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

CONFIDENTIAL DIRECT TESTIMONY AND EXHIBITS OF BRIANA KOBOR

ON BEHALF OF VOTE SOLAR

NOTICE OF CONFIDENTIALITY

A PORTION OF THIS TESTIMONY HAS BEEN FILED UNDER SEAL

Confidential and Competitively Sensitive Confidential Information on pages 8, 10, 11, and 13.

JUNE 24, 2016

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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.

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

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

Q. What is Vote Solar?

A. Vote Solar is a non-profit grassroots organization working to foster economic opportunity, promote energy independence, and fight climate change by making solar a mainstream energy resource across the United States. Since 2002, Vote Solar has engaged in state, local, and federal advocacy campaigns to remove regulatory barriers and implement key policies needed to bring solar to scale. Vote Solar is not a trade group and does not have corporate members. Vote Solar has approximately 60,000 members nationally and 3,500 in Arizona.

Q. By whom are you employed and in what capacity?

A. I serve as Program Director of Distributed Generation ("DG") Regulatory Policy for Vote Solar. I analyze policy initiatives, development, and implementation related to distributed solar generation. I also review regulatory filings, perform technical analyses, and testify in commission proceedings relating to distributed solar generation.

Q. Please describe your education and experience.

A. I have a degree in Environmental Economics and Policy from the University of California, Berkeley and I have been employed in the utility regulatory industry since 2007. Prior to joining Vote Solar in August 2015, I was employed for eight years by MRW & Associates, LLC ("MRW"), which is a specialized energy consulting firm. At MRW, I focused on electricity and natural gas markets, ratemaking, utility regulation, and energy policy development. I worked with a variety of clients including energy policy makers, developers, suppliers, and end-users. My clients included the California Public Utilities Commission, the California Energy Commission, the California Independent System Operator, and several publicly-owned utilities. I have experience evaluating utility cost of service studies, revenue allocation and ratemaking, wholesale and retail electric rate forecasting, asset valuation, and financial analyses. A summary of my background and qualifications is attached as Exhibit BK-1.

Q. Have you previously testified before the Arizona Corporation Commission (the "Commission")?

A. Yes. I have provided testimony in Docket No. E-04204A-l5-0142, the UNS Electric, Inc. General Rate Case, and Docket No. E-00000J-14-0023, entitled "In the Matter of the Commission's Investigation of Value and Cost of Distributed Generation."

Q. Have you previously testified before other regulatory commissions?

A. Yes. I have testified in proceedings before the California Public Utilities Commission. I have testified on behalf of the Coalition for Affordable Streetlights in A.14-06-014 Application of Southern California Edison Company (U338E) to Establish Marginal Costs, Allocate Revenues, Design Rates, and Implement Additional Dynamic Pricing Rates. I have also testified on behalf of the Utility Consumers' Action Network in A.14-11-003 Application of San Diego Gas & Electric Company (U902M) for Authority, Among Other Things, to Increase Rates and Charges for Electric and Gas Service Effective on January 1, 2016.

2 Purpose of Testimony and Summary of Recommendations

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

A. My testimony addresses certain rate design proposals put forth by Tucson Electric Power ("TEP" or the "Company") in its general rate case application. Among its rate design proposals, the Company has requested significant changes to rate design for net energy metering ("NEM") customers and modifications to the rate structure for residential and small commercial customers. The specific proposals I address in my testimony include: (1) the proposed modification of the NEM export rate from the retail rate to a Renewable Credit Rate; (2) the proposal to make a three-part tariff mandatory for NEM customers; (3) the request to increase fixed charges for residential and small commercial customers; and (4) the request to remove the third tier in the standard residential rate. There are a number of additional proposals in TEP's application that are not addressed in my testimony, but that does not imply that I agree with those proposals. I reserve the opportunity to discuss any additional proposals not addressed in my direct testimony through surrebuttal testimony.

Q. Please describe how your testimony is organized.

A. The remainder of my testimony consists of eight major sections. In the first section, I summarize TEP's rationale to support the rate design proposals listed above. In the second section, I examine whether that rationale supports TEP's NEM-specific proposals. In the third section, I examine TEP's specific NEM proposals, including (1) TEP's request to reduce the credit NEM customers receive for excess energy exports, and (2) TEP's proposal to implement a mandatory three-part rate structure for NEM customers. I also examine the relationship between TEP's proposed rate design changes and the Lost Fixed Cost Recovery ("LFCR") mechanism. In the fourth section, I address TEP's assessment of the impacts of its proposed NEM rate design changes. I also look at the potential implications of these proposals and examine the applicability of the

Commission's NEM rules to these proposals. In the fifth section, I evaluate TEP's proposals to increase the fixed charges for all residential and small commercial customers and to remove the third and fourth residential rate tiers. In the sixth section, I address the need to grandfather existing NEM customers in the event that major rate design changes are approved in this case. In the seventh section, I describe how TEP and the Commission should plan for distributed energy resources ("DERs") and the modern grid. Finally, the eighth section provides a summary of my recommendations.

Q. Please summarize your findings and recommendations.

A. TEP proposes significant changes to the existing rate structure for NEM customers. If approved, these changes would very likely curtail future DG growth in TEP's service territory. The Company claims that its proposals are necessary to address numerous problems caused by DG, such as declining retail sales, inequitable cost shifts among customers, and harmful grid impacts. However, my examination of the data reveals that NEM customers are not a significant driver of any of the problems TEP alleges. I show that DG is a minor contributor to the reduction in retail sales compared with other factors. In addition, I show that 98% of the residential customers that TEP alleges are causing an inequitable cost shift are not NEM customers. My analysis also shows that TEP has not established that DG causes significant grid impacts on the Company's system. As a result, TEP has not justified its proposals to dramatically alter NEM rates.

Even if NEM customers were a significant driver of the problems TEP highlights, the Company's two primary methods to address the problems are significantly flawed and should be rejected. First, TEP proposes to modify the existing NEM tariff to substantially reduce the credit NEM customers receive for excess generation. I find that TEP has not provided a sufficient basis for its recommendation that exports be valued at the Renewable Credit Rate. TEP has not conducted a full benefit/cost analysis, and without that analysis there is no way to determine the current relationship between the retail rate and the value of

NEM exports, and thus no way to determine the reasonableness of the Renewable Credit Rate. Moreover, I find significant flaws in the calculation of the Renewable Credit Rate. As a result, I recommend that the Commission reject TEP's proposal to lower the compensation rate it pays for NEM customers' excess generation. Exports should continue to be valued at the retail rate until an independent benefit/cost analysis has been completed.

Second, TEP proposes to implement a mandatory three-part rate structure with a demand charge for NEM customers. I show that NEM customers have no greater ability to respond to demand charges than non-NEM customers and that demand charges can be expected to have wide-ranging and significant impacts on customers, with the majority of customers expected to experience a bill increase. I show that the proposed demand charges are not reflective of cost. In addition, demand charges for residential and small commercial customers would not provide an actionable price signal to help customers make informed decisions regarding their energy usage. Because most customers lack the tools to effectively respond to the price signals in demand charges, these charges would act like an additional fixed charge for the majority of residential and small commercial customers. I find that mandatory demand charges are not appropriate for any residential or small commercial customers, and that singling out NEM customers for a mandatory demand charge would be discriminatory. I recommend that demand charges be offered only through optional rate tariffs for all residential and small commercial customers, including NEM customers.

In TEP's last general rate case, the Commission approved the LFCR. The LFCR is a decoupling mechanism designed to address any issues related to fixed cost recovery from DG and energy efficiency ("EE"). This tool is the preferred method for addressing these issues, rather than TEP's proposals to amend the NEM tariff and introduce a mandatory demand charge for NEM customers.

I also show that TEP has not adequately assessed how its NEM-specific proposals would impact customers. TEP's reliance on vague and hypothetical data fails to meet its burden of justifying changes to NEM rates under the Commission's rules. In addition, TEP's proposals would likely cause a significant decline in DG adoption rates in its service territory. Yet the Company did not assess how this would impact local employment.

I also address two aspects of TEP's proposals that would apply to all residential and small commercial customers, rather than just NEM customers. I find that a revised study of embedded and marginal costs based on a more reasonable allocation method demonstrates that current fixed charges for residential and small commercial customers are reasonable. As a result, I recommend that the Commission reject TEP's proposal to increase basic service charges for residential customers but may consider an increase in the small commercial customer charge from $15.50 to $15.85 per month. I also recommend that the Commission reject TEP's proposal to eliminate the third and fourth residential rate tiers. The Commission approved the current inclining block rate structure for the express purpose of incenting conservation, and the alleged fixed cost recovery differential between high and low-use customers under the current rate structure is reasonable.

I additionally find that TEP's rate design proposals would constitute major rate design changes that could not have been anticipated by existing NEM customers, many of whom were encouraged to make long-term investments in DG as a result of state incentives. As a result, I recommend that the Commission grandfather NEM customers who sign up prior to the effective date of this decision on a tiered two-part rate that preserves retail rate net metering.

Finally, I examine the fundamental changes occurring in the design and management of electricity distribution systems, and the implications of transforming the grid in a manner where consumers are more active participants. I recommend that the Commission create policies that ensure that the transition to the modern grid can happen in the most efficient manner, maximizing the benefits of distributed resources for the grid and minimizing overall customer costs.

3 TEP's Rationale for Its Rate Design Proposals

Q. Please describe the rationale TEP gives for its rate design proposals.

A. In a section of TEP's application labeled "Need for Updated Rate Design," the Company describes the rationale for its rate design proposals.[1] TEP states that an updated rate design is needed due to a 3% decrease in retail sales since the December 31, 2011 test year used in the last rate case.[2] TEP indicates that as a result of the lower level of sales, the Company must recover its fixed costs over a smaller number of kilowatt-hours ("kWh"), which can contribute to an under recovery of fixed costs over time.[3] TEP claims its current rate design, which recovers a portion of fixed costs through a volumetric per-kWh rate, "may have been appropriate in times of increasing customer usage and sales growth."[4] But according to the Company, because of the decline in retail sales "this approach has contributed to under-recovery of TEP's authorized revenue requirement."[5] The Company also states that the current rate design "does not fit our customers' evolving use of the electric system;"[6] and "it is creating greater inequities in recovering fixed costs from TEP's customers, increasing the level of cross-subsidies between customers, and discouraging the use and deployment of new technologies."[7]

In addition to the 3% decline in retail sales that TEP reported in its Application, TEP has indicated that the Company's largest retail customer has announced a 50% curtailment of mining production at the Sierrita copper mine and that studies evaluating the possible closure of the mine are underway.[8] While the Company referred to the mining reductions in its Application it was not until discovery filed

[1] Application at 3:7–4:16.
[2] *Id.* at 3:8–9.
[3] *Id.* at 3:13–17.
[4] *Id.* at 3:19–21.
[5] *Id.* at 3:17–21.
[6] *Id.* at 3:21–22.
[7] *Id.* at 3:22–24.
[8] Kenneth C. Grant Direct Testimony ("Grant Direct Test.") at 9:18–21 (November 5, 2015).

on June 6, 2016 that the magnitude of the reductions was reported.[9] In discovery TEP has indicated that the resulting reduction in sales will amount to an additional [redacted] reduction in sales compared with the prior test year, bringing the total reduction to nearly [redacted].[10]

Q. Does TEP describe what is behind the 3% reduction in retail sales described in its Application?

A. Yes. TEP stated: "The declining usage per customer and overall sales levels are due to several factors, including: (i) the effects of increased conservation, energy efficiency ("EE") and distributed generation ("DG"), and (ii) the slow pace of economic growth in the Tucson metropolitan area."[11]

Q. Does TEP provide any additional details on the rationale for its rate design proposals?

A. Yes. TEP identifies three factors that drive the need for its rate design proposals.

1. TEP claims that the Company is experiencing declining residential usage per customer.[12]

2. The Company reports that it "has many residential and small general service customers with relatively low volumetric usage over the course of a year."[13] TEP says that these customers include seasonal residents and customers with rooftop solar photovoltaic ("PV") systems and that under the current rate design, these customers do not pay "an equitable share of the fixed costs to operate and maintain the TEP grid to which they are connected."[14]

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[9] UDR 1.001 Projected Changes-BillingDeterminants-AdjustedProofofRevenue-CompSensConfidential.pdf.
[10] *Id.*
[11] Application at 3:10–12.
[12] *Id.* at 3:9–10.
[13] *Id.* at 3:25–26.
[14] *Id.* at 3:26–4:3.

3. TEP claims it "is also suffering lost revenues because the LFCR is not designed to capture all of the lost fixed cost revenues associated with meeting the Commission's Renewable Energy Standard and Energy Efficiency Rules."[15]

Q. According to TEP, what does the Company hope to achieve with its proposals?

A. TEP describes three "primary objectives" of the proposed rate design changes.[16] First, TEP claims that rate structures need to be updated to more closely match the price customers pay for the service they receive.[17] Second, TEP seeks to reduce the level of cross-subsidies between customers.[18] Third, TEP would like to give itself an opportunity to recover its fixed costs.[19]

4 TEP Has Not Provided Sufficient Evidence to Justify Changing the Rate Structure for NEM Customers

Q. Does TEP's rationale for its rate design changes support the NEM-related rate design proposals the Company is advocating for?

A. No. While there has indeed been a significant reduction in retail sales, TEP's rate design proposals focus disproportionately on NEM customers as the cause of the sales decline. As I explain in detail below, my examination of the data reveals that DG is not a significant driver of the reduction in retail sales that TEP has experienced since the last rate case. In fact, 98% of the residential customers that TEP alleges are causing a cost shift are not NEM customers.[20] In addition, TEP

[15] *Id.* at 4:6–9.
[16] David G. Hutchens Direct Testimony ("Hutchens Direct Test.") at 11:21–12:16 (November 5, 2015).
[17] *Id.* at 11:23–12:5.
[18] *Id.* at 12:7–9.
[19] *Id.* at 12:11–16.
[20] Schedule H-5; TEP Resp. to RUCO 7.13 (Ex. BK-3 at 28).

has not documented significant grid impacts related to DG, nor attempted to measure the existence of an alleged cost shift attributable to NEM customers.

4.1 Distributed Generation Is Not a Significant Driver of the Reduction in TEP's Retail Sales

Q. TEP has indicated that retail sales will decrease by [redacted] compared to the last rate case test year. What were the drivers of this reduction?

A. In addition to the loss of load from the mining sector, the Company attributes this reduction in retail sales to two factors: (1) the Commission's EE and DG requirements, and (2) the slow pace of economic recovery.[21]

Q. Have you examined the relative contribution of each of these factors to the loss of retail load?

A. Yes. Retail sales in the current rate case test year were roughly 3% less than retail sales in the prior test year.[22] After inclusion of recently announced mining sector losses, TEP's sales are expected to fall [redacted].[23] [redacted]. Indeed, the data shows that DG contributed only 100,000 MWh of reductions between test years, which represents [redacted] of the total reductions.[24]

Because mining sector losses are responsible for [redacted] of the loss of load, EE and "the slow pace of economic recovery"[25] are responsible for the remaining [redacted] of the decline in retail sales.

[21] Hutchens Direct Test. at 20:23–25.
[22] TEP Resp. to VS 2.32 (Ex. BK-3 at 13).
[23] UDR 1.001 Projected Changes-BillingDeterminants-AdjustedProofofRevenue-CompSensConfidential.pdf.
[24] UDR 1.109.
[25] *See* Hutchens Direct Test. at 20:23–25.

Figure 1 below provides a summary of the relative impact of mining sector reductions, DG, and EE/economic factors on the change in retail sales between the two rate case test years.

[redacted]

[redacted]

As Figure 1 clearly demonstrates, when compared with other factors, DG was a minor contributor to the [redacted] overall reduction in retail sales.

Q. **TEP has also indicated that its rate design proposals would address a decline in residential usage per customer. Have you examined what has driven the reduction in residential usage per customer?**

A. Yes. To support its rate design proposals, TEP points to the fact that residential usage per customer has declined 7.5% between test years.[27] Examination of the data made available by TEP shows a reduction of 8.2% in residential usage per customer.[28] Additional reductions from DG, however, were minimal, amounting

[26] Due to data limitations, the value shown for DG impact represents residential retail sales reductions due to DG between calendar years 2011 and 2014, rather than between the two test years and is therefore likely an overestimate of the DG impact between test years.
[27] Application at 3:9–10.
[28] TEP Resp. to VS 2.32 (Ex. BK-3 at 13).

to an additional decline of only 145 kWh per year for the average residential customer between test years.[29] This indicates that 83% of the decline in residential usage per customer was driven by factors other than growth of DG.

Q. You stated above that TEP also designed its rate design proposals to address the significant proportion of customers that have little to no volumetric usage. Has TEP provided any additional detail on these low-usage customers?

A. Yes. In Dallas Dukes' Direct Testimony, TEP attributes this problem to the fact that nearly one in every three residential bills issued by TEP during the test year reflected usage of 400 kWh or less.[30] TEP says that "[b]ecause even a studio apartment with basic appliances and moderate usage would likely consume almost 400 kWh per month, these bills probably were generated by vacant homes, seasonal customers and DG customers."[31]

Q. Have you been able to assess the proportion of bills amounting to 400 kWh or less that could be attributed to vacant homes, seasonal customers, and NEM customers?

A. In discovery, TEP stated that it does not track seasonal homes or vacant structures.[32] However, the Company did provide data on the number of NEM customer bills that fell below the 400 kWh threshold.[33] <u>TEP reports that nearly 96% of the 1,308,415 low-usage bills were from customers who were not NEM customers.</u>[34]

Q. Have you reached any conclusions regarding the contribution of DG to the reduction in retail sales that TEP claims is driving the need for its rate design proposals?

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[29] *Id.*; UDR 1.109.
[30] Dallas J. Dukes Direct Testimony ("Dukes Direct Test.") at 12:15–16 (November 5, 2015).
[31] *Id.* at 12:16–19.
[32] TEP Resp. to Staff 1.14 (Ex. BK-3 at 30).
[33] TEP Resp. to VS 2.10 (Ex. BK-3 at 6).
[34] *Id.*

A. Yes. It is clear from the data provided by TEP that DG is not a significant driver of the reduction in retail sales that TEP claims is driving the need for its rate design proposals. Specifically, three key facts show that DG is only a minor contributor, at most, to the reduction in TEP's retail sales.

1. DG contributed only [redacted] to the overall decline in retail sales—[redacted] of the decline can be attributed to other causes.

2. DG reduced average residential usage per customer by 145 kWh between test years, which means that only 17% of the decline in residential usage per customer is attributable to DG. 83% of the decline in residential usage per customer was due to factors other than DG.

3. Only 4% of the low-usage bills of under 400 kWh were attributable to NEM customers, so 96% of these low-usage bills were for customers who were <u>not</u> NEM customers.

The data shows that the problems TEP claims warrant their rate design proposals are not DG problems. In fact, drivers such as sales declines in the industrial and mining sector and reductions due to EE and other factors had a much larger impact on TEP's sales. Therefore, the Company should not single out NEM customers for rate reform based on the mistaken rationale that DG has caused a significant decrease in retail sales.

4.2 Ninety-Eight Percent of the Residential Customers TEP Alleges Are Causing a Cost Shift Are Not NEM Customers

Q. Please summarize TEP's claims regarding cost shifting between customers.

A. TEP alleges that under the current rate design, lower-usage customers shift fixed costs to higher-usage customers.[35] To illustrate this problem, TEP points to three examples of low-usage customers: (1) seasonal customers; (2) vacant homes or

[35] Dukes Direct Test. at 3:5–8.

businesses; and (3) NEM customers.[36] In addition, TEP provides a chart that claims to show that roughly two-thirds of the bills issued in the last four years to residential customers did not provide fixed cost recovery equivalent to the class average established in the most recent rate decision.[37] In the data underlying the chart, TEP shows that the usage level at which it defines customers as achieving fixed cost recovery is roughly 1,000 kWh per month.[38]

Q. Do you have any information to indicate what proportion of the low-usage customers TEP claims are responsible for shifting costs are NEM customers?

A. Yes. Very few of these low-usage customers are NEM customers. As described above, TEP points to problems associated with customers that use less than 400 kWh monthly. The Company suggests that these bills are related to seasonal customers, vacant homes, and NEM customers. The analysis described above reveals that NEM customers are in fact only 4% of this low-consumption cohort.[39]

TEP further alleges that two-thirds of residential customers (those with consumption under roughly 1,000 kWh monthly) do not pay their fair share of fixed costs. However, an examination of the number of NEM customers in that cohort reveals that NEM customer bills accounted for only 2% of all customer bills below 1,000 kWh in the test year.[40]

Q. What do these findings show?

A. TEP complains that NEM customers do not cover their fair share of fixed costs. But NEM customers represent just 2% of the TEP customers that do not pay their fair share of fixed costs, according to the Company's rationale. In other words, 98% of the customers causing the alleged cost shifting issues TEP complains of are not NEM customers. It is unreasonable and discriminatory for TEP to address

[36] *Id.* at 12:16–19.
[37] *Id.* at 13:8–27.
[38] UDR 1.001 workpaper "Residential Fixed Cost Analysis.xlsx."
[39] TEP Resp. to VS 2.10 (Ex. BK-3 at 6).
[40] Schedule H-5; TEP Resp. to RUCO 7.13 (Ex. BK-3 at 28).

an alleged cost shift by singling out the 2% that are NEM customers for differential treatment.

4.3 TEP Has Not Shown that DG Causes Significant Grid Impacts

Q. Does TEP claim that DG in its service territory impacts the Company's operations?

A. Yes. Carmine Tilghman's Direct Testimony describes several grid operation considerations associated with integrating DG, and in particular distributed solar generation.[41]

Q. What DG integration issues does TEP discuss in its testimony?

A. TEP breaks the discussion of DG integration issues into three categories: (1) intermittency of generation; (2) the utility's inability to monitor and control systems; and (3) excess generation flowing back to the grid.[42]

Q. Do you have any general opinions about TEP's approach to its discussion of the impacts of DG on the grid?

Underlying TEP's discussion of each of these categories is the Company's assumption that the typical NEM customer will size their system to offset 100% of annual usage. As I discuss in a later section of this testimony, TEP has not provided any data to support this assumption.[43] The lack of data to support this most basic premise is indicative of the imprecise nature of TEP's assertions regarding the impacts of DG on its grid. Furthermore, even if the Company were able to provide data to support this foundational assumption, TEP has failed to conduct any detailed analysis of issues related to DG on its system at either

[41] Carmine Tilghman Direct Testimony ("Tilghman Direct Test.") at 6:23–9:2 (November 5, 2015).
[42] *Id.* at 6:25–27.
[43] *See infra* at section 6.1.

current or anticipated levels of penetration. TEP instead relies on broad national and regional studies, which may or may not apply to TEP's grid and service territory. As a result, the entire discussion of grid impacts is speculative.

Q. What does TEP claim are the issues associated with intermittency of generation?

A. TEP claims that renewable generation requires "the continued services of the centralized grid in order to supply the necessary back-up energy and ancillary services to support solar and other intermittent renewable resources."[44] The Company also claims that "[t]his problem is exacerbated through policies such as net metering, which encourages customers to oversize their solar systems beyond their average load in order to 'bank' as many credits as possible for use later."[45] TEP reports that higher levels of intermittent generation will create greater load imbalance and fluctuations in voltage and frequency, requiring additional ancillary services.[46]

Q. Has TEP accurately described the issues associated with the intermittency of renewable generation?

A. In my opinion, TEP's testimony overstates the issue. While TEP makes claims about the existence of greater load imbalance and voltage fluctuations associated with DG, TEP has not calculated any direct costs associated with these issues.[47] In addition, TEP states in discovery that due to the relative size of DG versus total system capacity, frequency deviations attributable to DG are so small that they have not yet been measured.[48] For that same reason, TEP has not been able to measure any impact on the cost to provide service associated with DG-related frequency deviation.[49]

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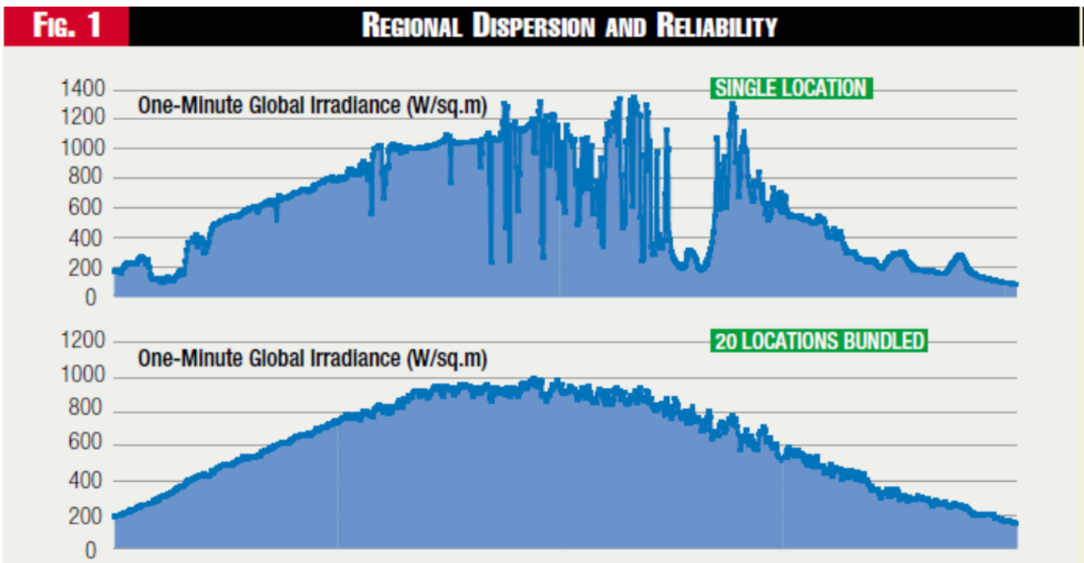
[44] Tilghman Direct Test. at 7:2–5.
[45] *Id.* at 7:5–8.
[46] *Id.* at 7:15–17.
[47] TEP Resp. to RUCO 3.17 (d), (e), (g), (h) (Ex. BK-3 at 24–25).
[48] *See id.* at 3.17(f) (Ex. BK-3 at 25).
[49] *See id.* at 3.17(i).

Q. Do you have any information regarding the intermittency of distributed solar generation?

A. Yes. While an individual PV system may produce electricity intermittently, experiencing generation reductions with passing clouds, a group of distributed solar PV systems will have a much less intermittent generation profile. This is similar to the way in which individual customer load shapes may vary, but load shapes of groups of customers exhibit a smoother load profile. Figure 2 below demonstrates the variability in a single PV array in comparison to a group of 20 arrays.

Figure 2: Effects of Geographic Diversity on PV System Intermittency[50]



Comparing the solar irradiance at one location on a single partly cloudy day (top) to that of 20 locations dispersed over approximately 100 square miles illustrates how system-wide distribution greatly reduces variability in solar energy.

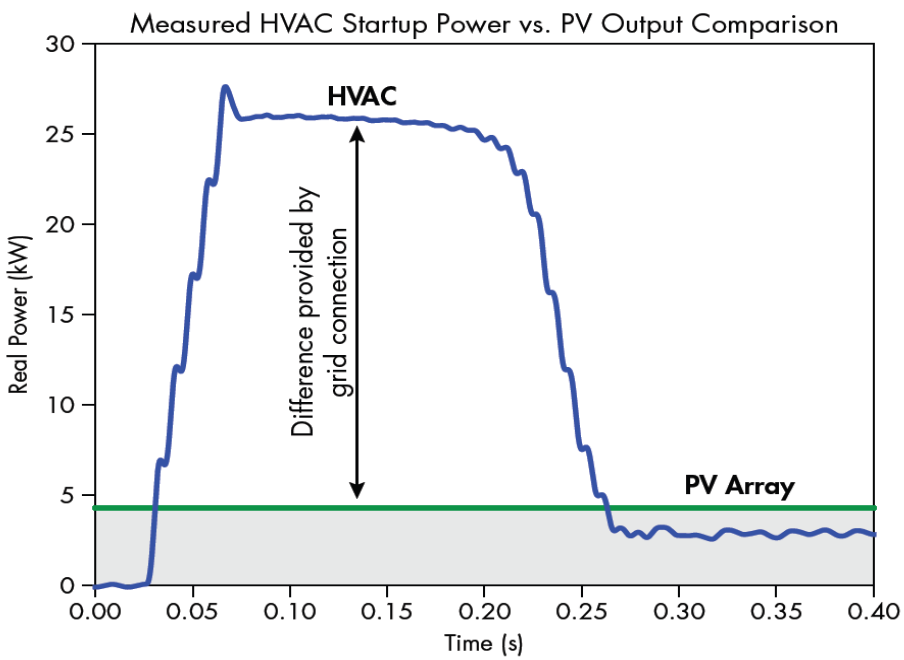
Because distributed PV systems are not uniformly intermittent, having a group of PV systems decreases variability and creates a more predictable pattern.

[50] Richard Perez et al., *Effective metrics give solar its due credit*, Fortnightly Magazine (Feb. 2009), *available at* http://www.fortnightly.com/fortnightly/2009/02/redefining-pv-capacity.

Q. Do non-NEM residential customers have perfectly predictable load profiles?

A. Absolutely not. Residential service loads are not constant; they vary throughout the day, in some cases dramatically, and utilities must stand ready to meet the entire customer load at all times. For example, when an air conditioner turns on, there is a spike in demand that can be quite high relative to a typical PV array, as shown in Figure 3 below.

Figure 3: Air Conditioning Startup Power[51]



A recent survey indicated that 77% of TEP customers have central AC in their homes.[52] As shown in Figure 3, if a group of air conditioners of this type started at the same time there would be significant swings in demand that may require support from additional ancillary services.

[51] Pub. Serv. Co. of Colo., Response to Questions Issued in Decision No. C14-1055-I and Attachment A, at 34 (Sept. 24, 2014), *available at* https://www.dora.state.co.us/pls/efi/efi_p2_v2_demo.show_document?p_dms_document_id=411763&p_session_id=

[52] TEP Resp. to VS 2.24 (Ex. BK-3 at 11).

