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Arizona Corporation Commission
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BEFORE THE ARIZONA CORPORATION COMMISSION

DOUG LITTLE, Chairman
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TOM FORESE
ANDY TOBIN

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA, AND FOR RELATED APPROVALS.

Docket No. E-04204A-15-0142

NOTICE OF FILING SURREBUTTAL 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 surrebuttal testimony of Briana Kobor.

DATED this 23rd day of February, 2016.

ARIZONA CENTER FOR LAW IN THE PUBLIC INTEREST

By______________________
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All Parties of Record

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BEFORE THE ARIZONA CORPORATION COMMISSION

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND FOR RELATED APPROVALS.	Docket No. E-04204A-15-0142

SURREBUTTAL TESTIMONY AND EXHIBITS OF BRIANA KOBOR

ON BEHALF OF VOTE SOLAR

FEBRUARY 23, 2016

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Exhibit BK-SR-4: ACC Decision No. 52593 (Nov. 9, 1981)

1 Introduction

Q. Please state your name and business address.

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

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

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

Q. Did you submit direct testimony in this proceeding?

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

2 Purpose of Testimony and Summary of Recommendations

Q. Please describe how your testimony is organized.

A. The remainder of my testimony consists of eight sections. In the first section, I address the augments made in Staff and intervenors' direct testimony and in Unisource Electric, Inc. ("UNSE") rebuttal regarding the appropriateness of differential rate treatment for net energy metering ("NEM") customers. In the second section, I address the parties' positions and proposals regarding modifying the existing compensation structure for NEM exports. In the third section, I address the various proposals for mandatory demand charges that have been put forth in this case. In the fourth section, I address preferred alternatives to the mandatory demand charge proposals. In the fifth section, I address UNSE's rebuttal regarding proposed increases to the fixed charge. In the sixth section, I summarize my position on alterations to the current NEM program. In the seventh section, I address the importance of grandfathering existing NEM customers in the event of major rate design change. Finally, in the eighth section, I summarize my conclusions and recommendations.

Q. Please briefly summarize your findings and recommendations.

A. In its rebuttal testimony, UNSE has attempted to bolster its proposals for differential rate treatment for NEM customers. However, the Company has still failed to provide sufficient evidence to support its proposals. Notably, UNSE has not provided any evidence to rebut my findings in direct testimony that NEM customers are not a significant contributor to the problems the Company alleges are occurring as a result of low-usage customers. In rebuttal, UNSE provides bill frequency data that allegedly shows that NEM customers differ from non-NEM customers. I show, however, that the bill frequency data provided by UNSE demonstrates that NEM customers' bills are not outliers and are consistent with the variation seen in the residential class. In addition, UNSE has presented rebuttal testimony from a new witness, Dr. Overcast, which purportedly demonstrates that there is a cost shift related to NEM customers. I find that the alleged NEM-related cost-shift Dr. Overcast refers to is materially flawed and should not be relied on. For illustrative purposes, I examine the potential cost shift due to seasonal and vacant homes adopting Dr. Overcast's approach. This analysis shows that the potential cost shift from seasonal and vacant homes is as much as 32 times the alleged NEM-related cost shift. As a result, UNSE's attempts to single-out NEM customers for different rate treatment designed to address NEM-related load reductions would not only be discriminatory, it would also not materially impact the load reduction problems that UNSE alleges are occurring.

I also address the various proposals for mandatory demand charges for UNSE's residential and small commercial customers. I find that no state-regulated utility in this country has been approved to implement mandatory demand charges for its residential customers and that the proposal to do so in this case would thus be unprecedented. In addition, UNSE lacks sufficient data to fully understand the impact of its proposal, as evidenced by the number of recommended safeguard measures. Even with these safeguard measures in place, I find that nearly one in five residential customers is expected to see a bill increase in excess of 30% and one third of small commercial customers would be expected to see a bill increase in excess of 50%. In addition, "vulnerable" customers will face considerable difficulty in self-identifying given that they do not have access to the usage data that would be needed to determine how the proposals would impact them. In addition, I find that the proposal to keep the rate case open for a period of time to address unforeseen bill impacts only points to the uncertain and unprecedented nature of the proposal. A proposal that requires so many safeguards should raise red flags at the Commission.

I find that mandatory demand charges for UNSE's residential and small commercial customers would constitute a dangerous experiment in unprecedented rate design changes that would have a large and unavoidable impact on real people with real investments. I find that while the proposed education plan may inform customers on why their bills have increased by 30%-50% or more, many customers will have little ability to do avoid those increases. While UNSE may argue that this would be an unfortunate but "fair" result of moving rates toward cost-causation, I examine real-world examples to show that the proposed demand charges may not be cost based at all. As a result of these findings, I recommend that the Commission reject the proposals for mandatory demand charges and instead approve demand charges only on an optional basis.

I also show that there are alternative rate design measures that would better address the problems UNSE and Staff hope to solve with demand charges. Time-of-use ("TOU") rates are a preferred alternative to demand charges because they provide a more actionable price signal to customers. In addition, minimum bills are a preferred alternative to demand charges for addressing the alleged problems from low-usage customers.

I additionally evaluate UNSE's rebuttal arguments for increasing the basic customer charge for residential and small commercial customers through the Minimum System Method, rather than continuing to use the Basic Customer Method. I find that UNSE's critiques of the Basic Customer Method are based on mischaracterizations, and I recommend that the Commission continue to approve the Basic Customer Method. I also find that the majority of parties to this proceeding are opposed to increases to the basic customer charge because increased fixed charges would have a detrimental impact on conservation, energy efficiency, and distributed generation ("DG"), and would disproportionately impact low-income customers. As a result I recommend that the Commission reject UNSE's proposed increased to the basic customer charge for residential and small commercial customers.

Finally, I show that the rate proposals put forth by UNSE, Staff, and the Residential Utility Consumer Office ("RUCO") would implement major rate design changes. If any of these proposals are approved, customers who have signed up for the NEM program before the decision in this proceeding should be grandfathered to protect the significant investments they have made.

3 UNSE has not demonstrated that NEM customer attributes warrant a new and discriminatory rate design

Q. Please provide a brief summary of your findings in direct testimony regarding the appropriateness of discriminatory rate treatment for NEM customers.

A. As I explain in detail in my direct testimony, UNSE claims that significant changes to the existing NEM tariff structure are necessary to address declining retail sales, inequitable cost shifts among customers, and harmful grid impacts. In examining the data, I found this rationale to be unfounded. DG is only a minor contributor to the reduction in retail sales compared with other factors. For example, 98% of the residential customers that UNSE alleges are causing an inequitable cost shift are not NEM customers. UNSE has also not established that DG causes significant impacts on the Company's grid.

3.1 Other parties' positions on whether NEM customers differ from similarly-situated customers and should be treated differently

Q. Have other parties addressed the appropriateness of discriminatory rate treatment for NEM customers in the UNSE application?

A. Yes, Staff and a number of intervenors agree that UNSE has not provided sufficient evidence to support discriminatory treatment of new NEM customers. These parties include Commission Staff, the Arizona Utility Ratepayer Alliance ("AURA"), the Alliance for Solar Choice ("TASC"), and Western Resource Advocates ("WRA"). RUCO has proposed an alternative rate design scheme for NEM customers.

Q. Please describe Staff's position on whether UNSE provided sufficient evidence to support a discriminatory rate treatment for NEM customers.

A. Staff has made it clear that it disagrees with UNSE's attempts to single-out NEM customers for differential treatment. Staff Director Broderick states:

> Staff does not agree with UNSE's proposal to treat new DG customers differently from existing DG customers in regard to the availability of tariff(s) offered by their utility. Staff believes the DG concern is an emerging concern for utilities and not yet of such a significant magnitude to warrant a one-off approach. For the most part, a utility's concern relates to future periods from forecasting continued DG penetration at increasing rates.[1]

[1] Broderick Direct Test. at 6:9–13.

Mr. Broderick additionally states, "Staff concludes it is best if utility rates are designed to be neutral, agnostic, and unbiased towards the technology and lifestyle choices of customers."[2] He elaborates by stating:

> A one-off tariff regime for new DG threatens to unravel the long-lasting system of subsidies and premiums embedded in existing utility rates. These existing subsidies do not need to be fully threatened as a result of new technology. Once DG customers are singled out for special treatment, it sets a precedent for singling out other customer categories enjoying other subsidies.[3]

Q. Please describe AURA's position on which customers currently receive subsidies under the existing rate structure.

A. Tom Alston, witness for AURA, points out that a number of other groups receive subsidies under the current rate structure, including owners of vacant properties, summer home owners, and seasonal "snowbirds."[4] Mr. Alston states:

> With the emphasis on volumetric rates, customers such as these are not covering their own share of fixed costs, which means they are being subsidized by other customers. UNS must provide and maintain generation, transmission lines, and distribution lines year-round, but actual energy usage is low. In many such cases, it is likely that these types of customers use fewer kWh per billing period than those utilizing DG, without any off-setting economic and societal benefits.[5]

Q. Does Vote Solar agree with Staff and AURA's statements?

Yes, Vote Solar generally agrees with Staff's and AURA's above-quoted statements. There are numerous subsidies embedded in rates. For example, urban customers typically subsidize rural customers, and commercial customers typically subsidize residential customers. If NEM customers are given separate rate treatment despite lack of any evidence showing that the alleged subsidy is greater than the many other subsidies inherent in rates, the Commission would

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[2] *Id.* at 6:22–23.
[3] *Id.* at 7:4–8.
[4] Alston Direct Test. at 3:1–3.
[5] *Id.* at 3:3–8.

need to consider separate rate treatment for rural customers, seasonal customers, low usage customers, customers employing refrigerated AC, etc. In the future, with greater deployment of distributed energy resources ("DERs"), the Commission would also need to consider separate rate treatment for customers adopting a number of additional technologies. Such extensive piecemeal ratemaking would add significant complexity. Moreover, unless rates are designed on a customer-by-customer basis, such piecemeal ratemaking would continue to include some level of cross-subsidization between customers. Finally, in order to reliably assess whether a subsidy exists between NEM customers and non-NEM customers, a full benefit/cost analysis of DG that is specific to the UNSE system must be completed. Section 3.2.2 of this testimony provides further information on the relationship between the alleged NEM subsidy and the potential subsidy attributable to seasonal and vacant homes.

Q. Please describe RUCO's alternative NEM proposal.

A. RUCO has offered an alternative proposal that is specific to NEM customers. Despite the lack of evidence in this proceeding to support differential rate treatment for NEM customers, RUCO's proposal would limit the rate options available to NEM customers. This proposal is addressed in detail in Section 4.3 of this testimony.

3.2 UNSE rebuttal

Q. Did UNSE provide any arguments to rebut your direct testimony showing that it did not provide sufficient data to support its proposed NEM tariff modifications?

A. No. UNSE attempts to justify its proposals singling-out NEM customers by claiming that they are categorically different than other residential and small commercial customers. But the Company does not address the fact that its case lacks any actual data to support its claims regarding the alleged cost shift and grid impacts it attributes to NEM customers. This is illustrated by the rebuttal testimonies of Mr. Dukes, Dr. Overcast, and Mr. Tilghman.

3.2.1 Rebuttal Testimony of Mr. Dukes

Q. What arguments did Mr. Dukes make in rebuttal testimony to support discriminatory rate treatment for NEM customers?

A. According to Mr. Dukes, Vote Solar's and TASC's arguments that the proposed differential rate treatment for NEM customers would be discriminatory is "wholly unfounded."[6] But he fails to provide any evidence to support this statement or UNSE's claims that NEM customers substantially differ from residential and small commercial customers. Mr. Dukes relies heavily on Dr. Overcast's rebuttal and, additionally, points to actions by the Public Utilities Commission of Nevada ("PUCN") and the Public Service Commission of Utah ("Utah PSC") as apparent evidence that discriminatory rate treatment would be appropriate in Arizona.[7]

Q. Please explain the action taken by the PUCN and the relevance to this case.

A. The PUCN recently approved a utility proposal to single-out NEM customers for punitive treatment. The measures apply to both existing and new NEM customers, and include a rate with a high fixed charge and a large reduction in the compensation paid for DG exports.[8] While Vote Solar does not support the cost study developed in the PUCN docket and has recommended that it be rejected, the docket did include a cost study based on actual NEM customer data from the two utilities in the case,[9] which UNSE has failed to provide in this case.

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[6] Dukes Rebuttal Test. at 17:9.
[7] *Id.* at 17:25–18:4.
[8] *Application of Nev. Power Co. y d/b/a NV Energy for approval of a cost-of-service study and net*, Order, Docket Nos. 15-07041, 15-07042 (PUCN Feb. 17, 2016) ("PUCN Order") *available at* http://pucweb1.state.nv.us/PDF/AxImages/DOCKETS_2015_THRU_PRESENT/2015-7/9692.pdf.
[9] *Id.* at 11.

The PUCN decision has little relevance to this case. The PUCN decision was in a different state and was based on a different set of facts and, therefore, is not any more helpful than any other state Commission decision when rationalizing factual findings in Arizona. It is notable that the PUCN decision on NEM changes has caused significant controversy and economic impacts in the state of Nevada. As a result of the PUCN decision, major solar companies have eliminated jobs in Nevada, putting hundreds of people out of work.[10]

Q. Please explain the action taken by the Utah PSC and the relevance to this case.

A. As Mr. Dukes stated in his testimony, the Utah PSC ordered that upcoming cost of service studies segregate NEM customers. The Utah PSC described the reasoning for this order as follows:

> Whereas comparing the segregated classes will allow the parties and the Commission to assess whether non-net metering customers are subsidizing net metering customers under the extant rate structure and to compare the magnitude of any subsidy to the total benefit (or cost) net metering customers bring to the class. To be clear, the Commission is not here concluding that a new rate class should be instituted for net metering customers. However, we believe segregating the customer classes for, at least, these limited analytical purposes will prove instructive in rate setting . . . .[11]

As discussed above, the factual findings of such an analysis would have little relevance to the present case. However, this decision echoes Vote Solar's procedural argument that Arizona's NEM rules require that the local utility must conduct a cost of service study that analyzes NEM customers as a separate class

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[10] Sean Whaley, *Utility regulators reject call to delay new rooftop-solar rates*, Las Vegas Review-Journal (Jan. 13, 2016), *available at* http://www.reviewjournal.com/business/energy/utility-regulators-reject-call-delay-new-rooftop-solar-rates.

[11] *In re the investigation of the costs and benefits of PacifiCorp's net metering program*, Order, Docket No. 14-035-114, at 11, (Utah PSC Nov. 10, 2015) ("Utah PSC Order"), *available at* http://www.psc.utah.gov/utilities/electric/elecindx/2014/documents/270449140351140.pdf.

in order to change the existing rate structure. As described in detail in my direct testimony, UNSE has failed to conduct a cost of service study that analyzes NEM customers as a separate group of customers from the residential and small commercial classes. In fact, UNSE has failed to conduct even a basic assessment of the usage data of its NEM customers, which is foundational to any examination of relative cost to serve.

Mr. Dukes cites to the Utah PSC Order in support of his claim that "utility commissions in other states are finding that DG customers impact the grid differently than traditional full requirements customers."[12] However, Mr. Dukes has mischaracterized the Utah PSC Order. Instead, the Order stressed the need for a full examination of the costs and benefits of DG in order to inform future NEM rate treatment.

3.2.2 Rebuttal Testimony of Dr. Overcast

Q. What arguments did Dr. Overcast make in rebuttal testimony to support discriminatory rate treatment for NEM customers?

A. Dr. Overcast attempts to argue that discriminatory rate treatment is appropriate for NEM customers by analyzing bill frequency data and attempting to quantify a cost shift that he attributes to installed NEM capacity. However, the bill frequency data actually proves that NEM customer bills are not significantly different than non-NEM customer bills. In addition, an examination of his cost shift analysis illustrates how the problems UNSE claims are occurring are not a result of NEM. Dr. Overcast's approach is flawed for several reasons:

(1) Like UNSE, Dr. Overcast does not examine any actual usage data from UNSE's NEM customers. More troubling, he attempts to extrapolate specific findings about DG exports from utility-scale solar data that contains no information about consumption patterns, resulting in significant errors in his assumptions.

[12] Dukes Rebuttal Test. at 18.3–4.

(2) Dr. Overcast's analysis is limited to short-term load reduction impacts when the Commission has clearly indicated that DG must be evaluated over the long term.[13]

(3) Dr. Overcast focuses only on load reductions due to DG despite evidence that DG-related load reductions are only a small part of UNSE's load concerns, and that load reductions from seasonal and vacant homes and energy efficiency reductions far eclipse the reductions from DG.

Q. Please comment on Dr. Overcast's use of bill frequency data in his testimony.

A. Dr. Overcast claims that "[w]hile it may be inconvenient for the solar advocates to recognize that solar DG customers differ from full requirements customers the evidence shows that this is precisely the case."[14] He attempts to back up this claim by examining bill frequency data and pointing to the fact that about 57% of the bills issued to NEM customers were for zero kWh usage. He also claims that about 89% of NEM customers' bills do not include usage in the third tier, while that figure is only 69% for non-NEM customers.[15]

Q. Do you agree that the bill frequency data demonstrates that NEM customers meaningfully differ from non-NEM customers?

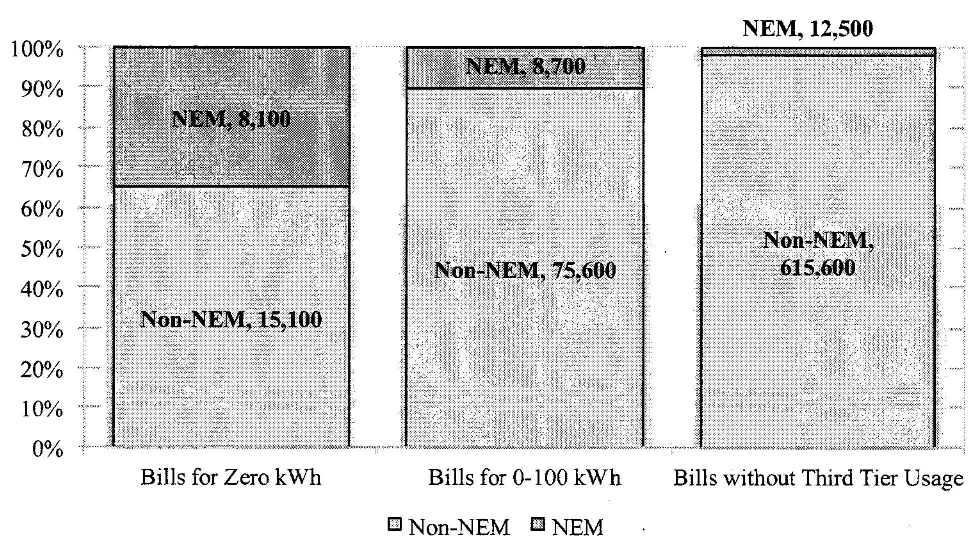
A. No. In fact, examination of the bill frequency data for NEM and non-NEM customers reveals just the opposite: NEM customer bills are not outliers, but rather are consistent with the variation seen in the residential class. While a larger proportion of NEM bills reflect zero kWh of usage, there were over 15,000 bills issued for zero kWh to non-NEM customers. Thus, nearly twice as many non-NEM customers received bills for zero kWh than NEM customers received. Moreover, when you look at bills for only a very small number of kWh (100 kWh or less), the data reveals that while NEM customers received only 8,700 bills for

[13] Comm'r Doug Little, Commissioner's Investigation of Value and Cost of Distributed Generation, Docket No. 14-0023, at 1 (Dec 22, 2015) ("Comm'r Little Letter").
[14] Overcast Rebuttal Test. at 24:15–17.
[15] *Id.* at 25:10–17.

100 kWh or less, non-NEM customers received 75,600 bills. This means that only 10% of bills for very low usage were issued to NEM customers. This finding is consistent with the data described in my direct testimony demonstrating that the majority of the problems UNSE is experiencing due to low usage customers are not a result of NEM. In fact, 9 out of 10 bills issued for exceedingly low usage were issued to non-NEM customers, likely customers with vacant or seasonal homes.

Dr. Overcast also attempts to make an issue of the proportion of NEM customer bills for usage that does not reach the third tier. However, the number of bills for usage below the third tier that were issued to non-NEM customers vastly overwhelms the number issued to NEM customers. The data shows that 615,600 bills were issued to non-NEM customers for usage below the third tier while only 12,500 such bills were issued to NEM customers. Thus, NEM bills accounted for only 2% of this category of bills. These findings are summarized in Figure 1 below.

Figure 1: Bill Frequency Comparison, NEM, and Non-NEM Residential Customers



These findings corroborate my discovery response that Dr. Overcast referred to in his rebuttal: UNSE has not provided evidence that the Company's NEM and non-

NEM customers have significantly different consumption patterns greater than the inevitable diversity in consumption within the residential and small commercial classes.[16] Indeed, they prove that NEM customers' bills are not outliers in the residential class, and that singling out these customers for differential rate treatment would in fact be discriminatory.

Q. Did UNSE utilize NEM customer usage data specific to its customers in this case?

A. No, in its original application UNSE failed to examine any actual data on its own NEM customers. Instead, the Company opted to analyze the impacts of its proposal based on average full requirements customer load shapes with an engineering-based assessment of solar generation assuming customers size their solar photovoltaic ("PV") systems to offset 100% of annual energy requirements.[17] I highlighted in my direct testimony that UNSE has not provided any information to assess the reasonableness of this assumption. And even if the Company did provide this information, a study would need to be made of the diversity among UNSE's NEM customers in order to properly assess the impact the company's proposals would have on NEM customers.[18]

Q. Should UNSE have used actual NEM customer usage data?

A. Yes, examining actual NEM customer usage data is not unusual when evaluating NEM-specific rate design changes. To cite just a few recent examples, Arizona Public Service Company's ("APS") recent NEM docket contained analyses of actual NEM customer load data,[19] as did the recent proceeding in Nevada,[20] and the order recently issued by the Utah PSC specifically instructed the utility to

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[16] *See id.* at 25:2–6 (stating Vote Solar's position in direct testimony).
[17] Kobor Direct Test. at 47:21–48:5.
[18] *Id.* at 49:7–13.
[19] UNSE Resp. to VS 5.53(c) (Ex. BK-SR-1 at 13).
[20] Note that Vote Solar does not support the cost study put forth in the Nevada proceeding and has recommended that it be rejected. *See* PUCN Order at 11.

examine NEM customers separate from non-NEM customers.[21] These examples indicate that it is reasonable to expect that as part of the due diligence to design and request far-reaching modifications to NEM rate structure, UNSE should take the time to isolate and understand the actual usage patterns of its own NEM customers.

Q. Please describe the data used by Dr. Overcast in support of his rebuttal testimony regarding the alleged subsidy related to NEM customers.

A. Dr. Overcast bases his analysis on solar production data from two utility-owned and operated solar facilities, La Senita and Rio Rico.[22] He has not examined any actual data on the consumption patterns of UNSE's NEM customers.[23] Moreover, Dr. Overcast's cost shift assumptions are not even based on UNSE customer usage data from the residential and small commercial classes.[24] Rather, his analysis is based on a number of broad-brush assumptions as discussed below, resulting in significant errors that are evident when the available data is examined.

