as I have demonstrated in my direct testimony. The higher the penetration of solar DG on a circuit the higher the delivery losses will be. And in no event are the losses from receipt point to delivery point ever zero.

Q. TASC WITNESS BEACH STATES AT PAGE 14 THAT THE SOLAR DG CUSTOMERS PAYS FULLY FOR THE USE OF THE SYSTEM JUST THE SAME AS ANY OTHER CUSTOMER. PLEASE COMMENT.

A. This statement is simply wrong. A customer with a net zero kWh bill pays only $120 in the year for all of the use of the grid and that does not even cover customer costs. In order for the statement to be true, avoided costs must be greater than the total costs to serve the DG customer. The cost of service studies in my direct testimony prove that is not the case. Further, under the FERC regulations implementing PURPA, the avoided energy cost is only the short-run avoided costs; and the avoided capital cost cannot include all of the adders that the solar DG witnesses seek to include, because the avoided capacity costs cannot exceed the actual avoided costs as I have noted above.

Given that we know the market value of DG (the value may be calculated as the difference between the latest utility scale solar DG winning bid price less the levelized cost of energy since the remainder is the implied market capacity value for solar DG), that calculated capacity value is even lower than avoided costs calculated on a least cost combustion turbine and it makes no sense from a policy perspective to pay more for solar DG than the market value. Doing so only enriches the rent seekers representing the solar sellers and installers at the expense of customers who do not have a solar option.

Q. VOTE SOLAR WITNESS VOLKMANN RECOMMENDS THE USE OF SMART INVERTERS FOR DG SOLAR AND STORAGE. PLEASE COMMENT.

A. I agree that smart inverter technology coupled with improved communication between the utility and the customers inverter is a positive approach to improving integration of solar DG. A requirement for both new solar DG and for existing solar DG as inverters are replaced will improve efficiency and operation at the expense of fewer kWh. With this requirement there must also be changes that provide better price signals to customers so that these inverters actually have value for the system. As an example, utility rates typically have power factor adjustment provisions in rates and those would provide a mechanism for charging low power factor customers.

Q. WITNESS VOLKMANN ALSO RECOMMENDS THAT A DETAILED MARGINAL COST STUDY OF TRANSMISSION AND DISTRIBUTION BE REQUIRED FOR EACH UTILITY. PLEASE COMMENT.

A. Having prepared a number of electric marginal cost studies for all of the utility costs including production, transmission, distribution and customer components, I believe such studies are useful as they relate to rate design. They are not useful for calculating avoided costs for transmission and distribution. As I have discussed above, marginal costs are not the same for an increment and a decrement of load. In many cases, a decrement of load has an avoided cost of zero because of the lumpy characteristics of utility assets. It is not likely that a small change in load on a circuit will allow the utility to save any capital costs currently and not even in the future unless the incremental reduction is sufficient to allow the next smallest size of equipment to replace the current installation. Consider for example that the energy saving (kW and kWh) may not equal the full technical savings because of the income effect on demand. That is, solar DG that lowers the cost of electric service will have an income effect on demand. That income effect may result in increased consumption based on keeping the premise cooler for example. If that is the case, capacity savings may well be lower than would have occurred with no change in comfort. In that case, there may be no net capacity saving at all.

In a marginal cost study, the typical approach is to add an increment of load that is typically at the periphery of the system. In that case, the costs could not be avoided by solar DG in any event so the value of a marginal cost study is not for use as a measure of avoided costs but for sending better price signals.

Q. ARE THERE LOCATION SPECIFIC BENEFITS FOR SOLAR DG AND OTHER DER PROGRAMS AS SUGGESTED BY VOTE SOLAR WITNESS VOLKMANN?

A. Yes. There may be parts of the system that over time have had growth that differs from the original expectations when the system was built. In that case it may be that added system capacity may be avoided by strategically placed increments of solar DG or other DER resources. By identifying these portions of the system and the optimal location solar developers may bid to locate at a site and receive a larger capacity credit than would be available for a general site on the system. The use of competitive bidding for these locations is consistent with least cost planning across the spectrum of utility resources. Witness Volkmann cites this type of process in his direct testimony.[30]

Q. WITNESS VOLKMANN ARGUES THAT SOLAR DG CAN AVOID SERVICE INTERRUPTIONS (DIRECT AT PAGE 27). PLEASE COMMENT.

A. I assume that this a theoretical statement since current IEEE regulations require solar to disconnect from the grid when there is an outage. The concept of islanding the system is being addressed, but to provide service during an outage is more complex than concluding solar DG can avoid service disruptions as a general conclusion. The key point is that depending on the load the solar DG would trip off because the load is too large in aggregate to be served by the DG capacity resulting in under voltage; or in the

[30] Volkmann Direct, p. 31

other extreme, there is not enough load to use the generation and the system trips off because of over voltage. While certain of these conditions change with smart inverters the current configuration does not increase system reliability.

