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**BEFORE THE ARIZONA CORPORATION COMMISSION**

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

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

Docket No. E-00000J-14-0023

**NOTICE OF FILING WRITTEN REBUTTAL TESTIMONY ON BEHALF OF VOTE SOLAR**

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

DATED this 7th day of April, 2016.

By______________________
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ORIGINAL and 13 COPIES of the Foregoing filed this 7th day of April, 2016, with:

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All Parties of Record

**BEFORE THE ARIZONA CORPORATION COMMISSION**

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

**REBUTTAL TESTIMONY OF CURT VOLKMANN**

**ON BEHALF OF VOTE SOLAR**

**April 7, 2016**

# Table of Contents

# List of Figures



# List of Exhibits

# 1 Introduction

**Q. Please state your name and business address.**

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

**Q. On whose behalf are you submitting this rebuttal testimony?**

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

**Q. Did you submit direct testimony in this proceeding?**

A. Yes, I did. My direct testimony includes an introduction to Vote Solar and a summary of my professional experience.

**Q. Are you sponsoring any exhibits?**

A. Yes, I am sponsoring Exhibit CV-R-1, which shows illustrative line loss calculations during higher load periods.

# 2 Summary of Testimony

**Q. Please provide a brief summary of your testimony.**

A. In their direct testimony, APS and TEP/UNSE stated that transmission and distribution ("T&D") and generation benefits from solar distributed generation ("DG") are minimal or non-existent. I will explain how solar DG, together with other distributed energy resources ("DER"), can reduce or eliminate the need for traditional utility investments, including capacity upgrades and voltage regulation equipment. I will also explain why it is important that the incremental investment-deferral contribution from DER is captured in any valuation methodology.

The utilities have also stated that T&D system enhancements are necessary to accommodate increasing penetration of solar DG, and that T&D line loss savings from DER are minimal. I will explain why grid enhancements to accommodate solar DG are minimal, and explain the importance of properly accounting for line loss reductions when valuing DER.

In my direct testimony, I explained the importance of establishing a methodology for valuing all DER types and DER portfolios.[1] I continue to believe it is important for the Commission to consider this broader approach, which I refer to as a VOS/DER methodology throughout this testimony.

# 3 Capacity benefits from DER are real and should be reflected in the VOS/DER methodology

**Q. Are there generation and T&D benefits associated with the deployment of solar DG and other DER?**

A. Yes. The output from solar DG reduces system loads and reduces the need for future T&D capacity expansion. The generation and transmission capacity deferral benefits are greater if the solar DG output coincides with system or regional peak demand. Distribution capacity deferral benefits are greater when the solar DG output coincides with local substation or circuit peak demand.

As I explained in my direct testimony, strategic orientation of solar DG and bundling solar DG with energy storage can effectively align solar DG output with load profiles to reduce local peak demands.[2] Furthermore, solar DG equipped with smart inverters can provide reactive power support and reduce the need for traditional utility voltage regulation and power quality investments.

**Q. Does APS recognize the T&D benefits from solar DG and other DER?**

A. APS witnesses Brown and Albert deny the T&D benefits of solar DG in their direct testimony. However, I believe APS does recognize the potential T&D benefits of solar DG, particularly when combined with storage and smart

[1] Curt Volkmann Direct Test. 30:12–32:22 (Feb. 25, 2016) (hereinafter "Volkmann Direct").
[2] *Id.* at 14:19–15:8.

inverters. The company is validating these benefits through its Solar Partner Program, approved in Decision No. 74878.

In response to a Vote Solar discovery request, APS describes the key design elements of the Solar Partner Program as:

- Install rooftop solar on approximately 1,500 homes
- Systems will include smart inverters (UL listing will be achieved by the end of March 2016) and 2-way communications to control each rooftop solar site
- Install 2MW of battery storage on 2 selected feeders
- Collection and analysis of real time data on energy production, energy usage, power regulation capabilities, and curtailment options
- Validate ability to manage solar impacts by configuring smart inverters and issuing real-time commands in a cyber secure environment
- Validate ability to mitigate adverse effects of increased photovoltaic (PV) through enhanced power regulating capabilities
- Validate ability to provide ancillary services from a series of grid-tied batteries in coordination with solar inverters and traditional grid devices
- Collection and analysis of information that helps anticipate, identify, and avoid impacts on the distribution grid
- Validate distribution system models to more accurately and efficiently plan grid upgrades[3]

**Q. Do APS and TEP/UNSE recognize the generation capacity benefits from solar DG and other DER?**

A. Yes. Generation capacity benefits from DG are widely accepted. Each of the utilities' most recent IRPs included estimates of the level of DG that they expect to contribute to system peak. Vote Solar witness Briana Kobor provided a table

[3] APS Resp. to VS 3.11 (Ex. CV-R-2 at 1).

with estimated of DG peak capacity contribution in 2020 for APS, TEP, and UNSE.[4]

## 3.1 Testimony of Mr. Brown

**Q. Have other parties in this proceeding stated opinions on the T&D benefits of solar DG and DERs?**

A. Yes. APS witness Ashley Brown and TEP/UNSE witness Edwin Overcast have offered opinions. Mr. Brown states: "It is virtually impossible to demonstrate that rooftop solar will obviate the need for transmission, much less quantify the cost savings associated with this purported benefit."[5] He also states that "[i]t is impossible, unless perhaps when a rooftop solar host leaves the grid, to envision a circumstance where rooftop solar would effectuate distribution savings."[6]

**Q. Do you agree with Mr. Brown?**

A. No. It is possible to not only envision, but to demonstrate and quantify, the transmission and distribution savings from strategic deployment of solar DG and other DER. In fact, in my direct testimony, I provided several examples of other utilities that are realizing these benefits, including Con Edison, National Grid, and Central Maine Power.[7]

## 3.2 Testimony of Dr. Overcast

**Q. What statements did Dr. Overcast make related to the T&D benefits of solar DG and DERs?**

A. Dr. Overcast states that "there are no avoided distribution costs as the result of solar DG customers on the system. This conclusion is theoretically sound because the non-coincident peak demand on the distribution system occurs when solar DG

[4] Briana Kobor Direct Test. 30:10 (Feb. 25, 2016).
[5] Ashley Brown Direct Test. 35:16–17 (Feb. 25, 2016) (hereinafter "Brown Direct").
[6] *Id.* at 36:2–4.
[7] Volkmann Direct 31:5–32:6.

customers are delivering excess generation to the system and there is no time diversity of solar DG production as there is with customer load."[8]

Dr. Overcast also states:

> Using data prepared by TEP based on hourly load data for about 374 full requirements customers with annual kWh usage above 13,000 kWhs and overlaying their usage with solar loads modeled using the National Renewable Energy Laboratory (NREL) solar data base for Arizona for 24 months from mid-2013 to mid-2015 we reach the same conclusion as found above with respect to the total class of Solar DG customers. This further confirms that the distribution system must be designed to meet this higher solar class NCP load rather than the residential class customer NCP load used for full requirements customers. The maximum average customer NCP (the sum of the highest hourly loads for all customers in the data base) for full requirements customers occurs in July at 12.87 kW per customer. The maximum excess delivery by a partial requirements customer occurred in April at 13.79 kW per customer. Although the differences are small, about one kW, the data confirms that there would be no distribution cost savings associated with the equipment in accounts 364-368. . . . Taken with other load data on class NCP it is also reasonable to assume that there would be no savings at the substation level for peak loads of solar DG customers.[9]

**Q. Do you agree?**

A. I do not agree or disagree without reviewing the data and analysis that Dr. Overcast references, which I am unable to do because TEP/UNSE has claimed it is confidential.

Based on the limited information I was able to review, it appears that the excess delivery of 13.79 kW by a solar DG customer cited by Dr. Overcast is high and not reflective of the majority of solar DG systems installed in TEP's service territory. Assuming PV system losses of 15%, it would require at least a 16.22 kW system to deliver 13.79 kW of power. According to data provided by TEP, only 80, or 0.9%, of installed solar DG systems have capacity of 16.22 kW or

[8] Edwin Overcast Direct Test. 5:26–6:4 (Feb. 25, 2016) (hereinafter "Overcast Direct").
[9] *Id.* at 17:11–18:4.

higher.[10] While there potentially may be a very small number of circuits where excess solar generation exceeds non-coincident peak ("NCP") load, it is not the case for all TEP circuits and it is therefore incorrect to conclude that there are no T&D cost savings from solar DG.

# 4 The VOS/DER methodology must recognize DER capacity benefits on a continuous basis

**Q. What is an appropriate way to consider the capacity benefits of DER in the VOS/DER methodology?**

A. As I stated in my direct testimony, DER can make small, incremental contributions to increase T&D capacity in areas where no immediate capacity upgrade is planned, and this contribution to longer-term capacity relief should be recognized in the valuation methodology.[11]

A recent Nexant report explains:

> The main value of integrating distributed energy resources into distribution planning and operations is in managing local, coincident demands that are shared across many customers. If a customer helps reduce coincident demand, either by injecting power within the distribution grid (e.g., behind-the-meter generation) or by reducing demand, the unused capacity can accommodate another customer's load growth and thereby help avoid or defer investments required to meet load growth.[12]

The Nexant report provides an example to illustrate this point. Figure 1 below shows how, absent DER, capacity upgrades for a hypothetical circuit are required in years 4, 9, and 14 to meet increasing demand. Deployment of DER to reduce

---

[10] *See* work papers provided in TEP Resp. to TASC 1.1.
[11] Volkmann Direct 18:13–19:11.
[12] Josh Bode et al., Nexant, *Designing and Unlocking Markets for Distributed Energy Resources* 6 (June 2015), *available at* http://www.nexant.com/resources/designing-and-unlocking-markets-distributed-energy-resources.

peak demand results in the need for only a single capacity upgrade in year 9. The economic impact is significant, as the DER solutions reduce the 15-year net present value (NPV) by $72 million, as shown in Figure 2.

**Figure 1: Local peak demand and distribution capacity**

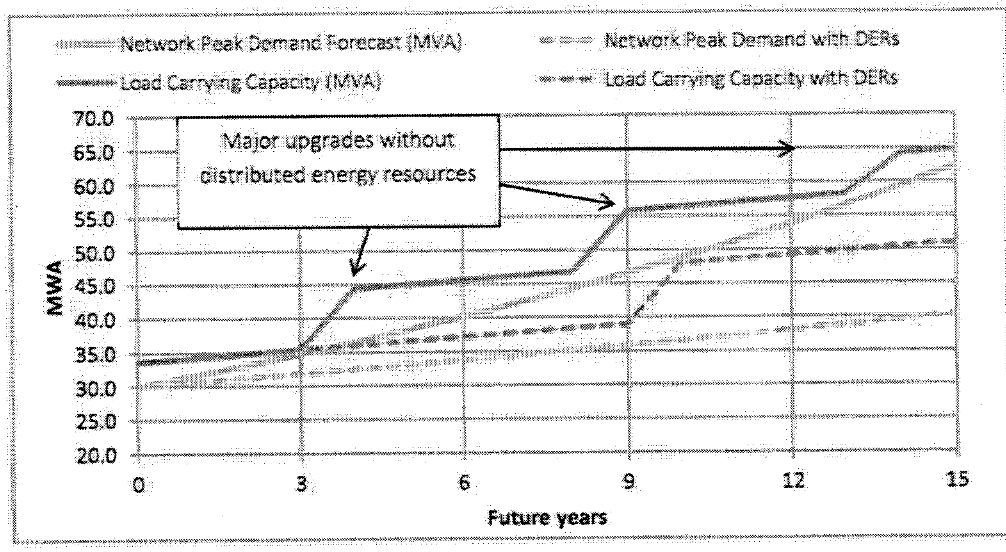
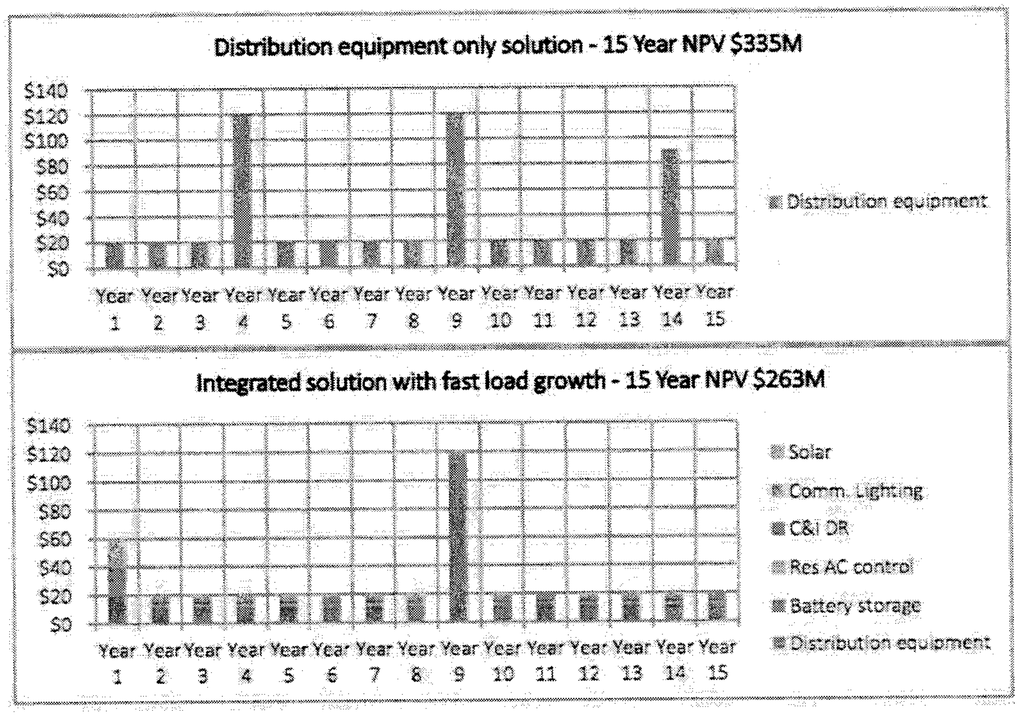



**Figure 2: Impact of DER on expenditures**



**Q. Have other parties in this proceeding commented on this issue?**

A. Yes. The updated report by Crossborder Energy included in the TASC testimony states:

> Solar DG will avoid transmission capacity costs to the extent that solar production occurs during the peak demand periods. Like energy efficiency and demand response resources, solar DG helps the utility to manage and to reduce load growth, thus avoiding and deferring the need for load-related transmission investments.[13]
>
> As DG penetration grows, and a deeper understanding is gained of the impacts of DG on distribution circuit loadings, we anticipate that utility distribution planners will integrate existing and expected DG capacity into their planning, enabling DG to avoid or defer distribution capacity costs. A comparable evolution has occurred over the last several decades, as the long-term impacts of EE and DR programs are now incorporated into utilities' capacity expansion plans for generation, transmission, and distribution, and it is generally recognized that these demand-side programs can help to manage demand growth even though the specific locations where these resources will be installed can be challenging to predict or to manage.[14]
>
> Moving forward, with the advent of smart inverters and other technologies, PV systems will be able to provide additional services and avoid additional costs than those attributable to capacity expansion alone. Such services include voltage regulation, power quality, and conservation voltage reduction.[15]

**Q. Do you agree?**

A. Yes. I agree that integrating existing and expected DER capacity and capabilities into T&D planning, including future capabilities from smart inverters, is critical to fully unlock the value of DER.

## 4.1 <u>Testimony of Mr. Brown</u>

**Q. What statements does Mr. Brown make related to the capacity benefits of solar DG and DER?**

---

[13] Thomas Beach Direct Test. Ex. 2 at 13 (Feb. 25, 2016).
[14] *Id.* at 15.
[15] *Id.*

A. Mr. Brown states:

> [T]he addition of rooftop solar, absent a truly massive amount of installation, will almost inevitably have no impact on transmission capacity planning. Indeed, since transmission must be sufficient to serve peak load, the fact that rooftop solar is intermittent, and non-coincident with peak, means that it will have no real impact on transmission capacity.[16]

**Q. Do you agree?**

A. No. While solar DG peak production may not fully coincide with system peak demand, solar DG does produce some level of output during system peaks and makes some incremental contribution to system capacity. Utilities conduct transmission planning over long time horizons and make large, "lumpy" capacity additions that may result in over-capacity for some periods of time. In order to ensure least-cost development of the electric delivery system, utilities must acknowledge the incremental capacity benefits of DG and other DER. Failure to recognize these benefits will result in premature, redundant, or unnecessary capital expenditures.

# 5 Grid upgrades and system resources to accommodate DER are minimal until penetrations significantly increase

**Q. Do T&D systems require upgrades to accommodate the proliferation of solar DG and other DER?**

A. T&D systems may require upgrades, depending on the system characteristics at each interconnection location. In addition, at very high penetration levels, utilities may need system resources to accommodate intermittency associated with DG. However, I believe T&D system upgrades and system resource needs to accommodate solar DG in Arizona are minimal until DER penetrations significantly increase.

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[16] Brown Direct 34:3–7.

**Q. Why do you believe T&D system upgrades are minimal now?**

A. As I explained in my direct testimony, conducting a hosting capacity analysis identifies how much DER each circuit and each subsection of a circuit can accommodate.[17] Utilities that have conducted detailed hosting capacity analyses have found that existing circuits can accommodate significant amounts of DER without the need for upgrades.[18] Furthermore, smart inverter technologies are eliminating the need for traditional grid enhancements to accommodate DER.[19]

## 5.1 Testimony of Mr. Albert

**Q. What do the parties say about the need for grid investment to accommodate solar DG and DER?**

A. APS witness Brad Albert states:

> APS has begun to experience high-voltage conditions on certain distribution feeders at times of the year when customer demand is low and solar energy production is high on those feeders. This could necessitate the installation of additional equipment to mitigate this condition to maintain reliable service to all customers on those feeders.[20]

**Q. Do you agree?**

A. No, I do not believe it requires the installation of additional equipment. In response to a Vote Solar discovery request related to this issue, the company stated:

> APS does not have system-wide voltage measurement capabilities at this time, and therefore cannot answer the specific questions raised in this data request. . . .
>
> However, APS did receive 95 inquiries in 2015 from customers with installed rooftop solar systems specifically related to

---

[17] Volkmann Direct 6:21–7:15.
[18] *Id.* at 8:20–27.
[19] *Id.* at 9:1–13.
[20] Bradley Albert Direct Test. 13:12–16 (Feb. 25, 2016) (hereinafter "Albert Direct").