In addition, as adoption of electric vehicles increases in Arizona, TEP will have to accommodate large swings in residential demand as consumers plug in their electric vehicles at home charging stations. The Nissan Leaf, for example, has a 6.6 kW charger option,[53] and could result in demand swings larger than the average residential PV system size of 5 kW.[54]

Q. What does TEP claim are the issues associated with the inability to monitor and control DG systems?

A. TEP says that because DG is not connected to the utility's energy management system, the utility has no ability to see the output or control the inverter.[55] TEP claims that this creates a situation where the utility is "driving blind" and that with larger amounts of DG this situation can result in significant load-to-generation imbalances.[56]

Q. Do you have an opinion on TEP's claims regarding the inability to monitor and control DG systems?

A. TEP possesses sophisticated technologies that it employs to produce forecasts of PV generation on a daily and hourly basis.[57] In addition, TEP requires that DG sources install a meter to collect generation production data.[58] Interconnected PV systems above 300kW-ac are also required to install advanced metering equipment at the customer's expense that transmits real-time production data to the utility.[59] TEP uses the data obtained from these larger systems to approximate production of the smaller customer-owned DG systems.[60] Additionally, while TEP does not possess the ability to monitor all DG systems in real time, it

[53] Nissan, 2016 Nissan Leaf Specs, http://www.nissanusa.com/electric-cars/leaf/versions-specs/version.sv.html (last visited June 23, 2016).
[54] Solar Energy Indus. Ass'n, Solar Photovoltaic Technology, http://www.seia.org/research-resources/solar-photovoltaic-technology (last visited June 23, 2016).
[55] Tilghman Direct Test. at 7:22–23.
[56] *Id.* at 7:23–8:2.
[57] TEP Resp. to Staff 1.20 (Ex. BK-3 at 31–32).
[58] TEP Resp. to Staff 1.21.
[59] *Id.*
[60] *Id.*

similarly lacks the ability to monitor all individual customer load fluctuations in real time. As discussed above, fluctuations in residential demand due to HVAC systems or electric vehicle cycling can exceed PV system output. TEP has managed to "drive blind" when it comes to other customer demand fluctuations for decades. It is not credible that an inability to monitor and control each DG system presents any exceptional challenges for the utility.

Q. What does TEP claim are the issues associated with excess generation flowing back to the grid?

A. TEP claims that excess energy that is exported from NEM customer generators to the grid creates "issues on the distribution system."[61] The issues listed include the potential to exceed capacity ratings on individual transformers or feeders; significantly higher energy flows that increase operations and maintenance costs and equipment wear and tear; exported energy flowing back up through the distribution system; and potential for reverse power flow and overload conditions.[62]

Q. Do you have an opinion regarding the issues with excess generation identified by TEP?

A. TEP has revealed through discovery that the Company has not conducted any studies concerning increased operations and maintenance costs or equipment wear and tear resulting from DG.[63] The Company has studied the impact of energy flowing back up through the distribution system as a result of projects in excess of 1 MW, but has not provided evidence of similar studies for the typical residential customer whose system may be 1/100th of that size.[64] TEP acknowledges that its statements were based on broad national and regional studies, rather than any analysis unique to the TEP territory and level of DG penetration.[65] In addition,

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[61] Tilghman Direct Test. at 8:4–6.
[62] *Id.* at 8:16–9:2.
[63] TEP Resp. to VS 2.04(a) (Ex. BK-3 at 1).
[64] TEP Resp. to RUCO 3.14 (Ex. BK-3 at 20–21); TEP Resp. to VS 2.04(b) (Ex. BK-3 at 1).
[65] TEP Resp. to VS 2.04(b) (Ex. BK-3 at 1).

TEP states that its claims regarding issues with excess generation are based on the assumption that the typical NEM customer will size their system to offset 100% of load.[66] But as noted above, there is no data to support this assumption.

Q. Has TEP adequately supported its claim that excess DG generation creates significant reverse power flow issues?

No. When TEP receives a generation interconnection request, the Company may model PV generation on the distribution system using SynerGEE Electric powerflow software.[67] Through this modeling, TEP has only identified three instances where the existing distribution facilities could not support the proposed generation source.[68] In all of those instances, upgrading the existing overhead feeder conductor was identified as a possible solution.[69] Again, the data do not indicate that this is a common issue on the TEP system.

Q. In your opinion, has TEP adequately demonstrated that DG in the Company's service territory causes significant grid impacts?

A. No. It is clear from the information provided by the Company that TEP's claims regarding the impacts of excess generation on the grid are not based on an analysis of the utility's own system. The limited impacts that TEP has been able to identify on its own system do not point to a large-scale problem due to these issues. While it is possible that these issues may increase as penetration levels rise, it is not clear how the proposals put forth by TEP in this proceeding address the concerns they have described, short of attempting to stifle solar deployment in their territory. If grid impacts due to DG are expected in the future, the Commission should promote more sophisticated distribution system planning in order to better understand the extent to which DG may result in benefits and costs on the distribution system.

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[66] Tilghman Direct Test. at 8:9–14.
[67] TEP Resp. to VS 2.35(a), (b) (Ex. BK-3 at 16).
[68] *Id.* at 2.35(d).
[69] *Id.* at 2.35(e).

4.4 There is no evidence of a NEM-related cost shift in TEP's service territory

Q. Has TEP made claims regarding a cost shift from NEM customers to non-NEM customers in their service territory?

A. Yes. As described above, TEP claims that "under the Company's current rates, which feature a tiered rate design that relies heavily on volumetric sales to recover fixed costs, solar DG users are not asked to pay for their fair share of the electric system. Instead, those costs are shifted to other customers."[70] The Company also points to a Commission decision regarding NEM rate design in Arizona Public Service Company's ("APS") territory as apparent evidence that a cost shift exists in its own territory.[71]

Q. Has TEP attempted to quantify the alleged NEM cost shift?

A. No. However, Mr. Dukes does provide an illustrative calculation of cost shifting related to low-usage customers. In his discussion of the 1,308,714 residential customer bills that were issued for 400 kWh or less, Mr. Dukes states that "if each of the residential bills referenced above recovered just the test year's average monthly fixed cost recovered for the class of $60, a minimum of $35 million would have been recovered and not have been shifted to other customers."[72]

Q. Do you agree with this cost shift characterization?

A. I do not. In order to quantify a cost shift, the first step would be to identify the appropriate or "fair" level of costs to be recovered by the group of customers in question. Mr. Dukes' $35 million cost-shift figure assumes that the fair level of costs for low-usage customers is the same as customers with average usage. This is inaccurate. TEP's cost of service study identifies a number of metrics for

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[70] Hutchens Direct Test. at 23:9–12.
[71] *Id.* at 20:14–18.
[72] Dukes Direct Test. at 12:25–13:2.

determining cost allocation, including energy usage, coincident peak demand, and contribution to class non-coincident peak demand.[73] Each of these metrics would be expected to be different for low-usage and average-usage residential customers, therefore the $35 million estimate overstates the alleged cost shift. In addition, as noted above, NEM customers make up only 4% of this low-consumption cohort, so even if one were to adopt Mr. Dukes' approach to evaluation of a cost shift, this would imply that the cost shift attributable to NEM customers was less than $1.5 million, or roughly $0.01/kWh in the test year.[74]

Q. How could a cost shift associated with NEM customers be evaluated?

A. In evaluating whether or not a cost shift associated with NEM customers exists in TEP's territory, it is important to treat NEM customers the same as other groups of customers. Cost to serve groups of customers is routinely examined in the context of a cost of service study based on their delivered load characteristics. TEP has failed to do this in this case. TEP's customer cost of service study ("CCOSS") does not look at NEM customers as a sub-class.[75] Indeed, TEP's entire argument regarding cost shifting from NEM customers is based on revenue recovery from full requirements customers versus hypothetical NEM customers who size their system to offset 100% of annual load.[76] This one-dimensional approach assumes that the cost to serve NEM customers is the same as the cost to serve non-NEM customers, and that all NEM customers achieve a 100% offset. Neither of these assumptions is correct.

In addition, by examining only the difference in revenue recovery from NEM customers versus average customers, TEP's approach conflates the price NEM customers pay for energy delivered to them by the utility with the compensation they receive for energy exported to the grid. Lumping these two revenue streams together while ignoring the value of the product that is being provided by the

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[73] Craig A. Jones Direct Testimony ("Jones Direct Test.") at 26:3–4, 24:19–25:5 (November 5, 2016).
[74] TEP Resp. to VS 2.10 (Ex. BK-3 at 6); UDR 1.109.
[75] TEP Resp. to Staff 1.46 (Ex. BK-3 at 34).
[76] *See id.*

NEM customer inflates the cost-shift allegations and does not accurately represent the costs and benefits associated with DG on TEP's system. It is clear that no evidence has been presented in this case to support the allegations that a NEM cost shift exists in TEP's service territory.

Q. If a cost shift were to be demonstrated would it automatically warrant differential rate treatment for NEM customers?

No. Cost shifting within rate classes is an inherent side effect of rate design. Even if TEP were to develop a reasonable estimate of the cost shift associated with NEM, it would not automatically justify differential rate treatment for NEM customers. The residential and small commercial rate classes each inevitably contain customers with widely varying costs to serve, yet these diverse customers are subject to the same rate design. For example, cooling technology can drive significant differences in customer load factors, and urban customers with higher population density can have a lower per-customer cost to serve than rural customers who may require lengthy line extensions.

Indeed, it is evident that even TEP is comfortable with some level of cost shifting between residential customers with and without solar generation. TEP is promoting expansion of the existing TEP Owned Rooftop Solar ("TORS") program that TEP calculates results in a cost-shift to non-participating customers of $0.02/kWh.[77] Notably, this cost shift is double the $0.01/kWh cost shift attributable to NEM customers under TEP's own inflated cost shift assessment discussed above.

Any difference between the cost to serve NEM and non-NEM customers would have to be significantly greater than the inevitable diversity within the residential and small commercial classes in order to warrant a rate design singling out NEM customers. Discriminatory rate treatment of NEM customers due to minor cost shifting would be a slippery slope toward segregation of other portions of the residential and small commercial classes (e.g., by cooling equipment or urban vs.

[77] REST Docket No. 15-0239, Carmine Tilghman Direct Testimony at 9:3–6 (February 12, 2016).

rural customers). Piecemeal subdivision of the residential and small commercial classes in this manner would add significant complexity and may harm low- and fixed-income ratepayers.

5 TEP's Proposals To Reduce DG Growth Are Flawed And Should Be Rejected

Q. What NEM-specific proposals will you address in your testimony?

A. I address TEP's proposal to reduce the NEM export rate and the proposal to require that NEM customers take service on a three-part tariff. I will additionally address the relationship between the proposed NEM rate changes and the LFCR.

5.1 The Commission Should Not Approve TEP's Proposed Amendments to the NEM Tariff

Q. What is net metering?

A. The Commission's rules define "net metering" as follows:

> 'Net Metering' means service to an Electric Utility Customer under which electric energy generated by or on behalf of that Electric Utility Customer from a Net Metering Facility and delivered to the Utility's local distribution facilities may be used to offset electric energy provided by the Electric Utility to the Electric Utility Customer during the applicable billing period.[78]

Net metering means when a NEM customer generates excess energy that is delivered to TEP, the customer has the right to correspondingly offset their electricity purchases from the Company. The NEM customer is thus entitled to a one-to-one energy offset under which the NEM customer is compensated for their energy exports at the retail rate.

Q. How has TEP proposed to amend the current NEM tariff?

[78] A.A.C. R14-2-2302(11).

A. TEP has proposed to decrease the credit NEM customers receive for their excess generation. Specifically, TEP has proposed to implement a new NEM tariff for customers submitting an application for interconnection after June 1, 2015, which would eliminate net metering by compensating NEM customers' excess generation at a rate less than the retail rate. Instead, TEP would compensate NEM customers for their exports at the "Renewable Credit Rate."[79] TEP is additionally requesting a partial waiver of Rule R14-2-2306 to "eliminate the 'roll over' of excess generation to offset future usage."[80] In place of the excess generation roll over, TEP proposes that NEM customers taking service under the new rider be able to "carry over unused bill credits to future months if they exceed the amount of their current bill."[81]

Q. What is the Renewable Credit Rate?

A. TEP's proposed Renewable Credit Rate is based on the most recent utility-scale renewable energy purchased power agreement ("PPA") connected to TEP's distribution system.[82] TEP proposes that the Renewable Credit Rate be updated annually with the Company's Renewable Energy Standard and Tariff ("REST") filing and that it would be based on the most recent comparable utility-scale PPA.[83] The Renewable Credit Rate proposed in this application is based on a PPA signed December 17, 2014, for a 21.5 MW ground-mounted PV system.[84] The initial Renewable Credit Rate based on this PPA would be set at 5.84¢/kWh.[85]

Q. Has TEP discussed its rationale for compensating NEM customers for excess generation at the Renewable Credit Rate, rather than at retail rates?

A. Mr. Tilghman states that because "the ratepayers ultimately pay the difference between conventional energy prices and renewable energy prices, the Company

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[79] Tilghman Direct Test. at 9:8–10.
[80] *Id.* at 9:10–12.
[81] *Id.* at 10:17–18.
[82] *Id.* at 9:19–21.
[83] *Id.* at 10:7–11.
[84] VS 2.06(b)–(d) (Ex. BK-3 at 3).
[85] Tilghman Direct Test. at 9:19–21.

believes it is appropriate that Net Metering customers receive the same financial compensation for their distributed energy that is available from other, larger, more cost-effective resources."[86] In addition, in discovery the Company states that "[i]t was determined that as long as the Company has a renewable energy requirement and would otherwise be procuring renewable energy, it was reasonable to pay the prevailing wholesale market price for renewable energy on our distribution grid."[87]

5.1.1 Grid-scale benchmarking is not appropriate for valuation of DG exports

Q. Do you have an opinion on TEP's rationale for the Renewable Credit Rate proposal?

A. TEP's proposed Renewable Credit Rate is an example of a grid-scale benchmarking methodology that has been discussed at length in the open Value of DG Docket.[88] The main arguments in support of a grid-scale methodology are centered on the idea that utility-scale solar PV provides many similar benefits and attributes when compared with distributed solar PV, yet due to the benefits of economies of scale, is generally available at a lower unit price.

Q. Do you agree with these statements?

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

[86] *Id.* at 10:1–4.
[87] TEP Resp. to VS 2.06(i) (Ex. BK-3 at 5).
[88] *See* Docket No. 14-0023.

For example, in testimony in the Value of DG docket, APS witness Brad Albert stated:

> Based upon the prudent utility planning principles that have been a basic premise upon which utility resource procurement decisions have historically been made, a utility has an obligation to seek out the lowest-cost, best-fit approach to fulfilling a resource need. The grid-scale adjusted methodology is consistent with this principle in that it identifies the lowest-cost, best-fit manner of achieving the same resource value.[89]

This concept is echoed by TEP witness Dr. Edwin Overcast in the same proceeding:

> DG energy sales from roof top residential customers are worth far less to the utility under net metering than under a year-round contract for solar generation.[90]

Both of these statements illustrate how the grid-scale benchmarking methodology approaches the issue of DG valuation from the utility perspective, making a false comparison between the two resources. The comparison of utility-scale pricing with distributed-scale pricing from the perspective of the utility ignores the fact that while utility-scale contracts may in fact be cheaper, no one is offering the non-participating ratepayer access to utility-scale solar at 5.84 ¢/kWh. The only product available to the non-participating ratepayer is delivered energy available at the full retail rate.

The non-participating ratepayer will be generally indifferent to and unaware of whether the electrons he is consuming are coming from his neighbor's PV array or whether they have been carried across the entire utility transmission and distribution system from a centralized power plant. Asking why the utility should pay more for DG than they pay for utility-scale solar PPAs asks the wrong question. From a non-participating ratepayer perspective, the right question to ask is: what is the level of costs avoided by the non-participating customer as a result

[89] Bradley J. Albert Direct Testimony in Value of DG Docket No. 14-0023 ("Albert Direct Test. DG Docket") at 32:13–18 (February 25, 2016).
[90] H. Edwin Overcast Direct Testimony in Value of DG Docket No. 14-0023 ("Overcast Direct Test. DG Docket") at 9:2–6 (February 25, 2016).

of the exported DG? The answer to this question is independent of the price paid for utility-scale solar. Therefore, while TEP has stated repeatedly that its motivation for proposing rate design changes in this case is to provide more accurate price signals and more cost-based rates, it is clear that the Renewable Credit Rate would not accomplish that goal.

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

A. I do not believe the grid-scale benchmarking approach has any merit for the determination of an appropriate DG export price. In the Value of DG Docket the Residential Utility Consumer Office ("RUCO") witness, Mr. Huber, agreed, stating, "[f]avorable costs of utility and community scale solar should not be used to determine that DG solar cannot be cost-effective, or should not be pursued."[91] The attempt to set pricing for DG exports based on utility-scale prices which have no bearing on the costs and benefits associated with DG creates a false choice. Arizona's utility customers support choice and they support clean energy.[92] TEP has not provided any evidence that compensating NEM exports at the retail rate shifts costs to other customers and, absent such a demonstration, the current NEM structure should be maintained.

5.1.2 TEP has not provided evidence that retail rate compensation for exports results in a cost shift

Q. Why do you dispute TEP's claim that compensating NEM exports at the retail rate shifts costs to other customers?

A. TEP has not provided any evidence in this proceeding to establish whether or not the current NEM tariff design, including compensation for NEM exports at the full retail rate, results in any cost shift either to or from NEM customers. The

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[91] Value of Solar Case, Docket No. 14-0023, Lon Huber Direct Testimony at 23:20–22 (February 25, 2016).

[92] Adrian Gray Consulting LLC, Memorandum to Environmental Defense Action Fund, *Survey of Arizona Voters* at 2 (Oct. 14, 2014), *available at* http://www.edfaction.org/sites/edactionfund.org/files/press-releases/edaf-az-2014.pdf.

question of whether a cost shift exists depends on the relationship between the retail rate credit and the value of exported solar generation. TEP has provided no evidence on which to analyze the relationship between the Company's retail rate and the value of exported solar generation. In order to determine whether a modification to the NEM tariff is warranted, the Commission must establish the costs and benefits of the exported DG for which the Renewable Credit Rate is intended to compensate. Because there has been no assessment of the costs and benefits of distributed solar on the TEP system, there is no basis to conclude whether retail-rate compensation is too high or too low, or if a cost shift exists (and in which direction).

Q. What evidence is needed in order to assess the relationship between the costs and benefits of solar and the retail rate?

A. In order to determine the relationship between the costs and benefits of distributed solar and the retail rate, a full benefit/cost analysis would need to be completed. I have provided testimony in the Value of DG docket that provides my detailed recommendations regarding the appropriate methodology for such an analysis.[93] In that docket I recommended that the Commission adopt a long-term avoided cost approach to the valuation of DG that could be used to inform whether the retail rate is an appropriate proxy for the value of DG exports to the non-participating ratepayer.

Q. Does evidence from other states suggest that NEM rates result in a cost shift from NEM to non-NEM customers?

A. No, in fact, evidence from other states suggests that the value of distributed solar may exceed the retail rate. In some cases, the value of distributed solar exceeds the retail rate by a significant amount. The results of distributed solar benefit/cost analyses can differ greatly depending on the assumptions and perspective of the entity sponsoring the study. As a result, it is important to look at studies

[93] *See* Value of Solar Case, Docket No. 14-0023, Briana Kobor Direct Testimony (February 25, 2016).

sponsored or performed by an independent party, such as a state agency. A number of notable studies have been sponsored by independent state entities concluding that the benefits that distributed solar generation provides to the utility exceed the costs. Table 1 below summarizes the results of recent studies performed by or for state governments.

Table 1: Recent Benefit/Cost Studies

State	Date	Sponsor	Resulting Value
ME	1-Mar-2015	Legislature	33.7¢/kWh levelized[94]
MS	19-Sep-2014	PSC	17.0¢/kWh levelized[95]
NV	Jul-2014	PUC	18.5¢/kWh levelized[96]
MN	31-Jan-2014	Dep't of Commerce	14.5¢/kWh levelized[97]
VT	1-Oct-2014	Legislature	23.7¢/kWh levelized[98]

This experience in other states shows that the existence of a cost shift should not be assumed in this proceeding. As the studies in Table 1 demonstrate, state sponsored studies have found that the benefits of solar can be as high as 25–30¢/kWh in some jurisdictions. Without evidence on the benefits and costs of solar in the TEP territory, the Commission has no means to determine the need for an alternate export rate.

[94] Me. Pub. Utils. Comm'n, *Maine Distributed Solar Valuation Study* 6 (Apr. 2015), *available at* http://www.maine.gov/mpuc/electricity/elect_generation/documents/MainePUCVOS-FullRevisedReport_4_15_15.pdf.

[95] Elizabeth A. Stanton et al., Synapse Energy Econ., Inc., *Net Metering in Mississippi: Costs, Benefits, and Policy Considerations* 43 (Sept. 2014), *available at* http://www.synapse-energy.com/sites/default/files/Net%20Metering%20in%20Mississippi.pdf.

[96] Energy & Envtl. Econ., *Nevada Net Energy Metering Impacts Evaluation* 93 (July 2014), *available at* http://puc.nv.gov/uploadedFiles/pucnvgov/Content/About/Media_Outreach/Announcements/Announcements/E3%20PUCN%20NEM%20Report%202014.pdf?pdf=Net-Metering-Study.

[97] Peter Fairley, *Minnesota Finds Net Metering Undervalues Rooftop Solar*, IEEE Spectrum (Mar. 24, 2014), *available at* http://spectrum.ieee.org/energywise/green-tech/solar/minnesota-finds-net-metering-undervalues-rooftop-solar.

[98] Vt. Pub. Serv. Dep't, *Evaluation of Net Metering in Vermont Conducted Pursuant to Act 99 of 2014*, at 17 (Nov. 2014), *available at* http://psb.vermont.gov/sites/psb/files/Act%2099%20NM%20Study%20Revised%20v1.pdf.

5.1.3 The proposed Renewable Credit Rate is flawed and should be rejected

Q. If the Commission elects to consider grid-scale benchmarking as an alternative export rate, do you have any comments on the specific aspects of the Renewable Credit Rate proposal?

A. Yes. If the Commission decides to consider an alternate credit rate despite the lack of evidence on the benefits and cost of distributed solar, there are several significant flaws in TEP's proposed Renewable Credit Rate.

Q. What are the flaws in the Renewable Credit Rate proposed by TEP?

A. The flaws in the proposed Renewable Credit Rate are threefold: (1) the Renewable Credit Rate does not appropriately approximate the value of distributed solar generation; (2) the Renewable Credit Rate would be extremely volatile and vulnerable to gaming; and (3) the Renewable Credit Rate would violate the Commission's existing NEM rules.

Q. Why do you contend that the Renewable Credit Rate does not appropriately approximate the value of distributed solar generation?

A. In addition to the fact that grid-scale benchmarking is not an appropriate proxy for the costs and benefits associated with DG, crediting DG exports at utility-scale renewable rates ignores many key benefits provided by DG that are not provided by utility-scale renewables. Distributed solar's unique benefits compared to utility-scale solar generation include: (1) higher generation capacity value due to the geographic diversity of DG systems; (2) potentially greater avoided distribution costs and grid services from DG; and (3) greater local employment benefits accruing from DG.

Q. Why would the proposed Renewable Credit Rate be volatile and subject to gaming?

A. TEP has proposed to base the Renewable Credit Rate on the single most recent contract and to update the rate annually. Utility supply contracts are complex agreements with pricing and terms established through a closed-door negotiation process, often with price escalators and performance-oriented terms. In fact, TEP has indicated that even the Company itself cannot predict future Renewable Credit Rates.[99] By setting the Renewable Credit Rate based on a single PPA, TEP has made the rate subject to large annual fluctuations. This can be seen through examination of utility-scale solar prices from recent TEP PPAs. The PPA used as the basis for TEP's proposal has a rate of 5.84¢/kWh, while another contract signed by TEP has a rate as high as 10.875¢/kWh.[100] A Renewable Credit Rate that could fluctuate so widely from year to year would subject NEM customers to significant uncertainty and volatility, potentially making financing of projects more difficult and expensive.

These fluctuations additionally make the proposed Renewable Credit Rate vulnerable to gaming. Since the rate would be based on the single most recent contract at the time of filing, TEP would have an incentive to time the finalization of more costly renewable PPAs in order to minimize the rate it would pay to compensate NEM customers.

Q. Why do you say that the Renewable Credit Rate would violate the Commission's existing NEM rules?

A. As I discussed above, Commission Rule R14-2-2302 defines net metering to give NEM customers the right to a one-to-one retail rate offset for excess generation. In addition, Commission Rule R14-2-2306(C) states:

> If the kWh supplied by the Electric Utility exceed the kWh that are generated by the Net Metering Facility and delivered back to the Electric Utility during the billing period, the Customer shall be billed for the net

[99] TEP Resp. to VS 2.06(h) (Ex. BK-3 at 5).
[100] UNSE Resp. to VS 3.01(f) in Docket No. 15-0142 (Ex. BK-2 at 11).

> kWh supplied by the Electric Utility in accordance with the rates and charges under the Customer's standard rate schedule.[101]

This concept of a one-to-one retail rate offset for excess generation is so fundamental to NEM policy that it is the reason this rate design is called "net" energy metering in the first place: the exports must "net" against consumption at the retail rate. While I am not a lawyer and I am not offering a legal opinion, it seems clear that TEP's proposal to reduce the compensation rate for excess generation would not be net metering and would thus violate the existing NEM rules.

Q. Has TEP requested a partial waiver of Rule R14-2-2306 as part of its proposal?

A. Yes, TEP has requested a partial waiver of Rule R14-2-2306 to "eliminate the 'roll over' of excess generation to offset future usage."[102] However, the Company has not addressed the fact that its proposal also violates the NEM rules by proposing to take the "net" out of net energy metering. The Commission has previously stated that compensation for exports at the retail rate is a fundamental part of the NEM rules. In Appendix B to Decision 69127 adopting the Renewable Energy Standard and Tariff Rules, the Commission explicitly addressed the question of customer compensation for generation supplied to the grid.[103] Faced with proposals, including a proposal from APS, to delete the requirement crediting exports at the full retail rate, the Commission concluded "Net Metering is an important piece of the regulatory infrastructure for distributed generation" and did not approve APS's proposed change.[104] TEP's proposal to credit DG solar exports at less than the retail rate would violate Commission rules, and the "partial waiver" it has requested would not cover the deviations from the NEM rules that the Company proposes.

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[101] A.A.C. R14-2-2306(C).
[102] Tilghman Direct Test. at 9:10–12.
[103] Decision No. 69127 at App. B 1:19–6:20 (Nov. 14, 2006).
[104] *Id.* at 2:2–5, 6:8–9.

Q. What are your recommendations regarding the proposed Renewable Credit Rate?

A. Commission rules dictate that TEP must compensate NEM customers' exported DG at the retail rate. Grid-scale benchmarking is not a reasonable approach to valuation of DG and, absent any evidence to reliably determine whether the current retail rate is above or below the value of DG on the TEP system, there is no basis on which to support a departure from the current NEM compensation structure. In addition, the proposed Renewable Credit Rate has several significant flaws. Therefore, even if the Commission decides to consider an alternate export rate, the proposed Renewable Credit Rate should be rejected.

5.2 Demand charges should not be mandatory for NEM customers, or any other residential or small commercial customers

Q. What is TEP proposing regarding demand charges for residential and small commercial customers?

A. The Company has proposed to implement optional tariff schedules for residential and small commercial customers that include a demand charge, in addition to the basic service charge and volumetric energy charge. This type of rate design is referred to as a "three-part" rate structure. TEP has proposed that a three-part rate structure be mandatory only for NEM customers.[105] While the Company has not proposed mandatory three-part rates for all residential and small commercial customers at this time, it hopes to "make such a move possible in its next rate filing."[106]

Q. What is the rationale that TEP provides in support of demand charges for residential and small commercial customers?

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[105] Dukes Direct Test. at 4:4–8.
[106] *Id.* at 18:5–8.

A. TEP claims:

> If properly designed, three-part rates more fairly allocate costs to the customers within a class that 'cause' them and provide proper price signals that help customers make informed decisions regarding their energy and electrical system usage. Three-part rates also reward customers for better load factors and reductions in peak usage – attributes that lead to lower system costs, which benefits all customers.[107]

In addition, TEP provides an exhibit identifying 39 utilities that offer residential rates that include demand charges.[108]

5.2.1 NEM and non-NEM customers are similarly situated regarding demand charges

Q. TEP has proposed to make the demand charge mandatory only for NEM customers: what is the rationale for this proposal?

A. TEP makes two claims to support mandatory demand charges for NEM customers. First, TEP claims that "two-part rates are designed to recover costs based on average consumption levels for <u>full-requirements</u> customers."[109] According to TEP, because NEM customers offset some of their energy requirements through onsite generation, the current rates that do not include a demand charge "are ill-equipped in accounting for how these customers use TEP's system and for fair recovery of fixed cost."[110] Second, TEP claims that requiring NEM customers to take service on a rate with a demand charge will help to mitigate the cost shift they allege is occurring.[111]

Q. Is there any evidence to support these claims?

A. In order to address these claims, it is important to consider what makes NEM customers different from other customers. The difference is twofold: (1) NEM

[107] *Id.* at 17:7–11.
[108] *Id.* at Ex. DJD-1.
[109] *Id.* at 5:10–12 (emphasis in original).
[110] *Id.* at 5:8–10.
[111] *Id.* at 5:13–15.

customers typically use DG to supply some proportion of their energy requirements and consume the balance of energy from the grid, and (2) NEM customers may export excess generation from their DG systems to the grid.

Q. Do TEP's NEM customers have different consumption patterns than non-NEM customers?

A. TEP has not provided any evidence as to whether the load factors and energy requirements from NEM customers differ significantly from the load factors and energy requirements of non-NEM customers. Indeed, the Company reports that they have no information on the similarities and differences in peak demand and energy consumption between residential customers with and without NEM.[112]

Q. Would NEM customers respond differently to the demand charge price signals than other residential and small commercial customers?