Q. Why is it not appropriate to look at solar production data from La Senita and Rio Rico to inform the discussion of NEM-related costs?

A. While I agree that production data from La Senita and Rio Rico may be informative as a proxy for the generation profile of NEM customers' solar DG systems, production data looks at only one piece of a complicated picture. To truly understand the impact that NEM customers have on UNSE's costs, it is necessary to examine of the timing and seasonality of DG exports and system deliveries to NEM customers. Dr. Overcast's analysis contains none of this information.[25] In fact, nowhere in his analysis does he even look at the average

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[21] Utah PSC Order at 11.
[22] Overcast Rebuttal Test. at 12:16–19.
[23] UNSE Resp. to VS 5.10(a) (Ex. BK-SR-1 at 7).
[24] Overcast Workpaper, BV Data Request_Analysis v4.xlsx.
[25] Overcast Workpaper, BV Data Request_Analysis v4.xlsx, UNSE Resp. to VS 5.05 (Ex. BK-SR-1 at 6); UNSE Resp. to VS 5.10(b) (BK-SR-1 at 7).

residential customer's load profile in relation to solar production.[26] As a result, Dr. Overcast attempts to draw conclusions that are simply not supported by the data.

Q. What conclusions does Dr. Overcast reach that are not supported by the data?

A. In Exhibit HEO-2 to his rebuttal testimony Dr. Overcast presents data on the temporal relationship between system marginal generation cost and solar production at La Senita and Rio Rico.[27] He makes the following statement about the data presented:

> I have also prepared Exhibit HEO-2 that shows for the same two facilities that the hours of maximum output occur in hours other than the highest marginal cost hours in both the winter and the summer. This means that excess generation sold back to the utility occurs on average at times when the avoided energy cost is less than the average energy cost and less than the marginal cost of energy used by solar DG customers to meet the load in excess of solar DG.[28]

The second sentence of this statement is incorrect. First, the work papers behind Exhibit HEO-2 do not estimate the temporal relationship between excess generation sales and usage by solar DG customers. As a result, there is absolutely no basis for Dr. Overcast's assertion that avoided costs due to exports is less than the marginal cost of energy used by solar DG customers. Second, while UNSE has failed to provide actual usage data from its NEM customers, an examination of the NEM load profile assumptions employed by UNSE shows that the opposite is true. In fact, as shown in Table 1, UNSE's own data reveals that NEM customers export generation to the grid during hours that correspond to a higher

[26] I do not agree with the approach UNSE utilized in its application, where average residential load was compared with engineering based solar generation figures. But this flawed approach is preferable to Dr. Overcast's method, which does not include any information on the relationship between solar generation and customer consumption. Overcast Workpaper, BV Data Request_Analysis v4.xlsx, UNSE Resp. to VS 5.05 (Ex. BK-SR-1 at 6); UNSE Resp. to VS 5.10(b) (BK-SR-1 at 7).
[27] Overcast Rebuttal Test. at Ex. HEO-2.
[28] Overcast Rebuttal Test. at 13:9–14.

marginal cost than the hours in which NEM customers consume energy from the grid. Even with Dr. Overcast's narrow framing of costs; this is a clear short-term benefit from DG that was excluded from his analysis.

Table 1: Average Marginal Cost Comparison ($/MWh)

Category	Average Annual Marginal Cost
Deliveries	$24.72
Exports	$27.56

Q. What implications does this have for Dr. Overcast's assessment of the alleged cost shift attributable to NEM customers?

A. Dr. Overcast takes significant liberties with his assumptions. As illustrated by the example above, in several cases his assumptions are directly contradicted by the available data. As a result, even if one were to accept the approach Dr. Overcast uses to examine the impact NEM customers have on UNSE's costs, his assessment of the alleged cost shift is flawed.

Q. Please explain the approach used by Dr. Overcast to examine the impact NEM customers have on UNSE's costs.

A. Dr. Overcast takes a narrow, short-term look at the cost implications of DG to conclude that NEM customers shift over $91 per year to non-NEM customers for each kW of installed solar DG.[29] He arrives at this number by estimating utility revenue reduction that results from NEM customers offsetting a portion of their energy needs with DG and assigning a small benefit to what he calculates as the avoided energy costs attributable to DG.

Q. Do you agree with Dr. Overcast's approach to examining the impact NEM customers have on UNSE's costs?

A. No. Dr. Overcast's approach is essentially an examination of the costs attributable to DG-related sales reductions with little to no accounting for the benefits

[29] *Id.* at 19:13–14.

provided by DG. A complete understanding of the impact NEM customers have on UNSE's costs would necessitate examining the full range of costs and benefits attributable to DG. Such an analysis is the subject of the ongoing value and cost of DG docket (Docket No. 14-0023). In that docket, Commissioner Little has requested that the parties discuss a methodology that considers the following seven categories:

1. Utility Distributed Solar Costs;
2. Energy Generation Savings;
3. Generation Capacity Savings;
4. Transmission Capacity Savings;
5. Distribution Capacity Savings;
6. Environmental Benefits; and
7. Economic Development Benefits.[30]

Of these seven categories, Dr. Overcast's analysis addresses only the first two: utility distributed solar costs and energy generation savings. This is in part because of the short-term nature of his analysis, which relies only on a snapshot of utility costs. The true implications of DG cannot be evaluated on such a short-term basis, but rather must include an evaluation of the costs and benefits that accrue over the period of the DG investment. In fact, Commissioner Little instructed parties to evaluate DG installations over the useful life of the system.[31]

In addition, even if one were to entertain the notion of a short-term examination of costs related to NEM customers, several problems remain: (1) Dr. Overcast has made unreasonable assumptions in his analysis that skew his results; and (2) NEM customers should not be considered in a vacuum—the data in this case clearly show that the vast majority of UNSE's customers with little to no usage are not NEM customers. Utilizing Dr. Overcast's approach to compare the short-term cost implications of NEM customers and customers with seasonal homes reveals

[30] Comm'r Little Letter at 1–2.
[31] *Id.* at 2.

that customers with seasonal homes likely enjoy a much larger subsidy than the alleged subsidy attributed to NEM.

Q. Please describe the unreasonable assumptions used in Dr. Overcast's analysis.

A. Dr. Overcast purports to calculate what he describes as the annual delivery subsidy attributable to NEM customers. He values this subsidy at $44 per installed kW.[32] He calculates this value based on customer usage assumptions outlined in Table 1 of his testimony.[33] In Table 1 he compares two customers, both with a 10 kW maximum demand and 35,040 kWh of annual energy consumption. This implies that his illustrative customers would have an average monthly bill for 2,920 kWh. Examination of the bill frequency data reveals that only 3% of UNSE's residential bills were for more than 2,500 kWh.[34] In fact, a customer with annual consumption of 35,040 kWh would consume three and a half times as much as the average residential customer consumption of 10,011 kWh,[35] yet Dr. Overcast uses this example as the basis for his generic cost calculation.

This assumption is problematic when one considers that UNSE has an inclining block charge for its Delivery Services – Energy charge. This means that Dr. Overcast assumes that all the reduction in consumption resulting from the solar installation will offset energy in the third and most expensive tier. Such an assumption results in the highest possible valuation of what he terms the "delivery subsidy" and is entirely inconsistent with UNSE's own assertion that most NEM customers size their systems to offset 100% of their load.[36]

While I disagree with Dr. Overcast's approach to valuing the short-term costs of DG while ignoring key benefits, for illustrative purposes I have recalculated his

[32] Overcast Rebuttal Test. at 16:3–4.
[33] *Id.* at 15:10.
[34] Overcast Workpaper, UNSE 2014 Bill Freq with NEM Breakouts.xlsx.
[35] Jones Rebuttal Test. at Ex. CA-J-R-4, Schedule H-2-1, p. 1.
[36] UNSE Resp. to VS 2.21 (Ex. BK-2 at 9).

purported $44/kW charge using more reasonable assumptions. Instead of looking at a customer who consumes in the top 3% of UNSE residential customers, I have examined a residential customer with average usage levels who has sized their DG system to offset 100% of annual energy consumption. This analysis reveals that under such assumptions, Dr. Overcast's approach would result in an estimated alleged subsidy of $24/kW—half of the $44/kW he attributes to installed solar capacity. Clearly, Dr. Overcast's assumptions have skewed his results.

Q. Can you describe how this alleged subsidy due to DG-related reductions in consumption relates to potential subsidies from other factors?

A. Yes. It has been widely demonstrated in this case that UNSE's purported problems due to low-usage customers are not NEM problems. This was illustrated in my direct testimony where I found that more than 95% of the bills issued for less than 300 kWh were issued to non-NEM customers.[37] Mr. Dukes has indicated that bills for less than 300 kWh are likely generated by vacant homes, seasonal customers, and NEM customers.[38] Dr. Overcast's analysis purports to evaluate the subsidy related to NEM customers, but ignores the fact that NEM customers constitute a very small proportion of the customers with low usage bills. For purposes of illustration, I have adopted Dr. Overcast's approach to develop an estimate of the subsidy attributable to seasonal customers that can be compared with Dr. Overcast's estimation of the subsidy attributable to NEM customers.

As a first step, it is necessary to convert Dr. Overcast's value of $91/kW to $/kWh. Using Dr. Overcast's assumptions this results in a value of 5.1¢/kWh that he attributes to customers' load reductions from energy that is supplied by a DG solar array rather than the grid. When the alleged delivery subsidy is recalculated based on more reasonable assumptions as described above, the alleged subsidy falls to 4.0¢/kWh for solar-related load reductions. Comparison with a potential

[37] Kobor Direct Test. at 15:3–8.
[38] Dukes Direct Test. at 12:11–13.

subsidy due to seasonal customers reveals a much larger value of 6.7¢/kWh of reductions in load due to seasonal occupancy. The value for seasonal customers is larger due to the fact that the majority of Dr. Overcast's calculations result from reductions in consumption attributed to DG. Like NEM customers, seasonal customers reduce their consumption compared with the average customer, however, unlike NEM customers, there is no energy benefit attributable to seasonal customers. The findings of my illustrative analysis are summarized in Table 2 below.

Table 2: Illustrative Results of Cost Shift Comparison b/w Seasonal and NEM Customers adopting Dr. Overcast's Approach (¢/kWh)

Component	Overcast Assumptions - NEM	Corrected Delivery Cost - NEM	Seasonal Customer Comparison
Delivery Cost	2.4	1.3	1.3
Energy Cost	5.4	5.4	5.4
Energy Benefit	-2.7	-2.7	-
Total	5.1	4.0	6.7

While I maintain that Dr. Overcast's approach has significant flaws and should not be used to draw conclusions about the impact that NEM customers have on UNSE's costs, I adopted Dr. Overcast's approach for the limited purpose of conducting an illustrative comparison between NEM customers and seasonal customers. As shown in Table 2 above, the alleged cost due to NEM is 40% less than the cost that could be attributed to seasonal/vacant customers on a per kWh basis. Because the data shows that seasonal or vacant homes cause nearly 20 times the number of low usage bills compared to NEM customers,[39] a quick calculation reveals that the cost shift due to seasonal or vacant homes may be as

[39] 5% of the bills for 300 kWh or less are attributable to NEM customers and UNSE describes the remaining 95% as attributable to seasonal or vacant homes. Thus, 95%/5% = 19.

much as <u>32 times as large</u> as the alleged cost shift Dr. Overcast attributes to NEM.[40]

Q. What do these findings imply?

A. These findings demonstrate that there is no basis for discriminatory rate treatment for NEM customers in this case. While Dr. Overcast has attempted to show that NEM customers shift costs to other customers, his approach is far too narrow and would find varying levels of subsidies for all customers that reduce consumption or have below average consumption. His approach excludes significant streams of benefits attributable to NEM customers, and when compared on equal terms with the potential cost shift due to seasonal and/or vacant homes, the alleged cost shift from NEM customers is insignificant.

3.2.3 Rebuttal Testimony of Mr. Tilghman

Q. What arguments does Mr. Tilghman make in rebuttal testimony to support discriminatory rate treatment for NEM customers?

A. Mr. Tilghman attempts to defend his position in direct testimony that DG is causing significant impacts on the Company's grid and that UNSE's proposal for differential rate treatment for NEM customers will ameliorate grid impacts. In addition, like Mr. Dukes, Mr. Tilghman points to a number of recent decisions by commissions in other states as apparent evidence that discriminatory rate treatment is appropriate in Arizona.

Q. What evidence does Mr. Tilghman provide in rebuttal to support the contention that DG causes significant impacts on the Company's grid?

A. In reference to my direct testimony showing that UNSE has not established that DG causes significant impacts on the Company's grid, Mr. Tilghman states:

[40] Alleged cost shift comparison: 6.6 ¢/kWh (seasonal) divided by 3.9 ¢/kWh (NEM) = 168%; 168% * 19 (see footnote above) = 32.

> Ms. Kobor simply points to a snapshot in time to justify her position. But the fact is that the cost-shift due to DG is a growing problem. Assuming that her conclusion is true (and we are not conceding that at this time) she ignores the increasing amount of DG installations that is [sic] and will augment the decline in retail sales beyond 6%.[41]

This characterization of my direct testimony is incorrect. In discovery, Vote Solar repeatedly asked UNSE to provide information about how the grid impacts the Company was describing would change with expected future levels of DG penetration, yet the Company failed to provide any such information.[42] Not only has UNSE failed to establish that DG is currently causing a significant impact on its grid, it has also failed to provide any information on the expected near-term "growing" impact.

More troubling, Mr. Tilghman argues that "now is the time to address this problem while it is at a manageable level."[43] However, UNSE has conducted no analysis of the impact that the Company's proposal would be expected to have on levels of DG deployment in the service territory.[44] As described in my direct testimony, approval of UNSE's proposed modifications would severely impact future solar adoption in its service territory, putting regulatory compliance at risk and potentially resulting in significant additional costs for ratepayers.[45] Essentially, UNSE has proposed sweeping changes based on a possible future problem, without any analysis as to the expected existence of the problem in its service territory. The Company has also not analyzed how and if its proposed solution would address the alleged problem.

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[41] Tilghman Rebuttal Test. at 3:25–4:1.
[42] *See, e.g.*, UNSE Resp. to VS 2.14 (Ex. BK-SR-1 at 1–2); UNSE Resp. to VS 2.16 (Ex. BK-SR-1 at 3); UNSE Resp. to VS 2.17 (Ex. BK-2 at 7).
[43] Tilghman Rebuttal Test. at 4:4–5.
[44] UNSE Resp. to VS 2.09(a) (Ex. BK-2 at 4).
[45] Kobor Direct Test. at 51–53.

Q. Does Mr. Tilghman provide any other evidence in rebuttal to support the contention that DG causes significant impacts on the Company's grid?

A. Yes. Mr. Tilghman attempts to use findings from other Arizona utilities and Commissions in other states to rationalize the sweeping changes advocated for regarding the current NEM structure. Specifically, Mr. Tilghman refers to Commission Decision No. 74202 regarding APS, and developments in Hawaii, Utah, and Nevada. The Utah and Nevada cases were discussed in response to Mr. Dukes' testimony above.

Q. How does Mr. Tilghman refer to Commission Decision No. 74202 and is it relevant to this case?

A. Mr. Tilghman claims that in Decision No. 74202, the Commission recognized that a cost-shift due to net metering exists.[46] What he fails to mention is that Decision No. 74202 was developed in a docket investigating NEM issues in APS' service territory and that it made no findings regarding a cost shift for the service territories of UNSE or Tucson Electric Power ("TEP").[47] Moreover, the proceeding that resulted in Decision No. 74202 included analysis on the actual usage characteristics of APS's NEM customers, something that is sorely lacking in UNSE's current case.[48] Finally, it is important to note that the Commission did not use this finding to authorize modification to the NEM export rate. In fact, Decision No. 74202 ordered "that the Commission will open a generic docket on the net metering issue and hold workshops with all stakeholders to help inform future Commission policy on the value that DG installations bring to the grid."[49] Mr. Tilghman's attempt to rationalize the proposed changes based on a Commission decision for a different utility based on a different (and more complete) set of facts is inappropriate. Rather than provide evidence to support approval of discriminatory rate treatment for UNSE's NEM customers, Decision

[46] Tilghman Rebuttal Test. at 4:12–13.
[47] UNSE Resp. to VS 5.53(a), (b) (Ex. BK-SR-1 at 13).
[48] *Id.* at UNSE Resp. to VS 5.53(c).
[49] Decision No. 74202 at 30:8–10 (Dec. 3, 2013).

No. 74202 points to the need for an examination of the value and cost of DG prior to approval of major changes to the NEM tariff structure.

Q. How does Mr. Tilghman refer to developments in Hawaii and are those developments relevant in this case?

A. Mr. Tilghman describes how regulators in Hawaii, where current NEM penetration is as much as 30% to 53% of system peak load, have recently implemented modifications to the state's NEM policies.[50] This comparison is problematic for two reasons. First, as described above in reference to Mr. Dukes' rebuttal testimony, it would be inappropriate for this Commission to set Arizona rate design based on decisions taken by a different commission in a different state based on a different set of facts. In addition, Arizona has nowhere near the level of DG penetration of Hawaii, nor is Arizona expected to reach Hawaii levels any time soon. Mr. Tilghman reports that net metering program capacity is currently only 3.5% of UNS's system peak load in the summer, and that in order to comply with Arizona RES rules, program capacity will increase to just over 10%.[51] The experience in Hawaii highlights the strength of the NEM policy, which was kept in place until DG penetration reached much higher levels of penetration than is expected in Arizona. The Hawaii Public Utilities Commission's order states the following:

> The commission has determined that DER policies and programs in Hawaii must evolve to meet changing customer and utility system needs. <u>This is in sharp contrast to the attempts in other states to alter or limit net metering before customer sited renewables have had the opportunity to scale or have resulted in significant technical integration challenges</u>. The NEM program has fulfilled its core objective of providing a simple and effective tool to jumpstart the adoption of distributed renewable energy. As a corollary, this policy also moved the DER industry in Hawaii past the early stages of development. Hawaii's electric utilities and the DER industry are now adapting to technical challenges not yet experienced in

[50] Tilghman Rebuttal Test. at 4:12–24.
[51] UNSE Resp. to VS 5.54(a), (b) (Ex. BK-SR-1 at 15).

> other jurisdictions, while developing advanced solutions that, in some cases, have not yet been tested in operating power systems.[52]

In addition, even with such large levels of DG penetration, Hawaii has continued to embrace solar development. The state recently passed legislation directing the utilities to generate 100% renewable power by 2045 and to promote deployment of additional distributed PV through community solar projects.[53]

4 The Commission should not modify the existing structure for NEM export remuneration

Q. Please provide a brief summary of your findings in direct testimony regarding the proposed modifications to the current NEM tariff structure.

A. As explained in detail in my direct testimony, UNSE has not established a need to modify the existing NEM tariff structure. The Company has not provided any evidence that would allow the Commission to make findings regarding the relationship between the Company's retail rate and the value of exported solar generation. In addition, even if the Commission were to determine that it was appropriate to modify the existing NEM structure, the proposed Renewable Credit Rate should be rejected because it does not appropriately approximate the value of DG, the proposed rate would be volatile and vulnerable to gaming, and the proposal would violate existing NEM rules.

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[52] *In re PUC Instituting a Proceeding to Investigate Distributed Energy Resource Policies*, Docket No. 2014-0192, at 161–62 (HPUC Oct. 13, 2015) (emphasis added), *available at* http://puc.hawaii.gov/wp-content/uploads/2015/10/2014-0192-Order-Resolving-Phase-1-Issues-final.pdf.

[53] Press Release: Hawaii.gov, Governor Ige signs bill setting 100 percent renewable energy goal in power sector, *available at* http://governor.hawaii.gov/newsroom/press-release-governor-ige-signs-bill-setting-100-percent-renewable-energy-goal-in-power-sector/.

4.1 Other Parties' positions

Q. Have any other parties expressed concern with the proposed Renewable Credit Rate?

A. Yes. Commission Staff and TASC raised detailed concerns with the proposed Renewable Credit Rate. Both Staff and TASC criticize UNSE's proposal to approximate the value of DG exports based on a utility scale power purchase agreement ("PPA") price. Staff witness Mr. Solganick states that "[e]xcess energy from a photovoltaic DG installation is not entirely representative of a utility scale PV facility because the DG customer is providing the net output equal to the photovoltaic output less any energy consumed by the customer."[54] In addition, Mr. Solganick raises questions regarding the inclusion of losses, transmission and distribution savings in the proposed Renewable Credit Rate.[55]

TASC witness Mr. Fulmer raises similar concerns about using the price of a utility-scale PPA to compensate customers for DG exports, and additionally raises issues associated with the volatility of the proposed rate and potential tax implications.[56]

The concerns raised by Staff and TASC support the need for a detailed benefit/cost study of DG on the UNSE system prior to modification of the NEM export rate. Indeed, Staff points out that Docket No. 14-0023 may provide useful information to the parties in this case.[57]

4.2 UNSE Rebuttal

Q. What was UNSE's response to the issues raised by Vote Solar, Staff, and TASC regarding the Renewable Credit Rate?

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[54] Solganick Direct Test. at 43:10–12.
[55] *Id.* at 44:21–45:14.
[56] Fulmer Direct Test. (Rate Design and Cost of Service) at 4:5–6:20.
[57] Broderick Direct Test. at 11:5–9.

A. UNSE's response highlights the fundamental tension regarding the appropriate valuation of DG exports. Namely, UNSE's proposal is centered on short-term costs, while other parties (and the Commission in its guidance of the value and cost of DG docket)[58] look to the long-term value of DG. This disconnect is illustrated in the following statement by Mr. Tilghman: "[T]he RCR is a far better reflection of the cost of energy produced by DG than the retail rate . . . [w]hile UNS Electric's proxy as to the RCR is not perfectly precise, it much better reflects the actual cost to produce the energy."[59]

UNSE's position is problematic because the compensation NEM customers receive for their exported energy should reflect the value that energy provides to the non-participating ratepayers who consume it, not just an estimation of the cost to produce the energy. Ensuring that the compensation NEM customers receive for exported energy reflects an appropriate level of value and benefits provided by that energy is essential to ensuring that optimal DG deployment can continue. In order to properly evaluate the benefits of solar, the Commission must consider real benefits that may differ between DG and utility scale solar such as reduction in line losses, avoided transmission, distribution and generation capacity needs, grid support services, local economic benefits, and differential environmental benefits.

UNSE had the opportunity in this proceeding to provide a credible assessment of the value of DG to inform its proposed departure from crediting DG exports at the retail rate under the current NEM tariff, but has failed to do so. Absent a credible analysis by which to determine the relationship between the current retail rate and the value of DG exports, the Commission has no basis on which to evaluate the proposed Renewable Credit Rate.

[58] Comm'r Little Letter at 2.
[59] Tilghman Rebuttal Test. at 7:5–10.