> substantiated high voltage issues. These 95 customers are located on 68 separate feeders, with 12 of those inquiries on a single feeder (the highest number for any one feeder in 2015). All 12 of these high voltage instances occurred in non-summer months, when customer loads are low, rooftop solar production is high, and rooftop systems are exporting energy to the grid.
>
> To date, APS has not incurred equipment or system costs directly attributable to high voltage concerns due to rooftop solar. . . .[21]

It is unclear what a customer "inquiry" entails, but the 95 customers that inquired represent 0.34% of the 28,254 rooftop solar customers in the APS service territory in 2014.[22] This does not indicate a widespread problem. In addition, smart inverter functionality can effectively address high-voltage conditions without the need for more expensive utility equipment installations.

## 5.2 <u>Testimony of Mr. Brown</u>

**Q. What does Mr. Brown say related to this issue?**

A. Mr. Brown states:

> It is more likely that rooftop solar will cause more distribution costs than it saves. That is because these generation sources could change voltage flows in ways that will require adjustments and maintenance. It will also inevitably increase transaction costs for the utility to execute interconnection agreements and do the billing for an inherently more complicated transaction than simply supplying energy to a customer.[23]

**Q. Do you agree?**

A. No, I do not believe that rooftop solar causes more costs than it saves, nor do I believe it will inevitably increase transaction costs for a utility. In response to a Vote Solar discovery request seeking specific examples of the increased costs Mr.

[21] APS Resp. to VS 3.16 (Ex. CV-R-2 at 3).
[22] *See* work papers provided in APS Resp. to VS 1.1.
[23] Brown Direct 35:25–36:2.

Brown refers to, APS acknowledges that "[t]his statement is a general statement not based on specific analysis of APS data."[24]

## 5.3 Testimony of Mr. Tilghman

**Q. What does Mr. Tilghman say related to this issue?**

A. TEP/UNSE witness Carmine Tilghman states:

> The bi-directional flow of energy associated with DG solar will require modifications and upgrades to the distribution system. As it is a newly identified phenomenon, the Companies do not have specific measures in place to address any adverse effects as a result of reverse power flow. The bi-directional energy flow on the electrical distribution system varies based on many system electrical parameters that are created by the location and size of the solar system. The problems that are created with bi-directional flows also vary by the time of day and seasonality.
>
> Additional measuring and monitoring equipment will be needed. New methods of modeling the distribution system will need to be developed to model and predict the impacts of a reverse power condition. Upgrades in system automation will be needed to phase balance transformer connections for load and for distributed generation. As reverse power affects the feeder power factor, the placement and sizing of switched distribution capacitor banks is affected as well as distribution transformer sizing.[25]

**Q. Do you agree?**

A. No. Until the companies conduct hosting capacity analyses to assess the distribution systems' ability to accommodate solar DG and other DER, any conclusions about required upgrades are purely speculative. Also, utilizing smart inverter functionality is a more cost effective approach for power factor correction than installing switched distribution capacitor banks. I do, however, agree that the utilities will require new methods of modeling distribution systems to fully integrate DER into system planning, as I describe in my direct testimony.[26]

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[24] APS Resp. to VS 3.23 (Ex. CV-R-2 at 5).
[25] Carmine Tilghman Direct Test. 16:9–22 (Feb. 25, 2016).
[26] Volkmann Direct 29:5–19.

## 5.4 Testimony of Mr. Huber

**Q. What does Mr. Huber say related to this issue?**

A. RUCO witness Lon Huber states: "The general production characteristic of solar, aggregated and at high penetrations, can change system wide load shapes to create new demands on the system. Large amounts of solar without batteries can create ramping needs and fast-start backup generation requirements."[27]

**Q. Do you agree?**

A. To the extent that Mr. Huber indicates that his statements refer to the potential for increased ramping capabilities and fast-start backup generation requirements at high penetration levels, I agree. However, I do not believe that one can assume the need for additional system resources at current or near-term DG penetration levels.

## 5.5 Testimony of Mr. O'Sheasy

**Q. What does Mr. O'Sheasy say related to this issue?**

A. AIC witness Michael O'Sheasy states:

> The energy generated from solar DG is non-firm, which means that it cannot be relied upon by the utility as a source to serve load. Solar DG output flows onto the grid periodically depending upon the operations of the rooftop solar system and the site load requirements of the customer. This excess energy saves the utility from incurring some costs to serve, such as avoided fuel, variable operations and maintenance charges, and losses that would have occurred had the excess solar DG generated energy been otherwise produced by the utility. In addition, solar DG may impose some additional costs such as integration cost to accommodate the two-way flow of power on the distribution grid.[28]

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[27] Lon Huber Direct Test. 12:1–4 (Feb. 25, 2016).
[28] Michael O'Sheasy Direct Test. 10:16–24 (Feb. 25, 2016).

**Q. Do you agree?**

A. Like Mr. Huber's above quoted statement, Mr. O'Sheasy's statement is correct in regard to high penetration levels of DG, though such results cannot be assumed at current levels of DG penetration. A hosting capacity analysis will determine what, if any, integration costs are required to accommodate current and forecasted levels of solar DG and DER penetration.

# 6 The VOS/DER methodology must properly account for reduced line losses

**Q. What are line losses?**

A. Line losses include technical losses from the heat and magnetic energy created by the various system components, and non-technical losses from theft or utility usage. Non-technical losses are not relevant for purposes of this discussion.

Engineers further categorize technical losses into fixed and variable losses. Fixed losses take the form of heat or noise from energized equipment and do not vary with changes in current flow. These fixed or no-load losses are a characteristic of a specific system component, such as a transformer, and utilities can only reduce fixed losses by replacing components with lower-loss units or by removing components from the system altogether.

Variable technical losses occur when electrical energy converts to heat at a rate proportional to the square of the current flowing through a system component, also referred to as $I^2R$ losses. Variable losses are therefore lower at low levels of energy delivery and increase as current and energy flows increase. For purposes of valuing solar DG and DER, avoided variable technical losses are the most important to consider.

Variable technical losses fluctuate whenever a DER increases or decreases the load on the T&D system. The magnitude of the change in losses also depends on the interconnection point of the DER. For example, a utility-scale solar PV system connected directly to the transmission system only reduces transmission line losses. Alternatively, a residential load reduction measure reduces variable losses from the distribution secondary, distribution primary, substation, and transmission systems.

The timing of the DER load change also matters, as variable losses are proportional to the square of the current. Losses during peak periods are greater than the losses during off-peak periods. APS reports that average line losses on their system are about 7% annually, and approximately 12% at the time of peak demand.[29]

**Q. Are reduced line losses important to consider in the VOS/DER methodology?**

A. Yes. For the reasons I explained above, DER can alter load at or near the point of interconnection and therefore impact variable line losses.

**Q. Have other parties addressed line losses in this proceeding?**

A. Yes, but the APS witness testimony from Mr. Albert and Mr. Brown is conflicting. In addition, TEP/UNSE witness Dr. Overcast provides analysis of losses related to solar DG. I address each of these witnesses' testimonies regarding line losses below.

## 6.1 Testimony of Mr. Albert

**Q. What does Mr. Albert say about line losses?**

A. Mr. Albert states:

> Energy losses occur as electricity is transmitted across the grid. A portion of the electricity produced by a remotely-located power plant is lost as that electricity moves across the transmission and distribution system before arriving at the customer's premises. Because of this, there is an advantage to having generation sources like rooftop solar that are located

[29] Albert Direct 24:4–5.

> at the customer's premises. To the extent that this energy is consumed at the same site, energy losses are reduced because this power does not have to travel across the grid before arriving where it will be consumed[30]

Mr. Albert further states:

> Energy losses average about 7% over the course of the entire year and are estimated at approximately 12% at the time of peak demand. Both of these values are routinely factored into APS's load forecasts. To be clear, the values calculated for rooftop solar are higher than they would be otherwise because of the expected energy losses saved by reducing the need to transmit electricity from remotely located generation sources to the customer's site.[31]

**Q. Do you agree with Mr. Albert?**

A. Yes, I agree with Mr. Albert's explanation of how rooftop solar reduces line losses. I also consider the estimated losses of 7% average and 12% during peak periods to be reasonable for variable technical losses and consistent with what I have seen at other utilities.

**Q. Does Mr. Albert address any uncertainty about line losses?**

A. Yes. He states:

> . . . The logic that supports reduced losses is based on the actual mechanics of how electricity is transferred to customers. When energy is generated remotely, it goes through step-up transformers, is transmitted over long-distance transmission lines, gets transformed down to be put on the distribution system, and ultimately reduced to a voltage that customers can use. While this is an efficient means of transporting electricity over these distances, energy losses occur throughout this process. When the energy is generated locally, however, it doesn't go through this process. As a result, this logic concludes that locally generated energy avoids energy losses.
>
> Equally valid logic supports the opposite conclusion. Rooftop solar increases voltage on the distribution feeder during certain times of the year. This higher-voltage level is a function of the quantity of energy produced by rooftop solar, and results in higher overall energy use by customers experiencing these higher-voltage

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[30] *Id.* at 8:26–9:5.
[31] *Id.* at 24:4–9.

> conditions. The result is higher customer energy usage due to higher voltage levels.[32]

**Q. Do you agree?**

A. No. Mr. Albert is attempting to link the ongoing 7-12% T&D line loss reduction from DER with the potential for increased end-use energy consumption from temporary higher-voltage conditions. These are two entirely different concepts.

**Q. Is the increased energy consumption from temporary higher-voltage conditions significant?**

A. APS did not provide data in response to a Vote Solar discovery request that would allow me to answer this definitively.[33] However, since these temporary higher-voltage conditions occur during the times of year when customer demand is relatively low,[34] and APS is only experiencing customer "inquiries" related to voltage on 0.34% of rooftop solar installations, I do not believe this increased energy consumption is significant. Regardless, I recommend using the 7-12% line loss reduction values in the VOS/DER methodology for APS.

## 6.2 <u>Testimony of Mr. Brown</u>

**Q. What does Mr. Brown say about line losses?**

A. Mr. Brown contradicts Mr. Albert's testimony by stating:

> Whether or not rooftop solar systems "reduce the amount of energy lost in generation, long distance transmission and distribution" is a fact specific question. It is flat wrong to claim that solar PV systems, ipso facto, reduce losses. On distribution systems, even the theory underlying this claim is controversial among experts. The truthful answer appears to be that sometimes rooftop solar reduces energy losses on the distribution system, but often does not, and, indeed, could in some circumstances actually cause more losses. The validity of the claimed loss avoidance is very situation specific.[35]

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[32] *Id.* at 24:14–27.
[33] *See* APS Resp. to VS 3.18 (Ex. CV-R-2 at 4).
[34] Albert Direct 25:11–16.
[35] Brown Direct 26:3–9.

**Q. Do you agree with Mr. Brown?**

A. No. While I agree that the specific level of losses is indeed situation specific, as I stated previously, I agree with Mr. Albert's explanation of how solar DG reduces T&D line losses and find APS's 7-12% loss reduction estimate reasonable.

## 6.3 Testimony of Dr. Overcast

**Q. What does Dr. Overcast say about line losses?**

A. Dr. Overcast address line losses frequently in his testimony and states: "Solar DG customers are also likely to have higher costs than their full requirements counterparts because of costs they cause that are not tracked such as higher losses from the low power factor . . . and the higher losses they cause during low load periods."[36]

Dr. Overcast also includes in his testimony an analysis conducted by TEP engineers of line losses during low load, high solar production periods.[37] Specifically, the engineers calculated the impact of one, two, and three 7 kVA solar DG systems on a typical circuit configuration of 8 homes on a single 50 kVA transformer at noon in the month of March. The analysis shows that line losses and transformer loading increase as more solar is added to the typical circuit from energy flowing back through the distribution system during low load, high solar production periods.

**Q. Do you agree with this analysis?**

A. I agree with the analysis, but it fails to illustrate the full impact on line losses from solar DG. During warmer, higher load periods, increasing penetrations of solar can significantly reduce line losses and transformer loading. As the TEP engineers explain in their memo: "Typically, solar can reduce losses during high demand times by lowering transformer loading and reducing current . . . . The highest

[36] Overcast Direct 50:12–16.
[37] Overcast Ex. HEO-3.

values of losses associated with residential solar generation occur when the distribution system's demand is at noon peak and solar production is at its noon peak."[38]

**Q. Can you provide an example to illustrate this?**

A. Yes. Using the same circuit configuration, assumptions, and calculations as the TEP engineers, Exhibit CV-R-1 shows the impact on transformer loading and line losses from one, two, and three solar DG systems at noon on a hot day. I assume each of the eight homes has a demand of 3.5 kVA and, like the TEP engineers' analysis, ignore the impacts of reactive power.[39] Below is a comparison of the TEP engineers' analysis with the illustrative solar DG impacts on a hot day.

**Figure 3: Comparison of distribution line losses on cool and hot days**

| | Cool day | | Hot day | |
|---|---|---|---|---|
| Solar PV Systems per Transformer | Transformer Loading | Losses (W) | Transformer Loading | Losses (W) |
| 0 | 12% | 22.94 | 56% | 499.5 |
| 1 | 2% | 44.2 | 42% | 346.9 |
| 2 | 16% | 107.95 | 28% | 258.5 |
| 3 | 30% | 228.45 | 14% | 89.9 |

This shows that the magnitude of transformer loading and line loss reductions from solar DG during warmer, higher load days is much greater than the impacts during cool days. This analysis of hot day impacts is conservative, since it does not account for losses associated with reactive power and excludes the full distribution primary, substation, and transmission line loss impacts during high load periods.

Since Tucson experiences more warm days than cool days each year,[40] the line loss reductions and transformer loading relief from solar DG is a net positive, and should

[38] *Id.* at 1.

[39] Dr. Overcast has indicated that customers who install DG tend to have larger annual consumption. *See* TEP/UNSE Resp. to VS 1.16 (b), (c) (Ex. CV-R-2 at 6). Data provided by UNSE in Docket No. 15-0142 indicates that 3.5 kVA demand at noon in the summer is a reasonable assumption for larger customers.

[40] *See, e.g.*, Tucson Climate Info., Climate-zone.com, http://www.climate-zone.com/climate/united-states/arizona/tucson/ (last visited Apr. 6, 2016) (Tucson has an average or 2,954 cooling degree days and 1,678 heating degree days each year).

be fully accounted for in the VOS/DER methodology.

# 7 Summary of Recommendations

**Q. Please summarize your recommendations for the Commission**

A. I recommend that the Commission explicitly consider generation capacity and T&D benefits in the VOS/DER methodology. These benefits are real and significant, particularly if DER capabilities are explicitly integrated into distribution planning. I also recommend that the Commission require the utilities to conduct hosting capacity analyses to determine what system enhancements, if any, are required to accommodate increasing penetrations of DER. Finally, I recommend that the VOS/DER methodology fully account for the line loss reductions from DER deployment.

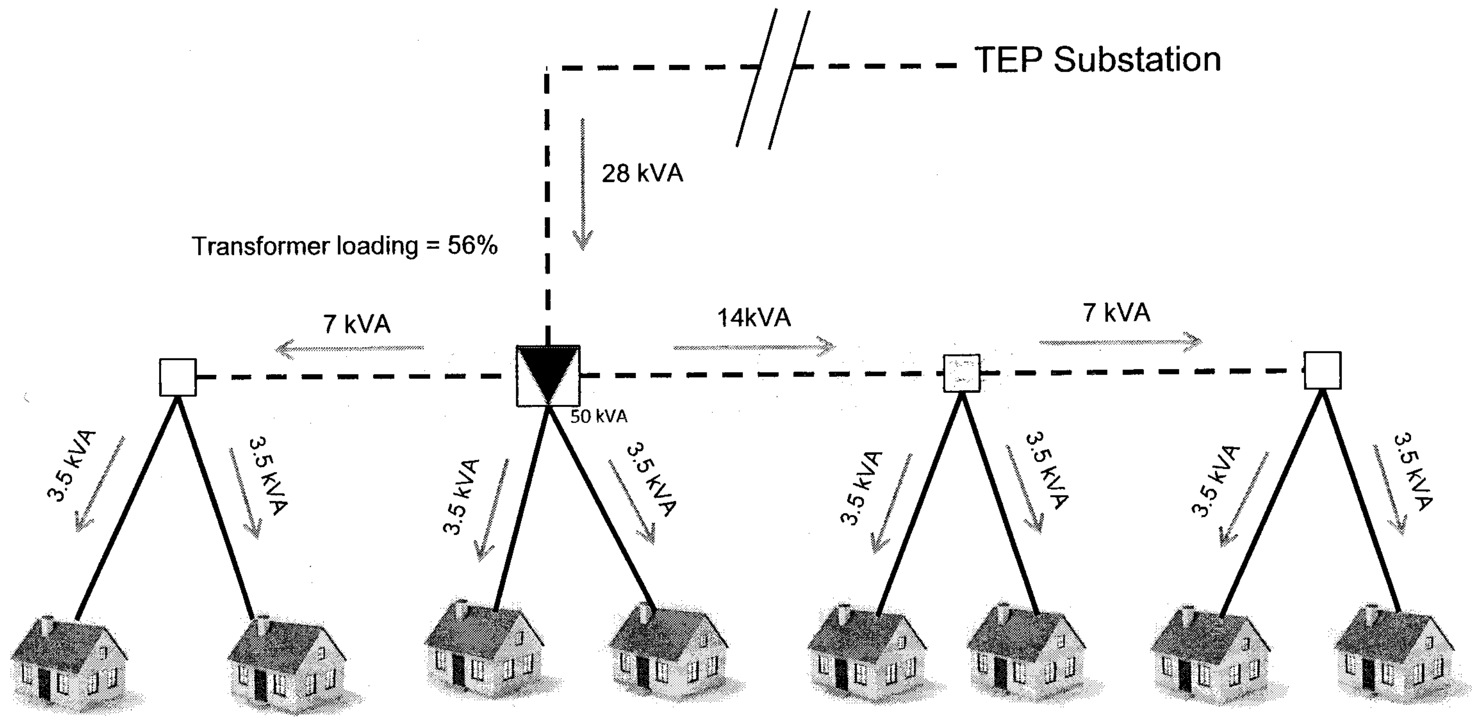
**Q. Does this conclude your testimony?**