Q. DO YOU AGREE WITH WITNESS VOLKMANN THAT DISTRIBUTION SYSTEM PLANNING MUST CHANGE?

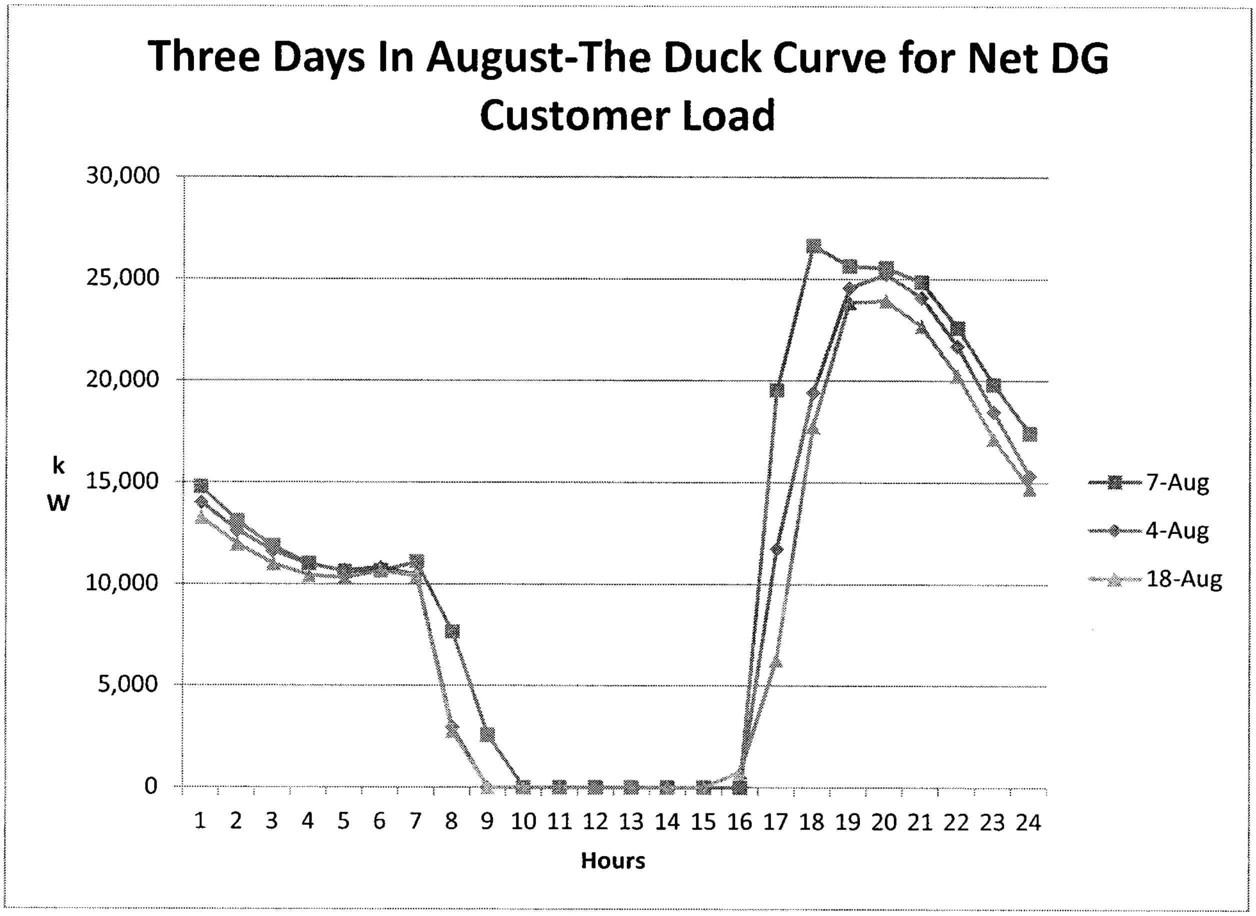
A. Yes. The impact of two way flow on systems designed for one way flow requires that engineers respond in ways that improve the overall efficiency and economics of the grid. The status quo is no longer an adequate set of considerations. By using available technology and improved communications protocols the power delivery system can accommodate the changing market dynamics. Although not mentioned by witness Volkmann it is likely that, in response to two ways flow from DG systems, delivery services will need to be modified in ways that will require increased investment in infrastructure. Regulations should be developed to permit this investment with tools such as infrastructure adjustment clauses designed to permit timely recovery of these costs under plans approved for each utility.

Q. WITNESS KOBOR STATES (DIRECT AT PAGE 9) THAT THE ONLY DIFFERENCE BETWEEN SOLAR DG AND ENERGY EFFICIENCY IS THE EXPORT OF POWER. PLEASE COMMENT.