Q. Has UNSE's recommendation regarding the Renewable Credit Rate changed in rebuttal testimony?

A. Yes. Mr. Tilghman states: "Staff has proposed a three-part rate structure that, if properly designed and implemented in a timely manner, would eliminate the need to specifically address the current NEM policy."[60] This implies that UNSE would support maintaining full retail rate compensation for NEM customers if a mandatory demand charge is approved. Interestingly, UNSE's original proposal included a larger demand charge for NEM customers than Staff's proposed demand charge ($6.00-$9.95/kW versus $4.78/kW).[61] Mr. Tilghman's evolution in opinion on this issue begs the question of why modification to the NEM export credit would be necessary under UNSE's original proposal in the first place. Vote Solar does not support approval of mandatory demand charges for any customers, NEM or non-NEM. But in the event that the Commission approves mandatory demand charges that would apply to NEM customers, full retail rate compensation for NEM exports should be maintained and the Commission should reject the proposed Renewable Credit Rate.

4.3 RUCO's NEM tariff proposal should be denied

Q. Please summarize RUCO's proposal for modifying the current NEM tariff.

A. RUCO has proposed a new NEM program that would include three different tariff options. The first option, called the "Non-Export Option," would allow NEM customers to take service on the standard residential rate, but would completely eliminate net metering by not allowing customers to receive any credit for exporting energy back to the grid. The second option, called the "Advanced DG TOU Option," would place DG customers on a rate with a minimum bill, require them to pay a demand charge for summer peaking hours, and implement a volumetric charge linked to a crude approximation of the value of solar.

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[60] *Id.* at 3:16–18.
[61] *See infra* p. 34, Table 3.

Compensation for solar generation would be based on this same crude approximation. The third option, called the "RPS Bill Credit Option," would allow customers to take service on the standard residential rate, but would require that all energy generated by the customer's DG system be sold to the utility at a predetermined credit rate that would decline over time. Under the latter two options, customers would be encouraged or required to provide renewable energy credits ("RECs") to UNSE.

Q. Do you support any of RUCO's proposals?

A. No. As described above and in my direct testimony, UNSE has not put forth sufficient evidence to establish whether the current NEM tariff structure results in a cost shift either to or from non-NEM customers. UNSE has also not established that the cost shift it alleges is occurring is greater than the many other cost shifts inherent in rates. As a result, there is no basis for approving differential rate treatment for NEM customers. In addition, even if the Commission were to find that differential rate treatment was warranted, the proposed tariff options put forth by RUCO are problematic and should not be adopted.

Q. Why do you not support the Non-Export Option?

A. RUCO's proposed non-export option would allow the customer to choose between available standard residential rates, but would restrict the customer's ability to export excess generation to the distribution grid.[62] Mr. Huber's testimony indicates that "[r]estricting power to the grid would be accomplished primarily through inverter curtailment."[63] In other words, rather than taking advantage of the electricity generated by customer-financed distributed energy, the excess energy would be wasted. Thus, under this option the excess energy would provide no benefit to the utility in terms of reducing the overall demand for electricity on the circuit, nor any benefit to customers who chose to install what is essentially a small power plant on their property at their own expense.

[62] Huber Direct Test at 13:2–3.
[63] *Id.* at 13:11–12.

The rationale behind the proposed non-export rate is important to consider. By design, the non-export rate acknowledges that customers who install DG have the right to self-consume the electricity they generate without being burdened with discriminatory rate treatment. The non-export rate falls short by failing to account for the value of excess energy supplied to the grid. Under-sizing DG systems and dumping excess energy through inverter curtailment is not the most efficient outcome for anyone. Clearly, it would be preferable to examine an appropriate value for DG exports to use as the basis for the credit customers would receive for these exports. Vote Solar is hopeful that the methodology by which to develop such a value can be informed by the ongoing generic docket on the value and cost of DG (Docket No. 14-0023).

Q. Why do you not support the Advanced DG TOU Rate option?

A. RUCO's Advanced DG TOU Rate has several problems. Although not immediately clear from the testimony, the rate is a buy-all sell-all tariff. This means that the customer would not have the right to self-consume the electricity they generate on their own property from their own investment.[64] Rather, the customer would be required to sell all energy output from their DG facility to UNSE.

Vote Solar does not support this buy-all sell-all arrangement. Every customer has the individual right to choose how much energy to consume or not consume from the utility whether modifying consumption through DG, through conservation or energy efficiency, by buying an electric car, or by installing a bigger AC unit. Customers should not be discriminated against for the technological choices they make regarding their personal energy consumption. The only thing that differentiates customers who install DG from customers who employ other forms of technology that change consumption patterns is the fact that DG systems may export energy to the grid. While Vote Solar looks forward to continuing the discussion over proper evaluation of DG exports in Docket No. 14-0023, it is

[64] RUCO Resp. to VS 1.3 (Ex. BK-SR-1 at 17).

important that rate design maintain customers' rights to self consume their own generation.

In addition, Mr. Huber performed what he describes as a basic calculation to approximate the value of solar.[65] His calculation results in a value of 8.5 ¢/kWh.[66] Appropriate valuation of DG is a complex analysis. The Commission has recognized the complexity and controversy involved in proper DG valuation through its guidance in Docket No. 14-0023, where the Commission is presently seeking input on the appropriate methodology for undertaking such an analysis. While Vote Solar acknowledges that there is some controversy over the full range of categories of benefits that should be quantified in a valuation of DG, Mr. Huber's crude approximation of the value of solar ignores key benefits accepted even by APS in recent studies.[67] As a result, it would be inappropriate to use the basic calculation put forth by RUCO as the basis for approximating the value of solar in rates.

Finally, Vote Solar is concerned with the large summer peak demand charge included in RUCO's Advanced DG TOU Rate option. As described in further detail below, NEM customers are similarly situated to non-NEM customers in regards to demand charges, and the evidence indicates that most customers will face considerable difficulty in responding to this type of charge. As a result, RUCO's proposed demand charges would potentially penalize customers for unexpected increases in peak demand.

Q. Why do you not support the RPS Bill Credit Option?

A. Again, although it is not immediately clear from the testimony, the RPS Bill Credit Option is a buy-all sell-all tariff in which the customer would be able to choose to take service on any standard residential tariff but would lose the right to

[65] Huber Direct Test. at 14:5–9.
[66] *Id.* at 18:10.
[67] SAIC, 2013 Updated Solar PV Value Report, prepared for APS, at 1–3 (May 10, 2013), *available at* https://www.azenergyfuture.com/getmedia/77708c68-7ca6-45c1-a46f-84382531bae3/2013_updated_solar_pv_value_report.pdf/?ext=.pdf.

self-consume the electricity they generate on their own property from their own investment.[68] For the reasons described above, Vote Solar does not support this buy-all sell-all arrangement.

In addition, the RPS Bill Credit Option would include a credit mechanism that would decline over time as DG grows in UNSE's territory. The final rate would be based on the Market Cost Comparable Conventional Generation ("MCCCG"), which is currently only 4.2 ¢/kWh for solar PV.[69] In other words, over time the RPS Bill Credit Option would compensate new DG at a level that is roughly half of even Mr. Huber's crude approximation of the value of solar. Such a rate would not capture the full value of DG solar and would not allow non-participating ratepayers to benefit from optimal DG deployment.

5 Mandatory demand charges should be rejected

Q. Please provide a summary of the mandatory demand charge proposals put forth in this proceeding.

A. In direct testimony, UNSE proposed a residential and small commercial tariff that included a demand charge. This original proposal would have made the demand rate optional for non-NEM residential and small commercial customers and mandatory only for NEM customers.[70] The demand charge would be measured over a one-hour period and would be based on the highest hour of demand at any time throughout the month.[71] This is defined as the non-coincident hourly peak ("NCP").

In direct testimony filed on December 9, 2015, Commission Staff indicated that they did not agree with UNSE's proposal for differential rate treatment for NEM

[68] RUCO Resp. to VS 1.4.

[69] *In re UNSE for approval of its 2016 Renewable Energy Standard Implementation Plan*, Ex. 2., Docket No. 15-0233 (July 1, 2015).

[70] Dukes Direct Test. at 4:1–2, 5:2–3.

[71] Jones Direct Test. at Ex. CAJ-3 (Proposed RES-01 Demand tariff).

customers.[72] As an alternative, Staff proposed a mandatory demand charge and TOU tariff structure for all residential and small commercial customers.[73] In contrast to UNSE's original proposal, Staff's proposed demand charge would apply only to the peak period.[74] The proposed demand charge would initially be calculated based on 75% of the unit cost for distribution.[75] Generation and transmission-related costs would continue to be recovered in the volumetric rate.[76]

In UNSE's rebuttal testimony, the Company indicated that it would support Staff's proposal for mandatory demand charges with a few modifications.[77] UNSE's revised proposed demand charge would be based on the peak period, but would be linked to generation-related costs rather than calculated based on 75% of the unit cost for distribution.[78] The Company has indicated that in order to have the initial demand charge be on par with the dollar value of Staff's proposed demand charge, a lower percentage of generation related costs would need to be included.[79] A summary of the proposed demand charges is provided in Table 3.

[72] Broderick Direct Test. at 6:9–13.
[73] Solganick Direct Test. at 31:5–6.
[74] *Id.* at 31:9.
[75] *Id.* at 31:6-7.
[76] Staff Resp. to VS 3.11(b) (Ex. BK-SR-1 at 19).
[77] Jones Rebuttal Test. at 12:18.
[78] *Id.* at 12:25–26.
[79] *Id.* at 13:1-6.

Table 3: Summary of Proposed Residential Demand Charges

Party	Proposed Charge	Timing	Applicability
UNSE Application[80]	$6.00-$9.95/kW	Non-Coincident Peak	Mandatory: NEM Optional: Non-NEM
Staff[81]	$4.78/kW	Peak	Mandatory
UNSE Rebuttal[82]	$5.15/kW	Peak	Mandatory

5.1 NEM customers and Non-NEM customers are similarly situated regarding demand charges

Q. Do NEM customers have a greater ability than non-NEM customers to modify consumption in response to a mandatory demand charge?

A. No. As described in my direct testimony, NEM customers are similarly situated to other residential and small commercial customers regarding the ability to understand and respond to demand charges. DG installations are effective at reducing a customer's energy consumption, but do little to impact peak demand. According to UNSE's own assumptions, NEM customers' peak demand will be equivalent to the non-NEM customers' peak in all but 4 months of the year, and in those 4 months, NEM customers' peak demand will be reduced by 6% or less.[83]

Q. Have any other parties provided testimony on this issue?

A. Yes. Commission Staff recognizes that NEM customers will have no greater ability to respond to mandatory demand charges. This is illustrated by Staff's critique of the UNSE proposal, in which new NEM customers would find themselves subject to a demand charge at the same time that they would make the decision to install DG. Staff states:

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[80] Proposed RES-01 Demand tariff.
[81] Staff Resp. to VS 3.11(a) (Ex. BK-SR-1 at 19).
[82] Jones Rebuttal Test. at Ex. CA-J-R-4, at 4.
[83] *See* Kobor Direct Test. at 41–42.

> Even if customers receive history on their demand kW usage and receive a good explanation of a three-part tariff, customers would not likely have any actual previous experience with a three-part tariff. Customers, therefore, may not know to inquire about other lifestyle changes or other technology choices that are alternatives to or useful additions to DG. Mistakes could be very costly to consumers and are unnecessary.[84]

Staff additionally states that "[i]f the Commission were to conclude that a migration to a three-part tariff should be voluntary, Staff recommends that it be voluntary for all DG customers as well."[85]

As demonstrated in a Section 3 of this testimony, sufficient evidence has not been provided in this case to justify differential treatment for NEM customers. This extends to the proposal for mandatory demand charges. In the sections below, I will demonstrate why mandatory demand charges should not be approved for any residential or small commercial customers, regardless of whether they are NEM customers.

5.2 It would be premature and overly aggressive to approve mandatory demand charges in this case

Q. Were mandatory demand charges for all residential and small commercial customers a part of UNSE's original proposal?

A. No. UNSE originally proposed an optional demand charge tariff for all residential and small commercial customers, and a mandatory demand charge for NEM customers. In rebuttal testimony, the Company indicated that it did not initially propose mandatory demand charges for all residential and small commercial customers because such a proposal "seemed somewhat aggressive."[86]

[84] Broderick Direct Test. at 6:17–21.
[85] *Id.* at 7:23–25.
[86] Dukes Rebuttal Test. at 4:15–19.

Q. Why did the Company indicate that a mandatory demand charge proposal was considered "aggressive"?

A. UNSE does not yet have sufficient metering capabilities to implement a mandatory demand charge for all residential and small commercial customers. According to Mr. Dukes, the original plan was to complete installation of the automated meter reading system in 2017.[87] Given this fact, implementation of mandatory demand charges by mid-2016 would have been impractical. Moreover, because the Company lacks the metering capability to implement a demand charge, it also lacks sufficient data on its customers' usage patterns that would enable it to fully understand and anticipate the impact that a mandatory demand charge would have on customer bills and revenue recovery. This is discussed in further detail in Section 5.5.

Q. Why is the Company now advocating for mandatory demand charges?

A. In response to the developments in this case, it appears that UNSE has accelerated its plans for meter replacement and is now indicating that it plans to have demand reading capability in place for all customers by the end of 2016.[88] UNSE's current proposal is to implement demand charges for all residential and small commercial customers at once sometime in February or March 2017.[89] It appears that the roll-out date is linked to the earliest date by which UNSE will have at least three-months of demand data for all customers.

Q. Do you believe that implementation of mandatory demand charges for all residential and small commercial customers is aggressive?

A. Yes. UNSE is not only planning to implement a major rate design overhaul right on the heels of meter deployment, it is also requesting Commission approval for a rate design measure that no other state regulator has authorized. While several parties to this case, including UNSE, Staff, and APS, try to make the case that

[87] *Id.* at 4:16–17.
[88] *Id.* at 7:3–4.
[89] *Id.* at 11:9–11.

mandatory demand charges are not a new concept, no party has provided an example of a state-regulated utility employing mandatory demand charges for all residential customers.

Q. What evidence do the other parties provide to support the claim that mandatory demand charges are not unusual?

A. Dr. Overcast makes a number of claims in an attempt to characterize mandatory demand charges as commonplace. In his rebuttal testimony, Dr. Overcast claims that "some utilities" have used a contract demand charge for demand-billed customers. But in discovery, he was not able to provide a single specific example.[90] In addition, when asked for examples of utilities that use a mandatory demand charge for residential customers, Dr. Overcast cited only to one: Lakeland Electric, a small municipal utility in Florida.[91] However, review of the tariff reveals that the Lakeland Electric demand charge tariff is mandatory only for NEM customers, and recent media indicates that Lakeland has only 73 existing NEM customers.[92] Dr. Overcast also provides the example of a Kansas coop that implemented mandatory demand charges for all residential customers to allegedly demonstrate that savings have resulted from the mandatory residential demand charge.[93] While documentation provided on the Kansas coop does indicate that some level of savings was achieved, there is no information on the distribution of savings or the magnitude of that savings in relation to several other significant events experienced by the coop.[94]

Tellingly, Dr. Overcast has not provided a single example of a state-regulated utility in this country that has implemented mandatory demand charges for

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[90] UNSE Resp. to VS 5.38(a) (Ex. BK-SR-1 at 8).
[91] *Id.* at UNSE Resp. to VS 5.38(b).
[92] Christopher Guinn, *Solar price plan to reduce hidden subsidy for Lakeland Electric customers*, The Ledger, (Nov. 23, 2015), *available at* http://www.theledger.com/article/20151123/news/151129801?p=1&tc=pg.
[93] Overcast Rebuttal Test. at 35:13–19.
[94] Other events include debt refinancing and profits from the propane division. Overcast Rebuttal Test. at Ex. HEO-5, UNSE Resp. to VS 5.42 (Ex. BK-SR-1 at 9).

residential customers. In fact, he has to go as far as Italy and Australia to find examples, yet he calls this "broad recognition of demand charges as a means to fairly recover distribution related costs."[95]

Q. Do any other witnesses address the prevalence of mandatory demand charges?

A. APS witness Dr. Faruqui makes reference to more than 40 pilot studies involving over 200 rate offerings that have found that customers respond to new price signals by changing their energy consumption patterns. But in discovery, APS reveals that <u>not a single one of these studies included a demand charge</u>.[96] He additionally cites to four studies that purport to show that customers respond to demand charges specifically, but review of those studies reveals that they all addressed voluntary demand charges.[97] Indeed, one study highlighted this fact, stating: "It is emphasized that the findings of this experiment apply only to this volunteer population. It would not be appropriate to draw inferences from these results for a mandatory program."[98]

Q. Have you reached any conclusions based on this evidence?

A. Yes. Several parties to this proceeding have attempted to paint a picture of mandatory demand charges for all residential and small commercial classes as a forgone conclusion based on academic arguments of cost causation. However, the evidence reveals that no single state-regulated utility in this country has been authorized to implement mandatory demand charges on its residential customers. While limited examples of mandatory demand charges exist among self-regulated utilities, these examples are few and far between. In fact, it appears that only a

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[95] Overcast Rebuttal Test. at 35:7–9.
[96] APS Resp. to TASC 1.1 (Ex. BK-SR-1 at 20).
[97] Studies provided in APS Resp. to TASC 1.1.
[98] Thomas N. Taylor, *Time-of-Day Pricing with a Demand Charge: Three-Year Results for a Summer Peak*, MSU Pub. Util. Papers, Award Papers in Public Util. Econ. and Regulation, 236 (Taylor Paper), *available at* http://ipu.msu.edu/library/pdfs/publications/Award%20Papers%20in%20Public%20Utility%20Economics%20and%20Regulation%20(1982).pdf.

single rural electric coop serving just 11,500 customers in Kansas has implemented mandatory demand charges on residential customers.[99] Approval of the proposal for mandatory demand charges in UNSE's service territory would be novel and unprecedented. As a result, I recommend that the Commission strongly consider whether the purported benefits of such a proposal exceed the risks involved.

5.3 UNSE admits the Company does not fully understand the impacts of its proposal

Q. How has the Company characterized its ability to assess the potential impacts of the proposal for mandatory demand charges for all residential and small commercial customers?

A. In rebuttal testimony, Mr. Jones acknowledges that "the estimation of monthly billing demands will be difficult because of the potential for customer response and the limited data base used to develop that billing determinant."[100] Indeed, the Company has not even tracked the number of residential and small commercial customers for whom it is lacking demand data.[101] In fact, UNSE was only able to confirm that it has 12 months of data for the 2,309 residential customers and 2,239 SGS customers used in its sample.[102] For the residential class, this value represents only 3% of customers.[103] In addition, while much discussion has been presented in this case regarding the need for proper customer education and the ability of residential and small commercial customers to respond to a demand charge, no analysis has been conducted as to how UNSE customer response may impact revenues. This problem is part of what drives the Company's proposal to leave the rate case open to resolve any unanticipated problems.

[99] Butler Rural Coop., Inc., About Us, *available at* http://www.butlerrural.coop/content/about-us.
[100] Jones Rebuttal Test. at 6:19–21.
[101] UNSE Resp. to VS 6.5 (Ex. BK-SR-1 at 16).
[102] UNSE Resp. to VS 5.48(c) (Ex. BK-SR-1 at 10).
[103] *Id.*; *see also* UNSE Resp. to VS 3.22 (Ex. BK-SR-1 at 4).

Q. What are the implications of this uncertainty?

A. The considerable uncertainty regarding potential customer bill impacts and revenue implications from proposed mandatory demand charges means that it is likely that the rates approved in this rate case may differ from the rates that are implemented. Mr. Jones indicates that the uncertainty may even extend beyond the residential and small commercial classes. Mr. Jones states:

> [I]f it is determined that the information obtained from the original data used to support the initial three-part rates is either under or over stated. These changes should be addressed if the expected revenues (using all available actual data, adjusted for normal weather) is more (or less) than when the initial rates were created. Any changes should be limited to the residential and SGS rate classes, but may be applied to the other customer classes if needed.[104]

This means that even the projected bill impacts provided by UNSE are subject to change.

5.4 Any rate design proposal that requires so many safeguards should raise red flags

Q. What are the risks involved with approving mandatory demand charges for residential and small commercial customers?

A. There is broad recognition among parties to this proceeding that mandatory demand charges for residential and small commercial customers are a significant rate design change that may be accompanied by unforeseen and extreme customer impacts. For example, Mr. Jones states that "the implementation of three-part rates for all customers is a special circumstance which may yield results that were unintended."[105] In addition, Staff's Mr. Broderick indicates that "[m]istakes could be very costly to consumers."[106] Staff witness Mr. Solganick states that "due to

[104] Jones Rebuttal Test. at 7:13–19.
[105] *Id.* at 6:14–16.
[106] Broderick Direct Test. at 6:21.

the changes proposed the Commission should keep the rate design portion of the case open to resolve unanticipated customer rate impacts."[107] These quotes demonstrate that demand charges are a risky and unproven measure that may negatively impact customers.

Q. Have Staff and UNSE made any proposals to mitigate the risk involved with approval of mandatory demand charges?

A. Yes. Staff and UNSE have proposed a number of safeguard measures. These measures include: (1) implementation of a temporary minimum load factor to moderate bill impacts; (2) asking vulnerable customers to self-identify for separate rate treatment; and (3) leaving the rate case open for a period of time after approval in case unforeseen problems occur.

Q. In your opinion would these safeguard measures provide sufficient protection for customers against unforeseen and extreme impacts?

A. No. Unforeseen and extreme bill impacts are expected even with these safeguard measures in place. In addition, I find each of the safeguard measures to be flawed and believe that the fact that the proposal for mandatory demand charges necessitates so many safeguards indicates that it is a proposal that comes with significant risk that should raise red flags at the Commission.

Q. Please discuss the proposed temporary minimum load factor.

A. UNSE has proposed to implement a temporary measure to mitigate what it describes as "outlier bills" by adjusting bills for customers whose load factors fall below 15% in a given month.[108] The impact of this safeguard measure would be to cap the monthly demand charge that any customer would be charged and to reallocate any revenue shortfall to all customers within the class.[109] UNSE claims

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[107] Solganick Direct Test. at 3:21–22.
[108] Jones Rebuttal Test. at 13:10–19.
[109] Dukes Rebuttal Workpaper, UNSE Res Dem-OnPk kW_01-09-16_r0.xlsx; UNSE SGS Dem-OnPk kW_01-09-16_r0.xlsx.

that with the temporary minimum load factor in place, the available data indicate that movement from the two-part transition rate to the three-part rate will result in an average bill impact of 3.2% for residential customers.[110] However, this figure only quantifies the impact of moving from the two-part transition rates to three part rates and therefore demonstrates only part of the picture. Examination of the rate impact of moving from current rates to the proposed three-part tariff reveals that an average bill impact of 16% for residential customers and nearly 40% for small commercial customers with the proposed minimum load factor adjustment.[111]

Implementation of a mandatory demand charge is a proposal that will create winners and losers. As a result, it is not particularly meaningful to look at average impacts, but rather at the distribution of proposed impacts. Figure 2 and Figure 3 below show the distribution of customer bill impacts moving from the current rate to UNSE's proposed three-part time-of-use tariff with the minimum load factor safeguard measure.