A. Yes.

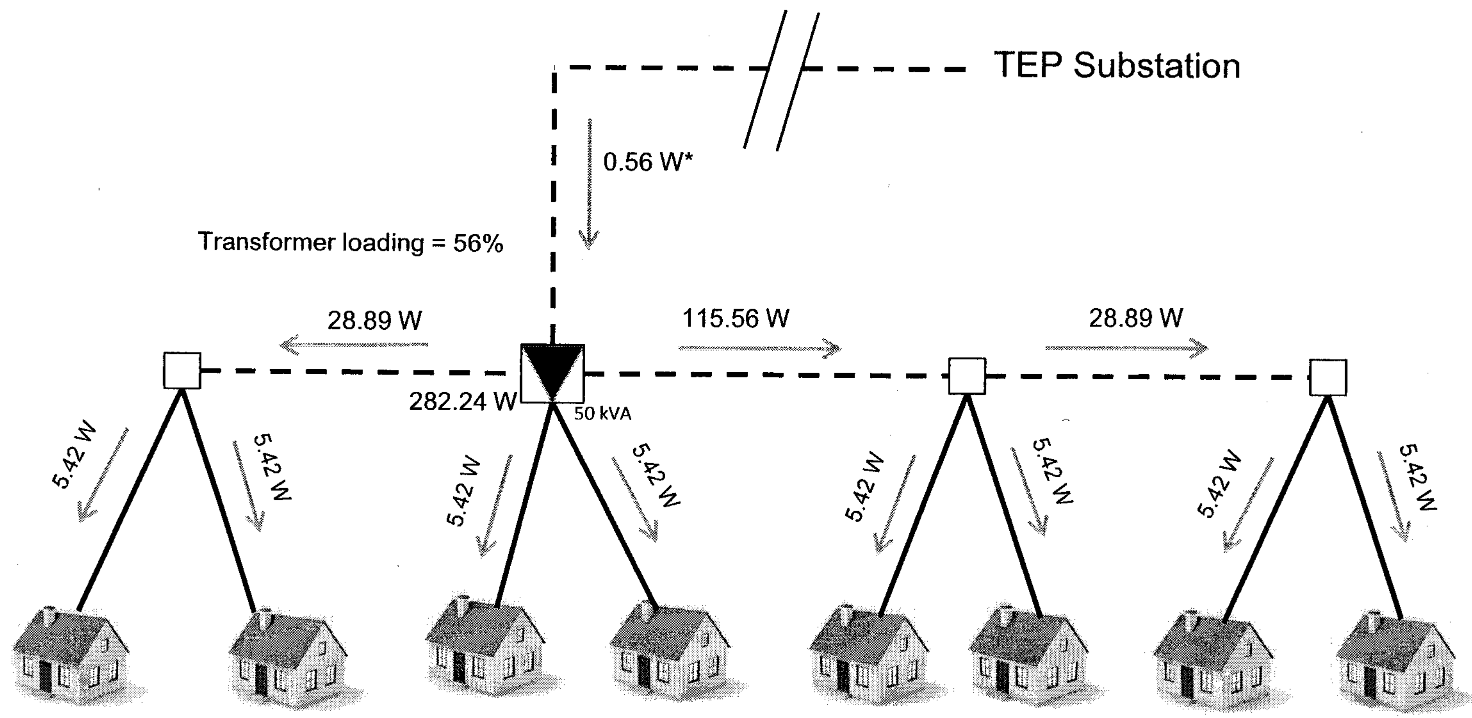
# Exhibit CV-R-1

## Illustrative Line Loss Calculations During Higher Load Periods

# Figure 1 - Loading at noon on a hot day with no Solar Generation



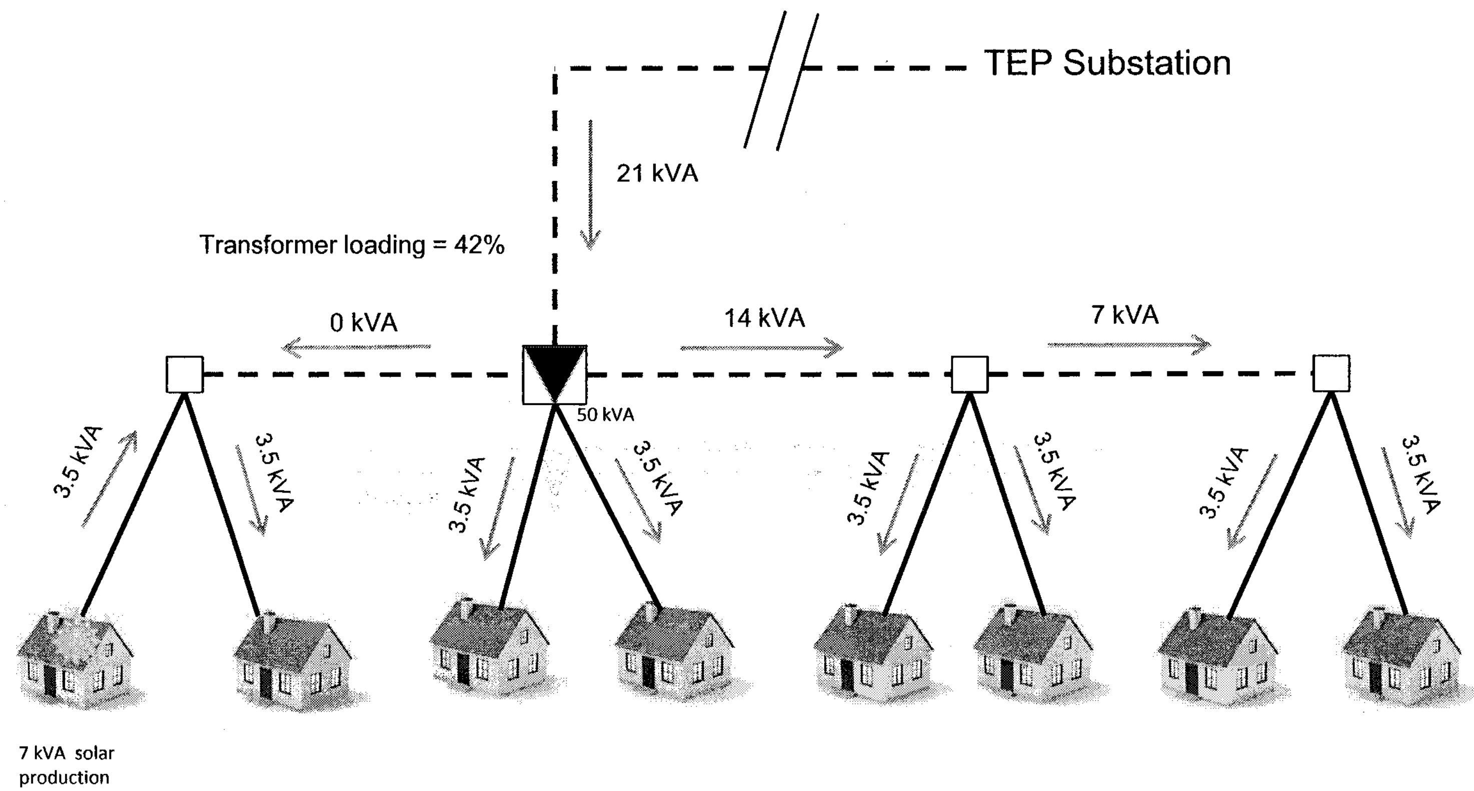
## Figure 2 – Primary/secondary losses at noon on a hot day with no Solar Generation



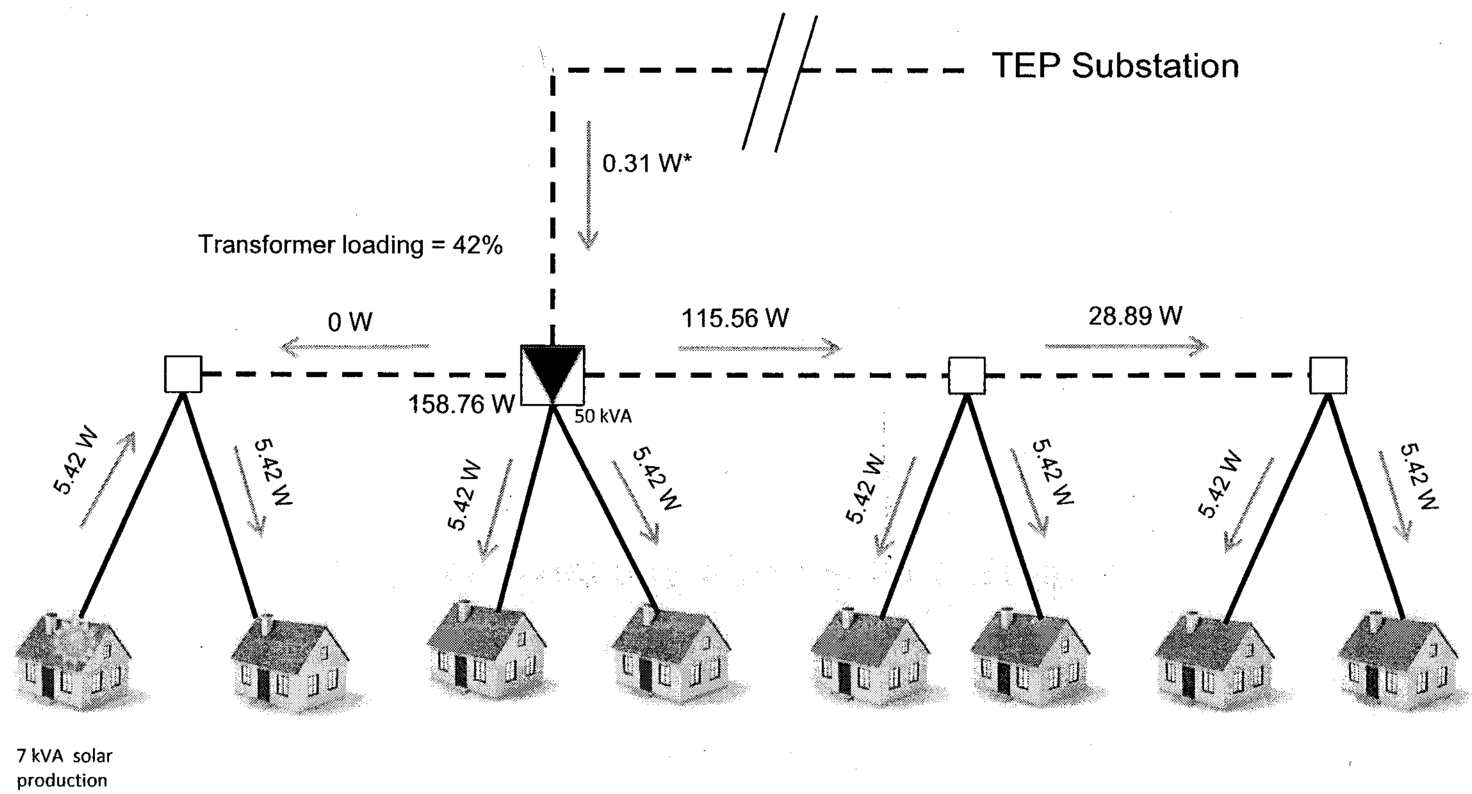

Total primary/secondary losses = 499.5 watts

* - assuming only 400 ft. of primary conductor

# Figure 3 - Loading at noon on a hot day with 1 solar customer



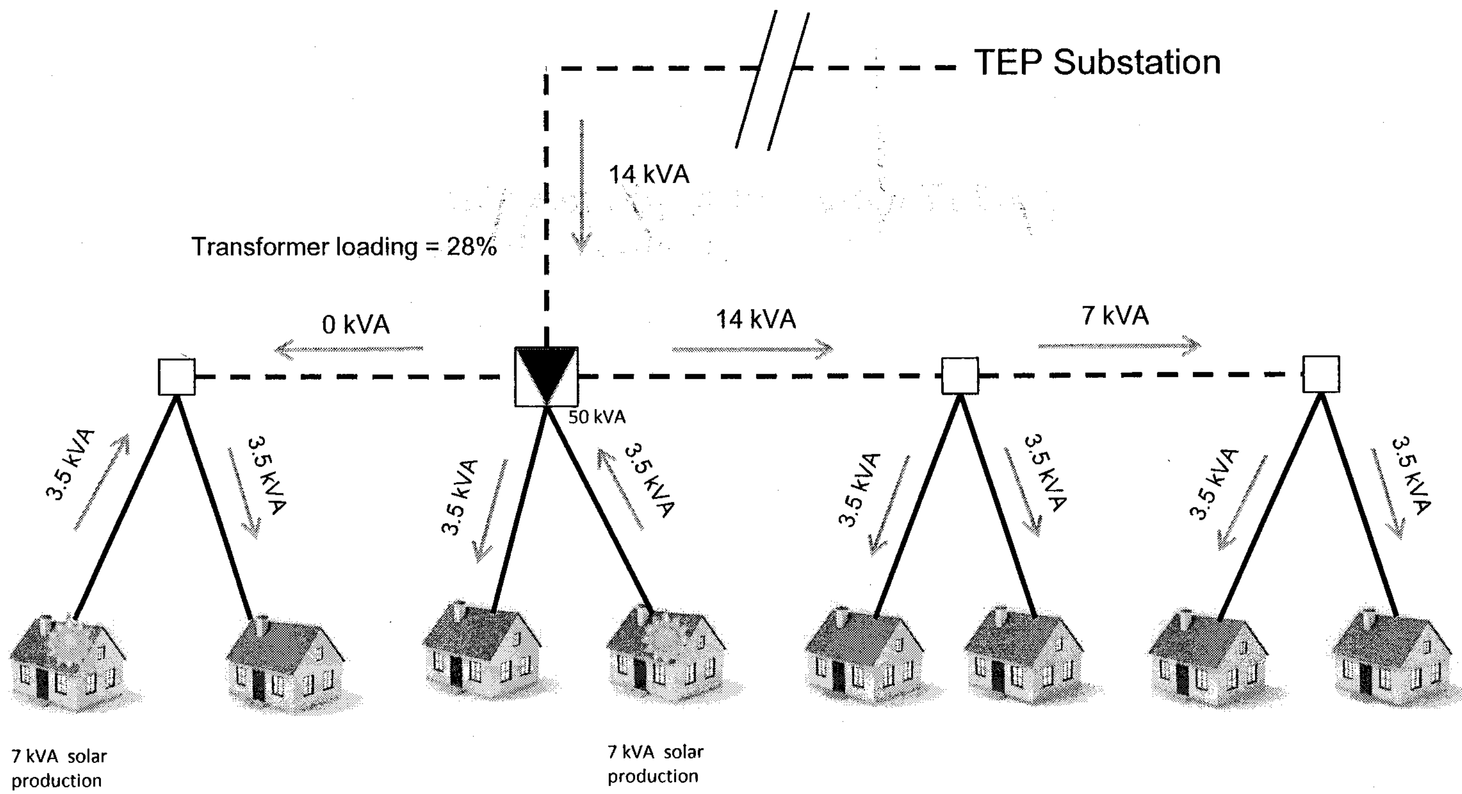
# Figure 4 – Primary/secondary losses at noon on a hot day with 1 solar customer



