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Arizona Corporation Commission
DOCKETED

JUN 24 2016

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BEFORE THE ARIZONA CORPORATION COMMISSION

13 DOUG LITTLE - Chairman
14 BOB STUMP
15 BOB BURNS
16 TOM FORESE
17 ANDY TOBIN

18 IN THE MATTER OF THE APPLICATION OF
19 TUCSON ELECTRIC POWER COMPANY FOR
20 THE ESTABLISHMENT OF JUST AND
21 REASONABLE RATES AND CHARGES
22 DESIGNED TO REALIZE A REASONABLE
23 RATE OF RETURN ON THE FAIR VALUE OF
24 THE PROPERTIES OF TUCSON ELECTRIC
25 POWER COMPANY DEVOTED TO ITS
26 OPERATIONS THROUGHOUT THE STATE OF
ARIZONA AND FOR RELATED APPROVALS.

Docket No. E-01933A-15-0239

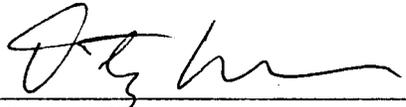
Docket No. E-01933A-15-0322

**NOTICE OF FILING
CONFIDENTIAL WRITTEN
DIRECT TESTIMONY OF
BRIANA KOBOR ON
BEHALF OF VOTE SOLAR**

Vote Solar, through its undersigned counsel, hereby provides notice that it has this day filed the attached CONFIDENTIAL written direct testimony of Briana Kobar. A hard copy of the sealed, confidential portions of Ms. Kobar's testimony have been

1 provided to Judge Rodda and the Commissioners; and the sealed, confidential testimony
2 has been emailed to Tucson Electric Power Company, Staff, and RUCO. A public,
3 redacted version has been docketed and served on the parties to this proceeding.

4
5 DATED this 24th day of June, 2016.

6 By 
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16 ORIGINAL and 13 COPIES of the
17 Foregoing filed this 24th day of June,
18 2016, with:

19 Docketing Supervisor
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26 24th day of June, 2016, to:

All Parties of Record

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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List of Exhibits

Exhibit BK-1:	Statement of Qualifications
Exhibit BK-2:	Distribution of Residential Bill Impacts
Exhibit BK-3:	Discovery Responses Referenced in Testimony
Exhibit BK-4:	ACC Decision No. 51472 (Oct. 21, 1980)
Exhibit BK-5:	ACC Decision No. 53615 (June 27, 1983)
Exhibit BK-6:	ACC Decision No. 52593 (Nov. 9, 1981)

1 Introduction

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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

1 consulting firm. At MRW, I focused on electricity and natural gas markets,
2 ratemaking, utility regulation, and energy policy development. I worked with a
3 variety of clients including energy policy makers, developers, suppliers, and end-
4 users. My clients included the California Public Utilities Commission, the
5 California Energy Commission, the California Independent System Operator, and
6 several publicly-owned utilities. I have experience evaluating utility cost of
7 service studies, revenue allocation and ratemaking, wholesale and retail electric
8 rate forecasting, asset valuation, and financial analyses. A summary of my
9 background and qualifications is attached as Exhibit BK-1.

10 **Q. Have you previously testified before the Arizona Corporation Commission**
11 **(the “Commission”)?**

12 A. Yes. I have provided testimony in Docket No. E-04204A-15-0142, the UNS
13 Electric, Inc. General Rate Case, and Docket No. E-00000J-14-0023, entitled “In
14 the Matter of the Commission’s Investigation of Value and Cost of Distributed
15 Generation.”

16 **Q. Have you previously testified before other regulatory commissions?**

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

25

2 Purpose of Testimony and Summary of Recommendations

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

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

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

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

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

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

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

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

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

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

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

28 I also show that TEP has not adequately assessed how its NEM-specific proposals
29 would impact customers. TEP's reliance on vague and hypothetical data fails to

1 meet its burden of justifying changes to NEM rates under the Commission's rules.
2 In addition, TEP's proposals would likely cause a significant decline in DG
3 adoption rates in its service territory. Yet the Company did not assess how this
4 would impact local employment.

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

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

24 Finally, I examine the fundamental changes occurring in the design and
25 management of electricity distribution systems, and the implications of
26 transforming the grid in a manner where consumers are more active participants. I
27 recommend that the Commission create policies that ensure that the transition to
28 the modern grid can happen in the most efficient manner, maximizing the benefits
29 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).

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

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

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

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

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

14 1. TEP claims that the Company is experiencing declining residential usage per
15 customer.¹²

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

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.

1 3. TEP claims it “is also suffering lost revenues because the LFCR is not
2 designed to capture all of the lost fixed cost revenues associated with meeting the
3 Commission’s Renewable Energy Standard and Energy Efficiency Rules.”¹⁵

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

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

11 **4 TEP Has Not Provided Sufficient Evidence to** 12 **Justify Changing the Rate Structure for NEM** 13 **Customers**

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

16 A. No. While there has indeed been a significant reduction in retail sales, TEP’s rate
17 design proposals focus disproportionately on NEM customers as the cause of the
18 sales decline. As I explain in detail below, my examination of the data reveals
19 that DG is not a significant driver of the reduction in retail sales that TEP has
20 experienced since the last rate case. In fact, 98% of the residential customers that
21 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).

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

3 **4.1 Distributed Generation Is Not a Significant Driver of the**
4 **Reduction in TEP's Retail Sales**

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

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

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

12 A. Yes. Retail sales in the current rate case test year were roughly 3% less than retail
13 sales in the prior test year.²² After inclusion of recently announced mining sector
14 losses, TEP's sales are expected to fall [REDACTED].²³ [REDACTED]

15 [REDACTED]
16 Indeed, the data shows that DG contributed only 100,000 MWh of reductions
17 between test years, which represents [REDACTED] of the total reductions.²⁴

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

²¹ Hutchens Direct Test. at 20:23–25.

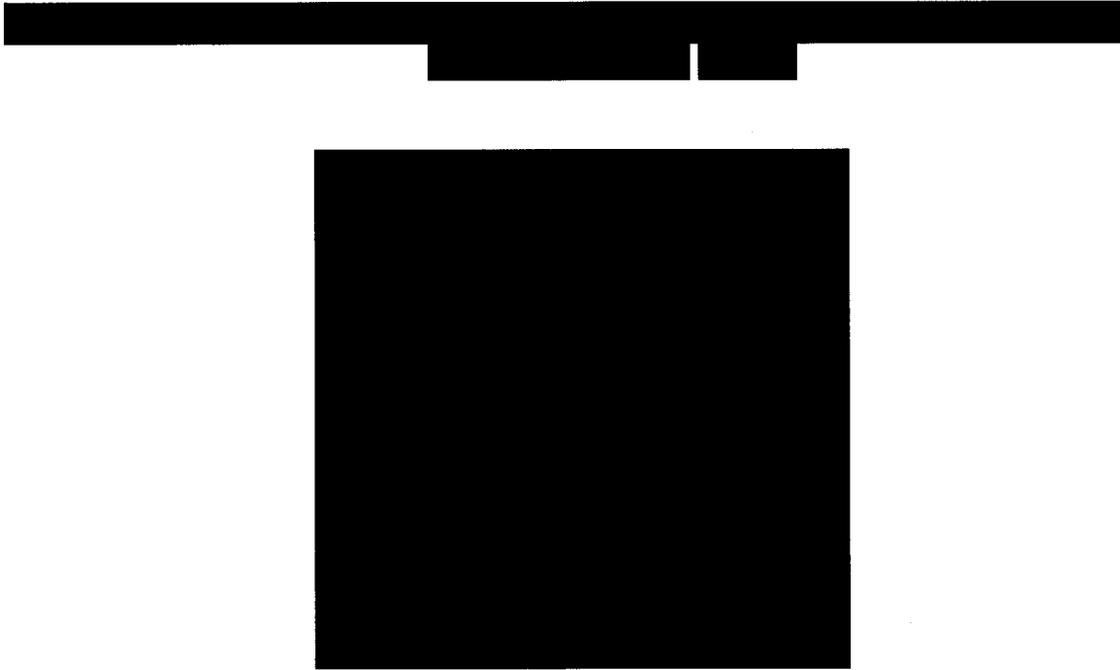
²² TEP Resp. to VS 2.32 (Ex. BK-3 at 13).

²³ UDR 1.001 Projected Changes-BillingDeterminants-AdjustedProofofRevenue-CompSensConfidential.pdf.

²⁴ UDR 1.109.

²⁵ See Hutchens Direct Test. at 20:23–25.

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



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

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

12 A. Yes. To support its rate design proposals, TEP points to the fact that residential
13 usage per customer has declined 7.5% between test years.²⁷ Examination of the
14 data made available by TEP shows a reduction of 8.2% in residential usage per
15 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).

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

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

8 A. Yes. In Dallas Dukes' Direct Testimony, TEP attributes this problem to the fact
9 that nearly one in every three residential bills issued by TEP during the test year
10 reflected usage of 400 kWh or less.³⁰ TEP says that "[b]ecause even a studio
11 apartment with basic appliances and moderate usage would likely consume almost
12 400 kWh per month, these bills probably were generated by vacant homes,
13 seasonal customers and DG customers."³¹

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

17 A. In discovery, TEP stated that it does not track seasonal homes or vacant
18 structures.³² However, the Company did provide data on the number of NEM
19 customer bills that fell below the 400 kWh threshold.³³ TEP reports that nearly
20 96% of the 1,308,415 low-usage bills were from customers who were not NEM
21 customers.³⁴

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

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.*

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

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

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

11 3. Only 4% of the low-usage bills of under 400 kWh were attributable to
12 NEM customers, so 96% of these low-usage bills were for customers who
13 were not NEM customers.

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

20 **4.2 Ninety-Eight Percent of the Residential Customers TEP** 21 **Alleges Are Causing a Cost Shift Are Not NEM Customers**

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

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

³⁵ Dukes Direct Test. at 3:5-8.

