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Transcript Exhibit(s)

Docket #(s): E-04204A-15-0142

Arizona Corporation Commission
DOCKETED
MAR 25 2016
DOCKETED BY

Exhibit #: AIC-A-I; APS 1-10; AECC/NS-1-6
FPAA 1-3

Part 1 of 8

For Part 2, see Barcode 0000169257

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To: Docket Control

Date: March 25, 2016

Re: UNS Electric / Rates
E-04204A-15-0142
March 1 through 23, 2016
Volumes I through XV, Concluded

## STATUS OF ORIGINAL EXHIBITS

### *EXHIBITS FILED WITH DOCKET CONTROL*
***(See attached exhibit index for all admitted exhibits)***

### *EXHIBITS NOT OFFERED*

UNS Electric (UNSE Exhibits)

UNSE-42 (***Returned to party)***

Vote Solar (Vote Solar Exhibits)

Vote Solar-9

### *EXHIBITS NOT UTILIZED*
***(by design or oversight)***

TASC (TASC Exhibits)

TASC-3

**NOTE:** The index pages list exhibits for Fresh Produce Association of the Americas as FAPP, it should be FPAA. The text of the transcript is correct, as are the exhibit label stickers.

Copy to: via email to ALJ Rodda and all parties

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1 BEFORE THE ARIZONA CORPORATION COMMISSION

2

3 IN THE MATTER OF THE APPLICATION OF )
UNS ELECTRIC, INC. FOR THE ) DOCKET NO.
4 ESTABLISHMENT OF JUST AND REASONABLE ) E-04204A-15-0142
RATES AND CHARGES DESIGNED TO REALIZE)
5 A REASONABLE RATE OF RETURN ON THE )
FAIR VALUE OF THE PROPERTIES OF UNS )
6 ELECTRIC, INC. DEVOTED TO ITS )
OPERATIONS THROUGHOUT THE STATE OF )
7 ARIZONA AND FOR RELATED APPROVALS. )
)
8

9

10
At: Tucson, Arizona
11

12

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14

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Volumes I through XV, Concluded
16

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Certified Reporter
25 Certificate No. 50658

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**BEFORE THE ARIZONA CORPORATION COMMISSION**

**COMMISSIONERS**

SUSAN BITTER SMITH – CHAIRMAN

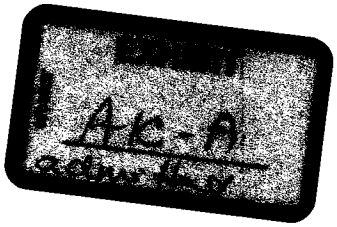
BOB STUMP

BOB BURNS

DOUG LITTLE

TOM FORESE

| | | |
|---|---|---|
| **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 REGULATED APPROVALS.** | ) | **DOCKET NO. E-04204A-15-0142** |




Direct Testimony and Exhibits of

Gary Yaquinto

on Behalf of

Arizona Investment Council

December 9, 2015

AIC Exhibit A

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## I. QUALIFICATIONS

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

A. My name is Gary M. Yaquinto. I am President and CEO of the Arizona Investment Council ("AIC"). Our offices are located at 2100 North Central Avenue, Phoenix, Arizona 85004.

**Q. Please summarize your educational background and professional experience.**

A. I earned B.S. and M.S. Degrees in Economics in 1974 from Arizona State University, as well as an MBA from the University of Phoenix in 2005. From 1975 to 1977, I was employed by the State of Wyoming as an economist responsible for evaluating the economic, fiscal and demographic effects of resource development in Wyoming. From 1977 to 1980, I was Chief Research Economist for the Arizona House of Representatives, and from 1980 to 1984, I was employed as an economist in the consulting industry. Since 1984, I have worked in various capacities in government and the private sector in the area of utility regulation, including positions with the Arizona Corporation Commission's ("ACC") Utilities Division Staff, a competitive local exchange telephone carrier, and as a consultant. While a member of the ACC Staff, I served as Director of the Utilities Division from 1988 to 1997. I also served as the Chief Economist at the Arizona Attorney General's Office from 2003-2005 and as the Director of the Governor's Office of Strategic Planning and Budgeting from 2005-2006. I became AIC's President in December of 2006.

## II. INTRODUCTION AND PURPOSE

**Q. What is AIC and what is its mission?**

A. AIC is an association organized under Chapter 501(c)(6) of the Internal Revenue Code. AIC's membership includes approximately 6,000 individuals – many of whom are debt and equity investors in Arizona utility companies and other Arizona businesses.

AIC's mission is to advocate on behalf of its members' interests, primarily before regulatory bodies as well as the Arizona Legislature. Specifically, we seek to maintain and support public policies and governmental actions that positively impact investors and protect their investments.

AIC also works with the Commission and policymakers generally to find ways to support investment in Arizona's essential backbone infrastructure, including improvements to, or remediation of, existing facilities. This aspect of our mission is complementary to our core investor interest concerns.

**Q. What is the purpose of your testimony?**

A. The purpose of my testimony is twofold: (1) to support UNS Electric, Inc.'s ("UNS Electric" or "Company") proposed Economic Development Rider 13, and (2) to oppose the generation buy-through tariff, Rider 14, offered by the Company.

AIC supports the Economic Development proposal because it is targeted at assisting communities within the Company's service territory in attracting new businesses and expanding existing businesses, both of which create new jobs. The bill discounts under the proposed Economic Development Rider would be available only to large

commercial and industrial operations that UNS Electric can serve efficiently, and for which it has available facilities. Because the cost to serve these entities is low relative to other customers, and the power served under the program is new load added beyond the test year, the bill discount will not result in a cost-shift between customer classes. In addition, the new load generated by the Economic Development Rider will help the company make up some of the decline in sales that have occurred since the last rate case. It's a win-win for Mohave and Santa Cruz communities and for the Company.

However, the generation buy-through offering, Rider 14, benefits only those large commercial and industrial customers that have the ability to arrange for generation service from providers other than UNS Electric and are lucky enough to be selected for the program. While existing enterprises that are selected to participate in the program might be able to lower their electricity bills under a buy-through arrangement, the arrangement may not lead to the kinds of community-wide economic benefits that result from the Economic Development proposal. The buy-through rate, unless very carefully designed, also shifts fixed costs onto non-participating customers. Furthermore, like a very similar program implemented on an experimental basis for APS in 2012, the potential effects on the company and its other customers is uncertain. The APS buy-through rate was a pilot, and we have yet to see the data from that program that would inform the design for such a rate in this case. Rather than implement a buy-through rate for UNS Electric now, the Commission should wait until it is able to analyze the performance of the APS pilot AG-1 rate and resolve any attendant pricing or legal issues implicated by such a rate .

## III. ECONOMIC DEVELOPMENT RATE, RIDER 13

**Q. Mr. Yaquinto have you reviewed the company's proposed bill discount proposal for economic development?**

A. Yes.

**Q. Please describe the company's economic development proposal.**

A. The company is proposing to offer a discount off the total bill for certain large customers who locate new operations or expand existing operations within the company's service territory. Qualifying customers for the discount must also meet eligibility criteria outlined in the proposed tariff, Rider-13, for minimum peak load and load factor. Additionally, availability under Rider-13 is limited to UNS Electric's capacity to serve the new load. Finally, the term of the discount is limited to five years and the amount of the discount is stepped-down each year.

**Q. Please explain the qualifying conditions imposed in the economic development discount proposal.**

A. First, the economic development discount is available to commercial and industrial customers where UNS Electric has available service capacity. Eligibility is restricted to customers with a peak load of at least 1,000 kW and a load factor greater than 75 percent.

Customers applying for the economic development discount must demonstrate they are either locating new operations in the company's service territory or expanding existing operations. Eligibility is determined by providing written documentation to the Company that the customer has qualified for either the State of Arizona's Quality Jobs Credit, or Qualified Facilities Credit. The criteria under the Quality Jobs Credit

include demonstration that a specified level of capital investment is made and that a certain number of jobs are created at specified pay levels and health care benefits. For application within UNS Electric's service territory, the Quality Jobs Credit requires a capital investment of at least $5 million and creation of at least five jobs. The Facilities Credit is available for manufacturing facilities and research and development operations, which create jobs paying 125 percent of the median county wage and cover at least 80 percent of health care premiums.

**Q. Are there other limitations attached to the Economic Development proposal?**

A. Yes, the program is limited to 50 MW of applicable load.

**Q. You mentioned that the amount of discount for each customer served under the Economic Development Rate is stepped down over a five year period. Please explain how the discounts are applied.**

A. First, Rider 13 establishes two categories of eligible customer discounts. The categories are Economic Development and Economic Redevelopment. The distinction between the categories is whether new facilities are built and occupied, or if existing vacant facilities are used. The amount of discount is higher for using vacant facilities.

If a qualifying customer is building new facilities, the discounts are:

Year 1:20%; Year 2: 15%; Year 3: 10%; Year 4: 5%; and Year 5: 2.5%

If a qualifying customer is occupying vacant facilities, the discounts are:

Year 1: 30%; Year 2: 25%; Year 3: 20%; Year 4: 10%; and Year 5: 5%.

1 **Q. Mr. Yaquinto, does AIC support the Company's proposed Economic**
2 **Development Rate?**
3 A. Yes. For several reasons.
4 First, as Company witness Dallas J. Dukes explains in his testimony, the areas served
5 by UNS Electric have been slower to recover than other areas of the State of Arizona
6 as a whole from the last economic recession, which began in late 2007. Encouraging
7 economic development through incentives like discounted electricity rates is a way of
8 assisting that recovery, which benefits the Company, customers and communities in
9 Mohave and Santa Cruz counties.
10 In his testimony, Mr. Dukes provided a graph clearly showing that the economies of
11 both Mohave and Santa Cruz counties, where UNS Electric provides service, have
12 lagged behind other areas in Arizona (Direct Testimony, Dallas J. Dukes, p. 31, lines
13 1:11). If the Economic Development program is successful in encouraging new basic
14 industries to locate or expand operations and bring new direct industry jobs to
15 Kingman or Nogales, for example, jobs in the service sectors of these economies will
16 also increase through the multiplier effect, providing additional economic benefits to
17 these communities.
18 Attracting new businesses to locate or expand operations in rural or smaller urban
19 communities is difficult. These communities must develop mechanisms to compete
20 with other areas in Arizona and other states that have location amenities and
21 advantages not available in smaller communities. Discounted electricity rates could
22 offer a comparative advantage for attracting new business within UNS Electric's
service territory. For high wage industries that are also energy-intensive like mining,

refining and manufacturing, or for data centers, gaining a lower electric bill through a special economic development discount could be the difference in location or expansion decisions.

Second, UNS Electric has sufficient capacity, under the 50 MW load limit to allow the discounts for attracting new business. Additionally, by restricting eligibility to new or expanding operations with high peak load demand and load factor characteristics, the program targets those customers that UNS Electric can most efficiently serve through its facilities. Because the rate is aligned with the cost to serve these more efficient customers, there should be no concern about any resulting cost-shift. Indeed, if UNS Electric is successful in encouraging new business and industry to locate within its service territory, the burden of fixed cost recovery from other customers is lowered, since the program is designed to recover a portion of system fixed costs from new load.

Finally, by piggybacking onto the State's economic development tax credits for eligibility requirements, UNS Electric mitigates some of its administrative costs related to implementing the tariff as well as lessening or defusing potential claims of "free ridership" should customers receive a discount when they might not otherwise be entitled to one.

**Q. Do you have a recommendation regarding the company's Economic Development Rate?**

A. Yes. I recommend the Commission approve UNS Electric's proposed Rider-13, Economic Development Rate.

## IV. BUY-THROUGH RATE, RIDER 14

**Q. Have you also reviewed the company's buy-through offering?**

A. Yes.

**Q. What is your understanding of the origin of the company's buy-through proposal?**

A. Provision 31 of the Settlement Agreement reached among parties in Dockets No. E-04230A-14-0011 and E-01933A-14-0011, regarding the acquisition of UNS Energy Corporation by Fortis, Inc. requires the Company to propose a pilot program for a buy-through tariff. It states:

> "31. In their next rate cases, TEP and UNS Electric will propose a pilot program for a "buy-through" tariff available to Large Light and Power Service and Large Power Service customers, respectively." (Exhibit A, Attachment A, UNS Energy Corporation and Fortis, Inc., Joint Notice of Reorganization, Settlement Agreement, p. 5, May 16, 2004).

**Q. Did the Commission approve the Settlement Agreement?**

A. Yes, in Decision No. 74689.

**Q. Did you participate in the Settlement Agreement and were you a signatory to that agreement?**

A. Yes.

**Q. Does provision 31 in the Settlement Agreement, which requires the Company to propose a pilot program for a buy-through tariff, also require that the Company or any party to the Settlement Agreement support the proposed buy-through tariff?**

1 A. No. The Company makes it clear it is only proposing the buy-through tariff pilot to
2 comply with the Settlement Agreement. As stated by Company witness Craig Jones
3 in his pre-filed direct testimony:

4 **To be clear, UNS Electric is merely presenting this experimental rider in order to comply with the settlement agreement and is**
5 **neither endorsing the concept nor approval of this specific tariff (Direct Testimony of Craig Jones, p. 6, May 5, 2015).**

6 **Q. Mr. Yaquinto, as a signatory to the Settlement Agreement, do you**
7 **believe you are required to support or otherwise endorse the pilot**
8 **program buy-through tariff proposed in this case?**

9 A. No. In fact, I oppose the experimental buy-through tariff.

10 **Q. What is your general understanding of the proposed buy-through proposal?**

11 A. UNS Electric's buy-through pilot program is generally modeled, with some
12 differences, after a similar experimental pilot program in place for Arizona Public
13 Service Company since 2012.

14 The UNS Electric buy-through proposal is an experimental pilot program that would
15 allow certain large customers the opportunity to arrange for purchase of generation
16 capacity from an alternative provider. UNS Electric would then enter into an
17 agreement with the alternative provider to acquire the power on behalf of the
18 customer, which UNS Electric would deliver to the customer over its facilities. The
19 customer would be charged for services provided by UNS Electric, but would not be
20 subject to power supply charges and purchased power and fuel adjustment charges.
21 Additionally, the UNS Electric pilot program is limited to 10 MW and would run for
22 a period of 4 years.

**Q. Why do you oppose the experimental buy-through tariff?**

A. I oppose it in this case for several reasons.

First, as its name clearly indicates, the tariff is experimental and, in fact, is the second experiment of this nature proposed to the Commission. The Commission has previously authorized a similar experimental buy-through tariff, AG-1, for Arizona Public Service Company in Decision No. 73183 (May 24, 2012). That Decision, which approved a Settlement Agreement reached by the parties in APS's last rate case, requires APS in its next rate case to explain whether its experimental buy-through rate led to any unrecovered fixed costs.

Furthermore, in provision 17.2 of the APS Settlement Agreement (Decision No.73183), if the APS buy-through tariff results in unrecovered fixed costs, residential customers will be held harmless – the implication being that other commercial and industrial customers or shareholders must bear the burden of those unrecovered fixed costs.

> **"17.2 . . . Because AG-1 is an experimental program that may benefit certain General Service customers, and because residential customers cannot participate in the program, any APS proposal in APS's next general rate case that seeks to collect lost fixed generation costs related to the AG-1 experimental rate shall not propose to recover such costs from residential customers".**

Arizona Public Service Company, Proposed Settlement Agreement, Docket No. E-01345A-11-0224, January 6, 2012.

The purpose of any experimental program is to determine whether the results obtained from the experiment match program goals or expectations.

Alternatively, an experiment also tests whether any adverse consequences occur.

The APS buy-through experiment is now approaching its four-year target life, and APS will be filing its examination of the AG-1 experimental pilot program in its next rate case, now expected in mid-2016. At this point, we do not know the relative size of benefits or costs, nor the risks imposed on other stakeholders by the pilot program.

Before launching a similar experiment for UNS Electric, the Commission should first consider the results of the original buy-through experiment introduced through APS and whether extension to other Arizona regulated electric utilities is appropriate or warranted.

Q: **Mr. Yaquinto, you mentioned that the experimental pilot program introduced in this case by the Company is similar to the experimental pilot program authorized by the Commission for APS. You also mentioned that the UNS Electric buy-through offering contains some differences. Generally, what are the major differences introduced by UNS Electric?**

A: While the general provisions of the two programs are very similar, a few notable differences exist.

The UNS Electric pilot program attempts to recover a greater share of fixed costs from customers who participate in the pilot program. In UNS Electric's program, participating customers would be responsible for a Reserve Capacity

charge of 100 percent of the company's generation-related charges in the first year and 25 percent of generation related costs in the remaining years of the experiment. The 75 percent of unrecovered generation-related fixed costs after the first year on Rider 14 would be recovered from other customers through the Lost Fixed Cost Recovery mechanism.

Additionally, the UNS Electric experimental pilot program is limited to 10 MW of total load, while APS, being a much larger company, has a limit of 200 MW.

**Q: Are the differences in the two pilot programs and the additional restrictions imposed within the UNS Electric experimental program sufficient reason for the Commission to authorize the UNS Electric program?**

A: No. I agree with Company witness Craig Jones' observation that the pilot program introduced by UNS Electric enables large customers to "cherry pick" power supply based on the economics of currently available capacity. (Craig Jones, Direct Testimony, p. 56, 9:14). It results in costs being shifted onto other customers who do not have the same "shopping" advantages or privileges as those of the Company's largest customers who might be lucky enough to grab a share of the 10 MW dedicated to the pilot program. Although UNS Electric has attempted to structure its experimental pilot program to mitigate the exposure of other customers to increased rates, the pilot program nevertheless would likely continue to expose other customers to an unfair cost shift. The pilot program increases risks for a relatively small

utility and for other customers, and provides unfair advantages to a few, very large customers. The public interest simply is not served by a rate program that gives a competitive advantage to some customers to the detriment of all others.

**Q: Do you have other concerns with the proposed buy-through rate?**

A: Yes.

A major thrust of this rate case filing is to modernize rate design in a way that moves customer classes closer to their cost of service. Alternatively stated, the rate designs proposed by the Company partially remove the cross-subsidization among customer classes that results from the current rate design. The buy-through pilot program moves in precisely the opposite direction, imposing a new set of cost shifts onto non-participating customers.

Additionally, because outcomes under pilot programs are generally uncertain, they are typically limited in duration so that the results of the program can be assessed. Experimental programs, like the buy-through pilot, can benefit some stakeholders, but harm others. Before extending or expanding these experimental buy-through programs, the Commission should understand whether they pose any unintended consequences.

Although the UNS Electric buy-through program is limited to four years (a sufficient period for proper assessment of the program), those few customers lucky enough to derive benefit from the program have a vested interest in seeking extension beyond the pilot program's scheduled life, or in advance of a full evaluation of the program. This is particularly true if the rate design

1 does not adequately recover all of the capacity-related, administrative, and
2 other costs that UNS Electric will incur related to the buy-through customers,
3 thereby giving those customers an undeserved windfall that might prove
4 difficult to unwind in future rate cases.

5 Ultimately, the buy-through rate is one way for a few lucky customers to
6 circumvent current restrictions on retail electricity competition, which many
7 believe may not be ripe for consideration in Arizona, or constitutionally
8 permissible. There are other, better ways to stimulate economic growth and
9 encourage large companies to locate in Arizona, such as the Economic
10 Development Rider that UNS Electric has proposed.

11 **Q: Do you have a recommendation regarding the experimental buy-through**
12 **Rider 14?**

13 A: Yes. I recommend that the Commission reject the implementation of an
14 experimental buy-through rate for UNS Electric.

15 Unlike the Economic Development rate proposed by the Company, the buy-
16 through rate is clearly a "free ride" of sorts for a few existing customers. It is
17 unlikely that a properly designed buy-through rate will provide enough price
18 incentive to encourage certain large customers to locate or expand operations
19 in Arizona, and any improperly designed rate that would give those customers
20 such a price incentive will simply result in a non-cost based cost shift
21 benefiting a select group of privileged, large customers. Simply put, the buy-
22 through program enables a handful of elite corporate entities doing business in

UNS Electric's service territory to obtain cheap power from out-of-state energy providers at the expense of other customers and stakeholders.

AIC strongly encourages economic development – but that goal is not accomplished through a buy-through rate. Other rate mechanisms exist that will encourage economic development and create new jobs for the community, without the cost-shift and other risks attending a buy-through rate design.

## V. Conclusion

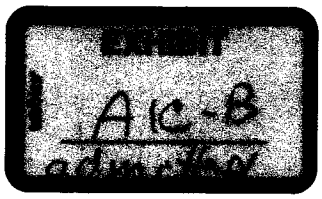
**Q: Does this conclude your testimony?**

A: Yes.

**BEFORE THE ARIZONA CORPORATION COMMISSION**

**COMMISSIONERS**

DOUG LITTLE – CHAIRMAN
BOB STUMP
BOB BURNS
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 REGULATED APPROVALS.** | **DOCKET NO. E-04204A-15-0142** |

Surrebuttal Testimony of

Gary Yaquinto

on Behalf of

Arizona Investment Council

February 23, 2016

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

A. My name is Gary Yaquinto. My business address is 2100 N. Central Ave., Suite 210, Phoenix, Arizona 85004.

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

A. I am submitting testimony on behalf of Arizona Investment Council.

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

A. Yes. I submitted testimony in support of UNS Electric's proposed Economic Development Rate and opposed the Company's Rate Rider 14 Experimental Buy-Through program.

**Q. What is the purpose of your surrebuttal testimony?**

A. The purpose of my surrebuttal testimony is to respond to recommendations and comments of several parties regarding Rate Rider 14. Specifically, I am responding to the recommendations offered by the witness for the companies collectively known as Arizonans for Electric Choice and Competition ("AECC"), Arizona Corporation Commission ("ACC") Staff and Wal-Mart Stores, Inc.

## I. RESPONSE TO AECC

**Q. Mr. Yaquinto, have you reviewed the testimony submitted by Kevin C. Higgins on behalf of Freeport Minerals Corporation, Arizonans for Electric Choice & Competition and Noble Americas Energy Solutions LLC?**

A. Yes. I specifically focused on the sections of Mr. Higgins testimony devoted to the Company's Rate Rider 14 offering, also known as the Buy-Through program.

**Q. In your pre-filed direct testimony of December 9, 2015, you opposed the buy through program altogether. Has Mr. Higgins offered any additional information regarding the buy through rate that might cause you to support it?**

A. No. Ironically, Mr. Higgins' testimony serves to support my principal objection to the UNS Electric buy-through offering – that it not be considered or implemented until a full evaluation has been completed on a similar experimental program authorized for Arizona Public Service Company ("APS").

**Q. Please explain.**

A. My direct testimony in opposition to Rate Rider 14 was premised on the fact that the benefits and costs of a buy-through program are speculative and unknown. While the program might benefit a few large customers, it has the potential to harm other customers, the Company and its shareholders. I recommend the Commission not approve a buy through program for UNS Electric because a similar experimental buy through pilot program is currently underway for APS, and the benefits and costs of that rate experiment have not been fully analyzed and vetted with the Commission.

In my opinion, it would be imprudent and highly premature to authorize another experimental program, absent a full and thorough analysis of the benefits and costs of the APS experimental buy through program. Doing so now for UNS Electric, a much smaller utility company, could pose potentially greater risks to UNS Electric and its stakeholders.

It appears that UNS Electric shares my concerns and, in an effort to mitigate obvious cost shift risks inherent in the APS buy-through pilot program, UNS Electric proposed several modifications within its buy-through proposal.

However, Mr. Higgins disagrees with most elements of UNS Electric's proposal and recommends the Commission's ". . . adoption of a buy-through program that is as similar as reasonably possible to the AG-1 program approved for APS" (Direct Testimony of Kevin C. Higgins, December 9, 2015, p. 5, lns 6-7).

Mr. Higgins does concede, however, that UNS Electric is a smaller utility and, therefore, agrees with the Company's proposed program scale, which limits the program to 10 MW of load. On the other hand, he also recommends substantially expanding the potential number of participants by lowering the minimum load requirement and aggregation threshold proposed by the Company.

**Q. How does Mr. Higgins' recommendation support your contention and recommendation that the Rate Rider 14 Experimental buy-through program NOT be implemented?**

A. While the APS AG-1 rate will not be fully evaluated until APS files its next rate case later this year, we now have some evidence that the AG-1 pilot program has serious flaws that impair recovery of program costs and result in cost shifts to other customers and stakeholders – flaws that could carry over to the Rate Rider 14 buy-through program. Until these issues are thoroughly vetted and resolved, it makes little sense to proceed with another buy-through experimental program for another utility, especially one modeled after APS's AG-1 rate.

**Q. What evidence shows that APS' AG-1 pilot program is flawed?**

A. APS initially signaled cost recovery issues related to the AG-1 program in a filing with the Commission in late 2014 (Docket No. E-01345A-11-0224, (Arizona Public Service Company's Response to AG-1 Customers' and AG Generation Service Providers' Joint Motion to Extend Experimental Rate Rider Schedule AG-1)). In that filing, APS estimated that it had incurred AG-1 related losses in an amount between $5 million and $15 million. Although APS had not identified all of the reasons for those unrecovered costs at that time, the company pointed to the reserve capacity charge fixed at 15 percent of participant load and the "woefully inadequate" administrative charge of $0.0006 per kWh.

**Q. Mr. Yaquinto, do you have more recent information regarding flaws inherent in the AG-1 rate design?**

A. Yes. In response to an AIC data request in this docket, intervenor APS provided additional information about unrecovered costs and additional concerns with the AG-1 program design. Responding to AIC data request 1.1, attached hereto as Exhibit A, APS estimates its net losses from the AG-1 program between the start of the program in November 2012 to May 2015 at $16.8 million.

**Q. You describe the $16.8 million as "net." Please explain.**

A. APS is able to mitigate the losses through wholesale sales of capacity freed-up as a result of the buy-through program. According to APS' response to AIC data requests, the gross loss under AG-1 for the November 2012 through May 2015 period was $45.3 million, which was offset through wholesale margins of $28.5 million. Thus, the net loss, or unmitigated portion of AG-1 was $16.8 million.

**Q. In addition to the net unrecovered costs of $16.8 million for this period, what other deficiencies in the AG-1 pilot program has APS identified?**

A. In response to AIC data request 1.2, attached hereto as Exhibit B, APS stated that it has observed two primary deficiencies with its current experimental AG-1 program. First, because the current energy imbalance process is based on existing FERC protocols, which are typically used for large *wholesale* power transactions, that process does not reflect the actual imbalance cost for *retail* AG-1 customers. APS must therefore continue to provide the load-following service for AG-1 customers with its own power plants. The AG-1 program does not compensate the Company adequately for this service. Second, the program design leads to unrecovered generation costs. These costs stem from provision of load-following services with APS generation facilities, the reliance on backup power from APS in the event a participant's generation provider fails to deliver power, and the fact that APS must plan for providing power to AG-1 customers through the long-term resource planning process since these customers have the option to return to standard service.

**Q. Based on its experience to date with AG-1, does APS believe the administrative fee of $0.0006 is sufficient?**

A. No. In response to AIC data request 1.3, attached hereto as Exhibit C, APS indicates the AG-1 experimental program is not self-supporting and the management fee is too small and should ***at least*** be doubled.

**Q. Does APS believe that the reserve capacity charge of 15 percent, which is a component of the AG-1 rate, is appropriate?**

A. No. Again responding to AIC data request 1.3, APS states that "[t]he reserve capacity charge (which likely should be recomputed using today's embedded generation costs) should be applied to 100% of the customer's billed demand.

**Q. Mr. Yaquinto, what do you conclude from APS's experience to date with the AG-1 experimental program and its extension with certain modifications to UNS Electric as recommended by Mr. Higgins?**

A. My conclusion is that the AG-1 program contains serious flaws and should not be used as a model for a similar experimental program for UNS Electric. Mr. Higgins' recommendation that a buy-through program for UNS Electric should be designed as close as possible to the APS AG-1 program, without fully knowing the benefits and costs of that program, also reinforces my original reasons for opposing Rate Rider 14. Furthermore, while the APS response to AIC data requests in this docket provides an initial indication of negative consequences stemming from a buy through program, a complete analysis of the APS experience could uncover additional problems which I believe must be fully considered and remedied before proceeding with another buy through experiment.

**Q. Finally, Mr. Higgins mentions market transactions experience and economic development as benefits of a buy-through program for UNS electric. Do you agree with Mr. Higgins' statement that a buy-through program for UNS Electric's eligible customers ". . . provides customers with the opportunity to gain experience with market transactions and potentially reduce their energy costs, thereby enhancing the economic development climate of the UNSE service territory and of the state generally?"[1]**

A. No. First, the Experimental Buy-Through program proposed by UNS Electric is intended to serve very large customers, like Mr. Higgins' clients and global retailer, Wal-Mart. These companies already have extensive experience in energy market transactions -- nationally and internationally-- and will gain little,

[1] Direct Testimony of Kevin C. Higgins, p. 16, lines 20-22 and p. 17, line 1, December 9, 2015.

if any, market transaction experience through a UNS Electric buy-through program. In fact, Freeport and Wal-Mart are two of the eight corporations currently participating in APS's AG-1 pilot program. What additional experience could they possibly gain from a UNS Electric buy-through experiment?

Second, unlike Rate Rider 13, UNS Electric's proposed Economic Development Rate, the buy-through pilot program would not likely lead to job creation, either through expansion of existing operations of eligible participants or relocation of new businesses. I do agree that the experimental buy-through program will likely reduce the energy costs of a few existing large customers for a period of time. But the program will shift unrecovered fixed costs of UNS Electric onto other customers and/or shareholders. That cost-shift theoretically could, in fact, have the impact of driving other commercial customers into jurisdictions where utility rates do not include such a subsidy – an economic development benefit for a competing state, perhaps.

As further evidence of the program's potentially weak association with economic development, all eight participants in the APS AG-1 rate are non-relocating, existing customers of APS. Mr. Higgins contention that the buy-through experimental program will enhance the economic development climate of the region or state is simply unfounded.

Should the Commission desire to provide incentives for economic development in UNS Electric's service territory, the EDA rate proposal or special contracts with large customers predicated on measures of cost of service are preferable to a buy-through program.

## II. RESPONSE TO ACC Staff

**Q. Have you reviewed the ACC Staff's position regarding Rate Rider 14?**

A. Yes. Staff consultant, Howard Solganick provided Staff's position on Rate Rider 14. Mr. Solganick states that Staff would have no objection to Rate Rider 14 so long as any lost revenues are not recouped through the LFCR or deferred for recovery at another time.

**Q. Do you agree with Staff's position?**

A. No. Absent some mechanism for recouping losses from the Rate Rider 14 buy-through program, either from Rider 14 participants themselves or customers eligible for the experimental program or other customer classes, those losses are simply transferred to the Company's shareholders. This is precisely what is happening with APS's AG-1 buy-through experimental program.

Recognizing this inherent problem with buy-through programs, UNS Electric, even though it does not support Rate Rider 14, has proposed recovering a portion of unrecovered costs through its LFCR mechanism. By opposing recovery of these costs from other customers as Staff does, the only choices are to force shareholders to take a hit or for Rate Rider 14 participants to absorb the costs. It is simply unfair to burden shareholders with costs for an experimental program that only benefits a few very large customers.

## III. RESPONSE TO WAL-MART

**Q. Did you review the testimony submitted by Wal-Mart Stores, Inc. regarding Rate Rider 14 Experimental Buy-Through Program?**

A. Yes. Wal-Mart witness Chris Hendrix recommends several changes to the UNS Electric buy-through proposal that would, if implemented, completely transform what is intended as a narrowly defined pilot program into a full-scale offering available to all customers meeting the load eligibility requirements and with no limit on term. Additionally, Mr. Hendrix recommends increasing the proposed program cap from 10 MW of load to 150 MW, which represents a third of the Company's peak load. He also testifies that participants in the Rate Rider 14 buy-through program, which he terms Alternative Generation Service, or "AGS" should not be ". . . responsible for of the Company's generation costs or any "lost revenues" since the AGS program is simply replacing wholesale market power purchases that the Company would have to make" (Direct Testimony of Chris Hendrix, p. 4, lines 3-6, December 9, 2015).

**Q. Do you agree with Mr. Hendrix's recommendations?**

A. No. Mr. Hendrix's recommendations would greatly increase the size and duration of the buy-through program compared with the Company's limited design for a pilot program as originally required through a previous Settlement Agreement. As I stated in my Direct Testimony, the company's offering stems from the Settlement Agreement in Dockets No. E-04230A-14-0011 and E-01993A-14-0011. Attachment A of that Settlement Agreement states:

> "31. In their next rate cases, TEP and UNS Electric will propose a pilot program for a "buy-through" tariff available to Large Light and Power Service and Large Power Service Customers" (Exhibit A Attachment A. UNS Energy Corporation and Fortis Inc., Joint Notice of Reorganization, Settlement Agreement, p. 5, May 16, 2014).

Furthermore, the provision of that Settlement Agreement pertaining to the buy-through pilot program does not require the Company or any party to the Agreement to support such a program.

Mr. Hendrix would turn the pilot, which the Company does not even support, into a full-blown permanent program with expanded eligibility. I do not believe this comports with the definition of a "pilot" program, as that term was used in the Settlement Agreement.

**Q. Finally, Mr. Hendrix testifies that Rate Rider 14 participants should not be responsible for any generation-related costs or lost revenues. Do you agree with his position?**

A. No, the Company must plan for and secure adequate resources to safely serve all customers, including those customers participating in the Rate Rider 14 buy-through pilot program should they decide or be forced to return to standard service. Rate Rider 14 participants, if any, should pay their fair share of these costs.

## IV. CONCLUSION

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

A. Yes.

# Exhibit A

ARIZONA INVESTMENT COUNCIL'S
FIRST SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY REGARDING
THE UNS RATE CASE
DOCKET NO. E-04204A-15-0142
JANUARY 19, 2016

AIC 1.1: In a filing made in December of 2014, APS indicated that it expected to lose between $5 and $15 million per year as a result of AG-1. How much revenue has APS lost each year since the AG-1 program was implemented? What would be the extent of that loss were APS not authorized to retain wholesale margins from generation resources freed up on account of AG-1?

Response: APS assumes that this set of data requests refers to the Company's filing of December 1, 2014 in Docket No. E-01345A-11-0224.

APS estimates that the net losses from the AG-1 program from the program start in November 2012 to May of 2015 were approximately $16.8 million. The amount mitigated through wholesale margin sales of the AG-1 load was $28.5 million. Therefore, the unmitigated losses over this period would have been $45.3 million without this provision. Monthly information per year is attached as APS15790.

