BEFORE THE ARIZONA CORPORATION COMMISSION

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.	Docket No. E-01933A-15-0322
IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. 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 UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND FOR RELATED APPROVALS.	Docket No. E-04204A-15-0142

PHASE 2 DIRECT TESTIMONY AND ATTACHMENTS

OF BRIANA KOBOR ON BEHALF OF VOTE SOLAR

May 19, 2017

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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, 94612.

Q. On whose behalf are you submitting this direct testimony?

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

Q. Did you submit testimony in Phase 1 of these proceedings?

A. Yes, I did. I submitted direct and surrebuttal testimony in Phase 1 of both the Tucson Electric Power Company ("TEP") and UNS Electric, Inc. ("UNSE") proceedings. My testimony focused primarily on net metering and solar rate design, grandfathering issues, and the solar meter fee. My Phase 1 direct testimony contains an introduction to Vote Solar as well as summary of my professional experience.

2 Purpose of Testimony and Summary of Recommendations

Q. What is the purpose of your testimony in this proceeding?

A. My testimony addresses the implementation of Decision 75859 in the Value of Distributed Generation ("DG") proceeding and the replacement of retail rate net metering with a compensation rate for DG exports. In addition, I address the proposals of TEP and UNSE (collectively "the Companies") to grandfather existing DG customers onto current rate design and retail rate net metering and to implement rate design changes for new DG customers. I additionally address TEP's proposed Residential Community Solar ("RCS") program.

Q. Please describe how your testimony is organized.

A. The remainder of my testimony consists of seven major sections. In the first section, I address the impact of Decision 75859 on DG in the Companies' service territories. In the second section, I address the need to grandfather existing DG customers onto current rate design and net metering. In the third section, I provide Vote Solar's proposal for implementation of an export compensation rate in place of the existing retail rate net metering program. In the fourth section, I address the Companies' proposals for rate design changes specific to new DG customers. In the fifth section, I address the Companies' proposals to increase DG Meter Fees. In the sixth section, I comment on TEP's proposed RCS program. And in the final section, I provide a summary of my conclusion and recommendations.

Q. Please summarize your findings.

A. The Commission established a second phase of these proceedings so that the prior proposals from the Companies related to net metering and DG rate design could be evaluated after the conclusion of the Value of DG docket, which was expected to provide guidance on these issues. In the Value of DG docket, the Commission issued Decision 75859, which called for a gradual transition away from retail rate net metering to a compensation rate for exports.[1] As I describe in this testimony, the implementation of Decision 75859 is expected to have a significant impact on DG in the Companies' territory as a result of the net metering changes ordered by the Commission. I find the implementation of Decision 75859 in this phase of the proceedings may significantly reduce the economics of investing in rooftop solar and will go a long way toward addressing the Companies' fixed cost recovery concerns. In light of these changes, I find that the Companies' additional proposals to further harm the economics of rooftop solar through punitive rate design is unreasonable and it is not gradual. Instead, I find that the most balanced policy solution is to eliminate net metering pursuant to Decision 75859, while leaving the existing rate design for solar customers in place.

[1] Decision No. 75859 at 170:6–8 (Jan. 3, 2017).

I review the testimony provided by Commission Staff ("Staff") regarding the proposed Resource Comparison Proxy ("RCP") rate and provide a recommendation for modifications to the Staff proposal that would more accurately implement Decision 75859. I recommend that the Base RCP value be calculated based on the five years up to and including the test year for each Company, as clearly ordered in Decision 75859. In addition, I provide a recommendation for the calculation of transmission, distribution, and line loss adders that are required by Decision 75859 to make the RCP an accurate proxy measure. Based on these factors I recommend a first year RCP value of $0.154 per kilowatt hour ("kWh") for TEP and $0.152 per kWh for UNSE. In addition, to provide much needed certainty to the families and small businesses that will be considering making an investment in local clean energy, I recommend that the Commission adopt a 10% floor on annual export compensation rate decline after the 10-year lock-in period. This proposal will balance the desire for a decline in export compensation rates under the new Value of DG methodology with critical certainty necessary to support customer investment.

In their Phase 2 direct testimony, the Companies have proposed to segregate new residential and small commercial DG customers into a separate rate class and to restrict customers to a choice between two different rates: (1) a two-part time-of-use ("TOU") rate with a Grid Access Charge, and (2) a three-part TOU rate. In support of this proposal, the Companies have offered cost of service studies ("COSS") and Proofs of Revenue purporting to show that the Companies' proposed rates will bring cost recovery from DG customers more in line with the cost recovery from the non-DG customers in the residential and small commercial classes.

After a thorough review of the COSSs and Proofs of Revenue filed by the Companies, I find that the rate design proposals are unsupported, unnecessary, and discriminatory. As a result, I recommend the Commission reject the Companies' rate design proposals for new DG customers. The most fundamental aspect of examining the cost to serve varying groups of customers in the COSS is the development of load data on which to base relative cost allocation. Unfortunately, rather than develop load data for DG customers based on readily available metered load information, the Companies have chosen to undertake a complex analysis to approximate hypothetical load shapes for DG customers. The Companies' approach introduces significant error into the analysis and renders the results unreliable. I explain the numerous inappropriate assumptions the Companies relied on in support of their analysis, and I recommend that the COSSs and Proofs of Revenue that result not be relied upon for ratemaking.

In addition to the deeply flawed approach to development of load data used to separate DG customers in the COSSs and Proofs of Revenue, the Companies employed two other inappropriate assumptions that significantly skew their results.

First, the Companies have chosen to allocate a significant proportion of system costs based on measures of peak DG customer export, rather than delivered load. As established in the direct testimony of Curt Volkmann on behalf of Vote Solar, the Companies do not incur any costs related to peak DG exports and it is therefore inappropriate to include this measure as an allocation factor in the COSS. Moreover, Decision 75859 clearly separated consideration of the costs and benefits of exports from consideration of the costs and benefits of self-consumption. As a result, even if the Companies were to prove that costs were incurred due to peak customer exports—which they have not—any such costs would be considered in the export compensation rate and should not be double-counted through inclusion in the COSS.

Second, the Companies underestimated the revenues from current rates and presented an inaccurate comparison between cost recovery under current and proposed rates. While the Companies have proposed rates that would apply based on instantaneously delivered load, they have compared the proposed rates to current rates based on the revenues received from DG customers net of the compensation the Companies pay those customers for exports under retail rate net metering. Because the Commission directed that exports and self-consumption should be considered separately, it is not an accurate representation of cost recovery under current rates to compare the cost to serve DG customers with a reduced level of revenues that reflects net metering payments to those customers. Rather, consistent with the methodology recommended for DG customer cost allocation, revenues received under current and proposed rates should be based on delivered load.

When these two inappropriate assumptions are corrected for, I find that DG customers recover more than their fair share of costs under current rates, even without the present DG Meter Fees. In addition, I find that the Companies' proposed rates would significantly overcharge DG customers, resulting in unreasonably large returns far in excess of the returns expected from rates approved for the residential and small commercial classes in Phase 1 of these proceedings. As a result, I find that the Companies' proposals for rate design changes are unnecessary and discriminatory, and I recommend they be rejected.

While I do not recommend the Companies' COSSs and Proofs of Revenue be relied upon for ratemaking, for illustrative purposes I have calculated a series of rates that could be charged to DG customers in order to achieve cost recovery commensurate with the cost recovery approved for non-DG residential and small commercial customers. These rates are identical to the existing standard tiered rates and volumetric TOU rates currently available to residential and small commercial customers, with the addition of a Grid Access Credit calibrated to address the relatively larger proportion of costs recovered from DG customers under current rates. The Grid Access Credit is similar to the Companies' proposed Grid Access Charge and provides a monthly credit per installed kilowatt ("kW") of the customers' DG system. The illustrative rates reveal appropriate Grid Access credits of up to roughly $6/kW for some customer classes.

Despite these illustrative results, I recommend against implementation of separate rates with a Grid Access Credit for DG customers for several reasons. First, as stated above, I do not believe that the COSS and Proof of Revenue results can be relied upon for ratemaking. Second, even if the COSSs and Proofs of Revenue were to be revised based on actual load data and corrected for the inappropriate assumptions described above, it is not in the public interest to pursue piecemeal subdivision of the residential and small commercial classes. Decision 75859 indicated that DG customers were a separate class of customers, but explicitly left open the question of what, if any, ratemaking implications should result. If the Commission were to develop separate rate design for residential and small commercial customers despite evidence that separate rate design is unnecessary and discriminatory, it would open the door to separation of other subgroups of customers which would add significant complexity and may harm low- and fixed-income ratepayers, particularly those located in rural Arizona.

In addition to the separate tariffs proposed for DG customers, the Companies have proposed to increase the DG Meter Fees previously approved in Phase 1 of these proceedings. Because the COSS evidence demonstrates that DG customers recover more than their fair share of costs on current rates without the DG Meter Fee, I find that these charges are unnecessary and should be eliminated. In the event that the Commission chooses to continue imposition of DG Meter Fees, I find that the Companies have provided insufficient evidence to support their proposed increases and recommend that the Commission maintain the existing fees for TEP and implement fees for UNSE based on a consistent methodology.

Finally, I reviewed the Companies proposed RCS program. I find that it is unnecessary to restrict the program to homeowners and recommend that if the program is approved, program access be expanded. In addition, I recommend that the Commission reject TEP’s request for a waiver to redefine “distributed generation” under the Renewable Energy Standard Tariff (“REST”) rules, as it is unnecessary and untimely given the ongoing discussion of the REST rules in Docket No. 16-0289.

Q **Please summarize your recommendations for Phase 2.**

A. Taking into account the analyses and evidence reviewed in this case, I recommend the following:

Grandfathering

- Existing DG customers should be grandfathered into retail rate net metering and current rate design options.

Net Metering and Export Compensation Rates

- The Commission should undertake a rulemaking to modify the existing net metering rules prior to implementation of an export compensation rate.
- If the Commission decides to implement an export compensation rate in this proceeding, the Commission should implement a first-year RCP of $0.154/kWh for TEP and $0.152/kWh for UNSE.
- The Commission should adopt a 10% floor on annual export compensation rate decline after the 10-year lock-in period.

Rate Design for New DG Customers

- The Commission should reject the COSSs and Proofs of Revenue filed by the Companies and direct them to submit revised analyses that measure load from DG customers based on actual instantaneously metered data, consistent with how all other customers are treated in the COSSs and Proofs of Revenue.
- The Commission should find that the COSSs and Proofs of Revenue are not sufficient to be relied on for ratemaking.
- The Commission should find that it is inappropriate to allocate costs to DG customers in the COSS based on exported load and that the appropriate measure for cost allocation is delivered load.
- The Commission should find that DG customers recover more than their fair share of costs under current rates, so separate rate treatment for DG customers is unnecessary.
- The Commission should find that the Companies' proposed rates would result in unreasonably large returns, are discriminatory, and should be rejected.

- If the Commission decides to separate DG customers for purposes of rate design, the Commission should provide DG customers with access to all current tariffs with a Grid Access Credit.

DG Meter Fees

- The current DG Meter Fees are unnecessary and should be eliminated.
- If the Commission desires to continue imposition of the DG Meter Fees, the current TEP Meter Fees should remain in place and the UNSE Meter Fees should be updated for consistency with the TEP fees. This would result in a one-time upfront charge of $136.00 for residential customers and $23.00 for small commercial customers, or an ongoing monthly fee of $2.18 for residential customers and $0.37 for small commercial customers.

Residential Community Solar Program

- If the RCS program is approved, the Commission should require that it be made available to all residential customers, not just those who own their own homes.
- The Commission should reject TEP's request for a waiver of the definition of "distributed generation" under the REST rules.

3 Decision 75859 in the Value of DG Docket Will Have a Significant Impact on DG in the Companies' Service Territories

Q. When the Commission created a second phase of the TEP and UNSE rate cases, did it explain why it wished to defer resolving the DG issues in Phase 1?

A. Yes. The initial phases of these rate cases were conducted before the Commission issued a decision in the Value of DG docket. It was expected that a decision in the Value of DG docket would provide guidance on how to evaluate the Companies' proposed changes to net metering and rate design for DG customers.[2] As a result,

[2] *See, e.g.*, Docket No. E-01933A-15-0322, Procedural Order (Aug. 22, 2016).

the Commission found it in the public interest to keep the net metering and rate design portions of these dockets open until the conclusion of the Value of DG docket.[3]

Q. Did the outcome of the Value of DG docket provide any such guidance?

A. It did. Decision 75859 established major policy changes for DG in Arizona, and instructed that these changes should be implemented in the pending rate cases.

Q. Please describe the DG policy changes established by Decision 75859.

A. Decision 75859 established a framework to reduce the compensation DG customers receive for the energy they export to the grid, which would eliminate net metering in Arizona. The Commission concluded: "There is a need for a valuation of DG methodology that will provide a gradual transition away from the current net metering model for compensating DG exports, toward compensation of DG exports that reflects the actual value of DG."[4] The Commission determined the compensation rate for exports would be based on both an Avoided Cost methodology and an RCP methodology.[5] But the Commission stated that only the RCP methodology should be implemented in the currently pending rate cases.[6] In addition, the Commission declared that rooftop solar customers are a separate class of customers, but it directed that "[t]he ratemaking implications of this separate class treatment are to be determined in each utility's rate case supported by a fully vetted cost of service analysis."[7]

Q. How will these policy changes impact DG in the Companies' service territories?

A. By eliminating net metering and reducing the compensation for DG exports, the Commission has introduced a significant level of uncertainty to customer-sited

[3] *See, e.g.*, Decision No. 75697 at 116:2–4 (Aug. 18, 2016).
[4] Decision No. 75859 at 170:6–8.
[5] *Id.* at 171:9–17.
[6] *Id.* at 172:13–15.
[7] *Id.* at 146:6–8.

DG investments. I expect that the value proposition for customers investing in rooftop solar will be reduced significantly over time. The uncertainty from this policy change is two-fold.

First, individual customers will likely have a difficult time determining what proportion of the energy they generate onsite will be subject to the reduced export rate. Under net metering, all energy generated onsite is essentially valued at the retail rate, regardless of whether it is consumed onsite or exported to the grid. But now, the energy generated onsite will have a different value based on whether it is consumed onsite or exported.

Second, there is significant uncertainty about the compensation rate customers will receive for exports after 10 years from the date of their interconnection. Under the Commission's new policy, new DG customers will be able to lock-in the applicable export compensation rate for 10 years, which provides some initial price certainty. But new rooftop solar systems have useful lives of 20-30 years or more, so there will still be substantial uncertainty about the compensation rate a new DG customer will receive for exports over the life of the system.

In addition to creating substantial uncertainty, these changes will also harm the economics of rooftop solar. As noted above, under net metering customers could expect that all solar energy, whether consumed onsite or exported to the grid, would be valued at the retail rate. And based on historical trends, a customer could reasonably expect that the retail rate would increase modestly over the life of the system. In contrast, under the valuation method adopted in Decision 75859, an individual customer will have their export compensation rate fixed for a period of 10 years, with no increase in compensation as retail rates rise. Moreover, it will be very difficult for a customer to determine the compensation rate they will receive for exports beginning in Year 11 and beyond.

Q. What impact do you expect these policy changes will have on the value proposition for households and small businesses that wish to invest in distributed generation?

A. It is difficult to determine the exact impact before we know the new compensation rate for exports. But I expect the impact will be significant. For example, I have estimated the change in net present value for solar exports under net metering, compared with a hypothetical RCP-based compensation rate set at retail rates and fixed for 20 years, rather than the 10-year fixed period adopted by Decision 75859. In other words, I have compared net metering to a new compensation rate that would lock-in the current retail rate for 20 years. Comparing net metering to this hypothetical export compensation rate shows that simply locking-in the current retail rate for 20 years would decrease the net present value of exports by 17%.[8] This is a conservative hypothetical, as the decrease would be more substantial if the new compensation rate is less than the current retail rate, or if the compensation rate further decreases after 10 years.

Q. Do you have any recommendations for how the Commission should consider the Companies' proposals in light of the policy changes implemented by Decision 75859?

A. Yes. Eliminating net metering as Decision 75859 anticipates may significantly reduce the economics and certainty of investing in rooftop solar, which will very likely reduce future DG growth in the Companies' territories. Eliminating net metering will also increase the Companies' fixed cost recovery from new solar customers. Thus, implementing Decision 75859 will reduce DG growth and go far toward addressing the Companies' fixed cost recovery concerns. However, as discussed below, the Companies have also proposed several other rate design changes that will further harm the economics of rooftop solar and make solar an even less economical proposition. This multi-pronged assault on DG is unreasonable and it is not gradual. Instead, the most reasonable and balanced

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[8] I have assumed the retail rate escalates at 2.5% annually, and a 7% discount rate.

solution is to eliminate net metering pursuant to Decision 75859, while leaving the existing rate design for solar customers in place.

In Decision 75859, the Commission broadly stated that rooftop solar customers should be considered a separate rate class because they are "partial requirements customers who export power to the grid."[9] However, the Commission also explained that this does not automatically mean that rooftop solar customers should be singled out for differential rate treatment.[10] As I will show below, implementing Decision 75859 in this rate case will result in a significant change to the valuation for rooftop solar exports, which will address the very attribute that makes rooftop solar customers different than other customers. As a result, it would be unnecessary, unreasonable, and discriminatory to approve the additional punitive rate design changes proposed by the Companies.

4 Existing DG Customers Should Be Grandfathered onto Retail Rate Net Metering and Current Rate Design Options

Q. What are your recommendations regarding grandfathering of existing DG customers?

A. It is essential that the Commission safeguard existing DG customers from drastic and unforeseen rate design changes. The Companies' existing DG customers made investments in rooftop solar systems to serve their family or small business needs based on price signals the Companies and the Commission were sending at the time. In fact, many of those customers were specifically encouraged to invest in DG through up-front incentives. Those customers responded correctly to the price signals and incentives; and by investing in rooftop solar, those customers fixed a portion of their electricity bills to offset fluctuating electricity rates. Many of these customers invested in rooftop solar as part of a long-term financial plan,

[9] Decision No. 75859 at 146:5.
[10] *Id.* at 146:6–8.

perhaps tied to retirement, college, or some other anticipated financial need. By investing in their own energy source, these customers can reduce monthly expenses when their system is paid off, improving savings potential much like paying off a mortgage. Drastic, unforeseen changes to the rate design for these customers have the potential to severely undercut their planned savings.

Q. What have the Companies proposed regarding grandfathering?

A. The Companies state their proposed rate modifications will apply only to DG customers who apply for interconnection after the date of the decision in Phase 2.[11] They do not provide additional detail regarding their grandfathering proposal.

Q. What do you recommend regarding the grandfathering of existing DG customers?

A. I recommend that the Commission adopt grandfathering provisions consistent with its decision in Phase 1 of the TEP case:

> IT IS FURTHER ORDERED that DG systems that have filed for interconnection to Tucson Electric Power Company's distribution system prior to the effective date of the Decision in Phase 2 shall be considered to be fully grandfathered and continue to utilize currently implemented DG-related rate design and net metering for a period of 20 years from the date the DG system is interconnected, except that DG customers who file for interconne[]ction after the effective date of this Decision shall be subject to the DG meter charges approved herein. Existing customers with DG systems will be subject to currently-existing rules and regulations impacting DG. Current commercial DG customers who will be transferred to the MGS Class or LGS Class shall be grandfathered on the MGS Class transition two-part rate design, subject to currently-existing rules and regulations impacting DG, with an option to adopt the MGS or LGS three-part rates.[12]

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[11] Richard Bachmeier Direct Test. at 1:18–21 (Mar. 17, 2017) [hereinafter "Bachmeier Phase 2 Direct"].
[12] Decision No. 75975 at 194:9–18 (Feb. 24, 2017).