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

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

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

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

19 **Q. What do these findings show?**

20 A. TEP complains that NEM customers do not cover their fair share of fixed costs.
21 But NEM customers represent just 2% of the TEP customers that do not pay their
22 fair share of fixed costs, according to the Company's rationale. In other words,
23 98% of the customers causing the alleged cost shifting issues TEP complains of
24 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).

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

3 **4.3 TEP Has Not Shown that DG Causes Significant Grid** 4 **Impacts**

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

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

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

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

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

16 Underlying TEP's discussion of each of these categories is the Company's
17 assumption that the typical NEM customer will size their system to offset 100%
18 of annual usage. As I discuss in a later section of this testimony, TEP has not
19 provided any data to support this assumption.⁴³ The lack of data to support this
20 most basic premise is indicative of the imprecise nature of TEP's assertions
21 regarding the impacts of DG on its grid. Furthermore, even if the Company were
22 able to provide data to support this foundational assumption, TEP has failed to
23 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.

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

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

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

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

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

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).

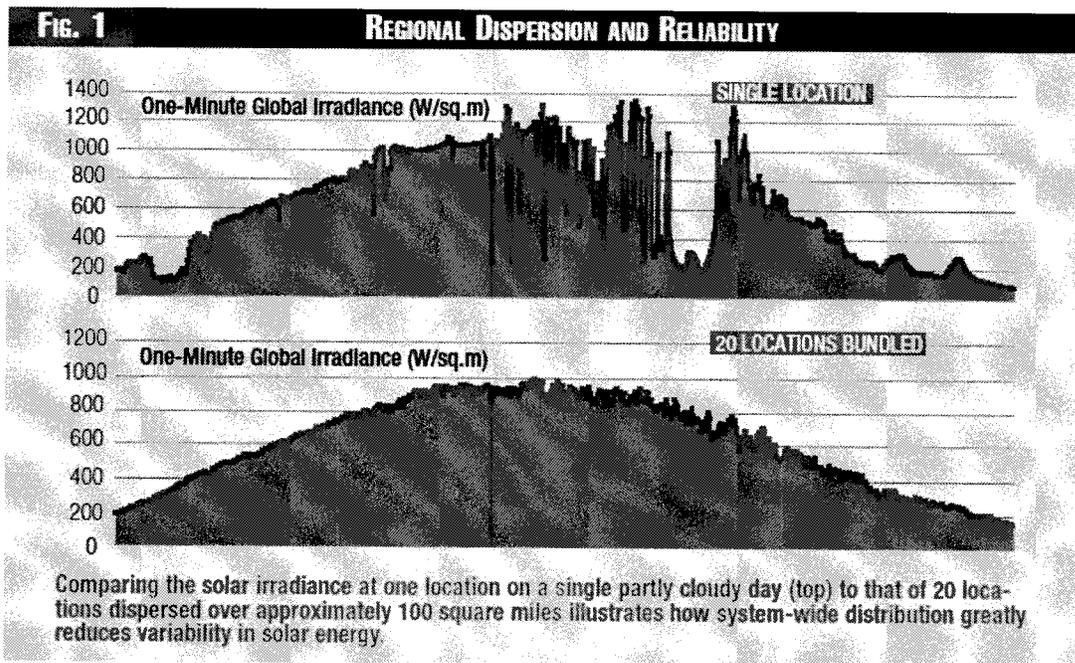
⁴⁸ *See id.* at 3.17(f) (Ex. BK-3 at 25).

⁴⁹ *See id.* at 3.17(i).

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

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

10 **Figure 2: Effects of Geographic Diversity on PV System Intermittency⁵⁰**

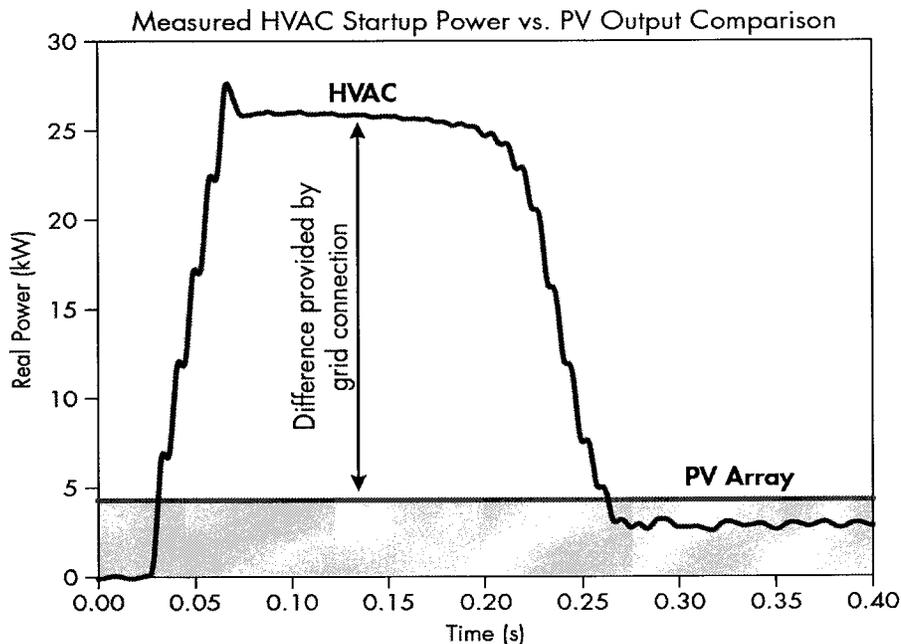


⁵⁰ Richard Perez et al., *Effective metrics give solar its due credit*, Fortnightly Magazine (Feb. 2009), available at <http://www.fortnightly.com/fortnightly/2009/02/redefining-pv-capacity>.

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

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

7 **Figure 3: Air Conditioning Startup Power⁵¹**



8

9 A recent survey indicated that 77% of TEP customers have central AC in their
10 homes.⁵² As shown in Figure 3, if a group of air conditioners of this type started at
11 the same time there would be significant swings in demand that may require
12 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).

1 In addition, as adoption of electric vehicles increases in Arizona, TEP will have to
2 accommodate large swings in residential demand as consumers plug in their
3 electric vehicles at home charging stations. The Nissan Leaf, for example, has a
4 6.6 kW charger option,⁵³ and could result in demand swings larger than the
5 average residential PV system size of 5 kW.⁵⁴

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

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

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

15 A. TEP possesses sophisticated technologies that it employs to produce forecasts of
16 PV generation on a daily and hourly basis.⁵⁷ In addition, TEP requires that DG
17 sources install a meter to collect generation production data.⁵⁸ Interconnected PV
18 systems above 300kW-ac are also required to install advanced metering
19 equipment at the customer's expense that transmits real-time production data to
20 the utility.⁵⁹ TEP uses the data obtained from these larger systems to approximate
21 production of the smaller customer-owned DG systems.⁶⁰ Additionally, while
22 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.*

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

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

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

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

18 A. TEP has revealed through discovery that the Company has not conducted any
19 studies concerning increased operations and maintenance costs or equipment wear
20 and tear resulting from DG.⁶³ The Company has studied the impact of energy
21 flowing back up through the distribution system as a result of projects in excess of
22 1 MW, but has not provided evidence of similar studies for the typical residential
23 customer whose system may be 1/100th of that size.⁶⁴ TEP acknowledges that its
24 statements were based on broad national and regional studies, rather than any
25 analysis unique to the TEP territory and level of DG penetration.⁶⁵ In addition,

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).

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

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

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

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

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

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).

1 **4.4 There is no evidence of a NEM-related cost shift in TEP's**
2 **service territory**

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

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

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

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

19 **Q. Do you agree with this cost shift characterization?**

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

⁷⁰ Hutchens Direct Test. at 23:9–12.

⁷¹ *Id.* at 20:14–18.

⁷² Dukes Direct Test. at 12:25–13:2.

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

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

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

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

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.*

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

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

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

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

23 Any difference between the cost to serve NEM and non-NEM customers would
24 have to be significantly greater than the inevitable diversity within the residential
25 and small commercial classes in order to warrant a rate design singling out NEM
26 customers. Discriminatory rate treatment of NEM customers due to minor cost
27 shifting would be a slippery slope toward segregation of other portions of the
28 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).

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

4 **5 TEP's Proposals To Reduce DG Growth Are** 5 **Flawed And Should Be Rejected**

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

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

10 **5.1 The Commission Should Not Approve TEP's Proposed** 11 **Amendments to the NEM Tariff**

12 **Q. What is net metering?**

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

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

20
21 Net metering means when a NEM customer generates excess energy that is
22 delivered to TEP, the customer has the right to correspondingly offset their
23 electricity purchases from the Company. The NEM customer is thus entitled to a
24 one-to-one energy offset under which the NEM customer is compensated for their
25 energy exports at the retail rate.

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

⁷⁸ A.A.C. R14-2-2302(11).

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

12 **Q. What is the Renewable Credit Rate?**

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

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

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

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.

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

8 ***5.1.1 Grid-scale benchmarking is not appropriate for valuation of DG***
9 ***exports***

10 **Q. Do you have an opinion on TEP’s rationale for the Renewable Credit Rate**
11 **proposal?**

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

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

19 A. I agree that due to economies of scale, utility-scale PV is generally available at a
20 lower unit price when compared to distributed solar generation. However, I
21 caution against drawing a parallel between the two resources in terms of rate
22 treatment. The statements in support of the grid-scale methodology
23 inappropriately conflate the value of DG from the perspective of the utility with
24 the value of DG from the perspective of the non-participating ratepayer and result
25 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.