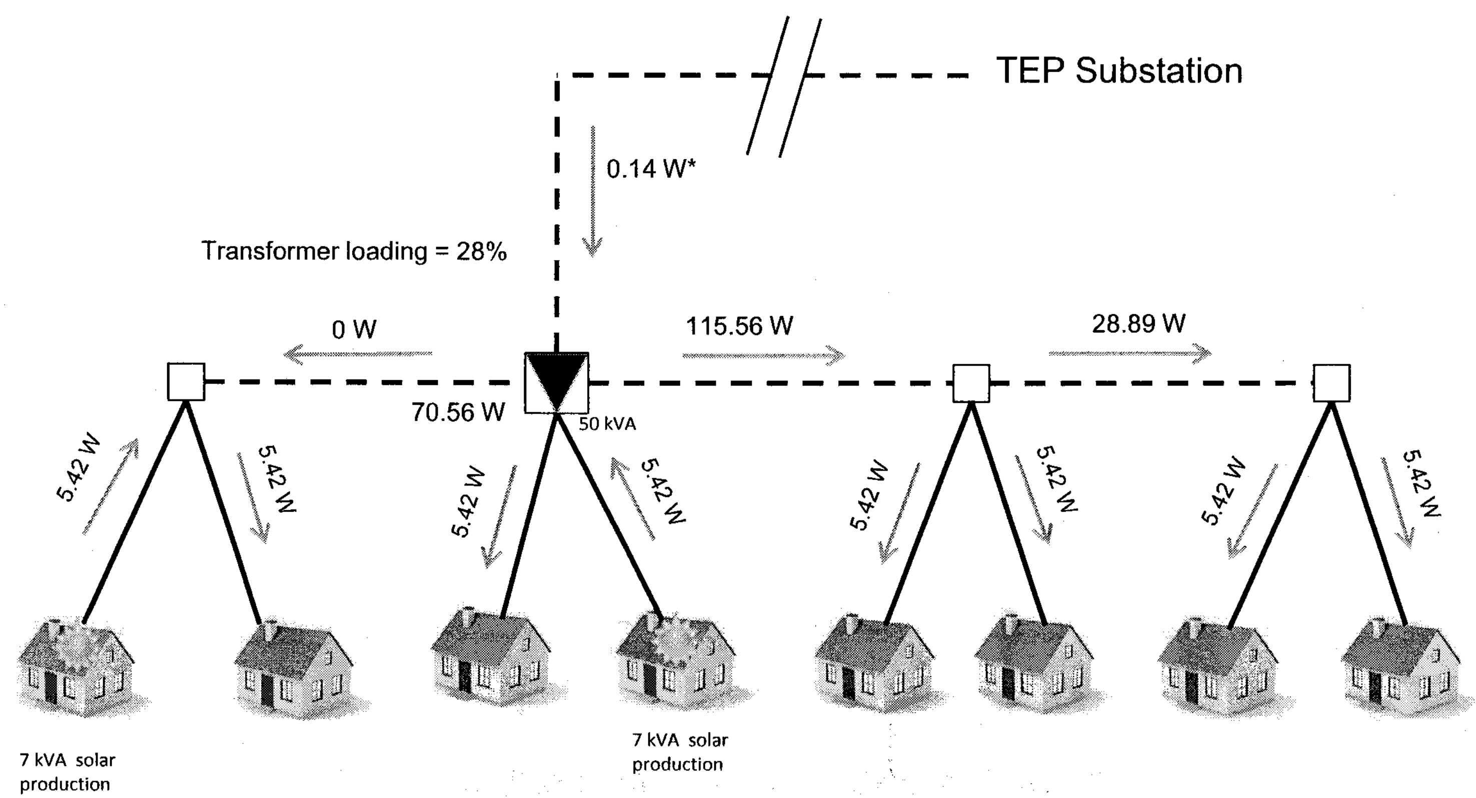

Total primary/secondary losses = 346.9 watts

* - assuming only 400 ft. of primary conductor

## Figure 5 - Loading at noon on a hot day with 2 solar customers



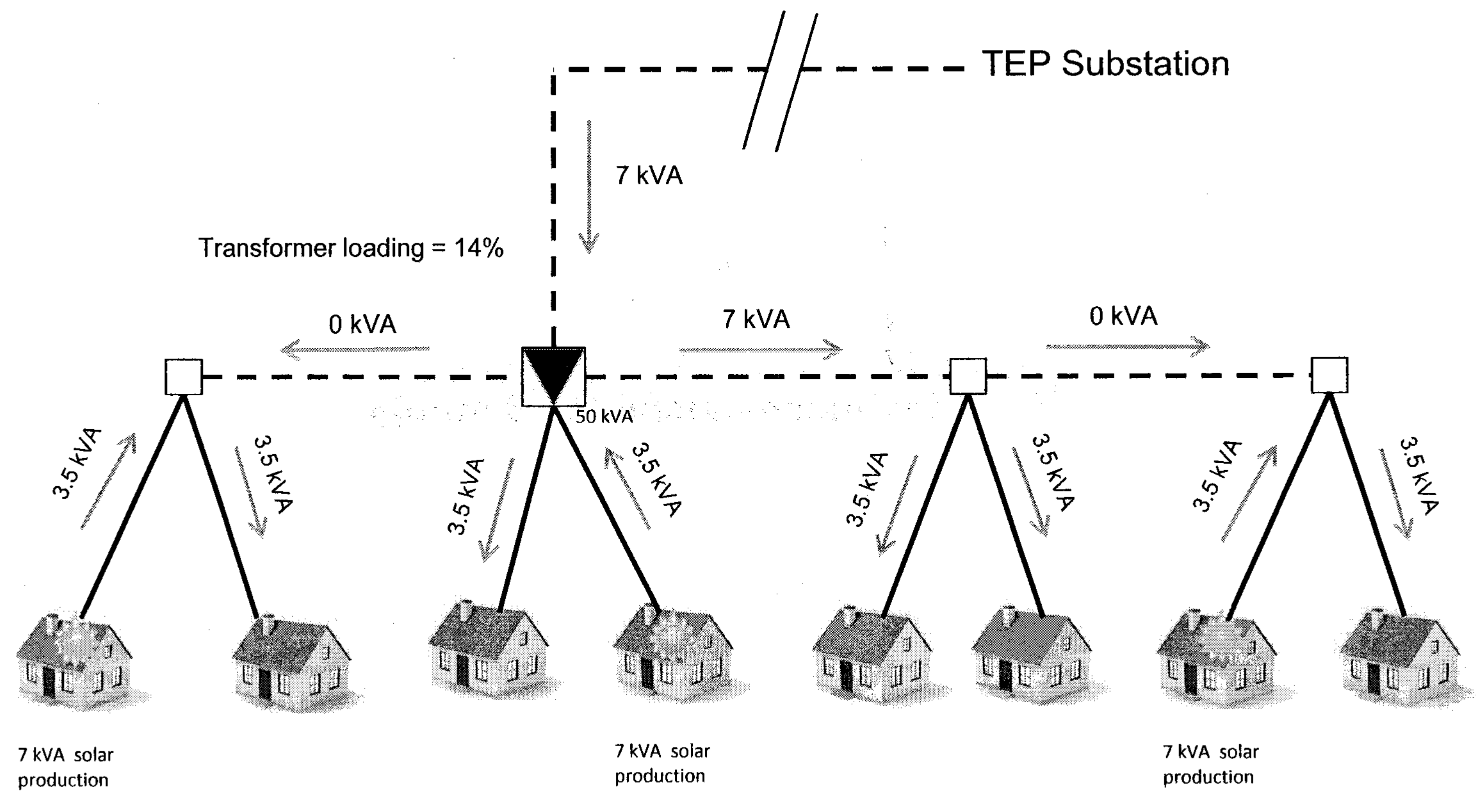
# Figure 6 – Primary/secondary losses at noon on a hot day with 2 solar customers



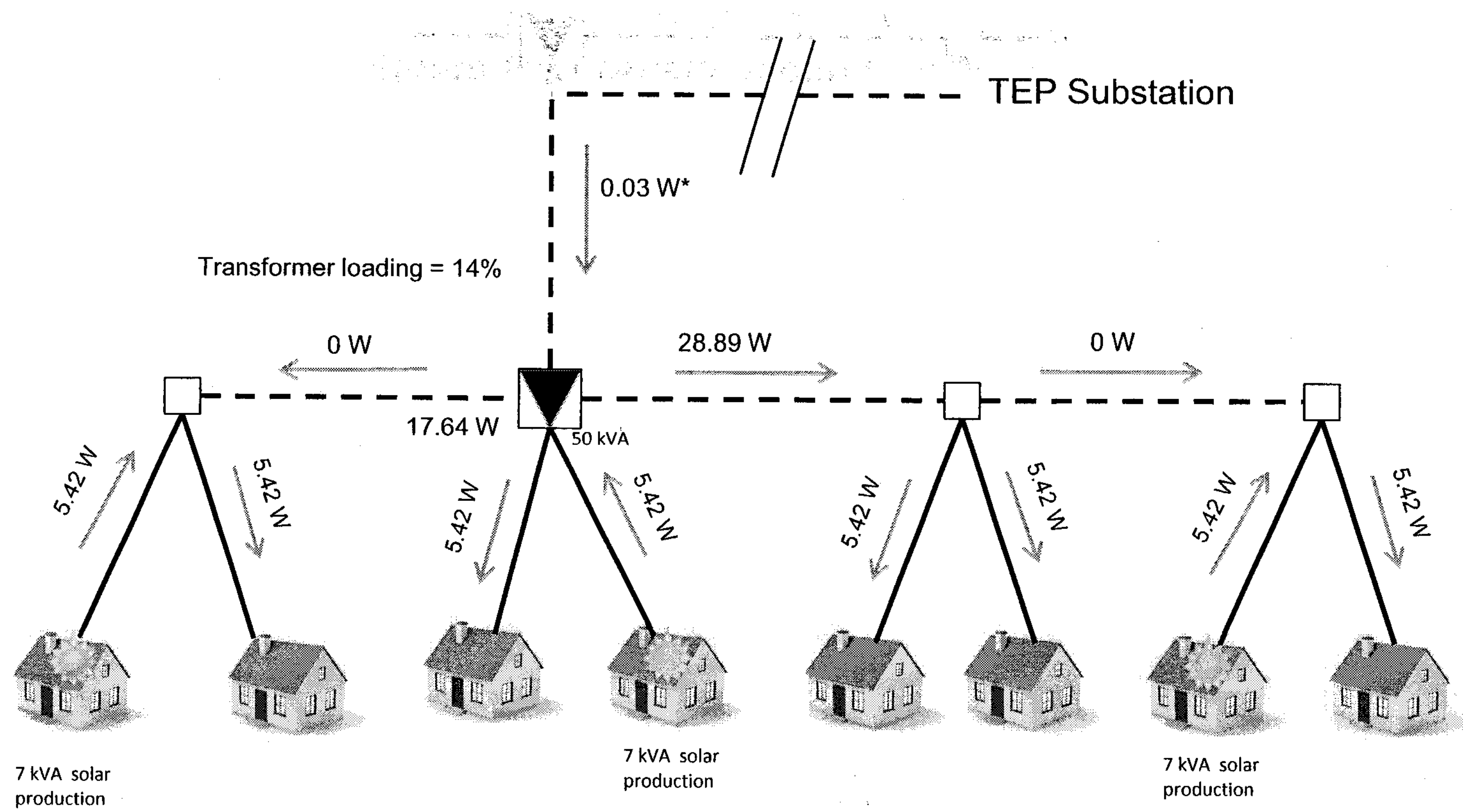

Total primary/secondary losses = 258.5 watts

* - assuming only 400 ft. of primary conductor

# Figure 7 - Loading at noon on a hot day with 3 solar customers



# Figure 8 – Primary/secondary losses at noon on a hot day with 3 solar customers




Total primary/secondary losses = 89.9 watts

* - assuming only 400 ft. of primary conductor

## Figure 9 – Summary of illustrative solar DG impacts at noon in cool and hot seasons

| | Cool day* | | Hot day | |
|---|---|---|---|---|
| Solar PV Systems per Transformer | Transformer Loading | Losses (W) | Transformer Loading | Losses (W) |
| 0 | 12% | 22.94 | 56% | 499.5 |
| 1 | 2% | 44.2 | 42% | 346.9 |
| 2 | 16% | 107.95 | 28% | 258.5 |
| 3 | 30% | 228.45 | 14% | 89.9 |

* - data for cool day (March) from Overcast testimony, Exhibit HEO-3

# Exhibit CV-R-2

## Discovery Responses Referenced in Testimony

ARIZONA CORPORATION COMMISSION
VOTE SOLAR'S THIRD SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY IN THE MATTER
REGARDING THE COMMISSION'S INVESTIGATION OF
VALUE AND COST OF DISTRIBUTED GENERATION
DOCKET NO. E-00000J-14-0023
MARCH 10, 2016

VS 3.11: **Regarding the direct testimony of Mr. Snook**

Please provide a description of the program design and results to date of the Solar Partners Program (ACC Decision No. 74878) referred to on page 17, lines 20-21 of Mr. Snook's direct testimony.

Response: APS Solar Partner is an APS-owned rooftop solar research and development initiative that will help APS enable grid integration of rooftop solar and battery storage while advancing secure communications.

The key design elements of the program are as follows:

- Install rooftop solar on approximately 1,500 homes
- Systems will include smart inverters (UL listing will be achieved by the end of March 2016) and 2-way communications to control each rooftop solar site
- Install 2MW of battery storage on 2 selected feeders
- Collection and analysis of real time data on energy production, energy usage, power regulation capabilities, and curtailment options
- Validate ability to manage solar impacts by configuring smart inverters and issuing real-time commands in a cyber secure environment
- Validate ability to mitigate adverse effects of increased photovoltaic (PV) through enhanced power regulating capabilities
- Validate ability to provide ancillary services from a series of grid-tied batteries in coordination with solar inverters and traditional grid devices
- Collection and analysis of information that helps anticipate, identify, and avoid impacts on the distribution grid
- Validate distribution system models to more accurately and efficiently plan grid upgrades

The status of the program to date is as follows:

- Collaboration with research partners like the Electric Power Research Institute, or EPRI, has been ongoing since 2015, beginning with the collecting and sharing of baseline data on research feeders
- Power quality monitors were installed across the research feeders between December 2015 and February 2016 to provide feeder visibility during the project
- APS established communication and control ability with the

Response to Vote Solar 3.11 continued:

advanced inverters in January 2016

- This control feature will be activated both in the advanced inverters already installed, as well as in those units awaiting installation, starting the first week of April 2016
- Customer interest in the APS Solar Partner project is high
  - As of March 15, 2016, more than 5,300 customers have applied to participate (many more than are eligible)
  - There are currently 1600+ active applications:
    - Operational systems—468
    - Installed, awaiting activation—383
    - Approved for construction—436
    - Awaiting application review or installer assignment for site visits—319
- All systems will be installed (with advanced inverters operational) by the end of June 2016
- Research continues through December 2017

ARIZONA CORPORATION COMMISSION
VOTE SOLAR'S THIRD SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY IN THE MATTER
REGARDING THE COMMISSION'S INVESTIGATION OF
VALUE AND COST OF DISTRIBUTED GENERATION
DOCKET NO. E-00000J-14-0023
MARCH 10, 2016

VS 3.16: **Regarding the direct testimony of Mr. Albert**

Please provide the information requested below regarding the following statement by Mr. Albert on page 13, lines 11–15 of his direct testimony: "APS has begun to experience high-voltage conditions on certain distribution feeders at times of the year when customer demand is low and solar energy production is high on those feeders. This could necessitate the installation of additional equipment to mitigate this condition to maintain reliable service to all customers on those feeders."

a) How many APS feeders are experiencing high-voltage conditions during certain times of the year due to high penetrations of rooftop solar? What percentage of total APS feeders does this represent?

b) How many hours of the year is each feeder experiencing high voltage conditions due to high penetrations of rooftop solar?

c) Please provide details, including equipment type, locations and costs, of all additional feeder equipment installed by APS to date in response to high-voltage conditions from rooftop solar.

Response: APS does not have system-wide voltage measurement capabilities at this time, and therefore cannot answer the specific questions raised in this data request. APS is currently expanding our voltage monitoring capability at all metering sites.

However, APS did receive 95 inquiries in 2015 from customers with installed rooftop solar systems specifically related to substantiated high voltage issues. These 95 customers are located on 68 separate feeders, with 12 of those inquiries on a single feeder (the highest number for any one feeder in 2015). All 12 of these high voltage instances occurred in non-summer months, when customer loads are low, rooftop solar production is high, and rooftop systems are exporting energy to the grid.

To date, APS has not incurred equipment or system costs directly attributable to high voltage concerns due to rooftop solar. Given the increasing penetration of rooftop solar, however, APS anticipates that the severity of high voltage issues will only increase.

ARIZONA CORPORATION COMMISSION
VOTE SOLAR'S THIRD SET OF DATA REQUESTS TO ARIZONA PUBLIC SERVICE COMPANY IN THE MATTER REGARDING THE COMMISSION'S INVESTIGATION OF VALUE AND COST OF DISTRIBUTED GENERATION
DOCKET NO. E-00000J-14-0023
MARCH 10, 2016

VS 3.18: **Regarding the direct testimony of Mr. Albert**

Please provide the information requested below regarding the following statement by Mr. Albert on page 24, lines 23-27 of his direct testimony: "Rooftop solar increases voltage on the distribution feeder during certain times of the year. This higher-voltage level is a function of the quantity of energy produced by rooftop solar, and results in higher overall energy use by customers experiencing these higher-voltage conditions. The result is higher customer energy usage due to higher voltage levels."

a) How many customers are experiencing high-voltage conditions during certain times of the year due to high penetrations of rooftop solar?

b) How much has energy use increased for these customers (in both total kWh and as a percentage of average annual usage) due to high-voltage conditions from rooftop solar?

Response: APS does not have system-wide voltage measurement capabilities at this time, and therefore cannot answer the specific questions raised in this data request. APS is currently expanding our voltage monitoring capability at all metering sites. However, as noted in the Company's response to Vote Solar Question 3.16, APS received 95 inquiries in 2015 regarding high voltage issues from customers with rooftop solar.

ARIZONA CORPORATION COMMISSION
VOTE SOLAR'S THIRD SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY IN THE MATTER
REGARDING THE COMMISSION'S INVESTIGATION OF
VALUE AND COST OF DISTRIBUTED GENERATION
DOCKET NO. E-00000J-14-0023
MARCH 10, 2016

VS 3.23: **Regarding the direct testimony of Mr. Brown**

Please provide the information requested below regarding the following statements made by Mr. Brown beginning on page 35, line 25 of his direct testimony: "It is more likely that rooftop solar will cause more distribution costs than it saves. That is because these generation sources could change voltage flows in ways that will require adjustments and maintenance. It will also inevitably increase transaction costs for the utility to execute interconnection agreements and do the billing for an inherently more complicated transaction than simply supplying energy to a customer. It is impossible, unless perhaps when a rooftop solar host leaves the grid, to envision a circumstance where rooftop solar would effectuate distribution savings."

a) Please provide specific examples and associated costs of adjustments and maintenance conducted by APS in response to changes in voltage flows from rooftop solar.

b) Please provide the full set of data describing the nature, timing, and magnitude of the increased transaction costs incurred by APS to execute interconnection agreements and bill rooftop solar customers.

Response: This statement is a general statement not based on specific analysis of APS data.

**TUCSON ELECTRIC POWER COMPANY'S AND UNS ELECTRIC, INC.'S JOINT RESPONSE TO VOTE SOLAR'S FIRST SET OF DATA REQUESTS REGARDING THE VALUE/COST OF DG INVESTIGATION**
**DOCKET NO. E-00000J-14-0023**
**March 28, 2016**

**VS 1.16**

Please provide the information requested below regarding the following statement by Dr. Overcast on page 17, lines 11–16 of his direct testimony: "Using data prepared by TEP based on hourly load data for about 374 full requirements customers with annual kWh usage above 13,000 kWhs and overlaying their usage with solar loads modeled using the National Renewable Energy Laboratory (NREL) solar data base for Arizona for 24 months from mid-2013 to mid-2015 we reach the same conclusion as found above with respect to the total class of Solar DG customers."

a. Please provide all work papers, data, and analyses to support the above-quoted statement.

b. Please indicate the rationale for the 374 customer sample size and selection and whether this sample is statistically representative of TEP's customers.

c. What is the customer class (i.e., residential, commercial, etc.) of each of the 374 customers in the sample?

d. What is the average annual kWh usage for each of the customer classes that are represented in the 374 customer sample?