In addition, in the case that a grandfathered DG customer sells their home, I recommend the grandfathering status remain with the installed system, rather than the customer, consistent with Decision 75859.[13]

5 Vote Solar's Proposed Export Compensation Rate

Q. Have you reviewed the Direct Resource Comparison Proxy Testimony of Staff Witness Ralph C. Smith?

A. I have. I believe Mr. Smith conducted a thorough review of the utility-scale solar projects and power purchase agreements ("PPAs") in each Company's RCP portfolio. I also believe Mr. Smith recommended a number of appropriate changes to the utility-supplied RCP model, including modifying the depreciation rates for utility-owned solar and resolving discrepancies in assumed first year operations.[14]

Q. What did Staff propose as an initial RCP rate for each of the Companies?

A. Staff proposed an initial RCP rate of $0.105/kWh for TEP, and an initial RCP rate of $0.128/kWh for UNSE.[15] This recommendation was based on an alternative calculation that included post-test year information, and the Companies' assumptions for transmission, distribution, and line loss adders.[16]

5.1 Base RCP Value

Q. Do you agree that a separate RCP should be adopted for TEP and UNSE?

A. I do. While I understand the Companies' wish to implement a single RCP for both TEP and UNSE, I agree with Staff's recommendation to calculate a separate RCP

[13] Decision No. 75859 at 179:6–10.
[14] Ralph Smith Direct Resource Comparison Proxy Calculation Test. at 30:17–23 (Apr. 20, 2017) [hereinafter "Smith Phase 2 RCP Direct"].
[15] *Id.* at 29:14–15.
[16] *Id.* at 28:20–25.

value for each utility. The Companies defend their proposal to use a single value for both utilities based on consistency with their position in the Value of DG proceeding and the fact that the utilities share a common balancing authority.[17] But the RCP is intended to provide a proxy value for the cost of utility-scale solar generation to non-solar customers. The cost to UNSE customers will depend on UNSE's portfolio of solar resources, and the cost to TEP's customers will depend on TEP's separate portfolio of resources. Because each utility has a robust RCP portfolio with multiple projects during the five-year period, the best and most accurate approach is to adopt a separate RCP for each utility.

Q. Do you agree with Staff's proposal to use an alternative calculation that includes post-test year information?

A. I do not. Decision 75859 clearly dictates the time frame that should be used for the initial RCP calculation in Ordering Paragraph 146:

> For the Resource Comparison Proxy Methodology with a Five Year Rolling Average (Based on Projects and PPAs with In-Service Dates within the Last Five Years), Staff shall use the spreadsheet described in this Decision to develop a proxy for rooftop solar generation, based on a utility's projects and PPAs with in-service dates <u>within the five years up to and including the test year of the rate case</u>.[18]

While Mr. Smith characterizes the Company test years as "relative[ly] stale[],"[19] the amount of time that has passed since the test year is not a compelling reason to materially depart from Decision 75859 and the methodology it clearly set forth. Mr. Smith bases his recommended initial RCP rates on a period that includes the 12 months after the test year for each utility, but he provides no rationale for this arbitrary update to the time period.

Vote Solar recommends that the initial RCP values be calculated based on the five-year period up to, and including, the test year for each utility, in accordance

[17] TEP & UNSE Joint Resp. to STF P2 2.1 (Attach. 1 at 1).
[18] Decision No. 75859 at 171:28–172:4 (emphasis added).
[19] Smith Phase 2 RCP Direct at 28:21.

with Decision 75859. In each subsequent year, Vote Solar recommends the RCP value be updated based on the then-current five year rolling average. This means that in the second year of the RCP calculation, the rate will be re-calculated based on more current information and implemented subject to the 10% annual step-down limitation outlined in Decision 75859. Such an approach will balance Mr. Smith's desire to include more recent information with the Commission's stated desire to "provide a path for a gradual transition away from the current net metering model to one that better reflects the value of DG."[20]

Q. Based on these recommendations, what base RCP value do you recommend the Commission adopt in this proceeding?

A. I recommend the Commission adopt a base RCP rate of $0.120/kWh for TEP and $0.124/kWh for UNSE. These numbers are consistent with Mr. Smith's calculations for the Base RCP using the five years up to and including each Company's test year.

5.2 Transmission and Distribution Adders

Q. In addition to the base RCP value, did the Commission provide any other guidance for setting export compensation rates?

A. Yes. In Decision 75859, the Commission stated:

> In order to be an accurate proxy, however, we do believe that DG should receive credit for costs that it avoids that central station solar (and other central station generation) do not avoid. As a result, the Resource Comparison Proxy we adopt herein will require that avoided transmission, distribution capacity and line losses be considered in the analysis. In order for the comparison between central station solar and DG to be meaningful and accurate, these key differences must be addressed and included in the Resource Comparison Proxy analysis that will occur in the rate cases.[21]

[20] Decision No. 75859 at 171:16–17 (emphasis added).
[21] *Id.* at 152:11–17.

Q. Did Staff include transmission and distribution capacity and line losses in its recommendation in Mr. Smith's Direct Testimony?

A. Staff's proposed initial RCP value includes a small adder for line losses, but it does not consider avoided transmission and distribution capacity. Mr. Smith explained that "[t]he model also currently reflects the Companies' proposed zero value for Avoided Distribution and Transmission Facilities."[22] Mr. Smith also stated: "Staff has not identified what it believes would be a reliable amount [] for Avoided Distribution and Transmission Facilities for TEP and UNSE at this time, and has therefore left this item with a zero amount in the RCP Model."[23]

Q. Do you believe it is appropriate to exclude adders to the RCP for avoided transmission and distribution capacity?

A. No. The Commission explicitly recognized that for the RCP to be an accurate proxy, transmission and distribution adders must be accounted for.

Q. Do you have a recommendation for the level of transmission and distribution and line loss adders that should be included in the export compensation rate?

A. Yes. The Commission stated this rate case should implement an RCP export compensation rate based on the concept that non-solar customers should pay for rooftop solar at an amount commensurate with what they pay for utility-scale solar.[24] Decision 75859 correctly noted that for the proxy to be accurate, several adjustments must be made to the base RCP to arrive at a fair compensation rate for rooftop solar exports. These adjustments recognize that utility-scale solar, like

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[22] Smith Phase 2 RCP Direct at 31:24–25.
[23] *Id.* at 32:15–17.
[24] Vote Solar opposed this valuation methodology throughout the Value of DG docket and continues to believe rooftop solar and utility-scale solar are not fungible resources, as rooftop solar provides unique benefits that utility-scale solar does not. As a result, rooftop solar should not be valued or compensated based on utility-scale prices. Instead, rooftop solar should be valued based on the full range of long-term benefits it provides to non-solar customers.

other central station generation, is bundled together with other system resources for delivery to end-use customers throughout the service territory.

Prior to consumption by the Companies' customers, utility-scale solar is bundled with other system resources. Customers pay for distribution and transmission services associated with the delivery of system resources through their retail rates. As a result, it is reasonable to approximate the value of transmission and distribution capacity based on the price customers pay for these services. Marginal costs for transmission and distribution service vary throughout the year, due to congestion on various portions of the grid. This phenomenon is accounted for through the various peak demand measures used to allocate transmission and distribution costs in the COSS. While it is difficult to approximate the average cost specific to the delivery of system resources during solar hours, examining the average embedded cost for transmission and distribution approved in the Companies' rate cases can provide a conservative approximation.

Q. Why is the average embedded cost of transmission and distribution a conservative measure of the costs associated with delivering system resources during solar hours?

A. Utility-scale solar is delivered on the grid at the time of relative peak, when the marginal cost of transmission and distribution service is expected to be high. So if marginal costs related to system resource delivery during solar hours were to be assessed, I expect the value would be higher than the average embedded cost. Examining the average embedded cost dilutes the relatively higher marginal cost for delivery of system resources during solar hours and incorporates savings resulting from depreciated assets on the existing utility system.

Q. Did you examine the marginal distribution and transmission costs of system resource delivery?

A. No. While it would be reasonable to adopt a marginal cost approach, I propose to use the average embedded costs of these adders for simplicity. This is consistent with the Commission's intention that the RCP calculation should be a formulaic exercise. Because of the robust spreadsheet developed by the utilities and Staff, we are able to update the base RCP values in a relatively straightforward manner. By adopting transmission and distribution adders based on average embedded costs, calculating these values will also be simple and easy to update in the future.

Q. How did you calculate the recommended transmission and distribution adders?

A. I calculated the adders by examining the average embedded cost per kWh related to distribution and transmission for each Company, based on the revenue requirements identified in the COSS. To achieve a volumetric rate, I divided the total approved revenue requirement for each category by the retail kWh sold by each utility. The calculation and results are summarized in Table 1 below.

Table 1: Vote Solar Proposed Transmission and Distribution Adders[25]

	TEP	UNSE
Transmission Revenue Requirement	$102,589,922	$14,511,531
Distribution Revenue Requirement	$103,304,827	$19,509,552
Total Retail Sales (kWh)	8,882,011,173	1,600,809,167
Transmission Rate ($/kWh)	$0.012	$0.009
Distribution Rate ($/kWh)	$0.012	$0.012

As shown in Table 1, adopting an average embedded cost methodology results in transmission adders of $0.012/kWh for TEP and $0.009/kWh for UNSE. It also results in distribution adders of $0.012/kWh for both TEP and UNSE.

Q. Does your method account for the small portion of the distribution system that is used to carry exported rooftop solar?

A. Yes. My methodology includes only the proportion of the distribution revenue requirements that the Companies have classified as demand related. As discussed

[25] UNSE and TEP Schedules G-6-1.

at length in Phase 1, the Companies have employed the Minimum System Method for the purpose of identifying large portions of their distribution system that they classify as related to the customer function in the COSS. While Vote Solar does not agree the Minimum System Method is appropriate for identifying customer related costs, in this limited context it provides a conservative proxy for the proportion of the distribution system that is utilized by rooftop solar exports. Table 2 below identifies the categories of distribution costs that are classified as customer-related and therefore excluded from the distribution adders described above.

Table 2: Distribution Costs Excluded from Distribution Adder[26]

FERC Account	TEP	UNSE
364 – Poles, Towers & Fixtures	64%	60%
365 – Overhead Conductors & Devices	20%	35%
366 – Underground Conduit	100%	100%
367 – Underground Conductor	41%	35%
368 – Line Transformers	24%	60%

As shown in Table 2, adopting the Minimum System Method excludes a large proportion of distribution system costs from the adder. This illustrates the proposed adder's conservative nature. I am not contending that the Minimum System Method is an accurate means to identify the proportion of the distribution system utilized for delivery of rooftop solar exports. Indeed, I expect the actual proportion bears little relationship to the percentages identified in Table 2 above. However, for the limited purpose of developing an RCP adder for transmission and distribution, the Minimum System Method is simple and easy to update, and I find that the proxy is reasonable.

[26] "Cust%" tab of COSSs.

5.3 Line Loss Adder

Q. Did Staff address the Commission's direction to include an adjustment for line losses in its proposed RCP?

A. Yes. Staff included an adjustment to the RCP based on the recommendation of the Companies.[27] The Companies developed a single line loss adder for both utilities based on 2016 values for system average losses that were derived for TEP.[28] The recommended line loss adjustment is 3.53%.[29]

Q. Do you support the Companies' proposed line loss adjustment?

A. No. The best approach would be to conduct a study of marginal system losses, rather than to rely on average system losses. As the Companies stated: "Losses will vary by time period, ambient temperature, type and size of conductor, voltage, etc. and, therefore, is not a single value."[30] In many cases, marginal system losses can exceed average losses by a significant amount. This is demonstrated by a study of marginal losses during solar hours in APS territory of 12%, in contrast with average losses of only 7%.[31] Unfortunately, the Companies have indicated in discovery that they have not conducted any analyses of marginal system losses.[32]

I recommend that the Commission require the Companies to study marginal line losses prior to the next general rate case. However, given the information available, I find it reasonable to base the line loss adjustment in this case on system average losses and I have two recommendations for how the proposed line loss adjustment should be modified: (1) separate line loss adjustments should be developed based on test-year information for TEP and UNSE to maintain

[27] Smith Phase 2 RCP Direct at 31:19–22.
[28] TEP & UNSE Joint Resp. to STF P2 3.17 (Attach. 1 at 3).
[29] *Id.*
[30] TEP & UNSE Joint Resp. to STF P2 3.28 (Attach. 1 at 4).
[31] SAIC, *2014 Updated Solar PV Value Report* 2-9 (2013); R.W. Beck, Inc., *Distributed Renewable Energy Operating Impacts and Valuation Study* 4-7, Table 4-3 (2009).
[32] TEP & UNSE Joint Resp. to VS P2 5.6 (Attach. 1 at 2).

consistency with the rest of the RCP calculation; and (2) the line loss adder should include losses associated with the transmission system.

Q. Please explain your recommendation that separate line loss adjustments should be developed based on test-year information for TEP and UNSE.

A. In the information supplied to Staff, the Companies proposed a single line loss adder based on 2016 data for TEP. As explained in Section 5.1, I agree with Staff witness Mr. Smith that separate RCP values should be developed for UNSE and TEP. As a result, it is reasonable to develop separate line loss adjustments for each Company based on the attributes specific to their systems. This will result in a lower overall adjustment for UNSE because their service territory experiences lower losses than TEP's.[33]

Because Decision 75859 was clear that the RCP should be based on the test year, and values used to derive transmission and distribution adders are also based on the test year, I recommend that the line loss adjustment also be linked to the test year to maintain internal consistency. For TEP the test year is the 12 months ending June 30, 2015, and for UNSE the test year is the 12 months ending December 31, 2014.

Table 3 and Table 4 below provide a summary of system average losses for each Company over the last three years.

[33] TEP & UNSE Joint Resp. to STF P2 3.17 (Attach. 1 at 3).

Table 3: TEP Annual System Loss Summary[34]

	2016	2015	2014
Retail Load, MWh	8,896,400	9,053,067	9,165,355
System Losses, MWh	741,188	809,142	824,479
Transmission Losses, MWh	293,581	298,751	302,457
138 kV Losses, MWh	88,964	90,531	91,654
Distribution Losses, MWh	358,643	419,860	430,369
System Loss Factor	8.33%	8.94%	9.00%
Transmission Loss Factor	3.30%	3.30%	3.30%
138 kV Loss Factor	1.00%	1.00%	1.00%
Distribution Loss Factor	4.03%	4.64%	4.70%
Three Year Average			**4.45%**

Table 4: UNSE Annual System Loss Summary[35]

	2016	2015	2014
Retail Load, MWh	1,637,805	1,628,038	1,677,445
System Losses, MWh	108,515	103,138	105,705
Transmission Losses, MWh	39,008	33,669	29,761
69 kV Losses, MWh	8,189	8,140	8,387
Distribution Losses, MWh	61,318	61,330	67,556
System Loss Factor	6.63%	6.34%	6.30%
Transmission Loss Factor	2.38%	2.07%	1.77%
69 kV Loss Factor	0.50%	0.50%	0.50%
Distribution Loss Factor	3.74%	3.77%	4.03%
Three Year Average			**3.85%**

Q. Please explain your recommendation that the line loss adjustment should include losses associated with the transmission system.

A. In their derivation of the proposed line loss adder, the Companies excluded losses associated with the transmission system. But as directed by the Commission, "In

[34] TEP & UNSE Joint Resp. to VS P2 7.1(b) (Attach. 1 at 5).
[35] TEP & UNSE Joint Resp. to VS P2 7.1(c) (Attach. 1 at 6).

order to be an accurate proxy . . . DG should receive credit for costs that it avoids that central station solar (and other central station generation) do not avoid."[36] Because utility-scale solar, like other central station generation, is bundled together with other system resources for delivery to end-use customers throughout the service territory, it is not reasonable to exclude transmission losses from the line loss adjustment.

Q. How do you propose that the line loss adjustment be derived?

A. I propose that the Commission adopt a separate line loss adjustment for TEP and UNSE based on the system average losses measured in their service territory during the test year. Because the TEP test year includes half of 2014 and half of 2015, I recommend that system average losses for those two years be averaged to develop the adjustment.

DG exports utilize a small portion of the distribution system as they are delivered to nearby customers. Accordingly, I agree with the Companies that it is reasonable to adjust the measure of system average losses to account for losses associated with the service entrance and line drop. According to discovery, these losses amount to roughly 0.5%.[37]

My recommended line loss adjustment is 8.5% for TEP and 5.8% for UNSE. To derive the line loss adder I recommend that this adjustment be multiplied by the Base RCP for each Company—resulting in a line loss adder of $0.010/kWh for TEP and $0.007/kWh for UNSE.

[36] Decision No. 75859 at 152:11–13.
[37] TEP & UNSE Joint Resp. to STF P2 3.17 (Attach. 1 at 3).

5.4 Vote Solar Recommended RCP

Q. As an initial matter, are you aware of any legal barriers to implementing the RCP in this case?

A. While I am not a lawyer and am not offering a legal opinion on this matter, I believe there is tension between Decision 75859 and the Commission's rules. Specifically, Decision 75859 calls for the elimination of net metering in this proceeding, but the Commission's regulations codify retail rate net metering.[38] Moreover, because the Commission's net metering rules were enacted through a rulemaking process and contain no waiver provision, it is unlikely the Commission can simply waive the net metering requirements in this proceeding.[39] Thus, I believe the Commission must undertake a rulemaking to amend the regulations before it can eliminate net metering. In any event, without waiving any potential future claims Vote Solar may make regarding the legality of replacing retail rate net metering with an RCP-based export compensation rate under the Commission's current rules, I offer recommendations on the RCP-based export compensation rate.

Q. What are your recommendations for the first year RCP value to be adopted in this proceeding?

A. My recommendation for the first year RCP value is summarized in Table 5 below.

[38] *See, e.g.*, A.A.C. R14-2-1801(M) (defining "net metering" as "a system of metering electricity by which the Affected Utility credits the customer at the full retail rate for each kilowatt-hour of electricity produced" by a DG system); *id.* R14-2-2302(11) (defining "net metering" as service to a DG customer under which electricity generated onsite and delivered to the utility "may be used to offset" electricity provided by the utility to the DG customer); *id.* R14-2-2306 (detailing the billing requirements for net metering).

[39] *See, e.g.*, Ariz. Rev. Stat. § 41-1001(19) (a "rule" subject to the Arizona Administrative Procedure Act includes "the amendment or repeal of a prior rule"); 15 Ariz. Admin. Reg. 638 (Apr. 17, 2009); 13 Ariz. Admin. Reg. 2389 (July 6, 2007).

Table 5: Vote Solar Proposed RCP

	TEP	UNSE
Base RCP	$0.120	$0.124
Transmission Adder	$0.012	$0.009
Distribution Adder	$0.012	$0.012
Line Loss Adder[40]	$0.010	$0.007
Total RCP	**$0.154**	**$0.152**

As shown in Table 5, I recommend a first year RCP of $0.154/kWh for TEP and $0.152/kWh for UNSE. In each year after this case's rates are implemented and before the rates in each Company's next general rate case are implemented, I recommend that the RCP values be recalculated based on utility-scale solar project costs for the prior five years and any potential changes in average transmission and distribution rates, subject to the 10% per year step down limitation the Commission adopted in Decision 75859.