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

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

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

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

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

23 The non-participating ratepayer will be generally indifferent to and unaware of
24 whether the electrons he is consuming are coming from his neighbor's PV array
25 or whether they have been carried across the entire utility transmission and
26 distribution system from a centralized power plant. Asking why the utility should
27 pay more for DG than they pay for utility-scale solar PPAs asks the wrong
28 question. From a non-participating ratepayer perspective, the right question to ask
29 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).

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

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

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

18 ***5.1.2 TEP has not provided evidence that retail rate compensation for***
19 ***exports results in a cost shift***

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

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

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>.

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

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

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

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

23 A. No, in fact, evidence from other states suggests that the value of distributed solar
24 may exceed the retail rate. In some cases, the value of distributed solar exceeds
25 the retail rate by a significant amount. The results of distributed solar benefit/cost
26 analyses can differ greatly depending on the assumptions and perspective of the
27 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).

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

6 **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

7
8 This experience in other states shows that the existence of a cost shift should not
9 be assumed in this proceeding. As the studies in Table 1 demonstrate, state
10 sponsored studies have found that the benefits of solar can be as high as 25–
11 30¢/kWh in some jurisdictions. Without evidence on the benefits and costs of
12 solar in the TEP territory, the Commission has no means to determine the need for
13 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 & Env'tl. Econ., *Nevada Net Energy Metering Impacts Evaluation* 93 (July 2014), available at http://puc.nv.gov/uploadedFiles/pucnv.gov/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>.

1 **5.1.3 *The proposed Renewable Credit Rate is flawed and should be***
2 ***rejected***

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

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

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

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

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

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

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

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

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

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

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

24 If the kWh supplied by the Electric Utility exceed the kWh that are
25 generated by the Net Metering Facility and delivered back to the Electric
26 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).

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

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

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

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

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.

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

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

11 **5.2 Demand charges should not be mandatory for NEM**
12 **customers, or any other residential or small commercial**
13 **customers**

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

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

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

¹⁰⁵ Dukes Direct Test. at 4:4–8.

¹⁰⁶ *Id.* at 18:5–8.

1 A. TEP claims:

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

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

10 ***5.2.1 NEM and non-NEM customers are similarly situated regarding***
11 ***demand charges***

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

14 A. TEP makes two claims to support mandatory demand charges for NEM
15 customers. First, TEP claims that “two-part rates are designed to recover costs
16 based on average consumption levels for full-requirements customers.”¹⁰⁹
17 According to TEP, because NEM customers offset some of their energy
18 requirements through onsite generation, the current rates that do not include a
19 demand charge “are ill-equipped in accounting for how these customers use
20 TEP’s system and for fair recovery of fixed cost.”¹¹⁰ Second, TEP claims that
21 requiring NEM customers to take service on a rate with a demand charge will help
22 to mitigate the cost shift they allege is occurring.¹¹¹

23 **Q. Is there any evidence to support these claims?**

24 A. In order to address these claims, it is important to consider what makes NEM
25 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.

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

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

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

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

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

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

¹¹² TEP Resp. to Staff 1.48 (Ex. BK-3-035).

¹¹³ Workpaper 2015 TEP R-01 Demand-PRS.xlsx.

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

12 **5.2.2 Demand charges create winners and losers**

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

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

18 **Table 2: TEP Assessment of Residential Bill Impacts of Three-Part Rate¹¹⁴**

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)

19
 20 When discussing these results Mr. Dukes states: “[b]ills calculated using the
 21 three-part rate will exceed bills using the two-part rate at lower levels of
 22 consumption. As usage increases, customers on the three-part tariff will have

¹¹⁴ Dukes Direct Test. at 25:1–5.

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

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

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

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

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

23 A. Yes. TEP provided a large amount of hourly residential customer data from which
24 I was able to calculate individual customer bill impacts for a sample of 17,000
25 residential customers.¹¹⁸ Exhibit BK-2 shows a scatterplot with each of the 17,000
26 customer bill impacts depicted by usage level. As shown in Exhibit BK-2, the
27 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).

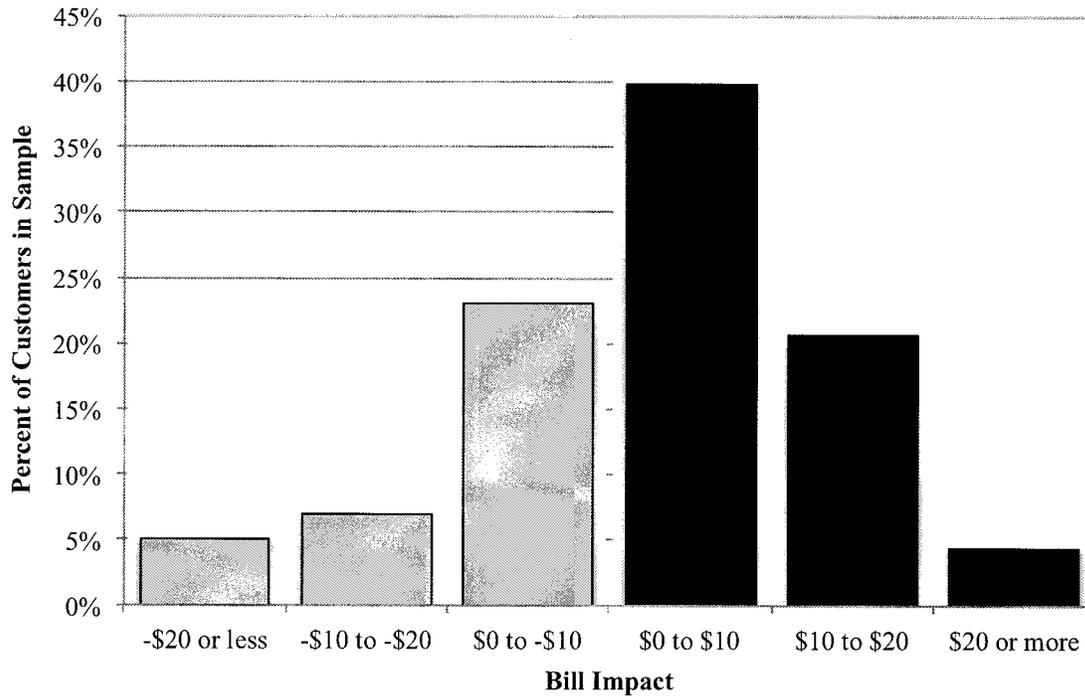
1 that customers would experience when moving from a tiered two-part rate to the
2 proposed three-part rate. For purposes of the Exhibit, I have used the two-part rate
3 proposed by TEP in this application, which includes a doubling of the fixed
4 charge from \$10/month to \$20/month, as well as a reduction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

11 Mr. Dukes' chart depicts the average bill impacts for a customer using 900 kWh
12 as being only \$0.47/month.¹¹⁹ However, when the data is examined for the 2,150
13 customers in the sample that have an average monthly usage of between 800 kWh
14 per month and 1,000 kWh per month, the data reveals that these customers will
15 have a large range of impacts. In fact, some customers' bills will increase by as
16 much as \$70/month, while others will decrease by as much as \$34/month,
17 depending on each individual's specific usage characteristics.¹²⁰ While these
18 figures represent the extreme ends of the spectrum, the depiction of an impact that
19 is less than one dollar a month does not begin to tell the story of how customers
20 would be impacted by moving to a demand charge rate. Figure 4 below
21 demonstrates the distribution of bill impacts comparing the proposed standard
22 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.

1 **Figure 4: Distribution of Residential Bill Impacts – Movement to Demand Charge**
2 **Rate**¹²¹



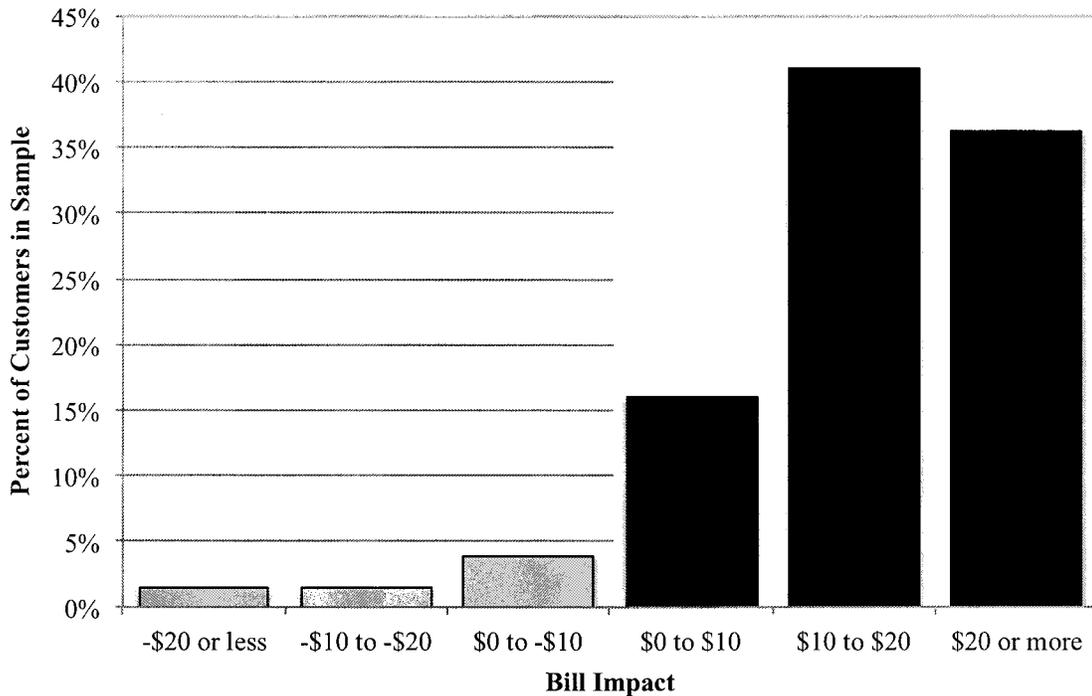
3
4 As seen in the figure, 65% of customers would experience bill increases if they
5 moved to a demand charge tariff. While the majority of customers with increases
6 will see bill increases of less than \$10 a month, 25% of customers' bills are
7 expected to increase by more than \$10 a month.