[110] Dukes Workpapers, UNSE Res Dem-OnPk kW_01-09-16_r0.xlsx, UNSE SGS Dem-OnPk kW_01-09-16_r0.xlsx.
[111] *Id.*

Figure 2: Distribution of Residential bill impacts under UNSE proposal[112]

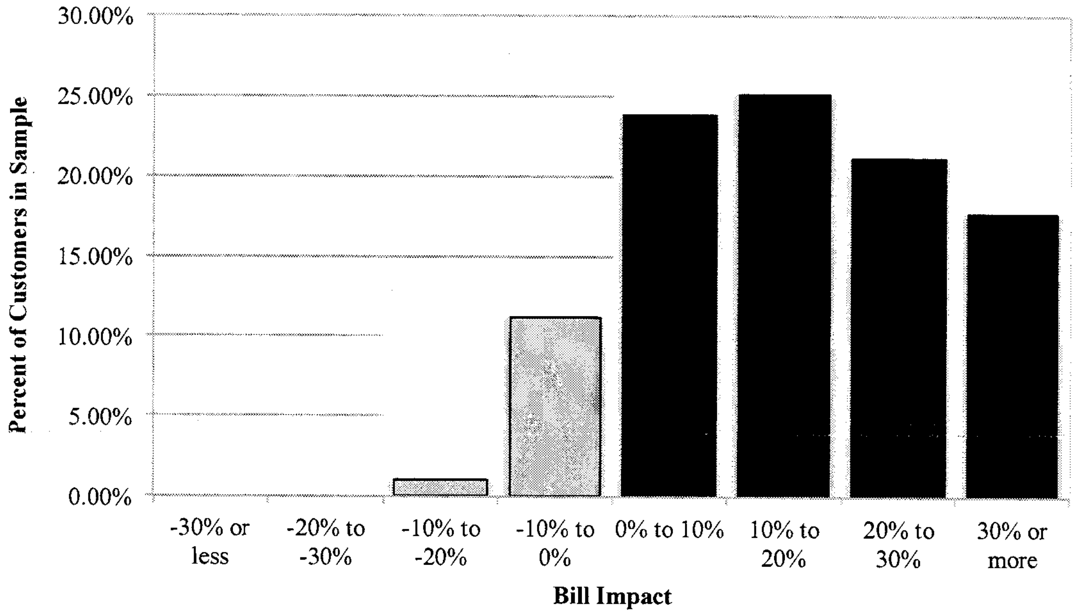
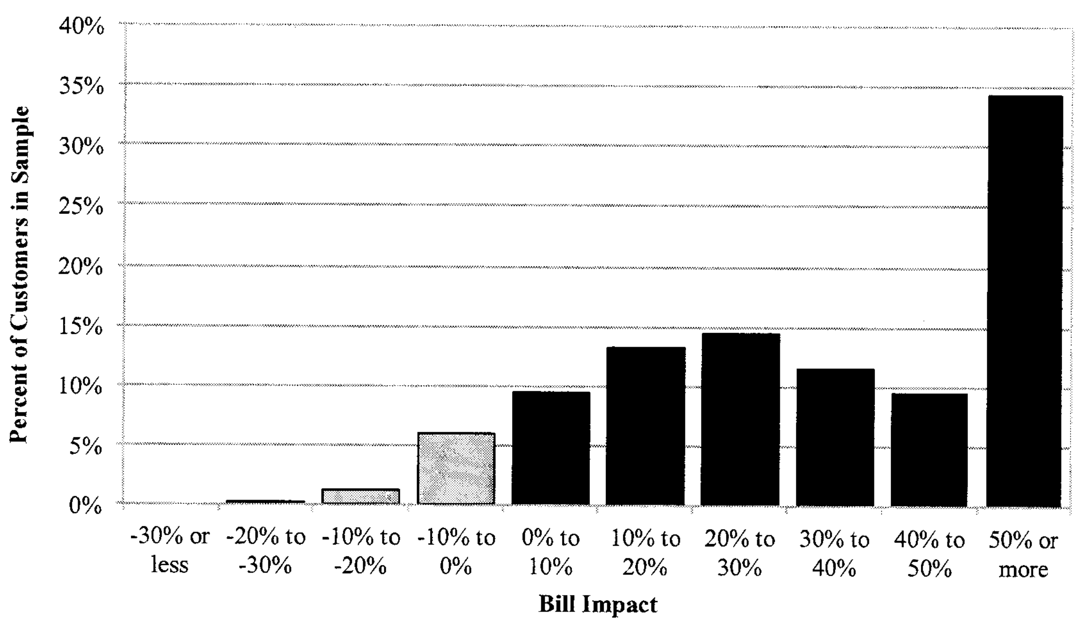


Figure 3: Distribution of Small Commercial bill impacts under UNSE proposal[113]



[112] *See* Dukes Rebuttal Workpapers, UNSE Res Dem-OnPk kW_01-09-16_r0.xlsx.
[113] *Id.*

As shown in Figure 2, nearly 88% of residential customers are expected to see bill increases under the UNSE proposal, with nearly one in five customers expected to have their monthly bills increase by more than 30%. Figure 3 demonstrates that 93% of small commercial customers will see bill increases under the UNSE proposal with over a third of customers experiencing bill increases of more than 50%. While UNSE claims that the proposed minimum load factor adjustment will mitigate significant bill impacts, the data clearly show that even with this safeguard measure a significant proportion of customers will be expected to face extremely large bill increases.

UNSE has indicated that the minimum load factor adjustment would be a temporary measure. Mr. Jones explains:

> This proposal was designed to complement the other provisions being proposed with the implementation of three-part rates to mitigate some of the significant bill impacts that may occur, thus allowing the customers to acclimate to the new rate design and adjust their individual usage habits or add new technologies that will allow them to lower their energy costs. It is the Company's position that this mitigation adjustment would be phased out as soon as possible, but no later than the implementation date of the next rate case.[114]

Because the minimum load factor adjustment reduces the largest bill impacts, it is expected that the impacts shown in Figure 2 and Figure 3 would only increase when it is removed. This fact is more troubling when you consider that UNSE has indicated that the proposed minimum load factor adjustment will moderate the bill impact for nearly all customers.[115]

Q. Have you reached any conclusions about the proposed minimum load factor adjustment?

A. Yes. UNSE's proposal to safeguard customers from significant bill impacts through the minimum load factor adjustment is flawed. Examination of the data

[114] Jones Rebuttal Test. at 15:17–23.
[115] *Id.* at 13:20–21.

reveals that extreme bill impacts are expected to occur even with implementation of the minimum load factor adjustment. A rate change that results in one in five residential customers shouldering average bill increases of more than 30% and one third of small commercial customers shouldering an increase of more than 50% is unacceptable. Even more troubling, the Company has proposed removing this safeguard measure by no later than the implementation date of the next rate case, meaning that customers would be expected to see even more extreme bill impacts in the future.

Q. Please discuss the proposal for vulnerable customers to self-identify.

A. Staff has proposed to permit "vulnerable customer groups" to be exempt from the migration to mandatory demand charges and has asked that any such groups self-identify in rebuttal testimony.[116] Mr. Broderick explains: "Staff does not presume that any group is so vulnerable as to be unable to understand and tolerate a demand kW charge. Customer vulnerability is quite different than mere opposition to an anticipated (initial) discomfort with a transition from a two-part to a three-part tariff."[117] He offers one potential example of a vulnerable group—customers with high kW medical equipment—and clarifies that existing NEM customers would not comprise a vulnerable group.[118]

Q. Do you have any comments on the proposal for vulnerable customers to self-identify in rebuttal testimony?

A. Yes. In my opinion the entire premise of asking vulnerable customers to proactively self-identify in rebuttal testimony is problematic. UNSE's customers do not currently have access to their own usage data,[119] so it is unclear how they would be able to assess how the proposed demand charge tariff would impact them. Mr. Broderick offers the example of customers with high kW medical

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116 Broderick Direct Test. at 2:13–17.
117 *Id.* at 9:15–18.
118 *Id.* at 9:20, 10:5–8.
119 Staff Resp. to RUCO 1.05(a) (Ex. BK-SR-1 at 21).

equipment as a group that may be vulnerable under a mandatory demand charge, but it is unlikely that such customers would be aware of the kW draw of their medical equipment in the first place. Even if they had this information, and access to their usage data, it would take considerable effort for these customers to figure out what their bill impact would be.

In addition, Staff's direct testimony stated that they believed existing NEM customers should not be classified as a vulnerable group, but it is my understanding that Staff may reverse their position on this. Existing NEM customers have made a long-term investment in DG and are particularly vulnerable to mandatory demand charges that would undercut this investment. To the extent that the Commission considers Staff's proposal to have vulnerable customers self-identify, it is essential that existing NEM customers be exempted from mandatory demand charges. This issue is discussed in more detail in Section 9 on grandfathering.

Q. Please discuss the proposal to leave the rate case open for a period of time after approval in case unforeseen problems occur.

A. This proposal originated with Staff witness Mr. Solganick, who suggested that "[t]he Commission should keep the rate case open beyond its revenue requirements decision to monitor the transition and deal with unknown problems if they occur."[120] UNSE has stated:

> Once new rates are approved, and prior to implementing the new rate design, [it] expect[s] to work closely with Staff and RUCO and share bill comparison data to identify and address bill impacts that were not anticipated as part of the approved rate design changes *prior* to implementing the three-part rates.[121]

[120] Solganick Direct Test. at 14:6–7.
[121] Dukes Rebuttal Test. at 12:15–19 (emphasis in original).

Q. Do you have any comments on the proposal to leave the rate case open for a period of time after approval in case unforeseen problems occur?

A. Yes. Like the minimum load factor adjustment proposal and the proposal for vulnerable customers to self-identify, this proposal is emblematic of the considerable risk and uncertainty involved in movement towards mandatory demand charges. The Company expects its proposal to result in bill increases in excess of 30% for nearly one in five residential customers and in excess of 50% for over one third of small commercial customers, yet acknowledges that even more extreme impacts may occur. While Staff raises the fact that the Commission has left a prior TEP rate case open for purposes of rate transition monitoring, that instance was limited to smart meter opt-out charges that would be expected to have a comparatively minor impact.[122] This proposal is expected to have a significant impact on all residential and small commercial customers. It is imperative that the full implications of such a proposal be fully discussed with all interested parties in the context of the general rate case. The proposal to leave the rate case open in order to potentially make changes to the approved rates is inappropriate and should be rejected by the Commission. Coupled with the fact that no regulated utility in this country has been authorized to implement mandatory demand charges for residential and small commercial customers, the proposal to leave the rate case open paints a picture of an unpredictable experiment in major rate design change that would have an extreme and unavoidable impact on real people with real investments.

5.5 <u>Customers will not be able to meaningfully respond to demand charges and the education plan is insufficient</u>

Q. What evidence has been presented in this case regarding the ability of residential and small commercial customers to respond to a mandatory demand charge?

[122] Decision No. 73912 at 73 (June 27, 2013).

A. As described above, parties to this proceeding have provided only one example of a utility that has implemented mandatory residential demand charges, Butler Rural Electric Coop in Kansas. While there is some indication that the demand charge resulted in customer response among the 11,500 customers of the electric coop, there is no information on the magnitude or distribution of customer impacts.[123] As demonstrated below, additional evidence provided suggests that customers will have difficulty responding to demand charges.

While Staff expresses the belief that no customer group would be unable to understand and tolerate a demand charge,[124] they do not provide any evidence to support this assertion. In addition, as described above, APS's witness Dr. Faruqui tries to make the case that customers have the ability to respond to new price signals, but examination of his sources reveals that, of the "40 pilot studies involving over 200 rate offerings" that he uses to support his statement, not a single study involved demand charges.[125] Moreover, the four additional studies he cited that did address demand charges were all based on voluntary programs. Indeed, one of the studies he cites even indicates that "[i]t would not be appropriate to draw inferences from these results for a mandatory program."[126] This is because customers that choose to opt-in to voluntary rate programs are inherently more likely to be able to understand and respond to the price signals in those programs, and any results from a voluntary program would be likely to overestimate customer response.

Q. Has any evidence been presented on customer response to optional or mandatory demand charges?

A. Interestingly, data from APS's optional demand charge tariff reveals that customer response has been mixed. As described in detail in my direct testimony, only 10% of APS's residential customers have elected to take service on the

[123] UNSE Resp. to VS 5.42 (Ex. BK-SR-1 at 9).
[124] Broderick Direct Test. at 9:15–16.
[125] APS Resp. to TASC 1.1 (Ex. BK-SR-1 at 20).
[126] Taylor Paper at 236.

demand charge tariff. This implies that, despite decades of availability, 90% of APS's customers have either not gained an understanding of how the demand charge rate would impact them, or they have decided that the demand charge rate is not the best option for them.[127] In addition, in response to discovery, APS has revealed that as many as 40% of its customers that recently switched from a two part rate to the optional demand charge rate actually increased their maximum on-peak demand.[128] This means that even among the few customers that self-selected onto the demand charge rate, 40% did not respond to the demand charge price signal in their optional tariff.

APS's current optional residential demand charge tariff was originally approved in October 1980 as a mandatory tariff for new residential customers with refrigerated air-conditioning.[129] However, the Commission removed the mandatory requirement less than three years later.[130] The Commission described the rationale for reversing its prior decision by making the demand charge tariff optional for all residential customers, stating the change was "in response to complaints that the mandatory nature of the EC-1 rate produced unfair results for low volume users."[131] In addition, the Commission stated that removal of the mandatory demand charge would "alleviate the necessity for investment by low consumption customers in load control devices to mitigate what would otherwise be significant rate impacts under the EC-1 rate."[132]

Q. What do you conclude about the evidence presented on customer response to mandatory demand charges?

A. Evidence on customer response to mandatory demand charges is extremely scarce. The limited evidence that does exist from the early 80's, when APS was authorized to implement a mandatory demand charge for new residential

[127] Kobor Direct Test. at 38.
[128] APS Resp. to RUCO 1.2 (Ex. BK-SR-1 at 23–31).
[129] Decision No. 51472 (Oct. 21, 1980) (Ex. BK-SR-2).
[130] Decision No. 53615 (June 27, 1983) (Ex. BK-SR-3).
[131] *Id.* at 7:18–19.
[132] *Id.* at 7:20–22.

customers with refrigerated air-conditioning, indicates that considerable customer backlash occurred due to significant rate impacts for low usage customers.[133] Moreover, the available evidence on customer response to optional demand charges in APS's territory shows that a considerable number of customers who opted in did not reduce their peak demand. Customer response to a mandatory demand charge would likely be even more limited. The limited evidence indicates that UNSE's residential and small commercial customers will have little ability to respond to mandatory demand charges.

Q. What have parties proposed with regard to customer education?

A. The proponents of demand charges in this proceeding all agree that proper customer education is an essential part of the proposal to impose mandatory demand charges. UNSE's education plan would consist of a number of passive education tools including customer focus groups, bill messages, website content, bill inserts, brochures, training of customer call center staff, newsletters, news media outreach, and social media.[134] Most importantly, UNSE is proposing to provide its customers with access to at least three months of usage data prior to implementing the demand charge.[135]

Q. How do parties claim that access to customer usage data would help educate customers?

A. According to Staff, customer access to private, secure, easy, timely and comprehensible individual usage data is a prerequisite for transition to mandatory demand charges.[136] Mr. Solganick provides an example of the type of usage information he imagines by using an example from his personal account.[137] He describes how he is able to view data on his hourly energy consumption with a two-day delay and asserts that "[f]rom this timely information, I can determine

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[133] *Id.* at 7:18–19.
[134] Dukes Rebuttal Test., at Ex. DJD-R-1.
[135] *Id.* at 9:21–23.
[136] Solganick Direct Test. at 13:17–18.
[137] *Id.* at 8:12–25.

the peak period(s) of energy usage and then decide if I wish to change my energy usage in the future."[138]

Q. Do you agree that access to customer usage data will give customers the tools needed to respond to mandatory demand charges?

A. No. While there would certainly be a proportion of residential and small commercial customers that would act on the information presented by UNSE and proactively examine their own usage data, most customers lack the understanding and/or time to conduct the level of research and analysis that would be required to use this data to their advantage. Even if customers could understand their usage data as it relates to demand charges, they would face considerable barriers to be able to modify behavior based on this information.

Consider what would actually be involved in order for customers to use this data to respond to a peak demand charge as proposed by UNSE:

- First, they would have to have access to the Internet in order to obtain their historical usage data.
- Then, they would need to examine this historical usage data to see when their household's maximum peak demand occurred. The timing of peak demand could be very different from day to day and week to week as varying activities such as family events, sick days, etc., can modify customer behavior.
- Customers would need to look at the date and time of the historical peaks and try to retroactively piece together what was happening in their household at that time. Such a task would be extremely complicated for families who most certainly do not keep detailed records of the timing of electrical usage activities for everyone in the house.

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[138] *Id.* at 8:24–25.

- Assuming customers were able to piece together what they were doing to cause the historical peak demand, the demand charge portion of their bill would already have been set for the month and they would be unable to mitigate the charge on their current bill.

It cannot be expected that the average customer would undergo this level of detailed retroactive analysis. Such an undertaking would take a considerable amount of time, not to mention a deep level of understanding of electricity usage in the household. Moreover, UNSE is proposing to provide some customers with only three-months of historical usage information prior to implementation of the demand charge.

Q. What is the issue with customers having only three months of historical usage information?

A. Customer consumption patterns differ dramatically by season. This fact is captured by UNSE's current peak period definition for residential customers, which defines the peak period as 2:00pm to 8:00pm in the summer and 5:00am to 9:00am as well as 5:00pm to 9:00pm in the winter.[139] UNSE is proposing to roll out its mandatory demand charge proposal in February or March of 2017.[140] This means that some customers would only have access to usage data from the winter period and would have absolutely no information on summer usage information. Therefore, the customer would have no understanding of when summer peak demand had occurred in the past, and the usage data would provide no tools for the customer to respond to the peak demand charge in the future. It is unclear how such a proposal would provide customers with tools to enable a meaningful response to a wholly new type of rate design.

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[139] UNSE Schedule RES-01 TOU.
[140] Dukes Rebuttal Test. at 11:9–11.

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

A. No. While I do believe that with considerable effort, UNSE would be able to educate many of its customers on what a demand charge is, I do not believe that average residential customers will be able to take action to mitigate the impact such a charge would have on their monthly bill. As shown above, 88% of UNSE's residential customers are expected to see their bills increase with this proposal, and one in five may face average bill increases of 30% or more. Even if these customers had a full understanding of what was causing their bills to increase, lifestyle limitations may undermine their ability to do anything about it.

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

A. Yes. Many residential customers have limited choice or control over when they use appliances. Consider that UNSE's peak demand charge would apply during the hours of 5:00am and 9:00am in the winter months. It is estimated that as many as 64% of UNSE's residential customers may have all-electric service.[141] Electric furnaces and water heaters can consume significant levels of electricity, with common models drawing 10.5 kW and 4.5 kW, respectively.[142] In addition, common hair dryers typically draw upwards of 1 kW, the average microwave or toaster oven can draw 1 kW, and an electric kettle can draw 1 kW.[143] Looking at this list, it is easy to see how the typical morning routine for a family would easily result in a peak demand of as much as 18 kW. While families may certainly be able to understand that this peak demand occurs, school schedules and work schedules may not allow them to do anything about it.

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[141] UNSE Resp. to WRA 1.16 (Ex. BK-SR-1 at 22).

[142] City of Santa Clara, Silicon Valley Power, Appliance Energy Use Chart, *available at* http://www.siliconvalleypower.com/for-residents/save-energy/appliance-energy-use-chart.

[143] Duke Energy, Electric Appliance Operating Cost List, *available at* http://www.duke-energy.com/pdfs/appliance_opcost_list_duke_v8.06.pdf.

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

A. While there is indeed potential for technology to aid in customer response to demand charges, these technologies are uncommon, costly to implement, and have not achieved widespread adoption. Interestingly, while Mr. Solganick makes reference to a "warning" system that would use a red/yellow/green indication, he indicates that he does not know if the product he mentions has even been commercialized.[144] Moreover, UNSE's education plan does not contain a single mention of enabling technologies, nor any indication that the Company would assist customers in adoption of such technologies.[145] Therefore, enabling technologies are expected to do little to help the average residential or small commercial customer to respond to demand charges.

Q. What do you conclude about the ability of customers to respond to mandatory demand charges in light of the proposed education plan?

A. While there is exceedingly little evidence about customer response to mandatory demand charges, the available evidence on optional demand charges indicates that customer response has been mixed. While UNSE has proposed a plan to educate its customers about the transition to mandatory demand charges, it is not clear that customers will be able to meaningfully <u>respond</u> to the charges. While, in theory, access to usage data may provide useful information, most customers will find that the level of effort required to undergo detailed retroactive analysis of household usage patterns and extrapolate into the future will be a barrier to behavior change. Moreover, in many cases customer lifestyle limitations will inhibit their ability to mitigate expected bill increases. As a result, I expect that mandatory demand charges will function more like fixed charges for most residential and small commercial customers in the UNSE service territory.

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[144] Staff Resp. to VS 3.4 (Ex. BK-SR-1 at 18).
[145] Dukes Rebuttal Test. at Ex. DJD-R-1.

5.6 The Commission should exercise caution in its consideration of mandatory demand charges

Q. Do you recommend that the Commission approve mandatory demand charges for residential and small commercial customers?

A. No. I find that the proposal to implement mandatory demand charges for UNSE residential and small commercial customers is premature, overly aggressive, and fraught with problems. Demand charges for residential and small commercial customers are likely to function as additional fixed charges, leaving customers with very little ability to respond. The Commission should strongly weigh the expected benefits of implementing a mandatory demand charge against the potential for extreme and not yet fully understood bill impacts. Indeed, UNSE is proposing to implement a major rate design change when it does not even have the metering in place to reliably assess the impact of the proposal. The safeguard measures proposed by the parties are problematic, and the Commission should consider whether a proposal that would necessitate so many safeguards is truly worth the risk.

The question of whether to implement mandatory demand charges is a major issue and is expected to be a focal point of discussion in Arizona in upcoming rate cases for other utilities. This is evidenced by APS's extensive and rather unprecedented involvement in the rate design discussion of another utility's general rate case. I urge the Commission to exercise caution in this proceeding. If the Commission believes that demand charges provide a worthwhile signal for residential and small commercial customers to modify their consumption patterns, I urge the Commission to implement demand charges for UNSE customers only on an optional basis. The Commission could instruct UNSE to proceed with its meter roll-out and customer education plan, and to market the optional demand charge tariffs to customers. This approach would allow customers who are able to respond to the demand charge to take advantage of such a rate while protecting other customers from extreme and unavoidable bill increases.

6 There are better solutions to the problems purportedly solved by mandatory demand charges

Q. What do the proponents of mandatory demand charges provide as the primary rationale for their proposal?

A. The main proponents of mandatory demand charges in this case are UNSE and Staff. Both parties support mandatory demand charges because they allege that the proposed demand charge tariffs are more closely linked to cost causation than rates without a demand charge.[146] As a result, both parties argue that a demand charge rate will provide more efficient price signals to customers.[147]

Q. Do you agree that rates with demand charges are more closely linked to cost causation than rates without demand charges?