Witness: Chuck Miessner

| | ENERGY | | | RATES | | | | REVENUE ($000s) | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | a | b | c | d | e | f | g | h | i | j | k | l | m |
| | AG-1 | | AG-1 to APS | APS | APS | AG-1 | AG-1 | APS | AG-1 | AG-1 | APS | AG-1 | APS |
| | Sales, MWH | Demand, MW | Ratio | Generation Rate[2] | Base Fuel Rate | Program Mgmt Fee | Capacity Reserve Fee | Unrecovered Costs[3] | Program Mgmt | Capacity Reserve | Off System Margin | Margin Mitigation | Net Margin[4] |
| Nov-12 | 32,915 | 50 | 17.6% | $ 0.049499 | $ 0.032071 | $ 0.000600 | $ 6.985 | $ (574) | $ 20 | $ 52 | $ 935 | $ 165 | $ (337) |
| Dec-12 | 40,561 | 64 | 19.6% | $ 0.049933 | $ 0.032071 | $ 0.000600 | $ 6.985 | $ (725) | $ 24 | $ 67 | $ 2,029 | $ 398 | $ (236) |
| Jan-13 | 39,914 | 71 | 28.6% | $ 0.050113 | $ 0.032071 | $ 0.000600 | $ 6.985 | $ (720) | $ 24 | $ 74 | $ 1,802 | $ 516 | $ (106) |
| Feb-13 | 48,414 | 103 | 17.5% | $ 0.052309 | $ 0.032071 | $ 0.000600 | $ 6.985 | $ (980) | $ 29 | $ 108 | $ 2,770 | $ 484 | $ (359) |
| Mar-13 | 72,692 | 119 | 17.7% | $ 0.052201 | $ 0.032071 | $ 0.000600 | $ 6.985 | $ (1,463) | $ 44 | $ 125 | $ 3,160 | $ 561 | $ (733) |
| Apr-13 | 89,981 | 173 | 57.2% | $ 0.052261 | $ 0.032071 | $ 0.000600 | $ 6.985 | $ (1,817) | $ 54 | $ 181 | $ 1,494 | $ 854 | $ (728) |
| May-13 | 92,220 | 176 | 35.4% | $ 0.052274 | $ 0.032071 | $ 0.000600 | $ 6.985 | $ (1,863) | $ 55 | $ 184 | $ 2,833 | $ 1,002 | $ (622) |
| Jun-13 | 86,366 | 178 | 69.3% | $ 0.052871 | $ 0.032071 | $ 0.000600 | $ 6.985 | $ (1,796) | $ 52 | $ 186 | $ 1,342 | $ 930 | $ (628) |
| Jul-13 | 100,848 | 183 | 37.8% | $ 0.052723 | $ 0.032071 | $ 0.000600 | $ 6.985 | $ (2,083) | $ 61 | $ 192 | $ 2,063 | $ 780 | $ (1,050) |
| Aug-13 | 100,610 | 184 | 31.5% | $ 0.052642 | $ 0.032071 | $ 0.000600 | $ 6.985 | $ (2,070) | $ 60 | $ 193 | $ 2,978 | $ 938 | $ (879) |
| Sep-13 | 91,236 | 179 | 26.8% | $ 0.052503 | $ 0.032071 | $ 0.000600 | $ 6.985 | $ (1,864) | $ 55 | $ 188 | $ 3,189 | $ 854 | $ (767) |
| Oct-13 | 86,716 | 169 | 24.3% | $ 0.052302 | $ 0.032071 | $ 0.000600 | $ 6.985 | $ (1,754) | $ 52 | $ 177 | $ 3,288 | $ 799 | $ (726) |
| Nov-13 | 78,744 | 158 | 55.2% | $ 0.052224 | $ 0.032071 | $ 0.000600 | $ 6.985 | $ (1,587) | $ 47 | $ 166 | $ 1,579 | $ 871 | $ (503) |
| Dec-13 | 82,458 | 164 | 38.5% | $ 0.052081 | $ 0.032071 | $ 0.000600 | $ 6.985 | $ (1,650) | $ 49 | $ 172 | $ 2,310 | $ 888 | $ (541) |
| Jan-14 | 83,274 | 167 | 31.5% | $ 0.052042 | $ 0.032071 | $ 0.000600 | $ 6.985 | $ (1,663) | $ 50 | $ 175 | $ 3,490 | $ 1,098 | $ (340) |
| Feb-14 | 74,817 | 174 | 19.8% | $ 0.053190 | $ 0.032071 | $ 0.000600 | $ 6.985 | $ (1,580) | $ 45 | $ 182 | $ 7,729 | $ 1,529 | $ 176 |
| Mar-14 | 87,481 | 171 | 19.0% | $ 0.053073 | $ 0.032071 | $ 0.000600 | $ 6.985 | $ (1,837) | $ 52 | $ 179 | $ 7,670 | $ 1,458 | $ (148) |
| Apr-14 | 85,650 | 173 | 29.8% | $ 0.053090 | $ 0.032071 | $ 0.000600 | $ 6.985 | $ (1,800) | $ 51 | $ 181 | $ 4,297 | $ 1,282 | $ (286) |
| May-14 | 95,089 | 180 | 35.2% | $ 0.053244 | $ 0.032071 | $ 0.000600 | $ 6.985 | $ (2,013) | $ 57 | $ 189 | $ 4,645 | $ 1,635 | $ (132) |
| Jun-14 | 91,108 | 181 | 41.3% | $ 0.053369 | $ 0.032071 | $ 0.000600 | $ 6.985 | $ (1,940) | $ 55 | $ 190 | $ 3,066 | $ 1,267 | $ (428) |
| Jul-14 | 98,547 | 181 | 28.3% | $ 0.053527 | $ 0.032071 | $ 0.000600 | $ 6.985 | $ (2,114) | $ 59 | $ 190 | $ 6,705 | $ 1,896 | $ 31 |
| Aug-14 | 100,894 | 183 | 16.8% | $ 0.053494 | $ 0.032071 | $ 0.000600 | $ 6.985 | $ (2,161) | $ 61 | $ 192 | $ 7,060 | $ 1,189 | $ (719) |
| Sep-14 | 85,450 | 175 | 14.4% | $ 0.053406 | $ 0.032071 | $ 0.000600 | $ 6.985 | $ (1,823) | $ 51 | $ 183 | $ 6,613 | $ 955 | $ (634) |
| Oct-14 | 91,429 | 158 | 22.8% | $ 0.053475 | $ 0.032071 | $ 0.000600 | $ 6.985 | $ (1,957) | $ 55 | $ 176 | $ 4,556 | $ 1,037 | $ (689) |
| Nov-14 | 81,993 | 157 | 36.0% | $ 0.053110 | $ 0.032071 | $ 0.000600 | $ 6.985 | $ (1,725) | $ 49 | $ 164 | $ 2,323 | $ 837 | $ (675) |
| Dec-14 | 83,106 | 158 | 21.8% | $ 0.052968 | $ 0.032071 | $ 0.000600 | $ 6.985 | $ (1,737) | $ 50 | $ 166 | $ 3,882 | $ 848 | $ (673) |
| Jan-15 | 81,409 | 163 | 34.6% | $ 0.053030 | $ 0.032071 | $ 0.000600 | $ 6.985 | $ (1,706) | $ 49 | $ 171 | $ 1,995 | $ 691 | $ (795) |
| Feb-15 | 71,519 | 162 | 22.5% | $ 0.053160 | $ 0.032071 | $ 0.000600 | $ 6.985 | $ (1,508) | $ 43 | $ 170 | $ 2,878 | $ 649 | $ (646) |
| Mar-15 | 85,369 | 164 | 19.6% | $ 0.053120 | $ 0.032071 | $ 0.000600 | $ 6.985 | $ (1,797) | $ 51 | $ 172 | $ 3,344 | $ 654 | $ (920) |
| Apr-15 | 85,853 | 169 | 26.5% | $ 0.053220 | $ 0.032071 | $ 0.000600 | $ 6.985 | $ (1,816) | $ 52 | $ 177 | $ 3,116 | $ 826 | $ (761) |
| May-15 | 88,495 | 169 | 17.4% | $ 0.053150 | $ 0.032071 | $ 0.000600 | $ 6.985 | $ (1,865) | $ 53 | $ 177 | $ 3,715 | $ 648 | $ (987) |
| | | | | | | | | h=round(-((a*d)-(a*e)),0) | i=round(a*f,0) | j=round((.15*b)*g),0) | | l=round(c*k,0) | m=h+i+j+l |

| | a | b |
|---|---|---|
| | Sales, MWH | Demand, MW |
| Nov-Dec 2012 | 73,476 | 64 |
| 2013 | 970,196 | 184 |
| 2014 | 1,058,838 | 183 |
| Jan-May 2015 | 412,645 | 169 |
| PTD | 2,515,155 | 184 |

| h | i | j | k | l | m |
|---|---|---|---|---|---|
| Unrecovered Costs[3] | Program Mgmt | Capacity Reserve | Off System Margin | Margin Mitigation | Net Margin[4] |
| $ (1,299) | $ 44 | $ 119 | $ 2,964 | $ 563 | $ (573) |
| $ (19,647) | $ 582 | $ 1,946 | $ 28,808 | $ 9,477 | $ (7,642) |
| $ (22,350) | $ 635 | $ 2,167 | $ 62,036 | $ 15,031 | $ (4,517) |
| $ (8,692) | $ 248 | $ 867 | $ 15,048 | $ 3,488 | $ (4,109) |
| $ (51,988) | $ 1,509 | $ 5,099 | $ 108,856 | $ 28,539 | $ (16,841) |

[1]Ratio of AG-1 Sales to Off-System Sales

[2]Average Unbundled Generation Rate of AG-1 Participants

[3]Unrecovered Non-Fuel Generation Revenue

[4]Net Margin Impact from AG-1 Program

# Exhibit B

ARIZONA INVESTMENT COUNCIL'S
FIRST SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY REGARDING
THE UNS RATE CASE
DOCKET NO. E-04204A-15-0142
JANUARY 19, 2016

AIC 1.2: That same December 2014 filing talks about the "inherent flaws of the [AG-1] program." What deficiencies exist in the AG-1 rate?

Response: APS has observed two primary deficiencies with its current experimental AG-1 program. One relates to the third party generation provider's (GSPs) obligation to provide imbalance service and imbalance settlements and the other pertains to recovery of APS generation costs.

Imbalance service refers to the requirement of the third party generation providers ("GSPs") to schedule and deliver power to the APS grid that matches the customer's hourly load. This obligation to "follow the load" is challenging for GSPs that must rely on wholesale market purchases to supply the customer's energy needs.

The current imbalance process is based on existing Federal Energy Regulatory Commission protocols typically used for large wholesale power transactions and does not reflect the imbalance cost for retail AG-1 transactions. Nor do they provide adequate incentives for GSPs to provide load following service. As a result, APS must generally continue to provide the load following service for AG-1 customers with its own power plants. APS believes that the imbalance issue would be appropriately addressed through a revised retail imbalance protocol.

The generation cost issue is more fundamental and may not be able to be adequately addressed through a revised program design. The basic concept of the AG-1 program is that the GSP is replacing APS as the customer's generation service provider. As a result, conceptually the customer would not rely on, or pay for, APS's power plants or the fuel to run them. Likewise, APS would no longer have to expend costs for power plants or fuel to serve the customer. In reality APS has found that AG-1 customers still rely on APS's power plants to serve them, but do not pay for them.

The reliance occurs in three ways. First, as discussed above APS continues to provide load following service with its power plants. Second, AG-1 customers still rely on APS's power plants to back up the GSP power in case the GSP fails to deliver. If the GSP fails to deliver power, APS must continue to provide service. While the GSP is obligated to pay for that power, that one-time event does not cover the cost to ensure reliable service, unlike an interruptible customer. AG-1 customers do pay a reserve capacity charge to address this issue, but the current charge is far below the actual cost to provide this service. Third, APS continues to provide power plants to AG-1 customers through the long-run planning process because the customers have the option to return to APS bundled service if the GSP market prices increase in the future.

Witness: Chuck Miessner

# Exhibit C

ARIZONA INVESTMENT COUNCIL'S
FIRST SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY REGARDING
THE UNS RATE CASE
DOCKET NO. E-04204A-15-0142
JANUARY 19, 2016

AIC 1.3: Assume for the purposes of the following questions that APS was not authorized to use revenue from off-system sales to offset any revenue losses resulting from the AG-1 program. In that case:

A. Would a management fee of $0.0006/kWh be reasonable? Why or why not?
B. Would a reserve capacity charge priced at the unbundled generation demand charge for the customer's rate schedule and applied to 15% of the customer's billed demand be reasonable? Why or why not?
C. Would any other pricing components in the AG-1 schedule require amendment? Please explain your answer.

Response: A, B, C. If the AG-1 program only reflected the retail revenue losses to APS without capturing the fuel cost savings or related wholesale margins resulting from the program, it would only result in financial losses to APS. Therefore, the program would not be self-supporting, regardless of any reasonable increases to the management fee and reserve capacity charge. That being said, the management fee is too small and should at least be doubled. The reserve capacity charge (which likely should be recomputed using today's embedded generation costs) should be applied to 100% of the customer's billed demand.

Witness: Chuck Miessner

**BEFORE THE ARIZONA CORPORATION COMMISSION**

**COMMISSIONERS**
SUSAN BITTER SMITH – CHAIRMAN
BOB STUMP
BOB BURNS
DOUG LITTLE
TOM FORESE

| | | |
|---|---|---|
| **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 REGULATED APPROVALS.** | ) | **DOCKET NO. E-04204A-15-0142** |

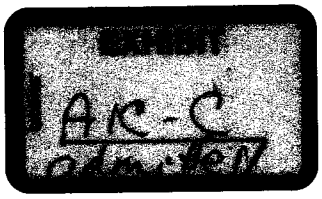
Direct Testimony and Exhibits of

Daniel G. Hansen

on Behalf of

Arizona Investment Council

December 9, 2015




AIC Exhibit C

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AIC EXHIBIT DGH-1 Résumé of Daniel G. Hansen

AIC EXHIBIT DGH-2 List of residential demand charge rates

## I. INTRODUCTION AND PURPOSE

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

A. My name is Daniel G. Hansen. I am a Vice President at Christensen Associates Energy Consulting, LLC located at Suite 400, 800 University Bay Drive, Madison, Wisconsin 53705.

**Q. Have you previously testified in utility regulation proceedings?**

A. Yes. I have testified on issues related to utility fixed cost recovery in Arizona, Connecticut, Minnesota, New Mexico, Nevada, Oregon, and Utah. In these proceedings, I represented a broad range of clients, including a regulator, an environmental organization, a non-profit organization of utility investors, and investor-owned utilities. My education and work experience are described in AIC Exhibit DGH-1.

**Q. On whose behalf are you testifying in this docket?**

A. I am testifying on behalf of the Arizona Investment Council ("AIC").

**Q. What is the purpose of your direct testimony?**

A. The purpose of my testimony is to support two proposals of UNS Electric, Inc. ("UNS Electric"): the introduction of a three-part rate (which has a demand charge in addition to the basic service charge and energy charge) that is optional for all residential and small commercial customers and mandatory for new net metering

customers (where "new" is defined as beginning service on the Net Metering Rider R-10 after June 1, 2015); and the introduction of a new net metering rider (Rider R-10) that is applicable to new net metering customers (defined as those that completed an application for interconnection to UNS Electric's grid facilities after June 1, 2015) that changes the way net metered customers are compensated for excess generation relative to the current net metering rider (Rider R-4). Specifically, in the sections that follow, I will discuss:

- What demand charges are;
- Where demand charges have been used;
- Why a three-part rate is appropriate for UNS Electric;
- A description of UNS Electric's proposed net metering modifications; and
- Why the proposed net metering modifications are appropriate for UNS Electric.

## II. DEMAND CHARGE DEFINITION, BENEFITS, AND APPLICATIONS

**Q. Please describe UNS Electric's three-part rate proposals.**

A. UNS Electric has proposed four new three-part rates, differentiated by their application to residential versus small commercial customers as well as whether the energy charges are differentiated by time-of-use ("TOU") pricing period. Specifically, the proposed tariffs are:

- Residential Service Demand (RES-01 Demand): optional for Residential Service customers, but mandatory for non-TOU Residential Service customers taking

service under Net Metering Rider R-10 (UNS Electric's proposed net metering rider, which is also discussed in this testimony) beginning after June 1, 2015.

- Residential Service Demand Time-of-Use (RES-01 Demand TOU): an optional version of the RES-01 Demand rate that contains energy charges that are differentiated by time-of-day and season. The rate is mandatory for Residential Service TOU customers taking service under Net Metering Rider R-10 beginning after June 1, 2015.
- Small General Service Demand (SGS-10 Demand): optional for Small General Service customers, but mandatory for non-TOU Small General Service customers taking service under Net Metering Rider R-10 beginning after June 1, 2015. Small General Service rates apply to customers with maximum demand below 40 kW.
- Small General Service Demand Time-of-Use (SGS-10 Demand TOU): an optional version of the SGS-10 Demand rate that contains energy charges that are differentiated by time-of-day and season. The rate is mandatory for Small General Service TOU customers taking service under Net Metering Rider R-10 beginning after June 1, 2015.

**Q. What is a demand charge?**

A. A demand charge bills the customer based on its maximum usage defined over a short time interval. Demand charges are in units of dollar-per-kW. The measure of demand used to calculate the customer's bill (called billing demand) can vary

across utilities and tariffs. For example, UNS Electric has proposed to base its residential and small commercial billing demand on the highest single hour of energy usage during the customer's billing month. Many demand-based rates (including UNS Electric's Large Power Service and Large General Service) measure billing demand over a 15-minute or 30-minute time interval. In addition, billing demand can be based on usage in previous billing months in addition to the current billing month (e.g., billing demand equals the greater of the maximum demand in the current month or 75 percent of the maximum demand in the previous eleven billing months). This is called a "ratcheted" demand charge. (UNS Electric has not proposed a ratcheted demand charge for its residential and small commercial customers.)

**Q. What are the benefits of including a demand charge in retail rates?**

**A.** Including a demand charge (in addition to a basic service charge and energy charges) in a retail rate provides customers with rates that better reflect the way utility costs are incurred. As I will describe below, this has several potential benefits, including:

- Giving customers appropriate incentives to manage their demand, thereby promoting a more efficient use of the system;
- Encouraging customers to adopt (and third parties to produce innovations in) capacity-saving technologies;

- Preventing the need for future rate modifications in response to emerging issues;
- Reducing intra-class cross subsidies; and
- Allowing UNS Electric to obtain more renewable energy for the same (or lower) total cost by purchasing (or building) at the utility scale.

**Q. How does UNS Electric's three-part rate design better reflect the way utility costs are incurred?**

A. UNS Electric's three-part rate has charges that better reflect the way utility costs are incurred, relative to the comparable non-demand rate. It is commonly accepted in utility cost-of-service studies that costs within functions (generation, transmission, distribution, and customer service) can be classified according to their primary driver, which can be one of the following:[1]

- **Customer-related costs**, which increase as the utility serves more customers, regardless of the amount of energy the customers use;
- **Energy-related costs**, which vary with the amount of energy used by customers; and
- **Demand-related costs**, which are associated with the maximum amount of energy used during a specified time interval (e.g., 15 to 60 minutes).

UNS Electric's demand rates contain charges that correspond to each of these cost drivers.

[1] National Association of Regulatory Utility Commissioners, Electric Utility Cost Allocation Manual, January 1992, pages 20-22.

1 **Q. How can customers benefit from managing their demand on a three-part**
2 **rate?**
3 **A.** When customers who take service on a three-part rate reduce their billed demand,
4 they can reduce their bill while at the same time contributing to lower utility costs
5 in the short- and/or long-run. Customers can reduce billing demand by avoiding
6 using electricity intensive appliances at the same time, ensuring that their demand
7 stays low even if their total energy consumption changes little (e.g., by delaying
8 washing clothes when the dishwasher is running).
9
10 **Q. How do three-part rates encourage adoption of capacity-saving technologies?**
11 **A.** Enabling technology can assist customers in managing their end uses to minimize
12 billed demand. For example, the Residential Demand Control program at Otter
13 Tail Power Company includes a demand controller and radio receiver to automate
14 control of the end-uses during "control periods," which are called by the utility. In
15 addition, the Rocky Mountain Institute (RMI) recently released a report on this
16 topic called "The Economics of Demand Flexibility."[2] This study simulated the
17 potential for customer bill savings on a variety of residential rates, with the largest
18 simulated benefits coming from Salt River Project's residential demand rate. In
19 addition, demand-based rates give customers with rooftop solar installations an
20 incentive to invest in battery storage technologies, which can be used to help the
21 customer manage its billing demand. This technology has the ability to effectively

[2] "The Economics of Demand Flexibility", Rocky Mountain Institute, August 2015. The report is available for download at RMI's web site: http://www.rmi.org/electricity_demand_flexibility.

turn distributed solar power from an intermittent resource into a dispatchable resource. In the absence of the demand charge (or TOU pricing), a net-metered customer has little reason to invest in battery storage.[3]

**Q. How do three-part rates reduce the need for future rate modifications in response to emerging issues?**

A. Demand-based rates have the potential to reduce the need for future rate modifications in response to emerging issues because they better reflect the way utility costs are incurred. That is, a well-designed retail rate is more likely to function well in a variety of circumstances. For example, while the current two-part rate design (with inclining block energy charges) is beneficial for customers installing PV solar, it serves as a barrier to the proliferation of electric vehicles ("EVs"). By shifting cost recovery away from energy charges and toward demand charges, three-part rates have the potential to reduce the cost of charging EVs at home. That is, by charging an EV within the confines of the customer's existing demand, a customer could significantly reduce the cost of charging the EV relative to a two-part rate. It is not hard for me to imagine stakeholders calling for UNS Electric to implement a dedicated "EV Rate" (or an EV discount to its standard residential rate) after technological improvements reduce EV prices (thus increasing the quantity of EVs demanded). UNS Electric's proposed RES-01 Demand TOU rate removes the need for such a rate or rider. That is, that rate

[3] In this case, the customer's incentive to invest in battery storage would likely be limited to improved reliability (in case of service interruption).

would provide EV customers with the appropriate incentives to manage their demand and charge during off-peak hours.

**Q. How do three-part rates reduce intra-class cross subsidies?**

A. Three-part rates reduce intra-class cross subsidies by making the charges customers pay more closely reflect the way utility costs are incurred. UNS Electric has to have enough generating capacity (through ownership or purchase agreements) and network capability to serve peak demands. Under two-part rates, these demand-related costs are included in the energy charges. Therefore, customers who have relatively low levels of energy use contribute little to fixed-cost recovery regardless of the level of their maximum demand. A customer with low energy use relative to its demand level is referred to as a "low load factor" customer.[4] Under two-part rates, low load factor customers tend to be subsidized by high load factor customers (those whose average usage is closer to their maximum demand). A customer's low load factor may be caused by a high proportion of AC load, seasonal occupation of a residence (reducing the customer's annual load factor), or the installation of on-site DG. By reflecting the customer's load factor in their rates (as three-part rates do), high load factor customers will pay a lower average rate than low load factor customers (all else equal), which is consistent with utility cost-of-service methods. That is, demand-based rates give customers an incentive to use the utility's assets more efficiently

[4] Load factor is defined as the average usage over a period of time divided by the customer's maximum demand over that same period of time (where the period of time is typically one month or year).

(e.g., helping prevent the need for a generating unit designed to serve a low number of peak hours each year).

**Q. Can the use of three-part rates for net metering customers allow for the acquisition of more renewable power?**

A. Yes. A potential benefit of implementing three-part rates for net metered customers is that UNS Electric may be able to obtain more renewable energy for the same total cost. As described in Section III, the most recent renewable energy purchase power agreement by UNS Electric's sister company (Tucson Electric Power) was priced at 5.84 cents/kWh. As I describe later, there is some evidence that this is a high cost relative to more current purchase power agreements in the region. UNS Electric's volumetric retail rate is much higher than that. The lost fixed cost recovery that results from applying retail rates to net metered generation eventually increases rates to all customers in the rate class (through some combination of the LFCR and a subsequent rate case). Instead of incurring this rate increase to subsidize customer-sited DG, that amount of money could have been put toward more economic utility-scale renewable power purchases or facility construction. Given recent market costs, UNS Electric could have obtained more total renewable energy by purchasing it through wholesale transactions rather than from its customers through net metering. Put slightly differently, the existing net metering framework coupled with the two-part rate design (in which demand-related costs are recovered through energy charges)

causes customers to overpay for renewable resources. Note that a three-part rate does not prevent an interested customer from installing PV solar, it simply reduces the amount of the subsidy that other customers are compelled to pay them if they do so. While the current subsidies embedded in UNS Electric's two-part rates may be the main factor behind some customer's decision to install PV solar, there are other customers would likely make the same decision in the absence of the subsidy. My preference for green power led me to enroll in a program in which I pay a 2.44 cent/kWh premium to offset 100 percent of my energy usage with green power.[5] This program, which is not subsidized by non-participants, provides an example in which customers purchased green power in the absence of a subsidy from other ratepayers.

**Q. Are demand charges commonly used in electricity pricing?**

**A.** Yes, demand charges are a common feature of electric tariffs. They are most commonly found in tariffs for medium and large commercial and industrial customers. For example, UNS Electric's Large General Service and Large Power Service rates include demand charges. Demand charges have also been applied to residential and small commercial customers for decades, and interest in applying demand charges to these customers appears to be growing. I am currently aware of 19 service territories in the United States in which the utility offers rates with demand charges to residential customers, including utilities in Alabama, Alaska,

[5] This is Madison Gas & Electric's Green Power Tomorrow program, which is described here: www.mge.com/environment/green-power/gpt/.

Arizona, Colorado, Georgia, Kansas, Minnesota, North Carolina, North Dakota, South Carolina, South Dakota, Vermont, Virginia, and Wyoming.[6] These rates are listed in AIC Exhibit DGH-2. Demand rates for these customer classes are also common in certain European countries and are being considered in Australia.

**Q. Have residential rates with demand charges been approved in Arizona?**

**A.** Yes, residential rates with demand charges have been approved for Arizona Public Service (APS) and Salt River Project (SRP). The Arizona Corporation Commission first approved a three-tiered residential demand rate for APS in 1980. Currently, APS's Rate Schedule ECT-2 (Residential Service Time-of-Use with Demand Charge Combined Advantage 7PM-Noon) has more than 110,000 enrolled residential customers.[7] In February 2015, SRP's board approved the Customer Generation Price Plan (E-27), which is a mandatory demand-based rate for customers that install on-site generation after December 8, 2014.[8] There is a corresponding voluntary pilot program for customers without on-site generation (E-27 P).

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[6] In addition to the rates contained in AIC Exhibit DGH-2, the Glasgow Electric Plant Board in Kentucky recently received approval to implement a mandatory residential demand rate in which the demand charge is based on the utility's monthly coincident peak. That is, the customer is billed based on their usage during the hour in which the entire utility's load is at its highest level. The rate will go into effect in January 2016.

[7] Snook and Grabel, "There and Back Again", Public Utilities Fortnightly, November 2015, pages 47-50.

[8] The press release for the board approval can be found at this link: http://www.srpnet.com/newsroom/releases/022615.aspx. The E-27 tariff can be found at this link: http://www.srpnet.com/prices/pdfx/April2015/E-27.pdf.

**Q. What factors do you believe contribute to the increasing interest in the application of demand charges to residential and small commercial customers?**

A. There are two likely causes for the increasing interest in offering demand charges to residential and small commercial customers. The first cause is the increasing ability of utilities to be able to bill a demand-based rate for smaller customers without incurring additional metering costs. Billing a rate that contains demand charges requires the ability to meter customer demand. In the past, energy-only meters have been in place for smaller customers. These meters are capable of measuring the total amount of energy consumed in a given billing period, but are not able to record the maximum amount of energy usage during any one short interval (e.g., a 15- to 60-minute period). In these cases, a separate demand meter is required to bill the demand-based rate, which entails additional meter costs. However, it has become more common for utilities to install advanced metering infrastructure (AMI) of some kind throughout their service territories, which is typically capable of recording customer usage on an hourly (or sub-hourly) basis.

**Q. What is the second factor you believe contributes to the increasing interest in the application of demand charges to residential and small commercial customers?**

A. The second factor contributing to increased interest in applying demand charges to smaller customers is the increase in distributed generation, particularly rooftop

solar installations. Standard residential and small customer rate designs, which typically contain only a basic service charge and volumetric energy charges, tend to recover a significant share of fixed costs through the energy charge (i.e., the basic service charge is set well below the level required to recover all fixed costs). When a customer generates energy on-site and offsets the energy purchased from the utility, it correspondingly avoids paying the fixed costs included in the energy charge. This can lead to utility fixed cost under-recovery and/or a shift of fixed cost recovery to other customers. When a demand charge is added to the rate design, all or a portion of the fixed costs are removed from the energy charge (which is thereby lowered) and recovered through the demand component and basic service charge. The result is that all customers, those with and without on-site generation, pay for the infrastructure costs that they use.

**Q. What are the proposed charges in UNS Electric's Residential Service Demand rate?**

A. The Residential Service Demand rate contains three types of charges: a basic service charge of $20 per month; an energy charge of $0.059260 per kWh; and a tiered demand charge of $6.00 per kW for zero to 7 kW and $9.95 per kW for kW in excess of 7 kW. The inclusion of these three types of charges is why UNS Electric refers to its proposed demand rates as "three-part" rates. By comparison, its non-demand Residential Service and Small General Service rates could be

1 considered "two-part" rates, because they include only a basic service charge and
2 energy charges.
3
4 **Q. Is UNS Electric's proposal to increase the basic service charge from $10 to**
5 **$20 appropriate?**
6 A. Yes. UNS Electric Witness Jones describes the proposed increase in the basic
7 service charge as "consistent with the results of the COSS and equitable fixed cost
8 recovery."[9] While the proposed $10 per month increase in the basic service
9 charge improves the extent to which UNS Electric's rates reflect the cost to serve,
10 the resulting $20 per month charge is still well below both the $54.46 per month
11 basic service charge that would be required to recover all fixed costs.[10]
12
13 **Q. How is the billing demand kW amount measured?**
14 A. The kW amount that is used for customer billing purposes is based on the highest
15 one-hour metered demand during the billing month. Intuitively, the billing
16 demand represents the hour of the billing month in which the customer uses the
17 most electricity. By basing billing demand on the maximum one-hour demand for
18 the current billing month, UNS Electric has chosen a comparatively customer-
19 friendly definition of billing demand. As AIC Exhibit DGH-2 shows, 26 out of 30
20 listed demand rates define billing demand using a 15- or 30-minute maximum
21 demands (including SRP, which uses a 30-minute demand measure). Basing

[9] Direct Testimony of Craig A. Jones, page 34, lines 12-13.
[10] Direct Testimony of Craig A. Jones, page 41, lines 1-4.

demand on a shorter time period increases the chance that a customer will have their billing demand increased by simultaneously using a set of electricity-intensive but short duration end uses. For example, a hair dryer or microwave oven can draw a relatively large amount of power, but they are not likely to be used for an extended period of time. Basing billing demand on longer periods of time helps smooth out the effect of some of these short-duration end uses.

**Q. How do the proposed charges in the Residential Service Demand rate compare to the proposed charges in the Residential Service rate (RES-01)?**

A. The demand and non-demand versions of the Residential Service rate contain the same basic service charge of $20 per month. The "standard" Residential Service rate excludes the demand charges, but contains higher (and tiered) energy charges. Specifically, the customers pay $0.08007 per kWh for the first 400 kWh consumed in a month and $0.10007 per kWh for kWh in excess of 400 kWh.

**Q. Why is UNS Electric proposing to make its three-part rate design mandatory for customers who install distributed generation (DG)?**

A. UNS Electric is proposing to make three-part rates mandatory for its new net metered customers (customers who install rooftop solar after June 1, 2015) due to the issues with respect to utility fixed cost recovery and customer cost shifting discussed above. Specifically, UNS Electric's two-part rates (e.g., RES-01) are designed to recover a significant amount of fixed costs through volumetric energy

charges. According to the Direct Testimony of UNS Electric Witness Jones, the Residential basic service charge would need to be $54.46 per month in order to recover all of UNS Electric's fixed costs (which include customer-related and demand-related costs).[11] In contrast, UNS Electric is proposing a $20 per month basic service charge and currently has a $10 per month basic service charge. The remainder of the fixed costs (i.e., the difference between the revenue that would be recovered with a $54.46 basic service charge and the proposed $20 per month basic service charge) is recovered through the energy charge. As a result, the amount of fixed cost recovery UNS Electric obtains is affected by the amount of energy sold to its customers.

**Q. What problems are caused by recovering fixed costs through energy charges for net metering customers?**

**A.** When net metered rates recover fixed costs through volumetric charges (such as RES-01 plus Rider R-4), the reduction in billed sales to the net metered customers reduces utility fixed-cost recovery, which leads to a combination of cross-subsidies (i.e., an increase in rates to non-net metered customers) and reduced opportunity for the utility to earn its authorized rate of return. That is, some of the lost fixed cost recovery from net metering will be shifted to other customers through the Lost Fixed Cost Revenue Recovery (LFCR) Rider (R-8). Remaining unrecovered fixed costs that are not shifted to other customers through the LFCR

[11] Direct Testimony of Craig A. Jones, page 41, lines 1-4.

are borne by the utility until rates are re-set during UNS Electric's next rate case. In the rate case, the reduced level of test-year billed sales associated with DG leads to an increase in the energy charges that are paid by all customers in the rate class. That is, the fixed cost recovery will be spread across fewer billing units, so the resulting energy charge (which is the test-year revenue requirement divided by the test-year sales) is higher. While this rate reset theoretically makes the utility whole for net metering at test-year sales going forward, the class-wide increase in rates that results from net metered output from customer-sited DG perpetuates the shift of fixed-cost recovery from net metered customers to non-net metered customers.

## III. PROPOSED NET METERING RIDER R-10

**Q. Is UNS Electric proposing a new net metering rider?**

A. Yes, UNS Electric has proposed Net Metering Rider R-10, which applies to customers taking service on one of the three-part rates proposed by UNS Electric. As such, this rider will only apply to customers who begin net metered service after June 1, 2015.

**Q. How does Rider R-10 differ from the existing Net Metering Rider R-4?**

A. The proposed R-10 differs from the existing net metering rider (R-4) in two ways: it replaces the "banking" of excess generation (the amount of generation during a billing month in excess of the customer's use) in favor of a bill credit calculated

in the current month; and R-10 compensates customers for excess generation at the Renewable Credit Rate, whereas R-4 compensated customers at UNS Electric's avoided costs for any banked excess generation that remained when the October bill is calculated.[12]

**Q. How is the Renewable Credit Rate set?**

**A.** According to the direct testimony of UNS Electric Witness Tilghman, the Renewable Credit Rate is based on "the most recent comparable utility scale purchased power agreement for renewable energy that is connected to the Company's or TEP's distribution system."[13] The proposed value is 5.84 cents per kWh, which is based on a recent agreement with Tucson Electric Power (TEP).

**Q. Does the proposed Renewable Credit Rate appear to be reasonable?**

**A.** Yes, the proposed Renewable Credit Rate of 5.84 cents/kWh appears reasonable based on recent reports I have seen. For example, according to a recent article in Megawatt Daily,[14] the New Mexico Public Regulation Commission approved two 25-year, 70-MW solar contracts (on October 7, 2015) at levelized costs of 4.155 cents/kWh and 4.208 cents/kWh. The article goes on to say that the pricing of these contracts is "part of a national trend, with recent levelized PPA prices in the

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[12] The R-4 tariff describes the avoided cost calculation as "the simple average of the hourly Market Cost of Comparable Conventional Generation (MCCCG) Rider R-3 for the applicable year."

[13] Tilghman Direct, p. 8, lines 7-9.

[14] "New Mexico PRC OKs $42/MWh solar contracts", Megawatt Daily, October 12, 2015, pages 13-14.

Southwest landing in the $40/MWh [4.0 cents/kWh] range, down from around $105/MWh [10.5 cents/kWh] on average in 2011, according to an annual report from the Lawrence Berkeley National Laboratory."

**Q. Does the downward trend in PPA prices referenced in that article indicate a potential benefit for customers from the proposed Renewable Credit Rate methodology?**

A. Yes, if recent trends continue, net metering customers can expect to benefit from UNS Electric's proposal to only update the Renewable Credit Rate when UNS Electric or TEP has entered into a new purchase power agreement or two years have passed, whichever comes first. That is, it is possible that UNS Electric customers will be paid a Renewable Energy Credit that is based on a purchased power agreement that is as much as two years old, in a market that has experienced significant recent cost/price reductions in recent years.

**Q. Do you agree that UNS Electric should compensate net metered customers for excess generation using the proposed Renewable Credit Rate?**

A. Yes. The proposed Renewable Credit Rate is consistent with UNS Electric's current practice of paying a premium for renewable energy in order to meet its renewable energy targets.

**Q. Do you agree with UNS Electric's proposal to end the "banking" contained in the current net metering rider (R-4) and replace it with current-month credits at the Renewable Credit Rate?**

A. Yes, I agree that the proposed current-month credits are preferred to the banking in the existing net meter rider (R-4). Compensating customers for excess generation in the current month at the Renewable Credit Rate is more reasonable than allowing customers to virtually store the excess generation in order to be compensated for it at their retail rate in a future month. This virtual storage does not correspond to any actual benefit provided by the customer-sited DG. I expect banking to be effective at increasing the cross subsidy that net metered customers receive, but that is not a policy goal I support.

## IV. CONCLUSIONS

**Q. Do you have any concluding observations?**

A. Yes, I conclude that the Arizona Corporation Commission (ACC) should approve UNS Electric's proposed three-part rates and net metering riders. The three-part rates have several benefits: they provide customers with incentives to change their behavior in ways that reduce system costs; they provide a pricing template that is appropriate for a wide range of circumstances; they reduce intra-class customer cross-subsidies; they send price signals that create a market for demand control, energy storage, and other third-party technologies; and they may allow UNS Electric to obtain more renewable energy at the same total cost. I also recommend

that the ACC approve UNS Electric's proposed net metering rider, which provides a more sensible means of compensating customers for excess generation than the current banking arrangement, while maintaining a subsidy (relative to UNS Electric's avoided costs) that encourages further adoption of renewable resources.

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

**A.** Yes.

# AIC EXHIBIT DGH-1

# Daniel G. Hansen

RESUME

November 2015

**Address:**

800 University Bay Drive, Suite 400
Madison, WI 53705–2299
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**Academic Background:**

Ph.D., Michigan State University, 1997, Economics
M.A., Michigan State University, 1993, Economics
B.A., Trinity University, 1991, Economics and History

**Positions Held:**

Vice President, Laurits R. Christensen Associates, Inc. 2006–present
Senior Economist, Laurits R. Christensen Associates, Inc., 1999–2005
Economist, Laurits R. Christensen Associates, Inc., 1997–1999

**Professional Experience:**

I work in a variety of areas related to retail and wholesale pricing in electricity and natural gas markets. I have used statistical models to forecast customer usage, estimate customer load response to changing prices, and estimate customer preferences for product attributes. I have developed and priced new product options; evaluated existing pricing programs; evaluated the risks associated with individual products and product portfolios; and developed cost-of-service studies. I have conducted evaluations and provided testimony regarding revenue decoupling and weather adjustment mechanisms.

**Major Projects:**

Developed long-term forecasting models for an electric utility.

Conducted a review of an electric utility's load forecasting methods.

Conducted an independent evaluation of a revenue decoupling mechanism for an electric utility.

Estimated load impacts for commercial and industrial demand response programs.

Evaluated a straight-fixed variable rate design for a natural gas utility.

Estimated the load impacts from a residential peak-time rebate program.

Worked with a state's regulatory staff to evaluate alternative electricity pricing structures for residential, commercial, and industrial customers.

Assisted a utility in meeting regulatory requirements regarding the allocation of distribution services.

Evaluated a residential electricity pricing pilot program.

Evaluated the cost effectiveness of automated demand response technologies.

Evaluated and modified short- and long-term electricity sales and demand forecasting models.

Created a short-term electricity demand forecasting model.

Prepared testimony regarding the return on equity effects associated with natural gas revenue decoupling mechanisms.

Conducted an independent evaluation of two natural gas revenue decoupling mechanisms

Created forecasts of load impacts from electricity demand response programs.

Estimated historical the load impacts from electricity demand response programs.

Prepared testimony regarding a proposed natural gas decoupling mechanism.

Prepared testimony regarding the weather normalization of test year sales and revenues.