8 However, demand charges are not the only rate design change proposed in this
9 docket. TEP is also requesting approval of a revenue requirement increase, a
10 doubling of the fixed customer charge, and a reduction in the number of
11 residential rate tiers. While Figure 4 depicts the range of bill impacts associated
12 with movement from the proposed two-part rate to the proposed three-part rate, it
13 does not depict the full level of changes that may be faced by customers in this
14 case. Figure 5 below shows the full level of changes faced by customers moving
15 from the current rate to the proposed three-part rate, a change that TEP is
16 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.

1
2

Figure 5: Distribution of Residential Bill Impacts – Current Rates to Proposed Demand Charge Rate¹²²



3

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

7 **Q. What do you conclude based on this data?**

8 A. Demand charges are a rate design that creates “winners” and “losers” among the
9 residential class. The data shows that 65% of customers are expected to face bill
10 increases on a demand charge tariff. While Exhibit BK-2 demonstrates that larger
11 customers tend to be among the biggest savers on a demand charge rate, the trend
12 is hardly linear, and individual customer bill impacts will vary greatly across
13 usage levels. TEP’s current proposal is to make a demand charge tariff mandatory
14 for new NEM customers. Most people considering installing DG systems would
15 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.

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

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

18 **5.2.3 Demand charges do not create actionable price signals for**
19 **residential customers**

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

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

24 [I]t is critical that each component of the three-part rate closely reflects the
25 actual cost of service. If properly designed, three-part rates more fairly
26 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.

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

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

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

16 A. This implies that TEP’s proposed demand charge will not treat all customers in an
17 equitable manner and for many will not reflect the costs that they cause. In sum
18 TEP cannot claim that the proposed demand charge is cost based. Under TEP’s
19 proposal, customers would be billed based on their highest one hour demand
20 during a billing period, regardless of the time of day in which that demand
21 occurs.¹²⁸ Data on the annual TEP system peak shows that the system peak can be
22 expected to occur in the mid-afternoon during the summer months.¹²⁹ A
23 residential customer, on the other hand, may set her peak demand in the early
24 morning while making coffee, and using the clothes dryer and hair dryer.
25 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).

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

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

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

22 A. In order for a rate structure to send a price signal to help customers make
23 informed decisions, the customers must be able to understand how to respond to
24 that price signal. In the case of demand charges, residential and small commercial
25 customers would first need to know when their peak demands occur. Because the
26 demand charge would be assessed based on the highest hour of consumption in a
27 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.

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

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

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

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

21 A. Yes. Many residential customers have limited choice or control over when they
22 use appliances. It is estimated that as many as 45% of TEP's residential customers
23 may have all-electric service.¹³³ Electric furnaces and water heaters can consume
24 significant levels of electricity, with common models drawing 10.5 kW and 4.5
25 kW, respectively.¹³⁴ In addition, common hair dryers typically draw upwards of 1
26 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).

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

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

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

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

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).

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

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

11 A. While there is indeed potential for technology to aid in customer response to
12 demand charges, these technologies are uncommon, costly to implement, and
13 have not achieved widespread adoption. For example, Mr. Dukes refers to a
14 demand control unit that would allow a customer with two AC units, a pool pump
15 and an electric water heater to prevent these appliances from coming on at one
16 time.¹⁴¹ However, in discovery it was revealed that to install this type of
17 technology the customer would need to spend \$3,700.¹⁴² This cost is out of reach
18 for the average residential customer, and enabling technologies are expected to do
19 little to help the average residential or small commercial customer to respond to
20 demand charges.

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

23 A. No. Of the 39 utilities identified by TEP as offering demand charges to residential
24 customers, only two are identified as having mandatory demand charge tariffs.¹⁴³
25 However, further examination reveals that neither of these are in fact mandatory
26 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.

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

11 **Q. Do other utilities’ experiences with demand charges shed light on customers’**
12 **ability to respond to such charges?**

13 A. APS has an optional demand charge residential rate, which has been in effect
14 since the 1980s and currently has roughly 11% enrollment.¹⁴⁵ In a case study of
15 its optional residential demand rate, APS explains that it “helps customers select
16 the best rate at time of new service through [its] website rate comparison tool.”¹⁴⁶
17 Not surprisingly, an examination of the relative size of residential customers that
18 have self-selected onto the demand rate reveals that they have an average monthly
19 consumption that is nearly three times the average monthly consumption of
20 customers on the default rate.¹⁴⁷ Because the optional demand rate also includes a
21 much lower volumetric rate, it is likely that the vast majority of APS customers
22 who have chosen to take service on the demand rate have done so because it
23 would lower their bills without any modification in consumption patterns. Current
24 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.

1 territory have the ability to respond to the price signal set by demand charges. To
2 the contrary, the fact that APS has marketed its optional demand charge rates for
3 upwards of three decades with only 10% current enrollment demonstrates that
4 90% of APS's customers have either not gained an understanding of how the
5 demand charge rate would impact them, or they have decided that the demand
6 charge rate is not the best option for them. Indeed, in response to discovery, APS
7 has revealed that as many as 40% of its customers that recently switched from a
8 two-part rate to the optional demand charge rate actually increased their
9 maximum on-peak demand.¹⁴⁸ This means that even among the small proportion
10 of customers that self-selected onto the demand charge rate, 40% did not respond
11 to the demand charge price signal in their optional tariff.

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

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

24 A. In February 2015, SRP approved a demand charge for new residential NEM
25 customers that it estimated would increase costs for these customers by about \$50
26 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.

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

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

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

19 ***5.2.4 The Commission should not approve mandatory demand charges for***
20 ***any residential or small commercial customers***

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

22 A. I recommend that TEP's proposed three-part rates for residential and small
23 commercial customers be approved only as optional rate schedules for customers
24 with and without DG. Demand charges for residential and small commercial
25 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.

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

14 ***5.2.5 TOU rates are a preferred alternative to demand charges***

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

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

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

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.

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

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

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

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

23 The rates charged by any electric utility for providing electric
24 service to each class of electric consumers shall be on a time-of-
25 day basis which reflects the costs of providing electric service to
26 such class of electric consumers at different times of the day unless
27 such rates are not cost-effective with respect to such class¹⁵⁹

¹⁵⁷ Rocky Mountain Inst., *supra* note 123, at 5.

¹⁵⁸ *Id.* at 45.

¹⁵⁹ 16 U.S.C. § 2621(d)(3) (emphasis added).

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

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

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

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

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.raonline.org/document/download/id/7844>.

¹⁶² *See id.*

¹⁶³ Decision No. 53615 at 6:9–10 (Ex. BK-5).

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

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

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

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

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

¹⁶⁴ *Id.*

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

14 Jim Lazar of the Regulatory Assistance Project has articulated some of the key
15 benefits of TOU rates over demand charges in the following table that adapts
16 principles from Garfield and Lovejoy's *Public Utility Economics* to the evaluation
17 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.

1 **Table 3: Garfield and Lovejoy Criteria¹⁶⁶**

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

2
3 While TOU rates may meet more of the Garfield and Lovejoy criteria and may be
4 easier for the average customer to respond to than demand charges, the
5 Commission should still exercise caution in considering a mandatory TOU rate.
6 Some customers will have a greater ability to modify their behavior in response to
7 TOU rates than others.

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

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

¹⁶⁶ Lazar, *supra* note 161, at 15.

1 **5.3 The Commission has already approved a mechanism to**
2 **address under-recovery of fixed costs through the LFCR**

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

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

9 **Q. What is the LFCR?**

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

21 **Q. How is the LFCR applied to customer rates?**

22 A. The LFCR is applied to rates as a percentage-based charge on total Delivery
23 Service and Power Supply Charges. The current LFCR is 0.8565% for EE and
24 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.

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

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

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

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

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

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

¹⁷⁰ TEP, Lost Fixed Cost Recovery (LFCR) 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.

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

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

10 **Q. Please summarize your recommendations regarding the LFCR.**

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

18 **6 TEP Has Not Adequately Evaluated the** 19 **Impacts of Its Proposals**

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

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

¹⁷³ *Id.* at 39:24–25.

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

3 **6.1 TEP Did Not Reliably Assess the Impacts of its Proposals** 4 **on NEM Customers**

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

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

10 **Q. What was the basis for TEP’s NEM customer impact assessments?**

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

18 **Q. How many of TEP’s NEM customers size their PV systems to offset 100% of**
19 **load?**

20 A. It is not clear. TEP has indicated in discovery that it does not track this
21 information.¹⁷⁷ Because I cannot verify TEP’s claims that the “typical” NEM
22 customer will offset 100% of load, there is no basis on which to evaluate the
23 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).

1 rate design proposals. Even if this claim could be verified, it is likely that at least
2 some level of diversity exists among the NEM customers. This diversity would
3 also need to be understood to provide a reliable assessment of the impact of the
4 proposals on NEM customers. Moreover, the representation of NEM customer bill
5 impacts on three-part rates suffers from the same problem discussed in section
6 5.2.2 of this testimony. Namely, TEP presents results based on various levels of
7 kWh usage while using a one-dimensional assumption for billing kW. It is
8 expected impacts shown in Mr. Dukes' testimony do not represent the full range
9 of impacts that may be seen under TEP's proposal.

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

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

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

20 A. To ensure that a rate change is just and reasonable, utilities often develop an
21 assessment of representative load data for customers impacted by a rate proposal
22 in order to provide evidence that a new rate will not unfairly impact the utility's
23 customers. TEP acknowledges this with the following statement: "To best
24 determine the true impact on the customer and the Company revenues, we went to
25 great lengths to determine the appropriate levels of billing determinants. It was
26 essential that we had a complete understanding of the billing determinants as we
27 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.