A. Not necessarily. Different types of demand charges are differently linked to cost causation. This is exhibited by the debate among parties in this proceeding over the most appropriate method for employing a demand charge. UNSE's original proposed demand charge was based on the NCP. Staff has proposed a demand charge based on the highest hour of demand during the peak period and has linked the demand rate to distribution costs. UNSE's rebuttal position is to advocate for a peak-based demand charge, but to link the rate to generation capacity costs instead. As described below, each of these proposals has different cost causation implications, which demonstrates that demand rates should not be accepted as *prima facia* improvements in cost causation.

For example, in response to UNSE's original proposal for a NCP demand charge, RUCO had the following critique: "Under UNSE's proposal, the demand charges associated with a high power draw at 3:00 am in March would be the same as a high power draw at 6:00 PM in July. This does not provide an accurate price

[146] Hutchens Rebuttal Test. at 3:16–19; Broderick Direct Test. at 2:20–22.
[147] Hutchens Rebuttal Test at 3:10–22; Broderick Direct Test. at 2:5–7.

signal to customers of system costs and reflects a poorly designed demand charge."[148] As a result of this critique, RUCO believes that demand charges should be limited to peak hours only during the summer months.[149]

While Vote Solar agrees with RUCO that NCP demand charges are not reflective of cost causation, there are additional concerns with demand charges that are linked to the peak period as described below.

Q. Are there any concerns associated with demand charges in Staff's proposal and the Company's revised proposal?

A. Yes. In support of UNSE's rebuttal position advocating for a peak demand charge that removes distribution-related costs, Mr. Jones states: "If the demand charge is based on the customer's on-peak demand, then it should recover the related generation costs. Distribution costs should be associated with the non-coincident peak a customer generates, which would be more appropriately recovered using the customer's individual peak, regardless of when that peak occurs."[150]

However, Mr. Jones ignores the fact that for residential customers, individual customer NCP is a poor proxy for local distribution peak that drives distribution costs. On a typical residential circuit there will be some customers who rise early for work and return early in the evening, others who work the night shift and are not home at all during daylight hours, and others who stay home throughout the day. Each of these types of customers will peak at different times, and the dependable diversity in their load shapes will allow for shared infrastructure. It is therefore the customer's contribution to the peak load on a particular portion of the distribution system, not individual peak, which drives costs. As a result, assessing distribution-related capacity charges based on customers' NCP cannot be defended based on cost causation.

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[148] Huber Direct Test. at 16:1–4.
[149] *See id.* at 15:18–20.
[150] Jones Rebuttal Test. at 12:25–13:1.

Staff's proposed demand charge would apply throughout the year but would only be assessed during peak hours. In rebuttal, UNSE witness Overcast criticizes the inclusion of distribution-related costs in a peak demand charge, explaining "the Staff proposal to collect these costs in a peak period is not cost based . . . ."[151] Interestingly, Dr. Overcast's solution is to employ a complicated multi-part demand charge that is not endorsed by the other UNSE witnesses.

The revised UNSE proposal to implement a peak-demand charge that is tied to the embedded costs of generation capacity is also flawed. While UNSE proposes to recover only a portion of embedded generation capacity costs in the on-peak demand charge, UNSE's own witness contends that the Company's rationale cannot be defended based on cost causation. According to Dr. Overcast, embedded costs for generation capacity are likely to be too high and "would create subsidies and promote investments in utility resources inconsistent with the least cost of total utility supply service."[152]

Q. Can you provide any real-world examples that may help to provide an understanding of whether the proposed demand charges are cost-based?

A. Yes. In an earlier section I gave an example of a family with all-electric service that rises in the morning to prepare for work and school and may need to use various appliances at once. In the winter, UNSE's proposed demand charge would apply between the hours of 5:00am and 9:00am, when many families would be expected to need to turn on the heat, take showers with hot water, use the hair dryer, and prepare breakfast in the toaster or microwave. As I demonstrated above, these common and necessary activities could result in the family setting a large peak demand.

Proponents of mandatory demand charges may argue that if this hypothetical family were part of the one in five customers that are expected to see bill

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[151] Overcast Rebuttal Test. at 31:20–21.
[152] *Id.* at 32:14–15.

increases in excess of 30%, that result would be an uncomfortable but "fair" result of moving rates to be more cost based.

This argument falls apart when you consider the fact that a peak monthly demand charge applied to the top monthly hour of usage occurring on a winter morning bears little relation to cost causation. While this family may indeed set its peak during such a time, other families on the same transformer and/or same circuit would be expected to set peaks during different hours, allowing for shared infrastructure on the system. This implies that Staff's proposed peak demand charge based on distribution costs would not reflect cost causation. In addition, because generation capacity is built to supply the overall system peak that occurs on summer afternoons, an individual customer's peak on a winter morning would bear little resemblance to cost causation under UNSE's proposed peak demand charge based on generation capacity costs.

Examination of real-world examples helps to illustrate the fact that rate design involves a large level of approximation. While parties may argue that demand charges are more reflective of cost causation on a theoretical basis, the proposals in this case involve a number of inherent approximations that result in charges that, in practice, may have little relation to cost.

Q. Do you agree that demand charges will provide more efficient price signals to customers?

A. No. As described in detail above and in my direct testimony, I believe that mandatory demand charges for residential and small commercial customers will function essentially as a fixed charge. Such a rate cannot provide a meaningful price signal to customers if those customers are not able to respond to the price signal.

6.1 <u>TOU rates are a better alternative to mandatory demand charges</u>

Q. Is there an alternative rate design methodology that is preferable to mandatory demand charges in terms of improving cost causation and providing an efficient price signal to customers?

A. Yes. TOU rates, or rates that include a time-varying energy component, improve the link to cost causation. Unlike demand charges, TOU rates are simple enough to provide actionable price signals to residential and small commercial customers. In addition, TOU rates would address many of the alleged problems that parties claim are occurring under the current rate structure.

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

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

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

> The rates charged by any electric utility for providing electric service to each class of electric consumers shall be on a time-of-day basis <u>which reflects the costs of providing electric service to</u>

> such class of electric consumers at different times of the day unless such rates are not cost-effective with respect to such class . . . .[153]

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

> As a general proposition, time-of-day rates trigger an accurate price signal to the consumer of electricity. Moreover, applied specifically to the APS system, we are persuaded that properly established time-of-day rates would encourage optimization of the efficiency and utilization of APS' facilities and resources. Accordingly, we hereby express our intention to authorize and encourage the implementation of time-of-day rates which are cost-effective (i.e., whenever the long-run benefits of such rate to APS and its affected consumers are likely to exceed the metering costs and other costs associated with the employment of such rates).[154]

TOU rates have long been recognized as beneficial for cost-based ratemaking. However, until recently, metering costs prohibited cost-effective adoption. In fact, historically, demand charges for large customers were developed as a second-best approach to capturing the time-varying value in energy consumption.[155] Because technological challenges meant that metering based on time of energy usage was cost prohibitive, demand charges were implemented for larger customers as a proxy for measuring the customer's peak consumption. This approach was somewhat accurate for commercial and industrial customers whose peak usage would generally occur coincident with system peak, but is wholly inappropriate for smaller commercial and residential customers who tend to be more diverse in usage patterns.[156]

In 1983, this Commission acknowledged that demand rates for residential customers were a second-best approach to TOU-based rates.[157] As discussed above, the Commission originally approved mandatory demand charges for new residential customers of APS with refrigerated air-conditioning. But in response

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[153] 16 U.S.C. § 2621(d)(3) (emphasis added).
[154] Decision No. 52593 at 7:2–12 (Nov. 9, 1981) (emphases added) (Ex. BK-SR-4).
[155] Lazar, Jim, *Use Great Caution in Design of Residential Demand Charges*, Natural Gas & Electricity, 15 (Feb. 2016) ("Lazar article"), *available at* https://www.researchgate.net/journal/1545-7907_Natural_Gas_Electricity.
[156] *See id.*
[157] Decision No. 53615 at 6:9–10 (June 27, 1983) (Ex. BK-SR-3).

to problems associated with mandatory demand-based rates for the residential class, the Commission removed the requirement that the demand charge be mandatory, allowing customers to choose a new tariff that did not include demand charges. In discussing the mandatory demand charge rate, the Commission stated: "This rate approximates a time of day rate but with much lower metering and administrative costs."[158]

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

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

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

A. Residential and small commercial customers are already accustomed to managing kWh energy usage through their existing rates. They are aware that the more electricity they use, the higher their bills will be. Educating customers on the

[158] *Id.*

additional layer of complexity associated with TOU rates would be a small issue compared to educating customers about demand charges. To respond to TOU rates, customers would only need to understand that electricity costs more at different times of the day and/or year.[159] To respond to a demand charge, in contrast, customers would need to know how to undertake detailed retroactive analysis of their consumption patterns and assess what actions caused historical peaks. In addition, in the event that customers were to accidentally consume a larger amount during the more expensive peak period one day, the impact on their monthly bills would be nowhere near as large as if customers were to inadvertently cause a high peak demand. As a result, TOU rates would not require the kind of safeguard measures proposed by parties in this case to mitigate the often extreme and unpredictable bill impacts of demand charges. Finally, TOU rates provide a better price signal than demand charges because they incent conservation in every hour of the peak period. In contrast, with a demand charge, once the monthly peak demand is reached, customers would have less incentive to conserve for the remainder of the month. This is true even in the instance of a combined demand and TOU rate due to the fact that the volumetric portion of the rate would be severely reduced, dampening the conservation signal in rates.

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

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

Table 4: Garfield and Lovejoy Criteria[160]

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

While TOU rates may meet more of the Garfield and Lovejoy criteria and may be easier for the average customer to respond to than demand charges, the Commission should still exercise caution in considering a mandatory TOU rate. Some customers will have a greater ability to modify their behavior in response to TOU rates than others. As a result, I recommend that if the Commission decides to consider large-scale movement towards TOU rates, those rates should be offered on an "opt-out" basis. That is, all residential and small commercial customers would be placed on a TOU rate by default, but would have the ability to return to the current tariff structure that does not include time-varying rates if they so choose. If the Commission considers adoption of opt-out TOU rates, it should fully consider the projected bill impacts, necessary customer education programs, and the appropriate phase-in period prior to approval.

Q. Please explain how TOU rates would address many of the alleged problems that parties in this proceeding have claimed are cause by the current rate structure.

A. There are two main issues with the current rate structure raised by parties that would be mitigated by adoption of TOU rates. These include: (1) improper

[160] Lazar article at 15.

incentives for efficient solar installation, and (2) inaccurate signaling of the relative value of DG exports and consumption of NEM customers.

Q. Please explain how TOU rates would help improve what parties allege are improper incentives for efficient solar installations.

A. Dr. Overcast raises this issue in his rebuttal testimony when he states:

> [T]he current price signal based on energy . . . incents the customer to install a system that maximizes energy production without regard to the capacity value of the solar facility. This means that solar panels would face south in the Northern Hemisphere to maximize energy production instead of west to maximize summer peaking capacity contribution.[161]

While Dr. Overcast argues that peak demand charges would help to mitigate this problem, he is incorrect.

The current peak period definition for residential customers is 2:00pm to 8:00pm in the summer and 5:00am to 9:00am and 5:00pm to 9:00pm in the winter.[162] This means that throughout most of the year, a good proportion of the peak period occurs outside of daylight hours. A peak demand charge would be imposed on customers based on their single largest hour of demand across all peak period hours in the month, which may include hours after dark and before sunrise. In addition, passing clouds can have a significant impact in a single hour in the afternoon and early evening in summer. The monthly demand charge would be set based on only one hour during the month. As a result, PV panel orientation alone could not help the customer to avoid or lessen their peak demand. Therefore, peak demand charges would not incent more efficient panel orientation.

TOU rates, however, would be successful at incenting more efficient PV panel orientation. By reflecting in rates that energy is more valuable during the daily peak period, a TOU rate would provide an incentive for customers installing solar PV to maximize the energy they produce during the peak period because under

[161] Overcast Rebuttal Test at 17:3–7.
[162] UNSE Schedule RES-01 TOU.

the TOU rate, every day matters. This may mean orienting panels to the west to capture more energy at the tail end of the day in summer, rather than orienting panels to the south to capture the most energy throughout the day.

Q. Please explain how TOU rates would help improve what parties allege are inaccurate signals of the relative value of DG exports and consumption of NEM customers.

A. Dr. Overcast alludes to an "arbitrage" benefit associated with NEM customers who "consume power in summer periods and deliver the energy in low cost daylight hours in the winter season."[163] A review of the data on the relative marginal cost of power during the hours solar is exported and the hours in which NEM customers consume energy from the grid reveals that no such arbitrage benefit exists.[164] In any event, a TOU rate would help to more accurately value the way in which energy costs and export credits vary by season and time of day. As a result, TOU rates would remove any potential arbitrage benefit from the current NEM structure.

Q. Do other parties in this proceeding advocate for TOU rates?

A. Yes. In fact both UNSE and Staff's proposals include TOU rates as part of their proposed demand charges tariffs. TASC and WRA additionally discuss the merits of TOU rates in their direct testimonies.[165] In addition, Dr. Overcast characterizes movement to TOU rates as "the first and most important step in this case."[166]

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[163] Overcast Rebuttal Test. at 19:14–17.
[164] See full discussion in Section 3.2.2.
[165] Fulmer Direct Test. (Rate Design and Cost of Service) at 1:22–2:4, Wilson Direct Test. at 3:4–5.
[166] Overcast Rebuttal Test. at 33:15–19.

6.2 Minimum bills are a possible solution to the prevalence of seasonal and vacant homes

Q. Are there any other alternative rate design structures that you believe will better address the problems purportedly solved by demand charges?

A. Yes. While not ideal from the perspective of cost-causation, the Commission could consider implementing a small minimum bill to address the problems that allegedly result from a large proportion of UNSE residential customers having little to no usage on their bills.

Q. Please describe the problem of low- or no-usage bills.

A. UNSE has reported that nearly one in four residential bills issued by UNSE during the test year were for little or no usage.[167] UNSE argues that these low-consuming customers do not contribute their fair share of fixed costs under the current rate structure. In my direct testimony, I pointed out that over 95% of these bills can be attributed to seasonal customers and vacant homes, while NEM customers account for less than 5%.[168] This indicates that the problem associated with bills reflecting little to no usage is not a NEM-related problem, but rather a problem associated with seasonal and vacant homes.

Q. Would implementation of a demand charge help mitigate the problem associated with the prevalence of bills for little to no usage?

A. No. Again, this problem is overwhelmingly caused by seasonal and vacant homes, not NEM customers. If a home is vacant during the billing month, the customer will have little to no kWh usage. In addition, the customer would have little to no peak demand during the billing cycle. Therefore, with implementation of a demand charge, the customer's bill will be similarly small, perpetuating the same problem associated with fixed cost recovery.

[167] Dukes Direct Test. at 12:9–10.
[168] Kobor Direct Test. at 15:5–8.

Q. Please describe how a minimum bill would help to address this issue.

A. A minimum bill sets a minimum level of monthly charges for electricity. The minimum bill will generally only affect customers with extremely small usage in a given month. By ensuring that some level of fixed costs are recovered from all customers on a monthly basis, the minimum bill would help to address the issue of customers with seasonal or vacant homes.

Q. Is there support for a minimum bill among other parties to this proceeding?

A. RUCO, TASC, and WRA all expressed some level of support for a minimum bill in their opening testimonies, and, in rebuttal testimony, Mr. Jones indicated that UNSE would consider a minimum bill.[169]

Q. Do you support implementation of a minimum bill to address this issue?

A. There are a number of problems associated with minimum bills. Because the minimum bill functions as a fixed charge for customers below a certain usage level, <u>there is the potential for the minimum bill to adversely affect the economics for energy efficiency and DG if the minimum bill is set too high</u>. However, if the minimum bill were to remain small, I would support it as an alternative to demand charges and/or increases in the fixed customer charge.

Q. What would be an appropriate level of minimum bill?

A. While I do not support use of the Minimum System Method for purposes of determining the basic customer charge, in this limited context it may provide a reasonable basis for a minimum bill to address UNSE's issues related to seasonal and vacant homes. By UNSE's own assessment, all costs in excess of the costs allocated to customers with the Minimum System Method are linked to various measures of usage (demand-related and energy-related). As a result, a minimum bill set according to the Minimum System Method would reasonably recover

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[169] Jones Rebuttal Test. at 43:5–13.

costs from seasonal and vacant homeowners related to the UNSE-defined cost to serve with little to no usage.

As described in my direct testimony, I recommend that the Commission continue to rely on the Basic Customer Method for evaluation of customer-related costs and the associated basic customer charge.[170] If the Commission accepts my recommendation to leave the montly basic customer charges for residential and small commercial customers at current levels, $10.00 for residential customers and $14.50 to $16.50 for small commercial customers, and wants to consider a monthly minimum bill, it should consider adopting a monthly minimum bill inclusive of customer charges of $14.00 for residential customers and $23.00 for small commercial customers.[171] If the Commission approves an increase in monthly fixed charges at or above $14.00 for residential customers and $23.00 for small commercial customers, no minimum bill would be necessary.

7 Fixed charges should not be increased

Q. Please provide a brief summary of your findings in direct testimony regarding UNSE's proposed fixed charge increase.

A. UNSE has proposed doubling the fixed customer charge for residential and small commercial customers. In support of this proposal, the Company advocates moving away from the methodology previously employed within the customer cost of service study ("CCOSS") for allocation of costs to the customer function. Namely, UNSE proposes to move from a Basic Customer Method approach to a Minimum System Method approach. In my direct testimony, I explain why the Minimum System Method should not be approved and provide a calculation of customer costs from UNSE's CCOSS based on the Basic Customer Method that

[170] Kobor Direct Test. at 55–63.
[171] These values reflect correction of a spreadsheet error related to meter cost allocation that affected the results of UNSE's original CCOSS. *See* Section 7 for a full discussion of the fixed charge proposal.

demonstrates that current levels of fixed charges are appropriate and that no increase is necessary.

Q. Does UNSE provide any additional information in rebuttal regarding the relative merits of the Basic Customer Method and the Minimum System Method?

A. Yes. Dr. Overcast's testimony advocates for the Minimum System Method over the Basic Customer Method, but this advocacy is based on multiple mischaracterizations.

Q. What do you believe that Dr. Overcast has mischaracterized in his rebuttal testimony?

A. Dr. Overcast's rebuttal includes the following statement regarding the Basic Customer Method, which is false:

> To see how biased this recommendation is relative to actual costs it is worth noting that the advocates of the Basic Customer Method do not even include all of the labor costs associated with meter reading, billing and customer service. This is true in spite of the accounting requirement to count pensions and benefits applicable to payroll costs in the current period. Further, the method does not account for any office space or equipment necessary to perform the functions deemed to be customer related.[172]

In reality, the Basic Customer Method includes 100% of customer account expenses related to meter reading, billing, and customer service. In addition, the method includes a portion of administrative and general expenses that account for office space, salaries, pensions, and benefits. All of these expenses were included in the Basic Customer Method calculation I presented in my direct testimony and are well documented in my work papers.

[172] Overcast Rebuttal Test. at 38:18–23.

Q. Has Dr. Overcast mischaracterized anything else in his discussion of customer costs?

A. Yes. Dr. Overcast attempts to paint the Basic Customer Method as an unacceptable methodology for calculation of customer-related costs, stating that "the Basic Customer Method should never be considered as a viable alternative for calculating the customer charge."[173] This extreme position is out of touch with reality. In fact, the Minimum System Method would mark a departure in methodology for the Commission, which approved the Basic Customer Method in the last UNSE rate case.

In addition, Dr. Overcast's testimony includes a lengthy discussion of Bonbright's ratemaking principles as they relate to the two customer charge methodologies in an attempt to rationalize moving to the Minimum System Method. Dr. Overcast states "that the UNSE proposal is completely consistent with Bonbright"[174] and attempts to prove this through a discussion of the principles of fairness, efficiency, and gradualism. But Dr. Overcast's discussion blatantly ignores Professor Bonbright's very clear opinion on the Minimum System Method, which I quoted in my direct testimony.[175] In his original 1961 edition of "Principles of Public Utility Rates" Bonbright clearly opposed the Minimum System Method, stating that "the inclusion of the costs of a minimum-sized distribution system among the customer-related costs seems to me <u>clearly indefensible</u>."[176]

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[173] *Id.* at 37:18–19.
[174] *Id.* at 40:22–23.
[175] Kobor Direct Test. at 57:12–16.
[176] James C. Bonbright, *Principles of Public Utility Rates* 348 (1961) (emphasis added), *available at* http://media.terry.uga.edu/documents/exec_ed/bonbright/principles_of_public_utility_rates.pdf.

Q. Do you have any additional comments on the relative merits of the Basic Customer Method and the Minimum System Method?

A. Yes. Cost of service ratemaking involves a number of judgment calls on the part of the rate analyst. This topic has been the subject of debate for decades, and the debate will likely continue. In evaluating the proper approach for customer cost allocation for UNSE in this rate case, the Commission should consider not only the underlying theory behind the two competing methodologies, but also the policy implications of each approach.

The majority of parties in this proceeding, including the Arizona Community Action Association ("ACAA"), AURA, RUCO, the Southwest Energy Efficiency Project ("SWEEP"), TASC, Vote Solar, and WRA oppose increasing the fixed customer charge. Higher fixed charges dampen the conservation signal present in rates, undercutting the value of energy efficiency and DG. In addition, evidence put forth by ACAA shows that higher fixed charges will disproportionately impact low-income households.[177] In addition, Staff opposes the full customer charge increase by stating: "Staff believes this would be highly unfair and unpopular to raise significantly the monthly customer charge, especially with residential customers. It would eliminate nearly all customer ability to control or reduce electric bills. It would be highly unfriendly to new technologies and a major step backwards."[178] To the extent that the Minimum System Method results in a higher fixed charge, the Commission should weigh departing from the previously adopted Basic Customer Method against the environmental and social implications of increases to the customer charge.

Q. Does Dr. Overcast's support for the Minimum System Method rationalize the fixed charge increase proposed by UNSE?

A. No. UNSE's embedded cost study using the Minimum System Method results in a monthly fixed customer charge of only $14.00 for residential customers and

[177] Zwick Direct Test. at 13:15–20.
[178] Broderick Direct Test. at 9:4–7.

$28.18 for small commercial customers, yet the Company is requesting an increase to $20 for residential customers and $30 for small commercial. To support the higher customer charges requested, UNSE attempts to rationalize inclusion of additional demand-related costs in the customer charge. As described in my direct testimony, this approach is inappropriate.[179]

Q. If the Commission adopts the Minimum System Method, what would be the appropriate level of fixed charges?

A. While I strongly recommend that the Commission adopt the Basic Customer Method and approve no increase to the fixed charge, if the Commission adopts the Minimum System Method, the monthly fixed charge for residential and small commercial customers should be $14.00 and $23.00, respectively. These values reflect correction of a spreadsheet error related to meter cost allocation that affected the results of UNSE's original CCOSS. There is no rationale for the higher customer charges proposed by UNSE.

8 The Commission should not modify the existing NEM program

Q. Do you continue to recommend that the Commission reject UNSE's proposals to significantly alter the existing NEM program?