Participated on a regulatory proceeding panel to discuss decoupling mechanisms.

Prepared testimony regarding a proposed electricity decoupling mechanism.

Prepared a report and testimony regarding a natural gas decoupling mechanism.

Evaluated a model that estimated the costs associated with removing and relicensing hydroelectric facilities.

Assisted an electric utility in evaluating new rate options for commercial and industrial customers.

Designed and evaluated time-of-use and critical-peak pricing rates for an electric utility.

Reviewed cost-of-service study for a municipal electric utility.

Produced a report on rate design methods that provide appropriate incentives for demand response and energy efficiency.

Assisted in wholesale power procurement process.

Evaluated a weather-adjustment mechanism for a natural gas utility.

Assessed weather-related fixed cost recovery risk for an electric utility.

Evaluated a revenue decoupling mechanism for a natural gas utility.

Estimated price responsiveness of real-time pricing customers.

Evaluated the need for electricity transmission and distribution standby rates for a utility.

Developed a market share simulation model using conjoint survey results of electricity distributors.

Conducted conjoint surveyed of electricity distributors regarding rate structure preferences.

Developed a method to calculate a retail forward contract risk premium.

Prepared a report on the performance of Financial Transmission Rights (FTRs) in the PJM electricity market.

Reviewed a retail pricing model for use in a competitive electricity market.

Provided support in a natural gas rate case filing.

Simulated outcomes associated with alternative wholesale rate offers to electricity distributors.

Developed a business case to support a natural gas fixed bill product.

Assessed the accuracy of a natural gas fixed bill pricing algorithm.

Audited an evaluation of the costs associated with implementing a renewable portfolio standard.

Developed a model to value interruptible provisions in a long-term customer contract.

Performed a study on the determinants of electricity price differences across utilities and regions.

Developed long-term demand and energy forecasts.

Conducted market research to assess customer interest in new product options.

Recommended new retail pricing products for commercial and industrial customers.

Prepared a report on the fundamentals of retail electricity risk management.

Prepared a report that presented a taxonomy of retail electricity pricing products.

Presented at a workshop in Africa regarding deregulated electricity markets.

Prepared a report on the effectiveness of distributed resources in mitigating price risk.

Performed a valuation of energy derivatives consistent with FAS 133.

Created an electricity market share forecasting model.

Developed standby rates for an electric utility.

Developed an electricity wholesale price forecast.

Forecasted retail customer loads for an electric utility.

Assisted in mediating a new product development process with a utility and its industrial customers.

Developed a model that simulates wholesale market price changes due to retail load response.

Developed a pricing model for an innovative financial product.

Estimated changes in wholesale electricity prices due to customer load response.

Oversaw creation of software that estimates customer satisfaction with utilities.

Developed a model to economically evaluate a capital addition to a generator.

Developed a wholesale version of the Product Mix Model.

Evaluate Risk Implications of New Product Offering.

Mixed Logit Estimation of Customer Preferences.

Estimation of Customer Price Responsiveness.

Product Mix Model Workshops.

Unbundling and Rate Design.

Development of a Computer Program.

Large Commercial and Industrial Customer Rate Analysis.

Residential Customer Rate Analysis.

Survey of Power Marketers.

Development of Multi-Period Analysis Tool.

Evaluating the Effect of Alternative Rates on System Load.

Estimating the Persistence of Weather Patterns.

Electricity Customer Survey Data Analysis.

Product Mix Analysis for Small Customers.

Survey of Postal Facilities.

**Professional Papers:**

"2014 Statewide Load Impact Evaluation of California Aggregator Demand Response Programs: *Ex-post* and *Ex-ante* Load Impacts," with Steven Braithwait and David Armstrong, 2015.

"2014 Load Impact Evaluation of California Statewide Demand Bidding Programs (DBP) for Non-Residential Customers: *Ex-post* and *Ex-ante* Report," with Steven Braithwait and David Armstrong, 2015.

"2014 Load Impact Evaluation of California Statewide Base Interruptible Programs (BIP) for Non-Residential Customers: *Ex-post* and *Ex-ante* Report," with Tim Huegerich, 2015.

"2014 Load Impact Evaluation of Southern California Edison's Mandatory Time-of-Use Rates for Small and Medium-Sized Business and Agricultural Customers: *Ex-post* and *Ex-ante* Report," with Marlies Patton, 2015.

"2014 Load Impact Evaluation of Pacific Gas and Electric Company's Mandatory Time-of-Use Rates for Small and Medium Non-residential Customers: *Ex-post* and *Ex-ante* Report," with Marlies Patton, 2015.

"FirstEnergy's Smart Grid Investment Grant Consumer Behavior Study," with EPRI (B. Neenan) and Marlies Patton, 2015.

"An Evaluation of Portland General Electric's Decoupling Adjustment, Schedule 123," with Robert J. Camfield and Marlies C. Hilbrink, 2013.

"Evaluation of the Straight-Fixed Variable Rate Design Implemented at Columbia Gas of Ohio," with Marlies C. Hilbrink, 2012.

"The Effect on Electricity Consumption of the Commonwealth Edison Customer Application Program Pilot," with EPRI and CA Energy Consulting staff, 2012.

"The Effects of Critical Peak Pricing for Commercial and Industrial Customers for the Kansas Corporation Commission," with David A. Armstrong, 2012.

"Meeting Commonwealth Edison's Distribution Allocation Requirements from Illinois Commerce Commission Order 10-0467," with Michael O'Sheasy, A. Thomas Bozzo, and Bruce Chapman, 2011.

"Residential Rate Study for the Kansas Corporation Commission," with Michael T. O'Sheasy, 2011.

"An Evaluation of the Conservation Incentive Program Implemented for New Jersey Natural Gas and South Jersey Gas," with Bruce R. Chapman, 2009.

"A Review of Natural Gas Decoupling Mechanisms and Alternative Methods for Addressing Utility Disincentives to Promote Conservation," June 2007.

"Evaluation of the Klamath Project Alternatives Analysis Model: Reply to Addendum A of the Consultant Report Prepared for the California Energy Commission Dated March 2007," May 2007, with Laurence D. Kirsch and Michael P. Welsh.

"Evaluation of the Klamath Project Alternatives Analysis Model," March 2007, with Laurence D. Kirsch and Michael P. Welsh.

"A Review of the Weather Adjusted Rate Mechanism as Approved by the Oregon Public Utility Commission for Northwest Natural," October 2005, with Steven D. Braithwait.

"A Review of Distribution Margin Normalization as Approved by the Oregon Public Utility Commission for Northwest Natural," March 2005, with Steven D. Braithwait.

"Analysis of PJM's Transmission Rights Market," EPRI Report #1008523, December 2004, with Laurence Kirsch.

"Using Distributed Resources to Manage Price Risk," EPRI Report #1003972, November 2001, with Michael Welsh.

"Hedging Exposure to Volatile Retail Electricity Prices," *The Electricity Journal*, Vol. 14, number 5, pp. 33–38, June 2001, with A. Faruqui, C. Holmes and B. Chapman.

"Weather Hedges for Retail Electricity Customers," with C. Holmes, B. Chapman and D. Glyer. In papers for EPRI International Pricing Conference 2000.

"Worker Performance and Group Incentives: A Case Study," *Industrial and Labor Relations Review,* Vol. 51, No. 1, pp. 37–49, October 1997.

"Worker Quality and Profit Sharing: Does Unobserved Worker Quality Bias Firm-Level Estimates of the Productivity Effect of Profit Sharing?" Working Paper, May 1996.

"Supervision, Efficiency Wages, and Incentive Plans: How Are Monitoring Problems Solved?" Working Paper, November 1996, presented at the Western Economics Association Meetings, 1997.

"Has Job Stability Declined Yet? New Evidence for the 1990's," with David Neumark and Daniel Polsky, *The Journal of Labor Economics*, 1999.

**Testimony and Reports before Regulatory Agencies:**

Public Service Company of New Mexico (PNM), New Mexico Case No. 15-00261-UT: Testimony supporting a revenue decoupling mechanism on behalf of PNM, 2015.

Public Service Company of New Mexico (PNM), New Mexico Case No. 14-00332-UT: Testimony supporting a revenue decoupling mechanism on behalf of PNM, 2014.

Xcel Energy, Inc, Minnesota E002/GR-13-868: Testimony supporting a revenue decoupling mechanism on behalf of Xcel Energy, 2013.

Arizona Public Service Company, Arizona Docket No. E–01345A–11–0224: Testimony supporting a revenue decoupling mechanism proposed by APS on behalf of the Arizona Investment Council, 2011.

Southwest Gas Corporation, Arizona Docket No. G–01551A–10–0458: Testimony supporting a revenue decoupling mechanism contained in a settlement agreement on behalf of the Arizona Investment Council, 2011.

Otter Tail Power Company, Minnesota Docket No. E–017/GR–10–239: Testimony regarding the weather normalization of test year sales in a general rate case on behalf of Otter Tail Power Company, 2010.

Southwest Gas Corporation, Nevada Docket No. 09–04003: Testimony regarding a the return on equity effects associated with a proposed revenue decoupling mechanism on behalf of Southwest Gas Corporation, 2009.

Southwest Gas Corporation, Arizona Docket No. G–01551A–07–0504: Testimony regarding a proposed revenue decoupling mechanism on behalf of the Arizona Investment Council, 2008.

Otter Tail Power Company, Minnesota Docket No. E–017/GR–07–1178: Testimony regarding the weather normalization of test year sales and revenues in a general rate case on behalf of Otter Tail Power Company, 2008.

Massachusetts Department of Public Utilities, Docket No. DPU 07–50: Participation in a panel regarding an "Investigation into Rate Structures that will Promote Efficient Deployment of Demand Resources", on behalf of Environment Northeast, 2007.

Connecticut Light & Power Company, Docket No. 07–07–01: Testimony regarding a proposed electricity revenue decoupling mechanism on behalf of Environment Northeast, 2007.

Questar Gas Company, Docket No. 05–057–T01: Testimony regarding the effectiveness of a natural gas revenue decoupling mechanism on behalf of the Utah Division of Public Utilities, 2007.

PacifiCorp, FERC Docket No. 2082: "Evaluation of the Klamath Project Alternatives Analysis Model: Reply to Addendum A of the Consultant Report Prepared for the California Energy Commission Dated March 2007," May 2007, with Laurence D. Kirsch and Michael P. Welsh.

PacifiCorp, FERC Docket No. 2082: "Evaluation of the Klamath Project Alternatives Analysis Model," March 2007, with Laurence D. Kirsch and Michael P. Welsh.

Northwest Natural Gas Company, Oregon Docket UG 163: Testimony relating to an investigation regarding possible continuation of Distribution Margin Normalization, May 2005.

Northwest Natural Gas Company, Oregon Docket UG 152: Submitted a report in compliance with a requirement to evaluate the functioning of the Weather Adjusted Rate Mechanism, October 2005.

# AIC EXHIBIT DGH-2

| Number | Utility | State | Tariff | Name | Mandatory for Any Group | Billing Demand Definition |
|---|---|---|---|---|---|---|
| 19 | Otter Tail Power | SD | Schedule RDC | Residential Demand Control Service | No | 60-minute during controlled hours of previous 12 months |
| 20 | Otter Tail Power | MN | Schedule RDC | Residential Demand Control Service | No | 60-minute during controlled hours of previous 12 months |
| 21 | Otter Tail Power | ND | Schedule RDC | Residential Demand Control Service | No | 60-minute during controlled hours of previous 12 months |
| 22 | Midwest Energy | KS | Schedule RD | Residential Demand Rate Service | Yes, 25 kW or more in any month | Higher of: 15-min during billing month or 80% of 15-min max from previous 3 billing periods |
| 23 | Swanton Village Electric | VT | Schedule A-D | Residential Demand Service | Yes, monthly kWh>=1,800 or 8kW for 2 consecutive months | Higher of: 15-min during billing month or 85% of 15-min max from previous 11 billing periods |
| 24 | Fort Morgan Light & Power | CO | Rate Schedule RD | Residential Demand Metered | Utility may require for customers who can use 25 kW | 15-min during billing month |
| 25 | Dakota Electric Association | MN | Schedule 32 | Residential and Farm Demand Control Rate | No | 15-min during control periods of the billing month |
| 26 | Santee Cooper | SC | Rider RD-13 | Residential Demand Service | Utility may require for customers with tankless electric water heaters or anyone with annual | 30-min during billing month |
| 27 | Santee Cooper | SC | Schedule RB-14 | Residential Net Billing Rate | "Available on a first-come, first-served basis" | 30-min during billing month, by TOU period |
| 28 | City of Kinston | NC | E95 | Residential Time-of-Use Service | No | 15-min during on-peak hours of the billing month |
| 29 | Salt River Project | AZ | E-27 P | Pilot Price Plan for Residential Demand Rate Service | No | 30-min during on-peak hours of the billing month |
| 30 | Salt River Project | AZ | E-27 | Customer Generation Price Plan for Residential Service | Yes, for customers with on-site generation installed after | 30-min during on-peak hours of the billing month |

Source: "Top 10 Questions about Demand Charges", presented to the EUCI Residential Demand Charge Symposium by Ryan Hledik of The Brattle Group on August 31, 2015.

| Number | Utility | State | Tariff | Name | Mandatory for Any Group | Billing Demand Definition |
|---|---|---|---|---|---|---|
| 1 | Alabama Power | AL | Rate RTA | Residential Time Advantage | No | 15-min during billing month |
| 2 | Georgia Power | GA | Schedule TOU-RD-2 | Time of Use - Residential Demand | No | 30-min during billing month |
| 3 | Dominion Virginia Power | VA | Schedule 1S | Residential Service | No | 30-min during peak hours of the billing month |
| 4 | Dominion North Carolina Power | NC | Schedule 1P | Residential Service | No | 30-min during peak hours of the billing month |
| 5 | Duke Energy Carolinas | NC | Schedule RST (NC) | Residential Service, Time of Use Pilot | No | 30-min during billing month |
| 6 | Duke Energy Carolinas | NC | Schedule RT (NC) | Residential Service, Time of Use | No | 30-min during peak hours of the billing month |
| 7 | Duke Energy Carolinas | SC | Schedule RT (SC) | Residential Service, Time of Use | No | 30-min during peak hours of the billing month |
| 8 | Black Hills Power | SD | Rate Code 14 | Residential Demand Service | No | 15-min during billing month |
| 9 | Black Hills Power | SD | Rate Code 14 | Residential Demand Service, Maximum Value Option | No | 15-min during peak hours of the billing month |
| 10 | Black Hills Power | WY | Rate ID WY914 | Residential Demand Service | Yes, for on-site gen. customers (as of 10/1/2014) | 15-min during billing month |
| 11 | Black Hills Power | WY | Rate ID WY916 | Residential Demand Service, Maximum Value Option | Yes, for on-site gen. customers (as of 10/1/2014) | 15-min during peak hours of the billing month |
| 12 | Xcel Energy | CO | Schedule RD | Residential Demand Service | No | 15-min during billing month |
| 13 | APS | AZ | Rate Schedule ECT-2 | Residential Service, Time-of-Use with Demand, Charge Combined Advantage 7PM-Noon | No | 60-min during peak hours of the billing month |
| 14 | Alaska Electric Light & Power | AK | Rate 10-D | Residential with demand | Company may require if customers uses more than 5,000 kWh or 20kW for 3 consecutive | 15-min during billing month |
| 15 | LADWP | CA | Schedule R-3 | Residential Multifamily Service | No | 15-min during billing month, except for facilities charge which has a 12-month ratchet |
| 16 | Fort Collins Utilities | CO | E110, A110, B110 | Electric Demand Rate | No | 15-min during billing month |
| 17 | City of Longmont | CO | RD | Residential Demand Rate | No | 15-min during billing month |
| 18 | Westar Energy | KS | Schedule RS | Residential Peak Management Electric Service | Yes, for daily kWh>30. Closed to new enrollment. | 30-min during billing month |

**BEFORE THE ARIZONA CORPORATION COMMISSION**

**COMMISSIONERS**
DOUG LITTLE – CHAIRMAN
BOB STUMP
BOB BURNS
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 REGULATED APPROVALS.** | **DOCKET NO. E-04204A-15-0142** |

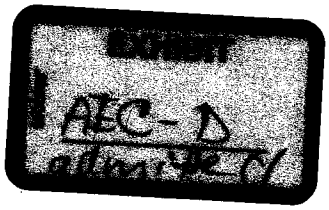
Surrebuttal Testimony of

Daniel G. Hansen

on Behalf of

Arizona Investment Council

February 23, 2016



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## I. INTRODUCTION AND PURPOSE

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

A. My name is Daniel G. Hansen. I am a Vice President at Christensen Associates Energy Consulting, LLC located at Suite 400, 800 University Bay Drive, Madison, Wisconsin 53705.

**Q. Have you previously provided testimony in this proceeding?**

A. Yes. I filed direct testimony on behalf of the Arizona Investment Council ("AIC") regarding two proposals of UNS Electric, Inc. ("UNS Electric"): the introduction of a three-part rate (which has a demand charge in addition to the basic service charge and energy charge) that is optional for all residential and small commercial customers and mandatory for new net metering customers; and the introduction of a new net metering rider (Rider R-10) that is applicable to new net metering customers and changes the way net metered customers are compensated for excess generation relative to the current net metering rider (Rider R-4).

**Q. Did any other parties provide testimony related to the proposed three-part rates or net metering rider?**

A. Yes, including Thomas Alston on behalf of the Arizona Utility Ratepayer Alliance ("AURA"); Mark Fulmer on behalf of The Alliance for Solar Choice ("TASC"); Lon Huber on behalf of the Residential Utility Consumer Office ("RUCO"); Briana Kobor on behalf of Vote Solar; Howard Solganick on behalf of the Utilities Division Staff ("Staff") of the Arizona Corporation Commission ("Commission"); and Kenneth L. Wilson on behalf of Western Resource Advocates ("WRA").

**Q. What is the purpose of your surrebuttal testimony?**

A. The purpose of my testimony is to respond to the following arguments from the testimonies listed above:

1. The claim that DG customers are no different from other low-use customers and therefore do not merit special treatment;
2. Proposed alternatives to a three-part rate, including time-of-use ("TOU") energy rates, a minimum bill provision, a lost fixed cost recovery ("LFCR") mechanism, and three suggested DG rate designs from RUCO witness Huber;
3. Staff witness Solganick's proposal to transition all Residential Service and Small General Service customers to mandatory three-part TOU rates; and
4. Arguments against the Renewable Credit Rate ("RCR") in UNS Electric's proposed Rider R-10.

**Q. What are your recommendations?**

A. I recommend the following:

- I continue to recommend that new net metering customers be served on a three-part rate that includes a basic service charge, energy charges, and a demand charge. The alternatives introduced by other parties fail to address the fundamental problem, which is that two-part rates allow DG customers to avoid paying the demand-related costs to serve them.
- I agree with other parties that UNS Electric's three-part rate design could be improved by measuring billed demand only over peak hours.
- I do not oppose Staff witness Solganick's proposal to transition all Residential Service and Small General Service customers to a mandatory three-part TOU rate.
- I support UNS Electric's proposed Net Metering Rider R-10, with the modifications that the renewable purchased power agreements that serve as

the basis for the RCR are limited to utility-scale solar agreements, and that the RCR includes a floor equal to UNS Electric's avoided energy costs.

**Q. How is your testimony organized?**

**A.** Section II describes how DG customers are different from most other low-use customers and therefore merit differential treatment. Section III describes how the various proposed alternatives to three-part rates are inadequate. Section IV addresses other misconceptions about demand charges and Staff witness Solganick's proposal to transition all Residential Service and Small General Service customers to mandatory three-part TOU rates. Section V addresses criticisms of UNS Electric's proposed Net Metering Rider R-10. Section VI contains a summary of my recommendations.

## II. DG CUSTOMERS ARE DIFFERENT FROM OTHER LOW-USE CUSTOMERS

**Q. Please summarize the arguments from other parties that DG customers are similar to other low-use customers.**

**A.** At least two witnesses make the argument that DG customers are not different from other low-use customers and therefore do not merit special treatment. WRA witness Wilson states: "When the issue of exported energy is removed from the discussion, DSG [Distributed Solar Generation] customers look like other customers with relatively low energy use."[1] This statement is in the context of his assertion that the "method of appropriately assessing the utility's fixed costs to DSG customer [*sic*] and non-DSG customers can be identical."[2]

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[1] Wilson Direct Testimony, page 3 lines 16-18.

[2] *Id.*, page 3 lines 15-16.

TASC witness Fulmer states "there are other low-usage customers who may not be paying what UNS characterizes as their fair share of utility costs: apartments, small efficient homes, seasonal residences and vacant homes. From a kilowatt-hour per month perspective, without looking into the home, these customers are not distinguishable... Residential customers with DG do not constitute a separate rate class, and as such should not be treated as one."[3]

**Q. Do you agree that DG customers are no different than other low-use customers from a cost allocation and rate design perspective?**

A. No, in fact Vote Solar witness Kobor agrees with my view that "DG systems are effective at reducing the customer's consumption of energy supplied by the utility, but they can have little impact on individual customer peak demand."[4] In contrast, low-use customers who live in apartments or small efficient residences are likely to have a relatively low demand value in addition to their low overall consumption level.

**Q. What is the basis of your assertion that non-DG low-use customers tend to have both relatively low demand and relatively low usage?**

A. I have conducted a number of evaluations of residential pricing programs in which I analyzed hourly usage data for residential customers. My general conclusion is that there is a high (and positive) correlation between a residential customer's average usage and its maximum demand. This makes intuitive sense. For example, a low-use customer in a smaller home has less space to cool on a hot summer day, requiring a lower capacity air conditioner. In addition, customers who are lower use because they installed more efficient lighting or appliances do not experience spikes in their demand when those

[3] Fulmer Direct Testimony, page 11 lines 5-9 and 17-18.
[4] Kobor Direct Testimony, page 41 lines 25-27.

technologies fail. The usage for an LED lightbulb goes to zero when it goes out, not to the level of the incandescent bulb it replaced. This is in contrast to solar DG customers, who experience spikes in demand corresponding (in part) to the intermittency of their generating resource.

**Q. How would you describe customers who have high demand relative to their average usage level?**

**A.** I refer to customers with high demand relative to their average usage level as "low load factor" customers. Load factor is defined as a customer's average usage divided by its maximum demand, measured over some period such as a month or year. Vote Solar witness Kobor's contention that DG customers reduce their usage by much more than their demand results in those customers having a lower load factor than a similarly situated non-DG customer.

**Q. Why is load factor an important consideration in cost of service and rate design?**

**A.** As I described on page 5 of my direct testimony, utility costs can be divided into three categories: customer-related costs, energy-related costs, and demand-related costs. Under UNS Electric's current two-part rates, demand-related costs are recovered through energy rates because there is no demand charge. Therefore, a customer who decreases its energy consumption by more than it decreases its demand (as Vote Solar witness Kobor concedes is the case for DG customers) will tend to pay less than its allocated share of demand-related costs. This does not tend to be the case for non-DG customers. That is, while there are certainly exceptions to the rule, for the most part a non-DG residential customer with lower average hourly usage also has lower demand. The fact that a typical non-DG customer's average usage is a good proxy for its demand means that two-part rates are an adequate method for recovering fixed costs

from these (non-DG) customers.[5] This is not the case for DG customers because the typical relationship between average usage and demand does not apply.

**Q. Do you believe DG customers deserve special consideration in cost of service and rate design?**

A. Yes. Because of the reasons I described above, the fact that a DG customer's demand will be high relative to its average energy usage prevents a two-part rate from recovering the demand-related costs associated with serving DG customers. The relatively high demand of DG customers (compared to their average usage) demonstrates their need to rely on the utility's network and generating assets to serve their needs. Therefore, it is reasonable to apply a different pricing methodology to those customers.[6]

**Q. Are there any caveats to your conclusion that DG customers merit separate treatment in cost of service and rate design?**

A. Yes. If *all* Residential and Small Power Service customers (DG and non-DG) are served under properly designed three-part rates, following a transition similar to that proposed by Staff witness Solganick (which I discuss in Section IV below), there would be no need to distinguish between DG and non-DG residential customers. That is, the presence of the demand charge would ensure that all customers pay for their demand-related costs regardless of their overall usage level.

---

[5] Three part pricing would still improve the pricing incentives for these customers, giving them an incentive to alter their load profile in a manner that reduces both its bill and utility costs (by increasing its load factor).

[6] I would also support a mandatory transition of customers with persistent low load factors to a three-part rate, regardless of whether they are a DG customer.

## III. THE PROPOSED ALTERNATIVES TO THREE-PART RATES ARE INADEQUATE

**Q. What alternatives to three-part rates did other parties suggest?**

A. I encountered four types of alternatives to UNS Electric's proposed three-part rates in the testimony of other parties:

1. TOU energy charges;
2. A minimum bill provision;
3. The LFCR; and
4. Three optional DG rate proposals by RUCO witness Huber.

I will discuss each of these proposals.

**Q. What are the arguments in favor of using TOU energy prices in lieu of a three-part rate?**

A. AURA witness Alston argues that TOU rates "are easier to understand and do not negate the benefits of energy-efficiency improvements."[7] TASC witness Fulmer argues that TOU rates are preferred to three-part rates because "they are much more easily understood..., customers can much more readily respond to time of use rates..., time-of-use rates can reflect utility cost causation..., demand charges can be counter to conservation..., and time of use rates already existence [*sic*], which would limit the need for customer education programs."[8] WRA witness Wilson states that "Many of the issues that UNSE is raising about the need to match cost recovery to cost causation can be handled by using TOU rates for all residential customers."[9]

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[7] Alston Direct Testimony, page 6 lines 8-9.
[8] Fulmer Direct Testimony, page 23 line 11 to page 24 line 15.
[9] Wilson Direct Testimony, page 13 lines 20-22.

**Q. Do you agree that TOU energy rates are a substitute for a three-part rate?**

A. No. While TOU energy rates have the benefit of producing energy prices that better reflect the way energy costs vary over time, they do nothing to solve the problem associated with recovering demand-related costs through energy charges. That is, a DG customer with high demand relative to its average energy use (i.e., a low load factor customer) will continue to pay less than its share of the utility's demand-related costs under a two-part rate with TOU energy prices.

**Q. Do you believe that TOU energy rates should be implemented at all?**

A. Yes, I believe that TOU energy rates are an appropriate component of an effective three-part rate design. In such a design, the demand charge would recover the demand-related costs, while the TOU energy charges would reflect the expected time-varying energy-related costs. The resulting improvement in the alignment of utility costs and rates will lead to more efficient decisions on the part of customers, both in terms of their usage and in the size and/or direction of solar installations they consider. On the latter point, TOU rates may properly provide DG customers with incentives to maximize the *value* of the DG's output rather than the *amount* of the DG's output. For example, the TOU rates may provide DG customers with an incentive to face their panels more toward the west rather than the south if the peak TOU period is later in the day (i.e., not when solar output is at its highest) and sufficiently higher priced than the off-peak TOU period.

**Q. What are the arguments in favor of using a minimum bill provision in lieu of a three-part rate?**

A. TASC witness Fulmer argues that "A minimum bill provision, combined with a purely volumetric energy rate, could be effective in collecting the appropriate

fixed costs from ALL low-use customers, and not just those with DG."[10] WRA witness Wilson states that "Charging customers a minimum bill each month is an alternative way to recover a portion of fixed costs that would otherwise not be recovered from very low use customers."[11]

**Q. What is a minimum bill provision?**

**A.** A minimum bill provision sets the minimum amount of a customer's monthly bill. The customer is charged the greater of its bill under the standard rates (e.g., the basic service charge plus the energy consumed multiplied by the energy rates) and the amount of the minimum bill. A minimum bill differs from a monthly basic service charge in that the customer pays the monthly basic service charge no matter what, but if the customer's bill under standard rates is higher than the minimum bill, it is as though the minimum bill did not exist.

**Q. How do witnesses Fulmer and Wilson propose to set the minimum bill?**

**A.** WRA witness Wilson does not advocate setting the minimum bill to cover all fixed costs. Instead, he proposes "One benchmark for setting a minimum bill is to look at how much electricity low use, low income users typically use. Monthly bills for low income, low use customers should not go up."[12] TASC witness Fulmer states that the "minimum monthly bill amount could be set that collects a reasonable amount of UNS's fixed charges."[13]

**Q. Do you agree that a minimum bill provision is an adequate substitute for a three-part rate?**

**A.** No. A minimum bill provision has three problems. First, it is unlikely that parties would agree to set it high enough to recover all customer- and demand-related

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[10] Fulmer Direct Testimony, page 24 lines 19-21.
[11] Wilson Direct Testimony, page 11, lines 21-23.
[12] Wilson Direct Testimony, page 12, lines 6-13.
[13] Fulmer Direct Testimony, page 24, lines 19-20.

costs.[14] Second, it represents a one-size-fits-all approach that is certain to lead to continued cross-subsidies from high- to low-load factor customers. That is, a demand charge ensures that customers pay demand-related costs in proportion to the demand they incur on the utility's system. In contrast, a minimum bill provision is a single dollar amount that applies to all customers served on the tariff, regardless of their usage, demand, or load factor. It therefore cannot distinguish between low-use customers with different load factors. Two customers with the same total energy usage would face the same minimum bill regardless of the amount of their maximum demand despite the fact that the customer with higher demand incurs more demand-related costs. The third disadvantage of a minimum bill provision compared to a three-part rate is that it does not provide customers with an incentive to improve their load factor by encouraging the adoption of capacity-saving technologies or behaviors. Because the customer's bill under a two-part rate with a minimum bill provision does not depend on the customer's demand, the rate gives the customer no incentive to manage its demand.

**Q. What are the arguments in favor of using an LFCR in lieu of a three-part rate?**

**A.** Vote Solar witness Kobor states that "the LFCR adopted in UNS's last general rate case is specifically designed to address under-recovery of fixed costs due to DG and EE… the LFCR appropriately compensates UNS for sales lost to

[14] AIC asked TASC witness Fulmer to how he would propose to calculate an appropriate minimum bill for UNS Electric (see The Alliance for Solar Choice's Response to Arizona Investment Council's First Set of Data Requests, question AIC 1.1, attached hereto as Exhibit A). AIC then asked UNS Electric to provide the minimum bill that would result from implementing TASC witness Fulmer's method, assuming the customer charge remains at its current level. The response was: "Distribution cost in the amount of $11.90 could be added to the basic service for a minimum bill." (See UNS Electric's response to AIC's 1st Informal Data Request - 2-12-2016 - UNSE Rate Case (15-0142), attached hereto as Exhibit B.)

EE and DG, while maintaining appropriate price signals to customers that indicate the value in conservation."[15]

**Q. Do you agree that the LFCR is a substitute for a three-part rate?**

**A.** No, the LFCR is not a substitute for a three-part rate for three reasons. First, UNS Electric argues that the LFCR does not recover all of UNS Electric's demand-related costs.[16] Therefore, the combination of the LFCR with two-part rates does not allow the utility to fully recover the demand-related costs avoided by DG customers. Second, the LFCR is not capable of removing the cross-subsidies that occur under two-part rates. That is, even if the LFCR were effective in making the utility whole for lost fixed costs due to DG, the non-DG customers would still subsidize a portion of the demand-related costs associated with serving DG customers. As DG proliferates, this would lead to an increasing share of demand-related costs being paid by a decreasing share of UNS Electric's customers. Third, the LFCR plus a two-part rate does not provide customers with incentives to manage their demand as would occur under a three-part rate.

**Q. What DG rate options did RUCO witness Huber propose?**

**A.** RUCO witness Huber proposed three rates from which DG customers could choose:[17]

1. Non-export Option: customers can select any of UNS Electric's standard rates and may not export power to the grid.
2. Advanced DG TOU Option: customers pay a three-part rate, including a minimum bill, a flat base energy rate ($0.084 per kWh), and a peak-hours demand charge ($19.50 per kW incurred between 2 and 8 p.m.). Customers may

[15] Kobor Direct Testimony, page 32 lines 7-8 and page 45 lines 16-18.
[16] Jones Direct Testimony, page 7, line 23 through page 8 line 1.
[17] Huber Direct Testimonyh, page 11.

export power to the grid, with the credit dependent upon whether the customer exchanges Renewable Energy Credits ("RECs") with UNS Electric.

3. RPS Bill Credit Option: customers can select any of UNS Electric's standard rates and receive a credit that is based on the amount of renewable capacity added over time, starting at $0.11 per kWh. The customer must exchange RECs with UNS Electric.

**Q. Why does RUCO witness Huber propose three options from which DG customers may choose?**

A. He states that "the Company's proposal is not appropriate because it lacks optionality for customers."[18] The Non-export Option "was designed after concurring with DG advocates who have insisted that DG customers 'not be treated differently.'"[19] The Advanced DG TOU Option is an option for "Customers with more sophistication and tools to control their peak loads".[20] The RPS Bill Credit Option "provides a bridge for the industry to use in preparation for using the TOU DG Rate."[21]

**Q. What is your opinion of the DG rate options proposed by RUCO witness Huber?**

A. I do not believe that his DG rate options would result in an outcome that is qualitatively different from the status quo. Because the Non-export Option and the RPS Bill Credit Option would allow DG customers to select any of UNS Electric's traditional rates (i.e., two-part rates), both options would perpetuate the ability of DG customers to avoid paying their demand-related costs. The third option, the Advanced DG TOU Option, is a three-part rate design that

[18] *Id.*, page 4 line 17.
[19] *Id.*, page 23, lines 9-10.
[20] *Id.*, page 23, line 18.
[21] *Id.*, page 23, lines 14-15.

would be helpful if not for the fact that it would be offered as an optional rate. As I explain below, I believe that virtually no DG customers would select the Advanced DG Option given the other options that would be available to them.

**Q. Which option does RUCO witness Huber expect DG customers to select?**

**A.** He expects the RPS Bill Credit Option will be "the most popular rate" and that the Non-export Option "will likely not be very popular among DG customers."[22]

**Q. Do you agree with his expectations about the option DG customers are most likely to select?**

**A.** Yes, though I would go further and expect virtually all DG customers to select the RPS Bill Credit Option. Consider RUCO witness Huber's options in two steps. First, compare the Non-export Option and the RPS Bill Credit Option. Both of these options allow customers to select one of UNS Electric's traditional rates, but RPS Bill Credit Option allows the DG customer to be paid for excess generation while the Non-export Option does not. No rational customer would pick a rate that pays them nothing rather than something for excess generation when the rates are otherwise equivalent. So in my opinion, the Non-export Option is not a relevant option to consider.

**Q. You have argued that DG customers would rationally select the RPS Bill Credit Option over the Non-export Option. Do you believe DG customers would select the RPS Bill Credit Option over the Advanced DG TOU Option?**

**A.** Yes. Because the RPS Bill Credit Option is based on a traditional UNS Electric rate (i.e., a two-part rate with no demand charge), DG customers who select

[22] *Id.*, page 23, line 23 and page 24, line 8.

this option are given the opportunity to avoid paying demand-related costs in the same manner that currently exists. The only difference between this option and the status quo is in the rate paid for excess generation. In contrast, the Advanced DG TOU Option contains a demand charge, thus collecting demand-related costs (at least as incurred during the 2 to 8 p.m. time period over which RUCO witness Huber proposes to measure demand). Because the RPS Bill Credit Option provides an easy opportunity for DG customers to avoid paying demand-related costs while the Advanced DG TOU Option would require managing peak demand to do so (in which case the customer ought to pay less), I expect virtually all DG customers would select the RPS Bill Credit Option.

**Q. Have you conducted a comparison of bills under the RPS Bill Credit Option and the Advanced DG TOU Option?**

**A.** Yes. The table below compares the bills under three scenarios: no DG; with DG and no management of billed demand (it is assumed to remain the same as the "no DG" case); and with DG and managing billed demand such that it is reduced by 75 percent. The "no DG" kWh and kW levels used in the analysis are taken from the direct testimony of UNS Electric witness Dukes.[23] In the "with DG" scenarios, I assume the customer generates enough electricity to meet 50 percent of its energy needs.[24] The RPS Bill Credit Option (in which the customer is assumed to select Residential Service) and Advanced DG TOU

[23] Dukes Direct Testimony, page 25. The kW level is calculated as average monthly usage divided by 730 hours divided by the load factor contained in Mr. Dukes's table.

[24] The conclusions of the table remain the same if the customer generates a higher percentage of its energy needs. When 100 percent of monthly energy needs are met by DG, the best a customer on the Advanced DG TOU Option can do is pay the minimum bill (i.e., if the customer manages billed demand down to nearly zero), which is higher than the customer charge under the Residential Service rate.