Q. Do you have any additional proposals regarding implementation of the RCP?

A. Yes. As described above, Decision 75859 indicates that the approved RCP-based export compensation rate will be fixed for an individual customer for a period of 10 years following that customers' interconnection to the system, but leaves open the question of what export compensation will be available after year 10. Without further definition regarding the export compensation a customer will receive in year 11 and beyond, it will be nearly impossible for an individual household or small business to assess the viability of an investment in rooftop solar.

As a result, I propose that the Commission approve the recommended RCP values and additionally approve a 10% floor on export compensation rate decline after the 10-year lock-in period. Under this proposal, an individual customer in TEP's territory would receive $0.154/kWh for the first 10 years their system is interconnected. In Year 1,1 their individual export compensation rate would drop to $0.139/kWh, dropping again to $0.125/kWh in year 12 and so on. Table 6 and

[40] Adders derived by multiplying line loss adjustments of 8.5% for TEP and 5.8% for UNSE by respective Base RCP values.

Table 7 below provide a snapshot of export compensation rates for the first 20 years under my proposal. For illustrative purposes, the tables also show rates available to new DG customers for the next three years if rates decrease up to the 10% cap, as provided for in Decision 75859.

Table 6: Vote Solar's Proposed TEP RCP Years 1-20 ($/kWh)

	2017	**2018**	**2019**	**2020**
Year 1	$0.154	$0.139	$0.125	$0.112
Year 2	$0.154	$0.139	$0.125	$0.112
Year 3	$0.154	$0.139	$0.125	$0.112
Year 4	$0.154	$0.139	$0.125	$0.112
Year 5	$0.154	$0.139	$0.125	$0.112
Year 6	$0.154	$0.139	$0.125	$0.112
Year 7	$0.154	$0.139	$0.125	$0.112
Year 8	$0.154	$0.139	$0.125	$0.112
Year 9	$0.154	$0.139	$0.125	$0.112
Year 10	$0.154	$0.139	$0.125	$0.112
Year 11	$0.139	$0.125	$0.112	$0.101
Year 12	$0.125	$0.112	$0.101	$0.091
Year 13	$0.112	$0.101	$0.091	$0.082
Year 14	$0.101	$0.091	$0.082	$0.074
Year 15	$0.091	$0.082	$0.074	$0.066
Year 16	$0.082	$0.074	$0.066	$0.060
Year 17	$0.074	$0.066	$0.060	$0.054
Year 18	$0.066	$0.060	$0.054	$0.048
Year 19	$0.060	$0.054	$0.048	$0.043
Year 20	$0.054	$0.048	$0.043	$0.039

Table 7: Vote Solar's Proposed UNSE RCP Years 1-20 ($/kWh)

	2017	2018	2019	2020
Year 1	$0.152	$0.137	$0.123	$0.111
Year 2	$0.152	$0.137	$0.123	$0.111
Year 3	$0.152	$0.137	$0.123	$0.111
Year 4	$0.152	$0.137	$0.123	$0.111
Year 5	$0.152	$0.137	$0.123	$0.111
Year 6	$0.152	$0.137	$0.123	$0.111
Year 7	$0.152	$0.137	$0.123	$0.111
Year 8	$0.152	$0.137	$0.123	$0.111
Year 9	$0.152	$0.137	$0.123	$0.111
Year 10	$0.152	$0.137	$0.123	$0.111
Year 11	$0.137	$0.123	$0.111	$0.100
Year 12	$0.123	$0.111	$0.100	$0.090
Year 13	$0.111	$0.100	$0.090	$0.081
Year 14	$0.100	$0.090	$0.081	$0.073
Year 15	$0.090	$0.081	$0.073	$0.065
Year 16	$0.081	$0.073	$0.065	$0.059
Year 17	$0.073	$0.065	$0.059	$0.053
Year 18	$0.065	$0.059	$0.053	$0.048
Year 19	$0.059	$0.053	$0.048	$0.043
Year 20	$0.053	$0.048	$0.043	$0.039

Q. Is your proposal consistent with Decision 75859?

A. Yes. Decision 75859 stated: "There is a need for a valuation of DG methodology that will provide a gradual transition away from the current net metering model for compensating DG exports, toward compensation of DG exports that reflects the actual value of DG."[41] While Decision 75859 clearly defines that the export compensation rate available to an individual customer will be fixed for a period of ten years from the date of interconnection,[42] it is silent on how the rate will change in years 11 and onwards. By defining a floor on export rate decline after year 10, my proposal balances the desire among other parties for a decline in the

[41] Decision No. 75859 at 170:6–8.
[42] *Id.* at 179:14–16.

rate with the critical need for certainty to support individual customers choosing to make a multi-decade investment in clean energy

Q. How does your proposal compare to the current compensation for exports under retail rate net metering for residential customers?

A. If the Commission approves my recommendation for an RCP of $0.154/kWh for TEP and $0.152/kWh for UNSE with a limitation on RCP decline in years 11 onwards of no more than 10%, the result will be a gradual and predictable decline in compensation paid for DG as compared to the current retail rate net metering program. In comparing expected compensation under the RCP with net metering, it is important to recognize the two structural changes inherent in elimination of net metering. First, under net metering a customer could reasonably expect their rate would increase over time, whereas under the RCP the rate will be fixed for the first ten years and decline thereafter. When examined over the expected life of the DG system, the difference is significant. Second, the rates available to new DG customers in subsequent years will further decline as the RCP is updated. When combined, these two factors work together to significantly reduce the export compensation provided to customers who install DG.

Because current retail rates differ by utility and rate class, the impact compared to net metering also differs. For TEP residential customers, the first year's RCP rate will be roughly equivalent to the compensation expected under retail rate net metering. For TEP small commercial customers, the first year's RCP rate will be more than 10% below the expected compensation under retail rate net metering. Because the current retail rates are relatively low for UNSE's residential and small commercial customers, the first year's RCP will be slightly above current net metering compensation. As the RCP declines in future years, all customers will be placed on a glide path for a predictable decline in export compensation. Table 8 below compares expected compensation under retail rate net metering with Vote Solar's proposed RCP for customers signing up in 2020.

Table 8: Net Metering and Vote Solar RCP Comparison, 2020-vintage Customers

	Reduction in Export Compensation
TEP Residential	28%
UNSE Residential	16%
TEP Small Commercial	37%
UNSE Small Commercial	18%

As shown in Table 8, Vote Solar's proposed RCP would result in significant decreases to the status quo regarding compensation expected under retail rate net metering, with expected declines of 16-37% across the Companies and rate classes.

6 The Companies' Rate Design Proposals Are Unsupported, Unnecessary, and Discriminatory

Q. Please describe the Companies' rate design proposals in Phase 2.

A. The Companies propose to single out new DG customers as a separate customer class, with a rate design that differs significantly from current residential and small commercial rate design.

Under the Companies' proposal, households and small businesses that install rooftop solar could not keep their current rates. Instead, these new DG customers would choose between (1) a volumetric TOU rate with a Grid Access Charge, or (2) a three-part TOU demand charge rate.[43]

Q. Please describe the proposal for a volumetric TOU rate with a Grid Access Charge.

A. According to the Companies:

[43] Bachmeier Phase 2 Direct at 3:11–14.

The structure of the two-part TOU DG Rate option would be similar to the Companies' two-part TOU rates for full-requirements customers (including the on-peak and off-peak periods) with two differences. First, the energy delivery charges will be flat with no tiers. Second, a customer taking service on the two-part TOU DG Rate will be assessed a DG Grid Access Charge.[44]

In addition, the two-part TOU DG Rate would have a higher fixed charge than the non-DG two-part TOU rate.[45]

Q. Please describe the proposal for a three-part TOU demand charge rate.

A. The three-part TOU demand charge rates are similar to the non-DG three-part TOU demand charge rates approved in Phase 1, with the exception that volumetric delivery charges and demand charges are increased based on the Companies' COSS results.[46] In addition, like the volumetric TOU offering, the three-part option would have a higher fixed charge than the non-DG three-part rate option.[47]

6.1 The Companies' COSSs are deeply flawed and do not support singling out DG customers for differential rate treatment.

Q. Have you reviewed the COSSs submitted by the Companies in support of their Phase 2 rate design proposals?

A. Yes. I have reviewed both Companies' COSSs in detail and have found a number of errors and inappropriate assumptions. I found the following fundamental errors, each of which is explained in detail below:

1) The COSS and revenue proof are premised on an inaccurate approximation of billing determinants, rather than actual DG customer data.

[44] *Id.* at 4:23–5:2.
[45] *Id.* at 7:3–9.
[46] *Id.* at 6:18–21.
[47] *Id.* at 7:3–9.

2) The COSS analyses are based on hourly netted load, but rates will apply instantaneously.

3) The Companies did not adjust DG customer data for weather normalization or customer annualization.

4) TEP's COSS analysis inappropriately adopts a time-varying load shape from UNSE.

5) The assumptions for installed system capacity are not reflective of available customer data.

6.1.1 The COSS and revenue proof are premised on an inaccurate approximation of billing determinants, rather than actual DG customer data

Q. Please describe your finding that the COSS and revenue proof are premised on an inaccurate approximation of billing determinants, rather than actual DG customer data.

A. In Phase 1, the Commission approved revised rates based on COSS evidence that analyzed and allocated costs related to different customer classes. To support the COSS that informed the rates adopted in Phase 1, the Companies relied on load research data derived from customer billing determinants during the test year for each class of customers. The process for developing the load data used to inform COSS allocation factors was described in response to discovery from Staff:

> Hourly load data is contained in the Company's Meter Data Management ("MDM") system for individual customers where the infrastructure that automatically collects metering data on a regular basis exists, and customers have meters capable of sending that data. Many customers do not meet those requirements and there are significant time costs associated with retrieving and processing large sets of hourly data, so random samples for the residential and commercial customer classes were used. These samples included hourly data for the entire test year (8,760 hours) for thousands of customers. Every customer for the large light and power service class ("LLP") was pulled and aggregated together because they all have hourly metering data and the class is small. Lighting customers do not have meters on their service so an approximation was made. Sunset and sunrise times were retrieved from the US

> Naval Observatory which was then multiplied by the wattage of bulbs installed in each district to estimate the 8,760 shape for lighting load.
>
> The 8,760 hours of data was retrieved or approximated for each rate class. This was compared to the 8,760 total system load data to determine CP and NCP data.[48]

Q. Did the Companies use a similar approach for developing load data to support the COSS allocation factors for DG customers in Phase 2?

A. They did not. Rather than querying the MDM system for test year hourly load information from DG customers, the Companies instead approximated hourly test year load based on a number of broad and unsupported assumptions.

Q. Please describe the analysis conducted by the Companies to approximate hourly test year load for DG customers.

A. My review of the Companies' work papers and responses obtained in discovery reveal that the Companies' analysis did not examine hourly usage information for a single DG customer.[49] Instead, they developed a sample of hourly test year usage from non-DG residential and small commercial customers. They aggregated the hourly load profile from each of these samples and made the assumption that, on average, new DG customers will have the same hourly load shape as the average non-DG customer from the sample. To approximate a DG customer's load shape without solar they then scaled these datasets based on aggregate monthly billing data from the Companies' actual DG customers over the test year. Finally, they scaled a sample of aggregate hourly DG production meter data based on customer DG capacity and mapped it onto the hourly residential load shape

[48] TEP Resp. to STF 1.12 (Attach. 1 at 7); *see also* UNSE Resp. to STF 2.014 (Attach. 1 at 8) (similar response).
[49] TEP & UNSE Joint Resp. to VS P2 2.11 (Attach. 1 at 9).

they developed in order to approximate hourly deliveries and exports from DG customers.[50]

Q. Could the Companies have used actual DG customers' load data, rather than approximating DG customers' load shape in this manner?

A. Yes. As I explain in detail below, it appears the data exists to treat DG customers in the same manner as all other customers analyzed in the COSS. Yet the Companies instead used an unnecessary and overly complex analysis to develop hypothetical load data for DG customers.

Q. Does the Companies' approach provide a reasonable approximation of actual DG customer load?

A. No. As Mr. Jones stated, under the Companies' approach "it was necessary to make a basic assumption that the load shape of residential solar DG customers was on average the same load shape as the residential load shape prior to the installation of solar DG."[51] When asked in discovery to provide support for this assumption, the Companies indicated they had none and stated: "The assumption is based on the fact that residential solar DG customers were residential customers prior to installation of DG. Since solar DG installation does not alter the premises in terms of connected load, thermal envelope, demographics, etc., the assumption is reasonable."[52] They additionally confirmed that a similar assumption was made for small commercial customers without any supporting research.[53]

The Companies' oversimplified approach ignores the reality that the subset of customers that choose to adopt rooftop solar has fundamentally different

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[50] Note that Mr. Jones' direct testimony indicates that the solar output load shape was based on metered data for a fixed axis DG installation. Craig Jones Direct Test. at 6:22 – 23 (Mar. 17, 2017) [hereinafter "Jones Phase 2 Direct"].But in discovery, the Companies indicated that this statement was incorrect and instead the analysis was based on a sample of DG customer load data. TEP & UNSE Joint Resp. to VS P2 2.04 (Attach. 1 at 10).

[51] Jones Phase 2 Direct at 6:6–8.

[52] TEP & UNSE Joint Resp. to VS P2 2.01(a) (Attach. 1 at 11).

[53] TEP & UNSE Joint Resp. to VS P2 2.01(b) (Attach. 1 at 11).

characteristics than the broader classes with which they take service. This is exhibited by examining the average monthly usage for customers with and without distributed generation for each utility and customer class. This data is summarized in Table 9 below.

Table 9: Comparison of Average Monthly On-Site Usage (kWh) for Customers With and Without DG[54]

Customer Class	Non-DG Customer	DG Customer	Difference
TEP Residential	801	981	22%
UNSE Residential	839	1,347	61%
TEP Small Commercial[55]	4,592	19,423	323%
UNSE Small Commercial	1,131	4,369	286%

As shown in Table 9, DG customers tend to be significantly larger than non-DG customers within their respective customer classes. Among the residential class, DG customers are 20-60% larger than their non-DG counterparts, and among the small commercial class they are roughly three times as large. This result is not surprising, as customers with relatively higher usage often experience higher electric bills and may be more motivated to examine possible cost-savings measures, such as DG.

By assuming that DG customers look the same as non-DG customers, but for the existence of their DG system, the Companies ignore the salient differences between these groups of customers. Given the relative size differences that exist between customers with and without DG, it cannot be reasonably assumed that the average load profile of a DG customer will resemble a scaled-up version of a non-DG customer.

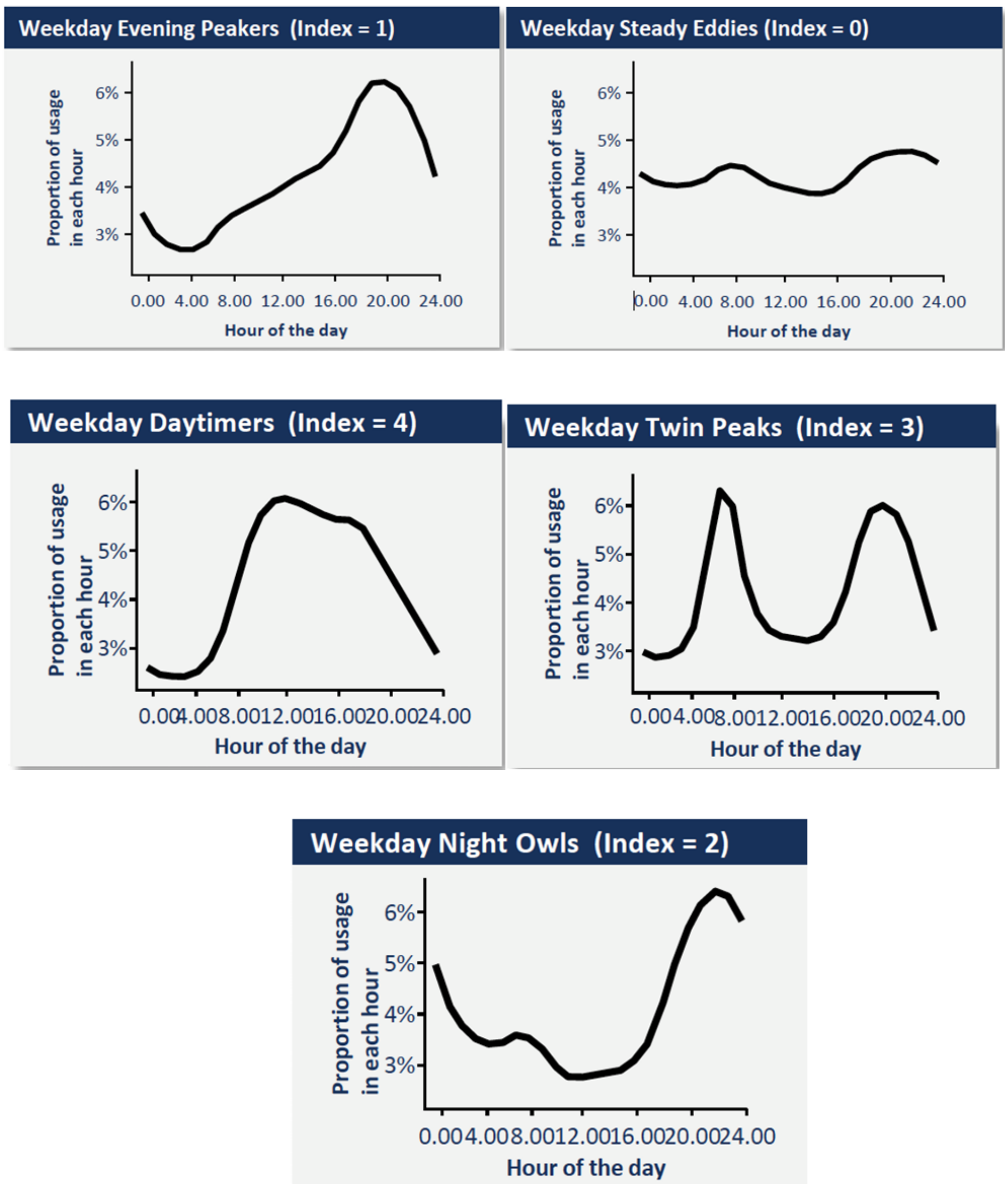
Examining actual customer load information is important because considerable differences exist between individual customer load shapes. For example, in its

[54] TEP and UNSE P2 COSS.

[55] The TEP COSS does not differentiate between Small General Service ("SGS") and Medium General Service ("MGS") customers. TEP & UNSE Joint Resp. to VS P2 6.3 (Attach. 1 at 12). Thus, all results presented in this testimony and in the Direct Testimony from TEP are based on both SGS and MGS information.

current rate case Arizona Public Service Company ("APS") developed a study of different load profile types that exist within its residential class. APS identified five different types of residential customers with very different usage patterns. Figure 1 shows illustrative load shapes from these customers.

Figure 1: APS Residential Customer Load Types[56]



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[56] Docket No. E-01345A-16-0036, APS Rate Case Third Technical Conference presentation, at slide 14 (Sept. 30, 2016).

In response to discovery, APS indicated that the residential class breaks down into five customer types, as shown in Table 10 below.

Table 10: APS Residential Customer Class by Customer Type[57]

Customer Type	Percentage of Customers
Weekday Evening Peakers	43%
Weekday Steady Eddies	20%
Weekday Daytimers	17%
Weekday Twin Peaks	10%
Weekday Night Owls	10%

While APS did not study load shapes relative to average monthly load, the data in Figure 1 and Table 10 illustrate that different subgroups of residential customers in its service territory may have significantly different average load shapes. Moreover, with the diversity that exists in the small commercial class that encompasses everything from nail salons to nightclubs, I expect differences may be even more pronounced. While the actual load shapes for TEP and UNSE DG customers will not be identical to the APS load shapes, the same general phenomenon would likely occur for TEP and UNSE DG customers.