A. The premise for this statement is false. Solar DG is very different than energy efficiency that reduces kWh consumption. By improving efficiency for end-use applications customers reduce load over the entire load shape of that particular end use.

By reducing use with solar DG (ignoring for a moment the excess generation), solar DG only changes the end-use applications during hours with sufficient insolation for the solar DG to operate. There is no **continuous** adjustment to load but rather a non-diversified demand adjustment in some hours and the adjustment for each individual premise are intermittent. The modification of the load shape is shown in Figure 1 below.

Figure 1



This curve shows how solar DG changes the customer net load shape. The change is far different from EE changes that would be uniform and consistent across all hours that the EE changes impact hourly load for the end-use. In fact, for two of the three days in the sample the peak occurs at hour ending 8 PM. Unlike EE, solar DG cannot be counted on for a uniform reduction of load in all hours nor can it be counted on for reduced load on a consistent basis in any particular hour.

When the added issue of power delivery to the utility system is added, the evidence shows that this represents the peak load on delivery system resources. Adding that difference to the list of reasons solar DG is very different than EE investments.

Q. WITNESS KOBOR STATES THAT THE CENTRAL QUESTION FOR DECISION IN THIS CASE IS WHETHER THE PRICE PAID FOR DG EXPORTS APPROPRIATELY REFLECTS THE VALUE OF THE ENERGY PROVIDED?[31] PLEASE COMMENT.

A. While I would like to agree, as I have noted above this position is not consistent with the PURPA FERC Rules. Under PURPA the avoided energy costs for an "as available" resource is the current period marginal cost as I have explained. However, the full value of the resource may also include a capacity component and that should be recognized. It is particularly important that the capacity value be part of the IRP assessment of rooftop solar DG as part of the resource mix to develop a least cost plan for each utility system. If that is the least cost option then it should remain as part of the mix regardless of other provisions. If it is not a least cost alternative its value will be solely to meet any mandated requirements for the technology and no more.

[31] Kobor Direct p. 4

Q. WITNESS KOBOR RECOMMENDS A THIRD PARTY EVALUATION OF AVOIDED COSTS (DIRECT AT PAGES 5 AND 48). DO YOU BELIEVE THAT PROCESS IS NECESSARY?

A. No. Utilities have made these estimates since the early 1980s and the methodology is broadly understood within the industry and the FERC regulations implementing PURPA provide clear benchmarks about the definition and determination of avoided costs. There is no inherent reason for each utility to incur the expense of funding a third party to make calculations the utility makes regularly and present to the Commission on a regular basis as well. I would note that rent seeking is not just an exercise for the solar DG industry but is also possible that consultants engage in the same practice.

Q. IS THE USE OF NET METERING AS A PROXY FOR SOLAR DG AVOIDED COSTS LOGICAL?

A. While witness Kobor makes this claim[32], there is no sound logic in support of net metering, a point recognized by even solar advocates when the process is referred to as "rough justice". As a general rule, utilities are so different that using this simple one size fits all approach cannot be justified as logical. This is a concept that witness Kobor confirms in her testimony.[33] For example, utilities that peak when there is no sunlight (there a significant number that have peaks in the winter morning or evening) have no capacity savings of any sort but all incur capacity costs for production, transmission and distribution that are included in base rates.

[32] Op. cit. p. 7
[33] Op. cit. p. 8 lines 8-9

I note above that the embedded cost of service credit for solar DG based on the TEP cost study far exceeds avoided costs based on actual solar DG output and avoided capacity costs. The correct logic would be pay credits based on the utilities actual avoided costs-short-run energy and long-run capacity.

Q. DOES THE COMPARISON OF AVOIDED COST STUDIES OVER TIME HAVE ANY VALUE RELATED TO METHODOLOGY OR ANALYSIS OF DIFFERENCES?

A. Witness Kobor seems to believe that the differences in studies over time and by different parties requires Commission guidance on studies even though she failed to do any basic due diligence related to the differences. At page 15 of witness Kobor's direct testimony she provides a table that reports on three studies done in two different periods and by three different parties for the same Arizona utility company. For the studies completed four year apart by essentially the same entity the results are dramatically different. The differences can be largely explained by two factors- lower natural gas prices delivered to electric generation and the excess generation capacity in the market.

As for the third study there are numerous errors related to the calculation of avoided costs. I have discussed these errors above and will not repeat that discussion except to note that the avoided CT costs are not based on the least expensive capital addition which is far less than the technology of the selected CT based on the Crossborder Energy filing in this case based on EIA data. Other factors are too high as well such as fixed O&M, the applicable carrying charge rate and in the case of TEP and UNSE the net dependable capacity at the time of the system peak. The end result is that errors of including costs not avoided based under the FERC definition, using an incorrect methodology for avoided T&D costs and the inflated values of the components of the equation leads to a conclusion that the Crossborder study differences are likely the result of numerous inaccuracies in the estimation procedure.