A. NEM customers are similarly situated to other residential and small commercial customers regarding the ability to understand and respond to demand charges. DG systems are effective at reducing the customer's consumption of energy supplied by the utility, but they can have little impact on individual customer peak demand. This is because the timing of the customer's peak may occur outside the hours in which the DG system is operating. This is illustrated by TEP's own assumptions in its assessment of a hypothetical NEM customer who sizes the DG system to offset 100% of load. TEP's analysis assumes that the NEM customer's peak demand will be equivalent to the non-NEM customer's peak in all but four months of the year when the DG system would reduce customer peak by 7% or less.[113]

Q. What does this imply about TEP's proposal to make demand charges mandatory only for NEM customers?

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[112] TEP Resp. to Staff 1.48 (Ex. BK-3-035).
[113] Workpaper 2015 TEP R-01 Demand-PRS.xlsx.

A. TEP's proposal to require demand charges for NEM customers is discriminatory ratemaking. As will be explained in detail below, demand charges are not appropriate as mandatory rate design for any residential and small commercial customers whether or not they have installed DG. TEP's proposal to require demand charges for NEM customers would effectively function as an additional fixed charge, because most NEM customers lack the ability to effectively respond to the price signal in demand charges. Imposing additional fixed charges solely on NEM customers would be unduly discriminatory because TEP has not provided evidence that NEM customers shift costs to other customers, nor that NEM customers constitute a meaningful proportion of the residential customers who allegedly do not pay their fair share of fixed costs.

5.2.2 Demand charges create winners and losers

Q. According to TEP, what is the impact on customers of moving from a two-part rate to a three-part rate?

A. In his direct testimony, Mr. Dukes presents a table purporting to show how the proposed three-part rates would impact residential customer bills. That table is reproduced below for illustrative purposes.

Table 2: TEP Assessment of Residential Bill Impacts of Three-Part Rate[114]

Average Monthly Usage	Average Monthly Load Factor	Average Monthly Bill RES-01	Average Monthly Bill RES-D	Difference
500 kWh	18.4%	$74.16	$83.51	$9.35
900 kWh	23.3%	$120.86	$121.33	$0.47
1,200 kWh	26.7%	$156.54	$147.29	($9.25)
1,500 kWh	31.5%	$192.10	$169.45	($22.65)

When discussing these results Mr. Dukes states: "[b]ills calculated using the three-part rate will exceed bills using the two-part rate at lower levels of consumption. As usage increases, customers on the three-part tariff will have

[114] Dukes Direct Test. at 25:1–5.

lower monthly bills."[115] He additionally contends that lower usage customers would not necessarily be put at a disadvantage on the three-part rate because the actual bill impact would depend in great part on their load factor.[116] He additionally states the following:

> The three-part rate with a demand charge rewards customers with higher load factors, all else equal. More important, a three-part rate will reward customers who improve their load factor. If residential customers choose to take service on a three-part rate they will reduce their electric bills by improving their load factor or maintaining a higher load factor.[117]

Q. Do you believe that TEP's testimony accurately states the impact on residential customers of moving to a three-part rate?

A. I do not. The results presented by Mr. Dukes show one dimension of a two dimensional picture of bill impacts. Historically, it has been standard practice to demonstrate the range of impacts that rate changes would have on residential customers by calculating the bill impacts at different usage levels measured in kWh, as Mr. Dukes has done in the table reproduced above. However, with the demand charge, TEP has proposed a wholly new rate component that varies not only on kWh usage but also on the customer's individual peak demand. This second dimension, measured in kW, is averaged out in Mr. Dukes' table. As a result, the broad range of impacts that individual customers will experience is not evident from the table.

Q. Have you been able to analyze how broad this range of impacts would be?

A. Yes. TEP provided a large amount of hourly residential customer data from which I was able to calculate individual customer bill impacts for a sample of 17,000 residential customers.[118] Exhibit BK-2 shows a scatterplot with each of the 17,000 customer bill impacts depicted by usage level. As shown in Exhibit BK-2, the table provided by Mr. Dukes does not begin to demonstrate the variety of impacts

[115] *Id.* at 24:24–26.
[116] *Id.* at 25:7–27.
[117] *Id.* at 26:2–6.
[118] Data provided in TEP Resp. to RUCO 7.11 (Ex. BK-3 at 28).

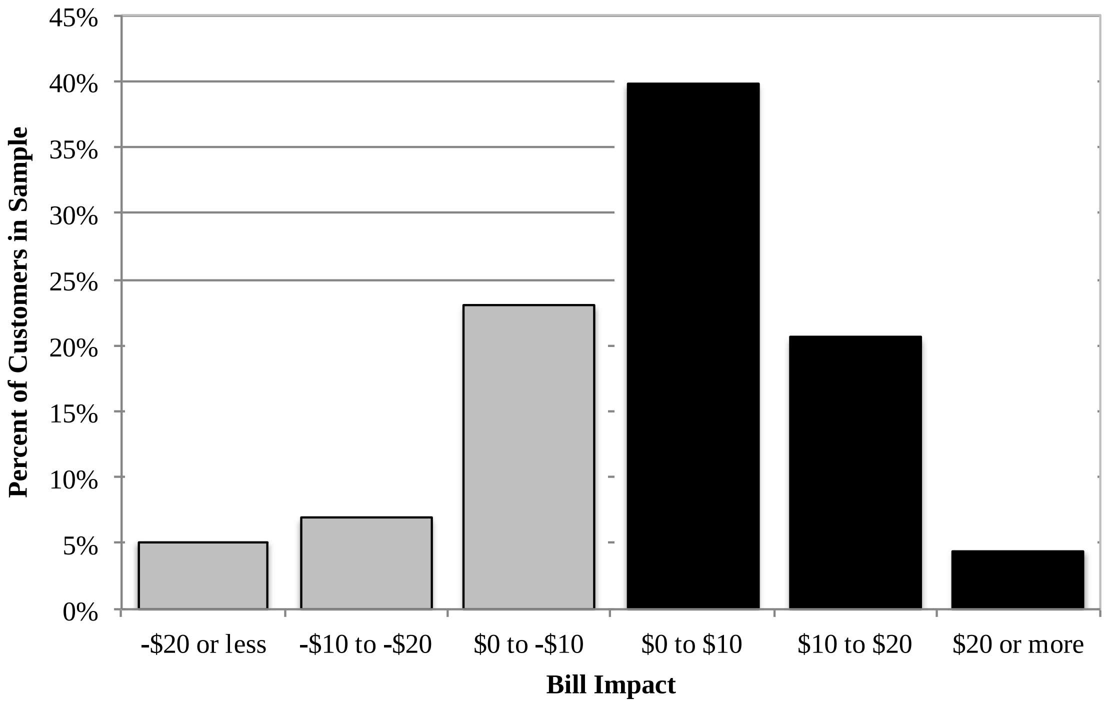
that customers would experience when moving from a tiered two-part rate to the proposed three-part rate. For purposes of the Exhibit, I have used the two-part rate proposed by TEP in this application, which includes a doubling of the fixed charge from $10/month to $20/month, as well as a reduction in the number of tiers from four tiers down to two tiers. By using the proposed two-part rate, I have compared rate designs on a revenue neutral basis. In addition to the bill impacts shown in Exhibit BK-2, all residential customers are expected to see additional increases as a result of the increase in revenue requirement, and lower-usage customers are expected to see additional increases as a result of the fixed charge and volumetric tiering changes being proposed.

Mr. Dukes' chart depicts the average bill impacts for a customer using 900 kWh as being only $0.47/month.[119] However, when the data is examined for the 2,150 customers in the sample that have an average monthly usage of between 800 kWh per month and 1,000 kWh per month, the data reveals that these customers will have a large range of impacts. In fact, some customers' bills will increase by as much as $70/month, while others will decrease by as much as $34/month, depending on each individual's specific usage characteristics.[120] While these figures represent the extreme ends of the spectrum, the depiction of an impact that is less than one dollar a month does not begin to tell the story of how customers would be impacted by moving to a demand charge rate. Figure 4 below demonstrates the distribution of bill impacts comparing the proposed standard two-part rate to the proposed three-part rate.

[119] This usage level is similar to the average usage for a TEP customer of 785 kWh/month, Schedule H-4, page 1.

[120] If one were to consider the total change being requested in this docket, including the increase in revenue requirement, increase in the basic customer charge and removal of two of the four tiers, sample customers with average monthly usage of 800-1,000 kWh would see average monthly bill impacts ranging from a $21 reduction to an $84 increase.

Figure 4: Distribution of Residential Bill Impacts – Movement to Demand Charge Rate[121]

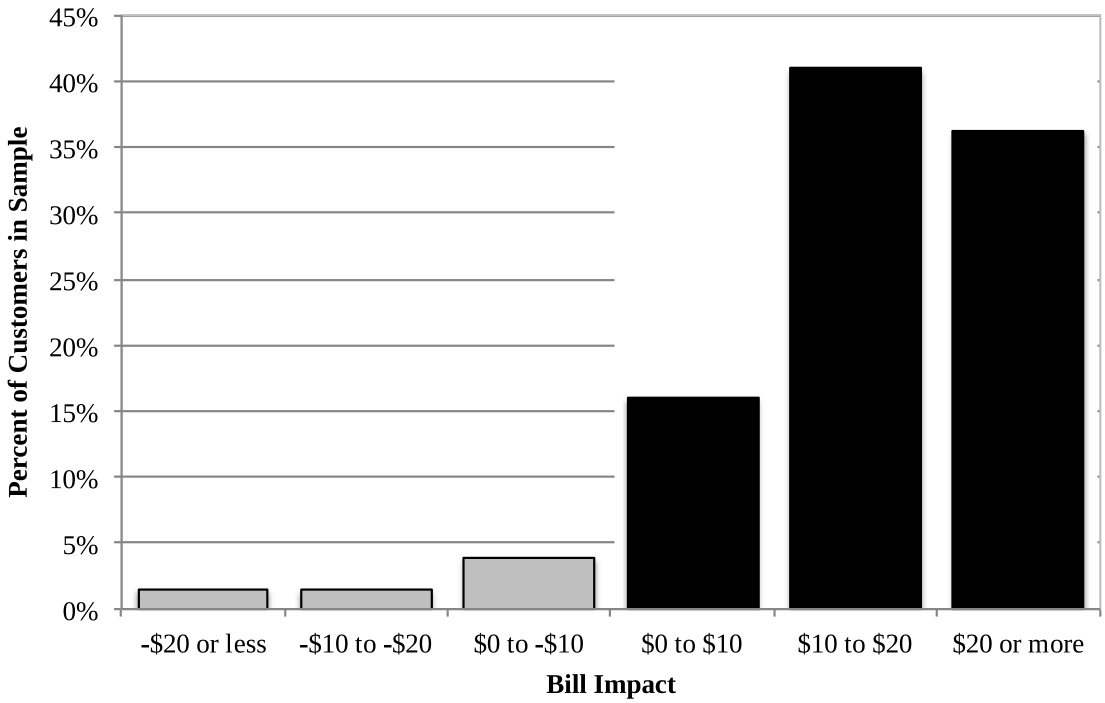


As seen in the figure, 65% of customers would experience bill increases if they moved to a demand charge tariff. While the majority of customers with increases will see bill increases of less than $10 a month, 25% of customers' bills are expected to increase by more than $10 a month.

However, demand charges are not the only rate design change proposed in this docket. TEP is also requesting approval of a revenue requirement increase, a doubling of the fixed customer charge, and a reduction in the number of residential rate tiers. While Figure 4 depicts the range of bill impacts associated with movement from the proposed two-part rate to the proposed three-part rate, it does not depict the full level of changes that may be faced by customers in this case. Figure 5 below shows the full level of changes faced by customers moving from the current rate to the proposed three-part rate, a change that TEP is requesting be mandatory for NEM customers.

[121] Data provided in TEP Resp. to RUCO 7.11 (Ex. BK-3 at 28). Figure compares bill impact from proposed Schedule RES-01 and proposed schedule RES-D.

Figure 5: Distribution of Residential Bill Impacts – Current Rates to Proposed Demand Charge Rate[122]



As shown in Figure 5, when the full range of revenue and rate design changes proposed in this case are examined, as many as 36% of residential customers are expected to see their monthly bills increase by $20 or more.

Q. What do you conclude based on this data?

A. Demand charges are a rate design that creates "winners" and "losers" among the residential class. The data shows that 65% of customers are expected to face bill increases on a demand charge tariff. While Exhibit BK-2 demonstrates that larger customers tend to be among the biggest savers on a demand charge rate, the trend is hardly linear, and individual customer bill impacts will vary greatly across usage levels. TEP's current proposal is to make a demand charge tariff mandatory for new NEM customers. Most people considering installing DG systems would thus face additional costs due to TEP's proposed demand charge.

[122] Data provided in TEP Resp. to RUCO 7.11 (Ex. BK-3 at 28). Figure compares bill impact from proposed Schedule RES-01 and proposed schedule RES-D.

Q. Given that TEP has stated that rates with demand charges are more cost based, isn't it appropriate for there to be winners and losers on the new tariff structure?

A. There are two problems with this argument that warrant discussion. First, TEP has not demonstrated that the proposed demand charge tariff is cost based. Therefore it cannot be determined that the resulting winners and losers will be treated equitably. Second, because most customers will encounter significant obstacles to respond to demand charges, even if demand charges could be proven to theoretically provide a cost-based price signal, these charges would not be an efficient or effective way to modify consumption patterns in a way that benefits other customers. In a recent study examining available evidence on demand charges for residential and small commercial customers, the Rocky Mountain Institute ("RMI") found "there is limited empirical evidence on the efficacy or impacts of mass-market demand charges on any desired outcome beyond cost recovery. It remains unclear whether demand charge rates effectively communicate price signals to customers about how to change their usage to reduce system cost."[123]

5.2.3 Demand charges do not create actionable price signals for residential customers

Q. Please discuss TEP's claim that the proposed demand charge tariff is cost based.

A. TEP acknowledges that a demand charge must be properly designed to match system costs in order for it to fairly allocate costs to customers within a class:

> [I]t is critical that each component of the three-part rate closely reflects the actual cost of service. If properly designed, three-part rates more fairly allocate costs to the customers within a class that "cause" them and

[123] Rocky Mountain Inst., *A Review of Alternative Rate Designs* 79 (2016), *available at* https://rmi.org/Content/Files/alternative_rate_designs.pdf.

provide proper price signals that help customers make informed decisions regarding their energy and electrical system usage.[124]

TEP summarizes the drivers of system costs as follows: "the distribution system is a network designed primarily to meet the non-coincidental peak demands of customers. The transmission and generation systems, by contrast, are designed to meet the coincidental peaks of the distribution system, with reserves and margins for growth and planning purposes."[125] The allocation factors employed in TEP's CCOSS are consistent with this: distribution system costs are allocated based on customer class non-coincident peak ("NCP") and generation and transmission costs are allocated based on a mixture between energy usage and coincident peak ("CP") demand.[126] For the residential class this means that 19% of the residential costs that the cost of service study classifies as demand related are related to the residential class NCP, 39% of the costs are related to the CP, and 42% of the costs are unrelated to demand, but rather, are based on energy usage.[127]

Q. What does this imply about the proposed demand charge?

A. This implies that TEP's proposed demand charge will not treat all customers in an equitable manner and for many will not reflect the costs that they cause. In sum TEP cannot claim that the proposed demand charge is cost based. Under TEP's proposal, customers would be billed based on their highest one hour demand during a billing period, regardless of the time of day in which that demand occurs.[128] Data on the annual TEP system peak shows that the system peak can be expected to occur in the mid-afternoon during the summer months.[129] A residential customer, on the other hand, may set her peak demand in the early morning while making coffee, and using the clothes dryer and hair dryer. Therefore, it is not clear that a demand charge based on the individual customer

[124] Dukes Direct Test. at 17:6–9.
[125] *Id.* at 14:27–15:3.
[126] 2015 TEP Schedule G – COSS REVISED-Competitively Sensitive Confidential.....xlsx.
[127] 2015 TEP Schedule G – COSS REVISED-Competitively Sensitive Confidential.....xlsx.
[128] Dukes Direct Test. at 24:7–8.
[129] TEP Resp. to RUCO 8.05 (Ex. BK-3 at 29).

peak, which can occur at any time day or night, would result in fair allocation of costs among customers within the residential and small commercial classes.

Moreover, as demonstrated above, costs are not caused by individual customer peak, but rather their aggregated contribution to class NCP, CP, and energy usage. Indeed, TEP acknowledges that the proposed rate would have an "indeterminate" impact on customers' coincident peak kW, as it would only promote reduction in individual customer peak, not coincident peak.[130] The Company further admits "reducing peak demand is not the primary objective of TEP's proposed three-part rates for residential and small general service customers. While peak demand reduction may be a benefit of the proposed three-part rate, the main objective of TEP's proposal is to better align cost recovery with how costs are incurred."[131] While it can be argued from economic theory that rates should be reflective of backward-looking costs, if customers are unable to respond to the price signals in demand charges, this rate design would provide little benefit going forward to the majority of ratepayers. TEP states: "Under a three-part rate, customers receive a price signal encouraging them to improve their load factor, which benefits the customer by reducing their electric bills and benefits all TEP customers as the system is used more efficiently."[132] However, the evidence shows that the average residential customer may not be able to respond to such a price signal.

Q. Why would the average residential customer not be able to respond to the price signals in demand charges?

A. In order for a rate structure to send a price signal to help customers make informed decisions, the customers must be able to understand how to respond to that price signal. In the case of demand charges, residential and small commercial customers would first need to know when their peak demands occur. Because the demand charge would be assessed based on the highest hour of consumption in a given billing period, there would be an average of 730 hours in which each

[130] TEP Resp. to SWEEP 1.08 (Ex. BK-3 at 37).
[131] TEP Resp. to SWEEP 2.15 (Ex. BK-3 at 38).
[132] Dukes Direct Test. at 26:7–9.

individual customer's peak demand may occur. Moreover, the day of the week and hour of the day in which that peak occurs may vary from month to month. In addition, to gain an understanding of when their peak demand may occur in any given month, customers would also need to understand how common behaviors such as staying home sick from work, having friends over for a poker night, or hosting an annual family holiday may impact the level and timing of their peak demand. Even if typical residential customers were to have this level of understanding of their peak demand, it is not clear how they would be able act to reduce their peak demand.

Q. Are you saying that the average customer is not smart enough to understand demand charges?

A. No. While I do believe that with considerable effort, TEP would be able to educate many of its customers on what a demand charge is, I do not believe that average residential customers will be able to take action to mitigate the impact such a charge would have on their monthly bills. As shown above, 65% of TEP's residential customers would be expected to see their bills increase on a demand charge tariff. Even if these customers had a full understanding of what was causing their bills to increase, lifestyle limitations may undermine their ability to do anything about it.

Q. Can you provide an example of what you mean by lifestyle limitations?

A. Yes. Many residential customers have limited choice or control over when they use appliances. It is estimated that as many as 45% of TEP's residential customers may have all-electric service.[133] Electric furnaces and water heaters can consume significant levels of electricity, with common models drawing 10.5 kW and 4.5 kW, respectively.[134] In addition, common hair dryers typically draw upwards of 1 kW, the average microwave or toaster oven can draw 1 kW, and an electric kettle

[133] TEP Resp. to VS 2.15(e) (Ex. BK-3 at 7).
[134] City of Santa Clara, Silicon Valley Power, Appliance Energy Use Chart, http://www.siliconvalleypower.com/for-residents/save-energy/appliance-energy-use-chart (last visited June 23, 2016).

can draw 1 kW.[135] Looking at this list, it is easy to see how the typical morning routine for a family would easily result in an instantaneous peak demand of as much as 18 kW and demand over a one-hour period in excess of 10 kW.[136] Under TEP's proposed demand charge tariff, a billed demand of 10 kW would result in charges of $87.50 in addition to the proposed $20 fixed monthly charge, meaning that this family would have little to no control over a full $107.50 of their monthly bill.[137] This is in excess of the total average monthly bill on the proposed standard rate.[138] While families may certainly be able to understand that this peak demand occurs, school schedules and work schedules may not allow them to do anything about it.

Q. Has TEP proposed any measures to help customers respond to demand charges?

A. I have not seen any proposals in this case to assist customers in understanding and responding to demand charges. In the UNSE case, when the proposal was to institute mandatory demand charges for all residential and small commercial ratepayers, UNSE placed a great emphasis on its customer education plans, the centerpiece of which was online access to personal usage information.[139] It appears as if TEP does not intend to provide even this most basic of tools to its customers. Currently, TEP customers have access to total monthly usage but have no information on the magnitude nor timing of their individual peak demands. In order to gain even this most basic level of understanding the customer would need to request hourly or interval data from the utility.

Unfortunately TEP is seeking to make this process even more burdensome on customers. TEP is proposing to add fees on customers who request interval

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[135] Duke Energy, Electric Appliance Operating Cost List, http://www.duke-energy.com/pdfs/appliance_opcost_list_duke_v8.06.pdf (last visited June 23, 2016).
[136] Assumes that the furnace and hot water heater run for 40 minutes in the hour and that each of the smaller appliances are used for 10 minutes in the hour.
[137] Proposed tariff RES-D.
[138] Schedule H-4.
[139] UNSE Rate Case, Docket No. E-04204A-15-0142, Dallas Dukes Rebuttal Test. at 9:16–10:6 (Jan. 19, 2016).

history and customers who request standard usage history more than once in a 12-month period.[140] Access to this data is necessary to obtain even the most basic level of understanding of how a customer would be impacted by movement to a demand charge-based tariff. By adding fees to access this data TEP is creating additional barriers to customer comprehension of demand charges. Because the demand charges are being proposed as mandatory only for NEM customers in the residential and small commercial classes, these additional fees will add to the discriminatory charges being levied on NEM customers in this case.

Q. What about the possibility of employing technology to help customers respond to mandatory demand charges?

A. While there is indeed potential for technology to aid in customer response to demand charges, these technologies are uncommon, costly to implement, and have not achieved widespread adoption. For example, Mr. Dukes refers to a demand control unit that would allow a customer with two AC units, a pool pump and an electric water heater to prevent these appliances from coming on at one time.[141] However, in discovery it was revealed that to install this type of technology the customer would need to spend $3,700.[142] This cost is out of reach for the average residential customer, and enabling technologies are expected to do little to help the average residential or small commercial customer to respond to demand charges.

Q. TEP states that 39 other utilities offer residential rates that include demand charges. Are these demand charges mandatory?

A. No. Of the 39 utilities identified by TEP as offering demand charges to residential customers, only two are identified as having mandatory demand charge tariffs.[143] However, further examination reveals that neither of these are in fact mandatory for all residential customers. The first utility TEP identifies is APS's tariff ECT-2,

[140] Jones Direct Test. at 74:21–25.
[141] Dukes Direct Test. at 26:13–16.
[142] TEP Resp. to SWEEP 2.22 (Ex. BK-3 at 39).
[143] Exhibit DJD-1 workpaper.pdf.

which is an optional tariff. The second is from a small municipal utility in rural Vermont, which requires that customers with average monthly usage above 1,800 kWh take service on a demand charge tariff, giving lower-usage customers the option to choose between a tariff with a demand charge and a flat two-part rate.[144] While it is my understanding that a few examples do exist of electric cooperatives with mandatory demand charges for residential customers, and there are additional examples of utilities that require DG customers to take service on a three-part rate, such as Salt River Project ("SRP"), these examples are few and far between. No state-regulated utility in this country has been authorized to implement mandatory demand charges on its residential customers.

Q. Do other utilities' experiences with demand charges shed light on customers' ability to respond to such charges?

A. APS has an optional demand charge residential rate, which has been in effect since the 1980s and currently has roughly 11% enrollment.[145] In a case study of its optional residential demand rate, APS explains that it "helps customers select the best rate at time of new service through [its] website rate comparison tool."[146] Not surprisingly, an examination of the relative size of residential customers that have self-selected onto the demand rate reveals that they have an average monthly consumption that is nearly three times the average monthly consumption of customers on the default rate.[147] Because the optional demand rate also includes a much lower volumetric rate, it is likely that the vast majority of APS customers who have chosen to take service on the demand rate have done so because it would lower their bills without any modification in consumption patterns. Current enrollment in APS's optional demand rate does not imply that customers in APS's

[144] Swanton Village Elec. Dep't, *Residential Service Schedule "A," available at* http://www.swanton.net/publicworks/wp-content/uploads/Residential-A.pdf; Swanton Village Elec. Dep't, *Residential Demand Service Schedule "A-D," available at* http://www.swanton.net/publicworks/wp-content/uploads/Residential-Demand-A-D.pdf.

[145] Meghan Grabel, APS, *Residential Demand Rates: APS Case Study* 3 (June 25, 2015), *available at* http://www.ksg.harvard.edu/hepg/Papers/2015/June%202015/Grabel%20Panel%201.pdf.

[146] *Id.*

[147] *Id.* at 7.

territory have the ability to respond to the price signal set by demand charges. To the contrary, the fact that APS has marketed its optional demand charge rates for upwards of three decades with only 10% current enrollment demonstrates that 90% of APS's customers have either not gained an understanding of how the demand charge rate would impact them, or they have decided that the demand charge rate is not the best option for them. Indeed, in response to discovery, APS has revealed that as many as 40% of its customers that recently switched from a two-part rate to the optional demand charge rate actually increased their maximum on-peak demand.[148] This means that even among the small proportion of customers that self-selected onto the demand charge rate, 40% did not respond to the demand charge price signal in their optional tariff.

APS's current optional residential demand charge tariff was originally approved in October 1980 as a mandatory tariff for new residential customers with refrigerated air-conditioning.[149] However, the Commission removed the mandatory requirement less than three years later.[150] The Commission described the rationale for reversing its prior decision by making the demand charge tariff optional for all residential customers, stating the change was "in response to complaints that the mandatory nature of the EC-1 rate produced unfair results for low volume users."[151] In addition, the Commission stated that removal of the mandatory demand charge would "alleviate the necessity for investment by low consumption customers in load control devices to mitigate what would otherwise be significant rate impacts under the EC-1 rate."[152]

Q. Can you provide any additional information on the SRP demand charge?

A. In February 2015, SRP approved a demand charge for new residential NEM customers that it estimated would increase costs for these customers by about $50 per month. After this rate was put into effect, applications for SRP's DG program

[148] APS Resp. to SWEEP 1.1 (Ex. BK-3 at 40).
[149] Decision No. 51472 (Oct. 21, 1980) (Ex. BK-4).
[150] Decision No. 53615 (June 27, 1983) (Ex. BK-5).
[151] *Id.* at 7:18–19.
[152] *Id.* at 7:20–22.

fell by 95%.[153] Both the SRP experience and the evidence from APS's optional demand charge make clear that the majority of residential customers do not fare well under demand charges.

Q. What do you conclude about customer response to mandatory demand charges?

A. Evidence on customer response to mandatory demand charges is extremely scarce. The limited evidence that does exist from the early 80's, when APS was authorized to implement a mandatory demand charge for new residential customers with refrigerated air-conditioning, indicates that considerable customer backlash occurred due to significant rate impacts for low usage customers.[154] Moreover, the available evidence on customer response to optional demand charges in APS's territory shows that a considerable number of customers who opted in did not reduce their peak demand. Customer response to a mandatory demand charge would likely be even more limited. The limited evidence indicates that TEP's residential and small commercial customers will have little ability to respond to mandatory demand charges. As a result, I expect that mandatory demand charges will function more like fixed charges for most residential and small commercial customers in the TEP service territory.

5.2.4 The Commission should not approve mandatory demand charges for any residential or small commercial customers

Q. What do you recommend in regards to demand charges in this application?

A. I recommend that TEP's proposed three-part rates for residential and small commercial customers be approved only as <u>optional</u> rate schedules for customers with and without DG. Demand charges for residential and small commercial customers are likely to function as additional fixed charges, leaving customers

[153] Bobby Magill, *New Fees May Weaken Demand for Rooftop Solar*, Climate Central, Nov. 11, 2015, *available at* http://www.scientificamerican.com/article/new-fees-may-weaken-demand-for-rooftop-solar/.
[154] Decision No. 53615 at 7:18–19.

with very little ability to respond. The Commission should strongly weigh the expected benefits of implementing a mandatory demand charge on NEM customers against the potential for extreme bill impacts and customer confusion. TEP's primary rationale for requesting that the demand charge be made mandatory for NEM customers is to increase its fixed cost recovery from these customers. However, TEP has not provided any evidence on whether or not the current rate treatment of NEM customers results in a cost shift. In fact, the available data indicate that 98% of the customers TEP alleges do not pay their fair share of fixed costs are not NEM customers. I urge the Commission to implement demand charges for TEP customers <u>only on an optional basis for all customers</u>. This approach would allow customers who are able to respond to the demand charge to take advantage of such a rate while protecting other customers from extreme and unavoidable bill increases.

5.2.5 TOU rates are a preferred alternative to demand charges

Q. Are there any alternative rate structures for residential and small commercial customers that may be preferred to demand charges?

A. Yes. While TEP argues that cost-causation should be considered the primary principle of rate design,[155] balanced rate making policy should consider each of the principles outlined by Professor Bonbright. In addition to cost-causation, these principles include simplicity, understandability and public accessibility; rate and revenue stability; and efficiency of the rates in discouraging wasteful use of service while promoting justified amounts and types of use, among others.[156] It is essential that the Commission weigh each of these principles as it considers rate design policy going forward.

With advanced metering infrastructure the opportunity exists to move towards more sophisticated rate designs for residential and small commercial customers,

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[155] Dukes Direct Test. at 9.15–19.

[156] James C. Bonbright, *Principles of Public Utility Rates* 291 (1961), *available at* http://media.terry.uga.edu/documents/exec_ed/bonbright/principles_of_public_utility_rates.pdf.

but in doing so the needs of the utility must be balanced against the needs of ratepayers. RMI has noted that "[a]n expanded rate design toolkit is needed, but it is critical that solutions do not reduce signals for energy efficiency or be difficult for customers to understand and respond to."[157] As an alternative to demand charges, RMI indicated that "[i]ndustry experience shows that well-designed time-based rates can reduce peak consumption without compromising customer acceptance."[158] Indeed, time-of-use ("TOU") rates present a promising opportunity to improve cost-causation while providing actionable price signals to residential and small commercial customers.

Q. Please explain how TOU rates improve the link to cost causation.

A. The current inclining block structure includes an energy component that values each kWh of energy the same regardless of the season or time of day in which that kWh is consumed. While this rate design has the benefit of being simple and easy for residential customers to respond to and budget for, it does not capture the fact that energy and capacity prices vary widely by season and time of day. While this problem has been recognized for decades, it is only recently that metering capabilities have advanced to the point where it is practical to consider TOU-based rates for larger numbers of customers, including the residential and small commercial classes.