A. Yes. UNSE claims that DG on its system causes a number of problems that must be resolved through a new rate design that would reduce DG growth by effectively lowering the value proposition for DG. However, the evidence shows that DG is not a major driver of the problems UNSE alleges, and, therefore, there is no DG "problem" on UNSE's system that must be fixed in this rate case. Moreover, even if the Company had demonstrated that there is a DG "problem"—which it has not—its proposals to reduce DG growth are seriously flawed. As a

[179] Kobor Direct Test. at 60.

result, I recommend that the Commission reject UNSE's DG proposals and maintain the current NEM program.

Q. How has UNSE responded to Vote Solar's recommendation that the Commission reject the Company's proposals to reduce DG growth?

A. Several UNSE witnesses criticize the fact that Vote Solar and other parties recommended that the Commission reject their proposed changes to the NEM program without proposing any alternatives.[180]

Q. How do you respond to these criticisms?

A. The Company's witnesses appear to believe that the Commission must modify the existing NEM program in this proceeding. But UNSE did not present sufficient evidence to justify the need to modify the existing NEM program. Therefore, Vote Solar recommends that the Commission maintain the existing NEM program. However, to address declining retail sales and cost-reflective ratemaking, as stated above, Vote Solar would be open to: (1) TOU rates, and (2) small minimum bills, so long as these measures are applied in a non-discriminatory manner.

Q. Is it Vote Solar's position that the Commission must wait to take action on UNSE's DG proposals until after the proceedings in the Value of Solar docket are complete?

A. Not necessarily. Mr. Tilghman claims that Vote Solar and other parties have "[a]ttempt[ed] to remove the Company's proposal from consideration in this rate case until the Value of Solar docket is completed."[181] This statement is incorrect. Vote Solar has consistently argued that a rate case is the proper proceeding for the Commission to consider any modifications to the existing NEM program because

[180] *E.g.*, Hutchens Rebuttal Test. at 4:9–12; Dukes Rebuttal Test. at 20:14–15.
[181] Tilghman Rebuttal Test. at 3:10–12.

a rate case should allow a comprehensive examination of costs across all customer classes, various rate designs, and an analysis of the full value of DG.[182]

The fact that a rate case is the proper proceeding to consider these issues does not mean that the Commission should actually modify the NEM program in this rate case without supporting evidence. As discussed above, UNSE's DG proposals are unsupported by the evidence and suffer from numerous flaws, and they should therefore be rejected. Nonetheless, if the Commission wishes to further consider changes to the existing NEM program, the Value of Solar proceeding may provide important information and insights due to the absence of a full value of solar analysis here.

9 In the event of major rate design changes, existing NEM Customers should be grandfathered

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

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

[182] *See, e.g.*, Vote Solar Brief In Support of Dismissal (May 15, 2015, Docket No. E-01933A-15-0100) 1:20–21.

design for these customers have the potential to severely undercut their planned savings.

Q. What have other parties in this proceeding proposed regarding grandfathering?

A. Among parties recommending differential DG rate treatment, UNSE proposed that existing NEM customers who signed up before June 1, 2015 be allowed to continue service on the existing NEM tariff that would allow them access to the standard two-part residential rate and full retail rate credit for their exported DG. Since June 1, 2015, UNSE has notified new NEM customers of the possibility of changes to the rate structure that may impact their savings potential. In direct testimony RUCO states that "these customers may not fully understand the magnitude of the negative impact to this value proposition that may come from a rate design."[183] As a result, RUCO recommends that customers who sign up before the conclusion of this case be grandfathered.[184]

Staff is not recommending differential rate treatment for DG customers, and had originally recommended that existing NEM customers not be grandfathered in the proposed move to mandatory demand charges.[185] It is my understanding that Staff may move away from this proposal and may advocate for grandfathering of existing NEM customers under their proposal.

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

A. As I stated above, it is essential that existing NEM customers be protected against drastic and unforeseen rate design changes. I believe that the proposals put forth by UNSE, RUCO, and Staff would all constitute drastic and unforeseen rate design changes. If the Commission approves one or more of these proposed changes, I recommend that NEM customers who sign up prior to the date of the

[183] Huber Direct Test. at 16:21–22.
[184] *Id.* at 16:23–17:3.
[185] Broderick Direct Test. at 10:5–8.

decision in this proceeding be grandfathered into the existing tariff structure that preserves a two-part rate with full retail rate credit for DG exports. I agree with RUCO that customers who have signed up after June 1, 2015, may not have a full understanding of the potential implications of the rate redesign, and it is important that these customers also be grandfathered.

10 Conclusions and Recommendations

Q. Please summarize your conclusions regarding the proposals put forth in the proceeding.

A. As I have described in detail in this testimony and in my direct testimony, UNSE has failed to support its proposals for differential rate treatment for NEM customers. In direct testimony, I demonstrated that NEM customers are not a significant contributor to UNSE's sales reductions—a fact that UNSE failed to provide any evidence to rebut. UNSE brought in a new witness, Dr. Overcast, in rebuttal testimony to argue for differential NEM rate treatment. But a review of his analysis reveals significant flaws. Bill frequency data demonstrates that NEM customers' bills fall within the range of non-NEM customers' bills, and a review of his narrow approach to a cost shift analysis shows a number of errors in assumptions. Dr. Overcast's approach to examination of the alleged NEM-related cost shift is one-sided, looking primarily at short-term costs he attributes to load reductions, while excluding quantification of any of the long-term DG-related benefits. While I do not recommend Dr. Overcast's approach, I adopted it for the limited purpose of comparing his alleged NEM-related cost shift with the cost shift that would be attributable to seasonal and/or vacant homes, and found the illustrative cost shift due to seasonal and vacant homes would be as much as 32 times the alleged NEM cost shift. As a result, rate treatment designed only to address NEM-related load reductions would not only be discriminatory, but it would not materially impact the load reduction problems that UNSE alleges are occurring.

In addition, I have reviewed the proposals for mandatory demand charges and found that implementation of mandatory demand charges for UNSE's residential and small commercial customers is an overly-aggressive proposal that has the potential to create extreme and unpredictable bill impacts that customers will have little ability to control. While several parties attempt to paint a picture of mandatory demand charges as a natural conclusion based on academic arguments of cost causation, the fact remains that not a single state-regulated utility in this country has approved mandatory demand charges for its residential customers.

The mandatory demand charge proposals call for major rate design overhaul to be implemented immediately following meter roll-out. Because metering is not yet in place, the Company lacks sufficient data to fully understand the impacts of its proposal. As a result, parties have proposed a number of safeguard measures including a temporary minimum load factor, a provision for vulnerable customers to self-identify for special rate treatment, and a proposal to leave this rate case open after approval to address potential unforeseen problems. I find that each of these safeguard measures is severely flawed and note that the very fact that the proposals for mandatory demand charges would necessitate so many safeguards should raise red flags at the Commission.

Even with the minimum load factor provision, the average residential customer would see a bill increase of 16%, and nearly one in five residential customers would see bill increases in excess of 30%. For small commercial customers the expected bill impact is even more extreme, with the average customer shouldering an increase of almost 40% and more than a third of customers seeing increases in excess of 50%. UNSE has indicated that the minimum load factor adjustment reduces nearly every customer's bill and, as a result, these impacts are expected to become more extreme when the temporary minimum load factor provision is removed. In addition, due to the lack of available data, it is not clear how vulnerable groups of customers would even be able to take advantage of the opportunity to self-identify, and the proposal to leave the rate case open to address any unforeseen problems raises questions about whether the full implications of this proposal can even be understood at this point in time.

Taken together, the unprecedented nature of the mandatory demand charge proposal and the need for proposed safeguards point to an extreme experiment in major rate design change that would have a large and unavoidable impact on real people with real investments. The problem becomes worse when one considers that many customers will have little to no ability to respond to the price signal presented by demand charges. While UNSE's customer education plan may make customers aware of the reasons why their bills have increased 30% to 50% or more, many customers will have daily routines that limit their ability to do anything about the increase. While some might argue such an occurrence is an uncomfortable but "fair" result of moving rates towards cost-causation, an examination of real-world examples reveals that the proposed demand charges may not be cost based at all. The Commission should proceed with caution regarding demand charges to protect customers from extreme, unpredictable, and unavoidable bill increases.

If the Commission deems it necessary to consider major rate design overhaul, TOU rates and a small minimum bill would better address the issues that demand charges purportedly solve. TOU rates are acknowledged in PURPA as reflective of cost causation, would not result in such extreme bill impacts, and would be easier for customers to understand and respond to than demand charges. In addition, TOU rates would provide an incentive for more efficient orientation of NEM customers' PV panels, while demand charges would not. Demand charges would also do nothing to address the problem UNSE describes associated with low-usage bills, as the vast majority of these bills are attributable to customers with seasonal or vacant homes. A better solution to this problem would be to implement a minimum bill that would allow for increased fixed-cost recovery from seasonal and vacant homeowners. The monthly minimum bill should not exceed $14.00 for residential customers and $23.00 for small commercial customers, inclusive of the basic customer charge.

In addition, I find that fixed customer charges should not be increased. While UNSE attempts to raise a number of issues in defense of its proposed increase to the fixed charges, Dr. Overcast's testimony in support of the Minimum System Method includes several mischaracterizations of the Basic Customer Method. The Commission approved the Basic Customer Method for UNSE in the last general rate case, and the method remains a reasonable means for developing customer charges in cost of service ratemaking. Increases to the fixed charge are opposed by ACAA, AURA, RUCO, SWEEP, TASC, Vote Solar, and WRA. These parties explain that fixed charge increases would dampen the conservation signal present in rates, undercut the value of energy efficiency and DG, and disproportionately impact low-income households. To the extent that the Minimum System Method results in a higher fixed charge, the Commission should weigh departing from the previously adopted Basic Customer Method against the environmental and social implications of increases to the customer charge.

Finally, I find that if the Commission decides to institute major rate design changes in this proceeding, it is imperative that existing NEM customers be grandfathered onto the current rate structure. Customers who have signed up for the NEM program after June 1, 2015, are unlikely to fully understand the potential impact that major rate design changes may have on their investments. As a result, all customers who sign up before the date of the decision in this proceeding should be afforded grandfathered rate treatment.

Q. What are your recommendations for the Commission?

A. I recommend the following:

- The Commission should deny proposals for discriminatory treatment for NEM customers.
- The Commission should maintain the retail rate credit for NEM exports pending a full benefit cost study specific to UNSE's territory, which would allow for evaluation of a potential change in the future.

- The Commission should not approve mandatory demand charges for any residential or small commercial customers, NEM or non-NEM.
- The Commission should consider approval of optional demand charges for residential and small commercial customers and should consider requiring UNSE to proceed with its proposed education plan as a marketing effort to prompt enrollment on these optional tariffs.
- If large-scale rate design changes are desired, the Commission should consider implementation of opt-out TOU rates.
- If the Commission wishes to address the problem of seasonal and vacant homes, it could consider implementation of a monthly minimum bill not to exceed $14.00 for residential customers and $23.00 for small commercial customers, inclusive of the basic customer charge.
- The Commission should reject UNSE's proposals to increase basic service charges for residential and small commercial customers.
- In the event of major rate design changes, the Commission should grandfather NEM customers that have signed up in advance of the decision in this proceeding.

Q. Does this conclude your testimony?

A. Yes.

Exhibit BK-SR-1

Discovery Responses Referenced in Testimony

VS 2.14

Please provide the information requested below regarding the following statement by Mr. Tilghman on page 4, lines 20-23 of his direct testimony: "In order to firm up the intermittency and meet the customers' expectations, [renewable energy] requires the continued services of the centralized grid to supply the necessary back-up energy and ancillary services to support solar and other intermittent renewable resources."

a. Please provide data, analyses, and any documentation to support this statement that are specific to the Company's service territory and that analyze distributed generation at current penetration levels and at penetration levels projected in response to data requests VS 2-9(b) and VS 2-11(b). If applicable, please provide responses in executable electronic format with formulas and links intact.

b. Please provide any data, analyses, and other documentation that are specific to the Company's service territory and that analyze whether the back-up energy and ancillary services required to support distributed generation customers are materially different than the back-up energy and ancillary services required to support other customers' demand fluctuations.

RESPONSE: September 28, 2015

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

RESPONDENT:

Carmine Tilghman

WITNESS:

Carmine Tilghman

SUPPLEMENTAL RESPONSE: September 29, 2015

a. The idea that intermittent resources create additional challenges and service on the distribution grid is well documented throughout the industry. Whitepapers, presentations, and other forms of documentation are widely available from organizations such as National Renewable Engineering Laboratory ("NREL"), Massachusetts Institute of Technology ("MIT"), Lawrence Berkley Engineering Laboratory ("LBEL"), Solar Electric Power Association ("SEPA"), Southwest Variable Energy Resource Initiative's ("SVERI") and others. All of these documents are public and easily attainable by Vote Solar.

UNS Electric is a relatively small utility that relies heavily on information received from its' sister company, TEP, and other reputable institutions such as those referenced above. It would not be cost effective to re-create those same studies specific to UNS Electric's service territory. However, as a member and participant in the Western Electricity Coordinating Council ("WECC"), the Company has access to (and is a participant in) the WECC Variable Generation Integration workgroup and its resources, as well as NERC variable integration documentation.

b. According to NERC and its Variable Generation Task Force report on accommodating high levels of variable generation, the following system flexibility/reliability functions and services must be considered to accommodate the characteristics of variable resources as part of the bulk power system design: inertial response, primary frequency response, regulation, load following & ramping, dispatchable energy, contingency spinning reserve, contingency non-spinning reserve, variable generation tail event reserve (loss of sun or wind), and voltage support.

Real Time output and levels of penetration are monitored and evaluated through TEP's partnership with the University of Arizona and located on the UAREN website: http://secure.uaren.info/tep/. Depending on the penetration level, all of these functions require additional resources to account for the variable generation because intermittent resources do not. Although an inverter may be set for a constant voltage and frequency (or acceptable bandwidth), without system control from the Balancing Authority it is an inoperable static device. As such, even the inverter's ability to provide voltage and frequency control is limited.

RESPONDENT:

Carmine Tilghman

WITNESS:

Carmine Tilghman

UNS ELECTRIC INC.'S SUPPLEMENTAL RESPONSE TO VOTE SOLAR'S SECOND SET OF DATA REQUESTS REGARDING THE 2015 UNS ELECTRIC RATE CASE DOCKET NO. E-04204A-15-0142
September 29, 2015

VS 2.16

Please provide the information requested below regarding Mr. Tilghman's statement beginning on page 4, line 26 of his direct testimony that net metering "results in excessive renewable capacity that requires the centralized grid's existing facilities to adjust to generation fluctuations created during solar production."

a. Please provide data, analyses, and any other documentation to support this statement that are specific to the Company's service territory and that contemplate distributed generation at current penetration levels and at penetration levels projected in response to data requests VS 2-9(b) and VS 2-11(b). If applicable, please provide responses in executable electronic format with formulas and links intact.

b. Please define "excessive renewable capacity" as used in this statement.

c. Please quantify the magnitude of the "generation fluctuations" created during solar production.

d. Please indicate how the magnitude of the fluctuations quantified in data request VS 2-16(c) compares to general fluctuations in customer demand.

RESPONSE: September 28, 2015

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

RESPONDENT:

Carmine Tilghman

WITNESS:

Carmine Tilghman

SUPPLEMENTAL RESPONSE: September 29, 2015

UNS Electric objects to this request as vague and ambiguous and unduly burdensome. Without waiving this objection, UNS Electric provides the following responses:

a. The statement reflects the Company's observations of DG systems being installed in its service area. It would be unduly burdensome to prepare a report that sets forth each DG customer's current excess generation profile..

b. Excessive renewable capacity as used in this statement is any additional energy above and beyond the customer's needs that is sent back onto the grid.

c. Generation fluctuations can be up to 100% of generating capacity.

d. The magnitude of fluctuations associated with PV can vary greatly relative to a customer's load fluctuation, and is entirely dependent of system size, seasonal production, and seasonal load characteristics.

RESPONDENT:

Carmine Tilghman

WITNESS:

Carmine Tilghman

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 3.22

Please provide the information requested below regarding the Company's response to Staff 2.014:

a. The Company states that many customers do not have meters capable of sending data to the Company's Meter Data Management (MDM) system. Please indicate the percentage and number of customers in each customer class who have meters capable of sending data to the Company's MDM system.

b. For customers with data available in the MDM system, please indicate the percentage and number of customers in each customer class that were selected in the Company's random sample.

c. How was the random sample generated?

d. Did the Company consider geographic diversity when it generated the random sample?

RESPONSE:

a. The Company objects to this question as to generate and verify a report that separates the customer classes would be time consuming and overly burdensome. However, without waiver of objection, the meter counts for all classes in the UNS Electric service territory that are in MDM are below. Please note that the percentage of customers in MDM is approximate because the relationship between meters and customers is not 1:1. The Company does not have reports readily available that track the count of meters in each class as its primary concern has been full deployment of interval metering being read by the advanced metering infrastructure.

	Interval Meters In MDM	Total Customers	Approx %
Start of Test Year	36,542	93,054	40%
End of Test Year	56,788	93,769	60%
Current (10/1/2015)	67,829	94,344	70%

b. Please note that customers may not have interval data during the entire test year as the number of customers on the MDM system has been rapidly increasing.

Customer Class	Population	Sample	Percentage
Residential	82,438	1,778	2.16%
Small General Service	8,699	2,601	29.90%
Large General Service	1,341	926	69.05%
Large Power Service	17	17	100.00%

c. The interval data customers where selected randomly, without replacement, for those customers that have interval data as indicated in the CC&B system. Once the interval data was obtained, it was compiled in a manner that allowed us to compare the monthly billing statistics of the sample against the population of monthly bills. The statistics included mean, median, and standard deviation as well as distribution shape. Because of the relative homogeneity of the residential class and the heterogeneity of the commercial classes, larger sample sizes were required for the commercial classes to approximate the population.

d. Yes, the Company verified that the percentage of customers from the three geographic regions served by UNS Electric were proportionally represented in the samples.

RESPONDENT:

Greg Strang

WITNESS:

Craig Jones

UNS ELECTRIC INC.'S RESPONSE TO VS'S FIFTH SET OF DATA REQUESTS
REGARDING THE 2015 UNS ELECTRIC RATE CASE
DOCKET NO. E-04204A-15-0142
February 4, 2015

VS 5.05

Does examination of solar production data from La Senita and Rio Rico allow for analysis of the hours and quantity of distributed generation that is exported to the grid? Please explain your answer.

RESPONSE:

Yes. Since under optimal conditions (an assumption that favors DG customers), the Rio Rico data provides the output load shape for DG customers on an hourly basis. Exports to the grid may be calculated by comparing the residential load shape to the DG production load shape to determine those load hours when power is exported to the grid. Please note that the analysis of the hourly marginal benefits from avoided energy cost only relies on the production load shape.

RESPONDENT:

H. Edwin Overcast

WITNESS:

H. Edwin Overcast

UNS ELECTRIC INC.'S RESPONSE TO VS'S FIFTH SET OF DATA REQUESTS REGARDING THE 2015 UNS ELECTRIC RATE CASE DOCKET NO. E-04204A-15-0142 February 4, 2015

VS 5.10

Please provide the information requested below regarding the following statement by Mr. Overcast at page 13, lines 11-14 of his rebuttal testimony: "This means that excess generation sold back to the utility occurs on average at times when the avoided energy cost is less than the average energy cost and less than the marginal cost of energy used by solar DG customers to meet the load in excess of solar DG."

a. Please indicate whether Mr. Overcast reviewed any actual data on distributed generation customer consumption patterns in UNSE service territory. If so, please provide the data.

b. Please indicate whether Mr. Overcast reviewed any data on the timing and seasonality of excess generation from distributed generation systems in UNSE service territory. If so, please provide the data.

c. Over what period are energy costs averaged to obtain the "average energy cost" referred to in the statement.

d. Please provide specific calculations based on the data in Exhibit HEO-2 to support the assertion that excess generation occurs when the avoided energy cost is less than the average energy cost.

e. Please provide specific calculations based on the data in Exhibit HEO-2 to support the assertion that excess generation occurs when the avoided energy cost is less than the marginal energy cost.

RESPONSE:

a. No. Consumption patterns were based on residential load research data for UNS Electric not just DG customers and the pattern of DG production.

b. See the response to a. above. Also see the comparisons of solar output to marginal cost and system load as filed in the rebuttal testimony Exhibits HEO-1 and HEO-2.

c. The test period for this rate case.

d./e. See the workpaper BV Data Request Analysis v4.xlsx, provided in response to UDR 3.1.

RESPONDENT:

H. Edwin Overcast

WITNESS:

H. Edwin Overcast

UNS ELECTRIC INC.'S RESPONSE TO VS'S FIFTH SET OF DATA REQUESTS REGARDING THE 2015 UNS ELECTRIC RATE CASE DOCKET NO. E-04204A-15-0142 February 4, 2015

VS 5.38

Please provide the information requested below regarding the following statements by Mr. Overcast at page 31, lines 13-17 of his rebuttal testimony: "Ideally this demand charge would be based on a contract demand rather than a measured demand in the future since this would reflect the sizing of the local facilities installed to serve the customer and would actually be a separate facilities charge. Some utilities have used this approach for demand billed customers."

a. Please list all utilities of which Mr. Overcast is aware that have used this approach for demand-billed residential customers.

b. For each utility listed in response to sub question (a) please indicate whether the residential rate that included a demand charge was mandatory or optional.

c. For each utility listed in response to sub question (a) please provide a copy of the tariff demonstrating a contract demand for residential customers.

RESPONSE:

a. Dr. Overcast cannot provide a complete list of utilities that specify demand charges based on the greater of actual demand or contract demand since he has not made a study of utility rates that have this provision. He is aware that rural cooperatives often have a provision in residential rates for applying a demand charge for facilities that are larger than a standard transformer based on a charge per kVa for the larger transformer. See for example US residential rates at the following website for examples: http://en.openei.org/wiki/Utility_Rate_Database.

b. There are both mandatory and optional demand rates for residential customers. In some cases the demand rates are mandatory for all customers; others are mandatory for a subclass such as all electric or even DG customers. Please see VS 5.38 Lakeland Demand Rate.pdf, Bates Nos. UNSE\015247-015248, for the Lakeland Electric rate applicable to solar DG customers.

c. See the responses to a. and b. above.

RESPONDENT:

H. Edwin Overcast

WITNESS:

H. Edwin Overcast

VS 5.42

Please provide the information requested below regarding Exhibit HEO-5:

a. The document provided in the Exhibit alludes to some level of savings attributed to many factors. Please indicate the total savings attributed to each of the factors listed in the Exhibit, including: conservation during the peak, debt refinancing, impacts from the propane division, and prepay contracts.

b. Please provide data on the level of peak period reduction in demand among residential customers of Butler REC in 2014.

c. Please provide data on the level of peak period reduction in demand among residential customers of Butler REC in 2009.

RESPONSE:

a.-c. The requested data has not been obtained by Dr. Overcast.