Q. Did the Companies use the same approximating analysis to develop the billing determinants in the Proofs of Revenue as was used to develop the load allocation factors in the COSS?

A. In part. In the Proofs of Revenue, the Companies based the billing determinants for total usage and billing demand on the analysis described above. However, to split energy usage by tier and time of use period, the Companies relied on the additional assumption that all DG customers install solar generation to offset 100% of their annual energy requirements.[58]

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[57] Docket Nos. E-01345A-16-0036 & E-01345A-16-0123, APS Resp. to VS 2.5 (Attach. 1 at 13).

[58] TEP & UNSE Joint Resp. to VS P2 4.8(c) (Attach. 1 at 14); TEP & UNSE Joint Resp. to VS P2 4.9(b) (Attach. 1 at 17).

Q. Do available data support the Companies' assumption that all DG customers install solar generation to offset 100% of their energy requirements?

A. No. In Phase 1, UNSE made a similar assumption to support its proposal, but it could not provide any evidence to support it. I raised concerns with this assumption in my direct testimony in Phase 1 of that proceeding.[59] Moreover, in Phase 2 we now have additional data that directly contradicts this assumption. In support of the Phase 2 COSSs, the Companies provided monthly billing data for their DG customers. This billing data reveals that even after netting out all solar generation under net metering, customers still consume substantial amounts of energy from the utility. This is summarized in Table 11 below.

Table 11: Average Monthly Billed Customer Usage with and without DG (kWh)[60]

	On-Site Usage	Usage Net DG Production	Offset kWh
TEP Residential	981	268	73%
UNSE Residential	1,347	302	78%
TEP Small Commercial	19,423	8,255	57%
UNSE Small Commercial	4,369	825	81%

As shown in Table 11, monthly billing data reveals that customers do not install DG systems to offset 100% of their annual usage. Indeed, residential customers offset an average of 73-78% of their usage, and small commercial customers offset 57%-81% of their usage.

Q. How does the Companies' assumption that all customers install DG to offset 100% of their annual load impact the Proofs of Revenue?

A. Because the Companies' assumption overestimates solar production, it underestimates the amount of electricity that the Companies deliver to DG customers. This in turn skews the rates analyzed in the Proofs of Revenue. This data is used to estimate the share of usage that occurs during the peak and off

[59] Docket No. E-04204A-15-0142, Briana Kobor Direct Test. at 47:20–49:4 (Dec. 9, 2015).
[60] TEP and UNSE Ph2 COSS.

peak period and the share of usage that occurs in each usage tier. The Companies' incorrect assumption that solar is installed to offset 100% of customer load skews both of these measures and results in an inaccurate analysis.

Q. How should the Companies revise their methodology for developing DG customer billing determinants in the COSSs and Proofs of Revenue?

A. Rather than undertake a complex and inaccurate methodology to construct DG customer billing determinants, I recommend the Companies treat DG customers in a manner similar to all other groups of customers in their COSSs and Proofs of Revenue. That is, the Companies should develop DG customer billing determinants based on actual metered customer data sampled from the MDM system. Doing so is a much more direct and accurate way to develop DG billing determinants than the Companies' hypothetical approach.

Q. Is it your understanding the DG customer data is available in the MDM system?

A. Yes. In discovery, the Companies stated: "Hourly accumulation of instantaneous power deliveries by the Companies, to its customers, exists for all customers where the necessary metering technology was in place."[61] In addition, the Companies confirmed that during the test year, all DG customers had meters capable of measuring hourly energy usage.[62] As a result, it appears that the data exists to analyze DG customers in a manner consistent with the method used for all other groups of customers in the COSS.

The Companies have stated that "there are significant time costs associated with retrieving and processing large sets of hourly data," which resulted in the need to create samples of hourly load data for the residential and small commercial load

[61] TEP & UNSE Joint Resp. to VS P2 1.06(a) (Attach. 1 at 18).
[62] TEP & UNSE Joint Resp. to VS P2 2.05 (Attach. 1 at 19); TEP & UNSE Joint Resp. to VS P2 6.1 (Attach. 1 at 20). As noted in VS P2 6.1, some meters did not communicate all intervals to the fixed network connection device.

classes in their Phase 1 COSSs.[63] However, the Companies have not explained why they were able take on the "significant" time costs associated with querying sample data for non-DG customers, but have not undertaken a similar approach for DG customers. Indeed, during the test year there were less than 10,000 DG customers across both utilities.[64] There are thus less DG customers in the test year across two rate classes and two utilities than the 16,962 TEP non-DG residential customers queried in support of the Phase 1 analysis for a single class of customers.[65]

6.1.2 The analyses are based on hourly netted load, but rates will apply instantaneously

Q. Please describe your finding that the analyses are based on hourly netted load, but rates will apply instantaneously.

A. Under retail rate net metering, measures of energy delivered to the customer and exported to the grid are netted against each other to produce a customer bill for the month. In contrast, as part of its decision to move away from retail rate net metering, the Commission ordered: "Once a DG customer is subject to a DG export compensation rate determined by one of the DG valuation methodologies adopted by this Decision, there will be no further netting or banking of exported DG kWh for that customer."[66]

In discovery, the Companies confirmed that energy subject to their proposed rates would be measured instantaneously, in compliance with Decision 75859.[67] However, the Companies based their COSS analysis and Proofs of Revenue on billing determinants for energy deliveries and exports netted hourly.[68]

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[63] TEP Resp. to STF 1.12 (Attach. 1 at 7); UNSE Resp. to STF 2.014 (Attach. 1 at 8).
[64] TEP & UNSE Joint Resp. to VS P2 2.03(a) & (b) (Attach. 1 at 21).
[65] Bachmeier Phase 2 Direct at 9:8–10.
[66] Decision No. 75859 at 178:25–27.
[67] TEP & UNSE Joint Resp. to VS P2 2.07(b) (Attach. 1 at 22).
[68] P2 COSS for TEP and UNSE.

With energy deliveries and exports netted hourly, the Companies' hourly load analyses contain either deliveries or exports in each hour of the test year. In contrast, the Commission's decision, and indeed the Companies' proposed rates, would typically result in measuring both deliveries and exports in each hour during which a DG customer's system is generating electricity and the customer is consuming energy. By netting usage hourly in their COSSs and Proofs of Revenue, the Companies have introduced additional error into their analysis.

Q. Have you assessed the level of error that hourly netting has introduced into the analysis?

A. I cannot determine the precise level of error the Companies' methodology introduces to the analysis without the actual DG metering data from the Companies' MDM systems. However, in the current APS rate case, deliveries were measured instantaneously based on meter DG customer data. Comparing the load data in the Companies' COSS with the APS load data reveals the error may cause a significant under-estimation of delivered load. Table 12 below compares the change in load measures in the APS case and the TEP and UNSE studies.

Table 12: Measure of Residential Site Load Versus Delivered Load for APS, TEP, and UNSE[69]

	Site Load (kWh)	Delivered Load (kWh)	Difference
APS	563,105	393,601	-30%
TEP	93,754	51,955	-45%
UNSE	20,098	11,774	-41%

As shown in Table 12, when measured instantaneously, the data from the APS case showed that delivered load was 30% less than site load for the customer. In contrast, measuring hourly net load for TEP and UNSE resulted in delivered load figures that were 41-45% less than site load. While I would not expect these figures to be the same for all three utilities, the fact that the TEP and UNSE

[69] Docket Nos. E-01345A-16-0036 & E-01345A-16-0123, APS Disc. Prefiled 1.40_2015 COS Load Data_APSRC00530.xlsx; COSSs.

measurements are substantially lower than the APS measurement suggests the Companies have underestimated delivered load.

Q. How does the Companies' choice to base the COSSs and Proofs of Revenue on hourly net load, rather than instantaneous load, impact the results?

A. By netting hourly, instead of measuring instantaneously, the Companies likely underestimated all measures of delivered load. This results in two problems: (1) it underestimates the cost to serve DG customers, and (2) it underestimates the revenues received from DG customers under current and proposed rates. Taken together, these two factors form the basis of the Companies' conclusions regarding whether DG customers cover their cost of service under current and proposed rates. By introducing a potentially significant level of error to the analysis, the Companies have produced an unreliable result.

6.1.3 The Companies did not adjust DG customer data for weather normalization or customer annualization.

Q. Please describe your finding that the Companies did not adjust DG customer data for weather normalization or customer annualization.

A. It is standard practice when developing load data allocators for use in a COSS analysis to scale the test year information to ensure it is representative of future sales conditions. This includes standard adjustments for weather normalization and customer annualization. In Phase 1, the Companies included a negative weather normalization adjustment for the residential and commercial classes to account for the fact that weather during their respective test years was more extreme than normal.[70] In addition, the Companies included a customer annualization adjustment to reflect aggregate class load conditions at the time the rates become effective.[71]

[70] *See, e.g.*, Docket No. E-01933A-15-0322, Craig Jones Direct Test. at 71:2–4 (Nov. 5, 2015).
[71] *See, e.g.*, *id.* at 72:18–26.

While these standard adjustments were completed for the residential and small commercial classes in the COSSs supporting the rates approved in Phase 1, the Companies did not make these adjustments to the test year load data they used for DG customers in the Phase 2 COSS.[72] Similar to the issues identified above, this introduces additional error into the assessment of DG customer cost recovery compared to non-DG customers.

6.1.4 TEP's analysis inappropriately adopts the time-varying load shape from UNSE.

Q. Please describe your finding that the TEP analysis inappropriately adopts the time-varying load shape from UNSE.

A. While this assumption is directly related to the issues identified in section 6.1.1 above, it warrants highlighting because it is emblematic of the rough approximations the Companies have employed to support their cases despite the availability of more accurate data. In my review of the Company's work papers, I discovered that the TEP Proof of Revenue relies on data from UNSE regarding the share of DG customer energy usage expected to occur during the peak and off-peak periods. While both Companies have the same definition of peak period hours, they have different seasonal definitions. In TEP's territory, the summer is defined as the five-month period from May through September, while in UNSE's territory the summer lasts six months from May through October. By employing UNSE data on seasonal and peak usage share for TEP, the Companies have introduced additional error into the analysis.

Q. Do you have a recommendation regarding this finding?

A. The Companies should be instructed to revise the TEP Proof of Revenue to reflect hourly TEP usage information. Because the Companies possess similar data on

[72] No weather normalization adjustment were shown in the COSSs. *See also* TEP & UNSE Joint Resp. to VS P2 2.03(d) (Attach. 1 at 21) (no customer annualization).

the TEP and UNSE peak usage share, it is unclear why TEP chose to base its Proof of Revenue on UNSE information.

6.1.5 The assumptions for installed system capacity are not reflective of available customer data.

Q. Please describe your finding that the Companies' assumptions for installed system capacity are not reflective of available customer data.

A. To develop the Proofs of Revenue in support of the proposed Grid Access Charge, the Companies made an assumption regarding the average installed system size that would be subject to their proposed $/kW rate. These assumptions were integral to the Companies' calibration of their proposed Grid Access Charge in accordance with their COSS results. Unfortunately, rather than examine the customer billing data available in their COSSs, the Companies chose to develop an assumption for DG system size that bears no relation to reality.

To develop the assumptions for average system size, the Companies appear to have calculated the PV capacity that would be necessary to offset 100% of annual usage for an average sized non-DG customer in each Company's residential and small commercial class. This approach is flawed for two reasons. First, as demonstrated in Table 9, residential customers with DG are 20-60% larger than their non-DG counterparts, and among the small commercial class they are roughly three times as large. Second, as demonstrated in Table 11, monthly billing data reveals that customers do not install DG systems to offset 100% of their annual usage. Residential customers offset an average of 73-78% of their usage, and small commercial customers offset 57%-81% of their usage. As a result, the Companies' assumptions for installed system size are not reflective of the installed systems in their territories.

Fortunately, it appears that the Companies have supplied information on the installed capacity of existing DG customers with the monthly billing information provided in their COSSs. This information is presented alongside the Companies' assumptions in Table 13 below.

Table 13: Average Installed DG Capacity (kW)

	Test Year Billing Data	Company Assumption	Difference
TEP Residential	6.6	5.2	-21%
UNSE Residential	7.3	5.3	-27%
TEP Small Commercial	75.0	7.4	-90%
UNSE Small Commercial	19.1	4.3	-77%

As shown in Table 13, an examination of the average installed capacity for customers in the COSSs reveals that the Companies' methodology resulted in an underestimate of installed system capacity. The impact was most dramatic on the small commercial classes, likely due to the fact that small commercial DG customers are so much larger than their non-DG counterparts. The Companies' choice to approximate the installed capacity based on a hypothetical average non-DG customer that offsets 100% of load results in an inflated Grid Access Charge.

Q. Do you have a recommendation regarding this finding?

A. The Companies should be instructed to revise their COSSs and Proofs of Revenue to reflect actual average DG system sizing. In my analysis below I have conducted this revision to the Companies' analysis based on the monthly billing data provided in the COSSs.

6.1.6 The Commission should require the Companies to submit revised COSSs and Proofs of Revenue that treat DG customers similarly to all other customers

Q. What do you recommend based on these findings?

A. Because of the numerous COSS and Proof of Revenue flaws discussed above, I recommend the Commission reject the COSSs and Proofs of Revenue submitted by the Companies in support of their Phase 2 rate design proposals. As I have demonstrated, the Companies relied on a complex and hypothetical analysis that is predicated on a number of inappropriate assumptions. These unreasonable assumptions likely resulted in significant errors in the measures of DG customer cost recovery and revenues expected under the proposed rates. These assumptions and hypothetical data are unreasonable and unwarranted because the Companies posses actual DG customer data that would more directly and accurately measure these factors. The Commission should thus instruct the Companies to resubmit their analyses based on actual DG customer data measured instantaneously and extracted from their MDM systems, in a manner consistent with how all other customers are treated in the COSSs and Proofs of Revenue.

6.2 The data shows that the Companies' proposals are unnecessary because DG customers recover more than their fair share of costs under current rates

Q. Irrespective of the flawed load data employed in the Companies' analyses, have you conducted additional review of the cost to serve DG customers based on the Companies' COSSs?

A. I have. Even if one were to accept the flawed and unnecessarily complicated analyses used to develop the load data in support of the Companies' COSSs and Proofs of Revenue, the Companies have adopted two inappropriate assumptions that skew their results.

Q. What are those two assumptions?

A. First, the Companies have elected to include exports in their measure of DG load for purposes of cost allocation. Second, the Companies selectively underestimated revenue recovery from current rates, which underestimates cost recovery from DG customers under the current rate structure.

6.2.1 COSSs should be based on delivered load

Q. Please describe how the Companies included exports in their measure of DG load for purposes of cost allocation.

A. Mr. Jones states the Companies employed two different methodologies for analyzing the cost to serve DG customers in their COSSs: a "Base Case" study and a "DG Class" study.[73] He describes the Base Case study as "the standard cost study with the DG customers allocated costs just like the residential class based on actual load characteristics of the class."[74] In contrast he states that "[t]he DG Class cost study is identical to the Base Case except that for [non-coincident peak ("NCP")] and [coincident peak ("CP")] determination the DG Class NCP is based on the maximum DG Class NCP use of the distribution system for *either* consumption *or* export."[75] Mr. Jones indicates that it was the DG Class cost study that formed the basis of the Companies' proposal in this case.[76]

Q. What is the Companies' rationale for allocating costs to DG customers based on NCP of exports?

A. Mr. Jones states: "Using both the import and the export capacity requirements is essential for a partial requirements customer in order to incorporate the appropriate burden they place on the system."[77]

Q. Do you agree with this rationale?

A. No. Vote Solar witness Curt Volkmann has undertaken an analysis of loading on the distribution system. He finds that grid equipment is loaded at a higher level during the time of the class peak in the summer as opposed to at the time of photovoltaic ("PV") export peak in the spring. He concludes:

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[73] Jones Phase 2 Direct at 4:3–4.
[74] *Id.* at 4:8–9.
[75] *Id.* at 4:14–16.
[76] *Id.* at 4:21–22.
[77] *Id.* at 4:16–18.

> The updated Loss Study analysis using COSS values demonstrates that there is sufficient excess capacity on a typical TEP distribution circuit to easily accommodate the maximum PV reverse power flow on low load days. The analysis also shows that PV exports do not impose a burden, do not result in significantly higher energy flows, do not overload equipment, and do not impose additional costs.[78]

Mr. Volkmann demonstrates that there is no burden on the system related to rooftop solar exports. As a result, it is unreasonable for the Companies to allocate costs in the cost of service study based on the NCP of solar exports occurring during low-load spring days, as costs are not incurred from this usage.

Q. Does the adoption of an export compensation rate in place of retail rate net metering impact this discussion?

A. It does. Even if the Companies established that costs were incurred due to DG customer exports—which they have not done—the COSS would not be the appropriate place to analyze those costs. In Decision 75859, the Commission clearly indicated that method adopted by the Value of DG decision would address rooftop solar exports and not determine a monetary value of the energy a DG customer consumes onsite.[79] As a corollary, the COSS methods used to develop rate design for DG customers should also consider self-consumption separate from rooftop solar exports. The costs and benefits associated with rooftop solar exports are fully addressed in the Value of DG methodology described in Decision 75859, and the Commission believes the export compensation rate reflects these costs and benefits. Indeed, the Commission's approved methodology explicitly includes consideration of the costs and benefits of DG exports in both the RCP method and the Avoided Cost method.[80] If the Commission were to approve the Companies' proposal to factor costs associated with exports into both the export compensation rate and the rate design resulting from the COSS, these costs would be double counted.

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[78] Curt Volkmann Phase 2 Direct Test. at 10:19–24 (May 19, 2017).
[79] Decision No. 75859 at 147:18–21.
[80] *Id.* at 152:11–17 & Ex. A.

Q. How should the Companies analyze DG customer load for purposes of cost allocation in the COSS?

A. I recommend that DG customer load allocation factors be assessed based on delivered load, in a manner consistent with all other groups of customers in the COSS. The Companies' choice to allocate costs in the COSS based in part on exported load is inappropriate and inconsistent with the direction of the Commission in Decision 75859.

Q. Have you analyzed the cost to serve DG customers when costs are allocated based on delivered load?

A. In part. I have developed a revised COSS analysis that allocates costs based on delivered load, rather then exported load for the NCP-based allocators. This revised analysis implements the "Base Case" COSS developed by the Companies. In their COSSs, the Companies allocated demand-related distribution costs based on NCP and allocated production and transmission costs based on measures of Average and Excess Demand that are in part dependent on NCP. As a result, modifying NCP-based allocation factors is expected to significantly impact the assessment of cost to serve DG customers.

While I was able to produce results for each group of customers, the results exhibit some of the problems with the underlying load data that I described in the previous section. To demonstrate the differences between the allocation factors based on delivered load and exported load, Table 14 below presents the NCP allocation factors from the Base Case COSS, which uses delivered load, and the DG Class COSS, which uses exported load.

Table 14: NCP Allocation Factors (kW)

	Delivered Load	Exported Load	Difference
TEP Residential	12,278	32,108	262%
UNSE Residential	3,122	6,463	207%
TEP Small Commercial	5,532	15,918	288%
UNSE Small Commercial	0	1,002	n/a

As shown in Table 14, the NCP allocation factors the Companies used in the DG Class COSS were 2-3 times greater than the NCP allocation factors measured based on delivered load in the Base Case COSS. This is consistent with Mr. Jones' claim that "the NCP associated with exporting energy was nearly three times as high as the import NCP for the residential partial requirements customer reflected in the Base Case cost study."[81]

Interestingly, Table 14 depicts a zero kW delivered load NCP allocator for the UNSE small commercial class. The UNSE small commercial class reached its class NCP during the test year on July 24, 2014 at 3:00 p.m.[82] The hourly load profile constructed by UNSE shows a zero value for delivered load on this day and hour.