**RESPONSE:**

a. See VS 1.16 NCP Residential Summary 13000kWh Plus.xlsx.

b. This was a sample of large users only to test customers who were larger than average since one hypothesis is that solar DG customers tend to be larger than average. The analysis was not used to draw any conclusions related to the population and just represents a subset of larger residential customers.

c. See b. above.

d. The annual average use for the residential class in the test period is about 10,700 kWh.

**RESPONDENT:**

Edwin Overcast

**WITNESS:**

Edwin Overcast

**BEFORE THE ARIZONA CORPORATION COMMISSION**

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

**REBUTTAL TESTIMONY OF BRIANA KOBOR**

**ON BEHALF OF VOTE SOLAR**

**APRIL 7, 2016**

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# List of Tables



# List of Figures

# 1 Introduction

**Q. Please state your name and business address.**

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

**Q. On whose behalf are you submitting this rebuttal testimony?**

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

**Q. Did you submit direct testimony in this proceeding?**

A. Yes, I did. My direct testimony contains an introduction to Vote Solar, as well as a summary of my professional experience.

# 2 Purpose of Testimony and Summary of Recommendations

**Q. Please describe how your testimony is organized.**

A. The remainder of my testimony consists of five main sections. The first section discusses the common ground among parties to this proceeding on analyzing exports and self-consumption separately. The second section discusses the cost-of-service study ("COSS") evidence presented in the direct testimonies of Arizona Public Service Company ("APS") and Tucson Electric Power Company and UNS Electric ("TEP/UNSE"). The third section addresses various proposals for approaching the valuation of distributed generation ("DG"), and discusses why DG should be valued using the long-term avoided-cost approach. The fourth section discusses two issues brought up in the direct testimony of other parties concerning (1) the distribution of DG benefits, and (2) attempts by parties to make rate design recommendations in this docket. Finally, the fifth section summarizes my recommendations.

**Q. Please summarize your findings and recommendations.**

A. First and foremost, I find it is important for the Commission to determine what aims to accomplish in this proceeding. Commissioner Little's letter to the docket indicated that he envisions the following result from this proceeding:

> Development of a methodology that would inform future proceedings as to how the value and cost of solar should be evaluated and determined as part of a rate case. Since the specifics of each rate case are different and can vary widely for each utility and service area, the methodology would not assign specific values, but rather provide guidance as to how values would be determined in the context of an individual rate case.[1]

I fully support this approach and recommend that the Commission keep this vision in mind while evaluating the testimony provided by parties to this proceeding. To this end, I recommend that the Commission not make findings on specific evidence from cost of service studies introduced in this docket, nor analyses of the long-term value of solar. The role of this docket should remain the development of a robust and standardized methodology for the valuation of DG; a methodology that can be employed in future proceedings to develop specific findings for each Arizona utility.

In my review of other parties' testimonies I found there appears to be common ground among several parties on the need to analyze self-consumption and DG exports separately. This approach is supported by Commission Staff ("Staff"), The Alliance for Solar Choice ("TASC"), and Vote Solar, and appears to be in line with statements made by APS. I recommend that the Commission recognize that what truly differentiates DG customers from other utility customers is the ability to export excess energy to the grid. All customers should have the right to make a choice to consume as much or as little energy from their utility as they like—whether they modify their consumption patterns through behavioral change, use of technology (including efficiency and DG), or because their life circumstances change (e.g., their kids go off to college).

[1] Commissioner Little's Letter to the Parties at 1, Dec. 22, 2015 ("Guidance Letter").

As a result, I recommend that the Commission separately consider the value of DG exports and the value of self-consumption, and that this proceeding develop a robust, standard methodology for valuing DG exports. To determine the appropriate rate treatment for utility service to DG customers, these customers should be analyzed in forthcoming utility cost-of-service studies in a fair and transparent way based on well-developed COSS allocation methodologies. Through a separate analysis, appropriate compensation for DG exports should be evaluated over the useful life of the DG system using a long-term avoided cost approach. I do not recommend that the Commission set the export rate precisely at the value determined for solar. Rather, the best approach would be to quantify the value of solar and then to make a policy decision regarding the best export rate level that would ensure the benefits of solar are shared with non-participating ratepayers, while also providing sufficient compensation to incent DG adoption.

I was only able to conduct a limited review of the COSS evidence provided in this docket by APS and TEP/UNSE. APS's COSS evidence in this docket is the product of a proprietary back-end model that does not allow intervenors to fully evaluate the model functionality nor carry out alternate analyses. As a result I was able to review the assumptions made by APS but was not able evaluate how the COSS findings would change if the assumptions were modified. APS found that net energy metering ("NEM") customers shift $29-67 per month in costs to non-NEM customers, but I found significant flaws that overinflate the costs allocated to NEM customers and conflate costs and revenues associated with utility services with compensation provided to NEM customers for exported energy. As a result, I do not find that there is sufficient evidence in this proceeding to support the alleged cost shift calculation put forth by APS.

My ability to review the TEP/UNSE COSS evidence has been even more limited. TEP/UNSE has presented evidence from three TEP-related cost of service studies in this docket but failed to provide Vote Solar with timely access to working COSS models or functioning work papers that would allow for an evaluation of the methodologies and assumptions therein.[2] As a result, my ability to review the reasonableness of the COSS-based evidence, including TEP/UNSE's claim that NEM customers shift $874-967 per year to non-NEM customers has been extremely limited. The limited information from TEP/UNSE that I was able to review indicates that TEP/UNSE's analysis overinflated the cost to serve NEM customers, conflated revenues and costs associated with utility service with compensation paid for exports, and did not appropriately take into account the impact of TEP's request for a $109.5 million revenue increase in its currently open rate case.[3] As a result, there is insufficient evidence in this proceeding to support the alleged cost shift calculation put forth by TEP/UNSE.

In light of my findings that there are significant methodological flaws in APS's and TEP/UNSE's approaches to quantification of the alleged NEM cost shift and the intended scope of this proceeding as indicated by Commissioner Little, I recommend that the Commission not make findings on specific evidence regarding the existence of a NEM cost shift in this proceeding.

I recommend that future cost of service studies evaluated in the context of individual utility rate cases analyze NEM customers in the same manner in which other customers are analyzed: based on delivered load. Utility cost of service studies include standard measures of load for purposes of cost allocation, including energy usage, non-coincident peak demand of the customer class, average and excess demand, etc. These allocation factors are designed to model the load attributes that

[2] In response to discovery due March 30, 2016 and negotiations between TEP/UNSE and Vote Solar regarding the confidentiality of the spreadsheet analyses, TEP/UNSE provided Vote Solar with confidential work papers to its analyses on April 5, 2016, two days prior to the due date for filing rebuttal testimony in this case. I have not had a chance to conduct any substantive review of the work papers in advance of filing this testimony, but may conduct such review in advance of the hearing, and reserve the right to provide additional substantive response to the evidence at that time.

[3] *See* ACC Docket No. E-1933A-15-0322, *In the matter of the application of Tucson Electric Power Company for the establishment of just and reasonable rates and charges designed to realize a reasonable rate of return on the fair value of the properties of Tucson Electric Power Company devoted to its operations throughout the state of Arizona and for related approvals*, Sep. 9, 2015.

cause costs to the utility system and may be used to analyze the cost to serve a utility's NEM customers.

I also recommend that this proceeding develop a robust, standardized methodology for valuing DG exports, and that DG exports be analyzed separately from self-consumption. I review the valuation methodologies discussed by other parties to this proceeding. I find that the short-term avoided cost approach is flawed and would not fully capture the costs and benefits associated with DG. I additionally find that the grid-scale benchmarking approach creates a false comparison between DG and utility-scale solar and does not have merit for consideration as an approach to setting an export rate for DG. I recommend that a robust and standardized methodology be developed to quantify the long-term valuation of DG exports from the perspective of the non-participating ratepayer over the useful life of the DG asset. The results of such an analysis can be used to inform the appropriate compensation of DG customers for energy exports.

I additionally discuss two other issues raised by parties in this proceeding. The first issue relates to a mischaracterization of the empirical evidence regarding income distribution of solar customers. I find that empirical evidence from Arizona demonstrates that DG is being installed across the income spectrum with a proportionate amount of solar installations at the lower ends of the income spectrum. I additionally find that if a robust approach to the quantification of the costs and benefits associated with DG can be used to set a rate for exports that allows a sharing of net benefits between customers that do and do not install DG, all customers will benefit, regardless of income level.

The second and final issue relates to the attempt by parties in this proceeding to affect rate design policy in this docket. I recommend that the Commission determine that this docket is not the appropriate venue for such recommendations and that it would not be appropriate to consider specific rate design proposals absent a body of evidence to support those proposals including utility cost of service studies and bill impact analyses—neither of which have been provided for the rate design recommendations discussed in this case.

# 3 Common Ground Among Parties on Analyzing Exports and Self-Consumption Separately

**Q. Have you reviewed the direct testimony filed by other parties to this proceeding?**

A. Yes. I have reviewed the direct testimony filed by Staff; the Arizona Investment Council ("AIC"); APS; the Grand Canyon State Electric Cooperative Association ("GCSECA"),; the International Brotherhood of Electrical Workers ("IBEW"),; the Residential Utility Consumer Office ("RUCO"); Sulphur Springs Valley Electric Cooperative, Inc. ("SSVEC"),; TASC; and TEP/UNSE.

**Q. Have you identified any areas of agreement among the parties in this proceeding?**

A. Yes. While there are a number of significant disagreements among the parties in this proceeding, it appears that a number of parties support similar positions on analyzing DG exports and self-consumption separately.

**Q. Please discuss the parties' positions on the separate consideration of self-consumption and exports.**

A. Staff witness Howard Solganick addresses this issue directly with the following statement:

> Staff's perspective is based on the concept that what happens behind the meter is the customer's business. Whether load is reduced by conservation, insulation, high efficiency appliances, storage or the installation of a DG system that is solely the customer's right and decision and a proper rate structure will offer accurate price signals to assist a customer making a decision. Any excess energy not needed by the customer can then be delivered to the utility and purchased at its value at the time and location of delivery.[4]

[4] Direct Test. of Howard Solganick 7:8-13 ("Solganick Direct").

TASC witness Beach also recommends "that the appropriate framework for assessing the relative benefits and costs of net metering is to focus on the value that customer receives for the electricity that is exported from their premises."[5]

These statements echo Vote Solar's argument presented in my direct testimony that every customer should have the individual right to choose how much energy to consume or not consume from the utility.[6] In support of this position, Vote Solar has proposed that the methodology for evaluating the costs and benefits of DG focus on the question of "whether the price paid for DG exports appropriately reflects the value of the energy provided."[7] Self-consumption of DG is best addressed in individual utility rate cases.[8]

**Q. Do any of the utilities share this view?**

A. Yes, statements by APS appear to show common ground on this issue. For example, APS witness Snook states:

> [T]he methodology for determining Value of Solar established by the Commission as a result of this docket should be approved as an appropriate analysis tool for determining (i) the value of solar in the resource planning context; and (ii) calibrating the price paid for *energy exported to the grid from rooftop solar arrays*.[9]

**Q. Based on your review of other parties' positions on this issue, do you have any recommendations for the Commission?**

A. I recommend that the Commission recognize that a bright line exists between self-consumption of DG and the energy customers export to the grid. The Commission should explicitly recognize the right to self-consume electricity generated on private property largely through private investment. Based on this recognition, the Commission should ensure that customers who choose to install DG or any other technologies that modify their consumption of utility-delivered energy are treated the

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[5] Direct Test. of R. Thomas Beach at i ("Beach Direct").
[6] Direct Test. of Briana Kobor 8:26-9:2 ("Kobor Direct").
[7] Kobor Direct 8:21-23 (emphasis omitted).
[8], *Id.* 9:12-16.
[9] Direct Test. of Leland Snook 2:9-12 ("Snook Direct") (emphasis added).

same as their next-door neighbors who have not installed such technologies regarding cost-of-service allocation and rate design methodologies, tariffs under which they may take service, and/or any applicable charges imposed by their utility. This proceeding should focus on the appropriate level of compensation for DG exports only. The Commission should seek to develop a methodology for ensuring that the price paid for exports reflects the long-term value of the energy provided from the perspective of the non-participating ratepayer.

# 4 Cost of Service Studies should analyze NEM Customers in a fair and transparent way

**Q. Please describe the COSS evidence put forth by parties to this proceeding.**

A. Witnesses from APS and TEP/UNSE have sponsored cost of service studies purporting to show that a cost shift exists from NEM customers to non-NEM customers. APS claims that NEM customers on two-part rates shift approximately $29-67 per month in costs to non-NEM customers.[10] TEP/UNSE claims that TEP's NEM customers shift $874-967 per year to non-NEM customers.[11]

**Q. Have you been able to evaluate the reasonableness of these utility-reported cost shifts?**

A. Unfortunately, I have not been able to comprehensively evaluate the utility-reported cost shifts because the utilities have not provided data allowing me to do so.[12] I was able to evaluate inputs to APS's COSS and have found it to be based on flawed and inconsistent methodologies. As a result, the APS COSS overinflates the cost to serve

[10] Snook Direct 3:18-22.
[11] Direct Test. of H. Edwin Overcast 5:14-15 ("Overcast Direct").
[12] APS has indicated that they are using a new cost-of-service model with a proprietary back-end. They have provided spreadsheets with inputs and outputs to the model as well as a proxy version of the model, but the proxy version is not linked to the inputs and outputs provided and therefore does not enable a full evaluation nor assessment of results under alternate scenarios. In conversations with APS they indicated that they would not be willing to re-run the model with alternate assumptions in this case.

NEM customers, conflates the cost to serve with the compensation paid for DG exports, and skews the results. While TEP/UNSE has entered testimony in this docket regarding various measures of the cost of service and purported cost shifts, it has failed to provide Vote Solar with functioning copies of the cost of service studies in a timely manner and as a result I have not been able to fully examine the methodologies used, nor the conclusions reached in the testimony of Dr. Overcast.[13] My limited review based on the available information indicates flaws in the TEP/UNSE methodology that overinflate the results. These findings are discussed in detail separately for APS and TEP/UNSE in the following sections.

## 4.1 APS Cost-of-Service Study

**Q. Please describe the approach used by APS to evaluate the costs to serve its NEM customers.**

A. Mr. Snook uses a cost-of-service study based on embedded costs from test year 2014 to evaluate costs to serve APS's NEM customers.[14] Mr. Snook describes the COSS as follows:

> A COSS is the fundamental tool for allocating a utility's costs among its customers based upon their responsibility for incurring such costs. It is foundational in developing appropriate pricing structures that align the rates customers pay for the services received with the customers who are driving the costs. This is often described as the "cost causation principle."[15]

To examine NEM customers specifically, APS grouped its existing NEM customers into two classes: NEM customers on "energy-based" or two-part rates (Schedules E-12, ET-1 and ET-2) and NEM customers on "demand-based" or three-part rates

[13] In response to discovery due March 30, 2016 and negotiations between TEP/UNSE and Vote Solar regarding the confidentiality of the spreadsheet analyses, TEP/UNSE provided confidential work papers to its analyses on April 5, 2016, two days prior to the due date for filing rebuttal testimony in this case. I have not had a chance to conduct any substantive review of the work papers in advance of filing this testimony but may conduct such review in advance of the hearing and reserve the right to provide additional substantive response to the evidence at that time.
[14] Snook Direct 8:3-5.
[15] *Id.* 7:8-12.

(Schedules ECT-1 and ECT-2).[16] APS allocated costs to these groups of customers based on the NEM customer's entire load at the customer's home, including the portion of the load served by APS-delivered energy and the portion served by the energy the customer generated with his/her DG system.[17] APS then applied "credit[s]" to the NEM customers based on APS's assessment of capacity and energy savings resulting from the customer's DG production.[18] Mr. Snook summarizes his discussion of this methodology by stating: "The result is that the COSS analysis only allocates capacity and energy costs to NEM customers based on what APS has to provide."[19]

**Q. Do you support this methodology?**

A. I do not. In APS's own words, the COSS is designed to "align the rates customers pay for the services received."[20] However, allocating costs to NEM customers based on their total site load does not align with the services received. NEM customers' site loads are served only partially by their utility, with their DG systems serving some portion of their loads as well. It is wholly inappropriate to allocate utility costs to NEM customers based on services the utility did not provide. The only appropriate basis for allocating costs in the COSS is allocation based on the services provided by the utility, which for all customers, NEM and non-NEM, is delivered load.

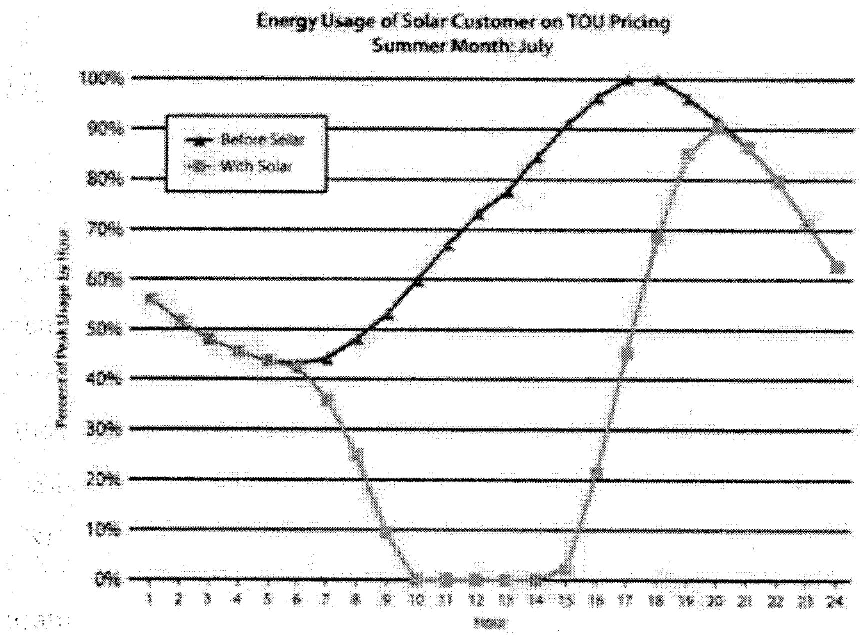
Reaching behind the meter and allocating NEM costs based on total site load (regardless of whether a portion of the load is met by self-generation) is equivalent to allocating costs to a customer for the energy they would have consumed had they not installed energy-efficient windows, or the energy they would have consumed had their kids not gone off to college. When a customer chooses to install new technology or undergoes a lifestyle change that affects their energy consumption, the services

[16] *Id.* 15:9-12.
[17] *Id.* 15:14-17.
[18] *Id.* 15:18-23.
[19] *Id.* 15:26-16:2.
[20] *Id.* 7:9-11.

they require of their utility change. As a result, the utility's service to that customer changes.