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

8 **6.2 TEP Did Not Provide the Cost of Service and Benefit/Cost** 9 **Analyses Required by Commission Rule 14-2-2305**

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

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

15 Net Metering charges shall be assessed on a nondiscriminatory basis. Any
16 proposed charge that would increase a Net Metering Customer’s costs
17 beyond those of other customers with similar load characteristics or
18 customers in the same rate class that the Net Metering Customer would
19 qualify for if not participating in Net Metering shall be filed by the
20 Electric Utility with the Commission for consideration and approval. The
21 charges shall be fully supported with cost of service studies and
22 benefit/cost analyses. The Electric Utility shall have the burden of proof
23 on any proposed charge.¹⁸¹

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

26 A. No. As described in Section 4.4 of this testimony, while TEP attempts to single
27 out NEM customers for differential treatment compared to non-NEM customers,
28 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).

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

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

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

9 **6.3 TEP Should Consider Solar Jobs Along with the Economic**
10 **Development Rider**

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

12 A. TEP has proposed to offer a discounted rate to business customers with a
13 projected peak demand of 1,000 kW or more, and a load factor of 75% or
14 higher.¹⁸² The rate discount would decline over a five-year period beginning with
15 a 20% discount in Year 1 and declining to a 2.5% discount in Year 5.¹⁸³ The
16 Economic Development Rider would be available for five years and enrollment
17 would be capped at 200 MW.¹⁸⁴ To qualify for the Economic Development Rider,
18 a customer must qualify for at least one of two existing Arizona state tax
19 programs.¹⁸⁵

20

21

22

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.

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

3 A. TEP points out that its service territory has been slow to recover from the
4 economic downturn post-2007.¹⁸⁶ TEP claims that the Economic Development
5 Rider would put TEP's service territory in a better competitive position to attract
6 and expand business load, which would be beneficial to the entire customer base
7 and the State of Arizona.¹⁸⁷

8 **Q. Will the Economic Development Rider generate new jobs?**

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

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

12 A. Yes. As of November 2014, there were 6,922 solar workers employed in Arizona
13 with an additional 580 solar jobs expected in 2016.¹⁸⁹

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

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

21

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).

1 **7 TEP Claims It Needs to Modernize Its Rate**
2 **Design, but Its Proposals Are Regressive**

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

4 A. TEP’s application characterizes its proposals as necessary to “modernize” rate
5 design.¹⁹¹ The Company claims that “[i]n this proceeding, TEP seeks approval for
6 21st century rates.”¹⁹²

7 **Q. In your opinion, are TEP’s proposals a step toward a modernized rate**
8 **design?**

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

13 **7.1 TEP’s Request to Increase Fixed Charges for Residential**
14 **and Small Commercial Customers Should Be Rejected**

15 **Q. Please describe TEP’s proposal to increase fixed service charges.**

16 A. TEP proposes to increase all monthly basic service charges “in a manner
17 consistent with the results of the CCROSS and equitable fixed cost recovery.”¹⁹³
18 TEP proposes to increase the residential fixed charge from \$10/month to
19 \$20/month¹⁹⁴ and the small commercial fixed charge from \$15.50/month to
20 \$30/month.¹⁹⁵ Current and proposed fixed charges for residential and small
21 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.

1 **Table 4: Current and Proposed Fixed Charges – Residential and Small**
2 **Commercial**¹⁹⁶

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

3
4 **Q. What support does TEP give for its proposal?**

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

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

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

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

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>.

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

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

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

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

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>.

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

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

5 **Table 5: CCOSS Customer Cost Results using Minimum System Method²⁰²**

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

6
7 **Q. How do TEP's CCOSS results inform the proposed basic service charges?**

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

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

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

21 A. It appears that TEP ultimately used the results of the embedded cost study for
22 both customer-related costs and demand-related costs as the foundation of its
23 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.

1 \$20 residential basic service charge proposal represents 21% of the \$93.61 in
2 combined customer-and demand-related charges identified for the residential
3 customer.²⁰⁴

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

6 A. TEP states:

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

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

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

19 A. It does not. Despite an over allocation of costs to the customer-related category,
20 the Minimum System Method identified only \$15.67 in embedded customer costs
21 for residential customers.²⁰⁷ In support of its proposal, TEP also looks at the
22 \$77.94 its own methodology classified as unrelated to the customer function. This
23 approach is wholly inappropriate. TEP is seeking to over-allocate costs to the
24 customer charge by mischaracterizing demand-related costs as customer costs.
25 Demand-related costs identified by the CCOSS should not be considered in the

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.

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

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

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

20 **Table 6: Distribution Cost Allocation²¹⁰**

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%

21
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).

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

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

9 **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

10

11 As shown in Table 7, using the Basic Customer Method instead of the Minimum
12 System Method results in a significantly lower estimate of customer-related costs.
13 When the Basic Customer Method is employed, the marginal cost for residential
14 and small commercial customers is estimated at \$9.72 and \$10.12, respectively.
15 The embedded cost is estimated at \$9.58 for residential customers and \$15.85 for
16 small commercial customers. These results demonstrate that the Minimum System
17 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.

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

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

9 **Q. Do TEP’s proposed increased fixed charges present policy implications?**

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

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

²¹³ Jones Direct Test. at 40:26–41:2.

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

5 **7.2 TEP’s Request to Eliminate the Third and Fourth**
6 **Residential Tiers Should Be Rejected**

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

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

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

15 A. An inclining block rate structure was first put into rates in 2008 with Decision No.
16 70628, which included the following finding of fact: “The inclining block rate
17 structure, TOU rates and other rate design changes as set forth in the 2008
18 Settlement Agreement will promote energy conservation and beneficial load
19 shifting.”²¹⁶ Inclining block rates were never intended to be based on cost
20 causation, but rather, were approved by the Commission for the express purpose
21 of incenting conservation.

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

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).

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

6 **8 In the Event of Major Rate Design Changes,**
7 **Existing NEM Customers Should Be**
8 **Grandfathered**

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

11 A. It is essential that the Commission safeguard existing NEM customers from
12 drastic and unforeseen rate design changes. TEP's existing NEM customers have
13 made investments in DG systems to serve their family or small business's needs.
14 Many of these customers were encouraged to invest in DG through Commission
15 incentives. By investing in rooftop solar, customers fix a portion of their
16 electricity bills to offset fluctuating electricity rates. Many of these customers
17 have made the investment in rooftop solar as part of a long-term financial plan,
18 perhaps tied to retirement, college, or some other anticipated financial need. By
19 investing in their own energy source, these customers can reduce monthly
20 expenses when their system is paid off, improving savings potential much like
21 paying off a mortgage. Drastic, unforeseen changes to the rate design for these
22 customers have the potential to severely undercut their planned savings.

23 **Q. What has TEP proposed regarding grandfathering?**

24 A. TEP has proposed that existing NEM customers who signed up before June 1,
25 2015, be allowed to continue service on the existing NEM tariff that would allow
26 them access to the standard two-part rate and full retail rate credit for their

1 exported DG. Since June 1, 2015, TEP has notified new NEM customers of the
2 possibility of changes to the rate structure that may impact their savings potential.

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

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

16 **9 The Commission Should Consider TEP's** 17 **Proposals in the Context of the Modern Grid**

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

19 A. With increasing availability of new technologies, the fundamental operation of the
20 distribution grid is changing. In the evolution to the modern grid, the consumer is
21 becoming a much more active participant in the production and consumption of
22 their electricity through various DERs.²¹⁷ The modern grid will empower
23 customers of all sizes to manage their energy usage and production in
24 coordination with the utility for the benefit of both the consumer and the grid.
25 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>.

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

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

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

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

²¹⁸ *Id.*

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

5 According to the LBNL study:

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

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

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

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

26 A. TEP has recommended far-reaching changes to rates paid by customers who elect
27 to install DG. The changes seek to make DG less cost effective for customers and
28 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.*

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

6 **10 Conclusions and Recommendations**

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

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

16 TEP's proposed solutions to the alleged "problems" created by DG are seriously
17 flawed and would unjustly discriminate against NEM customers. First, the
18 Company proposes to modify the NEM tariff to significantly reduce the credit
19 NEM customers receive for excess generation. However, TEP has not
20 demonstrated, or even analyzed, whether the reduced credit it proposes would
21 appropriately approximate the value of solar DG. Moreover, the proposed credit
22 rate would be extremely volatile and subject to gaming, and it would also likely
23 violate the Commission's NEM rules. Next, TEP proposes to create a mandatory
24 demand charge for NEM customers. This mandatory demand charge would
25 effectively function as an additional fixed charge solely for NEM customers, as
26 residential and small commercial customers lack the tools to effectively respond
27 to demand charges. In TEP's last rate case, the Commission approved the LFCR
28 to address any cost recovery issues created by DG and EE. This transparent

1 mechanism better addresses TEP's concerns regarding DG than its other
2 proposals, and there is no need for the flawed and discriminatory proposals
3 regarding DG that TEP has asked the Commission to approve.