Option rates are based on RUCO witness Huber's proposals (Exhibit 2 of his direct testimony).

| Avg. Monthly Usage | Monthly Billed Demand | RPS Bill Credit Option, Selecting Residential Service | Advanced DG TOU Option |
|---|---|---|---|
| **No DG** | | | |
| 500 kWh | 3.5 kW | $54.79 | $111.35 |
| 900 kWh | 5.5 kW | $96.54 | $183.83 |
| 1,200 kWh | 6.6 kW | $129.19 | $230.22 |
| 1,500 kWh | 7.6 kW | $162.50 | $275.90 |
| **With DG, assuming 50% of energy needs met by DG and billed demand remains unchanged** | | | |
| 250 kWh | 3.5 kW | $32.32 | $90.10 |
| 450 kWh | 5.5 kW | $49.57 | $145.58 |
| 600 kWh | 6.6 kW | $65.23 | $179.22 |
| 750 kWh | 7.6 kW | $80.89 | $212.15 |
| **With DG, assuming 50% of energy needs met by DG and billed demand is managed such that it is reduced by 75%** | | | |
| 250 kWh | 0.9 kW | $32.32 | $38.46 |
| 450 kWh | 1.4 kW | $49.57 | $65.08 |
| 600 kWh | 1.6 kW | $65.23 | $83.05 |
| 750 kWh | 1.9 kW | $80.89 | $100.85 |

In the "No DG" case in the top panel of the table, the Advanced DG TOU Option results in bills that are 1.7 to 2.0 times higher than the bill under the RPS Bill Credit Option, depending on the customer's usage level. In the second panel, which represents a DG customer who does not manage demand, the bill under the Advanced DG TOU Option is 2.6 to 2.9 times higher than the bill under the RPS Bill Credit Option. Finally, the third panel shows the bills when the DG customer manages its billed demand such that it is reduced by 75 percent. Even in this case, the DG customer would pay 19 to 31 percent more under the Advanced DG TOU Option than it would on the RPS Bill Credit Option. I calculated that the DG customers in these scenarios would have to

reduce their billed demand by 84 to 89 percent (depending on the average monthly usage) in order to break even on the Advanced DG TOU Option compared to the RPS Bill Credit Option. Given these comparisons, I do not expect that a DG customer could benefit by selecting the Advanced DG TOU Option, once the costs of managing demand are factored in.

**Q. What do you conclude about RUCO witness Huber's three DG rate options?**

**A.** Based on my analyses described above, I find that only one of the three options is relevant: the RPS Bill Credit Option. I would not expect any customers to select one of the other two options, so those options should play essentially no role in evaluating the efficacy of RUCO witness Huber's proposal. The RPS Bill Credit Option (the only option I would expect any DG customers to select) only differs from the status quo in the method used to pay for excess generation. RUCO witness Huber stated that "RUCO would like to begin by ensuring that rooftop DG can be a neutral cost proposition for ratepayers as soon as possible."[25] He also stated "It can be argued that UNSE's rates are in need of modernization, especially in light of the proliferation of DG options for consumers."[26] I find that his DG rate proposals amount to a continuation of the status quo and are not capable of accomplishing the goals he established.

**Q. What do you conclude about the various proposed alternatives to UNS Electric's three-part rates?**

**A.** None of the proposed alternatives to three-part rates (TOU energy charges, a minimum bill provision, an LFCR, or RUCO witness Huber's DG rate proposals) deal with the fundamental problem that demand-related costs exist and the current two-part rate structures (that recover demand-related costs

[25] Huber Direct Testimony, page 12, lines 19-21.
[26] *Id.*, page 10, lines 2-3.

through energy charges) allow DG customers to avoid paying the demand-related costs to serve them. Eventually, those costs are passed on to non-DG customers either through the LFCR or following a subsequent rate case. Requiring DG customers to be served on a three-part rate is the best (and perhaps only) way of ensuring they pay for the demand-related costs to serve them and provide them with incentives to manage their demand in a way that can reduce both their bill and the cost to serve them.

## IV. RESPONDING TO STAFF'S PROPOSAL TO IMPLEMENT MANDATORY THREE-PART RATES AND MISCONCEPTIONS ABOUT DEMAND CHARGES

**Q. What issues will address in this section of your testimony?**

A. In this section, I will address two arguments made regarding three-part rates that I believe mischaracterize how they work. My lack of commentary on other arguments about demand charges does not imply my agreement. I will also discuss Staff witness Solganick's proposal to transition all Residential Service and Small General Service customers to mandatory three-part rates.

**Q. What does WRA witness Wilson argue about the effect of demand charges on electric vehicles ("EVs")?**

A. WRA witness Wilson states that "Demand charges are bad for electric vehicles charging… Charging an electric vehicle puts a substantial load that lasts for several hours."[27] He goes on to argue that the effect of charging EVs on the customer's billed demand could make it very expensive to charge the EV, regardless of the time of day during which it is done.

[27] Wilson Direct Testimony, page 10, lines 12-14.

**Q. Do you agree with his argument that "demand charges are bad for electric vehicles charging"?**

A. No, I believe three-part rates can lower the costs of charging EVs and help increase EV adoption rates. In the absence of a demand charge, demand-related costs are recovered through energy charges. Because EV charging is an energy-intensive activity, two-part rates are likely to result in EV customers overpaying for their demand-related costs. Using three-part rates could allow EVs to be charged at a lower cost provided that the customer can manage its demand. I agree with WRA witness Wilson that this would be more difficult for the EV customer to do under an all-hours demand charge. However, I believe a peak-hours demand charge would be a more effective three-part rate design for reflecting the majority of the demand-related costs, and would make it easy for customers to charge EVs overnight without increasing their billed demand.

**Q. How does TASC witness Fulmer think DG customers would react to a three-part rate?**

A. TASC witness Fulmer does not believe it is reasonable "that the demand charge will help improve a customer's load factor and thus save them money." He argues: "Given that customers cannot easily reduce their peak demand… [t]he easiest and primary way that customers can improve their load factor is to consume more power… 'The more you use, the more you save,' is not a message that I believe UNS should be sending."[28]

**Q. Do you agree with TASC witness Fulmer that a customer will save more as they use more under a demand-based rate?**

[28] Fulmer Direct Testimony, page 20 line 19 through page 21 lines 6-7.

A. No. In reaching this conclusion, TASC witness Fulmer confused a reduction in average rate paid with a reduction in the customer's bill. It is true that increasing usage while holding demand constant would reduce the customer's average price paid per kWh, but it would also increase the customer's total bill. UNS Electric's three-part rate would not send customers a message that "the more you use, the more you save." Rather, the three-part rates would give customers the incentive to make the most efficient use of UNS Electric's resources.

**Q. Please describe Staff witness Solganick's proposal to transition all Residential Service and Small General Service customers to mandatory three-part TOU rates.**

A. Staff witness Solganick proposes to transition all Residential Service and Small General Service customers to mandatory three-part TOU rates "subject to a Company-filed transition plan… [t]he transition would not begin until the Company is able to provide each customer with at least three months of demand and TOU data from AMI meters."[29] He proposes to complete the transition by the end of 2017.

**Q. What three-part TOU rate design does Staff witness Solganick propose?**

A. Staff witness Solganick states that "Rate design should recognize the concepts of customer, demand and energy, and also recognize TOU and seasonality… [t]here would be no demand ratchet… [d]emand rates would apply only to On-Peak periods."[30]

**Q. What is your reaction to Staff witness Solganick proposed three-part TOU rate design?**

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[29] Solganick Direct Testimony, page 30, lines 14-18.

[30] *Id.*, page 10 lines 15-16 and page 31 lines 8-9.

A. I agree that the design elements, including seasonal TOU energy rates and a peak-period demand charge, can be combined to provide a three-part rate that does a good job of reflecting the utility's cost drivers and therefore provide customers with the proper behavioral incentives.

## V. ADDRESSING CONCERNS ABOUT UNS ELECTRIC'S PROPOSED RENEWABLE CREDIT RATE IN NET METERING RIDER R-10

**Q. In your view, what were the primary arguments made by other parties against UNS Electric's proposed RCR in Net Metering Rider R-10?**

A. TASC witness Fulmer has five concerns about the RCR:

1. DG solar can provide greater benefit to the grid than utility-scale solar;
2. The RCR is set based upon a transaction at a different utility;
3. The potential variability of this payment is concerning;
4. The value of renewable power is not the same across technologies; and
5. Concerns around taxation of income derived from exported power sold to the utility.[31]

Vote Solar witness Kobor lists three "flaws" in the proposed RCR:

1. The RCR does not appropriately approximate the value of distributed solar generation;
2. The RCR would be extremely volatile and vulnerable to gaming; and
3. The RCR would violate the Commission's existing NEM rules.[32]

**Q. How do you respond to these criticisms of UNS Electric's proposed RCR?**

A. The primary objection appears to be that the RCR does not approximate the value of solar DG, for a variety of reasons. However, both TASC witness

[31] Fulmer Direct Testimony, page 4 lines 5-6, page 5 lines 10 and 15, page 6 lines 9 and 17-18.
[32] Kobor Direct Testimony, page 30 lines 2-6.

Fulmer and Vote Solar witness Kobor recommend the rejection of UNS Electric's proposal and a continuation of status quo, which would also not result in excess generation being compensated based on a value of solar calculation. Under the current Net Metering Rider R-4, net metered customers are compensated for excess generation at the retail rate in a following month. The retail rate has very little to do with the value of DG. The variable energy cost is a component of the retail rate, but (as discussed above) demand-related costs are also included in the retail energy rate. To be clear, no one is proposing to set the RCR at the precise value of solar DG. (However, Vote Solar witness Kobor does suggest a benefit/cost study of the issue that I discuss below.) My view is that it is more reasonable to compensate DG customers for excess generation at the proposed RCR rather than at the retail rate.

**Q. Why do you believe it is more reasonable to compensate DG customers for excess generation at the proposed RCR rather than at the retail rate?**

**A.** In addition to a commitment to provide renewable power, UNS Electric has a responsibility to provide affordable power. Cynthia Zwick's direct testimony on behalf of Arizona Community Action Association describes the importance of energy affordability.[33] At the same time, the utility is compelled to purchase DG from its customers through Arizona's net metering policy and at some point UNS Electric's customers pay for that power. UNS Electric's proposed RCR balances the concerns of energy affordability with the desire to expand Arizona's renewable generating portfolio by compensating DG customers for excess generation at a rate approximately equal to the cost of obtaining renewable power from an alternate source. This is fairer to *all* UNS Electric customers than the current net metering policies.

[33] Zwick Direct Testimony, page 10 lines 13-17.

**Q. Are there any modifications you would suggest for the proposed Net Metering Rider R-10 in response to these criticisms?**

A. Yes, I recommend two modifications. First, the RCR should be based on purchased power agreements of only utility-scale solar power, which would be expected to provide a more comparable time pattern of generation to solar DG than other renewable sources (e.g., wind power). Because the value of generation varies by time of day, the expected daily pattern of generation should be embedded in the purchased power agreement. Second, the RCR could be specified to be the maximum of the current method or the utility's avoided energy costs. This would ensure that the RCR would not compensate DG customers for excess energy at a rate less than the utility's avoided energy cost, in the event that renewable energy prices become very low.

**Q. How do you respond to the criticisms that the RCR would be volatile and prone to gaming?**

A. I believe the concerns about the variability of the RCR are overblown. First, the RCR applies only to excess generation. Net metered customers are guaranteed to be compensated for their generation at the retail rate up to the amount of their monthly consumption. According to UNS Electric witness Tilghman, "under current net metering rules the customer can generate 125% of their connected load annually."[34] This limit places an upper bound on the importance of the RCR on a DG customer's return on investment. In addition, I don't find the "prone to gaming" critique to be compelling. From DG customer's perspective, "gaming" would constitute UNS Electric or Tucson Electric Power obtaining renewable power at a lower price than it has in the

[34] Tilghman Direct Testimony, page 6 lines 4-5.

past. This "gaming" would benefit Arizona's electric customers by providing them with low-cost renewable power.

**Q. Vote Solar witness Kobor states that "the Commission must establish the value of the exported DG for which the Renewable Credit Rate is intended to compensate."[35] Do you have any concerns about the benefit/cost study suggested by Vote Solar witness Kobor?**

A. Yes. The categories of benefits and costs (listed on pages 27 and 28 of her direct testimony) include factors such as "environmental services" that are not part of a regulated cost-of-service study. Attributing the value of such a service to solar DG and not to other activities that confer the same benefit leads to cross-subsidies and a distortion of customer incentives. For example, suppose solar DG is assigned a high environmental services value when setting the RCR. Other activities, such as conservation or the purchase of more energy efficient appliances will not receive this benefit. This could result in inefficient decisions, such purchasing and installing solar panels instead of simply using less energy (perhaps by setting the thermostat higher in summer). The detailed assessment of the costs and benefits of solar DG is not proposed to be applied to other potential sources of those same benefits and costs. I suggest that if the Commission identifies a significant category of benefits or costs (e.g., environmental services), that it attempt to quantify that benefit or cost and apply it equally to the pricing of all sources of it.

**Q. Do you have any response to the RCR concerns related to taxation and Commission's NEM rules?**

A. No, I am not qualified to respond to those criticisms.

[35] Kobor Direct Testimony, page 26 lines 25-26.

## VI. CONCLUSIONS AND RECOMMENDATIONS

**Q. Do you have any concluding observations and recommendations?**

A. Yes. I continue to support UNS Electric's proposal to apply three-part rates to new net metered customers. I recommend that UNS Electric's initial proposal be modified to measure billed demand over only peak hours. My other conclusions are as follows:

1. DG customers are different from non-DG low-use customers and it is reasonable to treat them differently.
2. TOU energy rates are not a substitute for a three-part rate. However, TOU energy rates are a useful component of a three-part rate.
3. A minimum bill provision is not a substitute for a three-part rate.
4. A lost fixed cost recovery mechanism is not a substitute for a three-part rate.
5. The DG rate options proposed by RUCO witness Huber would result in virtually all DG customers selecting the RPS Bill Credit Option, which would amount to a continuation of the status quo that would not further progress toward his stated goals.
6. I do not object to Staff witness Solganick's proposal to transition all Residential Service and General Power Service customers to a mandatory three-part TOU rate.
7. I support UNS Electric's proposed RCR, with the modifications that it be based only on utility-scale solar purchased power agreements (rather than purchased power agreements from any renewable source) and have a floor equal to UNS Electric's avoided energy costs. I believe this RCR appropriately balances UNS Electric's commitments to provide affordable energy and expand the sources of renewable power.

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

**A.** Yes.

# Exhibit A

**THE ALLIANCE FOR SOLAR CHOICE'S RESPONSE TO**
**ARIZONA INVESTMENT COUNCIL'S**
**FIRST SET OF DATA REQUESTS**
**UNS DOCKET NO. E-04204A-15-0142**

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**AIC 1.1** On page 25 lines 5-6 of Mr. Fulmer's direct testimony (rate design and cost of service), he states that he has not calculated "what an appropriate minimum bill would be for UNS." Please describe how Mr. Fulmer would perform such a calculation.

**RESPONSE:** **A (residential) minimum bill should be based on the costs that are customer-driven by the specific customer for interconnection and retails service, but not collected in any monthly fixed charge. Costs associated with line drops, meters, and transformers to household voltage, metering and billing services, and customer services could be covered by a minimum bill. The sum of the annual revenue requirements for these assets and activities would be divided by the number of customer-months to arrive at a minimum bill amount.**

**Source: Mark Fulmer**

# Exhibit B

**UNS ELECTRIC INC.'S RESPONSE TO AIC'S FIRST INFORMAL DATA REQUEST**
**REGARDING THE 2015 UNS ELECTRIC RATE CASE**
**DOCKET NO. E-04204A-15-0142**
**February 12, 2016**

**AIC Infrml 1.1**

What would the minimum bill be if the calculation identified in TASC Witness Fuller was performed, under the assumption that the customer charge remains at its current level?

**RESPONSE:**

Distribution cost in the amount of $11.90 could be added to the basic service for a minimum bill.

**RESPONDENT:**

Brenda Pries

**WITNESS:**

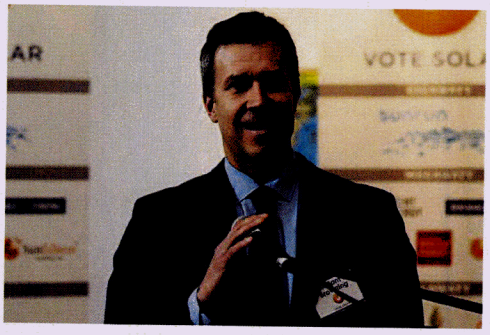
Craig Jones

EXHIBIT
tabbies
A K-5
admitted

VOTE SOLAR

# 2014 ANNUAL REPORT

# LETTER FROM THE EXECUTIVE DIRECTOR




When you think of the energy challenges facing the world, what gives you hope? For me, it's this . . .

In 2014, a third of the new power generation built in the US was solar.

The solar-cheaper-than-coal club has a lot of new members. Georgia, Minnesota, Idaho, Utah, Texas, North Carolina, Colorado, New Mexico, Arizona and California are all building massive amounts of solar at prices cheaper than dirty fossil.

There's a rooftop revolution underway in New York. We put 5 years into a campaign, and it paid off with a commitment to ten times more solar in the state and a process to reform the electricity landscape with customer-driven renewables at the center. And we're not stopping there. The state's now making moves to give renters and millions of other New Yorkers the opportunity to participate in and benefit from the solar economy.

In 2014, nearly $1 billion flowed into PACE financing programs that are helping families and businesses make clean energy upgrades and save on their bills. That's billion with a 'b.' And 2015 is looking even better. This also after years of hard work — passing enabling legislation in states around the country, writing best-practice policy guides, battling with the Federal Housing Finance Agency.

Some utilities and the Edison Electric Institute took their best shot at squashing rooftop solar by rolling back net metering and changing rates to make solar a bad deal for customers. But those big-money attacks fell flat against the massive outcry from the people like you who support solar. Discriminatory solar fees were defeated in Idaho, Louisiana and Utah. Vermont, New York and Massachusetts all raised their net metering caps to allow more solar participation. And South Carolina just joined the 43 other states that offer residents the ability to get fair credit for rooftop solar through net metering. This is the existential battleground for the future of energy in this country, and so far solar is winning.

Bottom line, it's not just promise that gives us hope — it's progress. It's real steel in the ground, silicon on the roof, and sunshine powering our lives.

How does progress happen?

Solar falls free from the sky, but policy doesn't. Vote Solar now has 16 staff around the country, dedicated and working day (and too many nights) to bring solar into the mainstream. In 2014 we led solar campaigns in 21 states, sweated interventions in 31 regulatory dockets, worked on 10 legislative campaigns, and fought discriminatory solar fees in 11 rate cases and utility proceedings. Members like you delivered 108,677 messages to policymakers in support of pro-solar policies. 2,575 homeowners participated in our GroupEnergy bulk solar programs, which made it easier and 20% cheaper for communities to go solar. We hired new staff in four states: California, Colorado, Massachusetts, and Florida. We biked 300 miles from NY to DC to raise money for our work, and threw two Equinox parties that put smiles on the faces of 1,100 revelers.

Vote Solar was founded on a simple strategy: we build scale by making solar cheaper and more accessible. And it's working. We thank the many donors, partners and supporters who are helping us succeed.

Sincerely,

Adam Browning
Co-founder and Executive Director

## WHO WE ARE

Vote Solar is a non-profit grassroots organization working to foster economic opportunity, promote energy independence and fight climate change by making solar a mainstream energy resource across the United States.

## WHY WE DO IT

Whether it's the challenges of global climate change, energy security or economic development - reliable, homegrown solar energy is ready to be a big solution. Solar is our fastest growing electricity source, but it still accounts for a mere 1% of our nation's overall energy portfolio. The problem is not technology; the solar we have today works great and is cost-competitive. The real problem is policies and regulations that create unnecessary costs and confusion for families, towns, schools, businesses and many others looking to go solar. We work to overcome those hurdles for both distributed and large-scale solar power.

## HOW WE WORK

**We work with policymakers:**

Solar policy is complex and changing all the time. We help regulators and legislators understand their policy options, quantify the costs and benefits, draft legislation, and implement the programs that are going to most effectively support a solar market that benefits individuals, businesses, and communities alike.

**We work with other advocates:**

We make the most of our own limited resources and those of our skilled advocacy peers by collaborating wherever possible. Whether it's sharing our deep policy design expertise or highlighting the best practices of others, we provide the tools, guidance and support needed to help others make a difference in their own communities and nationwide.

**We work with people:**

We are a grassroots organization with approximately 60,000 members in all 50 states. We help our members stay informed about the latest in solar policy through emails, blog posts, social media, webinars and strategic press outreach. We mobilize our supporters and give them easy tools to make their voices heard.

**We commit for the long-term:**

Each solar law and program successfully enacted requires sustained attention to make sure it is implemented correctly, operating effectively, protected from opposing interests, and amended when necessary. We build long-term partnerships and maintain watchdog vigilance to ensure positive progress is made.

# KEY ISSUES

**Net Energy Metering and Electricity Rate Design:** Net metering ensures that solar customers receive fair credit on their utility bills for the valuable excess clean power they occasionally deliver to the grid. This crediting arrangement combined with the way that utility rates are structured is what makes the switch from utility-generated fossil grid power to homegrown solar power an economic possibility for many Americans. Utilities are increasingly using rate cases and other regulatory proceedings to reduce net metering credit, impose new discriminatory fees, and otherwise make solar a poor investment for their customers, all in the interest of protecting their bottom-line.

**Renewable Procurement and Market-building Incentives:** Strong and healthy solar markets are those that provide a diverse range of opportunities to both residential customers and utility-scale developers. Rules that require utilities to increase the amount of renewable energy on the grid coupled with procurement programs that facilitate market development can be strong tools for achieving scale in new and established markets alike. Well-designed incentive programs can also jump-start a healthy retail market, enabling homes, schools and businesses to go solar, and prompting the local industry to grow toward an incentive-free marketplace.

**Financing Solutions:** Innovative financing options, including third-party financing, leasing, and PACE, have been a primary driver of consumer solar adoption in many states. Vote Solar works to ensure customers have access to the full suite of solar energy financing options that help reduce upfront costs and make solar more accessible.

**Soft Costs:** The costs of solar hardware, such as the solar panels themselves, have plummeted in the past half-decade. But non-hardware "soft costs" have not fallen apace, which makes this an area that's ripe for continued solar cost reduction. Our GroupEnergy program aims to tackle customer acquisition soft costs by helping consumers pool their purchasing power. We also work to streamline permitting practices to reduce soft costs and red tape at the local level.

**Grid Integration:** In places with the high solar penetration, grid operators are sounding the alarm on the challenges of integrating increasing amounts of this variable energy resource. Our challenge is to re-design regulatory regimes to effectively manage distributed and variable generation while minimizing costs and maximizing environmental benefits.

**Shared Solar:** Many consumers – notably renters and those with shaded roofs - face technical barriers to going solar through the traditional panels-on-your-roof approach. We work to advance innovative Shared Renewables programs that help connect these consumers with savings from an offsite solar energy system located somewhere else in their community.

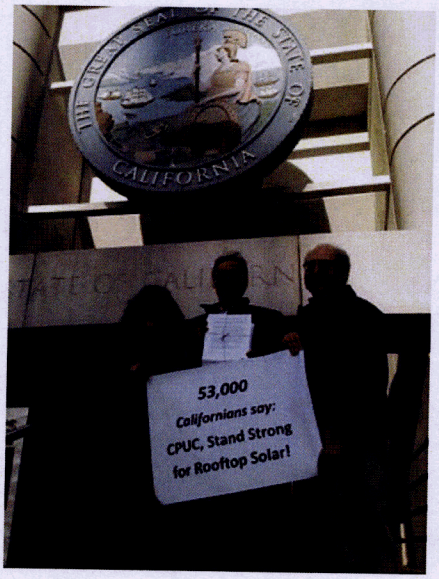
# CAMPAIGN HIGHLIGHTS:

## Defending Rooftop Solar Rights

For the first time in a century, there's real business model innovation happening in the electricity sector. For generations we have depended on a centralized, often monopoly-based utility model, but now affordable solar and other clean technologies are putting consumers in control like never before. This is exciting, game-changing stuff! But rather than seizing opportunity and finding ways to work with their customers to meet solar demand, most utilities are digging in their heels against change – turning to regulation and law to try to stem the tide. Net metering and rate design are the battlegrounds of this fight between traditional utilities and a cleaner, more participatory approach to energy - and Vote Solar is committed to engaging at the front lines. In 2014 we worked to coordinate activities and share resources with partners nationally to effectively combat the utility onslaught. Our team also engaged directly in a number of key state fights, leading public campaigns or providing the technical expertise needed to win.

Despite the number and scale of these utility attacks, states generally upheld and in some cases strengthened the pillars of consumer clean energy investment over the past year. This success was confirmed in *Freeing the Grid 2014*, a report card to all 50 states on net metering and interconnection procedures that we produced in partnership with the Interstate Renewable Energy Council (IREC). While this fight is far from over, it's heartening to see regulators nationwide – in red states and blue – stand strong for the energy choice and the solar progress that an overwhelming majority of Americans want.

With more solar installed than any other state, California is at the forefront of our rooftop revolution. In 2014 regulators began a multi-year process of implementing AB 327, a utility and rate reform law that will determine the long-term future of net metering in the state. As a first step, the Public Utilities Commission set out to decide how long existing solar customers can expect to have access to net metering as its known today. Considering that these homes, schools and businesses made significant multi-decade investments in solar expecting the state would not change the rules on them mid-stream, Vote Solar argued that it's only fair that their net metering benefits should remain in place for just as long. With utilities pushing for as little as 6 years, we intervened in the regulatory process and rallied grassroots power to deliver over 53,000 signatures in support of long-term net metering certainty. Ultimately, the CPUC decided to uphold net metering for existing customers for 20 years from the year they go solar - a win for solar certainty! Along with the Commission, we then turned our attention to what comes next after the current net metering program ends. We continue to make the case for a program that enables California energy customers to generate their own power for their own use and that fairly compensates them for any valuable solar energy they deliver to the grid for others to use.




Colorado's largest utility, Xcel Energy, took aim at net metering as part of its Renewable Energy Standard Compliance Plan docket. Thanks to the tremendous outpouring of public solar support that Vote Solar helped organize, in early 2014 the Public Utility Commission agreed to put Xcel's attacks on hold and conduct a new, separate process to take a good look at this critically important solar program. We turned our attention to ensuring that the new PUC process is fair, open and transparent. We participated in these ongoing PUC-led workshops, providing technical input and ensuring that pro-solar voices as diverse as the local solar industry, environmental groups, the faith community and the NAACP were represented. The fight for Colorado's energy future is not over yet, but we are proud of the success that Vote Solar and our partners have achieved to date.

With the Commonwealth quickly approaching its net metering cap, we helped encourage Massachusetts policymakers to raise the cap and keep solar working for the state. State lawmakers decided to provide short term-relief – raising the caps from 3 to 5 percent for local governments and from 3 to 4 percent for commercial installations – and establish a stakeholder process for charting long-term program design. In an effort to make this process inclusive and effective, Vote Solar and our key partners formed the "Mass Solar Coalition." The group will work with the state's new Net Metering and Solar Task Force to make recommendations for the future of net metering and solar policy in Massachusetts.

Amid numerous unfounded claims about the costs of net metering, the Public Utilities Commission of Nevada found that rooftop solar makes sense – and cents – in the sun-drenched state. The PUCN commissioned a study that found

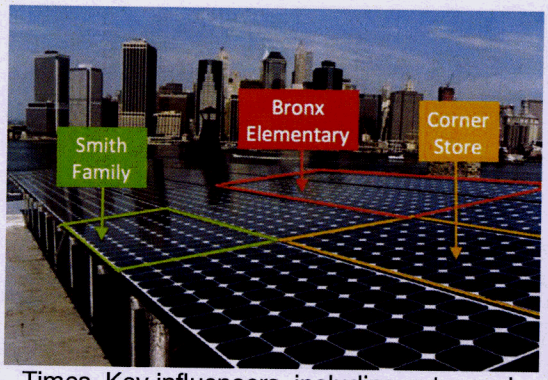
that net metered systems installed through 2016 will deliver $36 million in net benefits to ratepayers. We worked to educate stakeholders, policymakers and the public on the cost-saving benefits of net metering. We garnered more than 4,300 signatures and turned out dozens of Nevadans to rally for the program and its many benefits. With the state now approaching its current cap, this campaign provided important groundwork for future net metering progress.

It might come as a surprise to some, but Utah has one of the strongest net metering programs in the country. However, the state's major utility, Rocky Mountain Power, aimed to make solar a bad deal for its customers with a discriminatory new solar fee. Vote Solar provided expert testimony against this fee proposal in the RMP rate case. Our technical input complimented the strong local grassroots and press efforts to oppose the unfounded "solar tax." In a resounding win for solar self-determination, the Commission rejected RMP's solar fee.

State leadership has made building a more resilient, more distributed clean energy system a clear priority for New York. In order to meet the Empire State's impressive solar goals, state regulators raised the net metering cap from 3 percent to 6 percent. Vote Solar supported this doubling of net metering access through a joint petition we submitted to the Commission earlier in 2014. Bravo to the Empire State!

## Expanding Solar Access to Renters and Others

At Vote Solar we believe that the strongest solar market is one that allows diverse participation. For this reason, we are particularly exited about opportunities to help entirely new categories of consumers – renters, low-income families and others plug into the sun with innovative shared renewables programs.




In 2014, we made strong progress toward establishing shared renewables programs in both New York and Connecticut. We provided policymaker guidance on strong design for this relatively new concept. And in order to build the support needed to pass these programs, we coupled that policymaker education with grassroots and press activities. We put a particular focus on engaging the stakeholders – including low-income and community groups – for whom the traditional panels-on-your roof solar model just doesn't work.

Vote Solar, along with our hardworking and diverse coalition, drummed up nearly 10,000 signatures in support of the new programs and also garnered some impressive media coverage, including the New York Times. Key influencers, including actor and activist Mark Ruffalo, helped amplify our campaign and further shine light on the states' shared renewables opportunity. We're looking forward to building on this momentum to see these programs across the finish line in the coming year.

In California, we worked diligently at the CPUC to implement SB 43, which authorizes what could be the nation's largest shared renewables program (up to 600 MW by 2019). While the program holds tremendous promise for connecting more Californians with clean energy, success is dependent on good design. Vote Solar worked to guide strong implementation with a particular focus on ensuring that customer participants receive adequate credit on their utility bills and a fair amount of choice over the renewable energy projects in which they can participate. The CPUC is expected to decide on this landmark shared solar program in 2015.

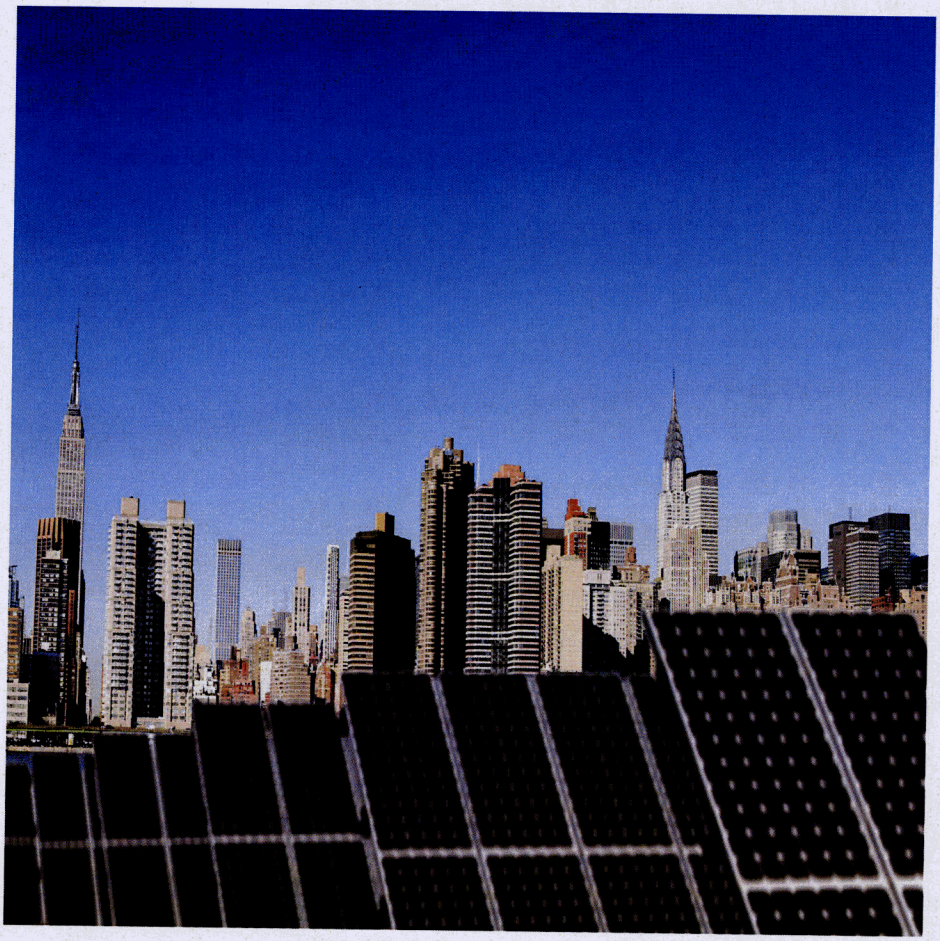
## Smart Policy for Strong Solar Markets

The state's largest utility, Arizona Public Service (APS) filed a proposal at the Arizona Corporation Commission (ACC) to eliminate the requirement to diversify their energy supply with small-scale solar projects, which would have cut the utility's overall renewables requirement and leave Arizona with one of the weakest clean energy goals in the West. We encouraged Vote Solar members to take action online and attend the ACC meeting, where Commissioners unanimously rejected APS's proposal to eliminate the carve-out. This was an important win in a state that has a massive solar resource to harness for job creation, grid reliability and water conservation.

Vote Solar intervened in Colorado to defeat a flawed Solar*Connect community solar proposal from Xcel Energy. On the surface, the basic concept - to provide a subscription-based program to retail customers that had limited or no access to rooftop solar or community solar gardens - was a progressive idea. In reality, however, Xcel's design meant that customers would pay an unnecessary premium, rather receiving a bill reduction, for their clean power. And adding insult to consumer protection injury, it would have also allowed Xcel to change subscription costs at any time for new customers. Plus the utility sought to retain any profits from the program for its shareholders. When asked if Xcel would consider allowing other, non-regulated businesses to make similar offerings, it declined. The Commission ultimately rejected the Solar*Connect plan as being anti-competitive and falling short on delivering ratepayer value. We hope to see more – better – utility proposals for supporting balanced and vibrant solar markets and that Commission provide thoughtful guidance to encourage those ideas and ideals.

With strong support from Governor Cuomo, New York state regulators approved long-term extension of the NY-Sun Initiative this year. This historic clean energy commitment will result in TEN TIMES more affordable solar up and down the state. The expected 3,000 megawatts of new solar capacity by 2023 will be enough to power nearly 500,000 New York homes and cut greenhouse gas emissions by 2.3 million tons annually. This bold commitment is the result of more than five years of blood, sweat and tears from our team, our members, and our strong coalition of environmental, consumer and business groups. Together we sent tens of thousands of emails urging policymakers to establish a big, bold solar program for New York. We've channeled New York's support for solar through Solar Job Days from Buffalo to Long Island, a Times Square photo contest, and one meme-worthy 'solar spill' billboard.

The plan's long-term horizon provides invaluable policy certainty so that industry and consumers can invest with confidence in the state's solar market over the coming years. By keeping energy dollars invested in New York communities, we calculate that the program will spur $8.3 billion dollars in local economic activity and support 10,000 local solar jobs. And its smart design puts the local industry on a growth path to provide New Yorkers with affordable, competitive solar free of direct state incentives. In other words, New York is busy reminding us that the sun does rise in the east!



## Rethinking the Grid

In order to take full advantage of the distinct benefits of solar and other clean technologies, we need to rethink the way our current grid is planned and operated.

The California PUC made it significantly easier for energy customers to pair a solar system with an energy storage device. Following a period of consumer uncertainty, the Commission decided to allow solar customers with energy storage to continue to qualify for the standard net metering program, and to exempt these customers from burdensome interconnection fees, standby charges and metering requirements. Responding to recommendations from Vote Solar and other parties, the Commission also required utilities to refund customers who were inappropriately charged these fees over the past year. Clearing the way for energy storage will help consumers bottle sunshine for times when we need that electricity most.

Nevada's biggest utility, NV Energy, formally filed to join the California Independent System Operator's Energy Imbalance Market (EIM). Vote Solar has long advocated for this regional approach to electricity markets, which helps break down the currently balkanized system and allows utilities to instead share generation resources. NV Energy's participation in the EIM mark forward progress for allow utilities across the region to avoid building expensive, redundant infrastructure and significantly lower the cost of keeping the lights on with significant new levels of solar and wind.

Building on the clean energy momentum of programs like NY-Sun and the Green Bank, New York regulators upped the ante by kicking off a major proceeding called "Reforming the Energy Vision" (REV). The REV aims to fundamentally rethink how electric utilities do

business. The main thrust is to move towards an energy landscape that is increasingly decentralized with consumers playing a more active role in climate-friendly energy decisions. Vote Solar is participating in these REV proceedings to help New York build a new system that unleashes the full potential of an inclusive, participatory solar marketplace.