Mr. Snook claims that NEM customers have "vastly different load characteristics, [that] warrant evaluating them as a separate sub-class."[21] To support this, he provides a figure depicting hourly energy usage by a NEM customer during July. That figure is copied below for illustrative purposes.

**Figure 1: Figure from APS Witness Mr. Snook's Direct Testimony[22]**




APS's methodology would allocate costs to NEM customers based on the "Before Solar" load shape shown on the top of Figure 1, with measures for crediting the customer based on APS's definition of the energy and capacity value associated with DG production. APS claims this load difference necessitates separate evaluation of NEM customers, but it ignores this difference in the COSS. The only way to fully capture the different load characteristics of NEM customers in the cost-of-service study is to examine the cost to serve those customers based on their delivered load. Delivered load is depicted as the "With Solar" load shape on the bottom of Figure 1.

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[21] *Id.* 12:12-14.
[22] *Id.* 13, fig. 2.

**Q. How do you propose APS evaluate the cost to serve its NEM customers?**

I recommend that APS examine the cost to serve its NEM customers using standard COSS allocation methods based on their delivered load. APS has presented an embedded cost study providing an historical snapshot of utility costs. APS has additionally presented a methodology for allocating those costs to its customers based on a number of standard measures (i.e., energy-related costs are allocated based on kilowatt-hour ("kWh") consumption, distribution costs are allocated based on non-coincident peak and individual customer peak, etc.). This method is widely accepted and may be used to capture the cost to serve groups of customers based on the allocation methods contained therein. Evaluating NEM customer costs based on delivered load would appropriately capture the cost to serve these customers.

**Q. How does your recommended COSS methodology address costs and benefits of energy exports?**

A. It doesn't. My recommended methodology separates self-consumed DG from DG exports. I recommend that the Commission ensure that customers who choose to install DG or any other technologies that modify their consumption of utility-delivered energy be treated the same as their next-door neighbors who have not installed such technologies regarding cost of service allocation and rate design methodologies, tariffs under which they may take service, and/or any applicable charges imposed by their utility. Rates that solar customers pay for energy deliveries from the utility should be based on standard cost-of-service principles and developed through utility cost-of-service studies in the context of individual utility rate cases.

What truly differentiates customers with solar DG from other customers is the DG customers' ability to export energy to the grid. The Commission should recognize that exports are appropriately evaluated separate from self-consumption and should use this proceeding to develop a robust, standardized methodology that would allow the Commission to adjust the DG export rate such that the price paid for exports appropriately reflects the value of the energy provided. To be clear, I do not recommend that the Commission set the export rate precisely at the value determined for solar. Rather, the best approach would be to quantify the value of solar and then to make a policy decision regarding the best export rate level that would ensure the benefits of solar are shared with non-participating ratepayers while providing sufficient compensation to incent DG adoption.

My recommendations are in line with APS's own statements that "compensation to a solar customer for net energy exported to the grid is distinct from the design of that customer's rate as established through a COSS."[23] Separating self-consumed DG from DG exports also recognizes Staff's position that "what happens behind the meter is the customer's business."[24] The costs and benefits associated with energy exports are better addressed through a value of solar study than conflated with cost-of-service ratemaking.

APS states "[a] valid Value of Solar study is a resource planning exercise and should not be conflated with a cost-of-service analysis used for ratemaking."[25] However, their own proposed methodology conflates the two. Rather than heed their own advice by "[u]sing a COSS to set rates [to protect] customers by ensuring that customers pay only for actual costs that they cause,"[26] APS has elected to allocate costs to NEM customers based on services not provided by the utility and to partially credit these customers based on their short-term evaluation of the value of solar. This short-term evaluation of the value of solar is flawed and including it in the COSS does not align with APS's own goals of cost-of-service ratemaking.

**Q. Why do you believe that APS's short-term evaluation of the value of solar is flawed?**

A. APS's short-term evaluation of the value of solar includes two "credits" that are applied to NEM customers in the COSS. The first is a credit for all energy produced by the DG system, both that which is consumed onsite and that which is exported to

[23] *Id.* 28:22-24.
[24] Solganick Direct 7:8-9.
[25] Snook Direct 30:18-20.
[26] *Id.* 29:10-11.

the grid.[27] The second is a credit for self-provided capacity that APS says is based on a comparison between site load and delivered load.[28]

It is not appropriate to allocate costs to NEM customers based on energy they do not consume from the utility, and then to partially "credit" them for that energy. APS's 2014 COSS data show that NEM customers on energy-based rates consumed an average of 14,700 kWh, yet APS only delivered an average 10,600 kWh to those customers. Rather than account for the fact that APS did not provide the difference of 4,100 kWh per customer, APS's methodology instead credits them based on the rate applied to net excess generation under the current net metering tariff (Schedule EPR-6) at a value of 2.895 c/kWh.[29] This approach is akin to allocating costs to a customer who installed a more efficient air conditioning unit based on what they would have consumed absent the new air conditioning unit and crediting them 2.895 c/kWh for their reductions. The more appropriate methodology would be to allocate costs to the customer based on what the utility actually provides: delivered load.

APS's approach to crediting NEM customers for self-provided capacity suffers from similar methodological issues. APS has indicated that this credit is designed to provide NEM customers with a credit for their reduced demand on APS's system.[30] To accomplish this, APS employs a complicated methodology that involves averaging the difference between delivered and site load based on the measures of demand during the system's four summer peaks ("4CP") and non-coincident peak demand. APS claims that "[t]his is consistent with the 'average and excess' method of allocating production demand cost required by the ACC."[31] While it is not clear that this approach is in fact consistent with the average and excess demand method, it also begs the question of why this after-the-fact calculation would be necessary if APS instead employed the average and excess demand method to allocate costs based on delivered load in the first place.

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[27] *Id.* 15:22-23.
[28] *Id.* 15:20-21.
[29] APS's Resp. to Vote Solar 2.3, APS15768 at 1 of 37.
[30] *See generally id.*
[31] *Id.* at 1 of 2.

**Q. Have you evaluated the cost to serve NEM customers based on your recommendation to use delivered load instead of site load?**

A. Unfortunately, I have not been able to carry out an evaluation of the cost to serve APS's NEM customers based on delivered load. It appears APS has chosen to use a new approach to its COSS that involves a back-end proprietary model. While APS has been able to provide spreadsheets showing many of the inputs and outputs to that model and a proxy version that they call the "Cost of Service Working Model," there is no linkage between the various parts of the study.[32] As a result, I was unable to modify the allocation methodology and produce revised results in the COSS; moreover, APS has indicated that it will not re-run the proprietary model using alternative inputs defined by Vote Solar.[33] While this barrier to comprehensive analysis of the COSS by intervenors has troubling implications for APS's upcoming rate case, my understanding of the purpose of this docket is that it is intended to address methodological recommendations, rather than make findings based on results.

However, APS has used results from its COSS methodology to make various claims regarding the existence of cost shifting from NEM customers to non-NEM customers. Namely, APS has alleged that NEM customers on energy-based rates shift $67 per month in costs and NEM customers on demand-based rates shift $29 per month in costs to non-NEM customers.[34] These claims are inaccurate and cannot be relied on for two reasons: (1) the claims are based on a drastic over-allocation of costs to NEM customers, and (2) APS's cost shift estimates conflate costs and revenues associated with services provided by the utility with compensation paid for energy exports under the NEM program.

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[32] APS's Resp. to VS 1.1, APS15747.
[33] Conversation between Vote Solar and APS, March 25, 2016.
[34] Snook Direct 3:18-22.

**Q. Please elaborate on your statement that APS's reported cost shift is based on over-allocation of costs to NEM customers.**

A. I have not been able to verify whether the actual cost to serve APS's NEM customers based on their delivered load characteristics is above or below the revenues they pay for those deliveries. However, comparing the COSS allocators using site load as proposed by APS, and using delivered load as I propose, reveals that APS's method drastically overstates the cost to serve NEM customers.

APS's COSS uses various allocation measures in its evaluation of cost to serve. These measures are based on the following usage characteristics: total energy consumption (MWh); demand coincident with the four summer peaks ("4CP (kW)"); non-coincident peak demand of the customer class ("NCP (kW)"); individual customer peak demand ("Individual Max (kW)"); and the number of customers in the customer class. Each of these allocators, with the exception of the number of customers, is higher when site load is considered instead of delivered load. This implies that COSS allocation based on site load will over-allocate costs to NEM customers. Table 1 and Table 2 compare each relevant allocator using site load and delivered load for NEM customers on energy-based rates and demand-based rates, respectively.

**Table 1: Comparison of Allocators Using Site Load and Delivered Load, NEM Customers on Energy-Based Rates**

| | Energy Consumption (MWh) | 4CP (kW) | NCP (kW) | Individual Max (kW) |
|---|---|---|---|---|
| Site Load Allocation | 1.36% | 2.02% | 1.76% | 1.89% |
| Delivered Load Allocation | 0.99% | 1.46% | 1.65% | 1.71% |
| Difference | 38% | 38% | 7% | 10% |

**Table 2: Comparison of Allocators Using Site Load and Delivered Load, NEM Customers on Demand-Based Rates**

| | Energy Consumption (MWh) | 4CP (kW) | NCP (kW) | Individual Max (kW) |
|---|---|---|---|---|
| Site Load Allocation | 0.09% | 0.12% | 0.11% | 0.11% |
| Delivered Load Allocation | 0.07% | 0.10% | 0.11% | 0.10% |
| Difference | 29% | 28% | 3% | 7% |

As shown in Table 1 and Table 2, allocation based on site load inflates energy-related costs and peak demand-related costs by 28-38%. Because energy- and peak demand-related costs drive roughly 63% of the overall revenue requirement, this is expected to have a significant impact on the assessment of cost to serve NEM customers.[35] Allocation based on site load rather than delivered load also inflates costs related to the non-coincident peak by 3-7% and individual maximum peak by 7-10%. Because APS did not serve site load, it is wholly inappropriate to allocate costs to NEM customers based on site load. The only appropriate methodology for cost allocation is to allocate costs based on the service that the utility provides which is delivered load.

Q. **Please elaborate on your statement that APS's cost shift estimates conflate costs and revenues associated with services provided by the utility with compensation paid for energy exports under the NEM program.**

A. APS's claim that NEM customers shift $29-67 of costs each month is based on a comparison between its assessment of the cost to serve these customers and the revenues received from these customers under the current rate structure. Issues with APS's assessment of the cost to serve these customers are described above. The value for revenues received from customers in APS's cost shift calculation improperly conflates revenue received from NEM customers for delivered energy with compensation provided to NEM customers for exported energy. Under the net metering program, customers are able to offset delivered energy with exported energy, effectively valuing exported energy at the retail rate.

[35] VS 1.1 Cost of Service Working Model 2014TY_APS15748.

For the purpose of evaluating NEM customers in the COSS, it is important to separate revenues received from NEM customers for delivered energy from compensation provided to NEM customers for exported energy. COSS methodologies and findings should address only the services provided to the customer through delivered load and the revenues paid by the customer for delivered load. The costs and revenues associated with energy exports should be evaluated through the Value of Solar approach.

**Q. Please comment on Mr. Snook's comparison of the cost to serve NEM customers in comparison to the cost to serve other subgroups of residential customers.**

A. Mr. Snook has compared cost recovery from apartment dwellers, seasonal customers, and customers with gas appliances to his estimate of cost recovery from solar customers. Mr. Snook makes this comparison in an attempt to make the case that differences in cost recovery from these other customer subgroups reflect the normal variations in energy usage within the class, while solar customers do not.[36] In support of these claims, Mr. Snook presents two figures showing the delivered load shapes of each subclass of customer compared with the average residential load shape. These figures are reproduced below.

[36] *Id.* 24:10-18.

**Figure 2: Residential Customer Usage Comparison, July**

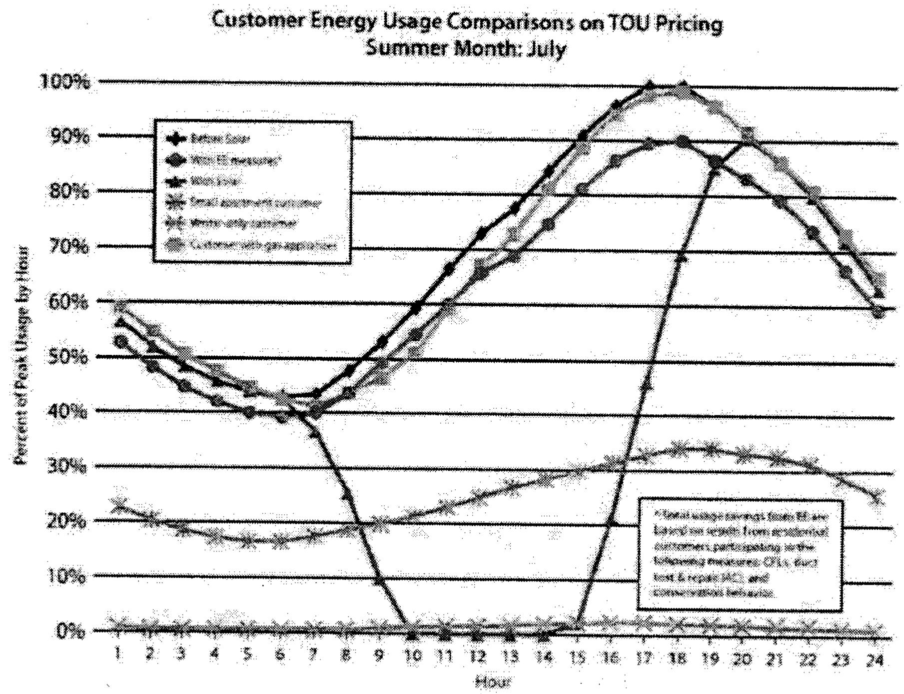
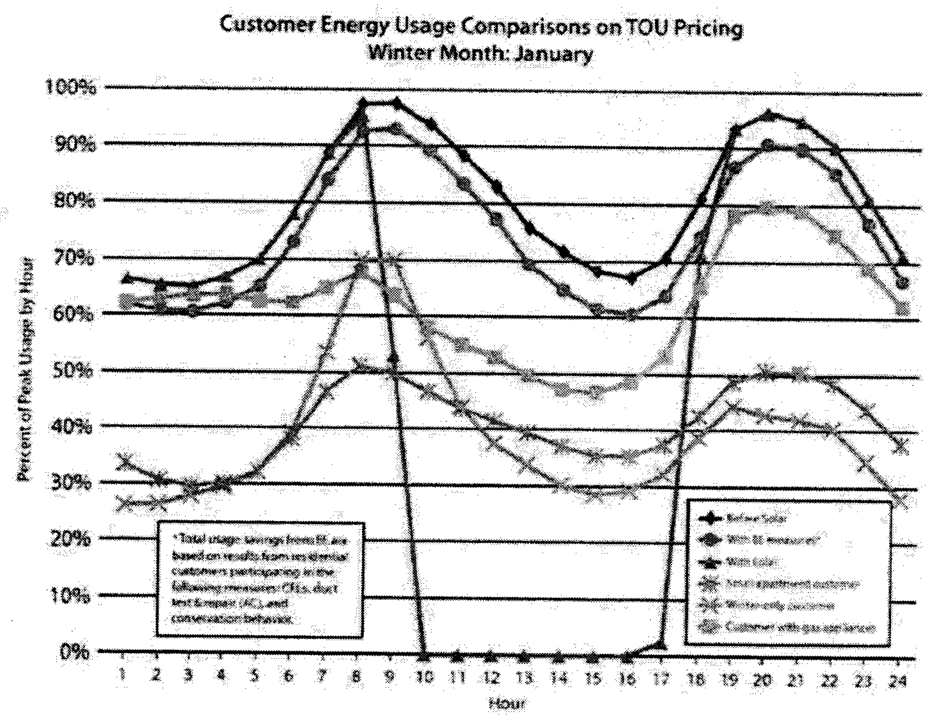



**Figure 3: Residential Customer Usage Comparison, January**



Mr. Snook's estimation of cost recovery from apartment dwellers, seasonal customers, and customer with gas appliances is based on the delivered load to each of those subgroups of customers and the revenues received from those customers for those deliveries. In contrast, his estimation of cost recovery from solar customers is not based on delivered load, but onsite load with partial credits. As a result, this is an apples-to-oranges comparison and cannot reasonably compare cost recovery from solar customers with cost recovery from any of the other subcategories.

**Q. How can an appropriate comparison be made between the cost to serve NEM customers and other subgroups of residential customers?**

A. An appropriate comparison could be made in one of two ways: (1) evaluate cost recovery for all customer subgroups, including solar customers, based on delivered load and revenue received for deliveries; or (2) analyze cost recovery for all customer subgroups based on average residential customer costs with credits applied for sub-class reductions. The second option would entail estimating what the seasonal customer's load would look like if he occupied his residence year-round, and what the customer with gas appliances would consume if she did not have gas service in her home. The second approach would be problematic for obvious reasons and I recommend that the first approach be adopted.