The Public Utility Regulatory Policies Act ("PURPA") established a preference for TOU-based rates, where the cost of metering would not outweigh the benefits of the more sophisticated rate structure. PURPA states:

> The rates charged by any electric utility for providing electric service to each class of electric consumers shall be on a time-of-day basis <u>which reflects the costs of providing electric service to such class of electric consumers</u> at different times of the day unless such rates are not cost-effective with respect to such class . . . .[159]

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[157] Rocky Mountain Inst., *supra* note 123, at 5.
[158] *Id.* at 45.
[159] 16 U.S.C. § 2621(d)(3) (emphasis added).

The Commission adopted PURPA's guideline in 1981 in Decision No. 52593, stating:

> As a general proposition, time-of-day rates trigger an accurate price signal to the consumer of electricity. Moreover, applied specifically to the APS system, we are persuaded that properly established time-of-day rates would encourage optimization of the efficiency and utilization of APS' facilities and resources. Accordingly, we hereby express our intention to authorize and encourage the implementation of time-of-day rates which are cost-effective (i.e., whenever the long-run benefits of such rate to APS and its affected consumers are likely to exceed the metering costs and other costs associated with the employment of such rates).[160]

TOU rates have long been recognized as beneficial for cost-based ratemaking. However, until recently, metering costs prohibited cost-effective adoption. In fact, historically, demand charges for large customers were developed as a second-best approach to capturing the time-varying value in energy consumption.[161] Because technological challenges meant that metering based on time of energy usage was cost prohibitive, demand charges were implemented for larger customers as a proxy for measuring the customer's peak consumption. This approach was somewhat accurate for commercial and industrial customers whose peak usage would generally occur coincident with system peak, but is wholly inappropriate for smaller commercial and residential customers who tend to be more diverse in usage patterns.[162]

In 1983, this Commission acknowledged that demand rates for residential customers were a second-best approach to TOU-based rates.[163] As discussed above, the Commission originally approved mandatory demand charges for new residential customers of APS with refrigerated air-conditioning. But in response to problems associated with mandatory demand-based rates for the residential class, the Commission removed the requirement that the demand charge be

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[160] Decision No. 52593 at 7:2–12 (Nov. 9, 1981) (emphases added) (Ex. BK-6).
[161] Jim Lazar, *Use Great Caution in Design of Residential Demand Charges*, Natural Gas & Electricity, at 15 (Feb. 2016), *available at* https://www.raponline.org/document/download/id/7844.
[162] *See id.*
[163] Decision No. 53615 at 6:9–10 (Ex. BK-5).

mandatory, allowing customers to choose a new tariff that did not include demand charges. In discussing the mandatory demand charge rate, the Commission stated: "This rate approximates a time of day rate but with much lower metering and administrative costs."[164]

Q. Do TOU rates provide a more actionable cost-based price signal than demand charges?

A. Yes. While there may be merit to the theoretical arguments linking demand charges with cost causation, examination of the proposals in this case using real-life examples demonstrates that the proposed mandatory demand charges may have little relation to cost. In addition, when comparing the relationship between different rate structures and cost, it is important to consider the reason for trying to reflect cost in rates in the first place—cost based rates are desired because they provide information to the customer on how the customer's actions affect the cost to serve them, incentivizing customers to modify behavior in such a way as to reduce system costs. The goal of cost-based ratemaking is undermined if customers cannot meaningfully respond to the cost-based rate they are faced with. TOU rates are more easily understandable and customers can more easily respond to them, while demand charges are confusing and harder for residential customers to respond to. As a result, TOU rates provide a better cost-based price signal to residential and small commercial customers than demand charges.

Q. Please explain how TOU rates offer a more actionable price signal to residential and small commercial customers.

A. Residential and small commercial customers are already accustomed to managing kWh energy usage through their existing rates. They are aware that the more electricity they use, the higher their bills will be. Educating customers on the additional layer of complexity associated with TOU rates would be a small issue compared to educating customers about demand charges. To respond to TOU rates, customers would only need to understand that electricity costs more at

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[164] *Id.*

different times of the day and/or year.[165] To respond to a demand charge, in contrast, customers would need to know how to undertake detailed retroactive analysis of their consumption patterns and assess what actions caused historical peaks. In addition, in the event that customers were to accidentally consume a larger amount during the more expensive peak period one day, the impact on their monthly bills would be nowhere near as large as if customers were to inadvertently cause a high peak demand. Finally, TOU rates provide a better price signal than demand charges because they incent conservation in every hour of the peak period. In contrast, with a demand charge, once the monthly peak demand is reached, customers would have less incentive to conserve for the remainder of the month. This is true even in the instance of a combined demand and TOU rate due to the fact that the volumetric portion of the rate would be severely reduced, dampening the conservation signal in rates.

Jim Lazar of the Regulatory Assistance Project has articulated some of the key benefits of TOU rates over demand charges in the following table that adapts principles from Garfield and Lovejoy's *Public Utility Economics* to the evaluation of demand charges versus TOU rates.

[165] This is similar to a number of other products that customers are already familiar with such as airplane tickets that cost more on weekends and around major holidays.

Table 3: Garfield and Lovejoy Criteria[166]

Garfield and Lovejoy Criteria	CP Demand Charge	NCP Demand Charge	TOU Energy Charge
All customers should contribute to the recovery of capacity costs.	N	Y	Y
The longer the period of time that customers pre-empt the use of capacity, the more they should pay for the use of that capacity.	N	N	Y
Any service making exclusive use of capacity should be assigned 100% of the relevant cost.	Y	N	Y
The allocation of capacity costs should change gradually with changes in the pattern of usage.	N	N	Y
Allocation of costs to one class should not be affected by how remaining costs are allocated to other classes.	N	N	Y
More demand costs should be allocated to usage on-peak than off-peak.	Y	N	Y
Interruptible service should be allocated less capacity costs, but still contribute something.	Y	N	Y

While TOU rates may meet more of the Garfield and Lovejoy criteria and may be easier for the average customer to respond to than demand charges, the Commission should still exercise caution in considering a mandatory TOU rate. Some customers will have a greater ability to modify their behavior in response to TOU rates than others.

Q. Do you have any recommendations regarding TOU rates in this proceeding?

A. TEP has requested major rate design changes in this proceeding. While TEP is focused on implementation of demand charges, I recommend that the Commission consider TOU rates as a preferred alternative to demand charges. Because TEP has not established that NEM customers are a significant driver of the load reductions they have experienced nor are NEM customers a significant proportion of customers who TEP alleges do not pay their fair share of fixed costs there would be no basis on which to treat NEM customers differently than other customers in terms of TOU rate implementation. However, if the Commission were to desire wide-scale adoption of more cost-based rate structures, encouraging increased adoption of TOU rates should be considered worthwhile policy to be pursued in this and future rate cases before the Commission.

[166] Lazar, *supra* note 161, at 15.

5.3 The Commission has already approved a mechanism to address under-recovery of fixed costs through the LFCR

Q. If the Commission does not approve TEP's proposed changes to the NEM tariff and its mandatory demand charge for NEM customers, will TEP be able to address the under-recovery of fixed costs it claims results from DG-reduced sales?

A. Yes, the LFCR is specifically designed to address under-recovery of fixed costs due to DG and EE.

Q. What is the LFCR?

A. The LFCR is a partial decoupling mechanism that supports EE and DG "at any level or pace set by this Commission."[167] The LFCR was agreed upon through settlement negotiations during TEP's last general rate case and reflects a compromise between numerous parties including TEP, Commission Staff, RUCO, and industry and solar representatives. The LFCR "is intended to recover a portion of distribution and transmission costs associated with residential, commercial and industrial customers when sales levels are reduced by EE and DG and not to recover lost fixed costs attributable to generation and other potential factors, such as weather or general economic conditions."[168] In this manner, the LFCR appropriately balances TEP's desire to recover fixed costs with Commission policy that promotes certain levels of EE and DG adoption.

Q. How is the LFCR applied to customer rates?

A. The LFCR is applied to rates as a percentage-based charge on total Delivery Service and Power Supply Charges. The current LFCR is 0.8565% for EE and 0.2770% for DG.[169] This means that EE-related charges are more than three times

[167] Decision No. 73912 at 53:18–19 (July 27, 2013).
[168] *Id.* at 26:5–9.
[169] TEP Statement of Charges (July 1, 2013), *available at* https://www.tep.com/doc/customer/rates/801_tep_statement_of_charges.pdf.

the level of DG-related charges, but both charges are small. TEP estimates that the average residential customer pays only 75¢/month for the EE-related LFCR and 24¢/month for the DG-related LFCR.[170]

Q. How does the LFCR relate to the NEM rate design changes proposed by TEP?

A. TEP claims that its proposed NEM rate design changes are needed to ensure greater recovery of fixed costs.[171] However, a transparent and targeted rate mechanism designed specifically to compensate TEP for lost fixed costs due to EE and DG already exists: the LFCR. The current LFCR, unlike TEP's other proposals, does not create a disincentive for EE and DG.

Q. Why is the LFCR a better method to address fixed cost recovery than TEP's rate design proposals?

A. Rate decoupling mechanisms, such as the LFCR, are useful tools that enable policy makers to separate utility revenue streams from the volume of sales. The Commission has recognized the value of sales reduction measures, including EE and DG, and has promoted certain levels of these activities through targeted policies. Under the current utility business model (i.e., return on rate base regulation), a reduction in sales can be problematic, not just because the reduction results in fewer units of energy over which to spread fixed costs, but also because reduced sales can delay or eliminate the need for future infrastructure investments that the utility could add to its rate base, thus boosting earnings.

TEP's preferred approach is to recover fixed costs through unavoidable fixed charges.[172] But this approach would undermine the Commission's efforts to increase EE and DG by making these measures less cost effective, as lower per kWh volumetric rates decrease the value of each kWh saved by EE and DG.

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[170] TEP, Lost Fixed Cost Recovery (LCFR) Charge, https://www.tep.com/news/updates/LFCR/ (last visited June 23, 2016).
[171] *E.g.*, Dukes Direct Test. at 20:14–17.
[172] Jones Direct Test. at 41:10–15.

Indeed, TEP has stated that "an over-dependence on fixed cost recovery through volumetric energy charges creates an economic disincentive for the Company to promote conservation, EE, and DG."[173] The LFCR has been designed precisely to address that disincentive and to compensate the utility accordingly.

Contrary to TEP's proposals, the LFCR is the better option to address lost fixed cost recovery from EE and DG. As a targeted decoupling mechanism, the LFCR appropriately compensates TEP for sales lost to EE and DG, while maintaining appropriate price signals to customers that indicate the value in conservation. The LFCR thus ultimately reduces energy costs for all ratepayers.

Q. Please summarize your recommendations regarding the LFCR.

A. I recommend that the Commission recognize that the LFCR is a targeted decoupling mechanism that efficiently addresses issues related to fixed cost recovery from sales lost to EE and DG. As a decoupling mechanism the LFCR is designed to compensate TEP for these lost sales, while maintaining the price signals necessary to incent conservation. As a result, the LFCR is a better method for addressing lost fixed cost recovery than other rate design changes proposed by TEP.

6 TEP Has Not Adequately Evaluated the Impacts of Its Proposals

Q. Has TEP adequately evaluated the impacts of its proposed rate design changes for NEM customers?

A. No. TEP has not adequately evaluated the impacts of its rate design proposals. As I discuss in detail below, TEP has failed to sufficiently analyze (1) how its proposed rate design changes will impact NEM customers; (2) the cost of service and benefit/cost analyses related to its DG proposals, as required by Commission

[173] *Id.* at 39:24–25.

Rule 14-2-2305; and (3) the solar jobs created by DG in Arizona that the proposals may put at risk.

6.1 TEP Did Not Reliably Assess the Impacts of its Proposals on NEM Customers

Q. Has TEP provided any information on the impact of its proposals on NEM customers?

A. Witness Dukes claims that he shows "how DG customers still save on their total electric bill" as a result of TEP's proposals.[174] However, the analyses put forth in his testimony are not based on actual NEM customer data.

Q. What was the basis for TEP's NEM customer impact assessments?

A. In Mr. Dukes' direct testimony, TEP presents two tables that purport to show the average monthly electric bills for residential customers with electric usage levels of 500 kWh, 900 kWh, 1,200 kWh, and 1,500 kWh.[175] The data in both of these tables were derived based on average full requirements customer load shapes with an engineering-based assessment of solar generation based on the assumption that customers will size their PV systems to offset 100% of annual energy requirements.[176] These tables were not based on actual NEM customer data.

Q. How many of TEP's NEM customers size their PV systems to offset 100% of load?

A. It is not clear. TEP has indicated in discovery that it does not track this information.[177] Because I cannot verify TEP's claims that the "typical" NEM customer will offset 100% of load, there is no basis on which to evaluate the reasonableness of TEP's purported NEM customer impacts from the Company's

[174] Dukes Direct Test. at 5:14–15.
[175] *Id.* at 21, 29.
[176] Dukes Workpaper 2015 TEP R-01 Demand-PRS.xlsx.
[177] TEP Resp. to VS 2.34 (Ex. BK-3 at 15).

rate design proposals. Even if this claim could be verified, it is likely that at least some level of diversity exists among the NEM customers. This diversity would also need to be understood to provide a reliable assessment of the impact of the proposals on NEM customers. Moreover, the representation of NEM customer bill impacts on three-part rates suffers from the same problem discussed in section 5.2.2 of this testimony. Namely, TEP presents results based on various levels of kWh usage while using a one-dimensional assumption for billing kW. It is expected impacts shown in Mr. Dukes' testimony do not represent the full range of impacts that may be seen under TEP's proposal.

Q. Has TEP provided any information on the expected bill impacts for small commercial NEM customers?

A. No. TEP has chosen to present impacts on residential NEM customers only. When asked in discovery to provide bill impact tables for the small commercial class, TEP replied that such tables had not been created and to do so would be overly burdensome.[178] Clearly, TEP has not fully evaluated the impact of its rate design proposals on residential customers and appears to have undergone no evaluation of the impact of its rate design proposals on small commercial customers.

Q. Why is it important that TEP provide a reliable assessment of the impact of its proposals on NEM customers?

A. To ensure that a rate change is just and reasonable, utilities often develop an assessment of representative load data for customers impacted by a rate proposal in order to provide evidence that a new rate will not unfairly impact the utility's customers. TEP acknowledges this with the following statement: "To best determine the true impact on the customer and the Company revenues, we went to great lengths to determine the appropriate levels of billing determinants. It was essential that we had a complete understanding of the billing determinants as we modified provisions within the tariffs."[179] In addition, TEP states that "in

[178] TEP Resp. to EFCA 2.10 (Ex. BK-3 at 36).
[179] Jones Direct Test. at 34:10–13.

developing these proposed modifications, a thorough analysis must be performed to best ensure that the impacts on the customer are understood and the proposals are fair and equitable."[180] However, despite TEP's own assertions that it is essential to have a complete understanding of the billing determinants and that a thorough analysis must be performed to ensure proposals are fair, TEP's case is not based on any actual NEM customer data, and the cost of service study does not separately analyze NEM customer billing determinants.

6.2 TEP Did Not Provide the Cost of Service and Benefit/Cost Analyses Required by Commission Rule 14-2-2305

Q Can you summarize Commission Rule 14-2-2305?

A. Yes. While I am not a lawyer and am not offering a legal opinion, Commission Rule R14-2-2305 says that utilities must provide a cost of service study and benefit/cost analyses if they propose to increase the costs paid by NEM customers relative to similar non-NEM customers. Specifically, the rule states:

> Net Metering charges shall be assessed on a nondiscriminatory basis. Any proposed charge that would increase a Net Metering Customer's costs beyond those of other customers with similar load characteristics or customers in the same rate class that the Net Metering Customer would qualify for if not participating in Net Metering shall be filed by the Electric Utility with the Commission for consideration and approval. <u>The charges shall be fully supported with cost of service studies and benefit/cost analyses. The Electric Utility shall have the burden of proof on any proposed charge</u>.[181]

Q. Has TEP supported its DG rate design proposals with an adequate cost of service study?

A. No. As described in Section 4.4 of this testimony, while TEP attempts to single out NEM customers for differential treatment compared to non-NEM customers, the Company's cost of service study does not analyze NEM customers as a

[180] *Id.* at 35:22–36:1.
[181] A.A.C. R14-2-2305 (emphasis added).

separate group of customers from the residential and small commercial classes. As a result, the cost of service study does not adequately support any new or additional charges for NEM customers.

Q. Has TEP supported its DG rate design proposals with benefit/cost analyses?

A. No. TEP has not provided any assessment of the costs or benefits of its proposal. TEP has not even analyzed the billing impact of its proposals on NEM customers. Furthermore, as discussed in Section 5.1.2 of this testimony, TEP has failed to conduct a benefit/cost analysis to support its proposal to modify the NEM tariff.

6.3 TEP Should Consider Solar Jobs Along with the Economic Development Rider

Q. Please describe the Economic Development Rider proposed by TEP.

A. TEP has proposed to offer a discounted rate to business customers with a projected peak demand of 1,000 kW or more, and a load factor of 75% or higher.[182] The rate discount would decline over a five-year period beginning with a 20% discount in Year 1 and declining to a 2.5% discount in Year 5.[183] The Economic Development Rider would be available for five years and enrollment would be capped at 200 MW.[184] To qualify for the Economic Development Rider, a customer must qualify for at least one of two existing Arizona state tax programs.[185]

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[182] Dukes Direct Test. at 31:12–13.
[183] *Id.* at 32:12–13.
[184] *Id.* at 31:13–18.
[185] *Id.* at 31:21–32:2.

Q. What rationale does TEP give in support of its proposed Economic Development Rider?

A. TEP points out that its service territory has been slow to recover from the economic downturn post-2007.[186] TEP claims that the Economic Development Rider would put TEP's service territory in a better competitive position to attract and expand business load, which would be beneficial to the entire customer base and the State of Arizona.[187]

Q. Will the Economic Development Rider generate new jobs?

A. That is unclear. TEP has not performed any estimation of the number of jobs that the Economic Development Rider would be expected to generate.[188]

Q. Does the solar industry provide a significant number of jobs in Arizona?

A. Yes. As of November 2014, there were 6,922 solar workers employed in Arizona with an additional 580 solar jobs expected in 2016.[189]

Q. How should the Commission consider solar jobs in Arizona when it acts on TEP's proposals?

A. As the Commission considers the merits of an Economic Development Rider that would reduce fixed cost recovery from participating customers,[190] it should also consider the very real economic benefits provided by the Arizona solar industry. TEP's proposed changes to the NEM tariff have the potential to destroy the solar market in TEP's service territory, putting real solar jobs at risk.

[186] *Id.* at 30:4–6.
[187] *Id.* at 31:3–7.
[188] TEP Resp. VS 2.17(b) (BK-3 at 9).
[189] Solar Found., *Arizona Solar Jobs Census 2015*, at 5 *available at* http://www.thesolarfoundation.org/wp-content/uploads/2016/02/Arizona-Solar-Jobs-Census-2015.pdf
[190] TEP Resp. to VS 2.17(a) (Ex. BD-3 at 9).

7 TEP Claims It Needs to Modernize Its Rate Design, but Its Proposals Are Regressive

Q. How does TEP frame its rate design requests in terms of general rate policy?

A. TEP's application characterizes its proposals as necessary to "modernize" rate design.[191] The Company claims that "[i]n this proceeding, TEP seeks approval for 21st century rates."[192]

Q. In your opinion, are TEP's proposals a step toward a modernized rate design?

A. No. TEP's proposal to double basic service charges for residential and small commercial customers and to reduce the number of residential tiers is not reflective of "modern" rate design. Instead, it reflects regressive actions that will undermine Commission policy.

7.1 TEP's Request to Increase Fixed Charges for Residential and Small Commercial Customers Should Be Rejected

Q. Please describe TEP's proposal to increase fixed service charges.

A. TEP proposes to increase all monthly basic service charges "in a manner consistent with the results of the CCOSS and equitable fixed cost recovery."[193] TEP proposes to increase the residential fixed charge from $10/month to $20/month[194] and the small commercial fixed charge from $15.50/month to $30/month.[195] Current and proposed fixed charges for residential and small commercial customers are summarized in Table 4.

[191] Application at 5:11.
[192] Hutchens Direct Test. at 5:3.
[193] Jones Direct Test. at 36:13–14.
[194] *Id.* at 43:26–44:1.
[195] *Id.* at 46:26–47:1.

Table 4: Current and Proposed Fixed Charges – Residential and Small Commercial[196]

Fixed Charge	Residential	Small Commercial
Current	$10.00	$15.50
Proposed	$20.00	$30.00

Q. What support does TEP give for its proposal?

A. TEP has completed a CCOSS, which includes an embedded cost study and a marginal cost study. TEP says "[t]he goal of the CCOSS is to determine fair cost allocation and rate design among the customer classes based on the principle of cost causation."[197] In developing the CCOSS, TEP classified utility costs into three basic categories: customer, demand, and energy.[198] TEP's approach to the CCOSS was similar to the approach used in the last general rate case, with one notable exception in the methodology for allocating distribution-related costs.

Q. What has TEP proposed for allocation of distribution-related costs?

A. TEP has proposed a significant change to the methodology for classifying distribution-related costs, which has inflated its estimates of customer-related costs. In the last rate case, TEP used the Basic Customer Method, basing customer costs on "metering, services, meter reading, customer service and billing."[199] In its application, TEP has proposed to re-classify a significant amount of additional costs as customer-related through the Minimum System Method.

Q. What is the Minimum System Method, and is it an appropriate method for classifying customer costs?

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[196] *Id.* at 43:26–44.1, 46:26–47:1.
[197] *Id.* at 3:17–18.
[198] *Id.* at 18:10–11.
[199] TEP 2013 General Rate Case, Docket No. E-01933A-12-029, Craig Jones Direct Testimony at 18:26–19:1 (July 2, 2012), *available at* http://images.edocket.azcc.gov/docketpdf/0000137960.pdf .

A. The Minimum System Method is an approach to utility cost classification that looks at the theoretical minimum demand of a customer and estimates the smallest size of infrastructure necessary to serve the theoretical minimum customer, including poles, cable, transformers, etc. Under the Minimum System Method, investments in the theoretical minimum-sized infrastructure are allocated to the customer cost function. The Minimum System Method is not a new approach to utility cost classification. In fact, Professor Bonbright addressed this method in his seminal text, Principles of Public Utility Rates in 1961. Bonbright did not agree with the Minimum System Method for customer cost allocation, stating that "the inclusion of the costs of a minimum-sized distribution system among the customer-related costs seems to me clearly indefensible."[200]

This sentiment has been echoed directly by the Washington Utilities and Transportation Commission:

> In this case, the only directive the Commission will give regarding future cost-of-service studies is to repeat its rejection of the inclusion of the costs of a minimum-sized distribution system among customer-related costs. As the Commission stated in previous orders, the minimum system method is likely to lead to the double allocation of costs to residential customers and over-allocation of costs to low-use customers. Costs such as meter reading, billing, the cost of meters and service drops, are properly attributable to the marginal cost of serving a single customer. The cost of a minimum-sized system is not. The parties should not use the minimum system approach in future studies.[201]

Because the Minimum System Method is not an appropriate means of allocating distribution related costs, the Commission should reject TEP's proposal to employ the Minimum System Method in this case. The Commission should instead require that TEP return to the Basic Customer Method approved in the last general rate case, which limits customer-related costs to metering, services, meter reading, customer service, and billing.

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[200] Bonbright, *supra* note 156, at 348.

[201] *Wash. Utils. & Transp. Comm'n v. Puget Sound Power & Light Co.*, 3d Supplemental Order, Docket Nos. U-89-2688-T & U-89-2955-T, at 71 (WUTC Jan. 17, 1990), *available at* http://www.utc.wa.gov/_layouts/CasesPublicWebsite/GetDocument.ashx?docID=89&year=1989&docketNumber=892688.

Q. What were the results of TEP's CCOSS with regard to residential and small commercial customer costs using the Minimum System Method?

A. Table 5 summarizes the results of TEP's embedded and marginal cost studies using the Minimum System Method.

Table 5: CCOSS Customer Cost Results using Minimum System Method[202]

Cost Study	**Residential**	**Small Commercial**
Marginal Customer Cost	$29.49	$219.60
Embedded Customer Cost	$15.67	$45.55

Q. How do TEP's CCOSS results inform the proposed basic service charges?

A. TEP described the relationship between the embedded cost study results, the marginal cost study results, and the proposed basic service charges as follows:

> The embedded cost of service study guides the allocation of revenues among the classes of service . . . In order to fully evaluate the appropriate level of basic service charge, a marginal cost of service is required in order to support and reflect a valid price signal related to connecting customers. . . . Together, the embedded and marginal cost studies provide the Commission with the full picture as to how total revenues should be allocated across classes; and in turn, how customer costs and the cost of connecting a customer should be set to send correct price signals to customers and to encourage economic use of the system.[203]

Q. How did TEP arrive at its proposal for a $20 residential customer charge and a $30 small commercial customer charge based on these results?

A. It appears that TEP ultimately used the results of the embedded cost study for both customer-related costs and demand-related costs as the foundation of its customer charge proposal. This is evidenced by the Company's assertion that its

[202] Jones Direct Test. at 31:1–5. The embedded cost study results in this table are reflective of the original cost of service study described in the testimony of Craig Jones. A revised cost of service study was filed with TEP's workpapers on May 19, 2016, reflecting a per customer embedded cost of $17.19 for residential customers and $38.43 for small commercial customers. I have focused on the original values in this section of testimony to more easily follow TEP's rationale for its proposals.
[203] *Id.* at 31:23–32:7.

$20 residential basic service charge proposal represents 21% of the $93.61 in combined customer-and demand-related charges identified for the residential customer.[204]

Q. How was the $93.61 in combined customer-and demand-related charges derived, and what is TEP's rationale for its importance?

A. TEP states:

> Historically, basic charges are limited to metering, meter-reading, service (service drop) to the specific customer, and customer service and billing. While these costs should be included in the basic service charge and may be used as the guide to what the basic service charge should be for classes with Demand Charges, they are not sufficient for classes without a Demand Charge.[205]

In support of this notion, TEP estimated the combined customer and demand related costs by adding together the $15.67 in customer costs and $77.94 in demand costs from the embedded cost study to arrive at an estimate of $93.61 for residential customers.[206]

Q. Does this estimated customer cost reflect the results of the Minimum System Method described earlier?

A. It does not. Despite an over allocation of costs to the customer-related category, the Minimum System Method identified only $15.67 in embedded customer costs for residential customers.[207] In support of its proposal, TEP also looks at the $77.94 its own methodology classified as unrelated to the customer function. This approach is wholly inappropriate. TEP is seeking to over-allocate costs to the customer charge by mischaracterizing demand-related costs as customer costs. Demand-related costs identified by the CCOSS should not be considered in the

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[204] *Id.* at 44:1–6.
[205] *Id.* at 40:9–13.
[206] Interestingly, despite the statement quoted above that this level of fixed costs is necessary for classes without a demand charge, TEP has proposed the same customer charges for its residential and small commercial three-part rates in this case.
[207] This figure was later revised to $17.19, see footnote 202.

assessment of an appropriate basic service charge, regardless of whether the customer class in question is subject to a demand charge. TEP's own assessment of cost causation in the CCOSS allocates demand-related costs based on various measures of customer usage. Therefore, these costs are variable and not fixed. Basic service charges should be limited to customer-related costs identified using the Basic Customer Method.

Q. Have you developed an estimate of the embedded and marginal customer costs for residential and small commercial customers using the Basic Customer Method?

A. I have. To derive my estimate, I used the following methodology and calculations. In support of using the Minimum System Method, TEP developed an estimate of the proportion of distribution costs in FERC Accounts 364-368 that should be classified as customer related.[208] TEP additionally assumed that a proportionate amount of operations and maintenance ("O&M") costs associated with these accounts should be customer related, as well as a certain level of general plant and administrative and general costs.[209] FERC Accounts 364-368 are associated with distribution system investments and are summarized in Table 6 below. Table 6 also shows the percent of costs by account that TEP allocated to customer costs in the current application and in the last approved rate case.

Table 6: Distribution Cost Allocation[210]

FERC Account	Description	Application Customer %	Last Rate Case Customer %
364	Poles Towers & Fixtures	64%	0%
365	Overhead Conductors & Devices	20%	0%
366	Underground Conduit	100%	0%
367	Underground Conductor	41%	0%
368	Line Transformers	24%	0%

[208] Jones Direct Test. at 22:23–26.
[209] *Id.* at 23:16–23.
[210] 2015 TEP Schedule G - COSS Competitively Sensitive Confidential.xlsx, tab Cust%; TEP Resp. to VS 4.1(a) (Ex. BK-3 at 19).

Q. How did you develop your estimate of embedded and marginal costs using the Basic Customer Method?

A. I modified TEP's CCOSS to include the methodology the Company used in its last rate case for allocating FERC Accounts 364 through 368 and associated O&M, general plant, and administrative and general costs.[211] This allowed me to develop an estimate of the embedded and marginal customer costs under the Basic Customer Method that is consistent with the methodology employed in the last rate case. My results are summarized in Table 7 below.

Table 7: CCOSS Customer Cost Results using Basic Customer Method

Cost Study	Residential	Small Commercial
Marginal Customer Cost[212]	$9.72	$10.12
Embedded Customer Cost	$9.58	$15.85

As shown in Table 7, using the Basic Customer Method instead of the Minimum System Method results in a significantly lower estimate of customer-related costs. When the Basic Customer Method is employed, the marginal cost for residential and small commercial customers is estimated at $9.72 and $10.12, respectively. The embedded cost is estimated at $9.58 for residential customers and $15.85 for small commercial customers. These results demonstrate that the Minimum System Method significantly over-allocates costs to the customer function.

[211] In addition, I modified the allocation factor employed to allocate costs in Account 369 related to customer service drops. TEP's CCOSS allocated these costs based on weighted meter costs however, this is not entirely accurate and in my opinion over-allocates costs to the small commercial class. A better metric for allocation of these costs would be based on typical service drop costs weighted by number of customers, however, this data point was not available. Instead, consistent with the methodology adopted in the UNSE case, I have allocated Account 369 based on number of customers.