RESPONDENT:

H. Edwin Overcast

WITNESS:

H. Edwin Overcast

VS 5.48

Please provide the information requested below regarding the following statement by Mr. Jones at page 10, lines 12-15 of his rebuttal testimony: "Since we do not have actual demand data for all residential and SGS customers, the impact of the three-part rate is based on data we have from a load research sample group, which is based on the actual usage data of a sample group of customers."

a. Please provide all data obtained on the load research sample group. Please provide data in excel format with formulas and links intact. If necessary, please anonymize any customer-specific information by replacing it with a serial identification number.

b. For each of the five customer size categories provided in Exhibit CAJ-R-4 (Xsm, Small, Medium, Large, Xlg) please indicate the total number of UNSE customers who fall into each category. Please answer separately for residential and SGS customers.

c. For each of the five customer size categories provided in Exhibit CAJ-R-4 (Xsm, Small, Medium, Large, Xlg) please indicate the number of customers for whom UNS has actual demand data. Please answer separately for residential and SGS customers.

d. For each of the five customer size categories provided in Exhibit CAJ-R-4 (Xsm, Small, Medium, Large, Xlg) please indicate the number of customers for whom UNS has actual demand data that were used in the sample group. Please answer separately for residential and SGS customers.

RESPONSE:

a. The load research sample groups consist of 2,309 residential and 2,239 SGS customers. See the following Excel files, which have been submitted with the Company's Rebuttal Testimony workpapers in UDR 3.1:

UNSE Res Dem-OnPk kW_01-09-16_r0.xlsx

UNSE SGS Dem-OnPk kW_01-09-16_r0.xlsx

RES Demand-DG_Staff Case_01-09-16_r0.xlsx

SGS Demand-DG_Staff Case_01-11-16_r0.xlsx

UNSE Res Dem_Data_01-11-16_r0.xlsx

UNSE SGS Dem_Data_01-12-16_r0.xlsx

b. The customer size categories used in Exhibit CAJ-R-4 were not based on the load research sample groups identified by Mr. Jones in his rebuttal testimony, but were based on data from the UNS Electric Customer Care & Billing (CC&B) System. The Xsm, Small, Medium, Large, Xlg customer categories correspond to CC&B monthly usage percentiles of 10%, 25%, 50%, 75%, and 95%, respectively.

Using the CC&B percentile breakpoints, the customer count breakdowns from the load research samples are as follows:

Residential Winter Bills (n=2,309)

Customer Size	Monthly kWh	Customers in Sample Below kWh Breakpoint
Xsm	100	128
Small	294	538
Medium	560	1,184
Large	914	1,775
Xlg	1,653	2,212

Residential Summer Bills (n=2,309)

Customer Size	Monthly kWh	Customers in Sample Below kWh Breakpoint
Xsm	117	174
Small	386	553
Medium	813	1,185
Large	1,395	1,817
Xlg	2,471	2,225

SGS Winter Bills (n=2,239)

Customer Size	Monthly kWh	Customers in Sample Below kWh Breakpoint
Xsm	173	627
Small	303	1,004
Medium	486	1,415
Large	1,254	1,958
Xlg	3,535	2,210

SGS Summer Bills (n=2,239)

Customer Size	Monthly kWh	Customers in Sample Below kWh Breakpoint
Xsm	226	795
Small	395	1,233
Medium	634	1,609
Large	1,634	2,072
Xlg	4,605	2,223

c. Actual demand data were used for both residential and SGS load research samples. Therefore, at a minimum UNS Electric has 12 months of demand data for 2,309 residential and 2,239 SGS customers. UNS Electric is currently in the process of installing meters that will register demand readings for all UNS Electric residential and SGS customers.

d. See response to VS 5.48(b). UNS Electric has a minimum of 12 months of demand data for all customers in the load research sample groups.

RESPONDENT:

Greg Strang/Rick Bachmeier

WITNESS:

Craig Jones

UNS ELECTRIC INC.'S RESPONSE TO VS'S FIFTH SET OF DATA REQUESTS
REGARDING THE 2015 UNS ELECTRIC RATE CASE
DOCKET NO. E-04204A-15-0142
February 4, 2015

Regarding the rebuttal testimony of Mr. Tilghman:

VS 5.53

Please provide the information requested below regarding the following statement by Mr. Tilghman at page 4, lines 12-13 of his rebuttal testimony: "Decision No. 74202 (December 3, 2013) recognized that a cost-shift due to net metering exists."

a. Please provide a specific citation to Decision No. 74202 in which the Commission expressed a finding of a cost shift due to net metering in the service territory of UNS.

b. Please provide a specific citation to Decision No. 74202 in which the Commission expressed a finding of a cost shift due to net metering in the service territory of TEP.

c. Please indicate whether the record in the proceeding that resulted in Decision No. 74202 included data on actual usage characteristics of APS NEM customers.

d. Please indicate whether the Decision No. 74202 authorized modification to the NEM export rate.

RESPONSE:

a. While Decision No. 74202 is specific to APS' application and does not address UNS Electric, Commission Staff acknowledges in their analysis that there is a cost shift from DG customers to non-DG customers as a result of the use of volumetric energy rates to recover a utility's fixed costs. As such, Commission Staff notes that these "additional fixed costs then must be picked up by non-DG customers either through higher energy rates or through other mechanisms such as APS's Lost Fixed Cost Recovery mechanism ("LFCR"). (page 6, line 16 through 20).

The Commission states (Page 23, Line 6): "In balancing the various positions expressed in the docket, the Commission finds that it is in the public interest to approve an interim LFCR DG adjustment that will be accounted for through APS's LFCR mechanism to address the cost shift from APS's residential DG customers to APS's residential non DG customers resulting from the proliferation of solar installations on residential rooftops."

Both Commission Staff and the Commission acknowledge a cost shift from DG customers to non-DG customers due to the current rate design structure. UNS Electric has a similar rate design structure that utilizes volumetric rates to recover fixed costs.

b. While Decision No. 74202 is specific to APS' application and does not address TEP, Commission Staff acknowledges in their analysis that there is a cost shift from DG customers to non-DG customers as a result of the use of volumetric energy rates to recover a utility's fixed costs. As such, Staff notes that these "additional fixed costs then must be picked up by non-DG customers either through higher energy rates or through other mechanisms such as APS's Lost Fixed Cost Recovery mechanism ("LFCR"). (page 6, line 16 through 20).

The Commission states (Page 23, Line 6): "In balancing the various positions expressed in the docket, the Commission finds that it is in the public interest to approve an interim LFCR DG adjustment that will be accounted for through APS's LFCR mechanism to address the cost shift from APS's residential DG customers to APS's residential non DG customers resulting from the proliferation of solar installations on residential rooftops."

Both Commission Staff and the Commission acknowledge a cost shift from DG customers to non-DG customers due to the current rate design structure. TEP has a similar rate design structure that utilizes volumetric rates to recover fixed costs.

c. It is the Company's understanding that during the multi-session technical conference held prior to APS' filing their application that resulted in Decision No. 74202, APS analyzed their NEM customer's actual usage in determining their annual cost shifts.

d. Decision No. 74202 does not authorize any change or modification to APS's NEM export rate. However, as noted above, Commission Staff acknowledges that these "additional fixed costs then must be picked up by non-DG customers either through higher energy rates or through other mechanisms..." Another mechanism for reducing the cost shift between DG customers and non-DG customers would be to modify the export rate for NEM customers.

RESPONDENT:

Carmine Tilghman

WITNESS:

Carmine Tilghman

UNS ELECTRIC INC.'S RESPONSE TO VS'S FIFTH SET OF DATA REQUESTS REGARDING THE 2015 UNS ELECTRIC RATE CASE DOCKET NO. E-04204A-15-0142 February 4, 2015

VS 5.54

Please provide the information requested below regarding the following statement by Mr. Tilghman at page 4, lines 21-24 of his rebuttal testimony: "The Hawaii Public Utilities Commission recognized that penetration had reached a level to warrant changes including with its net metering policy - noting that total net metering program capacity had reached between 30% and 53% of each of the HECO Companies system peak load."

a. Please indicate the current level of net metering program capacity in the UNS territory.

b. Please indicate the anticipated level of net metering program capacity in the UNS territory required to comply with the RES rules.

c. Please indicate roughly how many years UNS expects it will take for net metering program capacity to reach 30% if no major modifications are made to the current rate structure.

d. Please indicate roughly how many years UNS expects it will take for net metering program capacity to reach 53% if no major modifications are made to the current rate structure.

RESPONSE:

a. The current level of net metering program capacity is approximately 10% of UNS Electric's winter/spring system peak load, and approximately 3.5% of UNS Electric's summer/fall system peak load.

b. The anticipated level of net metering program capacity required to comply with the RES rules would be approximately three (3) times the current level.

c.-d. The response to this request would require information outside of the Company's knowledge or control, such as the business plans of solar installation or solar leasing companies, and any estimate by the Company at this point would be speculative.

RESPONDENT:

Carmine Tilghman

WITNESS:

Carmine Tilghman

UNS ELECTRIC INC.'S RESPONSE TO VS'S SIXTH SET OF DATA REQUESTS
REGARDING THE 2015 UNS ELECTRIC RATE CASE
DOCKET NO. E-04204A-15-0142
February 12, 2015

VS 6.5

Please state the number of residential and SGS customers for whom UNSE has the following levels of data, providing separate answers for the residential and SGS classes:

a. At least 12 months of demand data.

b. At least 3 months of demand data.

RESPONSE:

a.-b. The Company has not updated its numbers related to interval read counts for residential and SGS customers since its response to VS 3.22 and has not tracked how much historical data each customer has available. As the Company stated in its response to VS 3.22, "The Company does not have reports readily available that track the count of meters in each class as its primary concern has been full deployment of interval metering being read by the advanced metering infrastructure."

RESPONDENT:

Rick Bachmeier

WITNESS:

Dallas Dukes

Residential Utility Consumer Office's

Responses to Data Requests by Vote Solar

UNS Electric, Inc. Rate Case

Docket No. E-04204A-15-0142

VS 1.3

Q. Under the proposed "DG TOU Option," Mr. Huber proposes an 8.5¢/kWh credit for exported energy. Please indicate whether and how this export rate would be updated over time.

A. RUCO would like to clarify that all PV output, export and instantaneous consumption, would be linked to the 8.5c/kWh volumetric based energy rate (unless RECs are not exchanged). RUCO would like this rate to be updated on a regular basis, perhaps every two years. However, RUCO recognizes the need for some certainty for distributed generation customers that have signed up, especially during years when the capacity value is high. RUCO is open to stakeholder feedback in this regard. RUCO feels that there has to be some periodic movement to avoid excessive rate "vintaging". At the same time, some shielding should be available to past customers to protect them from large deviations in value swings due to market dynamics or methodology updates. RUCO is open to suggestions on if there is a certain symmetrical tolerance threshold, which once passed, locks-in a customer group.

VS 1.4

Q. Under the proposed "RPS Bill Credit Option," Mr. Huber proposes an initial 11¢/kWh credit for exported energy. Please provide the basis for this initial export rate.

A. RUCO would like to clarify that all PV output, export and instantaneous consumption, would be linked to the RPS Bill Credit Option's rate. The initial 11¢/kWh credit was chosen because it is very close to the current retail rate of a typical UNSE residential customer.

ARIZONA CORPORATION COMMISSION'S RESPONSES TO VOTE SOLAR'S THIRD SET OF DATA REQUESTS DOCKET NO. E-04204A-15-0142 FEBRUARY 8, 2016

VS 3.4	On page 11, lines 1-3 of his direct testimony, Mr. Solganick states: "In the long-term, customers might receive cost 'warning' using a simple red/yellow/green indication in their home or business and, for example, their demand controllers could access detailed price information online." Is Mr. Solganick aware of any such technologies on the market today? If so, please provide information on these technologies, including the cost of the technologies and any available information regarding customer adoption.
RESPONSE:	**Mr. Solganick observed the red/yellow/green technology in use in Missouri in 2007, but is not aware if it has been commercialized. Whirlpool indicates that its "Smart" washer and dryer can "Auto-delay laundry cycles during energy rush hours" working with the Nest thermostat. Mr. Solganick has not investigated the cost or adoption rate.**
RESPONDENT:	**Howard S. Solganick, Energy Tactics & Services, Inc., 810 Persimmons Lane, Langhorn, PA 19047**

ARIZONA CORPORATION COMMISSION'S RESPONSES TO VOTE SOLAR'S THIRD SET OF DATA REQUESTS DOCKET NO. E-04204A-15-0142 FEBRUARY 8, 2016

VS 3.11

Please provide the information requested below regarding the following statement by Mr. Solganick at page 31, lines 6-8 of his direct testimony: "The demand charge would not exceed 75 percent of the unit costs for distribution to lessen the impact while customers learn to manage their demand."

a) Please provide an estimate of the initial demand charges and volumetric rates for residential and small commercial customers under Staff's proposal.

b) Please indicate what Staff views as the basis for calculating the end-state demand charge. Would the end-state demand charge be set at 100% of distribution related costs? Would it contain any other costs?

c) Please provide an estimate of the end-state demand charge discussed in subquestion (b) above, as well as the resulting volumetric rates.

d) How long would it take for customers to learn to manage demand?

e) How do you define successful "management of demand"?

RESPONSE:

a) Residential $4.78/kW SGS $4.81/kW
The decrease in the volumetric rate due to the addition of the demand charge was estimated at approximately 1.1 cents/kWh for residential.

b) Demand related distribution costs; potentially yes; no.

c) Based on the costs in this case Residential $6.38/kW SGS $6.42/kW. Volumetric rates would depend on the eventual billing determinants at the end state.

d) That would vary between customers and is not known.

e) When a customer is satisfied.

RESPONDENT: **Howard S. Solganick, Energy Tactics & Services, Inc., 810 Persimmons Lane, Langhorn, PA 19047**

TASC'S FIRST SET OF DATA REQUESTS TO ARIZONA PUBLIC SERVICE COMPANY REGARDING UNS ELECTRIC RATE CASE DOCKET NO. E-04204A-15-0142 JANUARY 4, 2016

TASC 1.1: Regarding the Testimony of Mr. Faruqui:

1. Re: page 14, lines 16-19. In the set of 40 pilot studies and full-scale rate deployments referenced, please identify each study or full-scale rate utility deployment that included residential demand charges. If it is a study, please provide that study.

2. Please provide the four articles/studies cited on page 15.

Response:

1. The studies were referenced to make the general point that customers respond to changes in rate design. To Dr. Faruqui's knowledge, none of the rates included a demand charge.

2. The study entitled "An Analysis of a Demand Charge Electricity Grid Tariff in the Residential Sector" is attached as APS15769.

   The study entitled "A Residential Demand Charge: Evidence from the Duke Power Time-of-day Pricing Experiment" is attached as APS15770.

   The study entitled "Modeling Alternative Residential Peak-load Electricity Rate Structures" is attached as APS15771.

   The study entitled "Time-of-Day Pricing with a Demand Charge: Three-Year Results for a Summer Peak" is attached as APS15772.[1]

1/ Excerpted from Award Papers in Public Utility Economics and Regulation, Institute of Public Utilities, Graduate School of Business Administration, Michigan State University, 1982.

Witness: Dr. Ahmad Faruqui

ARIZONA CORPORATION COMMISSION STAFF'S AMENDED RESPONSES TO RESIDENTIAL UTILITY CONSUMER OFFICE'S FIRST SET OF DATA REQUESTS DOCKET NO. E-04204A-15-0142 DECEMBER 30, 2015

1.05 Rate Design – On page 8 of Staff witness Howard Solganick's testimony he states that his utility provides him with a portal so that he can monitor his usage and his neighbor's usage. Based on this statement please answer the following questions:

a. Do UNS customers currently have access to a portal so they can monitor their usage along with their neighbors?

b. If no to a., what does Mr. Solganick estimate the cost would be to implement this technology to UNS customers? In the response please include the initial set-up costs and ongoing yearly costs to maintain this portal that ratepayers will ultimately pay.

RESPONSE:

a. Staff witness Solganick was unable to find a UNSE portal with that capability.

b. Staff witness Solganick recognizes that the costs to develop a portal depends on the existing capabilities of the Company's infrastructure including website, customer information system, meter data management systems and whether the website would be extended to its affiliate TEP. Therefore Mr. Solganick made no estimates, however the Company may make that estimate in its transition plan that has been requested by Staff.

RESPONDENT: **Howard S. Solganick, Energy Tactics & Services, Inc., 810 Persimmons Lane, Langhorn, PA 19047**

UNS ELECTRIC INC.'S RESPONSE TO WESTERN RESOURCE ADVOCATES' FIRST SET OF DATA REQUESTS REGARDING THE 2015 UNS ELECTRIC RATE CASE
DOCKET NO. E-04204A-15-0142
October 29, 2015

WRA 1.16

Please provide data on the number of UNSE residential customers who have whole-house electric heating or whose primary source of home heating is electric. If data is not available, please provide an estimate.

RESPONSE:

UNS Electric does not have data that identifies which customers have "all electric" residences. Below are current number of electric and gas customers served by UNS Electric and UNS Gas by area, by which WRA may make its' own inferences regarding the data requested.

Kingman:	Electric:	31,467 residences
Havasu (LHC):	Electric:	35,580 residences
Combined Kingman/LHC Gas:	Gas:	23,034 residences
Santa Cruz:		
	Electric:	15,911 residences
	Gas:	6,791 residences

RESPONDENT:

Carmine Tilghman

WITNESS:

Carmine Tilghman

RESIDENTIAL UTILITY CONSUMER OFFICE'S
FIRST SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY IN THE MATTER
REGARDING UNS ELECTRIC RATE CASE
DOCKET NO. E-04204A-15-0142
DECEMBER 22, 2015

RUCO 1.2: APS'S Residential Three-Part Demand Charge Based Rates – On page 7, line 22 of APS witness Charles A. Miessner's rate design direct testimony he states that "We looked at a sample of customers that switched from an energy-only time-of-use rate to the three-part demand rate and found that about 60% of those customers saved on their demand and energy. We also found that those who actively manage their demand have achieved demand savings of 10% - 20% or more. On average, customers on the three-part rate reduce their monthly demand by 3% to 4% depending on the season. These customers also tend to save on their on-peak and monthly kWh usage after switching to the three-part rate." Based on that statement please answer the following questions:

a. Please state the methodology that APS employed to select its sample.

b. Please specify the number of residential customers under this plan that were used in APS's sample?

c. Please provide the worksheet and criteria used to justify the statement that "60% of residential customers that switched from a time of use plan to the APS residential three-part demand rates saved."

d. Please identify the 40 percent of the sample that did not save, and reasons why they did not save given APS's criteria.

e. Please provide your calculations, criteria, and supporting documentation to support the statement "We also found that those who actively manage their demand have achieved demand savings of 10% - 20% or more."

f. Please provide your calculations, criteria, and supporting documentation to support the statement "On average, customers on the three-part rate reduce their monthly demand by 3% to 4% depending on the season. These customers also tend to save on their on-peak and monthly kWh usage after switching to the three-part rate."

Response:

a. Information about the sample and the selection method is provided in the first page/tab of Attachment APS15766.

Witness: Charles Miessner

Response to RUCO 1.2 (continued):

b. The total study size was 977 customers, which constituted all customers meeting the criteria.

c. The summary information is provided in APS15766.

d. The summary information for the customers that did not save under a demand rate is included in APS15766. Typically these customers did not save under a demand rate because their on-peak demand was relatively high in relation to their overall energy consumption and it appears they did little or nothing additional to manage their electrical usage patterns.

e. As shown in the attachment, the top 20% (most successful) savers reduced their bills by 10% to 20% or more under the demand rate.

f. As provided in the attachment, the average demand reduction for the sample was 3% to 4% while the top 20% reduced their monthly demand by roughly 24% on average.

Witness: Charles Miessner

ARIZONA PUBLIC SERVICE COMPANY
Residential Demand Rate Analysis

Background:
Analysis performed in 2015
The purpose of the study was to assess the impact of a three-part demand rate on demand, energy, and monthly bills for residential customers.
The study isolated the demand chage impact by comparing the same customer before and after switching to a three-part rate.
Since the three-part rate was a time-of-use rate, APS compared customers moving from a two-part TOU rate with similar on-peak hours.
The study specifically compared the two-part Rate ET-2 with the three-part Rate ECT-2, both having on-peak hours of 12 noon to 7 pm weekdays.

Sampling Frame:
Phoenix Metro customers
Switched from ET-2 to ECT-2 in 2013
Had 12 months billing data in 2012 and 2014
Resided in same home for the three year period
Total sample size = 977 customers

Adjustments:
Load data was normalized for temperature and humidity for summer months.
Winter months were not adjusted because correlation factors between load and weather were very low.