## Helping Communities Go Solar Together

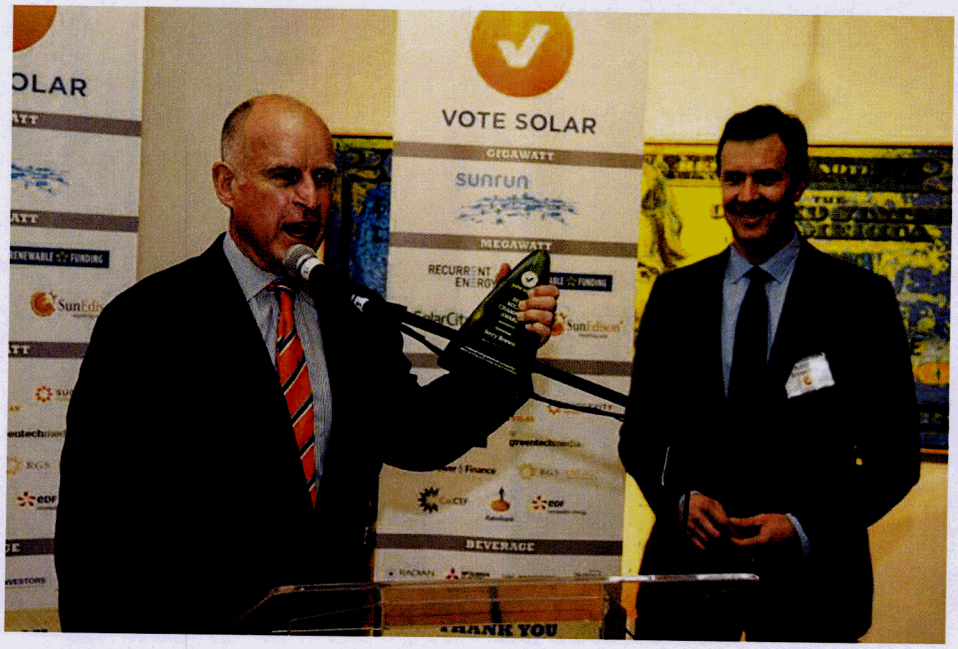
In 2014, Vote Solar's GroupEnergy programs helped more than 2500 homeowners sign contracts for nearly a megawatt of residential solar – all at prices 15-20% below average market installation costs. All of these new solar customers are real-world proof of solar progress in their communities.

We were excited to help solar shine brighter in the Windy City with. Alongside a host of partners including the City of Chicago, the Environmental Law and Policy Center and World Wildlife Fund, Vote Solar launched Solar Chicago with the goal of jumpstarting demand and identifying barriers in this nascent solar market. By pooling the buying power of Chicagoland homeowners, we were able to help deliver pricing that was below that of mature solar markets (like California), amazing! With over 2,000 participants in a three month period, Solar Chicago resulted in over 650 kilowatts of new residential contracts, which is DOUBLE what was previously installed community-wide. The program also helped reveal a number of steps the city and state can take to make it easier and more cost-effective for consumers to go solar in the future. Vote Solar prepared a report for the City with recommendations for making those improvements.

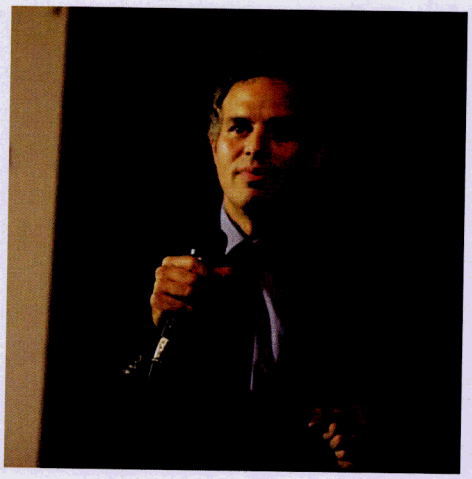
We also launched a second round of San Francisco's successful SunShares program to help some of the City's largest workforces come together to go solar and reduce greenhouse gas emissions. Now that's what we call an employee benefit. The impressive roster of 2014 participating employer organizations include the City and County of San Francisco, Arup, Genentech, Salesforce, the San Francisco Unified School District, the University of California at San Francisco, United Airlines and Virgin America.

## Good Times for the Solar Cause

Vote Solar is known for working hard, and playing hard, and our annual Equinox and new Equinox East celebrations really raised the roof for solar in 2014. We hosted 900 solar lovers at the Old Mint in San Francisco, and 200 revelers at the DUMBO Loft in Brooklyn. At the events, we honored Solar Champions California Governor Brown, New York Energy Czar Richard Kauffman, California PUC Commissioner Mark Ferron, and Vermont utility Green Mountain Power's CEO Mary Powell. And our favorite big green superhero, Mark Ruffalo, even joined in the fun in Brooklyn!




In September, our Climate Ride team pedaled 300 miles from New York City to Washington, D.C. to raise support and awareness for Vote Solar and other climate causes – and we had a ton of fun in the process. Pedal power and solar power: a perfect combination!



## New Organization, Same Great Work

We have come a long way since 2002, when Vote Solar was founded after a successful San Francisco ballot initiative to put solar on more city rooftops. We are still as focused as ever on turning grassroots support into smart policies that build solar scale. However, thanks to massive reductions in solar costs and successful market growth, the nature and scope of our work is quite different. Today we have fifteen staff located in six states serving markets from coast to coast - and we aim to grow from there. And we are excited to say that 2014 brought some significant organizational changes to help us meet those goals.

Since our founding, Vote Solar had operated as a fiscally-sponsored project of the Tides Center. In 2014 we successfully spun-off to form our own stand-alone 501(c)3 nonprofit organization. Our new standalone status will help us continue to grow and achieve Vote Solar's mission. We are exceedingly grateful for the support of the Tides Center over those many years and look forward to a new era of Vote Solar.

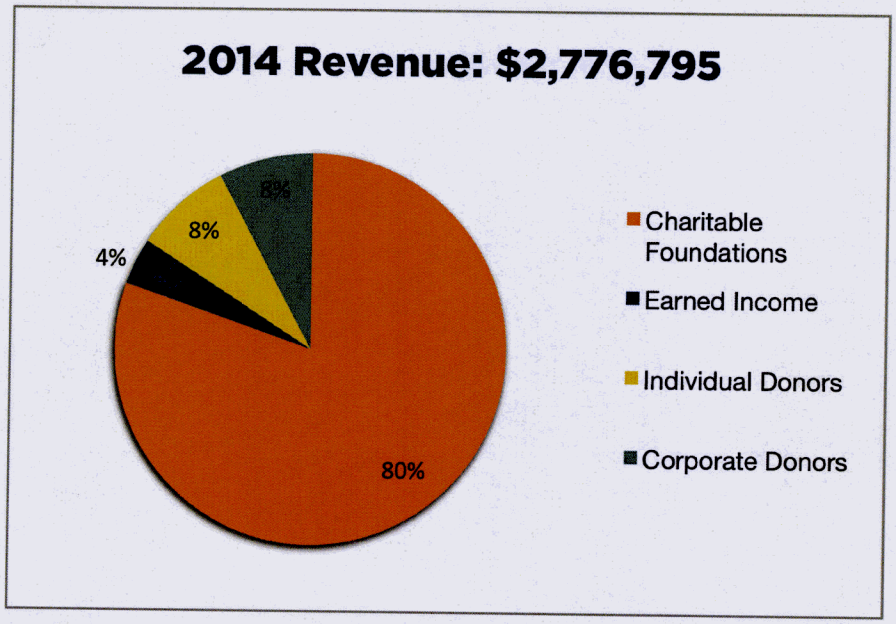
After more than a decade with our much-loved Golden Gate Bridge logo, we also unveiled a new look for Vote Solar in 2014. Our trusty Golden Gate logo signified a bridge to a sunnier energy future with a strong nod to our San Francisco roots, but it was high time for a new logo that better reflects our expanded scope of work and organizational vision.

We are honored and excited to be serving more of this incredibly diverse country of ours. The states we work in today run the gamut both in term of their policies and their politics. For us the single important unifying characteristic is that people overwhelmingly want more solar powering their homes, businesses and communities. Our goal is to continue to give solar supporters nationwide a voice in energy policy decision-making. Our new logo represents those figurative votes for solar.

VOTE SOLAR

# LEAN AND GREEN

Vote Solar has 15 staff in six states across the country working to build a clean energy economy, and we couldn't do it without the support of our donors. As a small-but-mighty organization, we our proud of the significant impact we are able to make with those generous donations.




# DONATE

Your contribution will directly support our continued efforts. We'll put it to use where it's most urgently needed in the fight for solar progress.

**Donate online at:**
https://secure.votesolar.org/page/contribute/donate

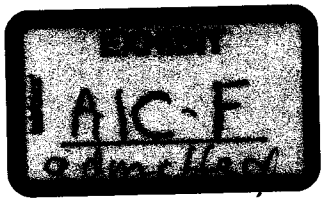
**Or if you prefer to send a check, you can mail to:**
Vote Solar, 360 22nd Street, Suite 730, Oakland, CA 94612

Vote Solar is a registered 501(c)3 nonprofit organization, and all contributions are tax-deductible. Vote Solar's tax identification number is 46-4396728.

# Utility Dive

# Report: Storage boom to rival solar as battery prices drop 40-60% by 2020

By Robert Walton | August 4, 2015




**Dive Brief:**

A report (http://arena.gov.au/files/2015/07/AECOM-Energy-Storage-Study.pdf) prepared by AECOM for the Australian Renewable Energy Agency predicts battery prices will fall 40-60% over the next five years, setting off a storage boom that could look similar to the growth in rooftop solar.

While all types of batteries are expected to see price reductions, the report found the largest reductions are likely to occur with li-ion and flow-battery technologies, with prices reducing from $550/kWh in 2014 to $200/kWh by 2020 for li-ion, and from $680/kWh to $350/kWh for flow batteries.

The report recommended the government agency work with industry participants such as technology suppliers and service providers to prepare for the boom and help create sustainable market structures.

**Dive Insight**

A report prepared for Austrlian renewable energy officials sees great potential in behind-the-meter storage, as prices fall and the technology proliferates along a path similar to the explosion in customer-owned rooftop solar.

"The rapid uptake of solar PV provides a useful analogy to what could occur in the energy storage market, as technology prices have potential to reduce as technology development simultaneously improves," the report concludes. "The behind-the-meter market segment of energy storage is widely expected to undergo a similar boom to the solar PV industry, with a tipping point expected within the next ten years."

But the report also cautioned that there are more risks involved with storage, in part due to the greater safety risks but also because of a wider range of applications and value streams, which could include frequency regulation for grid stability. As such, the report called for an active role for ARENA in facilitating storage market.

"By supporting the development of an efficient market for energy storage, ARENA will facilitate additional supply of renewable energy by addressing intermittency and power quality challenges that could otherwise stall growth in the market," the report found.

The report examines four key storage markets in the United States – Hawaii, California, Texas and New York – as well as Germany, Japan, South Korea and Italy.

**Recommended Reading**

Renew Economy: Energy storage 'megashift' ahead (http://reneweconomy.com.au/2015/energy-storage-megashift-ahead-battery-costs-set-to-fall-60-by-2020-2020)

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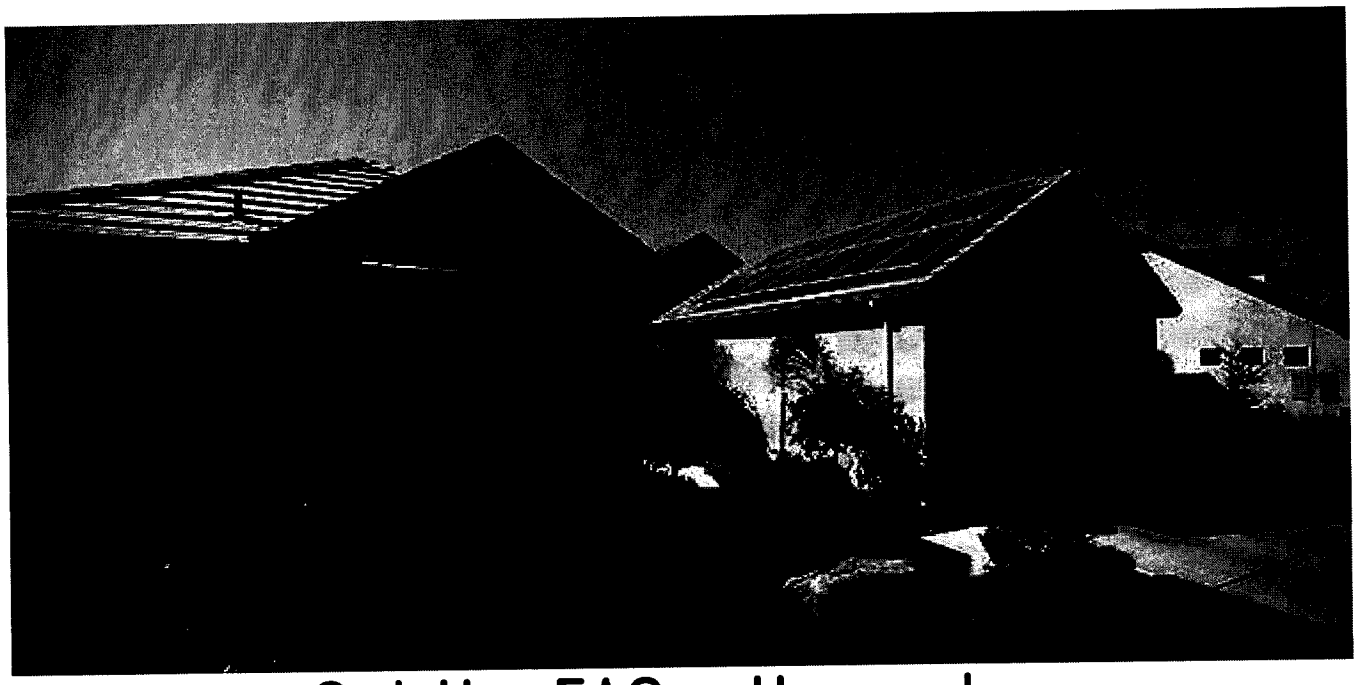
Top Image Credit: Tesla

## Filed Under:

Transmission & Distribution Energy Storage Distributed Energy Efficiency & Demand Response Technology

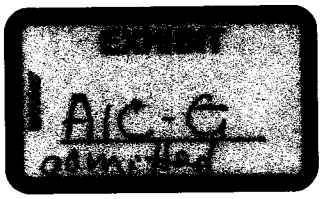


# Get the FAQs...then relax

## It's time to soak up the sun.

Get a Free Quote (https://gosolar.sunrun.com/151130b/?campid=SUNRUN2GOSOLAR)

## Going Solar



## Where is Sunrun available?

Sunrun is available in 14 states, listed below. You can read more about which utility companies Sunrun works with by clicking on each of the state links. If we're not in your neck of the woods, don't worry! We're expanding quickly and may be there any day.

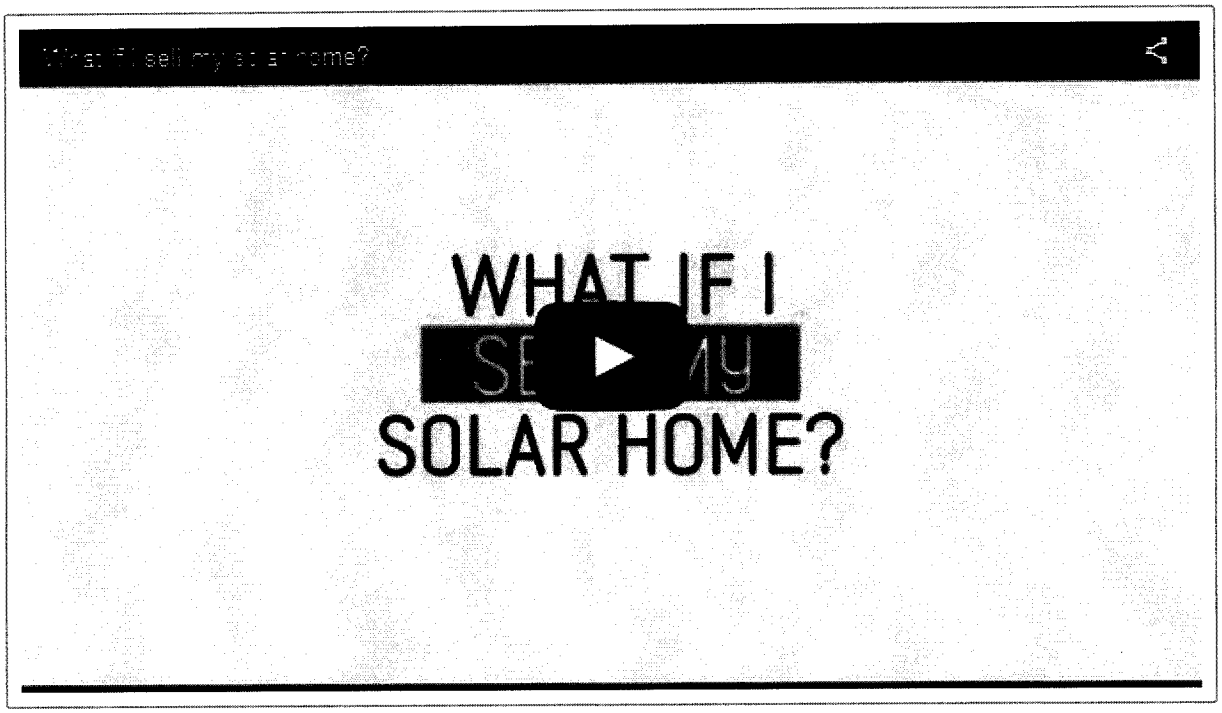
- Arizona (/solar-by-state/az)
- California (/solar-by-state/ca)
- Colorado (/solar-by-state/co)
- Connecticut (/solar-by-state/ct)
- Delaware (/solar-by-state/de)
- Hawaii (/solar-by-state/hi)
- Maryland (/solar-by-state/md)
- Massachusetts (/solar-by-state/ma)

- New Hampshire (/solar-by-state/nh)
- New Jersey (/solar-by-state/nj)
- New York (/solar-by-state/ny)
- Oregon (/solar-by-state/or)
- Pennsylvania (/solar-by-state/pa)
- South Carolina (/solar-by-state/sc)

# What happens if I move?

The hardest thing about moving isn't selling your home—it's saying sayonara to those beautiful, money-saving panels on your roof. That's right, no need to find a suitcase big enough to hold your solar panels. Sunrun makes it easy to transfer your solar lease agreement and pass along those ridiculously low energy bills to the new owners. Our Service Transfer Specialists handle everything from educating realtors and potential buyers, to working with escrow officers, title agents, home inspectors, and anyone else who might need to know about your system or solar lease agreement. Here are some tips to help ensure a smooth move:

- Connect with our Service Transfer team before your home goes on the market. We'll help prepare your realtor to sell the value of solar.
- Inform potential buyers early on that the solar lease agreement is a contingency of the home sale to avoid hiccups during negotiations.
- Once you've got a buyer, you'll both sign Sunrun's service transfer form and we'll run a credit check on the buyer.
- Then just send us confirmation that escrow has closed and you'll be home free.
- In the unlikely event that the buyer doesn't want to take on the agreement, you can prepay for the remainder of your service and bundle it into the selling price of your home.
- You can also buy the system outright and move it to your new home, but is generally easier and more cost effective to transfer the agreement.




## How will I pay for electricity when I have solar?

There you are, daydreaming about all the money you'll save by going solar (http://www.sunrun.com/solar-savings), the cleaner skies, the lower electric bill and the... wait. About that electric bill. What exactly happens to your bill when you make the switch to solar? Before you spend a single minute worrying about it, let us explain. Paying for electricity is no harder when you have solar. In fact, it's a lot easier because you won't have to worry about surprise rate hikes or hidden fees. Here's how it works:

- Your solar system will be connected to your local utility, and your energy usage affects how much you'll save.
- You'll owe less or even earn energy credit when you produce more electricity than you use.
- When you use more than you produce, say if you forget to turn off the AC, you could owe the utility company more.
- Annually, electricity costs will be lower with solar (http://www.sunrun.com/solar-lease/cost-of-solar), even though your savings will vary month-to-month due to seasonality—you'll earn more energy credits during summer's longer, sunny days than in winter's short ones, but they'll balance each other out over the course of a year.

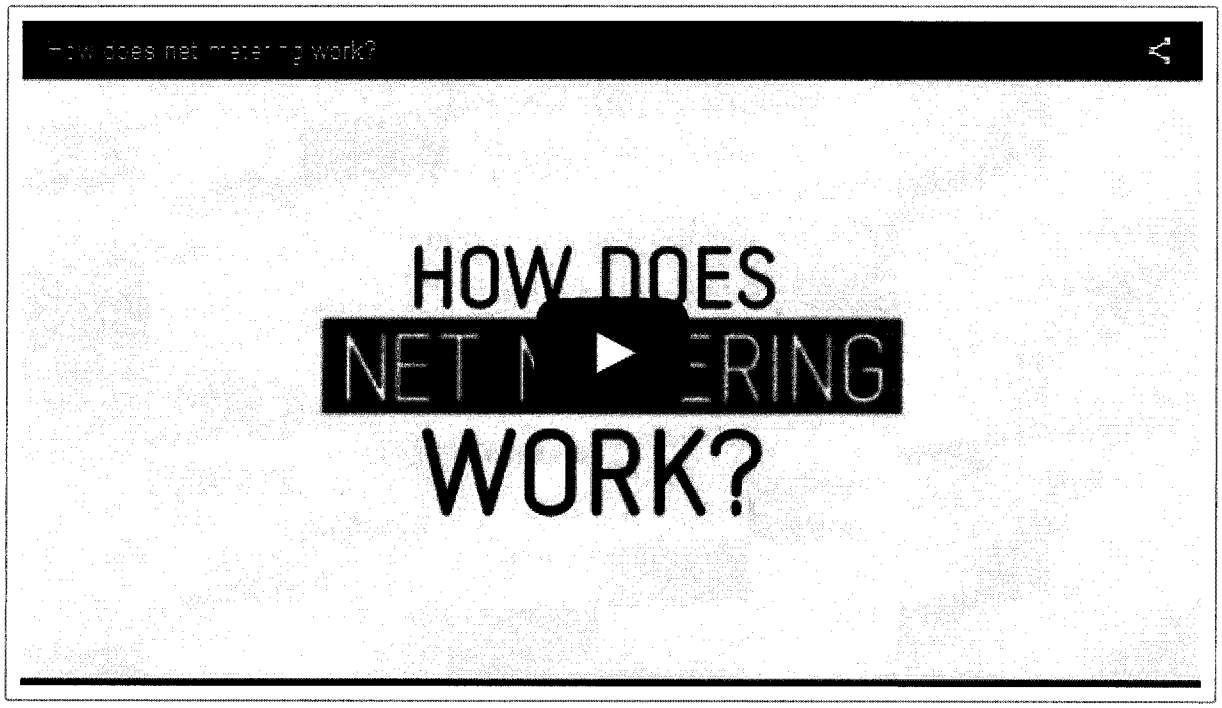
- You'll get two bills if you choose a monthly plan like most customers. One from the utility company and one from Sunrun. The Sunrun bill is your low, predictable solar rate. The utility bill covers any additional electricity used above and beyond what your solar system produces.

## Will I get credits from my utility with Sunrun?

Remember back in school when extra credit was kind of a big deal? Well now that you're thinking about going solar, it is again. That's because when your uber-efficient power-generating panels produce more energy than you need, you get automatic solar energy credit from the utility company. It's like they're paying you for once. Here's how it works:

- When the sun is up, your panels crank out energy like there's no tomorrow. If they produce more than it takes to power your life, that extra electricity is sent to the utility grid and you earn solar energy credit.
- When you have more power than you use, you owe the utility less.
- Conversely when you use more electricity than your system makes, like at night for example, when the sun is down, you draw from the grid.
- When you use more power than you make, you owe the utility more.

See? It's a give and take, but you don't have to lift a finger because the utility company's net meter keeps track of it all. You can expect to see some ups and downs on your utility bill throughout the year because you'll likely generate more power in the summer and less in the winter. But your total annual savings will be greater thanks to solar. Your system will be grid tied and you'll get credits from your utility when you're a Sunrun customer whether you choose to own your system or go solar through a lease or PPA.




## What if my panels don't produce enough power?

When the system is designed, we make sure it fits your household electricity needs to a tee, helping maximize your electricity savings (http://www.sunrun.com/solar-savings) over time. If the system produces less than predicted, we'll cover the difference.

## How many solar panels will I need?

Yup. Size Matters.You're ready for a highly efficient, money-saving solar power system on your roof. Great! So, what size home solar system should you have? Hey, you've got better things to do than worry about that. Which is why Sunrun will help handle all the details for you. Not only are we an experienced provider, we have proprietary solar design technology called BrightPath to help us create a customized system that maximizes energy production better and faster than if we did it by hand.

So instead of wracking your brain over "how many solar panels will I need?" or "what kind of inverter do I buy?", ask yourself these questions instead:

- How much power do I need? Check your electric bills to see how many kilowatts you use on an average day. A typical system generates 5 kilowatts per day but your home may need more or less.

- What's your climate like? The number of panels you need depends on how much solar radiation reaches the ground where you are. Believe it or not, solar can work well even if it's cloudy a lot!
- How much direct sun hits your roof? In general you'll need 100 square feet of south-facing roof space for every kilowatt of power, avoiding shadows from chimneys, trees or taller buildings. But don't worry, we can take a look and help with that, too.

# What happens at a solar installation?

After your sign your Sunrun agreement, you're ready for solar panel installation (https://www.sunrun.com/how-it-works/solar-panel-installation). Now the real fun begins! The best part? You don't have to lift a finger because we take care of everything from scheduling to submitting permits, to working with the city, and securing those big, beautiful panels to your roof. Naturally you'll have questions, and we'll be right there with you answering them every step of the way. Here's what you can expect:

- **Site Assessment**

A technician will visit you in your home to confirm your system design, verify measurements, and adjust for shade and obstructions on your roof. *Timing: 1-2 weeks*

- **Design Approval**

Following site evaluation, our solar design experts will make any necessary adjustments and email you for final approval. *Timing: 1-3 weeks*

- **Permitting**

Once you give the green light we'll submit your design to the city for permitting. The timing now depends on how quickly local government works and can take up to eight weeks. *Timing: 2-8 weeks*

- **Solar Installation** (https://www.sunrun.com/how-it-works/solar-panel-installation)

After your permit is granted we'll get to work placing those gorgeous new panels on the roof! *Timing: 2-5 days*

- **City/County Inspections**

When construction is finished, the city or county will do a final inspection before your system can be connected to the grid. *Timing: 1-4 weeks*

- **Utility Interconnection**

Now you're in the home stretch. We'll submit your documents to the utility company and they'll install a net meter allowing Sunrun to track how much solar electricity you produce and use. *Timing: 3-6 weeks*

- **Power Up and Start Saving**

When the utility company grants Permission to Operate, that means you're free to flip the switch and start generating clean, affordable, money-saving energy right from your roof. Congratulations, you're in!

# How does Sunrun compare to other solar companies?

You have a choice when it comes to solar providers. Actually, a lot of choices. With everybody vying for your business, your ability to compare solar companies (http://www.sunrun.com/why-sunrun) effectively is critical. And since you'll be working with your provider for the life of your system you'll want to choose an established one you can count on for the long haul.

| | sunrun | Industry Standard |
|---|---|---|
| Guarantees Production? | Yes | No |
| Roof Warranty | 10 years, regardless of whether your roof has a warranty. | 10 years, regardless of whether your roof has a warranty. |
| Free overproduction? | Yes | No |
| Free Monitoring? (Provided wireless signal vs. customer owned internet) | Yes | No |
| Exclusive focus on residential solar? | Yes | No |

**Sunrun direct sales PPA compared to SolarCity and Vivint Solar PPA, and SunPower and NRG lease. Claims based on contracts created in February, May, & July 2014

Here are some other key things to look for:

- A high volume of positive ratings and a great track record of service before, during and after installation.
- The best solar companies will make it easy by taking care of the paperwork, inspections, and working with the city.
- Flexible payment options including lease agreements and PPAs.
- Lifetime maintenance on your system should be included, not an add-on.

- An honest provider won't sell you solar if it can't save you money—insist on a performance guarantee.
- Choose a provider with the most residential experience.

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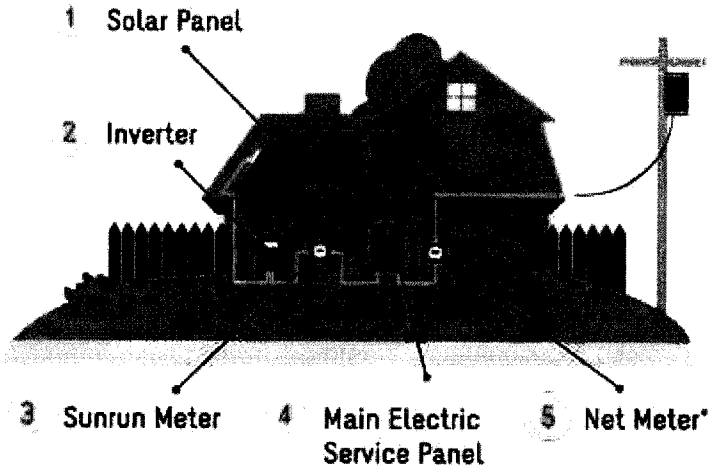
# Solar Basics

## What's a solar lease or PPA?

Until recently, you couldn't go solar without buying your system outright, and that meant hefting over a small fortune—we're talking anywhere from $18,000 to $25,000 up front, and maintenance and repairs are extra. Knowing there had to be a more affordable way to bring clean energy to the people, we invented solar leasing and power purchase agreements, or PPAs. So instead of waiting years for a return on your investment, most Sunrun customers see big savings in just the first year.

- The difference between a solar lease (http://www.sunrun.com/solar-lease) and solar PPA is simple: With a lease you pay a fixed monthly "rent" in return for use of the system. With a PPA you pay a fixed price per kWh for power generated.
- Both often require $0 down.
- It's hassle free—your provider handles installation, maintenance and repairs for the life of the agreement.
- You're entitled to all the energy your system produces, including any excess energy credits.
- You can transfer the agreement easily if you sell your home.
- Your provider passes down savings from rebates, tax incentives, and credits in the form of a lower bill.
- Flexible financing options let you pay as you go, or you can maximize savings with a prepaid option that eliminates monthly billing from Sunrun.
- Still think solar's out of reach? Learn all about how it works, then get your free quote.

## How does a solar system work?




1. **Solar Panels**
   Convert sunlight to direct current (DC electricity)
2. **Inverter**
   Converts the DC electricity produced by the panels into alternating current (AC electricity).
3. **Sunrun Meter**
   Monitors system production and sends the information to Sunrun through a wireless signal.
4. **Main Electric Service Panel**
   Solar electricity from inverter flows through this service panel to your home or the grid.
5. **Net Meter**
   Reads electricity that you use from the grid as well as the excess solar electricity that flows into the grid from your solar system.

# What are tiered utility rates?

Tiered utility rates are a structure in which the more electricity you use, the higher your rate gets. You are allowed a certain amount of power (kilowatt hours) in each tier. Once you've exceeded the amount in the tier, you move into the next highest tier. The lower tier rates are affordable and the higher tier rates are very expensive. In many cases, we'll recommend a system that only offsets only your expensive tiers to help you maximize your savings. Solar systems built for people with tiered rates often are designed to eliminate the expensive high tier electricity from your utility.

# Sunrun Partners

## If I go solar with Sunrun, who will do my installation?

Depending on where you live, Sunrun or one of our certified installer partners will do the installation. We partner city-by-city with local installers. They not only know the ins and outs of installing in your neighborhood, it also keeps thousands of jobs local. You can find a list of Sunrun's local installers below.

## I heard about Sunrun through another solar company. How does Sunrun work with partners?

Top drawer. Crème de la crème. The A-team.

Partnership is one of those terms that's easy to throw around. But at Sunrun, it really means something. Our nationwide network of certified partners are the bedrock our business because they allow us to provide stellar Sunrun service where you live. How's that for convenience?

What's more, they're are a huge part of why it's so easy to go solar with Sunrun.We only work with the best of the best so you can rest easy knowing that whether Sunrun installs your system or one of our trusted partners does, you'll have top-notch service as long as you're a customer.

# Sunrun certified partners:

- 1st Light Energy
- 360 Management Group, Inc.
- 360 Solar Energy
- Acos Energy LLC

- AGR Group
- All Seasons Solar
- Amergy Solar Inc.
- American Electric
- American Solar
- Arcadia Solar Solutions, LLC
- Argent Solar Electric
- Arise Solar
- Arizona Solar Solutions
- ASI Heating, Air & Solar
- Bland A/C and Heating, Inc.
- Bonterra Solar Hawaii
- C-TEC SOLAR
- Clean Solar
- Complete Solar Solution
- Corbin Electrical Services Inc.
- DRH Solar and Electrical
- Eco Solar
- Enlighten Power Solutions
- Green Engineering Solar Corp
- Green Homes of California
- Harmon Solar
- Harvest Power
- Heliopower
- Horizon Solar Power
- IES
- Imagine Energy
- Infinity Solar Systems
- Islandwide Solar
- Kopp Electric Company
- LG Energy (Hi-Tech Remodeling Group)
- LGCY Power
- Munro
- Neil Kelly
- Next Step Living
- OnForce Solar
- Onforce Solar Inc.
- Precis Solar
- Premier Solar Solutions
- RCL Enterprises, Inc

- Reliable Power Services
- Responsible Solar
- RevoluSun
- Rising Sun Solar
- Smart Energy Solar
- Solar Alliance of America
- Solar Energy World
- Solar Optimum
- Solar Service Center
- Solar Universe
- SolarFlair Energy, Inc.
- Solaris Energy
- SolarMax Technology Inc.
- SolarUnion DBA
- Solcius
- Standard Energy Solutions
- Start To Finish Solar
- Streamline Solar Power Systems LLC
- Summerwind Solar LLC
- Sun Phase Energy
- Sun Time Energy
- Sunlight Solar
- SunLux Energy
- Sunny Energy LLC
- Sunpro Solar
- Sunrun Installers
- SunWize Home
- Synergy Solar
- Taylor Energy
- Trinity Solar
- Uptown Solar
- Valley Solar Solutions

Looking to partner with Sunrun? Learn about our partnerships (/partner-with-us).

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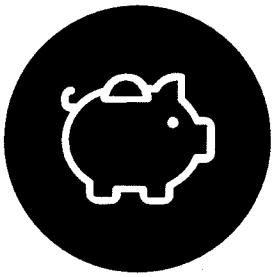
CATEGORIES

Going Solar

Solar Basics

Sunrun Partners



(/solar-lease/cost-of-solar)

## cost of solar (/solar-lease/cost-of-solar)

Electricity rates are skyrocketing but the cost of solar panels (/solar-lease/cost-of-solar/solar-panels) has never been lower. Learn why now's the time to switch.

(/solar-lease)

## solar leasing (/solar-lease)

No need to buy. Learn how to get a solar lease (/solar-lease) or PPA for as little as $0 down.

(/solar-by-state)

## where we are (/solar-by-state)

Solar in 14 states (/solar-by-state) and growing! If we aren't in yours yet stay tuned, we are rapidly growing.

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INVESTORS (HTTP://INVESTORS.SUNRUN.COM) CAREERS (/ABOUT/SOLAR-CAREERS)

PARTNER DIRECTORY (HTTP://WWW.SUNRUN.COM/HOW-IT-WORKS/FAQ#ITEM-2406)

WHERE'S SUNRUN?

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# Solar firm's home battery systems target SRP fees

Ryan Randazzo, The Republic | azcentral.com *6:11 p.m. PDT April 22, 2015*

*(Photo: John Samora/The Republic)*

A Scottsdale solar installation company is offering solar panels with batteries to help homeowners avoid the high "demand charge" Salt River Project recently approved for new solar customers.

The batteries will ensure customers don't set a high, momentary demand for power that will trigger steep fees from the utility.

SRP officials said the utility's new rate design will encourage customers to reduce their maximum demand on the utility grid. In the Phoenix area, the highest electricity use occurs in late summer afternoons, when air-conditioners crank up and, unfortunately, the sun is low in the sky and solar panels are not at their maximum output.

"If Arizona residents want to go solar, we are committed to finding a solution," American Solar and Roofing President/CEO Joy Seitz said. "It took a lot of manpower we had to invest to find a solution. I wouldn't say (SRP) was right (to charge higher solar fees), but in the world of running a business, you either play the game or leave. And we are committed to figuring it out."

SRP approved a new rate plan for solar customers in February that charges them less for electricity than current rate plans — about 4 cents per kilowatt-hour versus about 10 cents under a regular plan — but also a demand charge based on their highest use of electricity in a 30-minute period during the on-peak hours in the month.

**RELATED:** APS asks to raise solar fees (/story/money/business/2015/04/02/aps-asks-raise-solar-fees/70848750/)

**RELATED:** Rooftop-solar billing issues far from settled (/story/money/business/2015/03/02/rooftop-solar-billing-issues-far-settled/24255847/)

**RELATED:** SRP board OKs rate hike, new fees for solar customers (/story/money/business/2015/02/26/srp-board-oks-rate-hike-new-fees-solar-customers/24086473/)

The demand charges would average about $80 a month for the average solar customer with a peak demand of about 8.5 kilowatts each month, according to SRP.

That charge could be lowered to $32 for a customer with a peak demand of 4 kilowatts, but also could rise sharply if the demand goes higher. A 14-kilowatt peak brings a fee approaching $200 for the month, all before the costs of electricity and other services are included in the bill.

American Solar will offer solar arrays for customers designed specifically to avoid the demand charges from SRP and reduce afternoon peak loads.

The company's $30,000 solution involves aiming solar panels to the west, to capture the maximum late-afternoon sun. Most panels today are installed facing south, to capture the highest amount of sunshine year-round and maximize annual energy production.

American Solar also will equip the homes with lithium-ion batteries that can charge during midday when solar production peaks, and dispatch power in late afternoon to minimize power being drawn from the utility.

Key to the system is a controlling device made by German manufacturer SMA, which will allow the system to be programmed around SRP's rates, or any other utility that implements demand charges, Seitz said.

## In brief

American Solar and Roofing is offering rooftop solar panels with batteries.

The $30,000 systems with German technology to control the charge and discharge of batteries will help offset new solar demand charges at Salt River Project.

The company anticipates a 14-year payback on the systems.

*Source:* American Solar and Roofing.