**Q. Please summarize your conclusions and recommendations regarding the APS COSS presented in this docket.**

A. APS's COSS methodology is deeply flawed and should not be approved by the Commission. The only appropriate treatment for NEM customers in the COSS is to allocate costs to those customers based on the service actually provided by the utility, which is delivered load. This approach is consistent with how cost responsibility is allocated to other customers and groups of customers, and it is consistent with APS's own statements regarding the goals of cost-of-service ratemaking.

I additionally find APS's claims regarding a cost shift from NEM customers to other residential customers on the order of $29-67 per month are based on over-allocation of costs to NEM customers and a conflation of cost to serve with the values and costs of energy exports. APS has claimed that their cost shift estimate "affirms the Commission's finding that the cost shift resulting from NEM under current APS residential rate design exists."[37] To the contrary, no evidence exists to support any finding regarding the existence of a cost shift under the current rate design.

## 4.2 <u>TEP Cost-of-Service Study</u>

**Q. Please describe the approach used by TEP/UNSE to evaluate the costs to serve its NEM customers.**

A. TEP/UNSE witness Dr. Overcast has completed a series of three cost of service studies for the TEP system.[38] In his direct testimony, Dr. Overcast described the first study as a "standard cost study with the solar NEM customers' allocated costs just like the residential class based on actual load characteristics of the class."[39] The second study is referred to as the "counterfactual cost study" and analyzes costs that would be incurred if all TEP NEM customers did not have DG.[40] The third study is similar to the first, but includes "a separate class for evaluating the embedded costs of solar DG customers."[41]

**Q. Did TEP/UNSE present any results regarding a cost shift from NEM customers to non-NEM customers?**

A. Yes. Dr. Overcast presented a table of results that provides his estimate of the cost shift at $874-967 per NEM customer per year.[42] This total is based on the sum of four separate categories of costs estimated by Dr. Overcast: (1) "non power supply base rate," which appears to be his estimate of the difference between costs allocated to NEM customers in his COSS analyses and revenue received from those customers;

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[37] *Id.* 33:5-6.
[38] Overcast Direct 21:8-10.
[39] *Id.* 21:21-22.
[40] *Id.* 21:22-25.
[41] *Id.* 22:4-8.
[42] *Id.* 5:4-15.

(2) "banking arbitrage," which is based on his estimates of differing marginal costs associated with delivered energy and exported energy; (3) "excess generation," which applies a short-term value figure to all energy exports and contrasts that value with the full cost of energy embedded in the rate; and (4) "premise use," which is similar in concept to the "excess generation" figure though is based on energy consumed onsite.[43] My ability to review each of these categories has been severely limited by TEP/UNSE's failure to provide timely access to the models on which they are based. However, I have reviewed the available information and have identified issues with each of these categories.

**Q. What are the issues associated with Dr. Overcast's estimate of the difference between costs allocated to NEM customers in his COSS analyses and the revenues received from those customers?**

A. Dr. Overcast's estimate of a $729-822 annual per-customer cost for this category is based on the difference between two figures: (1) the cost of service for solar customers identified in the COSS models, and (2) the revenue received from NEM customers.[44] The first figure is the result of the COSS analysis completed by Dr. Overcast. The range reflects the difference between results from his "base COSS" and the "solar class COSS."[45]

**Q. Have you been able to evaluate the reasonableness of the COSS results?**

A. I have not. The reasonableness of any COSS results depends on the methodologies and assumptions employed in the specific study. One of the most critical assumptions in terms of differentiating the cost to serve various customer subgroups is the COSS allocation methodology. Unfortunately, TEP/UNSE failed to provide Vote Solar with functioning copies of the cost-of-service studies in a timely manner. As a result, my ability to analyze the methodologies employed in each of the three studies has been extremely limited.

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[43] *Id.* 5:4-15 Tbl. 1, 33:14-21, Ex. HEO-8.
[44] *Id.* 33:15-18 & nn. 5-6.
[45] *Id.*

TEP/UNSE provided a work paper in Adobe PDF format that purports to show the allocation factors used in each of the cost of service studies[46]; but the values shown in this work paper are inconsistent with the values shown in Exhibit HEO-8 of Dr. Overcast's testimony, which purports to show the inputs and results of the energy cost study.[47] As a result I cannot verify what measure (site load, delivered load, other) TEP/UNSE used to allocate costs to NEM customers in the various cost of service studies presented in the testimony of Dr. Overcast.

**Q. What implication does this have regarding the reasonableness of the COSS results?**

A. As I stated earlier in the section regarding APS's COSS, the only reasonable approach to an analysis of the cost to serve NEM customers as a separate group of customers is to allocate costs to these customers based on standard allocation measures applied to the load actually served by the utility. For all types of customers, NEM and non-NEM, this means the COSS must allocate costs based on delivered load.

Exhibit HEO-8 indicates that the annual delivered load to TEP's solar customers based on metered billing data was roughly 73 million kWh.[48] The "base COSS" appears to have used a higher value for annual kWh cost allocation and the "solar class COSS" appears to have used a lower value.[49] This indicates to me that costs were likely allocated on something other than delivered load, which would skew the results.

**Q. Have you been able to evaluate the reasonableness of the revenue Dr. Overcast compared with costs to quantify the alleged cost shift?**

A. Yes. Dr. Overcast used a figure of $3,352,194 in revenues from residential NEM customers,[50] and has indicated that this number was provided to him by TEP based on

[46] TASC 1.1 TEP Datasheet v5, Feb. 8, 2016.
[47] Overcast Direct 22:4-8, Ex. HEO-8.
[48] *Id.* Ex. HEO-8 Tbl. 1.
[49] *See id.* at **Error! Reference source not found.**.
[50] Overcast Direct 33:14-15.

actual revenues collected from TEP NEM customers during the rate case test year.[51] This implies the revenues on which the cost shift calculation was based reflect actual billed costs, while the cost to serve was calculated based on TEP's most recent rate case filing that includes a requested $109.5 million non-fuel revenue requirement increase.[52]

There are two issues with this methodology. The first is the same issue that is present in APS's cost shift analysis: the revenues to which costs are compared conflate revenues received by the utility for deliveries with the compensation awarded to the NEM customer for energy exports. To understand the relative cost to serve NEM and non-NEM customers, deliveries must be analyzed separately from exports. Allocating costs based on deliveries or site load and comparing those costs to revenues received net of compensation for exports will inflate the purported cost shift.

The second issue with this methodology is that it does not put NEM customers on equal footing with non-NEM residential customers in terms of cost recovery. In TEP's open rate case, the Company has requested an increase in the non-fuel revenue requirement of $109.5 million.[53] TEP's application indicates that this request would result in an increase of over 12% in adjusted test year revenues.[54] It is not surprising that costs allocated to NEM customers based on a total revenue requirement 12% higher than the revenues used to develop current rates would show an under-recovery of costs. In fact, I would expect Dr. Overcast's analysis to result in a showing of cost-shift for the non-NEM residential class as well.

In order to appropriately compare cost to serve with revenues to ascertain the magnitude of the potential cost shift, NEM customer cost recovery must be compared on equal terms with non-NEM customer cost recovery. This methodology was used in the APS study and should be applied to the TEP study as well. Dr. Overcast's

[51] Conversation with Dr. Overcast April 2, 2016. Dr. Overcast informed me in a telephone conversation that this number was provided to him by TEP based on actual revenues collected from TEP NEM customers during the rate case test year.
[52] *See* TEP Rate Case Appl. 1:14-16, No. E-1933A-15-0322.
[53] *Id.*
[54] *Id.*

comparison of NEM cost to serve based on TEP's rate case request with revenues received based on prior-approved rates overinflates the resulting assessment of the cost shift.

**Q. Have you assessed the reasonableness of Dr. Overcast's estimates of cost shift associated with "banking arbitrage," "excess generation," and "premise use"?**

A. Again, due to the limited data TEP/UNSE provided, I have only been able to conduct a limited review of these alleged cost shift categories. Dr. Overcast indicates that his analysis for these categories was based on the energy cost analyses conducted outside of the cost of service studies and presented in Exhibit HEO-8.[55] Because TEP/UNSE declined to provide any work papers supporting Exhibit HEO-8, it is difficult to assess the reasonableness of the calculations therein. In addition, little to no explanation of the methodology or meaning of each of these cost shift categories is provided in the body of the testimony.

Based on the brief descriptions of the methodology provided in Exhibit HEO-8, it appears that the value for "banking arbitrage" is based on an estimate of the differing marginal costs associated with delivered energy and exported energy. Exhibit HEO-8 indicates that the average marginal cost associated with DG exports was $24.62/MWh, while the average marginal costs associated with deliveries to DG customers was $26.97/MWh.[56] It is unclear precisely what data were used to conduct this analysis. However, in the recent UNSE rate case, Dr. Overcast made a similar claim, stating, "excess generation sold back to the utility occurs on average at times when the avoided energy cost is less than the average energy cost and less than the marginal cost of energy used by solar DG customers to meet the load in excess of solar DG."[57] In the UNSE rate case, Dr. Overcast provided the work papers to support this statement; however, it was found that the work papers did not provide support for

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[55] Overcast Direct, Ex. HEO-8 tbl. 2.
[56] *Id.*
[57] Overcast Rebuttal Test. 13:9-14, No. E-04204A-15-0142, Jan. 19, 2016.

his conclusion.[58] In fact, when other available data from the docket were examined, it was found that the average marginal cost during hours of energy exports actually exceeded the average marginal cost during hours associated with deliveries.[59] While a contradictory finding based on UNSE data does not indicate that Dr. Overcast's finding based on TEP is incorrect, it does indicate that the result should be closely examined prior to adoption by the Commission.

Descriptions of the other two categories of alleged costs—"excess generation" and "premise use"—appear to be based on comparison of the full retail rate with different levels of short-term valuation of energy exported to the grid and consumed onsite.[60] The short-term valuation of energy exports appears to be based on the average marginal cost associated with deliveries to DG customers while the short-term valuation of onsite DG consumption appears to be based on avoided fuel cost.[61]

**Q. Do you have any comments about the inclusion of the three energy cost categories in the cost shift assessment?**

A. While Dr. Overcast's methodology for allocating energy-related costs to NEM customers outside the COSS is considerably more complicated than the methodology employed by APS to allocate energy-related costs to NEM customers within the COSS, it appears Dr. Overcast's approach suffers from similar methodological flaws. By assigning costs to NEM customers based not only on load consumed onsite, but also total embedded costs associated with energy exports, Dr. Overcast's approach unfairly assigns costs to NEM customers based on services not provided by the utility. The more appropriate methodology would be to include energy-related costs in the COSS and to allocate energy-related costs to NEM customers based exclusively on delivered load. The long-term costs and benefits he associates with energy exports should be considered through the value of solar analysis separate from the COSS.

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[58] Surrebuttal Test. of Briana Kobor at 15:17-21, No. E-04204A-15-0142 ("Kobor Surrebuttal").
[59] Kobor Surrebuttal 15:21-16:5.
[60] Overcast Direct, Ex. HEO-8 Tbl. 1.
[61] *Id.* Tbl. 2.

**Q. Do you have any comments on TEP/UNSE's use of the counterfactual cost of service study?**

A. TEP/UNSE witness Mr. Tilghman has indicated the Companies recommend use of a counterfactual COSS "that assumes away the existence of NEM customers' power generation"[62] as part of a "more comprehensive [value of solar ("VOS")] model."[63] Dr. Overcast's testimony presents the results of such a counterfactual COSS.[64] Notably, the results of the counterfactual COSS do not appear to be used in Dr. Overcast's assessment of the alleged NEM cost shift, and it is not clear how he recommends that the results of such an analysis be used to set rates.

I do not recommend the counterfactual COSS approach for a number of reasons. First, the entire premise of comparing hypothetical costs based on the assumption that DG never existed is problematic. Development of such a study requires assumptions of what NEM customer consumption and utility costs would have been had customers never made the decision to invest in DG resources. This would create challenges associated with NEM customer load shape determination as well as quantification of how utility costs would have changed but for the DG assets offsetting a portion of customer load. In addition, the counterfactual COSS approach limits consideration of the costs and benefits associated with DG to the COSS test year, while the benefits of DG investment will accrue over the useful life of the system. This approach is unlikely to fully capture the costs and benefits associated with DG.

The preferred approach would be to consider the cost to serve NEM customers based on delivered load characteristics in the context of the traditional utility COSS and to evaluate the long-term costs and benefits associated with DG exports through the valuation of solar analysis using the methodology adopted in this proceeding.

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[62] Direct Test. of Carmine Tilghman 7:6-8 ("Tilghman Direct").
[63] Tilghman Direct 6:5-9.
[64] Overcast Direct 33:6.

## 4.3 Conclusions regarding the role of COSS-based evidence and methodological recommendations in this docket

**Q. Have you reached any conclusions regarding the COSS-based evidence presented in this docket?**

A. Yes. First, I do not believe sufficient evidence has been provided to support the alleged cost shift figures put forth by either APS or TEP/UNSE in this docket. A review of the methodology employed to arrive at APS's estimated $29-67 monthly cost shift reveals the underlying analysis overinflates the cost to serve NEM customers and conflates the costs and revenues associated with delivered energy with the compensation awarded to NEM customers for energy exports. Due to APS's adoption of a proprietary COSS model, I have been unable to determine what level of cost shift, if any, would result from adoption of my recommended methodological corrections.

My review of TEP/UNSE's alleged $874-967 annual cost shift figures was unfortunately limited by TEP/UNSE's failure to provide timely access to functioning work papers to support the analysis. However, information provided in the testimony and the PDF work papers indicates that the TEP/UNSE analysis likely suffers from similar methodological issues resulting in an over-inflation of the assessment of the cost to serve NEM customers. Moreover, the analysis includes an inaccurate comparison of costs with revenues, which conflates revenues from deliveries with compensation for exports and does not compare NEM customers on equal footing with non-NEM customers in terms of expected cost recovery in light of the large revenue increase requested in TEP's open rate case.

Commissioner Little has been clear in his guidance for this docket that he envisions the following outcome of this proceeding:

> Development of a methodology that would inform future proceedings as to how the value and cost of solar should be evaluated and determined as part of a rate case. Since the specifics of each rate case are different and can vary widely for each utility and service area, the

> methodology would not assign specific values, but rather provide guidance as to how values would be determined in the context of an individual rate case.[65]

Keeping with Commissioner Little's statement and in light of the lack of evidence provided to support the alleged cost shift attributable to NEM customers, I do not recommend that the Commission adopt any specific COSS findings in this docket.

**Q. Do you have any recommendations regarding the methodology for determination of the cost to serve solar customers in the context of a utility COSS?**

Both APS and TEP have requested that the Commission adopt their proposed COSS methodologies in this proceeding. I have identified several significant flaws in these proposed methodologies and offer the alternative recommendation that all customer groups be evaluated in future cost of service studies in a fair and transparent way based on the services they are provided by the utility. This means that cost allocation for all customers, NEM and non-NEM, must be consistent and based on delivered load. In addition, I recommend DG exports be considered separate from the COSS and evaluated based on a long-term avoided cost analysis as I discuss in the next section.

# 5 The value of DG exports must be based on long-term avoided costs to the non-participating ratepayer

**Q. What approaches to the valuation of DG have been discussed by parties in this docket?**

A. There are three approaches to the valuation of DG that have been discussed by parties in this docket: (1) short-term avoided cost, (2) grid-scale benchmarking, and (3) long-term avoided cost. In my opinion there are significant flaws with both the short-term

[65] Guidance Letter at 1.

avoided cost and grid-scale benchmarking approaches. I recommend that the Commission adopt the long-term avoided cost approach.

## 5.1 Short-term avoided cost approach

**Q. What is the short-term avoided cost approach to the valuation of DG?**

A. In general, the short-term avoided cost approach seeks to evaluate the costs and benefits of DG over the near-term. An example of this was provided in APS's testimony, where APS described a methodology for evaluating short-term avoided costs based on a year's worth of historical data.[66]

**Q. What do proponents argue are the merits of the short-term avoided cost approach?**

A. APS witness Albert implies that the short-term approach would avoid potential issues due to future failure of DG suppliers to maintain a resource that is available and capable of producing power over the expected life of the system.[67]

TEP/UNSE witness Dr. Overcast states that payment of levelized cost in the long-term approach "is inconsistent with rates and creates issue[s] of intergenerational equity and potential excess payments since solar DG has no obligation to operate at rated capacity over its useful life."[68] He additionally claims that inclusion of future energy costs would create an inter-temporal subsidy to the extent that future benefits are reflected in current rates.[69] Finally, Dr. Overcast states:

> The only way to provide for efficient outcomes is to separate the capital and the energy components of the payment stream. Energy payments based on short run costs is the exact same way that utility generation recovers energy costs. Over the life of some power plants that energy cost moves up and down with competitive input prices. There is no economic reason that solar DG should be any different

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[66] Direct Test. of Bradley Albert 17:22-18:27 ("Albert Direct").
[67] *Id.* 19:9-19.
[68] Overcast Direct 46:23-25.
[69] *Id.* 45:26-46:3.

> than a competitive power plant that bears the fuel cost risk in the short term.[70]

**Q. Do you agree with these statements?**

A. No. Mr. Albert's and Dr. Overcast's criticisms are based on the premise that evaluating DG over the long-term would create some sort of risk of long-term benefits not being realized if the DG customer were to fail to deliver as expected. But this is not unique to DG. It is standard practice to evaluate the long-term benefits and costs of utility investments, such as power plants and transmission lines. Often the decision is made to invest in these large projects in advance of the actual need for the total capacity the investment would provide. In any such case, one could argue that "inter-temporal inequities" exist from placing such investments in a utility rate base in advance of their need. Moreover, in the case that expected benefits of utility investments do not materialize, ratepayers are often still obligated to pay for the investment. If the utility provides the DG customer with compensation for the excess energy from their DG system that is linked to energy production, there is no reason to believe that any significant number of DG customers would fail to perform over the useful life of the system. While parties have raised future performance of DG as a hypothetical issue, none has provided evidence in this docket to support their theories.