Q. Is it accurate to assume a zero NCP allocator for the UNSE small commercial class?

A. No, it is not. As I described in detail above, one of the major problems with the load assessment in the Companies' COSS is the fact that they chose to develop a complicated hypothetical analysis to approximate hourly net load for DG customers, rather than use actual metered data like they did for all non-DG customers in the COSSs to measure instantaneously delivered load. For the UNSE small commercial class, this problem manifests as a zero value for load during the hour of class NCP. In reality, it is expected that UNSE small commercial DG customers consumed some level of energy from the grid during that hour, while also exporting energy to the grid.

This result also provides important context regarding the cost to serve DG customers. UNSE's analysis shows in the hour when small commercial customers collectively reached their class peak, customers with DG were net exporters to the grid. Class NCP is a standard measure for cost-causation in cost of service study analysis. If UNSE's small commercial customers with DG were actually

[81] Jones Phase 2 Direct at 4:18–21 (italics omitted).
[82] UNSE COSS tab "Load Data Allocators."

supplying more energy than they consumed from the grid during this critical hour, they were contributing to reduced congestion on the grid and displacing the need to deliver energy to end-use customers when it was most expensive.

Q. How should the Commission view your results in light of the load data on which it was based?

A. While the zero value NCP allocator for UNSE small commercial customers is certainly not an accurate measure for cost allocation, I am unable to develop a more reasonable measure of UNSE small commercial customer demand during the class peak hour, as the Companies have not made instantaneous DG customer data available. I have elected to conduct an analysis based on this assumption, with the caveat that the results should only be used to analyze differences between the results of the COSS using the Base Case method and the DG Class method recommended by the Companies.

Q. Do you believe the results for the other classes are more reliable than the Base Case UNSE small commercial results?

A. Not necessarily. While the zero value allocator for UNSE small commercial customers is certainly an outlier, it is emblematic of the problems with the Companies' approach. From a methodological standpoint, the UNSE small commercial load data in the Base Case COSS is no more unreasonable than the load data used to develop the Companies' own results presented in their direct testimony. As a result, I believe it is worthwhile to examine illustrative results from the Base Case COSS to compare with the Companies' recommended DG Class COSS. The results should not be relied on for ratemaking, but they do produce an important counterpoint to the Companies' analysis.

Q. Please summarize your illustrative results.

A. When I modified the Companies' COSSs to consider the Base Case COSS methodology for allocating costs based on delivered load, it became clear that the DG Class methodology employed by the Companies inflates the estimated revenue requirement significantly. The estimated Revenue Requirement for each group of DG customers is shown in Table 15 below.

Table 15: Revenue Requirement Results Under Base Case and DG Class COSS[83]

Group of Customers	Base Case	DG Class	Difference
TEP Residential	$7,227,000	$11,153,000	154%
UNSE Residential	$1,470,000	$1,928,000	131%
TEP Small Commercial	$3,105,000	$5,501,000	177%
UNSE Small Commercial	$111,000	$250,000	225%

As shown in Table 15, the Companies' decision to employ the DG Class methodology, as opposed to the Base Case methodology, results in a significantly higher revenue requirement for DG customers. The revenue requirement for residential customers increases 30-60% under the DG Class methodology, while the revenue requirement for small commercial customers roughly doubles. All of these results must be underlined with the significant caveat that the load data used to develop each revenue requirement is based on the Companies' complicated and inaccurate hypothetical methodology, including the UNSE Small Commercial Base Case result which is predicated on a zero value of NCP demand based on UNSE's own assessment.

Q. Are you able to draw any conclusions from these results?

A. Yes. If the Commission accepts the Companies' methodology for approximating DG customer load data to inform the COSSs, the results for the Base Case COSS are preferred to the results from the DG Class COSS. This is because the Base Case COSS properly allocates costs to DG customers based on delivered load, rather than developing NCP allocators based on DG exports. As described in the testimony of Mr. Volkmann, DG exports do not cause costs on the system. Moreover, even if DG exports did result in additional costs, those costs should be

[83] Results for the Base Case COSS additionally reflect minor changes as a result of the pro forma revenue analysis described in Section 6.2.2 below.

included in the assessment of the export compensation rates separate from the COSS analysis, consistent with Decision 75859.

6.2.2 The Companies have underestimated revenues from current rates.

Q. Please describe your finding that the Companies have underestimated revenues from current rates.

A. Mr. Jones claims DG customers produce a negative rate of return at current rates. In support of this analysis, Mr. Jones compared the results of the DG Class COSS analysis to revenues received from DG customers based on current rates with retail rate net metering.[84] The revenues analyzed therefore account for not only the price the customers would pay for delivered energy, but also the compensation they currently receive for exported energy.[85]

Decision 75859 has indicated that net metering will be replaced with a compensation rate for exports. Thus, it is an inaccurate representation of cost recovery under current rates to compare cost to serve DG customers with revenues they would pay under net metering. Rather, as the Commission directed, exports and self-consumption should be considered separately. Consistent with the methodology recommended for DG customer cost allocation, revenues received under current and proposed rates should be based on delivered load.

Q. How did the Companies' decision to measure revenues from current rates based on net load, rather than delivered load, impact their assessment?

A. The Companies' decision to measure revenues from current rates based on net load dramatically underestimates the revenues received from these customers. Table 16 below compares the revenues calculated by the Companies based on net load at current rates and revenues with a pro forma revenue analysis that calculates revenues from DG customers based on delivered load.

[84] Jones Phase 2 Direct at 10:1–11:22.

[85] Even though export compensation is included in the revenue assessment, Mr. Jones does not account for any benefits associated with rooftop solar exports.

Table 16: DG Customer Revenues at Current Rates

Group of Customers	Net Load	Delivered Load	Underestimate
TEP Residential	$3,655,000	$6,490,000	44%
UNSE Residential	$616,000	$1,292,000	52%
TEP Small Commercial	$3,757,000	$5,223,000	28%
UNSE Small Commercial	$75,000	$163,000	54%

As shown in Table 16, the Companies' methodology underestimated the revenues under current rates by 28-54%, depending on the group of customers. In contrast, the Companies measured revenues from proposed rates based on delivered load. The inconsistent methodology underestimates cost recovery at current rates and overestimates the difference between current and proposed rates.

6.2.3 DG customers pay more than their fair share of costs under current rates.

Q. Have you developed an assessment of cost recovery from DG customers after correcting for the two factors you describe above?

A. Yes. I have developed an assessment of cost recovery from DG customers based on the Base Case COSS methodology that allocates costs based on delivered load and the pro forma revenue analysis that calculates revenues based on delivered load. For purposes of this analysis, I excluded the revenues received from the DG meter fees that were approved in Phase 1. The results of this analysis are presented alongside the Companies' results in Table 17 below.

Table 17: Rate of Return at Present Standard Rates, No Meter Fee

Customer Group	Phase 1 Approved Class Rate of Return[86]	DG Customer (Company Assessment)[87]	DG Customer (Vote Solar Assessment)
TEP Residential	2.78%	-15.36%	7.53%
UNSE Residential	1.12%	-22.72%	2.08%
TEP Small Commercial	15.81%	-4.44%	46.38%
UNSE Small Commercial	11.36%	-23.93%	114.42%

While Mr. Jones contends the Companies receive a negative rate of return from DG customers at current rates, those results were based on the two flawed assumptions described above. When the analyses are corrected to assess costs and revenues based on delivered load, the results indicate that DG customers across all classes produce a positive rate of return on their standard rates prior to consideration of the DG Meter Fee. Indeed, Table 17 shows that the rates of return from DG customers are larger than the rates of return expected from the rates approved for the residential and small commercial classes in Phase 1.

Q. Have you conducted an analysis of relative cost recovery from DG customers under all the current rate options available to them?

A. Yes. Under the Companies' proposal, new DG customers would no longer have access to any of the current rate options that are available to them. The current rate choices for all residential and small commercial customers, including DG customers, are: (1) a standard two-part inclining block rate; (2) a two-part TOU rate; (3) a three-part rate with a flat volumetric charge; and (4) a three-part TOU rate. For purposes of comparison, I assessed the revenues and rates of returns expected from each of the current tariff options. The results of this analysis are shown in Table 18 below.

[86] COSSs Schedule G-2.
[87] Jones Phase 2 Direct at 10:1–11:22.

Table 18: Cost Recovery from DG Customers Under Current Rate Options, No Meter Fee

	Revenues[88]	Rate of Return
TEP Residential		
Residential Service Basic	$6,647,000	7.5%
Residential Service Time-of-Use	$6,474,000	6.5%
Residential Service Peak Demand	$5,451,000	0.6%
Residential Demand Time-of-Use	$5,322,000	-0.1%
UNSE Residential		
Residential Service Basic	$1,283,000	2.1%
Residential Service Time-of-Use	$1,309,000	3.1%
Residential Service Peak Demand	$1,144,000	-3.4%
Residential Demand Time-of-Use	$1,161,000	-2.7%
TEP Small Commercial		
Small General Service Basic	$4,888,000	46.4%
Small General Service Time-of-Use	$4,806,000	44.7%
Small General Service Peak Demand	$4,201,000	32.5%
Small General Service Demand Time-of-Use	$4,128,000	31.0%
UNSE Small Commercial		
Small General Service Basic	$150,000	114.4%
Small General Service Time-of-Use	$165,000	150.5%
Small General Service Peak Demand	$99,000	-8.7%
Small General Service Demand Time-of-Use	$111,000	21.1%

While the Companies have proposed to create separate rate schedules for DG customers, evidence from the cost of service analysis clearly indicates that differential rate treatment is unreasonable and unnecessary. As shown in Table 18, DG customers yield positive returns on the basic two-part tariffs that are currently available to them. Moreover, for TEP DG customers, the greatest rate of return is achieved from customers who take service on the basic two-part rate. For UNSE, return from customers on the basic rate is second to returns from customers on the two-part TOU rate. Interestingly, despite repeated claims by the Companies that rates with demand charges result in greater fixed cost recovery, rate options with demand charges result in a lower rate of return for the Companies.

[88] Basic rate revenues presented in Table 18 differ slightly from the revenues presented in Table 16 due to a slight variation in the Companies' billing determinant methodology.

Q. You indicated that these results did not include the current DG Meter Fees. How do results change when the DG Meter Fees are included?

A. Revenues and rates of return will increase for all rate options with the inclusion of the current DG Meter Fees.

Q. How do these results compare with revenues and rates of return under the Companies' proposed DG-only rate schedules?

A. Revenues and returns under the Companies' proposed rate schedules are significantly higher than under current rates. The Companies have proposed to reduce the number of rate options available to residential and small commercial customers from four to two, and to modify the remaining two rate options through increased fixed charges, a flattening of tiered volumetric charges, and the addition of a Grid Access Charge to the two-part TOU rate option. The Companies presented their assessment of returns from DG customers on the proposed two-part TOU rates in their Phase 2 direct testimony, which indicated that the proposed rates would result in modest rates of return. However, that finding was based on (1) their underestimation of the average installed capacity of DG systems as explained in Section 6.1.5, and (2) their use of the DG Class COSS, which significantly over-estimated revenue requirements for DG customers. When the installed system size is updated based on actual DG customer information, and Base Case COSS methodology is applied, the results are starkly different, as summarized in Table 19 below.

Table 19: Rate of Return at Proposed TOU Rates with Grid Access Charge

Customer Group	Phase 1 Approved Class Rate of Return[89]	DG Customer (Company Assessment)[90]	DG Customer (Vote Solar Assessment)
TEP Residential	2.78%	0.63%	21.20%
UNSE Residential	1.12%	0.00%	15.37%
TEP Small Commercial	15.81%	3.11%	65.49%
UNSE Small Commercial	11.36%	-4.23%	248.73%

When the COSS is revised to utilize the Base Case methodology where all costs are allocated consistently to customers based on delivered load, the results clearly demonstrate that the Companies have proposed rate schedules for DG customers that would generate large rates of return for the Companies. These inflated rates of return for DG customers bear little resemblance to the cost to serve DG customers. As shown in Table 19, the proposed two-part TOU rate with the Grid Access Charge would result in returns from the residential class of 15-21%. This elevated rate of return stands in stark contrast to the 1-3% returns expected from residential class revenues approved in Phase 1. In addition, the updated analysis reveals extreme rates of return for the small commercial class.

6.3 <u>The Companies' proposal to single out DG customers for differential rate treatment is discriminatory</u>

Q. Based on your cost of service analysis, have you been able to draw any conclusion about the Companies' rate design proposals?

A. Yes. First, the load data on which the COSSs were based treats DG customers in a different manner than all other customers. The Companies have elected to base their proposed rate designs for DG customers on cost of service analyses that rely on the inaccurate and hypothetical load data analyses, rather than using actual customer metered data as they do for all other groups of customers in the study.

[89] COSSs Schedule G-2.
[90] Jones Phase 2 Direct at 10:1–11:22.

Second, the results from the cost of service analysis described above demonstrate that (1) DG customers are paying more than their fair share of costs under current rates; and (2) the rate options proposed by the Companies would result in unreasonably large returns from DG customers that are far in excess of the rates of return based on revenues approved in Phase 1 of these proceedings. As a result, singling out DG customers for this differential rate treatment would be unnecessary, unreasonable, and discriminatory.

Q. Could DG tariffs be designed that would result in rates of return consistent with that expected from rates approved for their respective rate classes in Phase 1?

A. Yes. While I do not believe that the Companies' COSSs can be relied on for ratemaking purposes, as described in Section 6.1, for illustrative purposes I have analyzed a series of two-part rates that would achieve the same rates of return from DG customers as those approved for their respective classes in Phase 1 of this proceeding. To design these rates, I began with the rate options currently available to TEP and UNSE customers in the residential and small commercial classes and determined the appropriate Grid Access Credit that should be awarded to DG customers based on the size of their rooftop solar installation. The Grid Access Credit works in the same manner as the Companies' proposed Grid Access Charge. However, the Grid Access Credit recognizes the relatively lower cost to serve DG customers, so it provides a monthly bill credit to DG customers based on the installed capacity of their DG system. The illustrative DG-only tariffs are identical to the current non-DG tariffs in all respects except for the inclusion of the Grid Access Credits, which are summarized in Table 20 below.

Table 20: Illustrative Monthly Grid Access Credits for DG Customers ($/installed kW-DC)

	TEP	UNSE
Residential Service Basic	-$1.30	-$0.22
Residential Service Time-of-Use	-$1.02	-$0.46
Small General Service Basic	-$5.83	-$3.26
Small General Service Time-of-Use	-$5.51	-$4.40

Q. Do you recommend that the Commission adopt these rates with Grid Access Credits for DG customers?

A. I do not. First, these rates are presented purely as an illustration because the COSS on which they were premised is itself based on a flawed and inaccurate hypothetical assessment of DG customer load that cannot produce a reliable result for ratemaking.

In addition, even if the COSS were to be revised based on actual DG metered data, as I recommend, the Commission should not adopt Grid Access Credits, or any other differential rate treatment for DG customers. While the Commission indicated in Decision 75859 that DG customers should be considered a separate rate class, they explicitly left open the question of what the ratemaking implications of this separate class treatment may be. Notably, the Companies have not proposed differential rate treatment for DG customers in the medium and large commercial classes so it would appear that they do not believe Decision 75859 requires development of separate rates for DG customers.

Separation of DG customers in the COSS is a fundamental step to support any differential rate treatment for those customers. This is clearly stated by the Commission in Decision 75859, which specifically orders "fully vetted cost of service analysis" to support "ratemaking implications of this separate class treatment."[91] In its discussion of the reasoning behind this conclusion, the Commission stated:

[91] Decision No. 75859 at 178:9–11.

> [T]he appropriate test for the formation of a subclass of customers for purposes of rate design is whether a sub-group of customers is sufficiently different from the sub group's current classification in regard to service, load, or cost characteristics to place that sub-group into a separate class. The record in this proceeding demonstrates that rooftop solar customers are partial requirements customers who export power to the grid, and we therefore find that rooftop solar customers are a separate class of customers.[92]

In this section of the decision, the Commission identified three tests for whether or not a subgroup of customers should be considered a different class: (1) service, (2) load, and (3) cost. Given these three tests, the Commission decided that it was a difference in service—namely the fact that rooftop solar customers export power to the grid—that warranted separation of DG customers into another class. By eliminating net metering and adopting a new export compensation rate methodology, the Commission has accounted for the differences in service that may result from the fact that rooftop solar customers export power to the grid. In this proceeding, the Companies have the opportunity to establish whether there are sufficient differences in load and/or cost to warrant additional ratemaking considerations specific to DG customers. However, as demonstrated above, they have not met that burden.

Even though DG customers pay a larger proportion of their cost to serve than non-DG customers in the same rate class, I recommend they continue to be offered the same rates as non-DG customers. This is for two reasons. First, including DG customers on the standard rate offerings ensures the benefits of private investment in local clean energy resources are shared among participants and non-participants. Second, if the Commission were to approve differential rate treatment for DG customers it would open the door to differential rate treatment of other subsets of customers, which would not be in the public interest.

There are many groups of customers in the residential and small commercial classes that exhibit differences in service, load, or cost. For example, rural customers often require lengthy line extensions and as a group are likely more

[92] *Id.* at 146:1–6.

costly to serve than their urban counterparts. In addition, customers with pool pumps or varying types of cooling equipment are likely to have different costs to serve. By opening the door to differential rate treatment for DG customers, the Commission would need to single out these other subgroups as well. Piecemeal subdivision of the residential and small commercial classes in this manner would add significant complexity and may harm low- and fixed-income ratepayers, particularly those located in rural Arizona.

7 The DG Meter Fees Should Be Eliminated

Q. What have the Companies proposed for DG Meter Fees in this phase of the proceedings?

A. The Companies have proposed to increase the DG Meter Fees that were approved for new DG customers as of the effective dates of the rates in Phase 1 of each Company's rate case.[93] The current and proposed charges are summarized in Table 21 below. In this phase of the proceedings, the Companies have requested that these fees be applied to all DG customers who have signed up after the effective date of the Phase 1 rates.[94]

Table 21: Current and Proposed DG Meter Fees ($/month)

Customer Class	Current	Proposed
TEP Residential	$2.05	$4.32
TEP Small Commercial	$0.35	$5.62
UNSE Residential	$1.58	$3.92
UNSE Small Commercial	$1.58	$4.60

[93] Jones Phase 2 Direct at 14:14–17.
[94] *Id.* at 16:17–19.