Seitz added the batteries and SMA technology to the solar panels on her home and commissioned it earlier this week. The company has an arrangement with SMA to use the company's technology in the U.S., and hopes to design systems for solar installers in other utility territories with similar rates.

SRP spokesman Scott Harelson said the utility was anticipating this type of technology when it proposed the demand charge.

"The new price plan was designed to accommodate new technologies or consumer behaviors," he said. "Battery storage is one of those technologies. There are numerous other very interesting technologies and energy management tools that are being studied and deployed to manage energy demand and we anticipate they will also be used in our service territory in the near future."

SRP has been battling the perception that its new rates are killing solar deployment in its service territory, which includes nearly 1 million customers. The number of customers that have applied to interconnect new solar arrays in SRP territory since the new rates took effect has plummeted.

The company has gotten fewer than 100 applications for rooftop solar panels since Dec. 8, the last day to get in under the old rate plan, according to a public database maintained by the utilities. A year ago, the company was getting several hundred applications a month.

The $30,000 price tag American Solar is quoting would cover a 7-kilowatt solar array with batteries. It's about a $7,000-$8,000 premium over the same-sized array from the company without the batteries and SMA technology.

**The residential design manager of American Solar and Roofing, Chuck Adams, left, in blue with no hard hat, talks to with SRP engineers, Joel Dickenson, center, and Ernie Tom about the interface between the power grid and a new solar power inverter that just installed at a Phoenix home.** *(Photo: John Samora/The Republic)*

"Yes, the price is a little more expensive, but you are still not completely priced out," Seitz said. "You can still get a payback."

The higher price means it will take an estimated 14 years to pay off the system with lower electricity bills, American Solar estimates.

"But we foresee pricing coming down drastically because the cost is the lithium-ion battery and inverter," Seitz said. "I look forward to that pricing coming down and working with the utility in the short run for an incentive program to install storage."

SRP managers often referred to load controllers during their rate-hike process as a technology that could help customers avoid demand charges, but American Solar officials said that technology, which shuts off appliances to limit demand charges, is too expensive and impractical for most homeowners.

American Solar also hopes to use the system design in Arizona Public Service Co. territory. That utility recently announced a pilot project where 100 homes will be placed on a demand rate and equipped with battery storage.

Rooftop solar industry leader SolarCity Corp. has installed battery storage in hundreds of homes in California as part of its own test, but Seitz said the American Solar design is different because it is designed specifically to avoid utility demand charges, not to simply store power for when the sun sets.

Meanwhile, Tesla Motors is expected later this month to make an announcement regarding its own batteries for home power use.

Some consumers are eager for batteries to hit the market, including Bob Emmelkamp of Mesa, who was among the first SRP customers to install rooftop

solar in 2004.

SRP "grandfathered" the rates for customers like Emmelkamp who already had solar, but because he is an early adopter of solar, he only has about 10 more years under his current rate plan before SRP will impose a demand charge on him.

For that reason, he is keeping an eye out on what he will do when that time comes.

"This is the type of innovation that is going to be needed," he said of the American Solar plan. "Personally, I understand where the utilities are coming from. The problem we have in Arizona is peak sunshine does not match up with peak usage. This battery technology allows that (alignment) to happen."

**In brief**

American Solar and Roofing is offering rooftop solar panels with batteries.

The $30,000 systems with German technology to control the charge and discharge of batteries will help offset new solar demand charges at Salt River Project.

The company anticipates a 14-year payback on the systems.

*SOURCE: American Solar and Roofing.*

*Reach the reporter at ryan.randazzo@arizonarepublic.com.*

Read or Share this story: http://azc.cc/1yUj87A

EXHIBIT

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# 2015 Q4 REVIEW

March 10, 2016

**Creating a planet run by the sun**

# Safe Harbor & Forward Looking Statements

This presentation contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934, which statements involve substantial risks and uncertainties. Forward-looking statements in this presentation include, but are not limited to, statements related to financial and operating guidance and expectations for our first quarter and full year 2016, momentum in our business and our business strategies, expectations regarding customers, cost reduction, project value, MW booked, MW deployed, product mix and NPV as well as our ability to raise debt and tax equity, manage cash flow and liquidity, leverage our platform services and deliver on planned innovations and investments including in products, services, sales and facilities as well as expectations for our growth, the growth of the industry, macroeconomic trends and the legislative and regulatory environment of the industry.

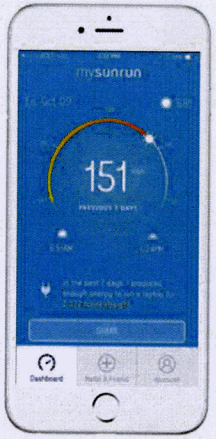
These forward-looking statements are subject to a number of risks, uncertainties and assumptions. The risks and uncertainties that could cause our results to differ materially and adversely from those expressed or implied by such forward-looking statements include: the availability of additional financing on acceptable terms; changes in the retail prices of traditional utility generated electricity; changes in policies and regulations including net metering and interconnection limits or caps; the availability of rebates, tax credits and other incentives; the availability of solar panels and other raw materials; our limited operating history, particularly as a new public company; our ability to attract and retain our relationships with third parties, including our solar partners; our ability to meet the covenants in our investment funds and debt facilities; and such other risks and uncertainties identified in the registration statements and reports that we have filed with the U.S. Securities and Exchange Commission, or SEC, from time to time. You should not rely on forward-looking statements as predictions of future events.

Although we believe that the expectations reflected in the forward-looking statements are reasonable, we cannot guarantee that the future results, performance or events and circumstances reflected in the forward-looking statements will be achieved or occur. All forward-looking statements in this presentation are based on information available to us as of the date hereof, and we assume no obligation to update publicly these forward-looking statements for any reason, except as required by law.

# We are creating a modern, customer-centric energy infrastructure

## Value to Customer

- Save 20% or more on electricity over initial 20-year agreement
- No or low upfront cost, low annual escalators
- Worry-free service, maintenance, and repairs included
- Agreement easily transferable in case of home sale



# Sunrun's strategy drives durable competitive advantage

## Project Value & NPV Maximization

- History of focus on high revenue markets and customers, premium service
- Smart customer targeting
- Residential-only focus

## Cost Structure

- Cost advantages from scale
- Unique advantage from monetizing platform services
- Broad multi-channel distribution leads to lower customer acquisition cost

## Flexibility

- Low cost debt and tax equity runway into Q4[1] with attractive advance rates and low capital costs
- No recourse debt outside working capital line, due 2018
- Blend of fixed and variable costs

(1) Includes executed term sheets.

# Sunrun delivered strong growth and focus on value creation in Q4 2015

## 80 MW Booked

**117%** year-over-year growth

## 68 MW Deployed

**83%** year-over-year organic growth

## 596 Cumulative MW Deployed

**52%** increase year-over year
**2nd** largest residential fleet

## $4.50 Project Value Per Watt

Compared to $4.70 in Q3 2015

## $3.64 Creation Cost Per Watt

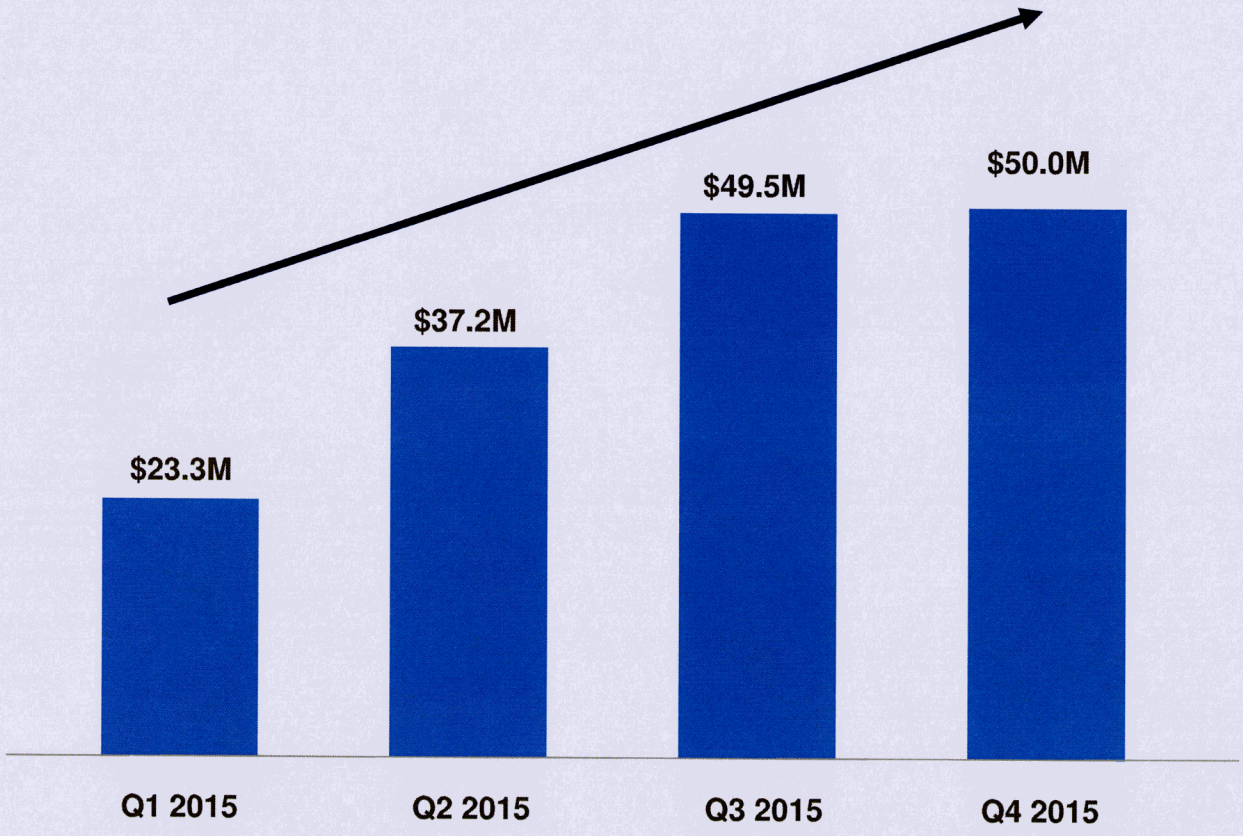
**$0.72** or **17%** decrease from Q1 2015

## $50M NPV Generated

**115%** growth over Q1 2015

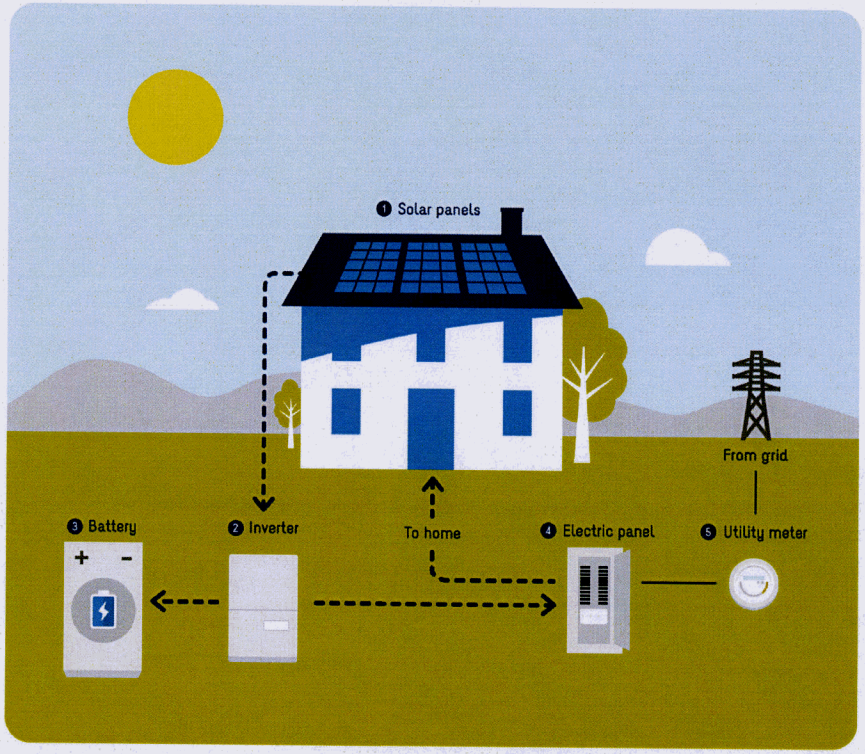
See appendix for glossary of terms.

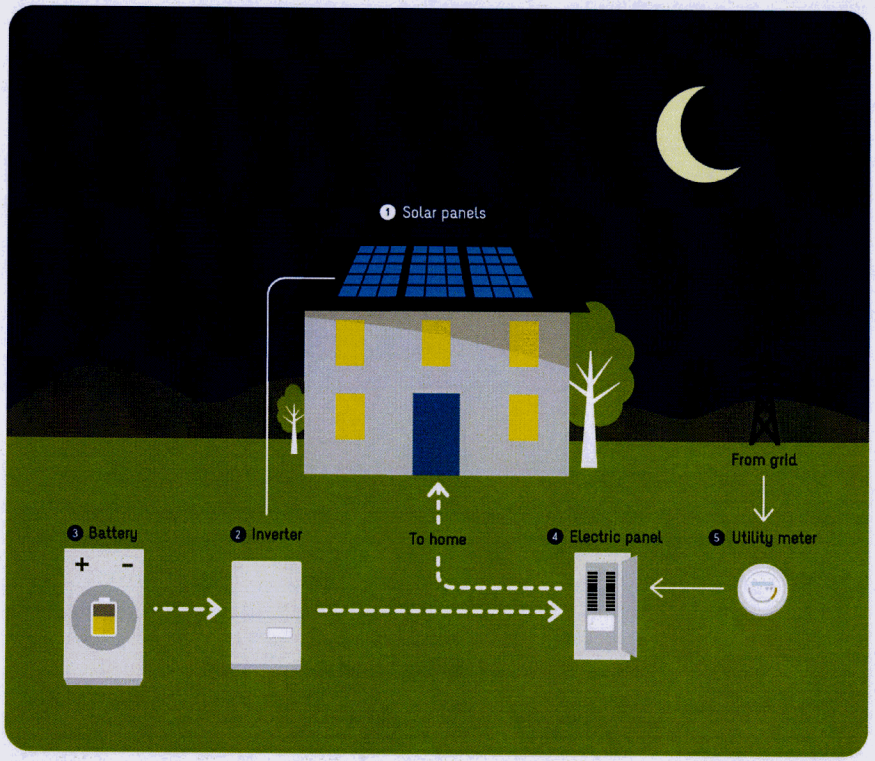
# Q4 2015 NPV grew 115% from Q1 2015




See appendix for glossary of terms.

# Commercialization of storage and energy management allows Sunrun to expand the in-home offering

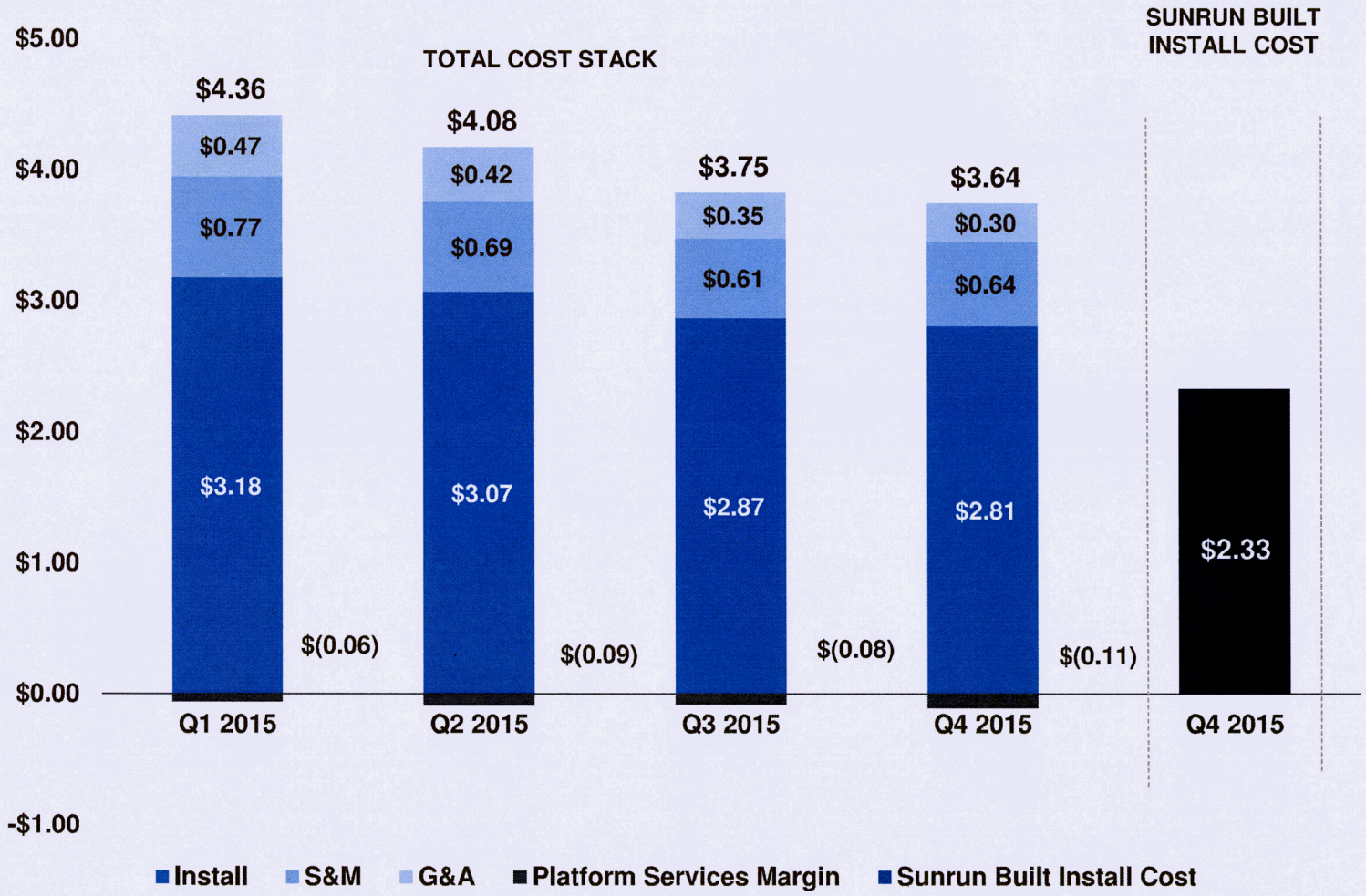



See appendix for glossary of terms.

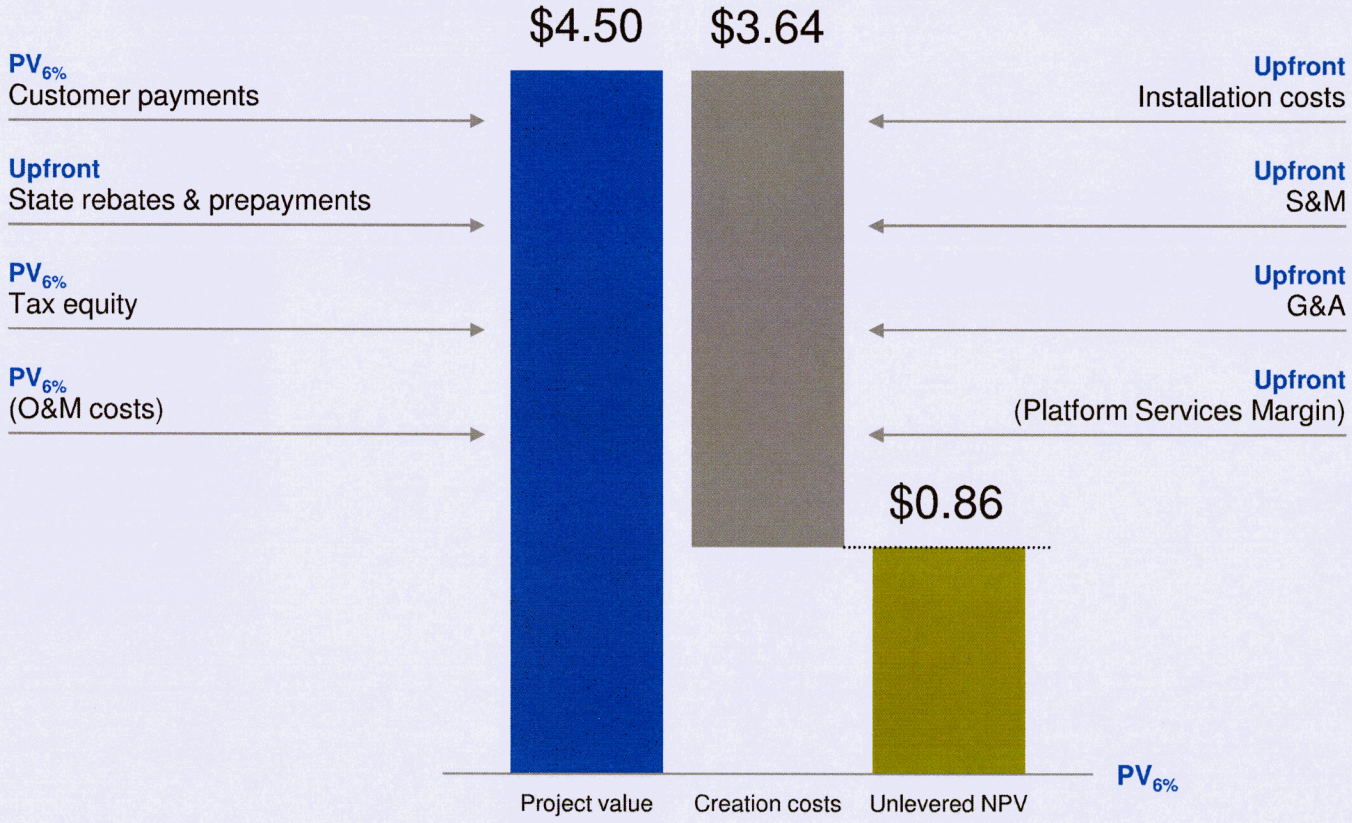
# Sunrun continues to realize rapid cost reductions

## Sunrun built install cost at $2.33 / watt




See appendix for glossary of terms.

# We generated unlevered NPV of $0.86 per watt in Q4




See appendix for glossary of terms.

# $1.5B in retained value and $1.0B in net retained value

| | |
|---|---|
| **Gross Retained Value (6%)** as of December 31, 2015 | **$1,517** |
| - Long-term debt | ($343) |
| - Lease pass-through financing | ($157) |
| - Line of credit | ($195) |
| + Cash and cash equivalents | $213 |
| **Net Retained Value** | **$1,035** |

$2.33
per watt

See appendix for glossary of terms.

# High quality of our assets is recognized by the markets

## Performance Exceeds Expectations

- Total cumulative production has exceeded forecast production to date
- Cumulative solar electricity production approaching 1,400 GWh to date

Production over-performance

## Customer Pay Their Bills

- Sunrun's credit standards yield a high credit customer pool
- Cumulative lost billings rate since inception is less than 1.0% (1)

**< 1%** Cumulative loss rate on billings

## Easy To Transfer

- In-house service transfer specialists successfully completed thousands of service transfers to date
- Service transfers achieve an average of 99% in total NPV recovery (2)

**~99%** Service transfer recovery rate

## Market Believes in Quality

- First securitization in sector to achieve a single A rating
- Class A notes priced at 4.4%, competitive with commercial bank debt

Rewarded with low cost of capital

Note: All figures represent fleetwide statistics as of December 31, 2015.

(1) Losses include uncollected recurring billings 5 months after invoice date, write downs and appeasement credits.

(2) Based on analysis of completed service transfers for monthly customers; Recoveries >100% arise from prepayments.

# Supply of tax equity from both new and existing Sunrun investors remains strong

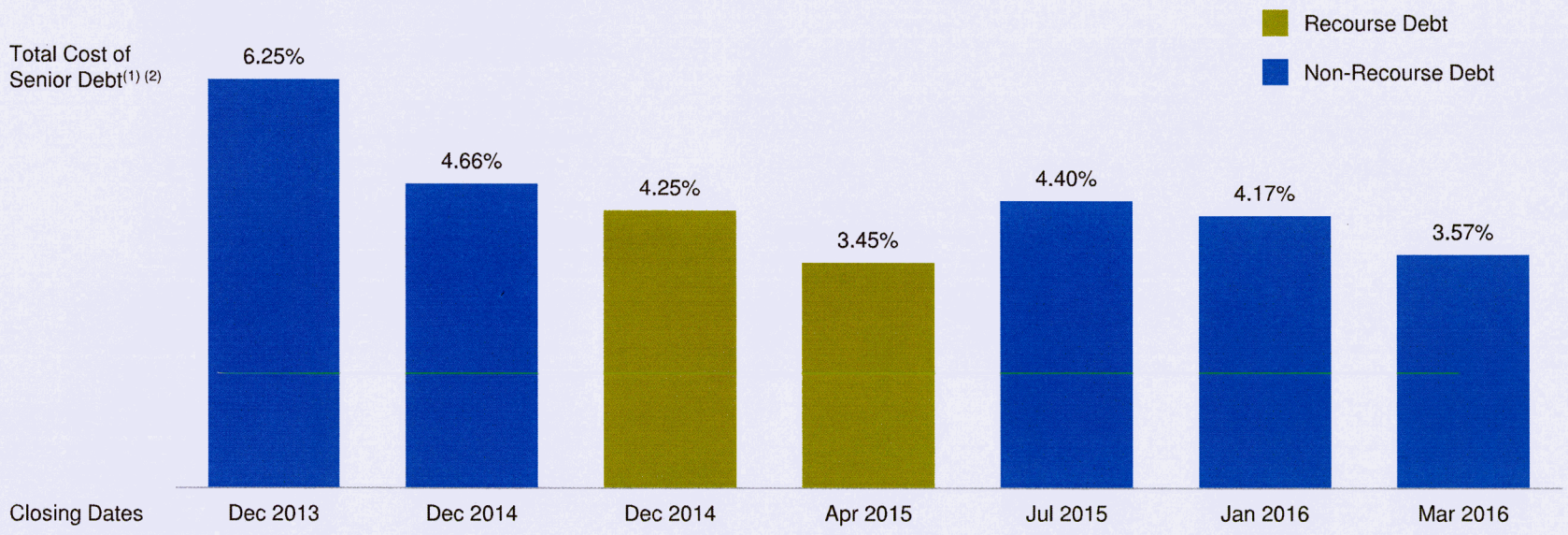
- In 2015, Sunrun focused on adding new tax equity investors. As a result, we have a large stable of existing relationships to support our growth in 2016 & 2017, as all 2014 and 2015 investors have expressed interest in another transaction.
- Relationships with individual counterparties are increasing. From 2010 to 2015, the MW capacity of the average Sunrun tax equity fund grew 240%. From 2014 to 2015, average MW per Fund grew 40%.
- As of today, Sunrun has committed tax equity financing or executed term sheets to provide tax equity capital to fund our forecasted growth into November.

**Tax Equity Investment Amounts(1)**

| Year | MW Funded | New Investors | Repeat Investors | Total Dollars |
|---|---|---|---|---|
| 2008–2012 | 173 | $316 | $380 | $696 |
| 2013 | 86 | 181 | 100 | 281 |
| 2014 | 170 | 0 | 470 | 470 |
| 2015 | 238 | 300 | 262 | 562 |

(1) Dollar amounts in millions
See appendix for glossary of terms.

# As performance track record has aged, credit costs have come down as market has deepened




| | | | | | | | |
|---|---|---|---|---|---|---|---|
| **Size of Debt Issuance(2)** | **$38.0** | **$195.4** | **$50.0** | **$205.0** | **$111.0** | **$250.0** | **$24.5** |
| **Cumulative # of Counterparties(2)** | **6** | **12** | **12** | **15** | **19** | **19** | **19** |

Note: Proceeds from several credit facilities have been used in part to repay previous indebtedness.

(1) Total Cost of Debt is equal to the fixed interest rate for fixed-rate debt instruments, or, for variable instruments, the actual interest rate incurred if the debt facility has been repaid, or, if a current debt facility, the spread plus the actual or estimated LIBOR swap rate, including swap premium.

(2) Total Cost of Debt in the graph excludes two subordinated term loans entered into in Dec 2014 and Jan 2016 at 6.00% and subordinated notes issued in July 2015 at 5.38%. The dollars raised in these subordinated debt facilities are reflected in the two lines below the chart.

See appendix for glossary of terms.

# Combining Sunrun's 2016 realized cost of debt and a 10% cost of project equity results in a 6% retained value discount rate.

- Given the 4.5%[1] cost of debt Sunrun secured in January 2016, and assuming a 70% advance rate, a retained value discount rate of 6% implies the discounting of contracted equity cash flows at about 10%.
- If cost of equity were 8.0%, the retained value discount rate for contracted cash flows would be appropriately 5.5%. If cost of equity were 12.0%, it would be appropriately 6.7%.

| | Cost | % of Capital | Total |
|---|---|---|---|
| Project-level debt [1] | 4.5% | 70.0% | 3.1% |
| Project-level equity | 9.6% | 30.0% | 2.9% |
| Capital | | | 6.0% |

| Net RV Discount Rate Sensitivity | |
|---|---|
| Cost of Equity | Implied Cost of Capital |
| 8.0% | 5.5% |
| 10.0% | 6.1% |
| 12.0% | 6.7% |

(1) Weighted average between A and B tranches. Assumes credit facility was swapped given market rates on March 9, 2016.
Analysis considers only contracted portion of customer cash flows

# Guidance

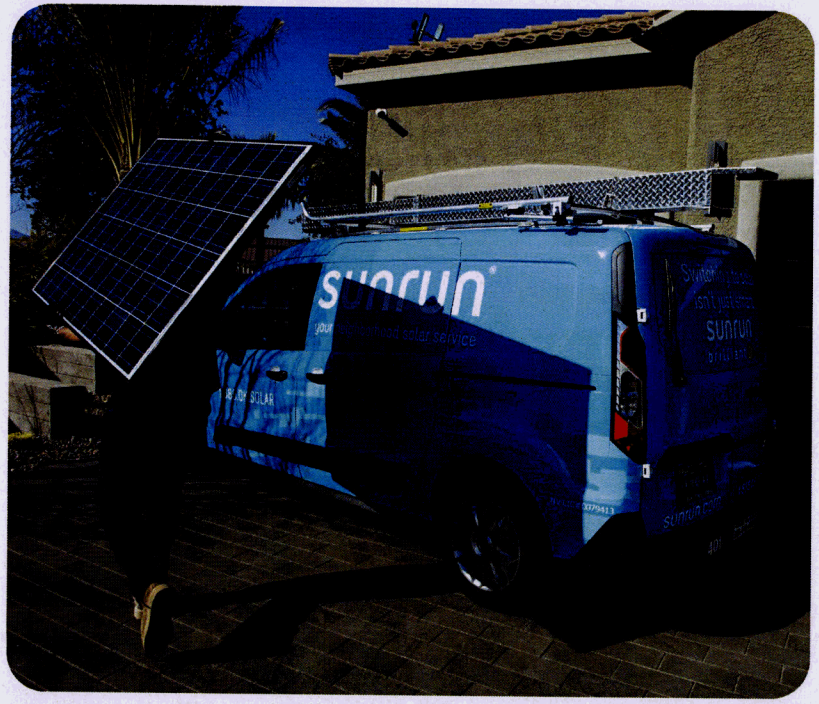
## 2016 Deployments

**Annual Growth Rates**

- ~100% for Sunrun deployed systems
- ~40% overall

**MW**

- 56 MW in Q1 (excludes ~12 MW of Nevada backlog not built due to market exit)
- ~285 MW in 2016



# Question & answer

# APPENDIX: Key Operating Metrics

| | Year ended | |
|---|---|---|
| | Dec. 31, 2014 | Dec. 31, 2015 |
| MW Booked (during the period) | 163 (1) | 274 |
| MW Deployed (during the period) | 130 (1) | 203 |
| Cumulative MW Deployed (end of period) | 393 | 596 |
| Estimated Nominal Contracted Payments Remaining (in millions) | $1,597 | $2,404 |
| Estimated Retained Value (in millions) | $1,000 | $1,517 |
| Estimated retained value under energy contract (in millions) | $643 | $1,029 |
| Estimated retained value of purchase or renewal (in millions) | $357 | $487 |
| Estimated retained value per watt | $2.40 | $2.33 |

| | Three months ended | |
|---|---|---|
| | Dec. 31, 2014 | Dec. 31, 2015 |
| MW Booked (during the period) | 37 | 79 |
| MW Deployed (during the period) | 37 | 68 |
| Cumulative MW Deployed (end of period) | 393 | 596 |
| Estimated Nominal Contracted Payments Remaining (in millions) | $1,597 | $2,404 |
| Estimated Retained Value (in millions) | $1,000 | $1,517 |
| Estimated retained value under energy contract (in millions) | $643 | $1,029 |
| Estimated retained value of purchase or renewal (in millions) | $357 | $487 |
| Estimated retained value per watt | $2.40 | $2.33 |

(1) Includes 14.7 MWs associated with purchase of asset portfolio in the second quarter of 2014.

# APPENDIX: Key Operating Metrics

| | Three Months Ended | | | | Year Ended |
|---|---|---|---|---|---|
| | March 30, 2015 | June 30, 2015 | Sept. 30, 2015 | Dec. 31, 2015 | Dec. 31, 2015 |
| Project Value (per watt) | $5.02 | $5.00[1] | $4.70 | $4.50 | $4.76 |
| Creation Costs (2) (per watt) | $4.36 | $4.08 | $3.75 | $3.64 | $3.89 |
| Unlevered NPV (per watt) | $0.66 | $0.92 | $0.95 | $0.86 | $0.87 |
| NPV (in millions) | $23 | $37 | $50 | $50 | $160 |

(1) Excludes materially all SREC value.

(2) Excludes IDC costs paid prior to deployments and excludes non-cash items such as amortization of intangible assets and stock-based compensation, and contingent consideration related to an acquisition

# APPENDIX: Glossary

**MW Booked** represents the aggregate megawatt production capacity of our solar energy systems sold to customers or subject to an executed customer agreement, net of cancellations.

**MW Deployed** represents the aggregate megawatt production capacity of our solar energy systems, whether sold directly to customers or subject to customer agreements, for which we have (i) confirmation that the systems are installed on the roof, subject to final inspection or (ii) in the case of certain system installations by our partners, accrued at least 80% of the expected project cost.

**Customers** refers to residential customers with solar energy systems that are installed or under contract to install, net of cancellations.

**Estimated Nominal Contracted Payments Remaining** equals the sum of the remaining cash payments that customers are expected to pay over the initial terms of their agreements (not including the value of any renewal or system purchase at the end of the initial agreement term), including estimated uncollected prepayments, for systems contracted as of the measurement date.

**Estimated Retained Value** represents the cash flows (discounted at 6%) we expect to receive pursuant to customer agreements during the initial agreement term, excluding substantially all value from solar renewable energy credits ("SRECs") prior to July 1, 2015. It also includes a discounted estimate of the value of the purchase or renewal of the agreement at the end of the initial term. Estimated retained value excludes estimated distributions to investors in consolidated joint ventures and estimated operating, maintenance and administrative expenses for systems contracted as of the measurement date. We do not deduct amounts we are obligated to pass through to investors in lease pass-throughs. Estimated retained value under energy contract represents the net cash flows during the initial 20-year term of our customer agreements. Estimated retained value of purchase or renewal is the forecasted net present value we would receive upon or following the expiration of the initial contract term.

**Project Value** represents the value of upfront and future payments by customers, the benefits received from utility and state incentives, as well as the present value of net proceeds derived through investment funds. Project value is calculated as the sum of the following items (all measured on a per-watt basis with respect to megawatts deployed under customer agreements during the period): (i) estimated retained value, (ii) utility or upfront state incentives, (iii) upfront payments from customers for deposits and partial or full prepayments of amounts otherwise due under customer agreements and which are not already included in estimated retained value and (iv) finance proceeds from tax equity investors. Project value includes contracted SRECS. Project value does not include cash true-up payments or the value of asset contributions in lieu of cash true-up payments made to investment fund investors, the cumulative impact of which is expected to be immaterial in 2015.

**Creation Costs** includes (i) certain installation and general and administrative costs after subtracting the gross margin on solar energy systems and product sales divided by watts deployed and (ii) certain sales and marketing expenses under new customer agreements, net of cancellations during the period divided by the related watts booked.

**Unlevered NPV** equals the difference between project value and estimated creation costs.

**Sunrun Direct Business** refers to solar service offerings installed by Sunrun.

# Expected impact of changes in long-term interest rates is limited

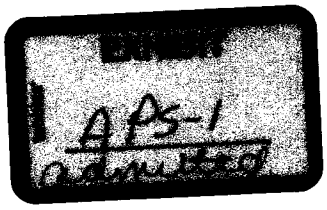
**During 2016, base rates are expected to be about 50 bps lower than at June 30, 2015. Even a decade from now, they are forecast to climb only about a third of a point from June 30, 2015.**

| Interest Rates[1] | Actual 6/30/15 | Forward 9/30/16 | Forward 9/30/27 |
|---|---|---|---|
| 7-Year Swap (for debt costs) | 2.15% | 1.62% | 2.51% |
| Average of 10 & 30-Year Treasury (for retained value calculation) | 2.74% | 2.28% | 3.08% |

(1) Source Data: Bloomberg, March 9, 2016.

sunrun®

EXHIBIT
APS-1
admitted



**SURREBUTTAL TESTIMONY OF ASHLEY C. BROWN**

**On Behalf of Arizona Public Service Company**

**Docket No. E-04204A-15-0142**

February 23, 2016

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**SURREBUTTAL TESTIMONY OF ASHLEY C. BROWN**
**ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY**
**(Docket No. E-04204A-15-0142)**

## I. INTRODUCTION

**Q. PLEASE STATE YOUR NAME, OCCUPATION, AND ADDRESS.**

A. My name is Ashley C. Brown. I am Executive Director of the Harvard Electricity Policy Group (HEPG) at the Harvard Kennedy School, at Harvard University. HEPG is a "think tank" on electricity policy, including pricing, market rules, regulation, environmental and social considerations. HEPG, as an institution, never takes a position on policy matters, so my testimony today represents solely my opinion, and not that of the HEPG or any other organization with which I may be affiliated.