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

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

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

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

28 A. I recommend the following:

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

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

20 **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

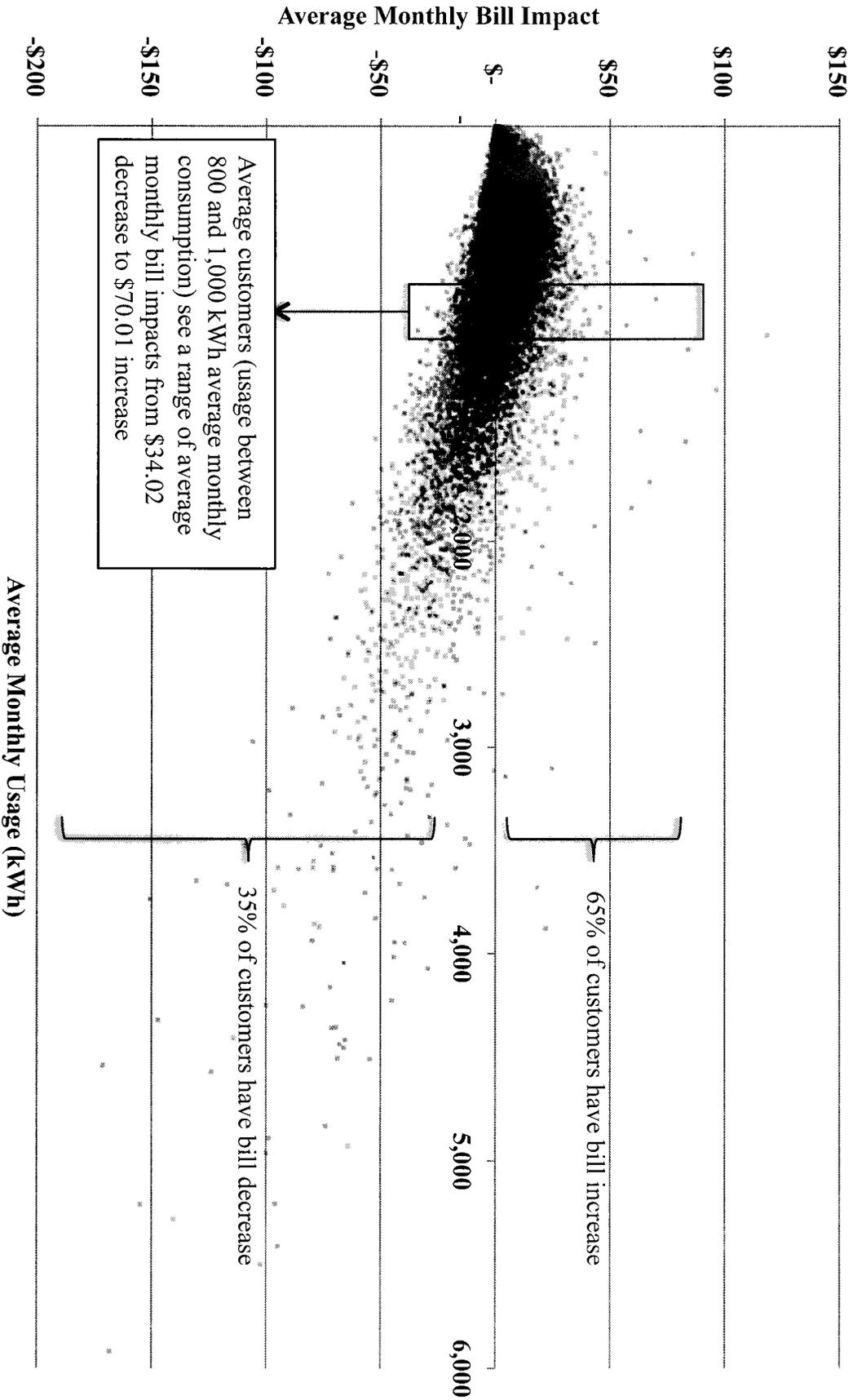


Exhibit BK-3

Discovery Responses Referenced in Testimony

**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 2.04

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%2Fxppls%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

**TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO VOTE SOLAR'S
SECOND SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
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June 1, 2016

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

**TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO VOTE SOLAR'S
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DOCKET NO. E-01933A-15-0322**

June 1, 2016

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 alternative(s) and why the proposed methodology was chosen over the alternative(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.

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June 1, 2016

- 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

**TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO VOTE SOLAR'S
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June 1, 2016

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

**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 2.10

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

**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 2.15

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.

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June 1, 2016

RESPONDENT:

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

WITNESS:

Denise Smith / Dallas Dukes

**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 2.17

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 electric 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

**TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO VOTE SOLAR'S
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DOCKET NO. E-01933A-15-0322**

June 1, 2016

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

**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

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

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VS 2.24 Website Results Presentation.pdf

TEP\024853-025018

RESPONDENT:

Dr. Sandra Holland

WITNESS:

Craig Jones

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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

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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

**TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO VOTE SOLAR'S
SECOND SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
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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

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SECOND SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
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June 1, 2016

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

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SECOND SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
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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

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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

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FOURTH SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
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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

**TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO RUCO'S THIRD SET OF
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March 14, 2016**

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 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%2Fxppls%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 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. Please see RUCO 3.14 Los Reales back flow-Confidential.pdf for example. For reference are three other technical

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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

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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.

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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.

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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

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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.

**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

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

**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 7.13

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 not identified by Bates numbers.

RESPONDENT:

Anne Trostle / Brenda Pries

WITNESS:

Craig Jones

**TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO RUCO'S EIGHTH SET
OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE**

DOCKET NO. E-01933A-15-0322

April 28, 2016

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

**TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO STAFF'S FIRST SET OF
DATA REQUESTS REGARDING THE 2015 TEP RATE CASE**

DOCKET NO. E-01933A-15-0322

February 2, 2016

STF 1.14

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

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

February 2, 2016

STF 1.20

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,

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

February 2, 2016

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

**TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO STAFF'S FIRST SET OF
DATA REQUESTS REGARDING THE 2015 TEP RATE CASE**

DOCKET NO. E-01933A-15-0322

February 2, 2016

STF 1.21

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

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

STF 1.46

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

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

February 2, 2016

STF 1.48

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

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

May 26, 2016

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

**TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO SWEEP'S SECOND SET
OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE**

DOCKET NO. E-01933A-15-0322

June 1, 2016

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.

**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

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)

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BEFORE THE ARIZONA CORPORATION COMMISSION

JIM WEEKS
Chairman
BUD TIMS
Commissioner
JOHN AHEARN
Commissioner

IN THE MATTER OF THE COMMISSION, ON) DOCKET NO. U-1345-80-98
ITS OWN MOTION, CONDUCTING A HEAR-)
ING PURSUANT TO A.R.S. SECTION 40-252) DECISION NO. 51472
TO CONSIDER AMENDING DECISION NO.)
49060) 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 be-
half 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 advisa-
bility 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

1 research activities being conducted by APS. By the aforesaid
2 decision the Commission also created an "Advisory Committee on APS
3 Time of Use Rate Design" and among other things referred the EC-1
4 rate to the committee for further study. Subsequently, the
5 Advisory Committee proposed that the Commission approve the EC-1
6 rate structure. By notice of hearing in the above docket, Decision
7 No. 51239, dated August 5, 1980, the Commission decided to reopen
8 its consideration of the appropriateness of the EC-1 rate pursuant
9 to A.R.S. § 40-252. Accordingly, a hearing was held on this pro-
10 ceeding on September 4, 1980, before the above named hearing officer
11 and the full Commission. At the hearing the Company presented two
12 witnesses and considerable evidence regarding design, implementation
13 and effect of the EC-1 rate concept. The record in this hearing
14 also consists of eighteen exhibits and official notice was taken of
15 that part of the APS 1978 rate case which dealt with EC-1 rate. No
16 evidence in opposition to the implementation of the EC-1 rate was
17 introduced. However, the Home Builders Association of Central
18 Arizona has indicated its opposition to mandatory load control
19 devices on new construction.

20 FINDINGS OF FACT

21 1. The APS residential electric rate structure has histor-
22 ically been based primarily on the consumption of each customer.
23 Such a rate structure ignores the fact that the cost of providing
24 electric service is increasingly a function the demand for electri-
25 city places on the system rather than total power consumed. Commer-
26 cial and industrial rates charged by APS have long recognized this
27 fact and it is now appropriate that residential rate design should
28 similarly reflect the primary components of cost of service. The

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

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

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

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

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

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

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

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

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

13 CONCLUSIONS OF LAW

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

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

18 ORDER

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

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

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

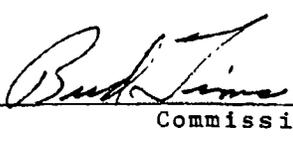
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1 IT IS FURTHER ORDERED: That load control devices located on
2 the customers side of the meter shall not be the responsibility of
3 the company.

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

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

12 BY ORDER OF THE ARIZONA CORPORATION COMMISSION

13   
14 Chairman Commissioner Commissioner
15

16
17 IN WITNESS WHEREOF, I, G.C. ANDERSON, JR.,
18 Executive Secretary, of the Arizona Corporation
19 Commission, have hereunto set my hand and caused
20 the official seal of this Commission to be
21 affixed at the Capitol, in the City of Phoenix,
22 this 21st day of October, 1980.

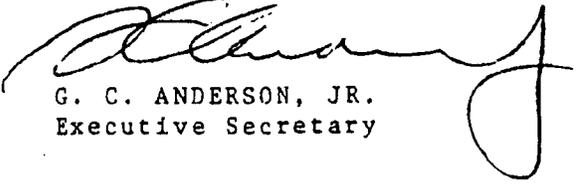
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G. C. ANDERSON, JR.
Executive Secretary

Exhibit BK-5

ACC Decision No. 53615 (June 27, 1983)

BEFORE THE ARIZONA CORPORATION COMMISSION

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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 COM-)
PANY FOR RATE MAKING PURPOSES, TO FIX)
A JUST AND REASONABLE RATE OF RETURN)
THEREON, AND THEREAFTER, TO DEVELOP)
SUCH RETURN, AND, IN CONNECTION THERE-)
WITH, 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

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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

1
2 In the instant proceeding, the issue which has created the greatest disagreement
3 among the parties, is the allocation of the total revenue increase, as provided in Decision
4 No. 52593, among the various customer classes. The differences concerning the correct
5 allocation of revenue requirements among customer classes primarily concern the weight
6 to be given cost of service studies and the manner in which they should be conducted.
7 APS submitted three cost of service studies, two of which were based on embedded cost
8 and the third study based upon marginal cost. EBASCO, the staff consultants, presented
9 evidence examining the APS cost of service studies and its own cost of service study which
10 was also based upon embedded cost, using the 4 CP method. With the exception of staff
11 and the intervenor, Arizona Cotton Growers Association, all parties chose to rely upon the
12 APS cost of service study.