ARIZONA PUBLIC SERVICE COMPANY

Residential Demand Rate Analysis

stratified by % kW change during summer months

The change in kW, kWh, and monthly bill resulting from switching from a two-part rate to a three-part rate

Summer Load Change (Weather Normalized - temp, humidity)									Summer Bill [1]	
% Customers	Total kWh	On-Pk kWh	Off-Pk kWh	On-Pk kW	% Total kWh	% On-Pk kWh	% Off-Pk kWh	% On-Pk kW	$ Change	% Change
5%	(617)	(234)	(383)	(3.0)	-27%	-40%	-22%	-39%	$ (93.94)	-35%
10%	(444)	(134)	(310)	(1.8)	-19%	-24%	-17%	-24%	$ (66.07)	-25%
15%	(386)	(139)	(247)	(1.6)	-15%	-21%	-13%	-19%	$ (64.35)	-22%
20%	(364)	(117)	(246)	(1.3)	-14%	-17%	-13%	-16%	$ (62.67)	-21%
25%	(358)	(89)	(269)	(1.1)	-14%	-14%	-14%	-13%	$ (58.15)	-20%
30%	(196)	(76)	(120)	(0.9)	-8%	-11%	-7%	-11%	$ (45.61)	-16%
35%	(99)	(48)	(51)	(0.7)	-4%	-8%	-3%	-9%	$ (37.68)	-14%
40%	(162)	(66)	(96)	(0.7)	-6%	-9%	-5%	-8%	$ (45.06)	-14%
45%	(40)	(29)	(11)	(0.5)	-2%	-5%	-1%	-6%	$ (29.43)	-11%
50%	(78)	(41)	(38)	(0.4)	-3%	-6%	-2%	-4%	$ (30.38)	-10%
55%	(31)	(25)	(6)	(0.2)	-1%	-4%	0%	-2%	$ (29.28)	-10%
60%	7	(12)	19	(0.1)	0%	-2%	1%	-1%	$ (22.88)	-9%
65%	2	(4)	6	0.1	0%	-1%	0%	1%	$ (17.45)	-6%
70%	68	8	60	0.2	3%	1%	4%	3%	$ (14.64)	-5%
75%	3	7	(4)	0.3	0%	1%	0%	4%	$ (17.65)	-6%
80%	181	25	156	0.5	8%	4%	9%	6%	$ (7.49)	-3%
85%	200	45	155	0.7	8%	7%	8%	9%	$ (1.01)	0%
90%	144	52	92	0.9	6%	9%	5%	12%	$ (3.11)	-1%
95%	256	63	193	1.2	11%	10%	11%	16%	$ 7.82	3%
100%	519	166	353	2.1	25%	34%	22%	33%	$ 41.43	18%
Average	(70)	(32)	(37)	(0.31)	-2.9%	-5.2%	-2.1%	-3.9%	$ (29.88)	-11%

APS15766_Demand Rate Analysis.xlsx
Load & Bill Impacts

ARIZONA PUBLIC SERVICE COMPANY

Residential Demand Rate Analysis

stratified by % kW change during summer months

Winter Load Change (No Weather Normalization)									Winter Bill[1]	
% Customers	Total kWh	On-Pk kWh	Off-Pk kWh	On-Pk kW	% Total kWh	% On-Pk kWh	% Off-Pk kWh	% On-Pk kW	$ Change	% Change
5%	(242)	(61)	(182)	(1.2)	-21%	-29%	-19%	-26%	$ (27.63)	-23%
10%	(159)	(45)	(115)	(0.9)	-12%	-18%	-11%	-18%	$ (25.31)	-19%
15%	(88)	(23)	(66)	(0.3)	-7%	-10%	-6%	-7%	$ (13.58)	-11%
20%	(140)	(32)	(108)	(0.5)	-10%	-13%	-10%	-10%	$ (18.44)	-14%
25%	(147)	(22)	(125)	(0.4)	-12%	-9%	-12%	-9%	$ (16.23)	-13%
30%	(52)	(5)	(46)	(0.3)	-4%	-2%	-5%	-6%	$ (10.51)	-8%
35%	(94)	(3)	(92)	(0.1)	-8%	-1%	-9%	-3%	$ (10.56)	-9%
40%	(63)	(9)	(54)	(0.3)	-4%	-3%	-5%	-5%	$ (13.28)	-9%
45%	(5)	1	(6)	(0.3)	0%	0%	-1%	-5%	$ (6.04)	-5%
50%	(22)	3	(24)	0.1	-2%	1%	-2%	2%	$ (7.40)	-6%
55%	(1)	11	(12)	(0.1)	0%	5%	-1%	-1%	$ (5.18)	-4%
60%	(18)	(0)	(17)	(0.2)	-2%	0%	-2%	-4%	$ (7.61)	-7%
65%	12	17	(5)	0.0	1%	8%	-1%	0%	$ (3.20)	-3%
70%	45	20	25	0.1	4%	10%	3%	2%	$ 0.77	1%
75%	23	16	7	0.1	2%	8%	1%	3%	$ (4.20)	-4%
80%	137	33	104	0.2	12%	16%	11%	4%	$ 5.20	4%
85%	53	26	27	0.2	4%	10%	2%	4%	$ (1.60)	-1%
90%	58	29	30	0.3	5%	14%	3%	6%	$ (0.26)	0%
95%	151	53	98	0.6	13%	26%	10%	13%	$ 9.10	8%
100%	231	68	163	0.8	19%	32%	17%	17%	$ 13.41	11%
Average	(16)	4	(20)	(0.11)	-1.3%	1.7%	-2.0%	-2.2%	$ (7.13)	-6%

ARIZONA PUBLIC SERVICE COMPANY

Residential Demand Rate Analysis

stratified by % kW change during summer months

Annual Load Change									Annual Bill [1]	
% Customers	Total kWh	On-Pk kWh	Off-Pk kWh	On-Pk kW	% Total kWh	% On-Pk kWh	% Off-Pk kWh	% On-Pk kW	$ Change	% Change
5%	(430)	(147)	(282)	(2.1)	-25%	-37%	-21%	-34%	$ (60.78)	-32%
10%	(302)	(89)	(213)	(1.3)	-16%	-22%	-15%	-21%	$ (45.69)	-23%
15%	(237)	(81)	(156)	(1.0)	-12%	-18%	-11%	-14%	$ (38.96)	-18%
20%	(252)	(75)	(177)	(0.9)	-13%	-16%	-12%	-13%	$ (40.56)	-18%
25%	(252)	(55)	(197)	(0.8)	-13%	-12%	-14%	-11%	$ (37.19)	-18%
30%	(124)	(41)	(83)	(0.6)	-7%	-9%	-6%	-9%	$ (28.06)	-14%
35%	(97)	(26)	(71)	(0.4)	-5%	-6%	-5%	-7%	$ (24.12)	-12%
40%	(113)	(37)	(75)	(0.5)	-5%	-8%	-5%	-6%	$ (29.17)	-13%
45%	(23)	(14)	(8)	(0.4)	-1%	-3%	-1%	-6%	$ (17.73)	-9%
50%	(50)	(19)	(31)	(0.1)	-3%	-4%	-2%	-2%	$ (18.89)	-9%
55%	(16)	(7)	(9)	(0.1)	-1%	-2%	-1%	-2%	$ (17.23)	-8%
60%	(5)	(6)	1	(0.1)	0%	-2%	0%	-2%	$ (15.25)	-8%
65%	7	7	0	0.1	0%	2%	0%	1%	$ (10.33)	-5%
70%	56	14	43	0.1	3%	3%	3%	2%	$ (6.93)	-4%
75%	13	12	1	0.2	1%	3%	0%	4%	$ (10.92)	-6%
80%	159	29	130	0.3	9%	7%	10%	5%	$ (1.15)	-1%
85%	127	36	91	0.5	7%	8%	6%	7%	$ (1.30)	-1%
90%	101	40	61	0.6	6%	10%	4%	10%	$ (1.68)	-1%
95%	204	58	146	0.9	12%	14%	11%	15%	$ 8.46	4%
100%	375	117	258	1.5	23%	33%	20%	26%	$ 27.42	16%
Average	(43)	(14)	(29)	(0.21)	-2.4%	-3.4%	-2.0%	-3.3%	$ (18.50)	-9%

Notes:

1. Excluding adjustors and taxes.

ARIZONA PUBLIC SERVICE COMPANY
Residential Demand Rate Analysis
stratified by % kW change during summer months

Three-part Demand Rate (Time-of-use)
ECT-2 Load (calendar year 2014)

	Summer Monthly Avg (May-Oct)				Winter Monthly Avg (Nov-April)				Annual				Avg Monthly Load Factor		
% Customers	Total kWh	On-Pk kWh	Off-Pk kWh	On-Pk kW	Total kWh	On-Pk kWh	Off-Pk kWh	On-Pk kW	Total kWh	On-Pk kWh	Off-Pk kWh	On-Pk kW	Summer	Winter	Annual
5%	1,700	345	1,355	4.7	937	149	788	3.5	1,319	247	1,071	4.1	49%	37%	43%
10%	1,898	432	1,465	5.8	1,162	199	963	4.1	1,530	316	1,214	4.9	45%	39%	42%
15%	2,156	526	1,630	7.0	1,209	206	1,003	4.7	1,683	366	1,316	5.9	42%	35%	38%
20%	2,272	566	1,705	7.3	1,222	221	1,001	4.9	1,747	394	1,353	6.1	42%	34%	38%
25%	2,195	572	1,623	7.2	1,098	217	881	4.7	1,647	394	1,252	6.0	41%	32%	37%
30%	2,252	587	1,665	7.4	1,173	234	939	4.9	1,713	410	1,302	6.1	41%	33%	37%
35%	2,254	581	1,673	7.1	1,137	215	921	4.8	1,695	398	1,297	6.0	43%	33%	38%
40%	2,563	637	1,926	8.1	1,379	254	1,124	5.4	1,971	446	1,525	6.7	43%	35%	39%
45%	2,329	602	1,727	7.5	1,211	217	994	4.8	1,770	410	1,360	6.2	42%	35%	38%
50%	2,454	638	1,816	8.3	1,304	255	1,049	5.4	1,879	447	1,433	6.9	40%	33%	37%
55%	2,421	620	1,801	7.7	1,248	233	1,015	5.0	1,834	426	1,408	6.4	42%	34%	38%
60%	2,240	571	1,668	7.1	1,081	196	885	4.2	1,660	384	1,277	5.7	43%	36%	39%
65%	2,410	624	1,786	8.2	1,234	236	998	5.0	1,822	430	1,392	6.6	40%	34%	37%
70%	2,388	631	1,757	8.0	1,182	224	958	5.0	1,785	428	1,357	6.5	40%	33%	37%
75%	2,428	616	1,812	8.0	1,201	231	970	4.8	1,815	424	1,391	6.4	41%	35%	38%
80%	2,540	646	1,894	8.1	1,301	240	1,061	5.1	1,920	443	1,478	6.6	42%	35%	39%
85%	2,685	693	1,992	8.9	1,419	274	1,145	5.7	2,052	484	1,568	7.3	41%	34%	38%
90%	2,515	649	1,866	8.3	1,228	235	993	4.9	1,871	442	1,430	6.6	41%	35%	38%
95%	2,569	671	1,897	8.7	1,312	260	1,052	5.4	1,940	466	1,475	7.1	40%	33%	37%
100%	2,606	654	1,952	8.5	1,424	282	1,142	5.7	2,015	468	1,547	7.1	42%	35%	38%
Average	2,344	593	1,751	7.6	1,223	229	994	4.9	1,783	411	1,372	6.3	42%	35%	38%

ARIZONA PUBLIC SERVICE COMPANY

Residential Demand Rate Analysis

stratified by % kW change during summer months

Two-part Energy Rate (Time-of-use)

ET-2 Load (calendar year 2012)

	Summer Monthly Avg (May-Oct)				Winter Monthly Avg (Nov-April)				Annual				Load Factor		
% Customers	Total kWh	On-Pk kWh	Off-Pk kWh	On-Pk kW	Total kWh	On-Pk kWh	Off-Pk kWh	On-Pk kW	Total kWh	On-Pk kWh	Off-Pk kWh	On-Pk kW	Summer	Winter	Annual
5%	2,317	579	1,738	7.7	1,179	210	969	4.7	1,748	394	1,354	6.2	41%	35%	38%
10%	2,342	566	1,776	7.6	1,321	244	1,078	5.0	1,832	405	1,427	6.3	42%	37%	39%
15%	2,542	665	1,877	8.6	1,297	229	1,068	5.1	1,920	447	1,473	6.8	40%	35%	38%
20%	2,635	683	1,952	8.6	1,362	254	1,108	5.5	1,999	469	1,530	7.1	41%	34%	38%
25%	2,553	661	1,892	8.3	1,245	238	1,007	5.2	1,899	450	1,449	6.7	42%	33%	38%
30%	2,448	663	1,785	8.4	1,225	239	986	5.2	1,837	451	1,385	6.8	40%	33%	36%
35%	2,353	630	1,724	7.9	1,231	218	1,013	4.9	1,792	424	1,368	6.4	41%	35%	38%
40%	2,725	703	2,023	8.7	1,442	263	1,179	5.7	2,084	483	1,601	7.2	42%	35%	39%
45%	2,369	632	1,737	8.0	1,217	217	1,000	5.1	1,793	424	1,369	6.5	40%	33%	37%
50%	2,533	679	1,854	8.7	1,326	252	1,074	5.3	1,929	466	1,464	7.0	40%	34%	37%
55%	2,452	645	1,808	7.9	1,249	222	1,026	5.1	1,851	434	1,417	6.5	42%	34%	38%
60%	2,232	583	1,650	7.2	1,099	196	902	4.3	1,666	390	1,276	5.8	42%	35%	39%
65%	2,409	629	1,780	8.1	1,221	218	1,003	5.0	1,815	423	1,392	6.6	40%	34%	37%
70%	2,320	623	1,697	7.8	1,137	204	933	4.9	1,729	414	1,315	6.3	40%	32%	36%
75%	2,426	609	1,816	7.7	1,178	215	963	4.6	1,802	412	1,390	6.2	43%	35%	39%
80%	2,359	621	1,738	7.7	1,164	207	957	4.9	1,761	414	1,348	6.3	42%	33%	37%
85%	2,485	648	1,837	8.2	1,366	248	1,118	5.5	1,925	448	1,477	6.9	41%	34%	38%
90%	2,371	597	1,774	7.4	1,170	206	964	4.6	1,770	402	1,369	6.0	44%	35%	39%
95%	2,312	608	1,704	7.5	1,161	207	954	4.8	1,736	408	1,329	6.1	42%	34%	38%
100%	2,087	488	1,600	6.4	1,193	214	979	4.9	1,640	351	1,290	5.6	45%	34%	39%
Average	2,414	626	1,788	7.9	1,239	225	1,014	5.0	1,826	425	1,401	6.5	41%	34%	38%

ARIZONA PUBLIC SERVICE COMPANY
Residential Demand Rate Analysis
stratified by % kW change during summer months

Three-part Demand Rate (Time-of-use)
ECT-2 Average Monthly Bill [1]

% Customers	Summer	Winter	Annual
5%	$ 171.15	$ 90.08	$ 130.61
10%	$ 198.22	$ 105.72	$ 151.97
15%	$ 230.36	$ 113.95	$ 172.16
20%	$ 241.06	$ 116.50	$ 178.78
25%	$ 236.56	$ 109.36	$ 172.96
30%	$ 242.96	$ 114.00	$ 178.48
35%	$ 238.98	$ 111.42	$ 175.20
40%	$ 267.80	$ 127.85	$ 197.82
45%	$ 248.55	$ 114.87	$ 181.71
50%	$ 266.28	$ 125.11	$ 195.69
55%	$ 256.19	$ 118.49	$ 187.34
60%	$ 237.77	$ 103.32	$ 170.54
65%	$ 262.34	$ 118.24	$ 190.29
70%	$ 258.80	$ 115.16	$ 186.98
75%	$ 259.67	$ 114.06	$ 186.86
80%	$ 267.91	$ 121.54	$ 194.72
85%	$ 287.12	$ 132.75	$ 209.93
90%	$ 268.61	$ 116.33	$ 192.47
95%	$ 277.96	$ 125.27	$ 201.62
100%	$ 275.72	$ 132.57	$ 204.14
Average	$ 249.70	$ 116.33	$ 183.01

Two-part Energy Rate (Time-of-use)
ET-2 Average Monthly Bill [1]

% Customers	Summer	Winter	Annual
5%	$ 265.09	$ 117.71	$ 191.40
10%	$ 264.30	$ 131.03	$ 197.66
15%	$ 294.71	$ 127.53	$ 211.12
20%	$ 303.73	$ 134.94	$ 219.34
25%	$ 294.71	$ 125.59	$ 210.15
30%	$ 288.58	$ 124.51	$ 206.54
35%	$ 276.66	$ 121.98	$ 199.32
40%	$ 312.86	$ 141.13	$ 226.99
45%	$ 277.98	$ 120.91	$ 199.44
50%	$ 296.66	$ 132.50	$ 214.58
55%	$ 285.47	$ 123.67	$ 204.57
60%	$ 260.65	$ 110.93	$ 185.79
65%	$ 279.79	$ 121.45	$ 200.62
70%	$ 273.44	$ 114.39	$ 193.91
75%	$ 277.31	$ 118.26	$ 197.79
80%	$ 275.40	$ 116.34	$ 195.87
85%	$ 288.13	$ 134.35	$ 211.24
90%	$ 271.72	$ 116.58	$ 194.15
95%	$ 270.15	$ 116.17	$ 193.16
100%	$ 234.29	$ 119.17	$ 176.73
Average	$ 279.58	$ 123.46	$ 201.52

Notes:
1. Excluding adjustors and taxes.

Exhibit BK-SR-2

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

BEFORE THE ARIZONA CORPORATION COMMISSION

JIM WEEKS
Chairman
BUD TIMS
Commissioner
JOHN AHEARN
Commissioner

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

DATE OF HEARING: September 4, 1980

PLACE OF HEARING: Phoenix, Arizona

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

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

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

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

John Michael Morris, on his own behalf

Godfrey J. Danielson, on his own behalf

William Eden, on his own behalf

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

FINDINGS OF FACT

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

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

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

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

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

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

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

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

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

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

CONCLUSIONS OF LAW

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

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

ORDER

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

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

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

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

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

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

BY ORDER OF THE ARIZONA CORPORATION COMMISSION

Chairman | Commissioner | Commissioner

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

G. C. ANDERSON, JR.
Executive Secretary

Exhibit BK-SR-3

ACC Decision No. 53615 (June 27, 1983)

wrg/jg

BEFORE THE ARIZONA CORPORATION COMMISSION

DIANE B. McCARTHY
Chairman
BUD TIMS
Commissioner
RICHARD KIMBALL
Commissioner

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

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

PLACE OF HEARING: Phoenix, Arizona

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

PRESIDING OFFICER: Wm. R. Giese

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

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

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

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

John C. Hall, in propria persona

John Michael Morris, in propria persona

Ralph W. Vaughn, in propria persona

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

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

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

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

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

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

Grace Frei, in propria persona

INTRODUCTION

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

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

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ALLOCATION OF REVENUE REQUIREMENTS

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

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

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

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

RATE DESIGN

RESIDENTIAL RATES

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

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

E-10 RATE

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

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

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

EC-1 RATE

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

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

. . .

ECT-1 AND ET-1 RATE

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

ECL-1

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

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

RESIDENTIAL RATE SUMMARY

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

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

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

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

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

TIME OF DAY RATE FOR EXTRA LARGE GENERAL SERVICE CLASS

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

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Decision No. 53615

IRRIGATION RATES

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

MISCELLANEOUS RATE CLASSES

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

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

APS PURCHASED POWER AND FUEL ADJUSTMENT CLAUSE

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

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

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

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

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ACCORDINGLY, IT IS ORDERED:

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

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

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

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

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

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

7. This Order shall become effective immediately.

BY ORDER OF THE ARIZONA CORPORATION COMMISSION.

Diane B McCarthy

CHAIRMAN COMMISSIONER COMMISSIONER

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

Thomas Mumaw

THOMAS MUMAW
Acting Executive Secretary

Exhibit BK-SR-4

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

BEFORE THE ARIZONA CORPORATION COMMISSION

BUD TIMS
Chairman
JIM WEEKS
Commissioner
DIANE McCARTHY
Commissioner

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATE-MAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, AND THEREAFTER TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN. (PHASE II)	DOCKET NO. U-1345 DECISION NO. 52593

DATES OF HEARING: January 12-23, 1981

PLACE OF HEARING: Phoenix, Arizona

HEARING OFFICER: Andrew W. Bettwy

APPEARANCES:

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

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

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

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

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

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

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

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

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

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

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

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

J. MICHAEL MORRIS, on his own behalf;

RALPH W. VAUGHN, on his own behalf;

GODFREY J. DANIELSON, on his own behalf;

RAYMOND RUGGE, on his own behalf;

ROLAND JAMES, on his own behalf.

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

PURPA STANDARDS

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

. . . . .

1. Conservation of energy supplied by electric utilities;

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

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

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

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

> (5) *Interruptible rates*.--Each electric utility shall offer each industrial and commercial electric consumer an interruptible rate which reflects the cost of providing interruptible service to the class of which such consumer is a member.
>
> (6) *Load management techniques*.--Each electric utility shall offer to its electric consumers such load management techniques as the State regulatory authority (or the nonregulated electric utility) has determined will--
>
> > (A) be practicable and cost-effective, as determined under section 2625(c) of this title,
> >
> > (B) be reliable, and
> >
> > (C) provide useful energy or capacity management advantages to the electric utility.

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

> (a) *Consideration and determination*.--Each State regulatory authority (with respect to each electric utility for which it has ratemaking authority) and each nonregulated electric utility *shall consider each standard* established by subsection *(d) of this section and made a determination concerning whether or not it is appropriate to implement such standard to carry out the purposes of this chapter*. For purposes of such consideration and determination in accordance with subsections (b) and (c) of this section, and for purposes of any review of such consideration and determination in any court in accordance with section 2633 of this title, the purposes of this chapter supplement otherwise applicable State law. Nothing in this subsection prohibits any State regulatory authority or nonregulated electric utility from making any determination that it is not appropriate to implement any such standard, pursuant to its authority under otherwise applicable State law.
>
> 16 U.S.C. § 261(a) (emphasis added).

. . . . .

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

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

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

COST OF SERVICE

Our adoption of the Cost of Service standard is qualified by our declaration that neither the adoption nor implementation of such standard requires a design of rates for the APS system which is based solely on the cost of furnishing electricity. Among other well-established principles of rate-making, we intend to continue to be sensitive to the desirability of rate stability and the potential impacts of abrupt changes in rate design which may affect adversely APS existing customers.

Further, we do not intend by our adoption of the Cost of Service standard to endorse any particular costing methodology; in that regard, we intend to maintain for all affected interests and this Commission the continued freedom to employ a marginal cost of service study or an embedded cost of service study or any other methodology or combination thereof. Consistent with that objective, and to assure meaningful assessments in future rate proceedings of available costing methodologies, APS is hereby directed to include both a marginal cost of service study and an embedded cost of service study in its rate design filings in future rate proceedings.

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

DECLINING BLOCK RATES

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

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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 system and to appropriately recognize those commercial and industrial users which are willing to tolerate interruption during peak periods, we conclude that adoption of the interruptible rates standard is appropriate for the APS system. The record discloses that APS has had limited success in its effort to make available interruptible rates to commercial and industrial customers on a voluntary basis. With the objective of improving that success record, APS is hereby directed to survey its industrial and commercial customers and to report to this Commission within 18 months after the effective date of this Decision regarding the viability of a voluntary interruptible rates program. The written report shall detail the costs of providing such service, the categories of customers which would benefit by such rates, the proposed timing and duration of interruptions, potential problems associated with participation by various categories of customers and any other information which would assist this Commission in its evaluation of the practicability of an effective voluntary interruptible rates program.

LOAD MANAGEMENT TECHNIQUES

It would be curious indeed if one were to not readily applaud management techniques which are directed to the reduction of peak demand, assuming the long-run cost savings of such reduction are likely to exceed the long-run costs associated with implementation of such techniques. Our adoption herein of the load management techniques standard reflects our commitment to encourage the implementation by APS of such techniques.

Within 18 months after the effective date of this

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

NON-PURPA ISSUES

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

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

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

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

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

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

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

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

2. <u>Modification to APS' Purchased Power and Fuel Adjustment Clause</u>.

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

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

Insofar as APS' requested modification relates to other layoff sales, a decision on that requested modification is deferred until the next general rate proceeding.

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

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

In an effort to avoid any unnecessary delay in the implementation of appropriate, mandatory time-of-day rates for APS' Extra Large General Service Customers, and in an effort to be assured that any action we take in that regard is based on reliable and complete information, APS and the parties representing the customers which would be affected by such rates are requested to submit to this Commission no later than December 1, 1981 specific information regarding expected impacts on individual customers within the Extra Large General Service class. Further, such parties may submit to this Commission on or before December 1, 1981 any additional information or comments pertaining in any manner whatsoever to the proposed implementation of mandatory time-of-day rates.

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

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

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

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

ACCORDINGLY, IT IS ORDERED:

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

2. The gas rate schedules and the associated terms

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

3. The rates, charges and tariff provisions established herein shall become effective on January 1, 1982.

4. Within the time frames stated, Arizona Public Service Company shall submit to this Commission the reports contemplated hereinabove in connection with our discussions of the PURPA standards pertaining to interruptible rates and load management techniques.

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

BY ORDER OF THE ARIZONA CORPORATION COMMISSION

Bud Tims — CHAIRMAN | Diane B. McCarthy — COMMISSIONER | Jim Weeks — COMMISSIONER

IN WITNESS WHEREOF, I, TIMOTHY A. BARROW, JR., Executive Secretary of the Arizona Corporation Commission, have hereunto set my hand and caused the official seal of the Commission to be affixed at the Capitol in the City of Phoenix, this 9th day of November, 1981.

Timothy A. Barrow
TIMOTHY A. BARROW
Executive Secretary