In addition, Dr. Overcast's claim that "[e]nergy payments based on short run costs is the exact same way that utility generation recovers energy costs"[71] ignores the fact that the majority of utility-scale power purchase agreements ("PPA") for renewable generation are 10-20-year fixed or escalating contracts. Indeed, there is no economic reason for compensating DG at short-term avoided costs based on fluctuations in fuel markets when "competitive power plants" are routinely offered long-term fixed-price contracts.

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[70] *Id.* 47:25-48:4.
[71] *Id.* 47:26-48:1.

**Q. What do you conclude regarding the short term avoided cost approach?**

A. The short-term avoided cost approach is not recommended for the valuation of the costs and benefits of DG exports. Indeed, neither APS nor TEP/UNSE appear to directly endorse this method either. Valuation of the costs and benefits of DG based only on the short term would ignore many significant benefits associated with DG that only accrue over the longer term. Compensation for exports that does not take into account the long-term benefits would result in a suboptimal level of DG deployment from the perspective of the non-participating ratepayer and society.

## 5.2 Grid-scale benchmarking approach

**Q. What is the grid-scale benchmarking approach to valuation of DG?**

A. Again, there is some variation in the exact methodology for the grid-scale benchmarking approach. TEP/UNSE has proposed a type of grid-scale benchmarking in the open rate cases for both TEP and UNSE.[72] TEP/UNSE's proposals are to link the price paid for DG exports to the price of the most recent utility-scale PPA signed by either TEP or UNSE and connected to the TEP/UNSE distribution system. In addition, APS witness Albert introduces the concept of a grid-scale benchmarking methodology in his testimony, which includes benchmarking the price of utility-scale PPAs and making adjustments for various "valuation differences" between grid-scale and rooftop solar.[73]

**Q. What do proponents argue are the merits of the grid-scale benchmarking approach?**

A. The main arguments in support of a grid-scale methodology are centered on the idea that utility-scale solar photovoltaic ("PV") provides many similar benefits and attributes when compared with distributed solar PV, yet due to the benefits of economies of scale is generally available at a lower unit price. APS witness Albert

[72] *See* Docket Nos. E-04204A-15-0142 and E-1933A-15-0322, respectively.
[73] Albert Direct 28:25-29:5.

states the "adjusted grid-scale value would represent the cost at which the utility could realize the same value attributes that rooftop solar systems supply."[74] Similarly, TEP/UNSE witness Dr. Overcasts states, "the proliferation of roof top solar is not the least cost alternative to acquiring renewable energy resources or even solar DG as the cost of solar is subject to economies of scale just as the utility costs benefit from scale economies."[75]

**Q. Do you agree with these statements?**

A. I agree that due to economies of scale, utility-scale PV is generally available at a lower unit price when compared to distributed solar generation. However, I caution against drawing a parallel between the two resources in terms of valuation. The statements in support of the grid-scale methodology inappropriately conflate the value of DG from the perspective of the utility with the value of DG from the perspective of the non-participating ratepayer and result in a false comparison between the two resources.

For example, Mr. Albert states:

> Based upon the prudent utility planning principles that have been a basic premise upon which utility resource procurement decisions have historically been made, a utility has an obligation to seek out the lowest-cost, best-fit approach to fulfilling a resource need. The grid-scale adjusted methodology is consistent with this principle in that it identifies the lowest-cost, best-fit manner of achieving the same resource value."[76]

This concept is echoed by Dr. Overcast:

> DG energy sales from roof top residential customers are worth far less to the utility under net metering than under a year round contract for solar generation. This is just another example of how markets have both a competitive option and regulation of the remaining natural monopoly.[77]

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[74] Albert Direct 29:3-5.
[75] Overcast Direct 8:19-22.
[76] Albert Direct 32:13-18.
[77] Overcast Direct 9:2-6.

Both of these statements illustrate how the grid-scale benchmarking methodology approaches the issue of DG valuation from the utility perspective, making a false comparison between the two resources. While I agree that utility-scale solar provides many of the same attributes to the electric system, often at a lower unit price, utility-scale solar prices should not be used to set DG compensation because DG customers cannot participate in that market and it would be inappropriate to bring prices from the competitive utility-scale market to bear on individual customers who make the choice to install DG when they do not have access to a market in which to sell their power.[78]

The utility customer who installs solar on his rooftop chooses to make a private investment in an energy resource that can export excess power to the grid to be consumed by nearby customers. There is only one buyer for his power—the utility. Currently, there is not a market in which, if he installs solar on his rooftop and is not using all of his power, he can sign a contract with his neighbor who can purchase that power. That market does not exist because the utility has been granted monopoly rights to deliver power in its service territory.

The comparison of utility-scale pricing with distributed-scale pricing from the perspective of the utility additionally ignores the fact that while utility-scale contracts may in fact be cheaper, no one is offering the non-participating ratepayer access to utility-scale solar at 5 c/kWh. The only product available to the non-participating ratepayer is delivered energy available at the full retail rate. The non-participating ratepayer will be generally indifferent to and unaware of whether the electrons he is consuming are coming from their neighbor's PV array or whether they have been carried across the entire utility transmission and distribution system from a faraway power plant. Asking why the utility should pay more for DG than they pay for utility-scale solar PPAs asks the wrong question. From a non-participating ratepayer perspective, the right question to ask is: What is the level of costs avoided by the non-

[78] In addition, DG provides unique benefits when compared to utility-scale solar, including higher generation capacity value due to the geographic diversity of DG systems, higher avoided line losses, and potentially greater avoided distribution costs and grid services from DG.

participating customer as a result of the exported DG? The answer to this question is independent of the price paid for utility-scale solar.

**Q. What do you conclude regarding the grid-scale benchmarking approach?**

A. I do not believe the grid-scale benchmarking approach has any merit for the valuation of the costs and benefits associated with DG exports. I disagree with APS's recommendation that the value resulting from the grid-scale benchmarking methodology be considered a ceiling on the price paid for DG exports.[79] RUCO's witness, Mr. Huber, agrees, stating, "[f]avorable costs of utility and community scale solar should not be used to determine that DG solar cannot be cost-effective, or should not be pursued."[80] The attempt to set pricing for DG exports based on utility-scale prices rather than based on non-participating ratepayer avoided costs creates a false choice. Arizona's utility customers support choice and they support clean energy.[81] DG exports can be priced to ensure that non-participating ratepayers benefit from the transaction and both utility-scale and distributed-scale solar PV should be encouraged.

## 5.3 Long-term avoided cost approach

**Q. What is the long-term avoided cost approach to valuation of DG?**

A. The long-term avoided cost approach is the methodology that is commonly referred to as a "value of solar analysis." In my direct testimony in this proceeding I outlined my recommendations for specific methodologies to assess the long-term values and costs of DG exports. The long-term avoided cost approach is the standard approach to DG valuation and was the approach used by APS in the R.W. Beck study from 2009[82] and

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[79] Albert Direct 3:20-26.

[80] Direct Test. of Lon Huber 23:20-22.

[81] Adrian Gray Consulting, *Survey of Arizona Voters*, Adrian Gray Consulting, LLC, 2 of 4 (Oct. 14, 2014), http://www.edfaction.org/sites/edactionfund.org/files/press-releases/edaf-az-2014.pdf.

[82] R.W. Beck, *Distributed Renewable Energy Operating Impacts and Valuation Study*, R.W. Beck, § 1.5 (Jan. 2009), http://files.meetup.com/1073632/RW-Beck-Report.pdf.

the 2013 SAIC update to that study.[83] The 2013 Crossborder Energy study also used the long-term avoided cost approach[84] as did the updated study presented by TASC witness Thomas Beach in this proceeding.[85] I recommend that the Commission adopt the long-term avoided cost approach to the valuation of DG exports.

**Q. Have parties provided arguments against the long-term avoided cost approach?**

A. Yes. APS witness Brown devotes the majority of his testimony to a section entitled "what's wrong with a 'VOS' analysis?"[86] In this section he states that the VOS analysis "is inherently subjective, readily manipulated, and inherently skewed,"[87] and details a list of what he calls "[f]oundational problems that can throw off the whole framework of a study."[88] He additionally criticizes some of the categories of costs and benefits outlined in the Interstate Renewable Energy Council guidebook,[89] and examines the results of several VOS analyses that have been completed in Arizona and other states.[90]

**Q. Do you agree with Mr. Brown's statements?**

A. No. Mr. Brown claims that "[s]tudies of the 'VOS' are highly subjective and readily manipulated because there is no established methodology, and, furthermore, given the complexity of the analyses needed to assess all the various 'VOS' claims, no analysis can effectively avoid the need to make multiple subjective analytical judgments."[91] However, Mr. Brown's testimony goes on to make a number of specific

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[83] SAIC, *2013 Updated Solar PV Value Report*. SAIC, § 2.1 (May 10, 2013), https://www.azenergyfuture.com/getmedia/77708c68-7ca6-45c1-a46f-84382531bae3/2013_updated_solar_pv_value_report.pdf/?ext=.pdf.
[84] R. Thomas Beach & Patrick G. McGuire, *The Benefits and Costs of Solar Distributed Generation for Arizona Public Service*, Crossborder Energy, 2 (May 8, 2013), https://www.seia.org/sites/default/files/resources/AZ-Distributed-Generation.pdf.
[85] Beach Direct, Ex. 2.
[86] Direct Test. of Ashley Brown 12:18-57 ("Brown Direct").
[87] *Id.* 13:1
[88] *Id.* 18:15.
[89] *Id.* 24:13.
[90] *Id.* 47:4-57.
[91] *Id.* 13:4-7.

recommendations regarding the appropriate methodology for the calculation of many of the inputs to the valuation analysis.[92]

In addition, Mr. Brown cites to the results of a study completed in Maine and a study completed in Louisiana, pointing out that the resulting c/kWh values were very different in the two studies as apparent support for his claims that such studies may be biased.[93] In reality, it is not at all surprising that the c/kWh valuation of solar would differ dramatically in studies that looked at two very different states with different climates, different customer usage patterns, and different energy supply mixes.

Mr. Brown's criticisms essentially support the view that that the methodology for long-term valuation of solar DG would benefit from guidance from the Commission in order to ensure that the resulting analysis is reliable and unbiased. This is precisely what I have recommended in my direct testimony[94] and is the purpose of this proceeding, as indicated by Commissioner Little.[95]

# 6 Other Issues

## 6.1 Distribution of benefits from DG solar

**Q. Have any parties in this proceeding made comments regarding the distribution of benefits from DG solar?**

A. Yes. Mr. Brown makes the following claim in his testimony:

> A VOS analysis typically ignores the social impact of policies, such as net metering implemented to support distributed solar. Empirical studies on this subject have indicated that net metering pricing has a regressive social impact. It is, in fact, a wealth transfer from lower-

[92] *See, e.g., id.* 25:4 (discussing avoided energy costs), 27:1 (discussing generation capacity savings).
[93] Brown Direct 13:7-11.
[94] Kobor Direct 49:11-13.
[95] Guidance Letter 1.

> income people to higher-income people.[96]

**Q. Do you agree with this claim?**

A. I do not. Studies on net metering do not show that there is a regressive social impact nor do they demonstrate a wealth transfer from lower-income people to higher-income people. In fact, the only empirical study Mr. Brown cites to in his testimony that includes data from Arizona is entitled "Solar Power to the People: The Rise of Rooftop Solar Among the Middle Class."[97] The following statement appears on the very first page of this study:

> The question is: Who is buying up all of those solar power systems? Through our analysis of solar installation data from **Arizona**, California, and New Jersey, we found that these installations are overwhelmingly occurring in middle-class neighborhoods that have median incomes ranging from $40,000 to $90,000. The areas that experienced the most growth from 2011 to 2012 had median incomes ranging from $40,000 to $50,000 in both **Arizona** and California and $30,000 to $40,000 in New Jersey. Additionally, the distribution of solar installations in these states aligns closely with the population distribution across income levels.[98]

That report additionally included a figure depicting the distribution of solar installations and households by income level for APS's territory. That figure is reproduced on the following page.

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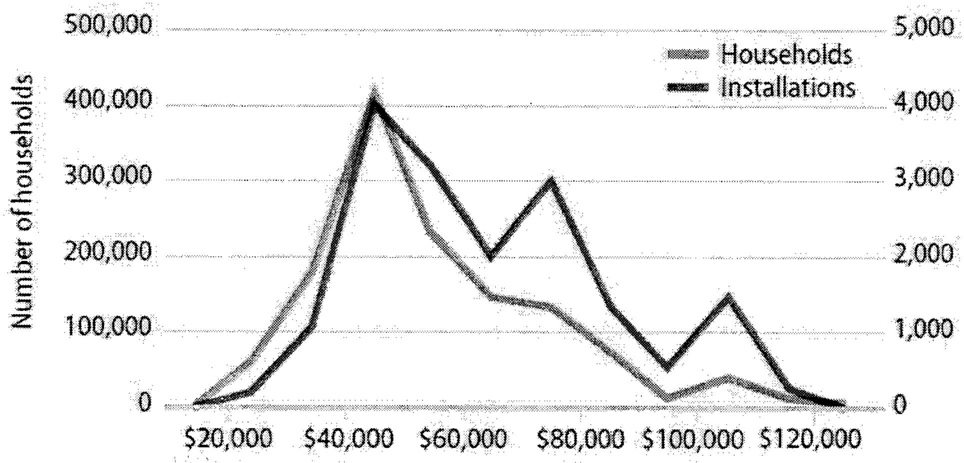
[96] Brown Direct 24:5-9.

[97] Brown Direct 24 n.26 (citing "Hernandez, Mari, *Solar Power to the People: The Rise of Rooftop Solar Among the Middle Class*. Center for American Progress, October 21, 2013. https://cdn.americanprogress.org/wp-content/uploads/2013/10/RooftopSolarv2.pdf").

[98] Mari Hernandez, *Solar Power to the People*, Center for American Progress, 1 (Oct. 21, 2013), https://cdn.americanprogress.org/wp-content/uploads/2013/10/RooftopSolarv2.pdf (emphasis added).

**Figure 4: APS Installations and Households by Income Level**[99]




This analysis clearly indicates solar DG is being installed across the income spectrum in Arizona with a proportionate amount of solar installations at the lower ends of the income spectrum.

The other studies referenced by Mr. Brown include a study from California that found that while the average income of customers with solar was higher than the general population, that gap has been decreasing since 2007.[100] Mr. Brown also referenced a study that looked at Maryland, Massachusetts, and New York, and found that like Arizona, Massachusetts and New York saw the majority of solar installations in middle-income areas, while Maryland skewed slightly more towards higher-income areas.[101]

While distribution of solar installations across the income spectrum is one part of the picture, Mr. Brown's allegations ignore the fact that if a robust approach to the quantification of the costs and benefits associated with DG can be used to set a rate

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[99] *Id.* 3.
[100] Energy and Envtl. Econ., *California Net Energy Metering Ratepayer Impacts Evaluation*, 113 (Oct.28, 2013), http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=5724.
[101] Brown Direct 46-47 n.45 (citing Mari Hernandez, *Rooftop Solar Adoption in Emerging Residential Markets*, 1 (May 29, 2014), https://cdn.americanprogress.org/wp-content/uploads/2014/05/RooftopSolar-brief3.pdf).

for exports that allows a sharing of net benefits between customers that do and do not install DG, all customers will benefit, regardless of income level.

## 6.2 This docket is not the appropriate venue for determination of specific rate design measures

**Q. Have any parties to this proceeding discussed specific rate design recommendations?**

A. Yes. Several parties, including APS witness Mr. Snook, TEP/UNSE witness Dr. Overcast, and AIC witness Mr. O'Sheasy, include specific rate design recommendations in their direct testimonies, including an endorsement of three-part rates that include a demand charge and increasing fixed customer service charges through use of the minimum system method.[102]

**Q. Do you have any comments on these recommendations?**

A. I do not believe this docket is the appropriate venue for recommendations or determinations regarding specific rate design proposals. The scope of this docket should be limited to development of a robust, standardized methodology for valuation of DG that can be employed to develop specific findings for each Arizona utility. Specific rate design measures may indeed impact the magnitude of DG benefits and costs calculated using the methodology developed in this proceeding and are an important consideration in each utility's own rate case. Moreover, it would not be appropriate to consider specific rate design proposals absent a body of evidence to support those proposals, including utility cost of service studies and bill impact analyses, neither of which has been provided for the rate design recommendations discussed in this case.

[102] Snook Direct 27:16-20; Overcast Direct 39:12-16; Direct Test. of Michael O'Sheasy 11:18-15:16.

# 7 Recommendations

**Q. What are your recommendations for the Commission?**

A. In addition to the recommendations summarized in my direct testimony, I recommend the following:

- The Commission should recognize that insufficient evidence has been provided to support the alleged cost shift calculations put forth by APS and TEP/UNSE in this docket and that the methodologies employed to develop these calculations overinflate the cost to serve NEM customers.
- The Commission should instruct the utilities to evaluate the cost to serve NEM customers in a fair and transparent way through standard utility cost-of-service analysis based on delivered load.
- The Commission should not make specific findings based on cost of service study evidence in this proceeding.
- The Commission should not endorse use of a counterfactual cost of service study as proposed by TEP/UNSE.
- The Commission should reject the short-term avoided cost approach to the valuation of DG.
- The Commission should reject the grid-scale benchmarking approach to the valuation of DG
- Valuation of DG exports should be considered separately from the cost to serve NEM customers, and the valuation should be based on a full assessment of the long-term costs and benefits associated with DG exports.
    - Detailed recommendations regarding the methodology for this valuation are provided in my direct testimony.[103]
- The Commission should recognize that the distribution of solar DG installations by income level reflects the income distribution of the state of Arizona.

[103] Kobor Direct 49-50.

- The Commission should recognize that this docket is not the appropriate venue for evaluation of specific rate design proposals. Rate design should be addressed in individual utility rate cases where the proposals can be fully evaluated.

**Q. Does this conclude your rebuttal testimony?**

A. Yes, it does.