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

20 The APS class revenue allocation was developed by a comprehensive process involving
21 consideration of the APS embedded cost and marginal cost of service studies, with due
22 consideration being given to the well accepted Bonbright principles of rate making (See,
23 Bonbright, James C., Principles of Public Utility Rates. New York: Columbia University
24 Press, 1961). While APS regards cost of service as the most important factor to be taken
25 into account on rate design, it also properly considered additional factors of a non-cost
26 nature such as continuity, equity, comprehensibility and revenue stability. (Tr. Vol. II,
27 p. 161-165, 183-186, 223-226) The process for revenue allocation used by APS in this pro-
28 ceeding is consistent and in harmony with this Commission's adoption of the PURPA cost

1 of service standard, in Decision No. 52593. That Decision provided that cost of service
2 was not to be the sole consideration of rate design and that other relevant factors could
3 also be considered. (Id. p. 5 & 6) For the Commission to allow the allocation of revenue
4 requirements and ultimately rate design, upon strict cost of service would deprive it of its
5 authority and discretion to use all available methods in the development of just and reason-
6 able rates.

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

17 RATE DESIGN

18 RESIDENTIAL RATES

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

24 As the present basic combination of the E-10, EC-1, ECT-1 and ET-1 rates provide a
25 wide practical range of choices to accommodate various customer consumption character-
26 istics, APS proposes continuation of these basic rate choices. However, APS proposes a
27 major modification to the E-10 rate and only minor changes to the EC-1, ECT-1 and ET-1
28 rates. Additionally, APS, Arizona Multihousing Association and Staff have proposed a new

1 optional rate schedule, called the ECL-1 rate, for low volume residential users with central
2 air conditioning. All of these changes and additions to the existing basic rate choices are
3 more fully discussed hereinafter.

4 E-10 RATE

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

15 For the summer portion of the E-10 rate, APS proposes to leave unchanged the inverted
16 block rate structure. The rate for the first consumption block (first 400 kWh) also remains
17 unchanged. However, APS has proposed to invert the second rate block, which is the next
18 400 kWh. Under the present rate the 401st kWh costs \$3.66 which results from all consump-
19 tion being billed at 6.306¢/kWh when use is over 400 kWh. By inverting the second rate
20 block the abrupt bill change occurring under the present rate design at 401 kWh would be
21 avoided. (Exh. A-8, p. 22) APS has further proposed to increase the rate for the third
22 and final block. The overall impact on summer bills would therefore be zero for all con-
23 sumption up to 400 kWh, a decrease for bills between 400 kWh and 578 kWh, and increases
24 for all consumption above that level. This will result in bill increases for high-volume,
25 residential customers of approximately 8.08%. However, the overall annual increase for
26 all E-10 customers is approximately 2% (Exh. A-8, p.23 & 24, Sch. HE-2, p. 1).

27 The resulting revenue shifts from winter to summer and from lower to higher consump-
28 tion customers is justified by cost of service studies conducted by APS. These studies have

1 shown that consumers who never exceeded 600 to 700 kWh in any month during the summer
2 period had lower average costs than those whose use exceeded that amount. The reduction
3 in the winter rate reduces the overall burden on the lower-user group since that group uses
4 relatively greater amounts during the winter. (Exh. A-8, p. 23 & 24)

5 EC-1 RATE

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

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

28

ECT-1 AND ET-1 RATE

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

ECL-1

15
16 During the instant hearing an agreement was reached by APS, Ariz. Multihousing
17 Association and the staff with regard to the development of a new rate for small use resi-
18 dential customers who have central air conditioning. This rate is in response to complaints
19 that the mandatory nature of the EC-1 rate produced unfair results for low volume users.
20 The rate design will alleviate the necessity for investment by low consumption customers
21 in load control devices to mitigate what would otherwise be significant rate impacts under
22 the EC-1 rate. (Tr. IV & V, p. 710, 735 & 736) The ECL-1 rate is described fully in Exhibit
23 A-23 and is consistent with the agreement reached by the parties as outlined in Exhibit
24 S-22(a). This rate schedule would be available to new residential electric customers with
25 central refrigerated air conditioning, and to any reconnections where the immediately
26 previous service was billed under the E-10 or E-207 rate. The winter portion of this rate
27 is identical to the E-10 rate proposed by APS. The summer ECL-1 rate is also equal to the
28 E-10 proposed rate by APS for the first two blocks, i. e., up to the first 800 kWh.

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

6 RESIDENTIAL RATE SUMMARY

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

10	<u>Type of Customer</u>	<u>Available Rates</u>
11	Existing residential customer as of May 1, 1981, with central air conditioning	E-10, EC-1, ECL-1, ECT-1, or ET-1
12	New residential customer after 1981 with central air conditioning	EC-1, ECL-1, ECT-1, or ET-1
14	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
16	New or existing residential customers without central air conditioning	E-10

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

18 The Commission adopts the proposal of APS for the creation of new two primary
 19 rates for the general service class E-32 and E-34 and the cancellation of existing rate
 20 schedules E-32-1, E-32-2, E-33, E-46, and its contract ("Magma") rate. The new E-32 rate
 21 contains several significant changes from previous general rate schedules, all of which are
 22 designed to more accurately track cost incurrence and to send appropriate price signals to
 23 APS customers. The E-34 rate divides the large general service class into two sections for
 24 rate making purposes. It distinguishes between those customers whose maximum demand
 25 was 3,000 kW or greater and those with less than 3,000 kW but with at least 1,000 kW
 26 demand. The proposed E-34 rate schedule is a straight forward three part, customer,
 27 demand and energy rate with a five month seasonal 80% ratchet. (Exh. A-8, p. 12) The
 28 individual components of the rate are based on the APS cost of service schedule and

1 its revenue index limit. Approximately one-third of the demand costs are recovered in
2 the energy component of the rate in order to recognize the coincidence and load factor
3 characteristics of the customers.

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

11 TIME OF DAY RATE FOR EXTRA LARGE GENERAL SERVICE CLASS

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

28 ...

IRRIGATION RATES

1 The evidence supports adoption of the irrigation rate design E-38 & E-143 presented
2 by APS. Exhibit A-21 indicates that adoption of the APS rate design proposal for irrigation
3 class results in an average increase of approximately 1.5%. However, individual customers
4 may experience different increases, or decreases, depending on their size, load factor, and
5 seasonal use pattern. APS has recommended seasonal rates for the irrigation class based
6 on the summer season of June through October. As a result, a higher energy charge will
7 be effective for the summer months over that charged during the winter months. For
8 consistency and other reasons more fully set forth in the record, the irrigation rates should
9 be priced on a seasonal basis identical to the residential class. Consequently, a summer
10 season of May through October should be utilized. (S-13, p. 36) Due to the similarity of the
11 E-38 and E-143 rates both should be consolidated into one rate.
12

MISCELLANEOUS RATE CLASSES

13 APS has made only minor modifications to its street lighting and other public authority
14 rates. (Exh. A-8, p. 34 & 35) These changes were not contested by the other parties and
15 their adoption appears to be just and reasonable.
16

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

1 but based upon a methodology that reflects the unit investment for each lamp. (Exh. S-13,
2 p.42)

3 APS PURCHASED POWER AND FUEL ADJUSTMENT CLAUSE

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

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

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

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

27 ...

28 ...

1 ACCORDINGLY, IT IS ORDERED:

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

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

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

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

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

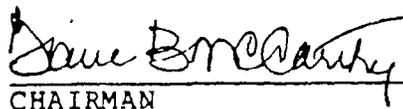
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6. APS shall file with the Utilities Division within thirty (30) days after the date of this Order detailed information on its proposed program to inform its customers of the new rate designs approved herein prior to their mandatory effective date.

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
 Acting Executive Secretary

Exhibit BK-6

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

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BEFORE THE ARIZONA CORPORATION COMMISSION

BUD TIMS
Chairman
JIM WEEKS
Commissioner
DIANE McCARTHY
Commissioner

Arizona Corporation Commission
Phoenix, Arizona
1981

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))

dmx

DOCKET NO. U-1345
DECISION NO. 52593

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;

1 NEISSER, CAMPANA & HORNE, by THOMAS C. HORNE,
2 Attorneys for Arizona Association of Indus-
tries and Arizona Energy Users Association;

3 CARMICHAEL, McCLUE & POWELL by DONALD W.
4 POWELL, Attorneys for Homebuilders Asso-
ciation of Central Arizona;

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

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

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

10 J. MICHAEL MORRIS, on his own behalf;

11 RALPH W. VAUGHN, on his own behalf;

12 GODFREY J. DANIELSON, on his own behalf;

13 RAYMOND RUGGE, on his own behalf;

14 ROLAND JAMES, on his own behalf.

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

21 PURPA STANDARDS

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

28

- 1 1. Conservation of energy supplied by electric util-
- 2 ities;
- 3 2. The optimization of the efficiency of use of facil-
- 4 ites and resources by electric utilities; and
- 5 3. Equitable rates to electric consumers.

16 U.S.C. § 2611.

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

9 (1) Cost of service.--Rates charged by any
10 electric utility for providing electric service
11 to each class of electric consumers shall be de-
12 signed, 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.

13 (2) Declining block rates.--The energy com-
14 ponent of a rate, or the amount attributable to
15 the energy component in a rate, charged by any
16 electric utility for providing electric service
17 during any period to any class of electric con-
18 sumers may not decrease as kilowatt-hour consump-
19 tion by such class increases during such period
except to the extent that such utility demon-
strates that the costs to such utility of provid-
ing electric service to such class, which costs
are attributable to such energy component, de-
crease as such consumption increases during such
period.