[212] It appears as if TEP has omitted marginal costs associated with Account 369 from its marginal costs study. If these costs were included it would be expected to raise the estimate. However, the impact would be minor and would not be expected to affect the recommendations made in this testimony.

Q. Do the results of the CCOSS using the Basic Customer Method support TEP's proposed increases to the basic service charges for residential and small commercial customers?

A. They do not. In fact, an examination of the results of the CCOSS using the Basic Customer Method show that TEP's current basic service charges for residential and small commercial customers are reasonable. It may be appropriate to increase the small commercial customer charge from $15.50 to $15.85 per month; however, the residential customer charge should not be increased.

Q. Do TEP's proposed increased fixed charges present policy implications?

A. Yes. In addition to the very clear results of the CCOSS using the Basic Customer Method, the Commission should consider the policy implications of increasing fixed customer charges. The Company states that "[m]odifying the rates to include a higher proportion of fixed costs in the monthly basic service charges will help send customers the right price signals and provide additional support for the Company's efforts to promote EE and DG."[213] However, increasing fixed costs would be expected to decrease deployment of EE and DG due to the lower volumetric rate. What TEP appears to mean by this statement is that an increase to fixed charges would diminish the unrecovered fixed costs from EE and DG. As discussed above under the section on the LFCR, however, this argument is flawed. Any need for fixed cost recovery resulting from EE and DG growth is better addressed through the LFCR decoupling mechanism than through rate design.

Increasing fixed charges as TEP proposes would have an impact beyond EE and DG. As discussed below, the Commission should take an active role in directing utilities to plan for the modern grid. This includes proactive planning on rate design structures that will enable efficient and cost-effective deployment of all distributed resources, not just EE and DG. Because higher fixed charges dampen the usage-based price signal, they interfere with price signals embedded in rates

[213] Jones Direct Test. at 40:26–41:2.

that motivate customers and DER providers to take action to reduce energy usage. A high fixed charge is not the "modern" rate design characterized by TEP, but rather a regressive blunt force instrument that is out of step with evolving technologies and the modern grid.

7.2 TEP's Request to Eliminate the Third and Fourth Residential Tiers Should Be Rejected

Q. What has TEP proposed regarding residential class rate tiers and what rationale was given for this proposal?

A. TEP has proposed elimination of the third and fourth tier in the standard residential rate.[214] TEP claims the existence of these tiers "adds no cost-based value to the rate class other than exacerbating the issues of fixed cost being inequitably recovered from the higher usage customers."[215]

Q. When was the inclining block structure put in place, and what was the Commission's reasoning for its approval?

A. An inclining block rate structure was first put into rates in 2008 with Decision No. 70628, which included the following finding of fact: "The inclining block rate structure, TOU rates and other rate design changes as set forth in the 2008 Settlement Agreement will promote energy conservation and beneficial load shifting."[216] Inclining block rates were never intended to be based on cost causation, but rather, were approved by the Commission for the express purpose of incenting conservation.

Q. Based on this procedural history, what is your recommendation regarding removal of the third and fourth residential tiers?

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[214] Dukes Direct Test. at 18:23–24.
[215] Jones Direct Test. at 45:5–7.
[216] Decision No. 70628 at 46:22–23 (Dec. 1, 2008).

A. Inclining block rates have been providing important conservation signals to TEP customers since 2008. The fact that inclining block rates result in proportionally higher charges for higher usage customers is no surprise. In fact, it is the intended outcome of the rate design measure. I recommend that the Commission reject TEP's proposal to remove the third and fourth tiers in its standard residential rate.

8 In the Event of Major Rate Design Changes, Existing NEM Customers Should Be Grandfathered

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

A. It is essential that the Commission safeguard existing NEM customers from drastic and unforeseen rate design changes. TEP's existing NEM customers have made investments in DG systems to serve their family or small business's needs. Many of these customers were encouraged to invest in DG through Commission incentives. By investing in rooftop solar, customers fix a portion of their electricity bills to offset fluctuating electricity rates. Many of these customers have made the investment in rooftop solar as part of a long-term financial plan, 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 has TEP proposed regarding grandfathering?

A. TEP has proposed that existing NEM customers who signed up before June 1, 2015, be allowed to continue service on the existing NEM tariff that would allow them access to the standard two-part rate and full retail rate credit for their exported DG. Since June 1, 2015, TEP has notified new NEM customers of the possibility of changes to the rate structure that may impact their savings potential.

Q. What are your recommendations regarding grandfathering under the various rate design proposals being discussed in this proceeding?

A. As I stated above, it is essential that existing NEM customers be protected against drastic and unforeseen rate design changes. I believe that the rate design proposals put forth by TEP in this case would constitute drastic and unforeseen rate design changes. If the Commission approves one or more of these proposed changes, I recommend that NEM customers who sign up prior to the date of the decision in this proceeding be grandfathered into their existing tariff structure that preserves a tiered two-part rate with full retail rate credit for DG exports. This includes SGS customers with NEM that TEP is recommending be moved to the new MGS class. I believe that customers who have signed up after June 1, 2015, may not have a full understanding of the potential implications of the rate redesign, and it is important that these customers also be grandfathered.

9 The Commission Should Consider TEP's Proposals in the Context of the Modern Grid

Q. What is the modern grid, and why is it important to consider?

A. With increasing availability of new technologies, the fundamental operation of the distribution grid is changing. In the evolution to the modern grid, the consumer is becoming a much more active participant in the production and consumption of their electricity through various DERs.[217] The modern grid will empower customers of all sizes to manage their energy usage and production in coordination with the utility for the benefit of both the consumer and the grid. Small customers may participate through third-party aggregators, while larger and

[217] *See* Steve Corneli & Steve Kihm, Lawrence Berkeley Nat'l Lab., *Electric Industry Structure and Regulatory Responses in a High Distributed Energy Resources Future* 1 (Nov. 2015), *available at* https://emp.lbl.gov/sites/all/files/lbnl-1003823.pdf.

more sophisticated customers may participate directly. Transition to the modern grid is being driven by technology development. This is already happening and will continue to accelerate as prices for photovoltaic generators, distributed energy storage, electric vehicles, and other technologies continue to decrease.

It is crucial that the Commission recognizes this evolution in order to ensure that DERs can be deployed in a way that provides maximum grid support and improves reliability, while lowering overall costs and maximizing consumer benefits. In a recent report from Lawrence Berkeley National Laboratory ("LBNL"), economists found that "DERs will not only improve customers' energy costs, resilience and power quality, they can help utilities avoid risky capital expenditures and operate their systems more efficiently. By facilitating DERs, utilities can both lower their costs and increase the benefits they can offer customers who deploy DERs . . . ."[218]

Q. How should the Commission address the evolution to a modern grid?

A. The Commission has already begun to consider the evolution to the modern grid. In late 2013, Commissioner Burns opened Docket No. E-00000J-13-0375 entitled "In the matter of the Commission's Inquiry into Potential Impacts to the Current Utility Model Resulting from Innovation and Technological Developments in Generation and Delivery of Energy." The Commission has held many useful workshops in this docket, which have provided important information on emerging technologies. The Commission should build on this work to proactively look at how to develop DERs in the way that maximizes grid benefits and reliability, reduces costs, and facilitates customer choice. The Commission should require TEP and other Arizona utilities to prepare distributed resource plans that examine the potential for all types of DERs and identify the specific grid services that DERs can provide in order to produce the maximum benefit for both the grid and consumers. Distributed resource planning should be extensive and specific enough to identify the location and characteristics of DERs that would be most

[218] *Id.*

beneficial. The Commission should then require the utilities to develop sourcing plans to encourage deployment of DERs in the locations, quantities, and with the characteristics that best meet the needs of the grid and provide the maximum value for customers.

According to the LBNL study:

> DERs—with appropriate levels of coordination or virtual integration—can augment the capabilities of the distribution system and even reduce the amount of capital the utility must invest in it. Further, to the extent DER owners and hosts can realize additional value from DER ownership by, for example, providing frequency regulation or voltage support to the wholesale markets and the local distribution system, this leveraging of utility investment can be further enhanced. In effect, by substituting for utility investment, customer DERs can help keep utility revenue requirements within the bounds that increasingly price-sensitive customers will pay for.[219]

Q. Does TEP have any policies, plans, or incentives related to evolving grid technologies?

A. Yes. TEP has indicated that it is working with Siemens to develop a ten-year grid modernization implementation plan and that it has installed a limited number of new distribution technologies.[220] In addition, TEP has policies and programs for electric vehicles, demand response, and energy efficiency and is in the process of installing two 10 MW grid tied battery storage systems.[221] These efforts indicate that TEP has begun to consider the evolution of the grid.

Q. Why should the Commission consider and address the evolution of the grid in this rate case?

A. TEP has recommended far-reaching changes to rates paid by customers who elect to install DG. The changes seek to make DG less cost effective for customers and will very likely slow down or stall the pace of DG deployment in TEP's service

[219] *Id.* at 18 (footnotes omitted).
[220] TEP Resp. to VS 2.40 (Ex. BK-3 at 17).
[221] *Id.*

territory. DG is just one of many forms of DER that will be deployed by customers or third parties on the TEP system. While TEP has implemented a number of polices related to other evolving grid technologies, there is an important role for the Commission to play in ensuring that the inevitable evolution of the grid will be efficient and preserve customer choice.

10 Conclusions and Recommendations

Q. Please summarize your conclusions on TEP's proposals.

A. As I have shown in my testimony, TEP has not provided a sufficient basis to support any NEM-specific rate changes, and its various proposals designed to reduce DG growth are flawed and would likely violate the Commission's Rules. Contrary to TEP's claims, I have shown that NEM customers are not a significant contributor to TEP's retail sales reductions, they do not cause an inequitable cost shift, and there is no evidence that their DG systems cause substantial grid impacts in TEP's service territory. As a result, TEP's premise that DG causes "problems" that should be fixed with a new rate design is unfounded.

TEP's proposed solutions to the alleged "problems" created by DG are seriously flawed and would unjustly discriminate against NEM customers. First, the Company proposes to modify the NEM tariff to significantly reduce the credit NEM customers receive for excess generation. However, TEP has not demonstrated, or even analyzed, whether the reduced credit it proposes would appropriately approximate the value of solar DG. Moreover, the proposed credit rate would be extremely volatile and subject to gaming, and it would also likely violate the Commission's NEM rules. Next, TEP proposes to create a mandatory demand charge for NEM customers. This mandatory demand charge would effectively function as an additional fixed charge solely for NEM customers, as residential and small commercial customers lack the tools to effectively respond to demand charges. In TEP's last rate case, the Commission approved the LFCR to address any cost recovery issues created by DG and EE. This transparent mechanism better addresses TEP's concerns regarding DG than its other proposals, and there is no need for the flawed and discriminatory proposals regarding DG that TEP has asked the Commission to approve.

TEP also failed to adequately analyze how its proposals related to DG would impact NEM customers. The Company similarly failed to conduct the cost of service study and benefit/cost analyses required by the Commission Rules. Moreover, while TEP has proposed an Economic Development Rider to increase economic growth in its service territory, it did not consider how its proposals would impact solar jobs.

Finally, TEP acknowledges the need to modernize its rate design in light of new technologies such as DG. However, its proposals are regressive and would not modernize the Company's rates. The Company proposes to significantly increase fixed charges for residential and small commercial customers based on an inappropriate methodology that over estimates customer-related costs. I offer an alternative assessment of customer costs based on the embedded cost study and marginal cost study and find that the results of this assessment indicate that current levels of basic service charges for residential and small commercial customers are reasonable. Similarly, the company proposes to reduce its current inclining block structure for residential rates in a manner that would undermine conservation, EE, and DG, and this proposal should therefore be rejected.

TEP's proposals reflect an outdated approach that is out of step with current trends toward grid modernization and the evolution of the grid to support consumer demands and advances in technology. Instead, TEP and the Commission should proactively consider how to utilize and incentivize EE, DG, and other DERs in a way that maximizes grid benefits, reduces costs, and facilitates customer choice.

Q. What are your recommendations for the Commission?

A. I recommend the following:

- The Commission should reject TEP’s proposal to modify the existing NEM tariff and should not grant any waiver of the Commission’s NEM rules.
- The Commission should reject TEP’s proposal to create a mandatory demand charge for NEM customers.
- The Commission should analyze how TEP’s proposals will impact solar jobs when it considers the proposed Economic Development Rider.
- The Commission should require TEP to use the Basic Customer Method in its embedded and marginal cost studies in place of the Minimum System Method.
- The Commission should reject TEP’s proposal to increase basic service charges for residential customers but may consider an increase in the small commercial customer charge from $15.50 to $15.85 per month.
- The Commission should reject TEP’s proposal to modify the existing inclining block structure of residential rates.
- If the major rate design changes are approved in this case, the Commission should grandfather existing NEM customers who sign up prior to the effective date of the decision in this case.
- The Commission should begin a formal proceeding to address distributed resource planning.

Q. Does this conclude your testimony?

A. Yes, it does.

Exhibit BK-1

Statement of Qualifications

Briana Kobor
Program Director-DG Regulatory Policy, Vote Solar
360 22nd Street, Suite 730
Oakland, CA 94612
briana@votesolar.org

PROFESSIONAL EMPLOYMENT

Program Director – DG Regulatory Policy, Vote Solar
August 2015-present

- Analyze policy initiatives, development, and implementation related to distributed solar generation
- Review regulatory filings, perform technical analyses, and testify in commission proceedings relating to distributed solar generation

Senior Associate, MRW & Associates
April 2007-August 2015

- Develop and sponsor expert witness testimony for numerous clients to assist intervention in the utility regulatory process including investor-owned utility general rate cases, policy rulemakings, utility applications for power plant and transmission development, and other rate-related proceedings
- Represent clients at regulatory workshops, hearings and settlement discussions
- Perform in-depth quantitative analysis of utility models and testimony in support of general rate case and other regulatory proceedings
- Conduct extensive analysis of energy policy, regulation, economics, and emerging energy trends
- Build and maintain spreadsheet models to forecast utility rates and rate components tailored to client needs
- Create analytical models to assess generator production, profitability and electricity costs under a variety of regulatory and market scenarios and conduct pro forma analyses and technical assessments of infrastructure development in support of business decisions
- Provide analyses to investors and developers on the impact of laws, regulations, and procurement practices on potential sales of generation in various markets, assess current procurement progress, estimate pricing expectations for power sales, identify potential considerations that affect the marketability of project generation
- Provide policy recommendations to the State of California regarding greenhouse gas reduction, nuclear power generation and natural gas storage

EDUCATION

University of California, Berkeley
Bachelor's of Science with Honors, Environmental Economics and Policy

PREPARED TESTIMONY

- CPUC Application A.14-06-014
  Testimony of Briana Kobor on behalf of the Coalition for Affordable Streetlights Concerning SCE's Proposed Street Light Rates. March 13, 2015.
- CPUC Application A.14-11-003
  Testimony of Briana Kobor on Behalf of the Utility Consumers' Action Network Concerning Sempra's Revenue Requirement Proposals for San Diego Gas & Electric and SoCalGas. May 15, 2015.

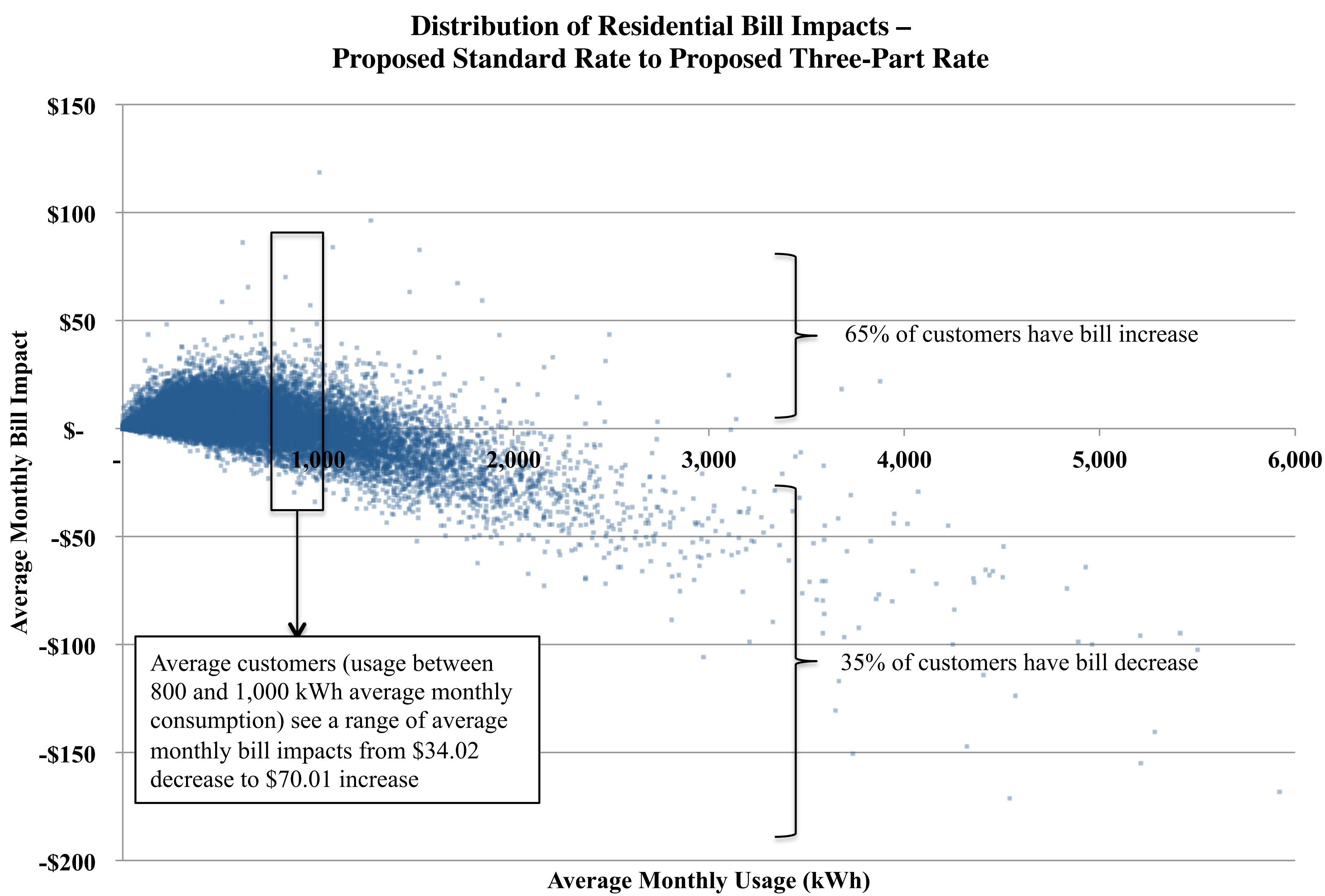
- ACC Docket No. E-04204A-15-0142
  UNS Electric, Inc. General Rate Case
  Direct Testimony and Exhibits of Briana Kobor on Behalf of Vote Solar. December 9, 2015.
- ACC Docket No. E-04204A-15-0142
  UNS Electric, Inc. General Rate Case
  Surrebuttal Testimony and Exhibits of Briana Kobor on Behalf of Vote Solar. February 23, 2016.
- ACC Docket No. E-00000J-14-0023
  In the Matter of the Commission's Investigation of Value and Cost of Distributed Generation
  Direct Testimony and Exhibits of Briana Kobor on Behalf of Vote Solar. February 25, 2016.
- ACC Docket No. E-00000J-14-0023
  In the Matter of the Commission's Investigation of Value and Cost of Distributed Generation
  Rebuttal Testimony of Briana Kobor on Behalf of Vote Solar. April 7, 2016.

SELECTED PUBLICATIONS AND PRESENTATIONS

- Kobor, Briana. Rate Design to Support the Distributed Energy Future. Arizona Energy at the Crossroads Conference. November 2015.
- Monsen, Bill and Kobor, Briana. California Rules Worry Out-of-State Generators. Project Finance Newswire, Chadbourne & Parke. May 2012.
- McClary, Steven C., Heather L. Mehta, Robert B. Weisenmiller, Mark E. Fulmer and Briana S. Kobor (MRW & Associates). 2009. Framework for Evaluating Greenhouse Gas Implications of Natural Gas-Fired Power Plants in California. California Energy Commission. CEC-700-2009-009.
- Mehta, Heather, Kobor, Briana, & Weisenmiller, Robert. California Plans a Carbon Diet. Project Finance Newswire, Chadbourne & Parke. January 2009.

Exhibit BK-2

Distribution of Residential Bill Impacts



Distribution of Residential Bill Impacts –
Proposed Standard Rate to Proposed Three-Part Rate
$150
$100
$50
$-
-$50
-$100
-$150
-$200
Average Monthly Bill Impact
-
1,000
2,000
3,000
4,000
5,000
6,000
Average Monthly Usage (kWh)
65% of customers have bill increase
35% of customers have bill decrease
Average customers (usage between 800 and 1,000 kWh average monthly consumption) see a range of average monthly bill impacts from $34.02 decrease to $70.01 increase

Exhibit BK-3

Discovery Responses Referenced in Testimony

VS 2.04

Please provide the requested information regarding page 8, lines 19-24 of Mr. Tilghman's direct testimony.

a. All studies conducted by or for TEP regarding increased operations and maintenance costs, equipment wear and tear, resulting from distributed solar generation.

b. All studies conducted by or for TEP regarding energy flowing back up through the distribution system resulting from distributed solar generation.

c. For each item a through b, if TEP has not such studies, please provide any and all data, reports or studies TEP relied upon for each statement. For each source, please provide specific citations (e.g., page number).

RESPONSE:

ONE OF THE FILES REFERENCED BELOW CONTAINS CONFIDENTIAL INFORMATION AND IS BEING PROVIDED PURSUANT TO THE TERMS OF THE PROTECTIVE AGREEMENT.

a. TEP has not performed any studies regarding increased operations and maintenance costs, equipment wear and tear, resulting from distributed solar generation.

b. Please see RUCO 3.14 Los Reales back flow-Confidential.pdf for specific issues associated to energy backflow. Additionally, please see RUCO 3.14 Sample Feasibility Study 100515-Redacted.pdf for a sample TEP feasibility study indicating the work performed and issues identified. This type of study is typically performed for all interconnections greater than 1MW in size. For reference are actual measurements taken from a TEP distribution feeder indicating power flow unbalance that has been introduced into the distribution network from DG sources.

c. Please refer to the following technical articles with web addresses provided for information regarding energy flows on the distribution system:

- Reiman, A. (2015). An Analysis of Distributed Photovoltaics on Single-Phase Laterals of Distribution Systems. D-Scholarship Institutional Repository at the University of Pittsburg [Website]. Retrieved from http://d-scholarship.pitt.edu/24047/.
- Jan-E-Alam, M., Muttaqi, K.M., and Sutanto, D. (2011, July 24-29). Assessment of distributed generation impacts on distribution networks using unbalanced three-phase power flow analysis. IEEE.org [Website]. Retrieved from http://ieeexplore.ieee.org/xpl/articleDetails.jsp?tp=&arnumber=6039789&url=http%3A%2F%2Fieeexplore.ieee.org%2Fxpls%2Fabs_all.jsp%3Farnumber%3D6039789
- Tang, J.H., Lim, Y.S., Morris, S., and Wong, J. (2012). Impacts on Centrally and Non-Centrally Planned Distributed Generation on Low Voltage Distribution

Network. International Journal of Smart Grid and Clean Energy. Retrieved from http://www.ijsgce.com/uploadfile/2012/1016/20121016114245643.pdf.

For information regarding O&M, TEP relies on multiple leading industry organizations to perform general studies regarding these issues, such as NREL, NERC, WECC, and LBEL.

Since a comprehensive understanding of the electric system is required to understand the information contained in these reports, Vote Solar representatives must read the entire report to understand Mr. Tilghman's references of increased O&M related to variable generation. Please read the following:

- Western Electricity Coordinating Council's Variable Generation Subcommittee Marketing Workgroup whitepaper – "Electricity Markets and Variable Generation Integration".
- Western Electricity Coordinating Council's – "WECC Variable Generation Planning Reference Book: A Guidebook for Including Variable Generation in the Planning Process".
- North American Electric Reliability Corporation (NERC) Special Report: Accommodating High Levels of Variable Generation, April 2009. http://www.nerc.com/files/IVGTF_Report_041609.pdf
- Western Wind and Solar Integration Study – "Analysis of Cycling Costs in Western Wind and Solar Integration Study". http://www.nrel.gov/docs/fy12osti/54864.pdf

RESPONDENT:

Carmine Tilghman

WITNESS:

Carmine Tilghman

VS 2.06

Please provide the information requested below regarding the following statement by Mr. Tilghman at page 9, lines 19-21 of his direct testimony: "The Renewable Credit Rate – currently proposed to be 5.84 cents per kWh – is equivalent to the most recent utility scale renewable energy purchased power agreement connected to TEP's distribution system."

a. Please provide all data, analyses, and other documentation that were used to support this proposal.

b. Please indicate the type of utility scale renewable resource associated with the purchased power agreement referred to in the statement.

c. Please indicate the date of the purchased power agreement referred to in the statement.

d. Please indicate the capacity of the resource associated with the purchased power agreement referred to in the statement.

e. Please provide all pricing details of the purchased power agreement referred to in the statement. Please include detailed terms related to payments for energy, capacity, and other services, as well as any escalation terms.

f. Please provide the information requested in subparts (b) through (e) of this question for all renewable energy purchased power agreements signed by UNSE and TEP in the last five years. For each agreement, please indicate whether the agreement was with UNSE or TEP. Please include information on resources that are not connected to the distribution system.

g. Please describe in detail the methodology for determining future Renewable Credit Rates.

h. Please provide a forecast of future Renewable Credit Rates.

i. Were alternative methodologies considered? If so, please identify the alternatives and provide all documents describing the alterative(s) and why the proposed methodology was chosen over the alterative(s).

RESPONSE:

a. No additional data, analysis, or other documentation was used to support the concept of using "the most recent utility scale renewable energy purchased power agreement connected to TEP's distribution system."

b. Single axis tracking photovoltaic facility

c. December 17, 2014

d. 21.526 MW(DC)

e. The price is an all-inclusive value for all energy delivered to TEP's system, with no escalation.

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

Please see the following agreements:

File Name	Bates Numbers
VS 2.06 Cliffrose Solar (Longview) PPA_PURPA.pdf (PUBLIC DOCUMENT)	TEP\007445-007493
VS 2.06 TEP Avalon Solar II Phase II PPA 12-17-14-COMPSENSCONFIDENTIAL.pdf	TEP\025028-025084
VS 2.06 TEP Cogenra (Washington Gas) PPA Amend No 1 9-19-13-COMPSENSCONFIDENTIAL.pdf	TEP\025085-025087
VS 2.06 TEP Cogenra (Washington Gas) PPA Amend No 2 10-13-15-COMPSENCONFIDENTIAL.pdf	TEP\025088-025094
VS 2.06 TEP Cogenra (Washington Gas) PPA Assignment 09-24-13-COMPSENSCONFIDENTIAL.pdf	TEP\025095-025099
VS 2.06 TEP Cogenra (Washington Gas) PPA Exhibit B 8-28-14-COMPSENSCONFIDENTIAL.pdf	TEP\025100-025101
VS 2.06 TEP Red Horse Wind 2 (Torch) PPA 1st Amend 2-12-2014-COMPSENSCONFIDENTIAL.pdf	TEP\025102-025109
VS 2.06 TEP Red Horse Wind 2 (Torch) PPA 2-20-13-COMPSENSCONFIDENTIAL.pdf	TEP\025110-025156
VS 2.06 TEP Red Horse Wind 2 (Torch) PPA 2nd Amend 02-12-14-COMPSENSCONFIDENTIAL.pdf	TEP\025157-025161
VS 2.06 TEP Red Horse Wind 2 RH3 (Torch) PPA 3rd Amend 08-05-2015-COMPSENSCONFIDENTIAL.pdf	TEP\025162-025172
VS 2.06 TEP REHNU PPA 3-08-16-COMPSENSCONFIDENTIAL.pdf	TEP\025173-025220

g. Future renewable credit rates would be determined by the most recent wholesale solar contract rate by either TEP or its affiliate UNS Electric, and would be filed with the Commission on an annual basis. This value may stay constant from one year to the next if no new contract has been executed; however, the Company would not allow the rate to remain unchanged for more than two years without supporting market data.

h. The Company does not have a forecast..

i. The Company considered alternatives such as (i) the Company's avoided cost rate that is filed each year with the Commission or (ii) the Company's base fuel and purchased power rate as approved in its most current rate case. It was determined that as long as the Company has a renewable energy requirement and would otherwise be procuring renewable energy, it was reasonable to pay the prevailing wholesale market price for renewable energy on our distribution grid.

RESPONDENT:

Carmine Tilghman

WITNESS:

Carmine Tilghman

VS 2.10

On page 12 lines 15-16 Mr. Dukes references 1,308,714 bills issued by TEP during the test year for 400kWh or less. Please indicate the number of these bills that were attributable to NEM customers.

RESPONSE:

Of the 1,308,714 residential R-01 bills for 400 kWh or less, 54,771 were from net metering customers.

RESPONDENT:

Anne Trostle

WITNESS:

Dallas Dukes

VS 2.15

Please provide the requested information regarding the following statement on page 26, lines 12-14 of Mr. Dukes' direct testimony: "Customers continue to have more options to save in the future when technology can help them manage and reduce demand. As a simple example, consider someone with two air conditioning units, a pool pump and an electric water heater."

a. Does TEP current have incentive programs in place that would provide assistance for investment in systems that prevent these appliances from coming on at one time? If so please describe any such programs. If not, please indicate whether any such programs are planned and when they would be implemented.

b. What percentage of TEP's residential customers have two air conditioning units?

c. What percentage of TEP's residential customers have a pool pump?

d. What percentage of TEP's residential customers have an electric water heater?

e. What percentage of TEP's residential customers are all-electric customers (do not have access to gas in their homes)?

RESPONSE:

a. No, TEP does not have programs in place that would provide assistance for investment in systems that prevent these appliances from coming on simultaneously.