The evidence does not support the need for Commission guidance so much for utilities who perform these calculations in planning studies but for the solar DG advocates who have developed and used methods that are not theoretically or practically sound and do not comply with the simple language of the FERC rules implementing PURPA requirements that proscribe the utilities actual avoided costs but for the solar DG capacity.

Q. SEVERAL SOLAR DG WITNESS RECOMMEND USING CAPACITY COSTS ON A CONTINUOUS BASIS. IS THAT A SOUND APPROACH?

A. No. That approach will never get the avoided capacity costs correct simply because it assumes that capacity additions are continuous. They are not. It may be an inconvenient fact that additions are lumpy, but it is a fact. There is no avoided capacity value based on a continuous analysis.

Q. WITNESS KOBOR OPINES THAT SOLAR DG EXPORTS OCCUR "DURING HEAVIER LOADING PERIODS".[34] IS THAT STATEMENT CORRECT?

A. No. This statement does not comport with the evidence in Exhibit HEO-1 from my direct testimony that shows solar DG production uniformly does not match heavier load periods. Couple that with the fact that Figure 1 above shows that in the highest cost summer hours the solar DG customer is consuming utility supplied kWhs not exporting. Exhibit HEO-2 from my direct further confirms that solar production does not match high cost periods in either season. Exports are greatest when loads are lowest both for customers and the system.

VIII. <u>CONCLUSIONS AND RECOMMENDATIONS</u>

Q. PLEASE PROVIDE A SUMMARY OF YOUR CONCLUSIONS.

A. My conclusions may be summarized as follows:

1. The determination of avoided costs is not some new process since under PURPA both utilities and Commissions have made these calculations since the 1980s.
2. Avoided costs do not require any speculation related to externalities that have not been internalized. If the utility does not pay the cost it cannot be avoided cost. While these externalities may be considered as part of an IRP process which screens alternatives, they cannot be part of a payment to solar DG customers because it becomes a tax on non-solar customers for the benefit of solar DG customers.

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[34] Kobor Direct, p. 29

3. The FERC Rules implementing PURPA provide for energy avoided cost on a short-run basis for intermittent resources such as solar DG. Long-run avoided energy costs may only be elected, not mandated, for an enforceable long-term contractual commitment.
4. Discount rates for utility avoided capacity cost must be based on the weighted average marginal cost of capital.
5. Social discount rates are not appropriate for calculating avoided private costs and all utility costs that can be avoided by a utility are private costs.
6. Marginal cost for an increment of load and a decrement of load are not the same.
7. Marginal T&D costs cannot be estimated with regression analysis because there is no measure of capacity available to use as the dependent variable because there are multiple measures of capacity.
8. Delaying capacity additions as a measure of avoided costs is a much smaller value than actually avoiding the cost.
9. Market based determination of avoided cost is superior to estimating avoided costs and is consistent with the current position of the FERC in its avoided cost rules.
10. The cost of service studies filed in this case support separate rate treatment for solar DG customers under the fully unbundled three part rate with separate cost based seasonal and TOU energy charges not encumbered with fixed cost recover.

11. The combination of the counterfactual cost study and the solar class subsidy prove that a cost studies do reflect capacity cost savings for solar DG customers and those savings exceed avoided costs.
12. The FERC Rules require just and reasonable rates for sales to solar DG customers based on consistent system wide cost allocations. This is exactly the method used in my cost studies filed in direct testimony and shown in the solar DG class study.
13. The cost studies filed in my direct testimony demonstrate that there is an embedded cost credit for generation capacity in excess of avoided costs when calculating the revenue requirements for the solar class. This results in an explicit subsidy based on system wide costing principles.
14. Solar DG customers do not have the same characteristics of low use full requirements customers. They have much lower load factors.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A. My recommendations remain unchanged from those in my direct testimony. In addition, I recommend that avoided costs be calculated consistent with the FERC rules promulgated to implement the various provisions of PURPA as amended over time. This would include treating avoided energy costs based on the same time period as the rates effective for sales to customers. In the alternative these rates could be calculated annually and paid for all excess generation when it is delivered to the system. Finally, I recommend that IRP screening tests such as the Rate Impact Measure, Total Resource Cost or Social Cost Tests be rejected as a means to value solar DG but continue to be used to screen resource options under the IRP. It should be incumbent on the utility to develop a best cost plan consistent with legislative mandates as they may be changed from time to time.

Q. DOES THIS COMPLETE YOUR TESTIMONY?

A. Yes.