20 (3) Time-of-day rates.--The rates charged
21 by any electric utility for providing electric
22 service to each class of electric consumers shall
23 be on a time-of-day basis which reflects the costs
24 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 sec-
tion 2625(b) of this title.

25 (4) Seasonal rates.--The rates charged by
26 an electric utility for providing electric ser-
27 vice to each class of electric consumers shall
28 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.

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(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 non-regulated 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 non-regulated 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).

.....

1 rate design which may affect adversely APS existing customers.

2 Further, we do not intend by our adoption of the Cost
3 of Service standard to endorse any particular costing method-
4 ology; in that regard, we intend to maintain for all affected
5 interests and this Commission the continued freedom to employ a
6 marginal cost of service study or an embedded cost of service
7 study or any other methodology or combination thereof. Consis-
8 tent with that objective, and to assure meaningful assessments in
9 future rate proceedings of available costing methodologies, APS
10 is hereby directed to include both a marginal cost of service
11 study and an embedded cost of service study in its rate design
12 filings in future rate proceedings.

13 In connection with our decision to adopt the Cost of
14 Service standard, we are mindful and supportive of our Staff's
15 recommendation that implementation be a cautious and gradual
16 process.

17
18 DECLINING BLOCK RATES

19 We hereby express our intention to effect the eventual
20 elimination of declining block rates for the APS system, except
21 to the extent APS demonstrates to the satisfaction of this
22 Commission in any particular instance that the energy-related
23 costs to APS of providing electricity decreases as consumption
24 increases. Our rate of progress in achieving that objective
25 will be dependent upon reasonable application of principles of
26 stability and continuity of rates.

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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

1 system and to appropriately recognize those commercial and indus-
2 trial users which are willing to tolerate interruption during
3 peak periods, we conclude that adoption of the interruptible
4 rates standard is appropriate for the APS system. The record
5 discloses that APS has had limited success in its effort to
6 make available interruptible rates to commercial and industrial
7 customers on a voluntary basis. With the objective of improving
8 that success record, APS is hereby directed to survey its indus-
9 trial and commercial customers and to report to this Commission
10 within 18 months after the effective date of this Decision regard-
11 ing the viability of a voluntary interruptible rates program.
12 The written report shall detail the costs of providing such ser-
13 vice, the categories of customers which would benefit by such
14 rates, the proposed timing and duration of interruptions, poten-
15 tial problems associated with participation by various categories
16 of customers and any other information which would assist this
17 Commission in its evaluation of the practicability of an effec-
18 tive voluntary interruptible rates program.

19
20 LOAD MANAGEMENT TECHNIQUES

21 It would be curious indeed if one were to not readily
22 applaud management techniques which are directed to the reduction
23 of peak demand, assuming the long-run cost savings of such reduc-
24 tion are likely to exceed the long-run costs associated with im-
25 plementation of such techniques. Our adoption herein of the load
26 management techniques standard reflects our commitment to encour-
27 age the implementation by APS of such techniques.

28 Within 18 months after the effective date of this

1 Decision, APS shall furnish a written report to this Commission
2 detailing (1) load management options which are available to
3 APS, (2) analyses of the cost effectiveness of the various
4 options and (3) a plan for load management.

5 NON-PURPA ISSUES

6 For the reasons detailed hereinafter, we hereby approve
7 (1) APS' proposed ECT-1 rate schedule, which provides optional
8 time-of-day rates for those residential customers who believe
9 their consumption characteristics would warrant being billed on
10 that basis, (2) Staff's proposed ET-1 rate schedule, which pro-
11 vides on alternate time-differentiated rate schedule and (3) to
12 a limited extent, APS' proposed modification to its Purchased
13 Power and Fuel Adjustment Clause to exclude from the calculation
14 of the system average the fuel and related costs for generation
15 units devoted to producing power for layoff sales.

16 1. Optional Time-of-Day Rates for Residential
17 Customers.

18 Since the rates included in APS' proposed ECT-1 rate
19 schedule do not include a revenue erosion adjustment and since
20 the expected impacts of time-of-day rates on the APS system for
21 residential customers continues somewhat in the experimental
22 stage, we are in agreement with our staff and APS' suggestion
23 that the rate be limited at this time to 1,000 customers.

24 Staff has proposed a tariff provision with respect to
25 meters for the ECT-1 rate schedule which we think is appropriate
26 and, accordingly, we adopt staff's proposed provision, which is:

27 The cost of metering facilities in excess
28 of the cost of metering for the EC-1 rate

1 shall be charged to the customer at a rate
2 of \$4.50 per month.

3 As an alternative to APS' proposed ECT-1 rate schedule,
4 we are approving Staff's proposed ET-1 rate schedule. Both
5 rates, of course, are being made available on an optional
6 basis; and each at the present time is being limited to 1,000
7 customers at the urging of both APS and our Staff. With respect
8 to the meters for the ET-1 rate, APS shall include the following
9 provision in the applicable tariff:

10 The cost of metering facilities in excess
11 of the cost of metering for the EC-1 rate
12 shall be charged to the customer at a rate
13 of \$2.40 per month.

14 2. Modification to APS' Purchased Power and Fuel
15 Adjustment Clause.

16 We are not prepared at this time to decide whether or
17 not it is appropriate, with respect to all non-jurisdictional
18 layoff sales of power, to exclude the associated fuel and related
19 costs from calculation of the system average when utilizing the
20 Purchase Power and Fuel Adjustment Clause.

21 However, we are satisfied at the present time that such
22 treatment of the layoff sales to Utah Power & Light from the
23 Cholla 4 Plant is justified and appropriate on the basis of the
24 record in this proceeding. Accordingly, we hereby approve such
25 treatment of those sales. However, our treatment herein of such
26 sales is subject to further examination; specifically, we intend
27 to scrutinize such treatment when modification of the adjustment
28 clause is considered next by the Commission.

Insofar as APS' requested modification relates to

1 other layoff sales, a decision on that requested modification
2 is deferred until the next general rate proceeding.

3 Mandatory Time-of-Day Rates for Extra Large General
4 Service Customers.

5 The record discloses that the affected extra large
6 customers already have the metering in place to commence imple-
7 mentation of mandatory time-of-day rates. Consistent with our
8 stated commitment hereinabove to encourage the implementation
9 of time-of-use rates that are cost-effective, we are anxious to
10 move forward immediately with implementation of either APS'
11 proposed ECT-2 rate schedule or some acceptable variation thereof;
12 however, we are concerned after our examination of the record
13 that we may not be informed sufficiently regarding the intra
14 class dislocations that could be expected to result and, most
15 particularly, how such dislocations likely may affect adversely
16 any individual customer.

17 In an effort to avoid any unnecessary delay in the im-
18 plementation of appropriate, mandatory time-of-day rates for APS'
19 Extra Large General Service Customers, and in an effort to be
20 assured that any action we take in that regard is based on re-
21 liable and complete information, APS and the parties representing
22 the customers which would be affected by such rates are requested
23 to submit to this Commission no later than December 1, 1981 spe-
24 cific information regarding expected impacts on individual cus-
25 tomers within the Extra Large General Service class. Further,
26 such parties may submit to this Commission on or before December
27 1, 1981 any additional information or comments pertaining in
28 any manner whatsoever to the proposed implementation of mandatory

1 time-of-day rates.

2 With respect to the remaining issues, which are related
3 to allocation of APS' revenue requirements among APS' customers
4 and the consequent design of specific rate schedules, we think
5 all affected interests would be served best by a deferral of our
6 treatment of such issues until the upcoming Phase II of the on-
7 going APS general rate proceeding.

8 Most importantly, to attempt a wholesale realignment
9 of rates at this time, with full knowledge that another compre-
10 hensive restructuring of rates reasonably can be expected within
11 the next 6 to 12 months in connection with the most current APS
12 general rate proceeding, would be to cause an unnecessary and
13 unwarranted disruption among all of APS' electric customers.

14 Considerations of rate stability mandate that we be
15 careful not to impose any more confusion and uncertainty re-
16 garding expected rates and charges than is required for our
17 regulatory purposes. Further, and of particular significance,
18 is the fact that our reexamination of APS' rate structure in
19 connection with the most current APS general rate proceeding
20 will be based on more current and more complete information.

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

23 ACCORDINGLY, IT IS ORDERED:

24 1. No later than December 10, 1981, Arizona Public
25 Service Company shall file with this Commission additions and/or
26 amendments to its existing tariffs which are consistent with
27 the findings, conclusions and directives set forth herein.

28 2. The gas rate schedules and the associated terms

1 and conditions which are included in the record as ATTACHMENT C
2 to APS' initial brief, filed June 5, 1981, are hereby adopted.

3 3. The rates, charges and tariff provisions estab-
4 lished herein shall become effective on January 1, 1982.

5 4. Within the time frames stated, Arizona Public Ser-
6 vice Company shall submit to this Commission the reports contem-
7 plated hereinabove in connection with our discussions of the PURPA
8 standards pertaining to interruptible rates and load management
9 techniques.

10 5. Arizona Public Service Company shall take immediate
11 steps which are reasonably calculated to lead to the provision of
12 electric service to residential customers under the new optional
13 time-of-day rate schedules.

14 BY ORDER OF THE ARIZONA CORPORATION COMMISSION

15
16 Bud Sims Diane Brumby Jim Walsh
17 CHAIRMAN COMMISSIONER COMMISSIONER

18
19 IN WITNESS WHEREOF, I, TIMOTHY A.
20 BARROW, JR., Executive Secretary
21 of the Arizona Corporation Commis-
22 sion, have hereunto set my hand
23 and caused the official seal of
24 the Commission to be affixed at
25 the Capitol in the City of Phoenix,
26 this 9th day of November
27 1981.

28
Timothy A. Barrow
TIMOTHY A. BARROW
Executive Secretary