TEP is in the process of vetting market ready technologies around which a future program can be developed. The current market is evolving from analogue hardware to software and cloud based solutions that will bring both greater value and complexity. TEP anticipates a phased approach to the development and implementation of such programs beginning in 2017 and following the availability of new cost-effective market solutions.

b. The Company does not have actual data on the percentage of residential customers with two air-conditioning units; however, in an opt-in, on-line survey conducted in 2012 13 percent of respondents indicated that they have 2 units (and 2 percent indicated they have 3). In the same survey, 15 percent of respondents indicated they have a 2-story home, it is likely that most, if not all, would have two units.

c. The Company does not have actual data on the percentage of residential customers with pool pumps; however, in an opt-in survey conducted in 2012, 20 percent of respondents reported they have a private pool and 19% provided pool-pump information.

d. The Company does not have actual data on the percentage of residential customers with electric water heaters; however, in an opt-in survey conducted in 2012, 35 percent of respondents reported they have electric water-heating.

e. The Company does not have actual data on the percentage of residential customers with electric water heaters; however, in an opt-in survey conducted in 2012, 55 percent of respondents reported their primary heating system was a gas furnace.

RESPONDENT:

Denise Smith (a) / Dr. Sandra Holland (b-d)

WITNESS:

Denise Smith / Dallas Dukes

VS 2.17

Please provide the information requested below regarding Mr. Dukes' statements about the Company's proposed Economic Development Rider on pages 30-32 of his direct testimony:

a. Will customers who take service under the proposed Economic Development Rider pay their entire share of fixed costs every year in which they take service under the Rider? If not, please quantify the proportion of fixed costs paid by Economic Development Rider customers in each year they receive the discount.

b. How many permanent full-time equivalent (FTE) jobs does the Company expect to be generated as a result of the proposed Economic Development Rider?

c. How will the Company know whether a customer that starts a new business or expands existing business operations in the Company's service territory did so because of the discounted electrics bills under the proposed Economic Development Rider?

d. Are there any safeguards in place to ensure that customers who qualify for the proposed Economic Development Rider would not start a new business or expand existing business operations in the Company's service territory without the Rider?

RESPONSE:

a. The Company's proposed Rider 13-Economic Development Rider (EDR) specifies two schedules of discounts that will apply to a qualifying customer's total bill over a 5-year period, if the customer remains qualified for the entire period. The schedule of discounts applicable to a particular qualifying customer will depend on whether the customer's new or expanding business is classified as Economic Development or Economic Redevelopment as defined in the rider. To the extent that a qualifying customer's total bill contains fixed cost recovery, that fixed cost recovery will be reduced according to the discounts specified in Rider 13. The Company has not estimated any possible non-recovery of fixed costs.

b. The Company has not estimated the number of additional FTE jobs it expects to be generated as a result of the proposed EDR. However, minimum additional FTE requirements are specified in the proposed Rider.

c. The Company can never be 100% sure that a customer who starts a new business or expands existing business operations in the Company's service area is doing so solely because of the bill discounts in the proposed EDR. TEP's incentive for proposing Rider 13 is to (i) provide additional incentives for existing and prospective TEP customers in order to support economic development in the Company's service territory, and (ii) provide for more efficient use of the current system and reduce fixed cost recovery for all customers. To that end, the Company can assure whether applicants for proposed Rider 13 meet the economic development criteria specified in the rider, which includes written documentation of qualification for either of two Arizona state tax credits designed to promote business recruitment and expansion.

d. See response to VS 2.17(c).

RESPONDENT:

Rick Bachmeier

WITNESS:

Dallas Dukes

Responses to Discovery

VS 2.24

Please provide all reports, quantitative results, data and work papers from the 2012 TEP survey referenced in the Company's response to UDR 1.089.

RESPONSE:

Please see the following files for the requested information.

File Name	Bates Numbers
VS 2.24 Data Appliances.xlsx	N/A
VS 2.24 Data Cool.xlsx	N/A
VS 2.24 Data Demog.xlsx	N/A
VS 2.24 Data EE Prog com.xlsx	N/A
VS 2.24 Data ESQuestionList.xlsx	N/A
VS 2.24 Data EV.xlsx	N/A
VS 2.24 Data Freezer.xlsx	N/A
VS 2.24 Data Fridge.xlsx	N/A
VS 2.24 Data GraphsAppliances.xlsx	N/A
VS 2.24 Data GraphsCool.xlsx	N/A
VS 2.24 Data GraphsCoolTempData .xlsx	N/A
VS 2.24 Data GraphsEE_Prog_com.xlsx	N/A
VS 2.24 Data GraphsEV.xlsx	N/A
VS 2.24 Data GraphsFreezer.xlsx	N/A
VS 2.24 Data GraphsFridge.xlsx	N/A
VS 2.24 Data GraphsHeat.xlsx	N/A
VS 2.24 Data GraphsHeatTempData.xlsx	N/A
VS 2.24 Data GraphsMiscQty.xlsx	N/A
VS 2.24 Data GraphsResidence.xlsx	N/A
VS 2.24 Data GraphsSpaPool.xlsx	N/A
VS 2.24 Data GraphsTV.xlsx	N/A
VS 2.24 Data H2OHeat.xlsx	N/A
VS 2.24 Data Heat.xlsx	N/A
VS 2.24 Data MiscQty.xlsx	N/A
VS 2.24 Data Modified Cooling Survey Data (2).xlsx	N/A
VS 2.24 Data Modified Heating Survey Data.xlsx	N/A
VS 2.24 Data ProcessedDataSetES.xlsx	N/A
VS 2.24 Data Residence.xlsx	N/A
VS 2.24 Data SpaPool.xlsx	N/A
VS 2.24 Data TV.xlsx	N/A
VS 2.24 DataGraphsH2OHeat.xlsx	N/A

VS 2.24 Website Results Presentation.pdf	TEP\024853-025018

RESPONDENT:

Dr. Sandra Holland

WITNESS:

Craig Jones

Other

VS 2.32

Please provide ~~UNSE's~~[TEP's] customer count, usage per customer, and total MWh sales historical data on a monthly basis by customer class for at least the past 10 years in excel format with formulas and links intact.

RESPONSE:

Please see the files listed below for monthly excel reports, which provide the data requested for years 2011 through 2015. The Company felt going back to the last approved test period was responsive to this request.

File Name	Bates Numbers
VS 2.32 01-11 Rev Sum.xls	N/A
VS 2.32 01-12 Rev Sum.xls	N/A
VS 2.32 01-13 Rev Sum.xlsx	N/A
VS 2.32 01-14 Rev Sum.xlsm	N/A
VS 2.32 01-15 Rev Sum.xlsm	N/A
VS 2.32 02-11 Rev Sum.xls	N/A
VS 2.32 02-12 Rev Sum.xls	N/A
VS 2.32 02-13 Rev Sum.xlsx	N/A
VS 2.32 02-14 Rev Sum.xlsm	N/A
VS 2.32 02-15 Rev Sum.xlsm	N/A
VS 2.32 03-11 Rev Sum.xls	N/A
VS 2.32 03-12 Rev Sum.xls	N/A
VS 2.32 03-13 Rev Sum.xlsm	N/A
VS 2.32 03-14 Rev Sum.xlsm	N/A
VS 2.32 03-15 Rev Sum.xlsm	N/A
VS 2.32 04-11 Rev Sum.xls	N/A
VS 2.32 04-12 Rev Sum.xls	N/A
VS 2.32 04-13 Rev Sum.xlsm	N/A
VS 2.32 04-14 Rev Sum.xlsm	N/A
VS 2.32 04-15 Rev Sum.xlsm	N/A
VS 2.32 05-11 Rev Sum.xls	N/A
VS 2.32 05-12 Rev Sum.xls	N/A
VS 2.32 05-13 Rev Sum.xlsm	N/A
VS 2.32 05-14 Rev Sum.xlsm	N/A
VS 2.32 05-15 Rev Sum.xlsm	N/A
VS 2.32 06-11 Rev Sum.xls	N/A
VS 2.32 06-12 Rev Sum.xls	N/A
VS 2.32 06-13 Rev Sum.xlsm	N/A
VS 2.32 06-14 Rev Sum.xlsm	N/A

VS 2.32 06-15 Rev Sum.xlsm	N/A
VS 2.32 07-11 Rev Sum.xls	N/A
VS 2.32 07-12 Rev Sum.xls	N/A
VS 2.32 07-13 Rev Sum.xlsm	N/A
VS 2.32 07-14 Rev Sum.xlsm	N/A
VS 2.32 07-15 Rev Sum.xlsm	N/A
VS 2.32 08-11 Rev Sum.xls	N/A
VS 2.32 08-12 Rev Sum.xlsx	N/A
VS 2.32 08-13 Rev Sum.xlsm	N/A
VS 2.32 08-14 Rev Sum.xlsm	N/A
VS 2.32 08-15 Rev Sum.xlsm	N/A
VS 2.32 09-11 Rev Sum.xls	N/A
VS 2.32 09-12 Rev Sum.xlsx	N/A
VS 2.32 09-13 Rev Sum.xlsm	N/A
VS 2.32 09-14 Rev Sum.xlsm	N/A
VS 2.32 09-15 REV Sum.xlsm	N/A
VS 2.32 10-11 Rev Sum.xls	N/A
VS 2.32 10-12 Rev Sum.xlsx	N/A
VS 2.32 10-13 Rev Sum.xlsm	N/A
VS 2.32 10-14 Rev Sum.xlsm	N/A
VS 2.32 10-15 REV Sum.xlsm	N/A
VS 2.32 11-11 Rev Sum.xls	N/A
VS 2.32 11-12 Rev Sum.xlsx	N/A
VS 2.32 11-13 Rev Sum.xlsm	N/A
VS 2.32 11-14 Rev Sum blp.xlsm	N/A
VS 2.32 11-14 Rev Sum.xlsm	N/A
VS 2.32 11-15 REV Sum.xlsm	N/A
VS 2.32 12-11 Rev Sum.xls	N/A
VS 2.32 12-12 Rev Sum.xlsx	N/A
VS 2.32 12-13 Rev Sum.xlsm	N/A
VS 2.32 12-14 Rev Sum.xlsm	N/A
VS 2.32 12-15 REV Sum.xlsm	N/A

RESPONDENT:

Brenda Pries

WITNESS:

Craig Jones

VS 2.34

Please provide the following information about TEP's NEM customers during the test year. For each question please answer separately for each customer class.

a. The number of NEM customers that net zero consumption for the year.

b. The number of NEM customers that offset 90-100% of annual consumption during the year.

c. The number of NEM customers that offset 80-90% of annual consumption during the year.

d. The number of NEM customers that offset 70-80% of annual consumption during the year.

e. The number of NEM customers that offset 60-70% of annual consumption during the year.

f. The number of NEM customers that offset 50-60% of annual consumption during the year.

g. The number of NEM customers that offset 50% or less of annual consumption during the year.

RESPONSE:

The Company objects to this question as being overly burdensome nor does the Company track this information in the manner requested. The Company does not routinely analyze all net metered customers' individual consumption and export data.

RESPONDENT:

Carmine Tilghman / Anne Trostle

WITNESS:

Craig Jones

VS 2.35

Please provide the requested information regarding feeder level PV generation modeling:

a. Please indicate the number of distribution circuits that have been selected for SynerGEE software analysis.

b. Please indicate why these circuits were selected.

c. Please describe any plans to expand SynerGEE software analysis to additional circuits, including the criteria for selection of additional circuits.

d. Please identify the number of circuits in which SynerGEE powerflow software analysis indicated PV generation would have an impact to operations.

e. Please describe, and to the extent possible quantify, any impact on operations identified in response to sub question (d).

RESPONSE:

a. SynerGEE Powerflow software is used to model all 405 Company distribution circuits when required.

b. Generation interconnection requests, system reinforcement projects, capacitor placement studies, customer voltage complaints, area studies, future development planning, operational studies, etc.

c. See (a) above.

d. Three (3) PV generation interconnection studies done with SynerGEE power flow software indicated existing distribution facilities could not support the proposed generation source and would therefore have an impact on operations.

e. Three (3) specific interconnection studies identified that the addition of generation would overload existing Company feeder conductors. For these instances, upgrading the existing overhead feeder conductor was identified as a possible solution for supporting the proposed generation facilities.

RESPONDENT:

Carmine Tilghman

WITNESS:

Carmine Tilghman

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO VOTE SOLAR'S SECOND SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE DOCKET NO. E-01933A-15-0322 June 1, 2016

VS 2.40

Does the Company currently have any policies, plans, or incentives addressing: (1) grid modernization, (2) electric vehicles, (3) demand response, (4) energy efficiency, (5) energy storage, and (6) advanced metering? If so, please describe and provide details on each of the Company's policies, plans, or incentives.

RESPONSE:

(1) Grid Modernization – At this time the Company has no specific policies or incentives addressing grid modernization. The Company is working with Siemens to develop a 10 year grid modernization implementation plan. The Company has also installed a limited number of distribution feeder measurement sensors with two way communications, distribution capacitor bank controllers with two way communications, and is working to install line switches for 46kV and 13.8kV applications with remote operations capabilities.

(2) Electric Vehicles – At this time the Company's residential time-of-use ("TOU") rate has a discount of 5% on the Base Fuel during the off-peak period and Purchased Power and Fuel Adjustment Clause ("PPFAC") for customers that provide documentation of having a highway approved electric vehicle.

(3) Demand Response – The Company has several Energy Efficiency programs and a commercial demand response program. The policies, plans and incentives for these programs are outlined in the Commission's Electric Energy Efficiency Standard Rules, TEP's current Energy Efficiency Plan and corresponding decisions. Information can also be found in TEP's EE Annual Report.

(4) Energy Efficiency – The Company has several Energy Efficiency programs and a commercial demand response program. The policies, plans and incentives for these programs are outlined in the Arizona Corporation Commission's Electric Energy Efficiency Standard Rules, TEP's current Energy Efficiency Plan and corresponding decisions. Information can also be found in TEP's EE Annual Report.

(5) Energy Storage – The Company is currently in the process of installing two 10 MW grid tied battery storage systems that were procured through a competitive solicitation process and approved by the ACC, as discussed in more detail in the Company's 2016 REST Implementation Plan. The Company is also installing a 1 MW battery storage facility in partnership with a storage solution provider to evaluate their control program. The Company currently does not have any incentive programs for storage, but does have interconnection standards for policies associated with the installation of storage devices on customer's premises.

(6) Advanced metering – The Company has installed AMR meters with electronic radio transmitters (ERT's) that allow them to be read remotely by a one way fixed communications network. These type of meters have been installed on all residential and the majority of commercial accounts. We have installed meters with two way communications capabilities on distribution feeders, industrial accounts and a limited number of commercial accounts. The Company plan is

to store interval data from all of the meters in a meter data management system. Programs are being proposed as part of this rate case utilizing the capabilities of the metering implementation.

RESPONDENT:

Carmine Tilghman / Denise Smith / Jim Taylor

WITNESS:

Carmine Tilghman

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO VOTE SOLAR'S FOURTH SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
June 3, 2016

VS 4.1

Please provide the information requested below regarding the tab entitled "Function Allocators" in 2015 TEP Schedule G – COSS REVISED-Competitively Sensitive Confidential.xlsx.

a. Please provide the equivalent functional allocators that were approved in the Company's last rate case in Docket No. E-01933A-12-0291.

b. To the extent any of the allocators presented in this case differ from the allocators approved in the Company's last rate case, please provide an explanation of the difference and the Company's rationale for updating the allocators.

RESPONSE:

a. Please see VS 4.1a Func Alloc.xlsx for the functional allocators used in the Class Cost of Service Study approved in the last rate case. The Excel file is not identified by Bates numbers.

b. TEP correctly recognized that the cost study used in prior years made assumptions that were incorrect and under allocated distribution costs to various residential customer rate schedules and the class as a whole. This is a result of using the basic customer method and Class NCP to allocate plant accounts 364-368. TEP adopted the minimum system as an alternative because it is a superior method for allocating costs based on theoretical, operational, accounting and empirical analysis of cost causation. It is straight forward to understand that adding a new customer to the system requires some minimum amount of distribution plant assets based on the smallest equipment used to connect a customer. If something more is required such as a larger transformer only the investment in excess of the minimum system is demand related. The minimum system method also reflects cost causation as it relates to distribution system planning and operation. Distribution plant and equipment do not come in continuous sizes and it is unreasonable and uneconomic and inefficient to stock every size and type of that equipment. Utility planners use the sizes and types of equipment that will accommodate customer delivery demands in the most efficient configuration for the service area characteristics. The reality of the minimum system is recognized in utility accounting as well. It is an important element of cost accounting. Finally the importance of customer related costs has been demonstrated in the economics literature as it relates to the analysis of production functions and total factor productivity by detailed theoretical and empirical analysis. This work has used modern theoretical techniques and better data to support the use of a customer variable in equations that estimate the changes in cost for a utility under price cap regulation as it relates to customer growth.

RESPONDENT:

Brenda Pries (a) / Edwin Overcast (b)

WITNESS:

Craig Jones

RUCO 3.14

Re: Grey Direct at 21:10-15, please provide any and all engineering analysis to support the statements that 1) with more distributed generation resources being deployed on the TEP distribution system puts demands on the T&D systems not previously contemplated. To meet these new demands, 2) requires TEP to utilize technology to add more sensing and measurement devices and new methods for managing and operating the distribution system.

RESPONSE:

THE FILES LISTED BELOW CONTAIN CONFIDENTIAL INFORMATION AND ARE BEING PROVIDED PURSUANT TO THE TERMS OF THE PROTECTIVE AGREEMENT.

1)

File Name	Bates Numbers
RUCO 3.14 Los Reales Feeder 14 backflow-Confidential.pdf	TEP\021154-021155
RUCO 3.14 Sample Feasibility Study 100515-Redacted-Confidential.pdf	TEP\021156-021165

Please see the following technical articles with web addresses provided:

- Reiman, A. (2015). An Analysis of Distributed Photovoltaics on Singe-Phase Laterals of Distrution Systems. *D-Scholoarship Institutional Respository at the University of Pittsburg* [Website]. Retrieved from http://d-scholarship.pitt.edu/24047/.
- Jan-E-Alam, M., Muttaqi, K.M., and Sutanto, D. (2011, July 24-29). Assessment of distributed generation impacts on distribution networks using unbalanced three-phase power flow analysis. *IEEE.org* [Website]. Retrieved from http://ieeexplore.ieee.org/xpl/articleDetails.jsp?tp=&arnumber=6039789&url=http%3A%2F%2Fieeexplore.ieee.org%2Fxpls%2Fabs_all.jsp%3Farnumber%3D6039789
- Tang, J.H., Lim, Y.S., Morris, S., and Wong, J. (2012). Impacts on Centrally and Non-Centrally Planned Distributed Generation on Low Voltage Distribution Network. *International Journal of Smart Grid and Clean Energy*. Retrieved from http://www.ijsgce.com/uploadfile/2012/1016/20121016114245643.pdf.

1) The distribution network was designed to provide power flows from the substation to the customer. By adding generation at the customer level to feed into the distribution network voltage, power quality, protection schemes, network losses and load balancing of feeders is affected differently than the system was originally designed. Please see RUCO 3.14 Sample Feasibility Study 100515-Redacted.pdf for a sample TEP feasibility study indicating the work performed and issues identified. This type of study is typically performed for all interconnection's greater then 1MW in size. For reference are actual measurements taken from a TEP distribution feeder indicating power flow unbalance that has been introduced into the distribution network from DG sources. Please see RUCO 3.14 Los Reales back flow-Confidential.pdf for example. For reference are three other technical

articles describing the complexity in accurately modeling the effects of DG on a distribution network and the effects of DG sources on the distribution network.

2) Electrically modeling the distribution network is a complicated activity. The model is being further complicated by the introduction of DG items such as energy efficiency, solar, storage and demand response. For reference refer to the technical articles referenced for part 1. To validate the model information sensing and measurement devices can be installed to provide electrical parameters that can be incorporated in different ways (i.e. state estimation) to validate or modify the electrical model to represent actual measurements. This corrects the model to better model the actual electrical system. With better information and modeling, management and operation of the distribution network can be improved. Where improvement refers to the management of side effects caused by DG on the distribution network. The common side effects are described the technical articles referenced in part 1.

RESPONDENT:

Jim Taylor

WITNESS:

Susan Gray

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO RUCO'S THIRD SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
March 14, 2016

RUCO 3.17

RE: Tilghman Direct at 7:2-18, with respect to the discussion of impacts of intermittent generation, for distributed generation (DG) resources not owned by the Company, please provide the following:

a. a list of each and every operational metric that TEP is concerned about with respect to DG with a definition of what it is and how TEP tracks the metric,

b. for each metric provided in response to part a) of this question please provide and any all data that TEP tracks with respect to the metric,

c. please explain how each metric identified in part a) of this question is the same or different depending on the various voltage levels that TEP operates (e.g. 500 kV, 345kV, 138kV, 46 kV, 13.8 kV, 4.16 kV, etc.),

d. any and all data that proves that intermittent generation from DG is creating greater load imbalance,

e. any and all data that proves that intermittent generation from DG is creating greater fluctuations in voltage,

f. any and all data that proves that intermittent generation from DG is creating greater fluctuation in frequency,

g. please explain how, if any, intermittent generation from DG impacts the cost of providing service from TEP due to greater load imbalance together with any and all engineering studies that support the explanation and cost by month for the last ten years.

h. please explain how, if any, intermittent generation from DG impacts the cost of providing service from TEP due to greater fluctuations in voltage together with any and all engineering studies that support the explanation and cost by month for the last ten years.

i. please explain how, if any, intermittent generation from DG impacts the cost of providing service from TEP due to greater fluctuation of frequency together with any and all engineering studies that support the explanation and cost by month for the last ten years.

RESPONSE:

Please see the following files, as referenced below.

File Name	Bates Numbers
RUCO 3.17(a) NERC Glossary_of_Terms.pdf	TEP\020589-020706
RUCO 3.17(b) BAL-001-1.pdf	TEP\020707-020718
RUCO 3.17(b) BAL-001-2.pdf	TEP\020719-020727
RUCO 3.17(b) BAL-002-1.pdf	TEP\020728-020732
RUCO 3.17(b) BAL-002-WECC-2.pdf	TEP\020733-020744
RUCO 3.17(b) BAL-003-1.1.pdf	TEP\020745-020756
RUCO 3.17(d) 2015_Sample_Variability.xlsx	N/A

a. Below is a list of Balancing Authority ("BA") Area metrics that TEP is concerned about with respect to DG. Metrics are calculated and stored by the Energy Management System ("EMS") in company databases.

Area Control Error ("ACE")

Per the NERC Glossary of Terms (see RUCO 3.17(a) NERC Glossary_of_Terms.pdf), "The instantaneous difference between a Balancing Authority's net actual and scheduled interchange, taking into account the effects of Frequency Bias, correction for meter error, and Automatic Time Error Correction ("ATEC"), if operating in the ATEC mode. ATEC is only applicable to Balancing Authorities in the Western Interconnection."

Frequency Response Measure ("FRM")

Per the NERC Glossary of Terms, "The median of all the Frequency Response observations reported annually by Balancing Authorities or Frequency Response Sharing Groups for frequency events specified by the ERO. This will be calculated as MW/0.1Hz."

Frequency Response Obligation ("FRO")

Per the NERC Glossary of Terms, "The Balancing Authority's share of the required Frequency Response needed for the reliable operation of an Interconnection. This will be calculated as MW/0.1Hz."

Disturbance Control Standard ("DCS")

Per the NERC Glossary of Terms, "The reliability standard that sets the time limit following a Disturbance within which a Balancing Authority must return its Area Control Error to within a specified range."

Balancing Authority ACE Limit ("BAAL")

A Balancing Authority-specific limit on ACE derived from the BA's frequency bias, scheduled frequency, actual interconnection frequency, and epsilon, a targeted frequency bound defined by NERC for each interconnection. Also referred to as "Reliability-based Control," or RBC. BAs may not exceed either a BAAL High or BAAL Low for longer than 30 minutes. Definitions and calculations from BAL-001-2 (see file RUCO 3.17(b) BAL-002-1.pdf), which goes into effect on July 1, 2016. RBC has been in effect as a field trial in WECC since March 1, 2010, and WECC has monitored BA compliance with RBC since then.

Contingency Reserve ("CR")

Per the NERC Glossary of Terms, "The provision of capacity deployed by the Balancing Authority to meet the Disturbance Control Standard ("DCS") and other NERC and Regional Reliability Organization contingency requirements. The provision of capacity that may be deployed by the Balancing Authority to respond to a Balancing Contingency Event and other contingency requirements…."

b. TEP objects to this request as providing all data collected by TEP with regard to the metrics in part a) would be overly burdensome. However, without waiver of objection, the data collected for metric calculations are specified in various NERC and WECC documents and are listed below.

The ACE calculation is comprised of the components specified in RUCO 3.17(b) BAL-001-1.pdf.

Frequency Response Measure is comprised of the components in RUCO 3.17(b) BAL-003-1.1.pdf.

Frequency Response Obligation is comprised of the components in RUCO 3.17(b) BAL-003-1.1.pdf.

Compliance with the Disturbance Control Standard is calculated in accordance with RUCO 3.17(b) BAL-002-1.pdf.

Balancing Authority ACE Limits are comprised of the components RUCO 3.17(b) BAL-001-2.pdf.

Contingency Reserve is comprised of the components in RUCO 3.17(b) BAL-002-WECC-2.pdf.

Data is collected and calculations are performed by the EMS every 2 seconds.

c. Voltage level is not taken into consideration for any of the metrics listed in part a).

d. The TEP Balancing Authority considers DG variability in 10 minute increments. This is because reserves, both spinning and non-spinning, are calculated by what they can provide within 10 minutes. Please see RUCO 3.17(d) 2015_Sample_Variability.xlsx.

Ten-minute output values from different large-scale distributed solar sites connected to the TEP system can be summed and compared to show an aggregate 10-minute variability. At the BA level, there is no differentiation between TEP-owned and PPA DG sites; these sites are all metered into the TEP Balancing Authority at the transmission or distribution level and do not reside behind customer meters, so the effect on the BA Area is the same regardless of whether they are TEP-owned or PPAs.

Site	AC MW Capacity	Location	TEP Owned
Picture Rocks (aka FRV)	20	Marana, AZ	No, PPA
Avra Valley (aka NRG)	25	Marana, AZ	No, PPA
Fort Huachuca Phase I	13.6	Sierra Vista, AZ	Yes
U of A Tech Park (UASTP I & II)	5.3	Tucson, AZ	Yes
U of A Tech Park (Amonix, Cogenra, E.On Tech Park, Gato Montes Solar)	12	Tucson, AZ	No, PPA

These example sites comprise about 76 MW of AC rated capacity, and they reside in Southern Arizona within the TEP metered boundary. These are sites which TEP either owns or has PPAs with, meters directly to its EMS for the calculation of generation and load, and do not reside behind any customer meters.

When generation within a Balancing Authority fluctuates, it causes other generation on Automatic Generation Control to fluctuate, as well as the amount of interchange over BA Area ties. These changes also cause fluctuations in the BA ACE, making it more difficult to comply with relevant reliability standards like BAAL because changes can happen so rapidly and unpredictably.

The maximum positive 10-minute variability measured in the aggregated 2015 data is 26.4 MW or 34.73%, and the maximum negative 10-minute variability measured is -44.7 MW or -58.94%.

The DG sites used in this example, which are geographically diverse within Southern Arizona and the Tucson Valley, can exhibit large changes over short periods of time, even when aggregated. Applying this behavior to the entirety of the distributed solar in the Tucson Valley shows the potential for the Valley's aggregated solar to have serious impacts to the requirements of traditional generation, the BA Area interchange ties, BA ACE, and ability to maintain operating reserves. The negative variability coupled with normal system disturbances can deplete reserves making it difficult to maintain compliance with the metrics mentioned above.

Positioned behind customer meters, distributed generation will change the amount of power the customer draws. Small fluctuations in customer load are expected and normal, and even larger fluctuations exhibited by a few customer meters will be less obvious at a system level. However, when many customers utilize distributed solar generation, the aggregated impacts will increase to levels that will impact the overall system and metrics.

Other studies regarding distributed generation and customer load may be viewed on the SVERI Public Access Data Portal at sveri.uaren.org.

e. Results from interconnection studies routinely performed for distributed generation facilities indicate that large penetration levels of distributed generation resources can cause fluctuations in distribution system voltage. TEP cannot provide copies of these studies since they contain sensitive customer information and require the consent of the customer.

f. Any and all generation within an interconnected system has an effect on system frequency; therefore, any new generation introduced to a power system, including DG, will contribute to deviations in frequency.

Due to the relative size of DG versus total system generation capacity, frequency deviations specifically attributable to solar DG have not been measured within the TEP BA Area. However, as DG penetration becomes a larger percentage of overall generation, TEP expects the adverse effects of DG to become more visible and more easily attributable.

g. While variability of solar distributed generation has been observed, TEP has not calculated the direct costs as of yet.

h. While variability of solar distributed generation has been observed, TEP has not calculated the direct costs as of yet.

i. As previously stated, due to the relative size of DG versus total system generation capacity, frequency deviations specifically attributable to solar DG have not been measured within the TEP BA Area. However, as DG penetration becomes a larger percentage of overall generation, TEP expects the adverse effects of DG to become more visible and more easily attributable.

RESPONDENT:

Lauren Briggs / Ana Bustamante (e and h)

WITNESS:

Carmine Tilghman / Susan Gray

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO RUCO'S SEVENTH SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
April 18, 2016

RUCO 7.11

Residential Customers - RE: Dukes Direct at page 11:22-25, please provide the following:

a. the number of seasonal residential customers that TEP has together with their energy use, by month, for a typical year;

b. the number of year round residential customers that TEP has together with their energy use, by month, for a typical year;

c. the estimated number of residential vacant homes, by month, for the years 2011-2015.

d. Please provide typical load profiles for a residential seasonal customer, a residential vacant home, a residential year round customer, and a residential customer with distributed generation. The load profiles should be for the winter period, the summer period, and the peak day.

RESPONSE:

a./b. The Company does not currently track seasonal versus year round customers and therefore does not have their energy use as requested.

c. The Company does not track vacant homes.

d. For the reasons above, the company does not have load profiles for the requested customer types. The company has a large swath of hourly data for a number of customers which include some of the customer types listed. Although there are not distributed generation customers in the sample, the Company is also including the NREL SAM 8760 production curve for the Tucson area for use in estimating solar DG customer hourly load shapes.

Please see the following files for the 8760 production curve.