**Q. PLEASE DESCRIBE YOUR PROFESSIONAL QUALIFICATIONS.**

A. I am an attorney with extensive experience in infrastructure, especially energy and regulatory matters. I served 10 years as a Commissioner of the Public Utilities Commission of Ohio (1983-1993), where I was appointed and re-appointed by Democratic Governor Richard Celeste. I also served as a member of the NARUC Executive Committee and as Chair of the NARUC Committee on Electricity. I was a member of the Advisory Board of the Electric Power Research Institute. I was also appointed by the U.S. Environmental Protection Agency as a member of the Advisory Committee on Implementation of the Clean Air Act Amendments of 1990, where I served on the subcommittee charged with implementing emissions trading. I am also a past member of the Boards of Directors of the National Regulatory Research Institute and the Center for Clean Air Policy. I have served on the Boards of Oglethorpe Power Corporation, Entegra Power Group, and e-Curve, and as Chair of the Municipal Light Advisory Board in Belmont, MA. I serve on the Editorial Advisory Board of the *Electricity Journal*.

I have been at Harvard continuously since 1993. During that time I have also been Senior Consultant at the firm of RCG/Hagler, Bailly, Inc. and have been Of Counsel to the law firms of Dewey & LeBouef and Greenberg Traurig. I have also taught in training programs for regulators at Michigan State University, University of Florida, and New Mexico State University (the three NARUC sanctioned training programs for regulators), as well as at Harvard, the European Union School of Regulation, and a number of other universities throughout the world. I have advised the World Bank and the Inter-American Development Banks on energy regulation and have advised governments and regulators in more than 25 countries around the world, including Brazil, Argentina, Chile, South Africa, Costa Rica, Zambia, Tanzania, Namibia, Ghana, Mozambique, Hungary, Ukraine, Russia, India, Bangladesh, Saudi Arabia, Indonesia, and the Philippines. I have written numerous journal articles and chapters in books on electricity markets and regulation, and I am co-author of the World Bank's *Handbook for Evaluating Infrastructure Regulatory Systems*.

I hold a B.S. from Bowling Green State University, an M.A. from the University of Cincinnati, and a J.D. from the University of Dayton. I have also completed all work, except for the dissertation, on a Ph.D. from New York University. My current CV is provided as Attachment ACB-1SR.

**Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE ARIZONA CORPORATION COMMISSION?**

A. No. I have testified, however, before FERC and various state commissions as well as before Congressional and state legislative committees.

**Q. ON WHOSE BEHALF DO YOU OFFER TESTIMONY?**

A. On behalf of the Arizona Public Service Company.

**Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

A. The purpose of my testimony is to rebut objections to UNS Electric's (UNSE) proposed rate design for solar DG customers. This includes addressing issues discussed in the testimony of TASC witness Mark Fulmer, Vote Solar witness Briana Kobor, and Western Resource Advocates witness Ken Wilson about Retail Net Metering, the value of solar, and what is in the long-term interests of solar as a technology and of the Arizona economy.

My testimony will be organized as follows:

- I will begin by examining and refuting suggestions by witnesses Kobor and Wilson that the proposed changes might somehow harm low income customers, showing that what hurts low income customers is the current net energy metering pricing system;

- In the next section of my testimony, I will address claims about the likely impact of UNSE's proposal on the future of solar power in Arizona. Solar witnesses argue the proposed reform is bad for the future of solar in the state; I will show that the proposed reform is in the true long-term interest of solar energy and solar DG customers (as opposed to the short-term rent seeking of current big solar DG installation firms, given their subsidy-based business model); and that there is no reasonable ground for the argument that the reform will have an overall negative impact on jobs. In fact, there is good evidence that the existing policy has a significant negative impact on jobs and on the Arizona economy as a whole;

- I will go on to examine various arguments for delay and inaction presented by Ms. Kobor and Mr. Fulmer, showing why none of these arguments present an adequate reason to continue with the existing unjust and inefficient net energy

metering system, especially given that the difficulty of changing this system increases the longer it is allowed to remain in place; and

- Finally, I will refute arguments presented by witnesses Fulmer and Kobor against UNSE's proposal for a renewable credit rate, and show that the UNSE proposal is not only reasonable, but introduces healthy market discipline to establishing fair compensation for DG energy.

**Q. ARE THERE OTHER RECURRING PROBLEMS WITH THE ARGUMENTS PRESENTED IN OPPOSITION TO UNSE'S PROPOSED SOLAR DG RATE REVISION THAT SHOULD BE HIGHLIGHTED?**

A. Yes. There are three recurring flaws with the testimony.

First, a lack of evidence, and failure to assume any responsibility for proving, or even establishing the plausibility of, their assertions. The testimony provided is often more of the rhetorical flourish one might expect in a political campaign, rather than the type of thoughtful and evidence-based analysis appropriate for a regulatory commission.

Second, one-dimensional thinking. Witnesses frequently selectively present one piece of a whole picture, without acknowledging real effects that go in different, and often polar opposite, directions.

Third, their arguments presuppose that solar DG, unlike any other resource in the state's portfolio, including other renewables, is entitled to be compensated at retail, rather than wholesale rates, that it should be insulated from cost and market pressures that discipline the prices of all other resources, and that any policy that delivers less than that privileged position in the marketplace is unduly discriminatory. As a corollary here, witnesses Ms. Kobor and Mr. Fulmer seem to assume that pricing and public policy in regard to solar should be judged entirely by one criterion: how much solar DG is sold. As I will argue below, they give no adequate reason why regulators should embrace such a self-serving, myopic view of public policy. Legitimate regulatory objectives,

such as efficient markets, fair and reasonable prices for consumers, incentives for productivity and efficiency gains, enabling effective competition between resources, even the long term economic viability of solar DG, all seem to give way, in the testimony of Ms. Kobor and Mr. Fulmer, to the single minded objective of selling solar DG.

## II. THE EFFECT UNSE'S PROPOSAL WILL HAVE ON LOW INCOME CUSTOMERS

**Q. VOTE SOLAR WITNESS BRIANA KOBOR EXPRESSES CONCERN THAT UNSE'S PROPOSAL MAY HURT LOW INCOME CUSTOMERS. PLEASE RESPOND.**

A. I disagree with the statement that Ms. Kobor makes on page 40 of her testimony. It is unsupported and speculative. And upon review, it is clear that the opposite is true. The current rate design and net metering tariff overly-subsidizes rooftop solar, and, in the aggregate, transfers wealth from less affluent to more affluent customers.

**Q. HOW DO ROOFTOP SOLAR SUBSIDIES HURT LOW INCOME CUSTOMERS?**

A. Higher income customers are more likely to install rooftop solar, and all other customers, including low income customers, pay the subsidies in question in the form of higher rates.[1] This is, in effect, a wealth transfer from lower income customers to higher income customers. All available analysis indicates that the cross-subsidies inherent in the current suite of net metering and volumetric rate design subsidies transfer wealth from low income customers to high income customers. A 2013 study by E3 Consulting of net metering in California found that the median income of net metering customers was 168% of the median California household income—and the system as a whole was projected to see another $1.1 billion annually in costs by 2020—costs, which would

[1] Low income customers lack the capital to invest in solar themselves, are less likely to live in a dwelling whose roofs they own, and, do not meet the stringent credit requirements solar DG lessors impose on customers. Moreover, even where low or fixed income households do own their own homes, many, particularly seniors, cannot accept the limitations solar lessors impose on selling their homes. Thus, in effect, low income people are almost systematically unable to participate in the solar DG market. It is the almost exclusive domain of more affluent households.

have to be borne by those (on average, poorer) households not participating in net metering.[2] The Center for American Progress has also done some recent work on this issue, looking at median-income data in relation to solar installation patterns from Maryland, Massachusetts, and New York and (in a separate article) in California, Arizona, and New Jersey. Although the main conclusion they emphasize is that solar installations are not limited to areas with predominantly "rich" households, there is a clear and important pattern in the data they show of few or no solar installations among areas with the lowest income households, and relatively many among the highest-income households.[3]

In specific regard to Arizona, the Staff of the Arizona Corporation Commission itself found, based on a review of the locations of customer DG installations within APS service territory, that there "may be a tendency for DG systems to be located in areas of higher income" in their analysis of the APS net metering proposal.[4] Low income customers are beginning to notice and object to the financial burden they are bearing to support better-off households. In my own state of Massachusetts, low income customers have recently filed a petition seeking relief from having to subsidize solar DG customers.[5]

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[2] Energy and Environmental Economics, *California Net Energy Metering Ratepayer Impacts Evaluation*. Prepared for the California Public Utilities Commission by Energy and Environmental Economics (October 28, 2013). It should be acknowledged here that the cross-subsidy impact of net metering in California from lower-income to higher-income customers is strengthened considerably by California's tiered rate system, under which the highest-consuming customers have the greatest financial motivation to install solar DG systems. However, I note that Ms. Kobor opposes UNSE's proposal to eliminate their highest rate tier (*see* Kobor Testimony at pp. 63-64), making the California cost-shift information relevant to this discussion.

[3] Hernandez, Mari. "Rooftop Solar Adoption in Emerging Residential Markets." Center for American Progress, May 29, 2014 and Hernandez, Mari, "Solar Power and the People: The Rise of Rooftop Solar Among the Middle Class." Center for American Progress, October 21, 2013.

[4] *See* Arizona Corporation Commission Docket No. E-01345A-13-0248, September 30, 2013, memo titled "Arizona Public Service Company – Application for Approval of Net Metering Cost Shift Solution."

[5] Petition of the Low-Income Weatherization and Fuel Assistance Program Network to Apply G.L. c. 164, sec. 141, submitted to the Commonwealth of Massachusetts Department of Public Utilities, November 17, 2015. National Grid Rate Case, D.P.U. 15-155.

As a former legal services lawyer, I find it troubling, to say the least, that we condone the continued existence of a tariff that consciously and deliberately forces lower income households to subsidize higher income households. I can see no justification for such an economically regressive policy.

**Q. IS MS. KOBOR CORRECT THAT UNSE'S PROPOSAL MIGHT CREATE A SLIPPERY SLOPE, AT THE END OF WHICH LOW INCOME CUSTOMERS ARE HARMED?**

A. The slippery slope argument is a red herring. Indeed, the real harm to low income customers, as already noted, is by perpetuating net metering. In general economic theory, of course, cross-subsidies are best avoided, but there may be circumstances where they cannot be. Thus, it is undeniable that some are embedded in tariffs, many of them inadvertent and/or economically insignificant, but also some that result from conscious policy decisions. Each one must be judged on its own merits and be narrowly targeted to meet a clearly articulated policy objective, and to do so in a way that neither asymmetrically inflates profits to particular actors in the marketplace at the consumers' expense, unduly dilutes price signals, renders markets less efficient, nor provides perverse incentives that discourage attainable productivity gains. Thus, cross subsidies designed to assure universal service, such as those supporting rural electrification or assisting low income households, support well-articulated policy objectives. They are generally designed to avoid the pitfalls noted, and are subject to regulatory oversight and review, as well as potential reformulation, to make certain that they continue to be effective in changing circumstances and that they do not have adverse social effects. In short, each cross-subsidy, and whether it needs to be retained and/or modified, stands on its own.

Thus, net metering must stand or fall on its own merits, not in the context of other cross-subsidies. The policy developed in a time when meters were dumb, energy price signals were less precise and solar panels cost far more than they do today, when the tax

subsidies were less certain, where storage technology was just a dream, where the social effects were largely unknown, and when solar DG market penetration was so small that price distortions were insignificant. All of those circumstances have changed dramatically, and net metering needs to be reassessed in its own context, and with reference to the standards I just mentioned. It can and should be done without regard to what other cross-subsidies may or may not exist. The slippery slope mentioned by Ms. Kobor simply does not exist.

**Q. WRA WITNESS KEN WILSON ALSO ARGUES THAT A DEMAND CHARGE COULD HARM LOW INCOME CUSTOMERS. IS HE CORRECT?**

A. No. First, Mr. Wilson fails to recognize that demand charges do not increase rates. They are revenue neutral since the demand costs are already embedded in tariffs. What demand charges do is make those costs transparent, and by doing so, enable all customers, low income included, to shape their demand in ways that can reduce their bill. It also provides an opportunity for programs like LIHEAP[6] to design their low income subsidies to capture that increased opportunity for saving.

Second, Mr. Wilson argues generally that low income customers would be penalized because their less efficient appliances cause higher loads.[7] He offers no empirical evidence to support this claim—it seems more likely, in the aggregate, that low income users, having fewer electrical appliances, have smaller loads than other customers. The future of solar after UNSE's proposal.

[6] LIHEAP – Low Income Home Energy Assistance Program.
[7] Wilson Direct Testimony at p. 9.

## III. THE FUTURE OF SOLAR AFTER UNSE'S PROPOSAL

**Q. TASC WITNESS MARC FULMER SUGGESTS THE UNSE PROPOSAL WILL "STIFLE" DG SOLAR; MS. KOBOR SAYS THAT IT WOULD "VERY LIKELY CURTAIL FUTURE DG GROWTH." WHAT, IN YOUR VIEW, IS THE IMPACT OF THE PROPOSAL ON THE FUTURE OF SOLAR IN AZ?**

A. To assess the possible impacts of the UNSE proposal on the future of solar in Arizona, it is important to first disentangle four things that Mr. Fulmer and Ms. Kobor conflate: the financial interests of solar installation companies, the financial interests of solar DG customers, the long-term prospects for solar DG in the electricity markets, and, of course, the public interest.

**Q. WHY IS IT IMPORTANT TO DISTINGUISH BETWEEN THE FINANCIAL INTERESTS OF SOLAR INSTALLATION COMPANIES AND THE FINANCIAL INTERESTS OF SOLAR DG CUSTOMERS?**

A. Advocates for large DG solar installation companies, such as Mr. Fulmer, simplistically assume that the interests of solar customers and solar companies are aligned with one another. For example, in his December testimony, Mr. Fulmer raises the issue of the impact UNSE's proposed rate change will have on PV adoption. His testimony takes the cost of solar DG installation as a given, and then asks what electricity price would be needed to support investment in solar DG.[8] The presumption is that if the end customer's payback is not rapid and guaranteed, then the proposed electricity price is not adequate to support solar DG.

His focus on recovery of customer investment obscures the tension between the interests of solar DG customers and solar installers. Prospective solar customers are looking for cost effective means of meeting their need for electricity. Many of them also are motivated by a public-spirited desire to increase the efficiency and "greenness" of the electricity system as a whole. These aims, however, are not at all technology specific, so going solar is but one option, not <u>the</u> option, as Ms. Kobor and Mr. Fulmer seem to

[8] Fulmer Direct Testimony at p. 15.

assume. It may not even be the most desirable option, and, as shown in this testimony and elsewhere, it is probably never the most cost effective option.

**Q. CAN YOU EXPLAIN WHERE THE INTERESTS OF LARGE ROOFTOP SOLAR COMPANIES DIVERGE FROM CUSTOMER INTERESTS?**

A. The interests of large rooftop solar companies and utility customers diverge on several levels. In regard to solar leases, the most cost effective installation for customers may be quite different than what is most profitable to the lessor. Solar DG companies, perhaps lessors even more than vendors, routinely make false sales representations about their products and benefits they offer, often retain the RECs and SRECs for their own use, as opposed to the use the customer may prefer, and offer lease agreements whose terms are notoriously onerous for customers.[9]

However, the primary divergence of interests relates to the massive profits made by these companies—profits that are effectively paid by utility customers. Solar DG profits by using the highly inflated and heavily subsidized net meter prices to shield themselves from market pressure and having to pass on the declining cost of solar panels, whereas the consumer interest is better served by having solar DG vendors/lessors be subject to the marketplace or regulatory disciplines to which all other players in the energy market are subject. Simply stated, it would be better if solar DG developers had to compete with other forms of energy, rather than chasing just subsidies for themselves.

Thus, the customers' energy efficiency objectives may require price signals and self-generation options that conflict with the objectives of solar DG developers. As seen in Ms. Kobor's and Mr. Fulmer's testimony, solar DG providers oppose demand charges and other types of pricing that would enable new energy service providers and vendors to offer consumers products to reduce their energy bills. They are committed to maintaining barriers to new entrants who might offer valuable products and services that

[9] A number of these practices are under active investigation by consumer protection agencies in a variety of jurisdictions across the U.S., including Arizona.

provide customers with more options, preferring to limit the diversity of products and services found in a robust market, so as to even further reduce the competition for solar DG. Solar DG interests also generally oppose pricing regimes that would make solar DG units more flexible, more attuned to system requirements, and more efficient, because they prefer the simplicity of selling primitive products without having to respond to price signals for a better, more efficient product, something that would add considerable value for customers, but require a more modern and sophisticated business model than simply peddling simple installations at inflated prices. Finally, consumers benefit from an efficient electricity market with competitive discipline, while solar DG companies are self-interested in preserving artificially high prices for their products at considerable cost to consumers, solar and non-solar alike.

**Q. IT IS NORMAL FOR COMPANIES TO MAKE PROFITS, SO WHY IS IT APPROPRIATE TO SEPARATELY CONSIDER PROFITS MADE BY LARGE ROOFTOP SOLAR COMPANIES?**

A. The problem is two-fold: how the profits are derived and the magnitude of the profits made by large rooftop solar companies. If the profits were derived from being more efficient, making productivity gains, and reducing costs, those profits would have been earned and deserved. For solar DG companies, however, as revealed in SolarCity's most recent 10K filing with the SEC[10] (discussed below), the profits are derived by chasing subsidies and cross subsidies, including having the price to beat, unlike every other energy source, be retail rather wholesale. Beyond that, of course, since the price they compete against is the bundled, monopoly retail rate,[11] they have the advantage of being paid a monopoly price without being subject to the discipline of cost based regulatory oversight.

[10] SolarCity Corp 10K, filed 2/24/15 for period ending 12/31/14, (available at http://files.shareholder.com/downloads/AMDA-14LQRE/1445127011x0xS1564590-15-897/1408356/filing.pdf).

[11] The retail price, they "compete" against, of course, includes compensation for a host of goods and services they do not provide, and reflects the benefits for them that are associated with reallocating revenue responsibility of a significant share of system costs to non-solar customers.

The second issue is the magnitude of profits that, until now, have gone largely unexamined. It seems that, so far, large solar DG companies have been quite effective in preserving large margins for themselves when making solar DG installations. As shown in the testimony of APS witness Cory Welch, filed concurrently with this testimony, rooftop solar leasing companies obtain an average of 40% margins on each installation in UNSE's service territory.[12] This is an astonishing return, particularly in the monopoly context described above. Policy makers and regulators would be well advised to see the issues of subsidies and cross subsidies in the context of such high profits provided to rooftop solar companies. The UNSE proposal for pricing solar DG constitutes a very reasonable way of restoring a marketplace discipline to the pricing and a fairer way of allocating costs.

**Q. HAS THE ISSUE OF ROOFTOP SOLAR COMPANIES' PROFITS BEEN STUDIED ELSEWHERE?**

A. A recent study by MIT, *The Future of Solar*, provides a comprehensive overview of the state of solar technology and of the industry as a whole and is very revealing.[13] While the authors of the study do not look specifically at profit levels, they do examine how prices that enable and encourage short term profit taking by solar DG companies have an adverse impact on the long term economic viability of solar energy. As part of this study, the MIT authors present a comparative analysis of the costs and prices associated with solar installations, contrasting utility-scale and DG installations. MIT built up its costs estimates from data on hardware costs, combined with surveys of installers and data about wages, and included costs for customer acquisition, sales taxes, margin, and general and administrative expenses—working to develop an estimate of costs that would be sufficient to sustain the industry. Then they compared their bottom-up costs estimates (per watt of installed capacity) with reported actual prices charged (per watt of

[12] Surrebuttal Testimony of Cory Welch Attachment CJW – 2SR.
[13] *See The Future of Solar Energy: An Interdisciplinary MIT Study.* MIT (2015). https://mitei.mit.edu/system/files/MIT%20Future%20of%20Solar%20Energy%20Study_compressed.pdf

installed capacity). An interesting pattern emerged—for utility-scale PV, MIT's bottom-up cost estimates were fairly closely matched to actual prices charged for the systems.

This was not the case for distributed generation installation of solar. As expected, due to the loss of certain economies of scale, MIT's bottom-up costs estimate was higher than for utility-scale solar. This finding is unsurprising. The surprise here is that MIT found a considerable gap between its bottom-up cost estimate and actual reported prices charged for solar DG systems. Here, average reported prices charged exceeded MIT's cost estimate by an average of 50%—a considerable margin.[14] The existing subsidy structure (including net metering, as well as federal tax incentives) makes it possible for homeowners to pay these prices while still coming out marginally ahead economically—but the prices they are being charged do not reflect the best possible value for consumers, and they provide no incentives for productivity and efficiency gains for solar DG. Indeed, they discourage such efforts. It is also reflective of the fact that while the costs of solar panels themselves have been in dramatic decline, the prices for installing the units have been increasing, thereby enabling the solar DG developers to retain most, if not all, of the benefits of declining panel costs for themselves rather than passing them on to their customers. This is reflected in a recent study by Lawrence Berkeley National Labs which found that out of six countries it compared to the U.S. (Germany, Japan, Italy, China, France, and Australia), only France had higher costs for installed residential PV systems.[15]

These developments may be in the short-term interests of residential PV system developers, but it is not in the long-term interest of solar power, whose interests would be better served by a pricing regime that encouraged increased productivity, better

[14] *Id.* p. 86.
[15] Barbose, Galen and Naim Darghouth. *Tracking the Sun VIII: The Installed Price of Residential and Non-Residential Photovoltaic Systems in the United States.* Lawrence Berkeley National Laboratory (August 2015).

compatibility with system requirements, and deployment of technology, such as storage and smart inverters, that would better secure solar DG's place in Arizona's energy resource portfolio.[16] Moreover, it is rate design and retail net metering that enables solar DG lessors to retain most of the margin, and essentially pass on pennies on the dollar to solar DG customers, recovering the balance of their profits from taxpayer funded subsidies plus cross-subsidies paid by non-solar customers. No competitive market or properly regulated market would enable that to happen. Thus, UNSE's use of large scale solar, procured in a competitive market, as the benchmark for pricing solar DG solves the problems and allows for more of the benefits of declining cost to be passed on to customers. It might also be noted that the UNSE proposal also has the very positive effect of not diverting capital from the more efficient large scale wind and solar renewable energy to the less efficient solar DG, a likely development if net metering is not replaced by a more rational pricing regime.

SolarCity's 10K filing is also quite revealing about its motivations for opposing pricing reforms:

> **Modifications to the utilities' peak hour pricing policies or rate design, such as to a flat rate, would require us to lower the price of our solar energy systems to compete with the price of electricity from the electric grid.**[17] (emphasis added)

This is the acknowledgement by the leading player in the solar DG that its business model is fully dependent on being shielded from competition, hardly a virtue from the standpoint of either consumers or the public interest. The actual cost, or even market valuation, to provide service is not mentioned—it is all about charging as much as possible, depending on the utility rates and existing incentives that will leave no incentive for productivity and will provide marginal benefits, at best, for solar DG

[16] *See* MIT Study.

[17] SolarCity Corp 10K, filed 2/24/15 for period ending 12/31/14, p. 11 (available at http://files.shareholder.com/downloads/AMDA-14LQRE/1445127011x0xS1564590-15-897/1408356/filing.pdf).

consumers. In short, net metering enables arbitrarily high prices for consumers, extraction of monopoly rents by solar DG vendors/lessors, and dim prospects for the future of solar DG.

**Q. WHAT DO THESE LARGE PROFIT MARGINS, AND THE PRICING STRUCTURE UNDERLYING ROOFTOP SOLAR LEASES, MEAN WHEN ASSESSING UNSE'S PROPOSAL?**

A. It means that the subsidies supporting rooftop solar can be reduced. Indeed, with the recent Congressional extension of the Investment Tax Credit for solar, cross subsidies can be eliminated, without doing harm to increased market penetration by rooftop solar. Indeed, with increased exposure to market risk, solar DG vendor/lessors would be compelled to reduce their prices and improve their products, developments that would make solar DG much more attractive to the public. This, of course, would require the solar DG industry to alter its business model of simple rent seeking and subsidy chasing to one of vigorous competition in the market place and to be willing to accept rates of return commensurate with its performance in the marketplace.

Based on the discussions of undisciplined profit margins above, advocates of net metering are presenting the wrong analysis when they argue that eliminating the retail net metering subsidy would make solar DG economically infeasible for end use customers. With the large surplus margins shown by Mr. Welch and the MIT study built into these prices (on top of normal business margins), there is a strong case to be made that the same DG installations could be provided at considerably lower cost—a cost which might well be affordable within the context of a revised tariff for solar DG customers—and still be profitable for DG vendors/lessors. Indeed, with the UNSE proposed reference price, both vendors and customers would be incentivized to improve both efficiency and productivity, as the savings would accrue to them, but would be earned, as opposed to being the gifts of a severely flawed pricing methodology.

TASC claims to champion competition and oppose monopoly power, and thereby serve as the consumer's champion in creating a competitive marketplace. In fact, the reality is exactly the opposite. Their advocacy of net metering in this proceeding and others around the country calls for perpetuation of an inefficient, highly inflated, price not subject to any competitive or even cost based pressure, a price that can only survive in a non-competitive environment. In effect, they are seeking a market where they are free to sell their product to customers, but where those very same customers have little opportunity to see competitive or cost based pressure on the prices they are compelled to pay for either purchasing solar DG or having to pay the cross-subsidies inherent in net metering.

Current rate design and retail net metering enables TASC members and other solar DG vendors/lessors to charge monopoly rents, subject only to the potential of competition from other DG vendors/lessors, who share the same self-interest of preserving arbitrarily high margins. They seek to preserve a business model in which customers are deprived of the pricing benefits associated with either competitive markets or cost based regulation. This is not in the interest of any utility customer, and in particular, the interests of UNSE's customers.

**Q. WHAT ABOUT THE FUTURE OF SOLAR ITSELF? DO THE INTERESTS OF LARGE SOLAR DG INSTALLATION COMPANIES THREATEN THE FUTURE OF DISTRIBUTED SOLAR AS A COMPETITIVE ENERGY TECHNOLOGY?**

A. Yes, the short term rent seeking business model of most, if not all, of these companies has created an unsustainable environment in which solar cannot flourish in the long run. In the short term, as noted, the current rate benefits the solar industry, because of the inherent wealth transfer from non-solar to solar customers, plus the wealth transfer from all customers to solar DG vendors/lessors discussed above. That is not a sustainable long-term strategy, particularly if significant expansions in solar DG adoption are hoped for. There are two reasons for this. The first is simply that the public appetite for paying

higher than necessary prices for goods and services is very limited, and their patience with that reality, once it becomes, as is inevitable, public, is not great.

Second, and perhaps even more important in the long term, is the fact that solar, like every other form of energy, must constantly be improving its productivity and overall performance to remain competitive. Thus, to align that reality with the incentives for the solar DG industry, incentives for productivity and efficiency gains should be embedded in rates.

Unfortunately, that is precisely the opposite of what occurs under current net metering tariffs. Current tariffs provide absolutely no incentive to improve the performance of a generating resource that already ranks last among renewables in efficiency and cost effectiveness, both in terms of economic efficiency and as a tool for reducing carbon emissions. Any money spent on improving the technology or on storage, under retail net metering, goes to reduce profits, not enhance them. The arbitrarily high, flat prices permitted by current rate design and retail net metering simply do not incentivize investing in improvements. Indeed, it does exactly the opposite.

**Q. MS. KOBOR AND MR. FULMER CLAIM THAT ADOPTING UNSE'S PROPOSAL WILL REDUCE THE NUMBER OF SOLAR JOBS. WHAT IS YOUR RESPONSE?**

A. First, neither Ms. Kobor nor Mr. Fulmer offer any specific evidence or analysis regarding UNSE's service territory, both in terms of the number of current solar jobs or the precise effect of UNSE's proposal on those jobs. In fact, in a recent proceeding before the Nevada Public Utilities Commission, TASC and others relied on the same Solar Foundation National Solar Jobs Census attached to Mr. Fulmer's testimony to similarly claim that demand charges proposed by NV Energy would cause a massive reduction in solar jobs. Upon review by Nevada PUC Staff, however, the Nevada Commission rejected the Solar Foundation National Solar Jobs Census, stating that "the

figures cannot be reasonably relied upon as an estimate of the number of solar jobs in Nevada or the number of jobs that could potentially be impacted by this Order."[18]

The Solar Foundation report should be rejected here for the same reason: there is no Arizona, much less UNSE, specific data that can be relied upon in considering the impact of UNSE's proposal on solar-related jobs.

**Q. ARE THERE OTHER PROBLEMS WITH MR. FULMER'S AND MS. KOBOR'S CLAIMS REGARDING SOLAR JOBS?**

Yes, both involve a very one-dimensional look at the economic impact of solar that is severely flawed and ultimately misleading. Advocates of subsidies for distributed solar generation often point to the supposed economic benefits—particularly job creation—of rooftop solar installation.[19] But claims about a positive impact on job creation are one-sided—they only count new jobs created in solar. They do not even bother to claim that net metering creates more jobs than competitively priced solar DG would. They simply look at solar DG jobs in a compete vacuum and without a real context. Perhaps more importantly, they fail to even consider the broader effect on the economy.

If the cost of electricity is higher, jobs are likely to be lost elsewhere in the economy—there is no reason to assume that the net job impact of distributed solar power is positive.[20] In fact, a recent study by Tim James, Anthony Evans and Lora Mwaniki-Lyman of Arizona State University used an Arizona-specific regional economic model (a REMI model), balancing the costs of installed DG capacity (and related financing

[18] Order, Application of Nevada Power Company d/b/a NV Energy for approval of a cost-of-service study and net metering tariffs, Public Utilities Commission of Nevada Docket Nos. 15-07041 & 15-07042 at paragraph 229 (December 23, 2015).

[19] There may be some question as to the quality of at least some of the jobs, the solar witnesses claim will be gained. In its most recent 10K filing with the SEC, SolarCity, the largest vendor/lessor of solar DG, disclosed that its employments practices are the subject of an active investigation by the U.S. Department of Labor.

[20] The *National Solar Jobs Census 2014* attached to Mr. Fulmer's testimony is a good example of the one-sided solar jobs cheerleading genre. It touts solar employment in isolation from the rest of the economy.

costs) against what APS estimates to be the related savings on generation purchases and generation capacity investment over thirty years (and their related customer savings), based on different levels of investment in solar DG that might be made in the APS service territory.[21] This study models the complexity of judging the economic and job impacts of a particular policy or subsidy—of course, there is an immediate positive impact on some jobs from additional solar employment, but, over time, taking into account the effects of lost spending power by consumers who have to pay more for their electricity, the projected impacts on jobs and on the gross state product of the Arizona economy are decidedly negative (for example, the model shows cumulative losses in gross state product, over time, in the multiple billions of dollars).[22]

Before leaving the topic of jobs, it is worth remembering that most solar panels sold or leased in the U.S. are manufactured in China. In all likelihood, more American jobs are associated with other forms of generation.

**Q. IS THE NUMBER OF SOLAR INSTALLATIONS THE DETERMINATIVE STANDARD AGAINST WHICH UNSE'S PROPOSAL SHOULD BE JUDGED?**

A. No, it is not. It is clear from their testimony that both Mr. Fulmer and Ms. Kobor believe that there is only one dimension by which to judge public policy on solar DG pricing: how much solar DG is sold or leased. The theory they seem to articulate is quite simple: if a tariff provision results in more solar DG, that is good, and if there is any slowdown in solar DG's rapid growth, that is bad as a matter of public policy.[23]

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[21] As detailed above, I am skeptical about how many of these savings will materialize.

[22] Evans, Anthony, Tim James, and Lora Mwaniki-Lyman. "The Economic Impact of Distributed Solar in the APS Service Territory, 2016-2035." Report, L. William Seidman Research Institute, W.P. Carey School of Business, Arizona State University, February 16, 2016. (Attachment ACB-2SR).

[23] *See, e.g.,* Kobor Direct Testimony at p. 51. It is also curious that neither Ms. Kobor nor Mr. Fulmer even bother to ask whether there might be a more efficient pricing methodology under which more solar DG would enter the market. They appear to be wed to the outdated, rent seeking business model of the interests for whom they are testifying to even contemplate new approaches that might advance solar DG out of its niche on the margins into the mainstream of Arizona's energy resources.

Public policy and regulatory decision making cannot and must not be as one dimensional as Ms. Kobor and Mr. Fulmer would urge. The point of an electricity rate is to establish a just and reasonable rate, disciplined by the market and/or cost. Such a rate should enable solar DG to compete as a mainstream energy source (even assuming it retains the advantages of federal tax subsidies and renewable energy requirements). If a short-term decline in the growth of solar DG results, that is not necessarily a bad outcome for the world—especially if it means investment is instead being directed towards more cost effective technologies, such as improved solar DG products, utility-scale renewables, and/or innovations that allow for more efficient and more productive means of providing solar DG.

**Q. HOW DO YOU RESPOND TO MS. KOBOR AND MR. FULMER'S CLAIMS ABOUT SOLAR INSTALLATIONS PLUMMETING IN SALT RIVER PROJECT'S TERRITORY AFTER DEMAND CHARGES WERE IMPLEMENTED?**

A. I don't think the level of DG installations in SRP's service territory is at all indicative, or even relevant, in considering the impact of demand charges on solar installation levels. After SRP implemented a demand charge, Ms. Kobor reports that applications for the DG program fell by 95%.[24] Mr. Fulmer makes the same point, and provides a chart showing monthly solar DG applications in SRP for three years before and nine months after the change.[25] The chart itself shows an interesting pattern not mentioned by Mr. Fulmer or Ms. Kobor—there was a significant increase in applications in the approximately nine months before the rate change, including a huge spike in the month prior to the change. (A rough estimate based on eyeballing the graph provided by Mr. Fulmer suggests that monthly applications were about ten times the monthly average of the first two years shown.)

[24] Kobor Direct Testimony at p. 39.
[25] Fulmer Direct Testimony at p. 17.

A look at the whole picture suggests a more nuanced and complex story than the one told by Mr. Fulmer and Ms. Kobor. As one would expect, the imminent change to a different rate formulation prompted a significant spike in demand—presumably, customers with some intention of installing solar DG in the next couple of years were highly motivated to get their applications in before the rate change. After this spurt of activity, as one would expect, with demand temporarily exhausted, applications dropped significantly. It remains to be seen what will happen once the system has absorbed the demand spike that occurred right before the rate change. It is also important to note that SolarCity has filed an anti-trust suit against SRP for its tariff reforms, alleging that these changes have made it impossible to compete in SRP territory. Thus, SolarCity and others in the solar DG industry have a powerful incentive to essentially boycott SRP customers. To do otherwise would undermine their anti-trust case, since doing business in SRP territory would effectively disprove their allegations of being unable to compete. Thus, the drop in solar DG installations in SRP territory, assuming it is true, could well be a self-fulfilling prophecy by the solar DG industry.

Indeed, that self-serving boycotting behavior was also evidenced by Nevada's very recent experience; namely, that large solar installers will attempt to pressure Commissioners, and even the Governor, to restore net metering by suspending operations in the state. Given the analysis of the large margins of profitability above, I would suggest that such a move might simply open up the market to new, local competitors.

Events in SRP's service territory offer little useful information for another reason: after SRP implemented demand charges, solar installers could literally walk across the street and sell rooftop solar at immense profit margins (60% per system, according to Mr. Welch's study[26]) in APS's service territory. It is not clear why rooftop solar companies

[26] Welch Surrebuttal Testimony, Attachment CJW – 2SR.

would voluntarily accept lower profits by installing in SRP's territory when they could continue receiving the (overly) rich subsidies available in APS's territory with no incremental effort.

**Q. WHY DO CURRENT RATE DESIGN AND RETAIL NET METERING MAKE THE FUTURE OF SOLAR UNSUSTAINABLE?**

In the long term, in order to be fully sustainable, solar energy needs to be fully competitive on both a price and qualitative basis. That means both that solar should be competitive on a price basis, independent of any subsidy, and that steps need to be taken to reduce the intermittent and off peak production characteristics of solar (e.g. link it to storage, or use western rather than southern exposure in order to better align production with peak demand).

Current rate design and retail net metering is exactly the wrong incentive. They simply throw utility customer money at distributed solar in its most inefficient and primitive form. Retail net metering not only fails to incent increases in productivity, but actually discourages them. It makes solar artificially *more* profitable when companies refrain from investing in technological development or taking other steps to improve productivity. Under markets driven by competitive forces, by contrast, investments in technological innovation increase the ability of companies to compete, and thus offer a positive rate of return that justifies that initial investment. What is critical to understand is that net metering, regardless of its profitability for solar DG vendors/lessors, is a subsidy so poorly designed that it actually runs contrary to the long run economic viability of distributed solar energy.