7.1 <u>Prior Commission guidance on the DG Meter Fees</u>

Q. What guidance did the Commission give in its decisions to implement the current DG Meter Fees?

A. The first DG Meter Fee to be implemented was in Phase 1 of the UNSE rate case. In Decision 75697, the Commission approved a monthly metering fee of $1.58 for new UNSE DG customers, based on the total embedded capital costs for metering equipment presented by UNSE.[95] In its Reply Brief, UNSE introduced the concept of a metering fee of $6.95, based on the fully loaded embedded costs of non-net metering residential meters.[96] The UNSE proposal included line items for billing and collection and meter reading, categories which include costs related to supervision, miscellaneous customer accounts expenses, customer assistance expenses, informational and instructional advertising expenses, and miscellaneous customer service and informational expenses, in addition to loaders for administrative and general expenses.[97] However, the Commission only approved the capital costs for inclusion in the metering fee and directed the parties to reconsider this issue in Phase 2 of the UNSE rate case.[98]

In Phase 1 of the TEP rate case, the DG Meter Fee was introduced much earlier in the process, allowing for a more complete consideration of the evidence.[99] In Phase 1 of the TEP case, both TEP and the Residential Utility Consumer Office ("RUCO") advocated for a meter fee that would cover the costs of the production meter that is installed with a DG system in addition to the costs associated with the bidirectional meter necessary for DG customer billing.[100] However, the Commission clearly decided that costs related to the production meter should not be included in the DG Meter Fee and that charges should be limited to

95 Decision No. 75697 at 118:6–18.
96 Docket No. E-04204A-15-0142, UNSE Reply Br. at 12:23–13:1 (May 11, 2016).
97 2015 UNSE Schedule G-COSS-R.xlsx.
98 Decision No. 75697 at 118:19–25.
99 *See* Decision No. 75975 at 155:18–20.
100 *Id.* at 154:16–17.

incremental costs associated with the bidirectional meter only. The Commission explained:

> [W]e also agree with Vote Solar's position that the fee should not be based on the cost of the production meter, but on the incremental cost of the bidirectional meter that is necessary for DG customers to receive credit for their systems' production and to receive compensation for their excess production. The production meter supports REST compliance (and LFCR calculations). The REST Rules are for the benefit of all ratepayers, the Company, and society in general, and the cost of REST compliance should not be imposed only on the group of customers who contribute to meeting renewable goals. The bidirectional meters, however, do benefit the DG customers who receive compensation for their production, and it is appropriate on an interim basis that new DG customers are responsible for the additional costs of serving them.[101]

With its approval of Vote Solar's proposed DG Meter Fee, the Commission additionally stated that "in both cases, the fee adopted in Phase l will be further evaluated in Phase 2, and may be further refined."[102]

7.2 The Companies have not provided sufficient evidence to support the proposed increase in the DG Meter Fees

Q. What additional evidence have the Companies produced to support the proposed Phase 2 increases to the DG Meter Fees?

A. It appears the Companies have introduced no new evidence to support their proposal. In testimony describing the increased DG Meter Fee proposal, the Companies reference the marginal cost studies introduced in Phase 1 of each proceeding. In discovery, the Companies have confirmed that they have not changed any aspect of the marginal cost studies presented.[103] Rather, the Companies make the same argument that was made in Phase 1 of the TEP rate case, namely that the DG Meter Fees should be as high as $8.62 per month for TEP residential customers and $9.13 per month for TEP small commercial

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[101] *Id.* at 155:2–11.
[102] *Id.* at 155:20–21.
[103] TEP & UNSE Joint Resp. to VS P2 1.13 (Attach. 1 at 23).

customers based on their marginal cost study including costs for administrative expenses such as the costs included in numerous FERC accounts (FERC Accounts 902, 903, 909, 910, and 920-935).[104] These accounts include expenses such as Meter Reading (Account 902), Customer Records and Collections (Account 903), Advertising (Account 909), and Salaries (Account 920). Inherent in TEP's argument is the assumption that all of these administrative costs double when a customer's standard meter is replaced with a bidirectional meter.

Vote Solar argued in Phase 1 of this proceeding that it is both illogical and counterintuitive that every type of administrative expense would double when a customer's metering equipment changes.[105] The Commission accepted Vote Solar's argument in Decision 75975 where it found that the appropriate DG Meter Fee should not include any of these administrative costs, but rather should be based exclusively on the total incremental capital and labor cost to install a bidirectional meter.[106]

Q. What is the rationale for the Companies' proposed DG Meter Fees in this Phase of the proceedings?

A. Mr. Jones states: "While the Companies believe a much higher charge [that includes 100% of the marginal costs of the bidirectional meter as well as a doubling of administrative costs] is justified, it is willing to accept charges that are slightly lower, in the spirit of gradualism."[107] Mr. Jones then goes on to assert that "[b]oth Vote Solar and the Commissioners seemed to support [the Companies' proposed] method as being acceptable, therefore, in the spirit of gradualism, the Companies are willing to accept the above amounts as the

[104] Jones Phase 2 Direct at 15:12–15.
[105] Docket No. E-01933A-15-0322, Vote Solar Initial Post-Hearing Br. at 8:5–11 (Oct. 31, 2016).
[106] Decision No. 75975 at 155:12–16.
[107] Jones Phase 2 Direct at 16:4–5.

minimum DG meter charges to be applied to new DG customers as the result of this proceeding."[108]

Q. Does Mr. Jones correctly characterize Vote Solar's position on this issue?

A. No. In this phase of the proceedings, the Companies have proposed to base new DG Metering Fees on the total embedded costs associated with bidirectional metering equipment. It was Vote Solar's position in the TEP Phase 1 case that any DG Meter Fee should be limited to the <u>incremental</u> costs associated with replacement of a standard meter with a bidirectional meter.[109] Because DG customers are already paying for the embedded costs of a standard meter through their current customer charges, consideration of a DG Meter Fee should be limited to the incremental costs of the bidirectional meter in excess of the standard meter. Notably, the Commission explicitly agreed with Vote Solar.[110]

Q. Does Mr. Jones provide any additional rationale for the Companies' proposal?

A. Yes. Mr. Jones states:

> At a minimum an increase is warranted based on the fact that the TEP Phase 1 decision approved a $5 per month incremental increase to the basic service charge for three-phase customers due to their more expensive service connection costs. This also supports the Companies' request to increase the incremental meter charge for distributed generation customers since they actually cost more to connect to the system than a three-phase customer.[111]

Q. Do you agree that incremental charges approved for three-phase residential customers support a request to increase the DG Meter Fees?

A. No. I find the two issues wholly unrelated. The magnitude of incremental customer charges for customers with different phases of service is unrelated to the

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[108] *Id.* at 16:14–17.
[109] Vote Solar Initial Post-Hearing Br. at 9:3–4.
[110] Decision No. 75975 at 155:12–16.
[111] Jones Phase 2 Direct at 16:24–17:2.

question of the appropriate DG Meter Fees. If it is correct that DG customers cost more to connect to the system than a three-phase customer, this warrants a reconsideration of the incremental three-phase customer charges approved in Phase 1 of this proceeding in TEP's next rate case, rather than a rationale for arbitrarily increasing DG Meter Fees.

7.3 Vote Solar recommendation

Q. What do you recommend for a DG Meter Fee in this case?

A. In Phase 1 of the TEP proceeding, Vote Solar repeatedly argued that the Meter Fee was more appropriate to consider in Phase 2 because approval of a meter fee in Phase 1 would prevent the Commission from holistically and comprehensively considering solar rate design and net metering proposals in Phase 2.[112] This was especially concerning in Phase 1 of the TEP proceeding in which the Commission chose not to conduct a full evidentiary hearing on solar rate design and net metering issues. The Commission nonetheless chose to approve DG Meter Fees in the first phase of these proceedings, without any evidence as to whether and to what extent DG customers were paying their cost to serve under current rates without the DG Meter Fees.

In this case we have, for the first time, COSS analysis that differentiates between customers with and without DG in TEP and UNSE's service territories. With this additional information, it is now clear that the approved DG Meter Fees are unnecessary. The Companies included costs for bidirectional meters in the allocation of customer costs to DG customers in the COSSs. As described in Section 6.2, evidence from the COSS demonstrates that DG customers are already paying more than their fair share of costs under current rates without the DG Meter Fees. It is therefore unnecessary to continue to charge customers this incremental fee, and I recommend it be eliminated.

[112] Vote Solar Initial Post-Hearing Br. at 3:11–14.

Q. If the Commission does not accept your recommendation to eliminate the DG Meter Fees, how do you propose that meter fees be set?

A. If the Commission wishes to maintain the DG Meter Fees I recommend that the meter fees approved and implemented for TEP be maintained and that similar fees be implemented for UNSE based on information specific to its costs of service. For both Companies, I recommend that the Commission offer DG customers a choice between a monthly fee or a one-time upfront payment.

Q. How should the UNSE Meter Fees be developed?

A. The Commission should replace the current $1.58 meter fee for UNSE residential and small commercial customers with fees that cover the incremental costs associated with capital and labor to install DG bidirectional meters for each class of customers. For residential customers the incremental capital and labor cost of the bidirectional meter is $136.00, and for small commercial customers the incremental cost is $23.00. I recommend that DG customers be given the option to pay these fees as single upfront payment or to pay a monthly charge. Using the carrying charge employed by UNSE in their marginal cost study, this results in a monthly charge of $2.18 for residential customers, and $0.37 for small commercial customers. The capital and labor costs used to derive these figures are provided in Attachment 2. For reference, Attachment 3 contains the TEP cost information used to develop the currently implemented TEP DG Meter Fees.

8 TEP's Residential Community Solar Program

Q. What has TEP proposed for its RCS Program?

A. TEP has proposed to implement an RCS Program similar to what has previously been proposed in this docket. For this program TEP will either build, own, and operate or contract with a third-party for a solar facility of roughly 5 MW.[113] As

[113] Carmine Tilghman Direct Test. at 3:14–18 (Mar. 17, 2017) [hereinafter "Tilghman Phase 2 Direct"].

part of its proposal, TEP proposes to exclude renters from the program,[114] and has requested a waiver of the DG definition as codified in the REST rules.[115] TEP proposes a fixed rate of $19/kW for participants.[116]

Q. What is Vote Solar's position on TEP's proposed RCS Program?

A. As a general principle, Vote Solar supports expanding access to solar energy to customers through community solar programs. However, there are several aspects of the proposed RCS program that Vote Solar opposes. First, Vote Solar does not support a community solar program that limits enrollment to home-owners. Second, Vote Solar does not support TEP's request for a waiver of the REST rules. While Vote Solar has not developed a position on the proposed RCS rates at this time, I may provide additional testimony on this topic at the hearing if necessary to respond to the Companies' rebuttal.

Q. Please explain why you do not support a community solar program that limits enrollment to home-owners.

A. One of the primary benefits of community solar is the ability to provide access to local, clean energy to customers who are not traditional participants in the current DG market. Customers who rent their homes are largely unable to access the DG market and stand to benefit from availability of community solar offerings. While TEP contends that renters would be eligible for the Bright Tucson program, there is no reason why they should not also be eligible for the RCS program. While TEP's proposal requires that participants own their own homes, the requirements could be modified to construct a contractual arrangement that would allow renter participation.

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[114] *Id.* at 10:6.
[115] *Id.* at 11:15.
[116] *Id.* at 3:23–25.

Q. Please explain why you do not support TEP's request for a waiver of the REST rules in this docket?

A. Under current law, the REST rules define "distributed generation" as "electric generation sited at a customer premises, providing electric energy to the customer load on that site or providing wholesale capacity and energy to the local Utility Distribution Company for use by multiple customers in contiguous distribution substation service areas."[117] TEP has requested a waiver of this definition to redefine "distributed generation" as all sources that are "directly connected to TEP's distribution system."[118]

As Mr. Tilghman correctly notes, TEP made a similar request in an early stage of this proceeding and the Commission ruled that this issue be addressed in Docket No. E-00000Q-16-0289.[119] Mr. Tilghman claims, "At the time, it was believed that that docket would proceed quickly. However, the Commission has not yet moved forward with that docket, so it is now necessary to address the waiver issue in this docket."[120]

Q. Do you agree with TEP's claim that this issue must be addressed now?

A. No. Docket No. E-00000Q-16-0289 is an active docket in which the Commission has engaged numerous stakeholders on questions relating to the current REST rules. A large number of parties submitted responses to questions from the Commissioners last fall, including the question of whether or not to modify the current DG carve-out and whether to specifically address community solar in the new rules.[121] The Commissioners are currently considering these issues and have scheduled an additional workshop on June 7, 2017. Ruling on TEP's request for a

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[117] A.A.C. R14-2-1801(E).
[118] Tilghman Phase 2 Direct at 12:10–12.
[119] *Id.* at 11:21–24.
[120] *Id.* at 12:1–3.
[121] *See, e.g.*, Docket No. E-00000Q-16-0289, Chairman Doug Little Letter (Sept. 14, 2016); Docket No. E-00000Q-16-0289, Various Comments (Nov. 30, 2016).

waiver is premature and unnecessary in light of the ongoing examination of these issues in Docket No. E-00000Q-16-0289.

Moreover, TEP has not demonstrated any need for a waiver to support the proposed RCS Program. Mr. Tilghman states: “A waiver will allow the RCS program to count towards compliance with the Commission’s REST standards for DG.”[122] However, for the past several years, the Commission has awarded TEP waivers to the residential DG requirement in recognition of the growth in DG in TEP’s service territory for which TEP is not entitled to renewable energy credits. As a result, the waiver TEP now requests will not provide any tangible relief to TEP and is unnecessary. If the Commission were to grant TEP’s requested waiver, it would undermine the policy purpose of the original REST rules and may undercut the Commission’s ability to comprehensively determine the best path forward for the Arizona REST program.

9 Conclusions and Recommendations

Q. Please summarize your conclusions.

A. As I have shown in my testimony, implementation of Decision 75859 is expected to have a significant impact on DG in the Companies’ service territories. As a result, I recommend that the Commission implement a gradual transition away from net metering that is consistent with the direction of the Commission in Decision 75859. Namely, I recommend that the Commission implement a first-year export rate of $0.154/kWh for TEP and $0.152/kWh for UNSE with a 10% floor on annual export compensation decline after the 10-year lock-in period. This would provide a gradual and predictable transition away from retail rate net metering and would appropriately balance the desire to reduce export compensation rates with the critical need for certainty for individual households and small businesses considering investment in local clean energy resources.

[122] Tilghman Phase 2 Direct at 11:17–18.

After conducting an in-depth review of the Companies COSSs and Proofs of Revenue, I find that both analyses are deeply flawed and should not be relied upon for ratemaking. The Companies' studies are premised on a complex analysis that approximates DG customer load data and introduces significant error. I conclude that the Companies' approach is not only inappropriate, but also unnecessary; as it appears that the data exists to simply sample actual DG customer usage information rather than rely on the hypothetical analysis employed by the Companies. I recommend that the Commission instruct the Companies to resubmit the COSSs and Proofs of Revenue based on DG customer load data developed in a manner consistent with the load data developed for all other groups of customers in the COSS and Proofs of Revenue.

I find that in addition to the flawed DG customer load data, the Companies employed two key assumptions that were inappropriate and significantly skewed their results. First, the Companies allocated costs to DG customers based in part on a measure of DG exports. There are no costs associated with DG exports, and even if there were, any such costs should be considered with the export compensation rate as ordered by Decision 75859. I recommend that DG customers be treated consistently with all other customers in the COSSs and that all costs be allocated based on delivered load. In addition, I find that the Companies' comparison of cost recovery from DG customers on current and proposed rates is based on an inappropriate calculation of revenues that conflates the price paid for deliveries with compensation received for exports under retail rate net metering.

When the COSSs are corrected for these two key assumptions, I find the evidence clearly shows that DG customers recover more than their fair share of costs under current rates without the DG Meter Fees. I find that the Companies' proposal would result in unreasonably large returns, far in excess of the returns from rates for non-DG customers approved in Phase 1. As a result, I conclude that the Companies' DG rate design proposals are unnecessary and discriminatory.

I also find that if the Commission desires to create separate rate design for DG customers, despite the lack of evidence to support the need, DG customers should be allowed to take service on any available rate schedule with the addition of a Grid Access Credit calibrated to ensure cost recovery from DG customers that is commensurate with that approved for the broader residential and small commercial classes. While I do not recommend this approach, I have provided illustrative Grid Access Credits that would achieve this outcome.

In addition, I find that the current DG Meter Fees should be eliminated because the evidence shows that DG customers already recover more than their fair share of costs under current rates without the DG Meter Fees. In the event that the Commission chooses to continue imposition of the DG Meter Fees, I find that the Companies has provided no evidence to support their proposed increases. As a result, I recommend the TEP DG Meter Fees be maintained and that the UNSE Meter Fees be updated to be consistent with the fees approved for TEP. This would result in a one-time upfront charge of $136.00 for residential customers and $23.00 for small commercial customers, or an ongoing monthly fee of $2.18 for residential customers and $0.37 for small commercial customers.

Finally, after review of TEP's proposed RCS program, I find it is unreasonable to restrict enrollment to home-owners and recommend that if the program is approved, it be made available to all residential customers. In addition, I find TEP's request for a waiver of the "distributed generation" definition in the REST rules is unnecessary, as the Commission has consistently provided TEP with waivers of compliance to the DG requirement under the current REST rules and is currently undertaking a comprehensive examination of the REST rules in Docket No. E-00000Q-16-0289. I recommend TEP's request for a waiver be rejected.

Q. What are your recommendations for the Commission?

A. Taking into account the analyses and evidence reviewed in this case I recommend the following:

Grandfathering

- Existing DG customers should be grandfathered into retail rate net metering and current rate design options.

Net Metering and Export Compensation Rates

- The Commission should undertake a rulemaking to modify the existing net metering rules prior to implementation of an export compensation rate.
- If the Commission decides to implement an export compensation rate in this proceeding, the Commission should implement a first-year RCP of $0.154/kWh for TEP and $0.152/kWh for UNSE.
- The Commission should adopt a 10% floor on annual export compensation rate decline after the 10-year lock-in period.

Rate Design for New DG Customers

- The Commission should reject the COSSs and Proofs of Revenue filed by the Companies and direct them to resubmit analyses that measure load from DG customers based on actual instantaneously metered data, consistent with how all other customers are treated in the COSSs and Proofs of Revenue.
- The Commission should find that the COSSs and Proofs of Revenue are not sufficient to be relied on for ratemaking.
- The Commission should find that it is inappropriate to allocate costs to DG customers in the COSS based on exported load and that the appropriate measure for cost allocation is delivered load.
- The Commission should find that DG customers recover more than their fair share of costs under current rates and separate rate treatment for DG customers is unnecessary.
- The Commission should find that the Companies' proposed rates would result in unreasonably large returns, are discriminatory, and should be rejected.

- If the Commission decides to separate DG customers for purposes of rate design, the Commission should provide DG customers with access to all current tariffs with a Grid Access Credit.

DG Meter Fees

- The current DG Meter Fees are unnecessary and should be eliminated.
- If the Commission desires to continue imposition of the DG Meter Fees, the current TEP Meter Fees should remain in place and the UNSE Meter Fees should be updated for consistency with the TEP fees. This would result in a one-time upfront charge of $136.00 for residential customers and $23.00 for small commercial customers, or an ongoing monthly fee of $2.18 for residential customers and $0.37 for small commercial customers.

Residential Community Solar Program

- If the RCS program is approved, the Commission should require that it be made available to all residential customers, not just those who own their own homes.
- The Commission should reject TEP's request for a waiver of the definition of "distributed generation" under the REST rules.

Q. Does this conclude your testimony?

A. Yes, it does.

Attachment 1

Discovery Responses Referenced in Testimony

TUCSON ELECTRIC POWER COMPANY'S AND UNS ELECTRIC, INC.'S JOINT RESPONSE TO STAFF'S SECOND SET OF DATA REQUESTS REGARDING PHASE 2 OF THE 2015 TEP RATE CASE AND THE 2015 UNSE RATE CASE DOCKET NO. E-01933A-15-0322 AND E-04204A-15-0142 April 7, 2017

STF P2 2.1

Please provide a detailed explanation as to why the Companies are proposing to use a single RCP rate for both service territories.