File Name	Bates Numbers
RUCO 7.11 Individual Customer Sample 2-Confidential.xlsx	N/A
RUCO 7.11 Individual Customer Sample 3-Confidential.xlsx	N/A
RUCO 7.11 Individual Customer Sample 4-Confidential.xlsx	N/A
RUCO 7.11 Individual Customer Sample 5-Confidential.xlsx	N/A
RUCO 7.11 Individual Customer Sample-Confidential.xlsx	N/A
RUCO 7.11 NREL SAM DATA-Confidential.xlsx	N/A

RESPONDENT:

Greg Strang

WITNESS:

Dallas Dukes

RUCO 7.13

Schedule H - RE: Schedule H, please provide Schedule H-5 for calendar years 2011, 2012, 2013, 2014 and 2015 for customers who take service under the Net Metering Rider.

RESPONSE:

The Company objects to this request as overly burdensome because it will require the creation of work products that TEP does not already possess. In addition to the Company's response to RUCO 7.12 the Company does not separate net metering customers from their standard rate schedule in the revenue proof. However, without waiver of objection, please refer to the file RUCO 7.13 NEM BF Data.xlsx, which provides unadjusted bill frequency data from the test year period for R-01 and GS-10 net metering customers, in the format of Schedule H-5. The Excel file is <u>not</u> identified by Bates numbers.

RESPONDENT:

Anne Trostle / Brenda Pries

WITNESS:

Craig Jones

RUCO 8.05

Hutchens Direct 13:11-24 – 18:1-18 - Please provide the monthly peak demand for TEP's retail delivery customers from January 2006-December 2015 on an actual basis and weather normalized basis.

RESPONSE:

Please see file RUCO 8.05 City Load Data.xlsx, sheet "Monthly Summary" for the monthly peak data requested. The Excel file is not identified by Bates numbers. The Company cannot provide weather normalized peak data as it does not perform such adjustments. This is because the peak model has a high degree of complexity, thus making peak normalizing very difficult and normalized peak values are of little value for system planning.

RESPONDENT:

Greg Strang

WITNESS:

Dallas Dukes

STF 1.14

Retail Sales: Please provide in an Excel worksheet a summary of the numbers of seasonal homes, vacant structures and net-metered rooftop PV systems including energy sales, demand and customer counts (by month or season) since January 2006 to the present. [Application 3:27 and Dukes 11:22]

RESPONSE:

Please see **STF 1.14 Net Metered PV Systems.xlsx** for net metered PV systems. TEP does not track seasonal homes or vacant structures. The Excel file is not identified by Bates numbers.

RESPONDENT:

Carmine Tilghman

WITNESS:

Carmine Tilghman / Dallas Dukes

STF 1.20

Renewable Resources: Please provide a narrative discussing how the Company forecasts short term (daily and hourly) PV generation. [Tilghman 7:1]

RESPONSE:

The Company utilizes a long standing relationship with the UA to forecast short-term (daily and hourly) PV generation by employing renewable power forecasts they have created. These forecasts include a number of forecasting technologies. These technologies include the use of numerical weather models, which enable us to forecast utility solar and DG solar for up to 10 days, satellite imagery analysis, which enables us to forecast utility and DG solar power generation for up to three hours, analysis of real-time utility and DG data, and a network of irradiance sensors, which enables the forecasting of utility and DG solar power generation for up to 120 minutes. Each of which will be discussed in further detail, below.

The Numerical Weather Prediction models make up the basis for the solar forecasts and allow us to forecast up to 10 days out. These models apply a numerical representation of weather affecting land and atmospheric processes. The specific model the Company uses is a southwestern United States specific Weather Research and Forecast ("WRF") model. This model was customized by the UA to create more accurate forecasts for the Desert Southwest. A specific modification to the model includes the running of the model at a higher resolution, in order to capture smaller scale weather phenomena, such as terrain induced winds, clouds, and monsoonal thunderstorms. This particular model is usually run by the UA around eight times a day and is initialized, every time it's run, with different data. Single model runs are highly unlikely to produce accurate forecasts every time; therefore, multiple model runs allow us to capture more in the forecasts. If a certain model run missed a weather event and we decided to utilize that model run, our forecast would be blaringly inaccurate. Having multiple model runs allows us to see the different events each model is forecasting and determine the most accurate forecast. The models are initialized by using observed data from weather balloons, surface weather stations, aircraft, and weather satellites. The renewable power forecasts are based on the 12 most recent weather forecasts.

The forecasting of short-term variability (up to three hours) is done by utilizing satellite image processing, which is the use of visible and infrared channels of the GOES satellite imagery to determine the irradiance that makes it to the ground. The irradiance calculation is combined with the PV power plant's clear sky expectation, which is a satellite production estimate. Real-time estimates of behind-the-meter generation can be determined from these calculations. Modeled wind speeds at the estimated cloud height are used to propagate the satellite-derived irradiance map forward to come up with the irradiance or PV power forecast.

A network of PV systems and irradiance sensors allow us to forecast PV power for up to 120 minutes. PV output, from the Company's utility-scale systems and 20 residential systems, is used as a proxy for irradiance. The UA also receives real-time production data, which is sent every two seconds to 15 minutes, from rooftop systems' data loggers from a local PV installer. Custom irradiance sensors, developed by the UA, that communicate by means of cellular modems are also used and send one-second resolution data every 60 seconds. Deviations from the clear sky profiles, which were created for each of the sensors by using filtered historical data, are interpreted and determined to be clouds or not. The clearness index (ratio of measured power to clear sky power) is calculated for each sensor. An interpolated clearness map across the forecasting domain is, then, created. The weather models' predicted wind velocities at their respective cloud heights determine the speed, direction, and uncertainty of the clearness map propagation. The resulting forecasted PV power can, then, be determined from the propagated clearness map.

The Company is also able to input information regarding any solar power plant outages into the forecast model created by the UA. By doing this, the forecast will change to account for the lack of availability during a given outage.

RESPONDENT:

Nicole Bell

WITNESS:

Carmine Tilghman

STF 1.21

Renewable Resources: Please provide a narrative discussing how the Company has either implemented and/or researched the use of metering at individual PV connections (upstream of the utility meter) to monitor PV generation at the source. [Tilghman 7:20]

RESPONSE:

The Company requires that a meter be installed at the output of all DG sources for the collection of generation production data. For systems above 300kWac, the Company, at the customer's expense, installs more advanced metering equipment to obtain real-time production data for operations purposes. This data is collected and aggregated with other systems above 300kWac to better monitor the intermittent production of these generators. The data obtained from the larger systems is also used to approximate the production for the other smaller customer-owned distributed generators that do not provide real-time production data to Operations.

RESPONDENT:

Carmine Tilghman

WITNESS:

Carmine Tilghman

STF 1.46

Cost of Service: Please provide any studies, investigations, analyses or reviews performed by or for the Company that establishes the return of the residential and/or small commercial *subclasses* consisting of customers using distributed generation. If the Company has not performed these studies please explain why not. [Jones 15:7]

RESPONSE:

The Company does not currently look at DG/net metering customers as a sub-class in the COSS nor are their billing determinants or revenues booked separately from standard offer service. The Company will review doing so prior to the next rate case.

The Company has looked at revenue recovery from a full requirement customer vs. a DG/net metering customer with 100% PV offset on an annual basis. See TEP's Supplemental Response to UDR 1.001 dated December 1, 2015, specifically files 2015 TEP R-01 Demand-PRS.xlsx and TEP 2015 SGS Load-PV Data.xlsx.

RESPONDENT:

Brenda Pries / Rick Bachmeier

WITNESS:

Craig Jones

STF 1.48

Cost of Service: Please provide any load research, studies, investigations, analyses or reviews performed by or for the Company that establishes the NCP, CP and energy consumption similarities and differences between R-01 Full Requirements Customers and R-01 DG Customers. [Jones 16:20]

RESPONSE:

The Company has no direct load research, studies, investigations, analyses or reviews of the type requested. However, the Company has compiled a sample of hourly data over a 24 month period (where available, 7/1/2013-6/30/2015) for over 11,000 residential customers. In this process the Company also layered in a "net zero" solar array that offsets annual kWh consumption based on the 8,760 solar production for the Tucson area from NREL's System Advisor Model. The monthly billing components for kWh and kW were compiled monthly for regular, time-of-use, super peak time-of-use, and a solar equipped customer for each of the scenarios. See TEP's Supplemental Response to UDR 1.001 dated December 1, 2015, specifically files 2015 TEP R-01 Demand-PRS.xlsx and TEP 2015 RES Load-PV Data.xlsx.

RESPONDENT:

Rick Bachmeier

WITNESS:

Craig Jones

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO EFCA'S FIRST SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
June 20, 2016

EFCA 2.10

Please provide equivalent tables to those on pg. 21 and pg. 29 referring to the bill impacts for residential NEM customers, for SGS, MGS, and LGS customers. Please adjust the monthly kWh load bands as appropriate.

RESPONSE:

The Company has not created these work sheets and objects to this question as overly burdensome.

RESPONDENT:

Rick Bachmeier

WITNESS:

Dallas Dukes / Carmine Tilghman

SWEEP 1.08

For the customers expected to migrate from the Company's current two part rate to the voluntary three part rate, has the Company estimated any changes in individual peak demand, coincident peak demand, and overall usage as a result of shifting to the three part rate? If yes, please provide all data, workpapers, and studies used to rely on these projections. If no, please describe why the Company does not expect any changes in usage for these customers.

RESPONSE:

The Company has not estimated any changes in individual peak demand, coincident peak demand, or overall usage as a result of shifting the proposed optional three-part rates.

The Company does expect changes in customer behavior as they migrate from a two-part to a three-part rate, especially when it comes to billing kW. If billing kW is defined as the customer's measured peak kW, economic theory predicts that as the price of peak kW is increased from zero to any positive amount, the quantity of peak kW consumed would decrease, all else equal. Because many variables will influence how the three-part rate may change a customer's coincident peak demand and overall usage, and the three-part rate only influences these quantities indirectly (unless billing kW is defined as coincident peak kW, which the Company is not proposing in this proceeding), the impact of the three-part rate on these quantities would be indeterminate.

While the Company expects changes in customer behavior as they migrate from a two-part to a three-part rate, the Company has not made an attempt to estimate the magnitude of any expected changes. However, the voluntary nature of the optional three-part rates will likely diminish any aggregate changes in customer behavior, i.e., peak demand reduction, because of customer self-selection. In other words, customers who will benefit from bill savings without significantly changing behavior will likely be the first to opt in to a voluntary three-part rate.

RESPONDENT:

Greg Strang / Rick Bachmeier

WITNESS:

Craig Jones

SWEEP 2.15

Has TEP conducted analysis or reviewed previous pricing studies to determine if a three part rate is superior to a two part time of use rate in reducing peak demand? If yes, please provide analysis or cite studies reviewed. If no, please explain why this analysis was not conducted.

RESPONSE:

TEP has not conducted any analyses or reviewed previous studies to determine if a three-part rate is superior to a two-part time-of-use rate in reducing peak demand. TEP has not conducted or reviewed such a study because reducing peak demand is not the primary objective of TEP's proposed three-part rates for residential and small general service customers. While peak demand reduction may be a benefit of the proposed three-part rate, the main objective of TEP's proposal is to better align cost recovery with how costs are incurred.

RESPONDENT:

Rick Bachmeier

WITNESS:

Dallas Dukes

TUCSON ELECTRIC POWER COMPANY'S SUPPLEMENTAL RESPONSE TO SWEEP'S SECOND SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
June 7, 2016

SWEEP 2.22

Referencing Dukes direct at 26, lines 14-20, what is the estimated cost of such a system? Please itemize both the actual costs of the system and the likely labor cost to install the system.

RESPONSE: June 1, 2016

TEP is in the process of gathering this information and will provide it as soon as possible.

RESPONDENT:

Dallas Dukes

WITNESS:

Dallas Dukes

RESPONSE: June 7, 2016

Currently, pricing on the type of demand control unit described in Mr. Dukes' testimony would run approximately $2,800 for the equipment and an additional $900 for installation. As utility rates move toward more equitable forms of cost recovery and are designed to appropriately recover fixed cost in ways more consistent with the way those costs are incurred, the demand for this type of equipment will increase and, like solar panels and much of the other developing technology, a decrease in costs will likely occur.

RESPONDENT:

Michael Baruch / Craig Jones

WITNESS:

Dallas Dukes

ARIZONA CORPORATION COMMISSION
SOUTHWEST ENERGY EFFICIENCY PROJECT'S
FIRST SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY IN THE MATTER
REGARDING TEP RATE CASE
DOCKET NO. E-01933A-15-0322
MAY 18, 2016

SWEEP 1.1: Has APS conducted any analysis on the price responsiveness of customers to residential demand charges? If yes, please include any and all studies, workpapers, and other documentation APS has produced on this subject. Please include data and analysis for the entire calendar year, not just summer months. Please also include raw data files used to conduct this analysis.

Response: In 2015, APS conducted a rate analysis to assess the impact of a three-part demand rate on energy usage, demand level, and monthly bills for residential customers. The analysis determined demand impacts by comparing individual customer characteristics before and after switching to a three-part rate.

Results of this analysis, along with an analysis description and summary load data, are attached as Excel file APS15766.

UNS ELECTRIC INC.'S RESPONSE TO VOTE SOLAR'S THIRD SET OF DATA REQUESTS REGARDING THE 2015 UNS ELECTRIC RATE CASE
DOCKET NO. E-04204A-15-0142
November 2, 2015

VS 3.01

Please provide the information requested below regarding the following statement by Mr. Tilghman at page 7, lines 14–17 of his direct testimony: "The Renewable Credit Rate – currently proposed to be 5.84 cents per kWh – is equivalent to the most recent utility scale renewable energy purchased power agreement connected to the distribution system of UNS Electric's affiliate, TEP."

a. Please provide all data, analyses, and other documentation that were used to support this proposal.

b. Please indicate the type of utility scale renewable resource associated with the purchased power agreement referred to in the statement.

c. Please indicate the date of the purchased power agreement referred to in the statement.

d. Please indicate the capacity of the resource associated with the purchased power agreement referred to in the statement.

e. Please provide all pricing details of the purchased power agreement referred to in the statement. Please include detailed terms related to payments for energy, capacity, and other services, as well as any escalation terms.

f. Please provide the information requested in subparts (b) through (e) of this question for all renewable energy purchased power agreements signed by UNS and TEP in the last five years. For each agreement, please indicate whether the agreement was with UNS or TEP.

RESPONSE:

THE FILE LISTED BELOW CONTAINS COMPETITIVELY-SENSITIVE CONFIDENTIAL INFORMATION THAT IS ONLY BEING PROVIDED TO THE REQUESTING PARTY PURSUANT TO THE TERMS OF THE PROTECTIVE AGREEMENT.

a. Please see STF 2.038 Avalon Solar Facility-Competitively Sensitive Confidential.pdf, Bates Nos. UNSE\013366-013386, for the Avalon Solar Facility contract (Phase II).

b. The facility is a ground-mounted single-axis tracking PV system.

c. The agreement is dated December 17, 2014.

d. Expected facility capacity is 21.526 MW (DC).

e. Please refer to agreement. Contract price is fixed with no escalation and is all-inclusive for energy, capacity, and environmental attributes.

f. UNS has recently filed a PURPA solar agreement, which can be viewed publicly under Docket NO. E-04204A-15-0314, dated August 31, 2015 for a 70 MW(ac) single axis tracking facility priced at the company's calculated avoided cost for 25 years (see Exhibit E of contract). Contract is awaiting ACC approval.

The following is a list of new TEP contracts signed in the last 5 years (assignment of older contracts excluded):

(a.) 1.0452 MW (dc) DCI panel tracking facility, dated October 1, 2015. Contract Price $58.00 per MWh, fixed with no escalation and includes all energy, capacity, and environmental attributes.

(b.) 1.38 MW(dc) LCPV facility, dated March 23, 2013. Contract Price $108.75 per MWh plus lease and land adjustments, fixed with no escalation and includes all energy, capacity, and environmental attributes.

Additionally, TEP has utility scale solar projects connected to its EHV transmission system (non-distribution) that are single axis tracking PV facilities with all-inclusive fixed pricing (no escalation) that ranges from $68.30 per MWh for a 2013 project to $50.60 per MWh for a 2015 solar facility. Even though the most recent contract is lower than the value being proposed as the current market price, it is not being used at the equivalent utility scale market price due to the fact that it is connected to the Company's EHV system and not its distribution system.

RESPONDENT:

Carmine Tilghman

WITNESS:

Carmine Tilghman

Exhibit BK-4

ACC Decision No. 51472 (Oct. 21, 1980)

BEFORE THE ARIZONA CORPORATION COMMISSION

JIM WEEKS
Chairman
BUD TIMS
Commissioner
JOHN AHEARN
Commissioner

IN THE MATTER OF THE COMMISSION, ON ITS OWN MOTION, CONDUCTING A HEARING PURSUANT TO A.R.S. SECTION 40-252 TO CONSIDER AMENDING DECISION NO. 49060	DOCKET NO. U-1345-80-98 DECISION NO. 51472 OPINION AND ORDER

DATE OF HEARING: September 4, 1980

PLACE OF HEARING: Phoenix, Arizona

PRESIDING OFFICERS: William R. Giese, Hearing Officer
Jim Weeks, Chairman
Bud Tims, Commissioner
John Ahearn, Commissioner

APPEARANCES: Robert K. Corbin, The Attorney General, by Thomas P.Prose, Assistant Attorney General, on behalf of the Arizona Corporation Commission

Snell & Wilmer, by Steven M. Wheeler, on behalf of Arizona Public Service Company

Carmichael, McClue & Powell, by Donald W. Powell, on behalf of the Homebuilders Association of Central Arizona

John Michael Morris, on his own behalf

Godfrey J. Danielson, on his own behalf

William Eden, on his own behalf

The purpose of the above proceeding was to consider the advisability of adopting a non-timed energy-capacity rate, known as the EC-1 Rate, for certain types of residential service. APS initially filed a proposed EC-1 rate on August 29, 1977 in Phase II of its 1977 rate case. By Decision No. 49060, dated June 9, 1978, the Commission deferred implementation of the EC-1 rate in order that further consideration might be given data obtained from certain load research activities being conducted by APS. By the aforesaid decision the Commission also created an "Advisory Committee on APS Time of Use Rate Design" and among other things referred the EC-1 rate to the committee for further study. Subsequently, the Advisory Committee proposed that the Commission approve the EC-1 rate structure. By notice of hearing in the above docket, Decision No. 51239, dated August 5, 1980, the Commission decided to reopen its consideration of the appropriateness of the EC-1 rate pursuant to A.R.S. § 40-252. Accordingly, a hearing was held on this proceeding on September 4, 1980, before the above named hearing officer and the full Commission. At the hearing the Company presented two witnesses and considerable evidence regarding design, implementation and effect of the EC-1 rate concept. The record in this hearing also consists of eighteen exhibits and official notice was taken of that part of the APS 1978 rate case which dealt with EC-1 rate. No evidence in opposition to the implementation of the EC-1 rate was introduced. However, the Home Builders Association of Central Arizona has indicated its opposition to mandatory load control devices on new construction.

FINDINGS OF FACT

1. The APS residential electric rate structure has historically been based primarily on the consumption of each customer. Such a rate structure ignores the fact that the cost of providing electric service is increasingly a function the demand for electricity places on the system rather than total power consumed. Commercial and industrial rates charged by APS have long recognized this fact and it is now appropriate that residential rate design should similarly reflect the primary components of cost of service. The

energy capacity rate (EC-1) as proposed by APS divides residential rates into three cost of service components: (1) a basic service charge, (2) a capacity charge based on the average KW rate supplied during the 60 minutes of maximum use during the month, and (3) an energy charge associated with the total number of kilowatt hours consumed during the month.

2. As proposed by APS, the EC-1 rate would be required for all new residential customers with central refrigerated air conditioning and optional for existing residential customers with central refrigerated air conditioning. APS further proposes that the special demand meter which is necessary for implementation of the EC-1 rate be installed and owned by the utility. The present cost of such a meter is approximately $100. Approximately 60% to 65% of the existing APS customers and 85% of the new customers are equipped with central air conditioning.

3. The three part EC-1 energy-demand rate concept provides an incentive to customers to manage their electric load in a manner that can result in lower electric bills for the individual customers and, equally important a reduction in APS peak demand which can have the effect of reducing the need for expensive additional generating facilities.

4. Without considering the demand modifications which the customers may make as a result of the load management incentive of the EC-1 rate, a composite study of the all electric and dual energy groups indicated a 50% division of increased and decreased electric bills. (Exhibit A-16) However, the installation of load management devices will increase the savings in electric bills to individual APS customers with all electric or dual energy systems.

Testimony indicated that such load control devices are presently available in varying degrees of sophistication. Exhibit A-11 indicates that the customer load control options vary in price with multiple circuit controllers, the most expensive ranging from $300 to $470, depending on the manufacturer. This price includes costs of installation presently estimated to be $150. Single circuit devices as indicated by Exhibit II can be purchased for nominal sums. As the market for such devices increases, it is anticipated that the cost will decrease.

5. The savings to an APS all electric customer could approximate as much as $200 per year with the addition of the multiple circuit controller on his residential electric service which presently would involve approximately $400 investment. Savings for other electric customers and the pay back periods for load control devices installed will vary depending on the type of load control device and the individual customer's load pattern. Thomas D. Morron of APS testified that the demand reduction of a dual energy customer with a load control device is going to approximate one-third of that of an all electric customer. APS proposed that the cost of the load management devices should be assumed by the individual residential customer. APS presently is studying financing proposals for financing this proposed customer cost.

6. The load management concept is one method by which both APS and its customers can combat the rising cost of electricity through reductions in the massive seasonal peak system demands and through the improvement of system load factor. The implementation of the EC-1 rate will help achieve this goal by rewarding the consumer for his contribution to capacity reductions on the APS

system. The adoption of the EC-1 rate will assist in meeting the company's objective of achieving the most efficient use of existing plant facilities while reducing the future need for costly expansion programs. Some APS customers will benefit by having the opportunity to reduce their electric bills by taking advantage of a rate design which rewards load management action.

7. To properly implement, promote and market the EC-1 rate, sufficient lead time must be available to APS, equipment manufacturers, home builders and customers. APS stated that for the EC-1 rate to be implemented by June 1, 1981, a Commission Order approving the EC-1 rate concept must be approved prior to November 1, 1980 and the actual EC-1 rate should be determined by March 1, 1981.

CONCLUSIONS OF LAW

1. Pursuant to A.R.S. § 40-252 the Commission has authority to alter or amend any order or decision made by it.

2. The EC-1 rate concept as approved herein is just, reasonable and otherwise in the public interest.

ORDER

WHEREFORE IT IS ORDERED: That the non-timed energy/demand rate concept described herein as EC-1 and required for all new homes with central electric refrigeration is hereby approved.

IT IS FURTHER ORDERED: That Arizona Public Service Company shall install non-timed energy/demand meters on new homes with central electric refrigeration on and after April 1, 1981.

IT IS FURTHER ORDERED: That the company shall give similar accounting treatment to those meters necessary to the implementation of the EC-1 rate as that utilized for current residential meters.

. . .

IT IS FURTHER ORDERED: That load control devices located on the customers side of the meter shall not be the responsibility of the company.

IT IS FURTHER ORDERED: That Arizona Public Service Company shall file appropriate tariff sheets with the Commission implementing the EC-1 rate, effective for usage on and after May 1, 1981, or as soon thereafter as the Commission may order, at such rate levels as shall be determined by the Commission in Phase II of the Company's present rate case.

IT IS FURTHER ORDERED: That Decision No. 49060 is hereby amended in accordance with this Order.

BY ORDER OF THE ARIZONA CORPORATION COMMISSION

Chairman	Commissioner	Commissioner

IN WITNESS WHEREOF, I, G.C. ANDERSON, JR., Executive Secretary, of the Arizona Corporation Commission, have hereunto set my hand and caused the official seal of this Commission to be affixed at the Capitol, in the City of Phoenix, this 21st day of October, 1980.

G. C. ANDERSON, JR.
Executive Secretary

Exhibit BK-5

ACC Decision No. 53615 (June 27, 1983)

wrg/jg

BEFORE THE ARIZONA CORPORATION COMMISSION

DIANE B. McCARTHY
Chairman
BUD TIMS
Commissioner
RICHARD KIMBALL
Commissioner

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATE MAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, AND THEREAFTER, TO DEVELOP SUCH RETURN, AND, IN CONNECTION THEREWITH, TO DETERMINE WHETHER THE INTERIM RATE INCREASE EFFECTIVE ON FEBRUARY 4, 1981 PURSUANT TO COMMISSION ORDER 51753 SHOULD BE MADE PERMANENT. (PHASE II - 1981)	DOCKET NO. U-1345-81-150 DECISION NO. 53615 OPINION AND ORDER

DATE OF HEARING: October 25, 1982 to October 29, 1982 incl.

PLACE OF HEARING: Phoenix, Arizona

IN ATTENDANCE: Bud Tims, Chairman
Jim Weeks, Commissioner
Diane McCarthy, Commissioner

PRESIDING OFFICER: Wm. R. Giese

APPEARANCES:

Snell & Wilmer, by Steven M. Wheeler, and Robert A. Schwartz, Arizona Public Service Company Legal Department, on behalf of Arizona Public Service Company

Robert K. Corbin, The Attorney General, by Lynwood J. Evans and James M. Flenner, Assistant Attorneys General, on behalf of Arizona Corporation Commission Staff

Martinez & Curtis, by Michael A. Curtis and William P. Sullivan, on behalf of Arizona Cotton Growers' Association

Campana & Horne, P.C., by Thomas C. Horne and Martha Kaplan, on behalf of Arizona Energy Users Association, Arizona Association of Industries, Arizona Hotel and Motel Association and Arizona Hospital Association

John C. Hall, in propria persona

John Michael Morris, in propria persona

Ralph W. Vaughn, in propria persona

Peter Q. Nyce, Jr., Regulatory Law Office, and Capt. Maurice A. Bergeron, on behalf of U. S. Department of Defense

Andy Baumert, City Attorney, by Ben P. Marshall, Assistant City Attorney, on behalf of the City of Phoenix

John F. Mills, Attorney at Law, on behalf of Magma Copper Company

Charles D. Wahl, Attorney at Law, on behalf of Sun City Taxpayers' Association, Inc.

Fennemore, Craig, von Ammon, Udall & Powers, by Scot Butler, III, on behalf of Arizona Multihousing Association and Arizona Chamber of Commerce

Gust, Rosenfeld, Divelbess & Henderson, by James M. Koontz, on behalf of Arizona Retailers Association

Grace Frei, in propria persona

INTRODUCTION

The instant proceeding concerned Phase II of the 1981 rate case of Arizona Public Service Company (APS). Phase I established a fair value rate base, a fair rate of return, and the appropriate revenue levels for APS pursuant to Commission Decision No. 52558, issued October 29, 1981. In Decision No. 52558, the Commission approved a $78.9 million settlement of APS's May 1, 1981, request for an increase in both electric and natural gas rates. The approved 10.4% electric rate increase and 6.9% overall gas increase became effective November 1, 1981. The Commission also made permanent a $79.5 million, 14% interim electric rate increase granted in Decision No. 51753, February 4, 1981.

The purpose of this Phase II proceeding is to: (1) allocate the authorized revenue levels among the various customer classes; (2) design and implement appropriate rate schedules by customer class which will permit APS to earn its authorized revenues; (3) consider certain additional, non-rate design issues. Pursuant to Commission Decision No. 52666, entered December 14, 1981, the issue of gas rate design was not re-litigated in this current Phase II proceeding.

. . .

. . .

ALLOCATION OF REVENUE REQUIREMENTS

In the instant proceeding, the issue which has created the greatest disagreement among the parties, is the allocation of the total revenue increase, as provided in Decision No. 52593, among the various customer classes. The differences concerning the correct allocation of revenue requirements among customer classes primarily concern the weight to be given cost of service studies and the manner in which they should be conducted. APS submitted three cost of service studies, two of which were based on embedded cost and the third study based upon marginal cost. EBASCO, the staff consultants, presented evidence examining the APS cost of service studies and its own cost of service study which was also based upon embedded cost, using the 4 CP method. With the exception of staff and the intervenor, Arizona Cotton Growers Association, all parties chose to rely upon the APS cost of service study.

All of the allocation of revenue recommendations of APS are based solely upon its embedded cost study set forth in schedules GE-1 & 3 which allocates cost on the basis of the four months coincident peak (4 CP) demand allocation methodology. The APS proposed class revenue allocation is fully set forth in Exhibit A-11. The indicated revenue allocation increases the revenue requirement for residential class by 2.03% and the irrigation class by 1.47%, while decreasing the revenue requirement for the general service class (commercial/industrial) by 1.85%, compared to current rates.

The APS class revenue allocation was developed by a comprehensive process involving consideration of the APS embedded cost and marginal cost of service studies, with due consideration being given to the well accepted Bonbright principles of rate making (See, Bonbright, James C., Principles of Public Utility Rates. New York: Columbia University Press, 1961). While APS regards cost of service as the most important factor to be taken into account on rate design, it also properly considered additional factors of a non-cost nature such as continuity, equity, comprehensibility and revenue stability. (Tr. Vol. II, p. 161-165, 183-186, 223-226) The process for revenue allocation used by APS in this proceeding is consistent and in harmony with this Commission's adoption of the PURPA cost of service standard, in Decision No. 52593. That Decision provided that cost of service was not to be the sole consideration of rate design and that other relevant factors could also be considered. (Id. p. 5 & 6) For the Commission to allow the allocation of revenue requirements and ultimately rate design, upon strict cost of service would deprive it of its authority and discretion to use all available methods in the development of just and reasonable rates.

The historical indices of return for the various customer classes of APS indicate a trend in the direction of a more uniform return for each customer class. As this movement has historically taken place in a gradual manner, the adoption of the APS proposals will continue that historical movement within a reasonable range or "band of tolerance." This "band of tolerance" takes into consideration the inexactitudes of cost of service studies and allows for due consideration of such non-cost factors as continuity, equity, comprehensibility, rate and revenue stability. The combination of the total APS rate design package including increased residential revenue requirement responsibility, greater seasonal residential differential and the continuation of the demand price signal, results in a continuing movement towards a reasonable range of revenue indices.