RESPONSE:

The single RCP that was calculated for both TEP and UNS Electric is consistent with both the Companies' testimony, as well as Staff's calculations used during the Cost and Value of Distributed Solar proceeding.

Commission Decision No. 75859 specifically states that "staff shall use the spreadsheet described in this Decision to develop a proxy for rooftop solar generation, …" (page 172, lines 1-2). The spreadsheet described in this Decision includes a single RCP calculation for both TEP and UNS Electric (see pages 114-117).

Additional testimony was filed in the most recent "Phase 1" UNS Electric and TEP rate cases (see Direct Testimony for Carmine Tilghman) regarding the use of a single proxy rate for both companies. The Companies believe and have consistently maintained that it is both reasonable and appropriate to use a single rate as TEP and UNS Electric share a common balancing authority, as well as the ability to transfer energy between transmission and distribution systems. As such, the Companies can take advantage of shared resources, which is of particular value to UNS Electric as it is smaller and serves more remote locations.

RESPONDENT:

Carmine Tilghman

WITNESS:

Carmine Tilghman

TUCSON ELECTRIC POWER COMPANY'S AND UNS ELECTRIC, INC.'S JOINT RESPONSE TO VOTE SOLAR'S FIFTH SET OF DATA REQUESTS REGARDING PHASE 2 OF THE 2015 TEP RATE CASE AND THE 2015 UNSE RATE CASE
DOCKET NOS. E-01933A-15-0322 AND E-04204A-15-0142
Originally Submitted: April 20, 2017
Updated: May 1, 2017

VS P2 5.6

Please indicate whether the Companies have conducted an analysis of marginal system losses on their systems. Please answer separately for TEP and UNSE. If the Companies have conducted an analysis, please provide all relevant reports, filings, analyses, and work papers in Excel format with formulas and links intact.

RESPONSE:

The Companies have not conducted any such analyses.

RESPONDENT:

Craig A. Jones

WITNESS:

Craig A. Jones

TUCSON ELECTRIC POWER COMPANY'S AND UNS ELECTRIC, INC.'S JOINT RESPONSE TO STAFF'S THIRD SET OF DATA REQUESTS REGARDING PHASE 2 OF THE 2015 TEP RATE CASE AND THE 2015 UNSE RATE CASE
DOCKET NO. E-01933A-15-0322 AND E-04204A-15-0142
Originally Submitted: April 7, 2017
Last Updated: April 14, 2017

STF P2 3.17

Refer to the "Load Components" tab of the RCP Model. Please explain how the information shown on that tab was used in computing the Companies' proposed RCP rate.

RESPONSE:

The Load Component tab derives TEP's Retail Loss Factor[1] for 2016. In 2016, TEP's estimated system losses were 741,188 MWh or 8.33% of retail load. From this retail loss factor, TEP subtracted its FERC approved loss factors for 345kV losses (3.3%) and 138kV losses (1.0%) to derive an estimated Distribution Loss Factor[2]. Based on TEP's estimated 2016 Distribution Loss Factor of 4.03%, TEP excluded the service drop and service entrance losses of 0.5% because the Company would continue to incur those losses as rooftop solar customers export their energy back to the grid[3]. As a result, the final Grid Scale Adjustment Factor[4] equals 3.53%. Since UNS Electric's losses are lower, the Companies used the higher grid scale adjustment factor for the aggregated TEP and UNS Electric RCP calculation.

RESPONDENT:

Michael Sheehan

WITNESS:

Carmine Tilghman

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[1] 2016 Retail Loss Factor % = (System Losses = 741,188 MWh / Retail Sales = 8,896,400 MWh).
[2] Distribution Loss Factor = System Loss Factor – 345kV Loss Factor – 138 kV Loss Factor.
[3] Based on APS's methodology as filed in APS supplemental direct testimony of Jeffery M. Burke on behalf of Arizona Public Service Company Docket No. E-01345A-16-0036 and E-01345A-16-0123.
[4] Grid Scale Adjustment Factor = Distribution Loss Factor – Service Drop Losses [4.03% - 0.5% = 3.53%].

TUCSON ELECTRIC POWER COMPANY'S AND UNS ELECTRIC, INC.'S JOINT RESPONSE TO STAFF'S THIRD SET OF DATA REQUESTS REGARDING PHASE 2 OF THE 2015 TEP RATE CASE AND THE 2015 UNSE RATE CASE
DOCKET NO. E-01933A-15-0322 AND E-04204A-15-0142
Originally Submitted: April 7, 2017
Last Updated: April 14, 2017

STF P2 3.28

Do TEP and UNSE have the same line loss factor? If not, please explain how the line losses are different for TEP and for UNSE and how each Company measures line losses.

RESPONSE:

THE FILES LISTED BELOW CONTAIN COMPETITIVELY-SENSITIVE CONFIDENTIAL INFORMATION THAT HAVE ONLY BEING PROVIDED TO THE REQUESTING PARTY PURSUANT TO THE TERMS OF THE PROTECTIVE AGREEMENT.

No, TEP and UNS Electric do not have the same line loss factors. Please refer to the response to STF P2 3.24. The losses used in each individual Companies most recent rate case were used. Retail rates were based on those averaged losses submitted in the respective rate cases and were, therefore, used in the reference calculations.

Losses will vary by time period, ambient temperature, type and size of conductor, voltage, etc. and, therefore, is not a single value. For UNS Electric, the losses were approximated by comparing electricity coming into the system over a specified period of time to the electricity delivered over that period of time. This was accumulated and averaged for use in the UNS Electric rate case and in this filing.

For TEP, a sample period and sample points were used to estimate the losses on the system and averaged on a weighted basis for application in the TEP rate case. Distribution losses were calculated in a manner similar to what was done for UNS Electric, but for distribution facilities only. These averages were used in the development of TEP's retail rates.

For the associated files, please see the files listed below that were submitted as workpapers in the Companies' rate cases and that have been uploaded to the Companies' electronic data room as workpapers for Craig A. Jones in Phase 2.

- For the TEP transmission losses, please see 2015 TEP Line_Loss_Summary Confidential.xlsx, tab "138 kV", cell J29.
- For the TEP distribution losses, please see 2015 TEPLoadResearchSum-CompSen-Confidential.xlsx (the number is the average of Column L minus 1, or, specifically, cell L8764 – 1).
- For UNS Electric, please see UNSE 2014 Annual Integrated Resource Plan_Losses - Competitively Sensitive Confidential.xlsx, tab "Attach 8 kWh Sources & Uses", cells S79 and S80.

RESPONDENT:

Craig A. Jones

WITNESS:

Carmine Tilghman / Craig A. Jones

TUCSON ELECTRIC POWER COMPANY'S AND UNS ELECTRIC, INC.'S JOINT RESPONSE TO VOTE SOLAR'S SEVENTH SET OF DATA REQUESTS REGARDING PHASE 2 OF THE 2015 TEP RATE CASE AND THE 2015 UNSE RATE CASE DOCKET NOS. E-01933A-15-0322 AND E-04204A-15-0142
May 8, 2017

VS P2 7.1

Regarding the Companies' response to Staff P2 3.17:

a. Please explain the differences between two loss figures: those discussed in the Companies' response to Staff P2 3.17, and those presented on the tab entitled "Load Data" in cells O42 to O47 of the TEP Cost of Service Study ("COSS").

b. Please confirm whether the Distribution Loss Factor of 4.03% presented in response to Staff P2 3.17 is an updated value for the 7.14% Distribution Loss Factor presented in the COSS. If there are differences between the 4.03% Distribution Loss Factor and the 7.14% Distribution Loss Factor, other than the time at which the Distribution Loss Factor was measured, please fully explain all such differences.

c. In response to Staff P2 3.17, the Companies indicated that UNSE's losses are lower than TEP's. Please provide a breakdown of UNSE's losses similar to the breakdown the Companies provided for TEP.

RESPONSE:

a. The system loss data shown in the Companies' response to Staff P2 3.17 was based on TEP's 2016 system loss data and was the basis for estimating the Grid Scale Adjustment. The loss factors shown in the TEP COSS were derived from a different study and was based on the test year period of July 2014 to June 2015.

b. No. The numbers shown in the Companies' response to Staff P2 3.17 reflect TEP's Distribution Loss Factor for the calendar year of 2016. In reconciling the two Distribution Loss Factors, TEP determined that the 7.14% Distribution Loss Factor estimate was incorrect. As shown in Table 1 below, TEP's estimated Distribution Loss Factor has ranged between 4.03% and 4.70%.

Table 1 – TEP Annual System Loss Summary

	2016	2015	2014
Retail Load, MWh	8,896,400	9,053,067	9,165,355
System Losses, MWh	741,188	809,142	824,479
Transmission Losses, MWh	293,581	298,751	302,457
138 kV Losses, MWh	88,964	90,531	91,654
Distribution Losses, MWh	358,643	419,860	430,369
System Loss Factor	8.33%	8.94%	9.00%
Transmission Loss Factor	3.30%	3.30%	3.30%
138 kV Loss Factor	1.00%	1.00%	1.00%
Distribution Loss Factor	4.03%	4.64%	4.70%
Three Year Average			**4.45%**

TUCSON ELECTRIC POWER COMPANY'S AND UNS ELECTRIC, INC.'S JOINT RESPONSE TO VOTE SOLAR'S SEVENTH SET OF DATA REQUESTS REGARDING PHASE 2 OF THE 2015 TEP RATE CASE AND THE 2015 UNSE RATE CASE DOCKET NOS. E-01933A-15-0322 AND E-04204A-15-0142 May 8, 2017

c. Table 2 below shows UNS Electric's estimated Distribution Loss Factor for 2014 – 2016. UNS Electric's Distribution Loss Factor has ranged between 3.74% and 4.03%

Table 2 – UNSE Annual System Loss Summary

	2016	2015	2014
Retail Load, MWh	1,637,805	1,628,038	1,677,445
System Losses, MWh	108,515	103,138	105,705
Transmission Losses, MWh	39,008	33,669	29,761
69 kV Losses, MWh	8,189	8,140	8,387
Distribution Losses, MWh	61,318	61,330	67,556
System Loss Factor	6.63%	6.34%	6.30%
Transmission Loss Factor	2.38%	2.07%	1.77%
69 kV Loss Factor	0.50%	0.50%	0.50%
Distribution Loss Factor	3.74%	3.77%	4.03%
Three Year Average			**3.85%**

RESPONDENT:

Jared Dang / Michael Sheehan

WITNESS:

Carmine Tilghman / Craig A. Jones

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO STAFF'S FIRST SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
February 2, 2016

STF 1.12

Background: Please provide a narrative describing the Company's load research program and the sources of the customer CP, NCP and other related data used within the Cost of Service Study and/or for system design. Explain the role of AMI and/or MDM if any.

RESPONSE:

Hourly load data is contained in the Company's Meter Data Management ("MDM") system for individual customers where the infrastructure that automatically collects metering data on a regular basis exists, and customers have meters capable of sending that data. Many customers do not meet those requirements and there are significant time costs associated with retrieving and processing large sets of hourly data, so random samples for the residential and commercial customer classes were used. These samples included hourly data for the entire test year (8,760 hours) for thousands of customers. Every customer for the large light and power service class ("LLP") was pulled and aggregated together because they all have hourly metering data and the class is small. Lighting customers do not have meters on their service so an approximation was made. Sunset and sunrise times were retrieved from the US Naval Observatory which was then multiplied by the wattage of bulbs installed in each district to estimate the 8,760 shape for lighting load.

The 8,760 hours of data was retrieved or approximated for each rate class. This was compared to the 8,760 total system load data to determine CP and NCP data.

RESPONDENT:

Greg Strang

WITNESS:

Craig Jones

UNS ELECTRIC INC.'S RESPONSE TO STAFF'S SECOND SET OF DATA REQUESTS REGARDING THE 2015 UNS ELECTRIC RATE CASE DOCKET NO. E-04204A-15-0142 August 31, 2015

STF 2.014

Background: Please provide a narrative describing the Company's load research program and the sources of the customer CP, NCP and other related data used within the Cost of Service Study and/or for system design. Explain the role of AMI and/or MDM if any.

RESPONSE:

Hourly load data is contained in the Company's Meter Data Management ("MDM") system for individual customers where the infrastructure that automatically collects metering data on a regular basis exists, and customers have meters capable of sending that data. Many customers do not meet those requirements and there are significant time costs associated with retrieving and processing large sets of hourly data, so random samples for the residential and commercial customer classes were used. These samples included hourly data for the entire test year (8,760 hours) for thousands of customers. Every customer for the large power service class ("LPS") was pulled and aggregated together because they all have hourly metering data and the class is small. Lighting customers do not have meters on their service so an approximation was made. Sunset and sunrise times were retrieved from the US Naval Observatory for each district which was then multiplied by the wattage of bulbs installed in each district to estimate the 8,760 shape for lighting load.

The 8,760 hours of data was retrieved or approximated for each rate class. This was compared to the 8,760 total system load data to determine CP and NCP data.

RESPONDENT:

Greg Strang

WITNESS:

Craig Jones

TUCSON ELECTRIC POWER COMPANY'S AND UNS ELECTRIC, INC.'S JOINT RESPONSE TO VOTE SOLAR'S SECOND SET OF DATA REQUESTS REGARDING PHASE 2 OF THE 2015 TEP RATE CASE AND THE 2015 UNSE RATE CASE DOCKET NOS. E-01933A-15-0322 AND E-04204A-15-0142 April 10, 2017

VS P2 2.11

Please provide the information requested below regarding the Companies' response to VS P2 1.09:

a. In response to VS P2 1.09(b), the Companies state they "examined meter data from tens of thousands of customers and analyzed them as both full requirements and partial requirements DG customers." Please explain how the Companies can analyze a customer as both a full requirements and partial requirements customer when the customer either does or does not have a DG system installed.

b. Please describe whether and how the Companies analyzed metered data from existing DG customers when they prepared their Phase 2 direct testimony.

c. In response to VS P2 1.09(c), the Companies state: "Please refer to Mr. Jones' testimony page 6, lines 3-15 where he indicates there is no reason to believe a DG customer's full requirements hourly delivery load profile would be significantly different than that same customer's load profile prior to installing PV equipment." Please identify all research, analyses, and other supporting documentation that supports this conclusion. If applicable, please provide responses in excel format with formulas and links intact.

RESPONSE:

a. The Companies retrieved hourly data for full requirements customers to model them as full requirements customers. To model them as NEM customers, the Companies layered a 100% offset system onto each individual customer's hourly load based on the actual hourly solar production based on geographic specific curves from the respective territories. For example, a TEP customer with an annual kWh of 12,000 would have a solar system layered onto their hourly load based on the average hourly production curve for DG systems in the TEP service territory.

b. The Companies retrieved hourly solar meter production data from DG systems. The Companies also retrieved monthly billing data for NEM customers.

c. The Companies do not have any explicit studies or analysis to support the assumption that NEM customers don't change consumption habits beyond a logical examination of the physical realities of DG system installation and economic principles. Installation of a DG system does not alter the premises in terms of connected load, thermal envelope, demographics, etc. and thus the assumption that the load shape does not change is reasonable.

RESPONDENT:

Greg Strang

WITNESS:

Craig A. Jones

TUCSON ELECTRIC POWER COMPANY'S AND UNS ELECTRIC, INC.'S JOINT RESPONSE TO VOTE SOLAR'S SECOND SET OF DATA REQUESTS REGARDING PHASE 2 OF THE 2015 TEP RATE CASE AND THE 2015 UNSE RATE CASE DOCKET NOS. E-01933A-15-0322 AND E-04204A-15-0142 April 10, 2017

VS P2 2.04

Page 6, lines 22 through 23 of Mr. Jones' Phase 2 direct testimony states the analysis was based on "the solar output load shape based on metered data for a fixed axis, south facing solar DG installation."

a. Please identify the fixed axis, south facing solar DG installation the Companies used. Please answer separately for TEP and UNSE.

b. Please provide any and all supporting research, analyses, and work papers to support the Companies' assumption that the hourly production profile of the chosen fixed axis, south facing solar DG installation reasonably approximates the hourly production profile of each TEP and UNSE DG installation during the test year. If applicable, please provide supporting documentation in excel format with formulas and links intact. Please answer separately for TEP and UNSE, and for residential and SGS customers.

c. To support this assumption, did the Companies examine any of the following information for its existing NEM customers? If so, please provide any and all relevant research, analyses, and workpapers; and please answer separately for TEP and UNSE, and for residential and SGS customers.

   i. System install date

   ii. System orientation

   iii. System shading

   iv. Roof pitch

RESPONSE:

The section referenced should have read "the solar output load shape based on a statistically significant sample of customer sited DG systems by service territory" as the load shape was not based totally on a single fixed axis south facing system. That said, most DG systems are typically south facing fixed axis.

a. Please see response to VS P2 1.08 for the load curve used.

b. The load curves used are based on a large statistically significant sample of customer sited DG systems. Due to weather, latitude, and altitude differences, the load curves are differentiated by service territory.

c. The load curves used are based on a large statistically significant sample of customer sited DG systems. By its nature, the load curve will represent typical system install dates, system tilt and azimuth, and system shading by service territory.

RESPONDENT:

Greg Strang

WITNESS:

Craig A. Jones

TUCSON ELECTRIC POWER COMPANY'S AND UNS ELECTRIC, INC.'S JOINT RESPONSE TO VOTE SOLAR'S SECOND SET OF DATA REQUESTS REGARDING PHASE 2 OF THE 2015 TEP RATE CASE AND THE 2015 UNSE RATE CASE DOCKET NOS. E-01933A-15-0322 AND E-04204A-15-0142 April 10, 2017

VS P2 2.01

Please provide the information requested below regarding the following statement by Mr. Jones on page 6, lines 6 through 11 of his Phase 2 direct testimony: "To develop the counterfactual load shape, it was necessary to make a basic assumption that the load shape of residential solar DG customers was on average the same load shape as the residential load shape prior to the installation of solar DG. That is the basic assumption i[s] that the hourly usage pattern for DG customers on average is no different from the residential class as a whole on average, even though the size of customers may vary."

a. Please provide any and all supporting load research, analyses, and work papers that support this assumption. If applicable, please provide supporting documentation in excel format with formulas and links intact. Please answer separately for TEP and UNSE.

b. Did the Companies make a similar load assumption for small commercial DG customers? If so, please provide any and all supporting load research, analyses, and work papers that support this assumption. If applicable, please provide supporting documentation in excel format with formulas and links intact. Please answer separately for TEP and UNSE.

RESPONSE:

a. There are no supporting load research, analyses, and work papers. The assumption is based on the fact that residential solar DG customers were residential customers prior to installation of DG. Since solar DG installation does not alter the premises in terms of connected load, thermal envelope, demographics, etc., the assumption is reasonable.

b. Yes, the Companies made similar assumption for small commercial DG customers. There are no supporting load research, analyses, and work papers. The assumption is based on the fact that small commercial DG customers were small commercial customers prior to installation of DG. Since solar DG installation does not alter the premises in terms of connected load, thermal envelope, demographics, etc., the assumption is reasonable.

RESPONDENT:

Craig A. Jones

WITNESS:

Craig A. Jones

TUCSON ELECTRIC POWER COMPANY'S AND UNS ELECTRIC, INC.'S JOINT RESPONSE TO VOTE SOLAR'S SIXTH SET OF DATA REQUESTS REGARDING PHASE 2 OF THE 2015 TEP RATE CASE AND THE 2015 UNSE RATE CASE DOCKET NOS. E-01933A-15-0322 AND E-04204A-15-0142
Originally Submitted: April 24, 2017
Updated: April 25, 2017

VS P2 6.3

In the TEP COSS there is a single category of customers entitled "General Service," which is identified as having 38,429 customers.

a. Please confirm that this category of customers in the COSS includes both Small General Service and Medium General Service customers.

b. The group of customers identified as "General Service" in the COSS is broken down into "Full Requirements Small General Service" and "Partial Requirements Small General Service." Please explain where the Company's MGS customers with and without DG are included in this categorization.

c. Please indicate whether the average hourly load shape used to scale monthly SGS billing data for the SGS NEM customers into hourly data for SGS NEM customers was based on TEP SGS customers or a combination of SGS and MGS customers.

d. Please indicate the number of SGS and MGS customers in the test year with and without DG systems.