RATE DESIGN

RESIDENTIAL RATES

The major residential rate of APS has been and continues to be, its E-10 rate schedule. During the 1981 test year, 99.79% of APS's residential customers and energy sales were billed under that rate schedule. The balance of APS's sales in the residential class were under three frozen rates, one experimental, and less than one hundred customers on APS's EC-1 rate for the last two months of the test year. (Exh. A-8, p. 20)

As the present basic combination of the E-10, EC-1, ECT-1 and ET-1 rates provide a wide practical range of choices to accommodate various customer consumption characteristics, APS proposes continuation of these basic rate choices. However, APS proposes a major modification to the E-10 rate and only minor changes to the EC-1, ECT-1 and ET-1 rates. Additionally, APS, Arizona Multihousing Association and Staff have proposed a new optional rate schedule, called the ECL-1 rate, for low volume residential users with central air conditioning. All of these changes and additions to the existing basic rate choices are more fully discussed hereinafter.

E-10 RATE

The APS proposed E-10 rate is set forth on Exhibit A-23. It consists of a basic service charge, unchanged from the last rate case, for all 12 months of $10.56, plus a commodity rate which varies depending upon the season and level of usage. The major modification of this rate involves changing the block rate structure for both the winter and summer rates. The present winter rate has a declining block which commences at the 1500 kWh level. APS would eliminate this block and bill all consumption during the winter on the E-10 rate at a flat rate per kWh. The revenue reduction resulting from this change has been transferred to the summer period for recovery. This seasonal revenue transfer will better reflect the very significant seasonal cost differences between those two periods (Exh. A-8, p. 22).

For the summer portion of the E-10 rate, APS proposes to leave unchanged the inverted block rate structure. The rate for the first consumption block (first 400 kWh) also remains unchanged. However, APS has proposed to invert the second rate block, which is the next 400 kWh. Under the present rate the 401st kWh costs $3.66 which results from all consumption being billed at 6.306¢/kWh when use is over 400 kWh. By inverting the second rate block the abrupt bill change occurring under the present rate design at 401 kWh would be avoided. (Exh. A-8, p. 22) APS has further proposed to increase the rate for the third and final block. The overall impact on summer bills would therefore be zero for all consumption up to 400 kWh, a decrease for bills between 400 kWh and 578 kWh, and increases for all consumption above that level. This will result in bill increases for high-volume, residential customers of approximately 8.08%. However, the overall annual increase for all E-10 customers is approximately 2% (Exh. A-8, p.23 & 24, Sch. HE-2, p. 1).

The resulting revenue shifts from winter to summer and from lower to higher consumption customers is justified by cost of service studies conducted by APS. These studies have shown that consumers who never exceeded 600 to 700 kWh in any month during the summer period had lower average costs than those whose use exceeded that amount. The reduction in the winter rate reduces the overall burden on the lower-user group since that group uses relatively greater amounts during the winter. (Exh. A-8, p. 23 & 24)

EC-1 RATE

The EC-1 rate is an energy-capacity rate having a separate price for the three major cost components of customer, demand and energy. The application of the EC-1 rate is limited to service locations with electric central air conditioning and which were first connected to the APS system after May 1, 1981. This rate approximates a time of day rate but with much lower metering and administrative costs. At the time of the instant hearing, there were approximately 8,000 customers on that rate making it the second largest residential rate as to the number of customers and sales. (Exh. A-8, p. 25) The EC-1 rate is designed to track the E-10 rate for each season (not monthly) for central air conditioning customers with average usage characteristics. Therefore, a change was required to reflect changes in the E-10 rate. The rate was also modified to reflect the actual experience of APS with the rate during the winter period from November 1981 through April 1982. This second modification has caused APS to propose an absolute limit to bills under the winter EC-1 rate of not more than 3.256¢/kWh. Imposing this limit recognizes that individual loads at low load factors tend to have a lower coincident demand, thus creating proportionately less demand on the system than those with normal and higher load factors. Such a ceiling, which is also applicable to the summer EC-1 rate also insures that there is a reasonable limit to the potential increases, as compared to E-10, that are experienced by the customers. (Exh. A-8, p. 27 to 30)

The summer rate portion of the EC-1 rate continues to track the E-10 rate. Modifications have been made to the rate level, but not to the rate form, because available data for the 1981 summer indicates that the EC-1 rate did track the E-10 rate quite well in terms of revenue equivalency. (Exh.A-8, p. 30)

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ECT-1 AND ET-1 RATE

Both the ECT-1 and ET-1 rate are optional for residential customers of APS and each are limited to 1,000 customers. At the time of the instant hearing, ECT-1 had approximately 60 customers and the ET-1 approximately 120. The ECT-1 rate charges for demand (or capacity) and for energy by daytime and nighttime use. It is a seasonal time of day rate that has a separate charge for the three major cost components of customer, demand and energy. This rate should be generally favorable to customers who can control their day-time demand and take overt action to use energy at night. The lack of a demand charge for nighttime use (except when night demands exceed day demands) makes this rate attractive to EC-1 customers whose life style requires major appliances to be used at night rather than during the day. The ET-1 rate also charges separately for energy during the day and night period. It does not have a charge for measured killowatts of demand. Since these rates have only been effective since January 1, 1982, both should be continued pending further definitive results.

ECL-1

During the instant hearing an agreement was reached by APS, Ariz. Multihousing Association and the staff with regard to the development of a new rate for small use residential customers who have central air conditioning. This rate is in response to complaints that the mandatory nature of the EC-1 rate produced unfair results for low volume users. The rate design will alleviate the necessity for investment by low consumption customers in load control devices to mitigate what would otherwise be significant rate impacts under the EC-1 rate. (Tr. IV & V, p. 710, 735 & 736) The ECL-1 rate is described fully in Exhibit A-23 and is consistent with the agreement reached by the parties as outlined in Exhibit S-22(a). This rate schedule would be available to new residential electric customers with central refrigerated air conditioning, and to any reconnections where the immediately previous service was billed under the E-10 or E-207 rate. The winter portion of this rate is identical to the E-10 rate proposed by APS. The summer ECL-1 rate is also equal to the E-10 proposed rate by APS for the first two blocks, i. e., up to the first 800 kWh.

The rate in excess of 800 kWh is higher than the E-10 rate and is designed to track revenue generated from the summer EC-1 rate for similar consumption levels above 800 kWh. This will result in an equal set of energy and demand rates for air conditioning customers. The adoption of the ECL-1 rate will not affect the allocation of revenue requirements among the various customer classes.

RESIDENTIAL RATE SUMMARY

The Commission adopts the modifications to the E-10 and EC-1 rates and the creation of the ECL-1 rate as proposed by APS as described in Exhibit A-23. Upon adoption of this Order the following rates shall be available to the customers of APS:

Type of Customer	Available Rates
Existing residential customer as of May 1, 1981, with central air conditioning	E-10, EC-1, ECL-1, ECT-1, or ET-1
New residential customer after 1981 with central air conditioning	EC-1, ECL-1, ECT-1, or ET-1
Reconnection of existing residences with central air conditioning (previously on E-10 or E-207 rate)	EC-1, ECL-1, ECT-1, or ET-1
New or existing residential customers without central air conditioning	E-10

LARGE AND EXTRA LARGE GENERAL SERVICE RATES - E-32 & E-34

The Commission adopts the proposal of APS for the creation of new two primary rates for the general service class E-32 and E-34 and the cancellation of existing rate schedules E-32-1, E-32-2, E-33, E-46, and its contract ("Magma") rate. The new E-32 rate contains several significant changes from previous general rate schedules, all of which are designed to more accurately track cost incurrence and to send appropriate price signals to APS customers. The E-34 rate divides the large general service class into two sections for rate making purposes. It distinguishes between those customers whose maximum demand was 3,000 kW or greater and those with less than 3,000 kW but with at least 1,000 kW demand. The proposed E-34 rate schedule is a straight forward three part, customer, demand and energy rate with a five month seasonal 80% rachet. (Exh. A-8, p. 12) The individual components of the rate are based on the APS cost of service schedule and its revenue index limit. Approximately one-third of the demand costs are recovered in the energy component of the rate in order to recognize the coincidence and load factor characteristics of the customers.

The average decrease projected for the general service class as the result of these proposed rates is approximately 1.9%. However, individual bills may be increased or decreased depending upon size and load factor. Extra large customers (E-34 rate) will have annual bill changes ranging from an 8% increase to an 8% decrease. The frozen service rates of APS (E-120, E-126, E-220, E-251, E-49 and E-57) will be initially increased approximately 10% and will have annual automatic 10% increases until such time as they no longer serve any customers.

TIME OF DAY RATE FOR EXTRA LARGE GENERAL SERVICE CLASS

APS designed but did not recommend, a mandatory time of day rate for those customers qualifying for the E-34 rate schedule. This time of day rate is referred to as ECT-2 and is fully set forth in Exhibit A-18. APS presented the ECT-2 rate as an alternative to the E-34 rate and not optional as proposed by staff. APS originally based its objections to an optional ECT-2 rate on the basis that the Company would be exposed to the definite possibility of revenue erosion and earnings instability. These objections can be overcome by the adoption of an adjustment clause similar to the present fuel adjustment clause of APS. In the long term, an optional industrial time of day rate would allow APS to more efficiently utilize its generating facilities. This will be accomplished by encouraging existing industrial customers to shift demand during the peak period to the off peak period. Furthermore, new customers would be encouraged to design their production facilities so as not to impose a demand at the time of the summer system peak. The Commission is of the opinion that revenue erosion resulting from the adoption of an optional ECT-2 rate can also be minimized by initially limiting its availability to three customers as recommended by staff. (S-13, p. 28 & 29) With the above conditions, the Commission approves the optional ECT-2 rate as provided in Exh. A-18.

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IRRIGATION RATES

The evidence supports adoption of the irrigation rate design E-38 & E-143 presented by APS. Exhibit A-21 indicates that adoption of the APS rate design proposal for irrigation class results in an average increase of approximately 1.5%. However, individual customers may experience different increases, or decreases, depending on their size, load factor, and seasonal use pattern. APS has recommended seasonal rates for the irrigation class based on the summer season of June through October. As a result, a higher energy charge will be effective for the summer months over that charged during the winter months. For consistency and other reasons more fully set forth in the record, the irrigation rates should be priced on a seasonal basis identical to the residential class. Consequently, a summer season of May through October should be utilized. (S-13, p. 36) Due to the similarity of the E-38 and E-143 rates both should be consolidated into one rate.

MISCELLANEOUS RATE CLASSES

APS has made only minor modifications to its street lighting and other public authority rates. (Exh. A-8, p. 34 & 35) These changes were not contested by the other parties and their adoption appears to be just and reasonable.

APS in making its determination of the revenue requirement of the lighting class used an "addendum approach." The use of this approach consists of determining the revenue requirement of the lighting as if it were a separate investment from the rest of APS. (Exh. S-13, p.39) The treatment of the lighting class in this manner ignores the fact that the lighting system is electrically intregated with the distribution system. As a result, in determining the revenue requirement for the lighting class, APS failed to include the recovery of any administrative and general expenses (other than employee benefits) as well as the cost of general plant which is normally allocated to a customer class. The Commission directs that in future Phase II proceedings, APS as a revenue requirement, alternative, use the same methodology as other classes, with such adjustments considered necessary because of the off peak use by the lighting class. It is further recommended that APS in the future submit lighting rates not based upon a uniform percent increase but based upon a methodology that reflects the unit investment for each lamp. (Exh. S-13, p.42)

APS PURCHASED POWER AND FUEL ADJUSTMENT CLAUSE

In Decision No. 52593, which was the result of the last APS Phase II hearing, the Commission deferred a general ruling regarding modification of the purchased power fuel adjustment clause, as it relates to non-jurisdictional layoff sales of power. In this proceeding, APS has again proposed to reduce the fuel expenses appearing in the purchased power and fuel adjustment clause for sales to non-jurisdictional customers made from specific generating units or plants. Previously, APS was authorized by Decision No. 52593 to use this particular treatment with respect to a specific layoff sale it made to Utah Power & Light Company from the Cholla Unit No. 4 plant. The Commission is of the opinion that this treatment should now be extended to all non-jurisdictional layoff sales of power by APS, and it is hereby approved.

Under the present application of the fuel adjustment clause, APS either over or under recovers its fuel costs whenever it makes sales at rates that are tied to specific plants or generating units. The adoption of this change in the PPF adjustment clause will allow APS to recover all of the allowable fuel expenses. Without this change, the resulting under or over collection of total fuel expenses, operates to defeat the purpose of the PPF adjustment clause. (Exh. S-13, p.42 to 45 & A-8, p.35 to 40)

The recommendation of staff to roll the current fuel adjustment into the current base rates is also approved. The result will be the avoidance of the cost of an additional hearing for the sole purpose of increasing the amount of base fuel collected in the fuel adjustment clause and is consistent with Decision No. 53256 which rolled fuel costs into base rates for APS as of December 1982.

The foregoing statements constitute the Findings of Fact and Conclusions of Law of this Commission.

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ACCORDINGLY, IT IS ORDERED:

1. On or before July 1, 1983, Arizona Public Service Company shall file with this Commission additions, cancellations and/or amendments to its existing tariffs including the revised EC-1 and the ECL-1 rates, which are consistent with the Findings, Conclusions and directives set forth herein.

2. With respect to any revenue shift to the residential class the proposed APS rate design shall be modified to allocate the revenue deficiency across all residential rates consistent with the other rate designs as initially proposed by APS.

3. The rates, charges and tariff provisions established herein shall become effective on November 1, 1983, except as otherwise provided below.

4. The ECL-1 residential rates shall be available, as of July 1, 1983 usage, on an optional basis as an alternative to E-10 or EC-1 for new residential customers, residential reconnects and existing residential customers, with central air conditioning. As of November 1, 1983, the ECL-1 rate shall become mandatory (except as to alternative EC-1) for new residential customers and residential customer reconnects, with central air conditioning.

5. All other rates and charges as proposed by APS, not specifically otherwise addressed in this Order, are hereby approved.

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6. APS shall file with the Utilities Division within thirty (30) days after the date of this Order detailed information on its proposed program to inform its customers of the new rate designs approved herein prior to their mandatory effective date.

7. This Order shall become effective immediately.

BY ORDER OF THE ARIZONA CORPORATION COMMISSION.

CHAIRMAN COMMISSIONER COMMISSIONER

IN WITNESS WHEREOF, I, THOMAS MUMAW, Acting Executive Secretary of the Arizona Corporation Commission, have hereunto set my hand and caused the official seal of this Commission to be affixed at the Capitol, in the City of Phoenix, this 27th day of June, 1983.

Thomas Mumaw

THOMAS MUMAW
Acting Executive Secretary

Exhibit BK-6

ACC Decision No. 52593 (Nov. 9, 1981)

BEFORE THE ARIZONA CORPORATION COMMISSION

BUD TIMS
Chairman
JIM WEEKS
Commissioner
DIANE McCARTHY
Commissioner

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATE-MAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, AND THEREAFTER TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN. (PHASE II)

DOCKET NO. U-1345

DECISION NO. 52593

dmk

DATES OF HEARING: January 12-23, 1981

PLACE OF HEARING: Phoenix, Arizona

HEARING OFFICER: Andrew W. Bettwy

APPEARANCES:

SNELL & WILMER, by JARON B. NORBERG and STEVEN M. WHEELER, Attorneys for Arizona Public Service Company;

ROBERT K. CORBIN, The Attorney General, by CHARLES S. PIERSON, Assistant Attorney General, on behalf of the Arizona Corporation Commission Staff;

BILBY, SHOENHAIR, WARNOCK & DOLPH, by DWIGHT M. WHITLEY, JR., Attorneys for ASARCO, Inc.;

PAUL W. PHILLIPS and LAWRENCE A. GOLLOMP, Assistant General Counsel, Attorneys for the Department of Energy;

BRUCE E. MEYERSON, Arizona Center for Law in the Public Interest, Attorney for Arizona Community Action Association (ACAA), and Danny Valenzuela;

PETER Q. NYCE, JR., General Attorney, Regulatory Law Office, U.S. Army Legal Services Agency, Attorney for the Department of Defense;

MILLER, PITT & FELDMAN, by HENRY M. HUFFORD, Attorneys for Arizona Retailers Association;

NEISSER, CAMPANA & HORNE, by THOMAS C. HORNE, Attorneys for Arizona Association of Industries and Arizona Energy Users Association;

CARMICHAEL, McCLUE & POWELL by DONALD W. POWELL, Attorneys for Homebuilders Association of Central Arizona;

TWITTY, SIEVWRIGHT & MILLS, by JOHN F. MILLS, Attorneys for Magma Copper Company;

MARTINEZ, CURTIS, GOODWIN & KARASEK, by MICHAEL A. CURTIS, Attorneys for the Arizona Cotton Growers Association;

JENNINGS, STROUSS & SALMON, by THOMAS J. TRIMBLE, Attorneys for Turf Paradise, Inc.;

J. MICHAEL MORRIS, on his own behalf;

RALPH W. VAUGHN, on his own behalf;

GODFREY J. DANIELSON, on his own behalf;

RAYMOND RUGGE, on his own behalf;

ROLAND JAMES, on his own behalf.

Addressed during Phase II have been issues related to (1) consideration of the six rate design standards embodied in the Public Utility Regulatory Policies Act of 1978 (PURPA), (2) allocation of responsibility for Arizona Public Service Company's revenue requirements among the various classes of APS' customers and (3) design of rate schedules.

PURPA STANDARDS

PURPA, which became effective in November of 1978, mandates consideration by this Commission of six rate design standards and, further, a determination by this Commission of whether or not adoption of any or all of the standards is appropriate for the APS System to further the requirements of Arizona's law and the following goals of PURPA:

.....

1. Conservation of energy supplied by electric utilities;

2. The optimization of the efficiency of use of facilites and resources by electric utilities; and

3. Equitable rates to electric consumers.
16 U.S.C. § 2611.

PURPA § 111 (i.e., 16 U.S.C. § 2621(d)) sets forth the six rate design standards as follows:

> (1) Cost of service.--Rates charged by any electric utility for providing electric service to each class of electric consumers shall be designed, to the maximum extent practicable, to reflect the costs of providing electric service to such class, as determined under section 2625 (a) of this title.
>
> (2) Declining block rates.--The energy component of a rate, or the amount attributable to the energy component in a rate, charged by any electric utility for providing electric service during any period to any class of electric consumers may not decrease as kilowatt-hour consumption by such class increases during such period except to the extent that such utility demonstrates that the costs to such utility of providing electric service to such class, which costs are attributable to such energy component, decrease as such consumption increases during such period.
>
> (3) Time-of-day rates.--The rates charged by any electric utility for providing electric service to each class of electric consumers shall be on a time-of-day basis which reflects the costs of providing electric service to such class of electric consumers at different times of the day unless such rates are not cost-effective with respect to such class, as determined under section 2625(b) of this title.
>
> (4) Seasonal rates.--The rates charged by an electric utility for providing electric service to each class of electric consumers shall be on a seasonal basis which reflects the costs of providing service to such class of consumers at different seasons of the year to the extent that such costs vary seasonally for such utility.

(5) Interruptible rates.--Each electric utility shall offer each industrial and commercial electric consumer an interruptible rate which reflects the cost of providing interruptible service to the class of which such consumer is a member.

(6) Load management techniques.--Each electric utility shall offer to its electric consumers such load management techniques as the State regulatory authority (or the nonregulated electric utility) has determined will--

(A) be practicable and cost-effective, as determined under section 2625(c) of this title,

(B) be reliable, and

(C) provide useful energy or capacity management advantages to the electric utility.

Our stated responsibility in this proceeding is established as follows in PURPA § 111(a):

(a) Consideration and determination.--Each State regulatory authority (with respect to each electric utility for which it has ratemaking authority) and each nonregulated electric utility shall consider each standard established by subsection (d) of this section and made a determination concerning whether or not it is appropriate to implement such standard to carry out the purposes of this chapter. For purposes of such consideration and determination in accordance with subsections (b) and (c) of this section, and for purposes of any review of such consideration and determination in any court in accordance with section 2633 of this title, the purposes of this chapter supplement otherwise applicable State law. Nothing in this subsection prohibits any State regulatory authority or nonregulated electric utility from making any determination that it is not appropriate to implement any such standard, pursuant to its authority under otherwise applicable State law.

16 U.S.C. § 261(a) (emphasis added).

. . . . .

We are confident that the six rate design standards enunciated in PURPA have been addressed exhaustively by the parties to this proceeding and, accordingly, we are satisfied that this Commission has been furnished with data, testimony and argument sufficient to make informed determinations regarding the appropriateness of adopting any or all of the six rate design standards for the APS system.

Subject to the qualifications expressed hereinafter, we hereby find and determine that, with respect to each of the six rate design standards promulgated by The Congress, its adoption for the APS system would promote one or more of the PURPA-stated goals and, accordingly, we conclude that adoption and implementation of all of the six rate design standards for the APS system would be appropriate.

Our adoption and implementation of the PURPA standards shall not in any manner supersede state law, restrict the lawful discretion of this Commission or prevent us from considering such other relevant factors such as but not limited to continuity, equity, comprehensibility and revenue stability as we may deem appropriate in the establishment of just and reasonable rates.

COST OF SERVICE

Our adoption of the Cost of Service standard is qualified by our declaration that neither the adoption nor implementation of such standard requires a design of rates for the APS system which is based solely on the cost of furnishing electricity. Among other well-established principles of rate-making, we intend to continue to be sensitive to the desirability of rate stability and the potential impacts of abrupt changes in rate design which may affect adversely APS existing customers.

Further, we do not intend by our adoption of the Cost of Service standard to endorse any particular costing methodology; in that regard, we intend to maintain for all affected interests and this Commission the continued freedom to employ a marginal cost of service study or an embedded cost of service study or any other methodology or combination thereof. Consistent with that objective, and to assure meaningful assessments in future rate proceedings of available costing methodologies, APS is hereby directed to include both a marginal cost of service study and an embedded cost of service study in its rate design filings in future rate proceedings.

In connection with our decision to adopt the Cost of Service standard, we are mindful and supportive of our Staff's recommendation that implementation be a cautious and gradual process.

DECLINING BLOCK RATES

We hereby express our intention to effect the eventual elimination of declining block rates for the APS system, except to the extent APS demonstrates to the satisfaction of this Commission in any particular instance that the energy-related costs to APS of providing electricity decreases as consumption increases. Our rate of progress in achieving that objective will be dependent upon reasonable application of principles of stability and continuity of rates.

.....

.....

TIME-OF-DAY RATES

As a general proposition, time-of-day rates trigger an accurate price signal to the consumer of electricity. Moreover, applied specifically to the APS system, we are persuaded that properly established time-of-day rates would encourage optimization of the efficiency and utilization of APS' facilities and resources. Accordingly, we hereby express our intention to authorize and encourage the implementation of time-of-day rates which are cost-effective (i.e., whenever the long-run benefits of such rate to APS and its affected consumers are likely to exceed the metering costs and other costs associated with the employment of such rates).

SEASONAL RATES

Since rates in APS' territory have reflected seasonality for several years, and since the evidence submitted by parties to this proceeding suggests that costs do vary substantially by season, we conclude that adoption of the seasonal rates standard is appropriate for the APS system. By our adoption of the seasonal rates standard, we do not endorse specifically any particular seasonal rate or rate design among those proposed by the parties to this proceeding; however, we do intend to assure that the existence of cost differentials by season generally be reflected in rate design, as historically has been the case with respect to APS' rates.

INTERRUPTIBLE RATES

In an effort to minimize peaking problems on the APS system and to appropriately recognize those commercial and industrial users which are willing to tolerate interruption during peak periods, we conclude that adoption of the interruptible rates standard is appropriate for the APS system. The record discloses that APS has had limited success in its effort to make available interruptible rates to commercial and industrial customers on a voluntary basis. With the objective of improving that success record, APS is hereby directed to survey its industrial and commercial customers and to report to this Commission within 18 months after the effective date of this Decision regarding the viability of a voluntary interruptible rates program. The written report shall detail the costs of providing such service, the categories of customers which would benefit by such rates, the proposed timing and duration of interruptions, potential problems associated with participation by various categories of customers and any other information which would assist this Commission in its evaluation of the practicability of an effective voluntary interruptible rates program.

LOAD MANAGEMENT TECHNIQUES

It would be curious indeed if one were to not readily applaud management techniques which are directed to the reduction of peak demand, assuming the long-run cost savings of such reduction are likely to exceed the long-run costs associated with implementation of such techniques. Our adoption herein of the load management techniques standard reflects our commitment to encourage the implementation by APS of such techniques.

Within 18 months after the effective date of this

Decision, APS shall furnish a written report to this Commission detailing (1) load management options which are available to APS, (2) analyses of the cost effectiveness of the various options and (3) a plan for load management.

NON-PURPA ISSUES

For the reasons detailed hereinafter, we hereby approve (1) APS' proposed ECT-1 rate schedule, which provides optional time-of-day rates for those residential customers who believe their consumption characteristics would warrant being billed on that basis, (2) Staff's proposed ET-1 rate schedule, which provides on alternate time-differentiated rate schedule and (3) to a limited extent, APS' proposed modification to its Purchased Power and Fuel Adjustment Clause to exclude from the calculation of the system average the fuel and related costs for generation units devoted to producing power for layoff sales.

1. Optional Time-of-Day Rates for Residential Customers.

Since the rates included in APS' proposed ECT-1 rate schedule do not include a revenue erosion adjustment and since the expected impacts of time-of-day rates on the APS system for residential customers continues somewhat in the experimental stage, we are in agreement with our staff and APS' suggestion that the rate be limited at this time to 1,000 customers.

Staff has proposed a tariff provision with respect to meters for the ECT-1 rate schedule which we think is appropriate and, accordingly, we adopt staff's proposed provision, which is:

> The cost of metering facilities in excess of the cost of metering for the EC-1 rate

shall be charged to the customer at a rate of $4.50 per month.

As an alternative to APS' proposed ECT-1 rate schedule, we are approving Staff's proposed ET-1 rate schedule. Both rates, of course, are being made available on an optional basis; and each at the present time is being limited to 1,000 customers at the urging of both APS and our Staff. With respect to the meters for the ET-1 rate, APS shall include the following provision in the applicable tariff:

> The cost of metering facilities in excess of the cost of metering for the EC-1 rate shall be charged to the customer at a rate of $2.40 per month.

2. Modification to APS' Purchased Power and Fuel Adjustment Clause.

We are not prepared at this time to decide whether or not it is appropriate, with respect to all non-jurisdictional layoff sales of power, to exclude the associated fuel and related costs from calculation of the system average when utilizing the Purchase Power and Fuel Adjustment Clause.

However, we are satisfied at the present time that such treatment of the layoff sales to Utah Power & Light from the Cholla 4 Plant is justified and appropriate on the basis of the record in this proceeding. Accordingly, we hereby approve such treatment of those sales. However, our treatment herein of such sales is subject to further examination; specifically, we intend to scrutinize such treatment when modification of the adjustment clause is considered next by the Commission.

Insofar as APS' requested modification relates to other layoff sales, a decision on that requested modification is deferred until the next general rate proceeding.

Mandatory Time-of-Day Rates for Extra Large General Service Customers.

The record discloses that the affected extra large customers already have the metering in place to commence implementation of mandatory time-of-day rates. Consistent with our stated commitment hereinabove to encourage the implementation of time-of-use rates that are cost-effective, we are anxious to move forward immediately with implementation of either APS' proposed ECT-2 rate schedule or some acceptable variation thereof; however, we are concerned after our examination of the record that we may not be informed sufficiently regarding the intra class dislocations that could be expected to result and, most particularly, how such dislocations likely may affect adversely any individual customer.

In an effort to avoid any unnecessary delay in the implementation of appropriate, mandatory time-of-day rates for APS' Extra Large General Service Customers, and in an effort to be assured that any action we take in that regard is based on reliable and complete information, APS and the parties representing the customers which would be affected by such rates are requested to submit to this Commission no later than December 1, 1981 specific information regarding expected impacts on individual customers within the Extra Large General Service class. Further, such parties may submit to this Commission on or before December 1, 1981 any additional information or comments pertaining in any manner whatsoever to the proposed implementation of mandatory time-of-day rates.

With respect to the remaining issues, which are related to allocation of APS' revenue requirements among APS' customers and the consequent design of specific rate schedules, we think all affected interests would be served best by a deferral of our treatment of such issues until the upcoming Phase II of the on-going APS general rate proceeding.

Most importantly, to attempt a wholesale realignment of rates at this time, with full knowledge that another comprehensive restructuring of rates reasonably can be expected within the next 6 to 12 months in connection with the most current APS general rate proceeding, would be to cause an unnecessary and unwarranted disruption among all of APS' electric customers.

Considerations of rate stability mandate that we be careful not to impose any more confusion and uncertainty regarding expected rates and charges than is required for our regulatory purposes. Further, and of particular significance, is the fact that our reexamination of APS' rate structure in connection with the most current APS general rate proceeding will be based on more current and more complete information.

The foregoing statements constitute the Findings of Fact and Conclusions of Law of this Commission.

ACCORDINGLY, IT IS ORDERED:

1. No later than December 10, 1981, Arizona Public Service Company shall file with this Commission additions and/or amendments to its existing tariffs which are consistent with the findings, conclusions and directives set forth herein.

2. The gas rate schedules and the associated terms

and conditions which are included in the record as ATTACHMENT C to APS' initial brief, filed June 5, 1981, are hereby adopted.

3. The rates, charges and tariff provisions established herein shall become effective on January 1, 1982.

4. Within the time frames stated, Arizona Public Service Company shall submit to this Commission the reports contemplated hereinabove in connection with our discussions of the PURPA standards pertaining to interruptible rates and load management techniques.

5. Arizona Public Service Company shall take immediate steps which are reasonably calculated to lead to the provision of electric service to residential customers under the new optional time-of-day rate schedules.

BY ORDER OF THE ARIZONA CORPORATION COMMISSION

Bud Tims	Diane B. McCarthy	Jim Weeks
CHAIRMAN	COMMISSIONER	COMMISSIONER

IN WITNESS WHEREOF, I, TIMOTHY A. BARROW, JR., Executive Secretary of the Arizona Corporation Commission, have hereunto set my hand and caused the official seal of the Commission to be affixed at the Capitol in the City of Phoenix, this 9th day of November, 1981.

Timothy A. Barrow
TIMOTHY A. BARROW
Executive Secretary