RESPONSE:

a. Confirmed.

b. They are included in both the "Full Requirements Small General Service" and the "Partial Requirements Small General Service" classes.

c. The average hourly load shape used to scale monthly SGS billing data was a combination of SGS and MGS customers.

d. There were no MGS customers during the test year.

RESPONDENT:

Craig A. Jones / Jared Dang

WITNESS:

Craig A. Jones

VOTE SOLAR'S
SECOND SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY REGARDING
THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-16-0036
AND
DOCKET NO. E-01345A-16-0123
NOVEMBER 23, 2016

VS 2.5: Please provide the following information regarding slide 13 of APS's Residential Customer Outreach and Rate Transition Plan filed in this docket on November 18, 2016:

a) Please provide work papers to support the five load profile types of APS's residential customers. Please provide information in excel format including links to underlying data and analyses with all formulas and links intact.

b) Please provide any analyses, reports and/or documentation to indicate what proportion of APS's residential customers fall into each of the five load profile types presented on this slide.

Response:

a) The requested analysis supporting the referenced load profiles was performed by a third party with a proprietary method and process that are not available to APS. The data necessary to perform a parallel analysis was provided in APS's response to Vote Solar 1.7.

b) See response to subpart a above. The requested information is as follows:

Customer Usage Profiles
Percent of APS Customers

Weekday Steady Eddies	20%
Weekday Evening Peakers	43%
Weekday Night Owls	10%
Weekday Twin Peaks	10%
Weekday Daytimers	17%

Witness: Chuck Miessner/Stacy Derstine

TUCSON ELECTRIC POWER COMPANY'S AND UNS ELECTRIC, INC.'S JOINT RESPONSE TO VOTE SOLAR'S FOURTH SET OF DATA REQUESTS REGARDING PHASE 2 OF THE 2015 TEP RATE CASE AND THE 2015 UNSE RATE CASE DOCKET NOS. E-01933A-15-0322 AND E-04204A-15-0142 April 14, 2017

VS P2 4.8

Please provide the information requested below regarding Mr. Bachmeier's work papers entitled "2015 TEP RES Load-PV Data.xlsx" and "2015 TEP SGS Load-PV Data.xlsx."

a. Please provide a fully functional version of each work paper, which includes source analysis underlying the values pasted in rows 70 and onwards on the tabs entitled "TY2015 Load-PV Bins."

b. Please provide source data and work papers to support the values in cells CS62:CS63 on the tab entitled "TY2015 Load-PV Bins" in the "2015 TEP SGS Load-PV Data.xlsx" work paper.

C. For all analysis in these work papers, please confirm whether:

   i. The load data was derived from full requirements customer data and then modeled with a PV system profile sized to offset 100% of load annually.

   ii. Hourly exports and deliveries were netted hourly, rather than estimated on an instantaneous basis.

RESPONSE:

The referenced files herein that were provided in Phase 1 of TEP and UNS Electric's rate cases have been uploaded to the Companies' electronic data room and stored within Mr. Bachmeier's direct testimony workpapers subfolder.

a. The work papers entitled "2015 TEP RES Load-PV Data.xlsx" and "2015 TEP SGS Load-PV Data.xlsx" are fully functional. The values in rows 70 and onwards in the tabs entitled "TY2015 Load-PV Bins" were originally entered as values and no links to the source data exist.

   The source data files for the values in rows 70 and onward in the aforementioned work papers were provided by TEP in UDR 1.001 during Phase 1 of this proceeding. The source data files for those values are:

   2015 TEP RES DATA_rb-sample2.xlsx

   2015 TEP SGS DATA_rb-sample2.xlsx

   The residential data in "2015 TEP RES DATA_rb-sample2.xlsx" were derived from SAS processing of a sample of TEP residential customer interval data. This interval data sample was provided by TEP in Phase 1 of this proceeded in response to RUCO 7.11. The file names are:

FILES LISTED BELOW CONTAIN CONFIDENTIAL INFORMATION AND ARE BEING PROVIDED (OR HAVE BEEN PROVIDED IN A PREVISOUS RESPONSE, AS REFERENCED) IN ACCORDANCE WITH THE TERMS OF THE PROTECTIVE AGREEMENT IN THIS MATTER.

RUCO 7.11 Individual Customer Sample 2-Confidential.xlsx

RUCO 7.11 Individual Customer Sample 3-Confidential.xlsx

RUCO 7.11 Individual Customer Sample 4-Confidential.xlsx

RUCO 7.11 Individual Customer Sample 5-Confidential.xlsx

RUCO 7.11 Individual Customer Sample-Confidential.xlsx

The SGS data in "2015 TEP SGS DATA_rb-sample2.xlsx" were derived from SAS processing of a sample of TEP SGS customer interval data. This interval data sample was provided by TEP in Phase 1 of this proceeded in response to Vote Solar 8.1.

For a description of the process that TEP used to derive "2015 TEP RES Load-PV Data.xlsx" and "2015 TEP SGS Load-PV Data.xlsx" from the source data, see pages 6 through 16 of the Rebuttal Testimony of Richard D. Bachmeier in Phase 1 of this proceeding.

b. The values in cells CS62:CS63 in the tab entitled "TY2015 Load-PV Bins" in the "2015 TEP SGS Load-PV Data.xlsx" work paper were derived from the following two Excel files that TEP submitted in Phase 1 of this proceeding:

2015 TEP Schedule H-4.xlsx

2015 TEP Revenue Proof_Public.xlsx

The value in cell CS62 was entered as a value from cell F7 in the file "2015 TEP Schedule H-4_FINAL.xlsx", tab "GS-76-W". The value in cell F7 in "2015 TEP Schedule H-4_FINAL.xlsx", tab "GS-76-W" was calculated by dividing the value in cell L60 in the file "2015 TEP Revenue Proof_Public_FINAL.xlsx", tab "General Service" by the sum of cells L60 and L61 in the same tab.

The value in cell CS63 was entered as a value from cell F7 in the file "2015 TEP Schedule H-4_FINAL.xlsx", tab "GS-76-S". The value in cell F7 in "2015 TEP Schedule H-4_FINAL.xlsx", tab "GS-76-S" was calculated by dividing the value in cell L58 in the file "2015 TEP Revenue Proof_Public_FINAL.xlsx", tab "General Service" by the sum of cells L58 and L59 in the same tab.

c. i. Confirmed.

ii. Confirmed.

TUCSON ELECTRIC POWER COMPANY'S AND UNS ELECTRIC, INC.'S JOINT RESPONSE TO VOTE SOLAR'S FOURTH SET OF DATA REQUESTS REGARDING PHASE 2 OF THE 2015 TEP RATE CASE AND THE 2015 UNSE RATE CASE
DOCKET NOS. E-01933A-15-0322 AND E-04204A-15-0142
April 14, 2017

RESPONDENT:

Richard Bachmeier

WITNESS:

Richard Bachmeier

TUCSON ELECTRIC POWER COMPANY'S AND UNS ELECTRIC, INC.'S JOINT RESPONSE TO VOTE SOLAR'S FOURTH SET OF DATA REQUESTS REGARDING PHASE 2 OF THE 2015 TEP RATE CASE AND THE 2015 UNSE RATE CASE DOCKET NOS. E-01933A-15-0322 AND E-04204A-15-0142

April 14, 2017

VS P2 4.9

Please provide the information requested below regarding Mr. Bachmeier's work papers entitled "2015 UNSE RES Load-PV Data.xlsx" and "2015 UNSE SGS Load-PV Data.xlsx."

a. Please provide a fully functional version of each work paper, which includes source analysis underlying the values pasted in rows 7 and onwards on the tabs entitled "LoadData."

b. For all analysis in these work papers, please confirm whether:

   i. The load data was derived from full requirements customer data and then modeled with a PV system profile sized to offset 100% of load annually.

   ii. Hourly exports and deliveries were netted hourly, rather than estimated on an instantaneous basis.

RESPONSE:

The referenced files herein that were provided in Phase 1 of TEP and UNS Electric's rate cases have been uploaded to the Companies' electronic data room and stored within Mr. Bachmeier's direct testimony workpapers subfolder.

a. The work papers entitled "2015 UNSE RES Load-PV Data.xlsx" and "2015 UNSE SGS Load-PV Data.xlsx" are fully functional. The values in rows 7 and onwards in the tabs entitled "LoadData" were originally entered as values and no links to the source data exist.

   The source data files for the values in rows 7 and onward in the aforementioned work papers were provided by UNS Electric in UDR 3.1 during Phase 1 of this proceeding. The source data files for those values are:

   TOU Solar UNSE Res Sample 1.xlsx

   TOU Solar UNSE SGS Sample 1.xlsx

   The data in "TOU Solar UNSE Res Sample 1.xlsx" and "TOU Solar UNSE SGS Sample 1.xlsx" were derived from SAS processing of respective samples of UNS Electric residential and SGS customer interval data.

b. i. Confirmed.

   ii. Confirmed.

RESPONDENT:

Richard Bachmeier

WITNESS:

Richard Bachmeier

TUCSON ELECTRIC POWER COMPANY'S AND UNS ELECTRIC, INC.'S JOINT RESPONSE TO VOTE SOLAR'S FIRST SET OF DATA REQUESTS REGARDING PHASE 2 OF THE 2015 TEP RATE CASE AND THE 2015 UNSE RATE CASE DOCKET NOS. E-01933A-15-0322 AND E-04204A-15-0142
March 30, 2017

VS P2 1.06

Please indicate whether the following usage information exists for the Companies' existing customers with DG during the test year. If differences in available data exist between the two utilities or between residential and SGS classes, please explain the differences and the reasons for the different data.

a. Hourly energy delivered by the Companies to the DG customer;

b. Hourly energy exported by the DG customer to the Companies; and

c. Hourly production from the DG customer facility as measured by the production meter.

RESPONSE:

The Companies' meters accumulate instantaneous power to calculate energy consistent with the physical definition of the power energy relationship, $\int_{t_i}^{t_f} P(t)dt = E$.

a. Hourly accumulation of instantaneous power deliveries by the Companies, to its customers, exists for all customers where the necessary metering technology was in place.

b. Monthly accumulation of instantaneous power exports by DG customers, to the Companies, exists for DG customers where the necessary metering technology was in place.

c. Hourly accumulation of instantaneous power production from DG facilities exists where the necessary metering technology was in place.

RESPONDENT:

Greg Strang

WITNESS:

Craig Jones / Carmine Tilghman

TUCSON ELECTRIC POWER COMPANY'S AND UNS ELECTRIC, INC.'S JOINT RESPONSE TO VOTE SOLAR'S SECOND SET OF DATA REQUESTS REGARDING PHASE 2 OF THE 2015 TEP RATE CASE AND THE 2015 UNSE RATE CASE DOCKET NOS. E-01933A-15-0322 AND E-04204A-15-0142 April 10, 2017

VS P2 2.05

Please indicate the number of DG customers with and without AMI meters capable of measuring hourly energy usage during the test year. Please answer separately for TEP and UNSE, and for residential and SGS customers.

RESPONSE:

Most DG customers have AMR meters with only a few having AMI meters (4 commercial and 1 residential). All are capable of measuring hourly energy usage, if programed to do so.

Please see the response to VS P2 2.03 a. and b. for the number of net-metering customers during the test year.

RESPONDENT:

Craig A. Jones

WITNESS:

Craig A. Jones

TUCSON ELECTRIC POWER COMPANY'S AND UNS ELECTRIC, INC.'S JOINT RESPONSE TO VOTE SOLAR'S SIXTH SET OF DATA REQUESTS REGARDING PHASE 2 OF THE 2015 TEP RATE CASE AND THE 2015 UNSE RATE CASE DOCKET NOS. E-01933A-15-0322 AND E-04204A-15-0142
Originally Submitted: April 24, 2017
Updated: April 25, 2017

VS P2 6.1

Regarding the Companies' response to VS P2 2.05: Please indicate the number of DG customers with AMR and AMI meters programed to measure hourly energy usage during the test year. Please answer separately for TEP and UNSE, and for residential and SGS customers.

RESPONSE:

All AMR and AMI meters referred to in the response to VS P2 2.03 and 2.05 for TEP and UNS Electric are programed to measure energy usage in intervals that allow hourly usage to be reported. However not all of the meter intervals were received by the fixed network collection device that would allow hourly usage data to be accumulated for all customers during the test year.

RESPONDENT:

Craig A. Jones / Chris Fleenor

WITNESS:

Craig A. Jones

TUCSON ELECTRIC POWER COMPANY'S AND UNS ELECTRIC, INC.'S JOINT RESPONSE TO VOTE SOLAR'S SECOND SET OF DATA REQUESTS REGARDING PHASE 2 OF THE 2015 TEP RATE CASE AND THE 2015 UNSE RATE CASE DOCKET NOS. E-01933A-15-0322 AND E-04204A-15-0142
April 10, 2017

VS P2 2.03

Please provide the information requested below regarding the following statement by Mr. Jones on page 7, lines 15 through 17 of his Phase 2 direct testimony: "The DG Class includes all customers with twelve months of data and a non-zero capacity value. (If the kW capacity for any solar customer was not available, that customer was excluded from the analysis.)"

a. Please indicate the number of residential customers enrolled in net metering during the test year. Please answer separately for TEP and UNSE.

b. Please indicate the number of SGS customers enrolled in net metering during the test year. Please answer separately for TEP and UNSE.

c. Please indicate the number of residential NEM customers with twelve months of data and a non-zero capacity value. Please answer separately for TEP and UNSE.

d. Please indicate the number of SGS NEM customers with twelve months of data and a non-zero capacity value. Please answer separately for TEP and UNSE.

RESPONSE:

a. Residential DG customer count is 8,138 for TEP and 1,344 for UNS Electric.

b. Small general service DG customer count is 325 for TEP and 92 for UNS Electric.

c. There were 5,125 residential DG customers with 12 months of data and a non-zero capacity value for TEP and 883 for UNS Electric.

d. There were 229 small general service DG customers with 12 months of data and a non-zero capacity value for TEP and 43 for UNS Electric.

The statement by Mr. Jones on page 7, lines 15 through 17 of his Phase 2 direct testimony should read as: "The DG Class includes all customers with a non-zero capacity value. (If the kW capacity for any solar customer was not available, that customer was excluded from the analysis.)".

If a customer is included for partial year, his/her billed kWh (and as a result, calculated peaks) are also included in analysis on a partial year basis only. There is no basis for including full requirements kWh in the billing determinants for partial requirements customers. Excluding customers with partial year of solar data does not make a significant difference in class rate of return.

RESPONDENT:

Craig A. Jones

WITNESS:

Craig A. Jones

TUCSON ELECTRIC POWER COMPANY'S AND UNS ELECTRIC, INC.'S JOINT RESPONSE TO VOTE SOLAR'S SECOND SET OF DATA REQUESTS REGARDING PHASE 2 OF THE 2015 TEP RATE CASE AND THE 2015 UNSE RATE CASE DOCKET NOS. E-01933A-15-0322 AND E-04204A-15-0142 April 10, 2017

VS P2 2.07

Please provide the information requested below regarding the proposed tariffs filed as RDB-P2-1. If the answers differ between TEP and UNSE, please explain.

a. How would the Companies measure energy usage subject to the tariff and energy exports to be compensated through the Rider?

b. Would deliveries and exports be netted hourly, measured instantaneously, or on some other basis?

c. Please describe the metering equipment the Companies would use to measure billing data for new DG customers, including the time intervals over which the metering equipment can be programmed to collect data.

RESPONSE:

a. The Companies' meters accumulate instantaneous power to calculate energy consistent with the physical definition of the power energy relationship, $\int_{t_i}^{t_f} P(t)dt = E$. See Companies' response to VS P2 1.06(a).

b. Instantaneously.

c. New DG customers will have the same two meters as currently installed for NEM customers. Current NEM metering equipment includes a bi-directional meter that measures energy flows to and from the electric grid and a unidirectional meter that measures energy generated by the DG system. The meter recording intervals will remain as currently configured, consistent with the Companies' response to VS P2 1.06.

RESPONDENT:

Richard Bachmeier

WITNESS:

Richard Bachmeier

TUCSON ELECTRIC POWER COMPANY'S AND UNS ELECTRIC, INC.'S JOINT RESPONSE TO VOTE SOLAR'S FIRST SET OF DATA REQUESTS REGARDING PHASE 2 OF THE 2015 TEP RATE CASE AND THE 2015 UNSE RATE CASE DOCKET NOS. E-01933A-15-0322 AND E-04204A-15-0142 March 30, 2017

VS P2 1.13

Please confirm that there have been no changes to the Marginal Cost Studies presented as CAJ-1 in Phase 1 and Phase 2 of the Companies' Applications.

RESPONSE:

Confirmed.

RESPONDENT:

Craig Jones

WITNESS:

Craig Jones

Attachment 2

UNSE Meters – Capital and Labor Costs

Capital and Labor Costs Associated with UNSE Meters
UNSE P2 Cost of Service Study

Line No.		(A) Residential Bidirectional	(B) Residential Standard	(C) SGS Bidirectional	(D) SGS Standard
1	Capital Cost	$ 160.00	$ 41.00	$ 201.00	$ 178.00
2	Labor	$ 50.00	$ 33.00	$ 50.00	$ 50.00
3	**Total Capital and Labor (sum lines 1,2)**	**$ 210.00**	**$ 74.00**	**$ 251.00**	**$ 228.00**
4	**Incremental Cost (A-B and C-D)**		**$ 136.00**		**$ 23.00**
5					
6	**Meter ECCR per CAJ-1**	**19.20%**			
7					
8		**Annual**	**Monthly**		
9	**Incremental Bidirectional Residential**	$ 26.11	$ 2.18		
10	**Incremental Bidirectonal SGS**	$ 4.42	$ 0.37		

Attachment 3

TEP Meters – Capital and Labor Costs

Capital and Labor Costs Associated with TEP Meters
VS 11.06-11.13

Line No.		(A) Residential Bidirectional	(B) Residential Standard	(C) SGS Bidirectional	(D) SGS Standard
1	Meter	$ 154.40	$ 35.00	$ 188.00	$ 188.00
2	Locking Ring	$ 14.60	$ 5.91	$ 14.60	$ 5.91
3	Meter Seal	$ 0.25	$ 0.15	$ 0.25	$ 0.15
4	**Total Capital (sum lines 1,2,3)**	**$ 169.25**	**$ 41.06**	**$ 202.85**	**$ 194.06**
5	Labor	$ 43.53	$ 28.77	$ 72.30	$ 57.35
6	**Total Capital and Labor (sum lines 4,5)**	**$ 212.78**	**$ 69.83**	**$ 275.15**	**$ 251.41**
7	**Incremental Cost (A-B and C-D)**		**$ 142.95**		**$ 23.74**
8					
9	**Meter ECCR per CAJ-1**	**17.22%**			
10					
11		**Annual**	**Monthly**		
12	**Incremental Bidirectional Residential**	$ 24.62	$ 2.05		
13	**Incremental Bidirectonal SGS**	$ 4.09	$ 0.34		