**Q. HOW MIGHT UNSE'S PROPOSAL AFFECT THE FUTURE OF SOLAR ENERGY IN ARIZONA?**

A. UNSE's proposal is an important, if not critical, first step to preserving the future of solar in Arizona. It is true that the proposed rate reform is likely to compel solar vendors/lessors to change their business model from chasing subsidies to competing

(something they are loathe to do because they are flourishing in a much too cozy environment at present). These companies will have to decide whether to change their model or not, and if not, some may well seek to move their model into other jurisdictions that may continue to shield them from market and regulatory pressures that provide greater opportunity for consumers. The world in which that is happening, fortunately, is changing, and the rooftop solar industry, just as every other segment of the energy sector, will have to become more competitive.

If some players refuse to adapt, new players will emerge who will see business opportunities and thrive on the challenge of well-functioning markets as opposed to extracting subsidies. In the long run, solar energy will have a much brighter future and will be better assured of finding its place in the mainstream of energy resources. The dire predictions of Ms. Kobor and Mr. Fulmer should be treated with a great deal of skepticism.

**Q. CONTRARY TO THE TESTIMONY OF MS. KOBOR AND MR. FULMER, HOW MIGHT DEMAND CHARGES ACTUALLY HELP THE FUTURE OF SOLAR?**

A. The demand charges proposed by UNSE provide price signals that will inevitably enhance the productivity and efficiency of solar DG. What the fixed charge proposal of UNSE does do is to promote overall system efficiency by tying rates and cost causality more closely together so that marginal rates better reflect actual marginal costs while the fixed rates recover unavoidable fixed costs. This improves the price signals to customers, reduces the degree to which cross subsidies are built into rates (including those that flow from non-solar to solar customers), and makes the actual market value of solar DG and energy efficiency more transparent. In short, the result of both the change in fixed costs and the adoption of demand charges for solar DG customers is to insert the disciplines of market and cost that have been lacking in the past. In specific regard to

solar DG, the UNSE proposals will provide price signals that will enable solar DG installations to operate optimally for both the solar host and the system as a whole.

What is important is that customers cannot respond to signals to shape their load in more efficient ways unless they are given price signals to do so. A recent study by the Rocky Mountain Institute (RMI) urges that demand rates be part of residential bills because they are inherent to the overall objective of energy efficiency.[27] Indeed, RMI coins a phrase, "flexiwatts," to describe the services and technology that exist to fill the business space demand charges will offer. A recent RMI blog post hails demand charges as an opportunity for new technologies, customer options, and reduced grid costs:

> Demand charges are a promising step in the direction of more sophisticated rate structures that incent optimal deployment and grid integration of customer-sited DERs. A demand charge more equitably charges customers for their impact on the grid, can reward DG customers with bill savings, and opens up potential for an improved customer experience using load management tools. It can also benefit all customers through reduced infrastructure investment and better integration of renewable, distributed generation.[28]

Similarly, a joint statement by the National Resources Defense Council and the Edison Electric Institute endorses the use of demand charges.[29]

The Natural Resources Defense Council also supported demand charges in a recent filing with the California Public Utilities Commission.[30] Those positions, as well as those taken by UNSE and the ACC Staff in this proceeding, are an excellent indication that there are a wide variety of parties and interests who see demand charges as an

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[27] Lehrman, Matt. "*Are Residential Demand Charges the Next Big Thing in Electricity Rate Design?*" Blog Post, RMI Outlet (May 21, 2015). http://blog.rmi.org/blog_2015_05_21_residential_demand_charges_next_big_thing_in_electricity_rate_design

[28] *Id.*

[29] EEI and NRDC, "EEI/NRDC Joint Statement to State Utility Regulators," February 12, 2014 (http://docs.nrdc.org/energy/files/ene_14021101a.pdf).

[30] Proposal of the National Resources Defense Council (NRDC) in Determining a Net Energy Metering Successor Standard Contract or Tariff, filed August 3, 2015 in Rulemaking 14-07-002 before the Public Utilities Commission of California.

important element of the efficient pricing of electricity. Demand charges work to smooth customer demand, reducing spikiness, and increasing the utility's ability to rely on more efficient resources, rather than turning to its last-resort, less energy efficient sources of generation.

One might expect that solar industry interests would see the value in price signals that would enable customers to shape their load in a manner that is both economically efficient and environmentally desirable. Instead of seeing the opportunities for solar energy to help customers shape their loads in more beneficial ways, witnesses Mr. Fulmer and Ms. Kobor oppose innovation and efficiency by defending and clinging to an inefficient and outdated business model of chasing subsidies for the most primitive and inefficient use of solar energy. Once again, it appears that Ms. Kobor and Mr. Fulmer seek to protect the short term profitability of their clients instead of looking out for the long term future of solar energy and for a more efficient and more environmentally friendly electricity marketplace.

**Q. ARE THERE OTHER EXAMPLES OF HOW TASC AND VOTE SOLAR'S POSITIONS WILL HARM THE FUTURE OF SOLAR?**

A. Mr. Fulmer and Ms. Kobor's apparent opposition to "enabling technologies" that could help customers manage their demand is another example of how their position disregards the long-term interests of solar energy. Ms. Kobor's argument is particularly ironic. Her main objection is that such technologies are "uncommon, costly to implement, and have not achieved widespread adoption."[31] It is ironic that she raises this as an objection to changing net metering rates, since it is exactly these kinds of archaic rates that make it hard for smart enabling technologies to take hold. Current net metering rates provide zero incentive for customers to invest in such technologies. It is hardly fair to complain that they have not been widely adopted while defending a rate structure that

[31] Kobor Direct Testimony at p. 35.

prevents customers from realizing any savings by using these technologies. One of the important benefits of UNSE's proposed revision to rates for DG customers would be that it should contribute to the development of these kinds of technologies.

Indeed, it is fair to say that not only is their position contrary to solar, but by opposing tariff changes, such as demand charges, they are effectively precluding innovations that would enable providers of sophisticated energy services to enter the market. That is because such companies depend on price signals to optimize the use of "negawatts" and "flexiwatts." Transparent and meaningful unbundled prices will enrich the marketplace, provide more options for consumers, and help to optimize the role that solar DG can play. It is ironic that, instead of seeing that as an opportunity for the solar DG industry, or a benefit for customers, the two witnesses argue for a "dumbed down" marketplace, the effect of which is to reduce the amount of goods and services, restrict market entry for otherwise valuable market participants, and, ironically provide channels for optimizing solar DG.

## IV. ARGUMENTS FOR DELAY AND INACTION SHOULD BE REJECTED

**Q. HOW DO MR. FULMER AND MS. KOBOR ARGUE THAT THE COMMISSION SHOULD DELAY OR TAKE NO ACTION REGARDING RETAIL NET METERING?**

A. Mr. Fulmer and Ms. Kobor provide a variety of arguments that urge no action. These include that (i) an unbiased "Value of Solar" study should be performed before any action is taken; (ii) rooftop solar customers only account for 2% of cost shifting in UNSE's service territory and that other, larger, cost shifts exist; (iii) UNSE has not performed specific studies on certain topics; (iv) rooftop solar is needed for UNSE to achieve compliance with the distributed generation component of Arizona's Renewable Energy Standard; (v) UNSE's proposal would violate Arizona net metering rules; and (vi) demand charges are not part of the modern trend in rate design. I address each in turn.

**Q. IS AN UNBIASED "VALUE OF SOLAR" STUDY NEEDED TO ADEQUATELY ASSESS UNSE'S PROPOSAL?**

A. No, it is not. Ms. Kobor argues that UNSE needs to conduct a "full benefit/cost analysis" (presumably, a "Value of Solar" study), stating that without such an analysis, there is "no way to determine the current relationship between the retail rate and the value of NEM exports, and thus no way to determine the reasonableness of the Renewable Credit Rate." If a cost shift exists, Ms. Kobor says, there is no way to even tell what direction it goes in![32] I beg to differ. This is like saying that unless I can give the precise height of an elephant, I can't say it is bigger than a horse.

The "value" of solar simply does not need to be assessed before UNSE's proposal is acted upon. Rates are based on either a market or cost base, not some theoretical and highly subjective notion of value. There have been a number of such studies in recent years, which come to quite diverse and often conflicting conclusions. I do not believe such studies can accurately determine what the prices should be, and I certainly do not see any basis for pricing all energy sources based on cost and market, while solar DG, alone, of all resources, is priced based on some consultant's subjective assessment of value.

**Q. WHY DO YOU BELIEVE THAT THE VALUE OF SOLAR CANNOT BE ACCURATELY DETERMINED THROUGH AN UNBIASED STUDY?**

A. Assessing the future value of solar necessarily involves making arbitrary and subjective determinations based on speculation about future events as well as monetizing alleged attributes of distributed solar, some of which may not, in fact, actually be attributes. It is simply impossible for one to conduct such a study on an unbiased, much less accurate, basis.

[32] Kobor Direct Testimony at p. 27.

Ms. Kobor herself recognizes the fundamental problem, acknowledging the existence of competing 2013 APS studies finding drastically different values.[33] She seems confident, however, that with Commission oversight, a cost/benefit analysis can be conducted that will produce a "reliable result," and suggests use of a guidebook prepared by the Interstate Renewable Energy Council, citing the categories of benefits identified in the IREC report:[34]

a) avoided energy benefits
b) system losses
c) generation capacity
d) transmission and distribution capacity
e) grid support services
f) financial services
g) security services
h) environmental services
i) social services
j) customer costs
k) utility costs
l) decline in value for incremental solar additions at high market penetration
m) transmission and distribution (T&D) line loss reduction (avoided transmission/distribution investment)
n) environmental benefits (emission mitigation costs)
o) avoided purchased power/risk
p) avoided grid support
q) economic development

[33] *See* Kobor Direct Testimony at p. 27.
[34] Ms. Kobor, pp. 27-28. Witness Mark Fulmer references many of these same elements in his Direct Testimony.

That Ms. Kobor considers the IREC Report to be an unbiased starting point proves more than she intended.

The IREC publication, rather than being a "best practices" guide, is an advocacy piece that simply lays out an outline for ways of arguing for cross subsidization of solar DG—without any developed evaluation methodology. Indeed, it is an attempt to find a rationale for the prices derived from retail net metering, which was never a carefully reasoned pricing regime, but was, rather, a default methodology that evolved for reasons that are no longer relevant in today's electricity market. Not only does IREC offer no methodological assistance, it provides no basis whatsoever for monetizing the criteria noted above. It is, in fact, little more than a laundry list of potential attributes solar advocates can use to call for higher prices for solar DG, without ever offering a serious, fact based rationale for the claims asserted. It suggests, for example, an examination of the impact of solar DG on carbon reduction, but gives little guidance on how such an effort should be undertaken, and, remarkably, never even suggests that one might examine the cost effectiveness of solar DG in reducing carbon emissions compared to such alternatives as energy efficiency, large scale solar, nuclear, and wind. Similarly, it fails to even reference the fact that in order to assess the carbon effects of solar DG, one needs to clearly identify what generating resources are being displaced (e.g. coal, combined cycle) by solar DG when it is producing energy and what the impact of the intermittent nature of solar DG is on dispatch, as well as the environmental impact, not to mention economic efficiency, of ramping generation up and down to accommodate the intermittent injection of solar DG energy into the system.

The point here is not that the IREC document, or any number of value of solar studies, are incomplete and biased, although the IREC report clearly is, as are many value of solar studies. Rather, it is that such studies are highly subjective, often quite arbitrary, and, if reasonably complete, extraordinarily complex (if the authors are truly

disinterested analysts, as opposed to advocates with a point of view), and, to be done correctly, these studies require a great deal of time and expense. Moreover, the results, no matter how honestly derived, are always going to be highly subjective, full of debatable assumptions, and subject to severe criticism by any number of interest groups with an axe to grind or a point of view to advance. Perhaps most interesting is that such studies rarely even reference the historic reference points used for pricing, markets and costs.

There is a reason we rely on markets and market prices, and not "value analysis," whenever possible. When we do use value analyses, it is important to keep these limitations in mind. Indeed, electricity pricing in the U.S. has always been based on one of two highly disciplined foundations, cost (including avoided cost), and/or market. Every energy source in the country is priced on one of those foundations. Pricing one resource based on someone's subjective view of "value," while pricing every other resource based on a disciplined and systematic approach, is simply indefensible as a matter of public policy. The public deserves better than that.

**Q. DO YOU AGREE WITH MS. KOBOR THAT THE EXISTENCE OF OTHER COST SHIFTS IS A REASON TO TAKE NO ACTION ON ROOFTOP SOLAR SUBSIDIES?**

A. I do not agree with her at all. First, the fact that there may be other cross-subsidies in rates is hardly a reason for refusing to remedy perhaps the most inefficient of cross subsidies. This is particularly true where the remedy, as proposed by UNSE, is so simple to put in place.

More importantly, Ms. Kobor misses the point almost completely. It may be true that other factors contribute more to UNSE's revenue deficiency. The much bigger issue, and the one Ms. Kobor completely ignores, is that current rate design and retail net metering causes shifts, socially regressive ones, in cost allocation among customers. If solar DG customers are excused, as they are under current rate design, from having to

pay their fair share of the fixed and demand costs associated with the energy service provided to them, those costs do not disappear. Regulators are then left with just two options, either pass on those costs to non-DG customers, or, alternatively, force utilities to absorb those lost revenues, an outcome that is very likely to result in underinvestment in the grid (and may not be legally permissible or consistent with the regulatory compact). Neither of those outcomes is acceptable in any event. The real issue is avoiding that highly unfortunate choice, and the way to fix it is to require all customers, including rooftop solar customers, to pay their fair share of the system's fixed and demand costs.

Ms. Kobor's testimony draws the wrong conclusion in reasoning that there is no good reason to single DG customers out as a class for special reformed rates. First, as noted by several witnesses, now including myself, in this proceeding, there are many reasons why UNSE is correct in making the tariff reforms it proposes. Revenue deficiency is only one of them, and perhaps not even the most important one. In specific regard to revenue deficiency, however, DG solar is expected to continue to grow in Arizona, and the more it grows, the bigger a burden the cross-subsidy will represent. Eventually, it will simply not be sustainable. Moreover, as can already be seen in this state and others, the politics of getting the tariffs right becomes increasingly difficult when more and more people are invested in a severely flawed tariff that skews the prices in costly and economically perverse ways. It is best to get the prices right from the beginning so that when customers make their decision about whether or not to go solar, the price signals are correct and the costs and benefits to society are correctly aligned in the tariff formulation. Failing to do so means that every new solar DG installation represents a significant investment made based on expectations of continuing out-of-market and above cost pricing, thereby increasing the difficulty of ever reforming the policy. In fairness to both DG and non-DG customers alike, it is important to get rate signals correct and sustainable as soon as possible.

**Q. MS. KOBOR ASSERTS THAT UNSE HAS FAILED TO ADEQUATELY PROVE ITS CLAIMS. PLEASE RESPOND.**

A. Ms. Kobor challenges UNSE's proposal that distributed generation has the potential to seriously impact the grid and UNSE's analysis of the incentive problems it creates for customers, by complaining that UNSE has not provided detailed evidence that the problems it fears are happening at scale today, complaining that "UNSE…relies on broad national and regional studies, which may or may not apply to UNSE's grid and service territory."[35] She herself, however, provides no actual evidence that the facts are on her side. She does not even present a plausible theory that would suggests the facts might be on her side or explain why she thinks Arizona's circumstances are not adequately captured by regional or national studies. What, exactly, does she think is different about Arizona? She never bothers to explain.

In doing this, she is failing to meet her client's burden of raising sufficient doubt as to the applicant's proposal to shift the burden of proof back to the utility. I was a regulator for ten years. I have taught regulation in more than two dozen countries, and at many institutions within the United States, including all three NARUC-approved training programs, at Michigan State University, the University of Florida, and New Mexico State University, as well as here at Harvard. The process that should be followed in cases like these is clear. The utility makes a proposal, and parties who wish to rebut the proposal, whether the staff of the Commission or outside parties, have the opportunity to do so. They do, however, also have a burden of providing evidence to support their rebuttal, and if they don't meet that burden, there is nothing for the Commission to go on. Witness Kobor has offered absolutely no probative evidence to meet that simple burden.

[35] Kobor Direct Testimony at pp. 16-17.

In fact, both Ms. Kobor and Mr. Fulmer complain that the extensive evidence and analysis provided by UNSE is somehow inadequate but fail to offer any countervailing evidence or even, in many cases, a strong theory suggesting why UNSE's analysis requires further support. What witnesses Mr. Fulmer and Ms. Kobor have provided here is testimony making broad assertions with no evidentiary basis. Consequently, they have failed what the law terms their burden of going forward with credible evidence supporting their assertions.

It is ironic that all this effort to undermine UNSE's analysis still fails to get to the heart of the issue. Ms. Kobor devotes many pages to an argument that points to the unsurprising fact that DG customers are still a relatively small part of the UNSE customer base—therefore, the gross amount of cross subsidy they are receiving is currently relatively small. It is not clear why Ms. Kobor chooses to focus on just one motivation for the tariff reforms proposed by UNSE, but her largely exclusive focus on it makes it appear that she has presented less than a complete understanding of all of the issues at hand.

**Q. SHOULD UNSE CONSIDER THE DISTRIBUTED GENERATION REQUIREMENT IN ARIZONA'S RENEWABLE ENERGY STANDARD (RES) IN SETTING ITS RATE FOR SOLAR DG ENERGY?**

No. Although Ms. Kobor warns that a change in the net metering rate might result in UNSE failing to meet its distributed generation requirement in upcoming years,[36] this is not a consideration that it is appropriate to incorporate into rate design. Significantly, she has also failed to make any showing that her assertion that implementing UNSE's rate proposals would cause UNSE to be out of compliance with its required quota of DG. In effect, she is pleading for distorted pricing and incentives over the long term in order to head off a specific, short-term problem which indeed may not turn out to be a problem at all. This is not good ratemaking as expounded by Professor Bonbright!

[36] Kobor Direct Testimony at p. 52.

Instead, if there is a need for additional solar DG to meet state requirements, that should be handled separately, helping to keep costs transparent and efficiency incentives in place. Moreover, the rule itself is absolutely within the discretion of the Commission to modify, eliminate, or waive.

**Q. WHAT IS THE RELEVANCE OF MS. KOBOR'S ARGUMENT THAT THE PROPOSED RENEWABLE CREDIT RATE WOULD VIOLATE THE COMMISSION'S EXISTING NET ENERGY METERING RULES?**

A. Ms. Kobor makes this argument on pp 32-33 of her testimony. Without evaluating this argument substantively (I have not examined the question of whether the proposed rate violates the existing rule or not), it is improbable that this is an insurmountable obstacle, should the Commission wish to approve the proposed rate. Whatever the existing rules are, they were established by the Commission. When I sat on the Public Utilities Commission of Ohio, we always had available the ability to repeal, modify, or waive commission-created rules where we believed the circumstances were such that the action(s) was (were) both warranted and reasonable.

**Q. IS THERE ANY BASIS FOR MS. KOBOR'S ASSERTION ON PAGE 37 THAT "MOVEMENT TOWARDS MANDATORY DEMAND CHARGES FOR ALL RESIDENTIAL CUSTOMERS IS IN NO WAY REFLECTIVE OF MODERN TRENDS IN RATEMAKING?"**

A. None at all. I am Executive Director of a leading "think tank" on electricity policy, and the potential role of demand charges in rate design is a frequent subject of discussion. Recent proceedings in Ms. Kobor's home state of California included significant debate over that issue. In fact, demand charges are a critical element in the movement in ratemaking toward unbundling prices, making prices more transparent, and providing customers with meaningful price signals in order to bring greater efficiency to the use of electric energy. Indeed, the position of the ACC Staff in this matter is a classic example of demand charges being at the center of regulatory thinking in the U.S. today. Suffice it to say that Ms. Kobor's deeming the idea as not reflective of modern trends in ratemaking is both uninformed and profoundly mistaken.

**Q. WOULD YOU AGREE WITH MS. KOBOR'S ASSERTION THAT THE PROPOSAL TO REDUCE THE NUMBER OF CUSTOMER TIERS IS ALSO NOT REFLECTIVE OF "MODERN RATE DESIGN?"**

A. No. Ms. Kobor has a distorted view of "modernized rate design" if she believes that reduction of the number of rate tiers is not compatible with it.[37] This issue has been vigorously debated within her own state very recently, and is a topic of debate across the country, indeed, around the world.

## V. UNSE'S PROPOSAL FOR A RENEWABLE CREDIT RATE IS AN APPROPRIATE WAY TO COMPENSATE CUSTOMERS FOR ENERGY EXPORTED TO THE GRID.

**Q. TURNING TO THE THIRD ELEMENT OF UNSE'S PROPOSED RATE, IS THE MOST RECENT RENEWABLE PPA A REASONABLE BENCHMARK FOR SETTING THE RENEWABLE CREDIT RATE FOR COMPENSATING DG SOLAR PRODUCTION?**

A. Yes, this approach is entirely reasonable. It uses a benchmark price established for intermittent renewable energy by looking at the last arms-length transaction to purchase intermittent renewable energy in the competitive bulk power market. By using the most recently negotiated rate, the price recognizes that energy prices fluctuate and does not lock in a higher than market standard offer for solar DG. It does not over-compensate distributed generation beyond levels of compensation offered to grid-scale renewables, thereby averting the potential for diverting capital from a more efficient generator to a less efficient one. Indeed, by gearing the price paid for solar DG to that of a more efficient resource, UNSE' proposal has the very positive effect of incentivizing solar DG to become more efficient and improve productivity. That incentive is completely lacking in the existing retail net metering pricing model, and that is one of the problems that cries out for reform of the type being proposed by the applicant in this proceeding. Nonetheless, UNSE's proposal is still generous in the sense that it is paying the same for solar DG as it does for utility-scale solar, despite the fact that the latter is the more efficient resource. Finally, the benchmark price is derived from transactions involving

[37] Kobor Direct Testimony at p. 55.

energy resources that are, like solar DG, intermittent. Thus, UNSE's proposal avoids having to compare apples with oranges. The price point is one that is subject to market discipline, recognizes fluctuations in the wholesale market, and prevents a reallocation of capital toward less efficient resources.

**Q. WHAT ABOUT MR. FULMER'S AND MS. KOBOR'S ARGUMENT THAT THE PRICE OFFERED FOR DG SOLAR SHOULD BE HIGHER THAN THE PRICE OF UTILITY-SCALE RENEWABLES, BECAUSE DG SOLAR OFFERS MORE VALUE TO THE UTILITY?**

A. The argument has no merit. The argument they are making is a variation on the "value of solar" theme discussed above. Ms. Fulmer and Ms. Kobor both suggest that rooftop solar offers more value than utility-scale solar in their discussion of UNSE's proposal to compensate DG solar at the going wholesale market rate, as established by the latest comparable PPA. The geographic diversity of solar DG systems is their main argument. This, they suggest, will alleviate the intermittency of solar power. At the same time, Mr. Fulmer argues, distributed solar systems do not have "the potential habitat, visual and cultural impacts associated with utility-scale solar plants."[38] However, neither of the two makes any effort to quantify this additional "value." They do not even try to show that the so called "value" they reference is equal to the full retail price of delivered electricity. Because they do, as noted, cite anecdotal examples of the added "value" they claim, I will address each of them.

**Assessing the value of geographic diversity relative to intermittency.** This argument is one dimensional thinking—Mr. Fulmer and Ms. Kobor highlight one or two small possible benefits of DG solar compared to utility-scale solar, while ignoring the overwhelming, evidence-based, consensus that grid-scale PV generation is more efficient—not just for the obvious reasons of economies of scale, and the fact that grid-scale plants are far more likely to have optimized panel placement and tracking, but also

[38] Fulmer Direct Testimony at p. 4.

because a utility-scale solar plant, purpose-built to produce solar power, is more likely to be optimally situated in areas of peak sunshine.[39]

It is unlikely this argument about geographic diversity points to any significant advantage of solar DG over grid-scale solar. For one thing, it is based on the false assumption that grid-scale solar plants are limited to a single location. Utility-scale solar plants can take advantage of geographic diversity as well—and the potential for diversity is great, since utilities can purchase power from distant plants, as long as they are connected to the transmission grid. Rooftop solar, of course, by its very nature is entirely concentrated within the narrower confines of a distribution utility. Thus, the claim of geographic diversity as a benefit of rooftop solar has no basis in fact.

Even if one accepts the dubious premise of greater geographic diversity in rooftop solar systems, the claim that this outweighs the benefits of utility-scale solar does not hold water. The previously cited Brattle Group study comparing grid-scale with rooftop solar systems looks at this issue in the terms proposed by Mr. Fulmer and Ms. Kobor, pitting the intermittency of a single utility-scale solar unit against an array of rooftop solar units. While acknowledging the potential role geographic diversity could play in reducing intermittency from the rooftop solar units, the Brattle analysis also looks at other significant factors, noting that "Utility-scale systems that oversize the panel array relative to inverter capacity will likely have a better profile (less variability) than any given residential-scale system," a factor that needs to be weighed against geographic diversity, stating that the net impact on ancillary services needs is "difficult to determine," but noting grid-scale solar's other advantages of "better location selection

[39] Tsuchida, Bruce, Sanem Sergii, Bob Mudge, Will Gorman, Peter Fos-Penner, and Jens Schoene. *Comparative Generation Costs of Utility-Scale and Residential-Scale PV in Xcel Energy Colorado's Service Area.* Brattle Group, 2015, p. 9. Available at http://brattle.com/system/publications/pdfs/000/005/188/original/Comparative_Generation_Costs_of_Utility-Scale_and_Residential-Scale_PV_in_Xcel_Energy_Colorado's_Service_Area.pdf?1436797265.

(higher insolation), better controllability and visibility by the system operator, and being able to provide downward ancillary services." After reviewing other factors, such as the higher capacity factor of utility-scale PV, the possible transmission loss reductions associated with distributed PV, the Brattle study concludes that "[o]verall, inclusion of these factors is likely to increase the cost difference between utility-scale and residential-scale PV systems."[40]

**Assessing the value of "habitat, visual and cultural impacts."** In his November, 2015, testimony, Mr. Fulmer cites the discussion of these potential impacts in the DOE's *Sunshot Vision Study* as an argument for the greater value of solar DG as opposed to utility-scale solar.[41] However, his presentation of the issue is one-sided, neglecting the issues faced by distributed solar, ironically raised by the same DOE study he cites only a few pages beyond the information he presents in his testimony:

> owners of existing systems face potential challenges when growing trees or new structures on neighboring property shade their solar collectors. Given that there is no common-law right to sunlight in the United States, these issues present serious barriers to the adoption of solar energy[42]

The DOE report goes on to suggest some legal mechanisms that may allow neighbors to navigate this issue through establishing "landowners' rights to present and future unobstructed direct sunlight" or through sale of easements, etc.—but they have appropriately pointed out that the installation of rooftop solar is not without implications to neighboring homes—particularly if it results in attempts to limit the growth of trees on a neighbor's property or their attempts to remodel or expand homes.[43] What DOE is

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[40] *Id.* at pp. 35-36.

[41] For those, like me, puzzled by the reference to "cultural impacts," the DOE study writes that "conflicts may arise if development impacts cultural sites or interferes with U.S. Department of Defense (DOD) activities." "The SunShot Vision Study," Department of Energy, February 2012, at p. 171. These potential "cultural impact" problems seem to be readily addressed through proper site selection.

[42] DOE SunShot Vision Study at 184.

[43] For that matter, it may be worth considering the incentive solar panels might present to cut down existing shade trees. When tree shade is an issue, certainly, the calculus about the environmental costs

discussing is selective destruction of other people's trees to accommodate solar DG. In short, we may often run the real risk of losing the aesthetic, shade, and carbon offset benefits provided by trees in order to accommodate solar DG. Thus Mr. Fulmer's claim that solar DG provides greater habitat value is highly dubious at best. Similarly in regard to the claim of "visual" value, another well-known source of neighborhood conflict related to solar DG is the potential for glare from solar panels to adversely impact neighbors. In short, visual and habitat impacts are not limited to utility-scale solar.

**Q. MR. FULMER CRITICIZES UNSE'S RENEWABLE ENERGY CREDIT BECAUSE IT IS SET UP TO ADJUST EVERY YEAR. WHAT IS YOUR EVALUATION OF THIS ARGUMENT?**

A. Mr. Fulmer raises a number of concerns about the proposed compensation methodology; however, not all his concerns seem to be consistent with each other. In part, his concern seems to be that the deal being offered to rooftop solar customers is not good enough. The proposal here is to tie rooftop solar compensation to a measure of the actual price of renewable energy in the open marketplace in a given year—instead, Mr. Fulmer suggests that rooftop solar customers should be given a twenty year price guarantee. He asserts, "the prudent utility will look at its needs in the future and consider all the options for meeting those needs in a least-cost fashion....If you can take actions NOW that can save ratepayers money (or reduce risk or meet some other planning goal) in the future, at higher costs today, they are likely the correct actions to take."[44]

Mr. Fulmer's stated concern for securing marginal efficiencies for ratepayers related to getting the most bang for their bucks in the purchase of renewable power is inconsistent with his main objection to the proposed pricing scheme: "Further, as proposed, Rider 11 will likely act more like a ratchet, ever going down. This obviously creates a problem

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and benefits of solar panels becomes increasingly complex, expanding to include the question of how much additional air conditioning power might be used to compensate for loss of shade.

[44] Fulmer Direct Testimony at p. 9.

for someone considering an investment in a fixed asset."[45] That is, Mr. Fulmer (correctly, in my opinion) anticipates that grid-scale renewable energy will get cheaper over time (keeping in mind that, as discussed above, that larger-scale renewables are more cost effective today).[46] And, disturbingly, he views this as a problem, one that should be solved by committing utility resources to overpaying for DG renewable energy for decades into the future—when that same amount of money, if indexed to declining renewables costs, could buy ratepayers far more renewable energy per dollar under the UNSE proposal, and would at the same time provide rooftop solar providers with an incentive to be more efficient.

**Q. WOULD THE RENEWABLE CREDIT RATE BE SUBJECT TO GAMING?**

A. Ms. Kobor raises the vulnerability of the proposed pricing system to gaming as a concern,[47] suggesting that the utility could manipulate its PPAs to artificially deflate the Renewable Credit Rate.

There is no system that is not at least theoretically vulnerable to some type of gaming. Indeed, policing against gaming that is contrary to the public interest is an important part of the *raison d'etre* of the ACC. Thus, the risk of gaming is simply not a sufficient reason to retain the severely flawed system of retail net metering, which itself is already being gamed by the solar DG industry.[48] What UNSE has proposed has the virtue of transparency. Through annual public filings, the Commission and the public will be able to review the Renewable Credit Rate and address any concerns about gaming that may

[45] Fulmer Direct Testimony at p. 7.

[46] Curiously, Mr. Fulmer does not object to the fact that utilities, under net metering buy excess solar DG at the retail rate, something which also fluctuates over time, but, based on solar DG industry marketing claims (and I received such a robo call very recently) that fluctuation is upward. Thus, Fulmer is essentially arguing not against uncertainty, but rather calls for a completely asymmetrical arrangement where solar DG gets the benefits of any upward price fluctuation, but has no risk of downward fluctuation in the marketplace.

[47] Kobor Direct Testimony at p. 31.

[48] SolarCity's recent 10K filing clearly describes that its business model is built on chasing subsidies, a classic example of gaming, which is not in the public interest. *See* SolarCity Corp. 10K (2/24/15) at p. 38.

arise. Moreover, the Commission itself has the requisite skills and intelligence to monitor, identify, analyze, and remedy any adverse gaming that may occur.

**Q. IS THE PROPOSAL MADE BY LON HUBER OF RUCO FOR THREE RATE OPTIONS FOR SOLAR DG CUSTOMERS A GOOD ALTERNATIVE RATE APPROACH?**

A. RUCO's aim here as explained by Mr. Huber is laudable:

> RUCO would like to begin by ensuring that rooftop DG can be a neutral cost proposition for ratepayers as soon as possible. Once that milestone is reached RUCO would like to see DG be a net benefit to all ratepayers. Finally, the third milestone, RUCO would like to see a closer cost parity between wholesale grid-connected solar and rooftop solar.

I agree with these goals. However, the rate structure RUCO proposes would not get Arizona there "as soon as possible"—in fact, though it might progress slowly in that direction, it would never actually arrive, even after twenty years. I think we can fix the retail net metering rate problem faster than that!

Mr. Huber suggests three rate options, all of which, in my opinion, are inferior to the UNS proposal. Among other issues, they don't seem to fit together in a way that constitutes consistent public policy. Although it appears from his testimony that he understands the issues, the RUCO proposals do not seem to have translated into a proposal that resolves the issues before the Commission. Here are the major problems with RUCO's proposal as I see them:

1. *The Non-Export Option.* With this option, solar DG customers could stay on traditional rates—they would just have to agree not to export solar power to the grid. To me, this does not address the issues. To the extent that customers choose any of the current rates, in which fixed costs are recovered through variable energy use charges, the cross subsidy issues above are not addressed at all. Furthermore, the non-export provision is not the direction Arizona should go if it wants to optimize the potential contributions of solar power—the aim, rather,

should be to optimize the benefit to the consumer and the grid of investments in solar, by having fair rates that create proper incentives for efficient deployment and use of solar DG—not to discourage customers from maximizing the benefits of their investment in solar energy.

2. *The DG "TOU" Option.* This proposed rate weakens some elements of the UNS proposal that is intended to correct inequities associated with solar DG's participation in retail net metering. The minimum bill (alternative to fixed charge) increase is smaller ($12); and the proposed payment for exported power is higher. The proposal is to pay 8.5 cents/kWh for excess power exported to the grid—considerably more than the going rate for utility-scale renewable energy. This higher rate is based on some very rough calculations of capacity savings undertaken by Mr. Huber. For the reasons of solar intermittency I discussed above, in my opinion these capacity savings will not be realized by the utility or its customers. At the same time, the proposal includes an aggressively high TOU demand charge during summer peak hours (2pm-8pm)—at $19.50/KW, the charge is almost twice as high as the higher of the two demand charges proposed by UNS for customers whose demand exceeds 7 kW. This does provide a strong incentive to customers who choose this rate to minimize their consumption during these summer peak hours—I would note, though, that (keeping in mind the California duck curve chart discussed earlier) the long-run interest of the utility and of the growth of solar in Arizona is to encourage solar DG customers to use energy when the sun is shining, but consciously reduce their usage when the weather is cloudy and when the sun declines and sets. The 2pm-8pm TOU rate proposed is too blunt an instrument to promote this behavior. Overall, it is a little hard to tell what the impact of this proposed option would be, in terms of minimizing cross subsidies. The element of choice of rates endorsed by RUCO

would be the decisive factor in preserving cross-subsidies, since presumably only customers who hope to benefit from such a rate would choose it.

3. *RPS Bill Credit Option.* This final (very generous) option addresses only the export rate portion of the cross subsidy. Reforming the export rate is a step in the right direction, but to be comprehensive, it must be coupled with rate design reforms. Further, this RPS Bill Credit Option pursues this partial reform in a way that would be better described as "glacial" than "gradual." The renewable credit rate would start at a generous 11 cents/kWh—a rate which customers could lock in for twenty years. For new customers, the initial rate offer would slowly decline as more solar capacity was added, reaching competitiveness with current utility-scale renewable energy rates as late as 2025 (though potentially this could happen earlier, depending on how fast growth in solar capacity occurs). Throughout this period, customers could lock in these elevated per kWh reimbursement rates for twenty years at a time. So it would be twenty to thirty years before the utility was buying DG solar power at a competitive rate (assuming, meanwhile, that utility-scale renewable costs do not decline further)—and even then, cross-subsidies associated with the use of solar to offset a customer's own consumption would not be addressed at all. While this option has some merit in its structure and intent, it takes gradualism far beyond what the respected Professor Bonbright could have intended!

**Q. DO YOU HAVE ANY COMMENTS ON THE ISSUE OF RATE GRADUALISM THAT THE RUCO PROPOSAL IS TRYING TO ADDRESS?**

A. Yes. On the issue of rate gradualism, I must disagree with Mr. Huber's assertion that UNSE's proposal violates this principle. Increasing the fixed charge from $10 to $20 (and now, as revised by UNSE, $15) is not "seriously adverse to existing customers" and is well short of revolutionary. For most customers, this change will, if anything, be accompanied by a slight reduction in the overall bill, as the burden of paying for cross

subsidies to other customers is eased. And the individual customers likely to experience the largest bill increases, DG customers, could for the most part protected by grandfathering. The major change here is to the rates prospective new DG customers will face, as they receive a more accurate signal about the value of the solar DG in which they are considering investing.

## VI. CONCLUSION

**Q. DO YOU HAVE ANY CONCLUDING REMARKS?**

A. Yes. As I have explained in my testimony, the central issue for solar DG in this matter is not a conflict between the utility and solar energy providers. Rather, UNSE's proposed rate change for solar DG customers is an attempt to enable effective competition between different energy resources, in which solar DG will enjoy the "mainstream" energy role called for by Vote Solar witness Ms. Kobor. The new UNSE rate would provide powerful incentives to increase the productivity and efficiency of distributive solar generation, ones that envision long term financial sustainability for distributed solar energy. This attempt is being strenuously opposed by a solar DG industry dedicated to preserving its special status as the beneficiary of arbitrarily high, out of market, non-cost based, heavily subsidized prices, resulting in higher profits for themselves at the expense of consumers, solar and non-solar alike, to the long run detriment of the viability of distributed solar generation.

UNSE's proposals before the Commission would not only remedy an urgent and growing problem related to the subsidies of higher-income customers by lower-income customers entailed by net energy metering, reduce the risk of depriving the grid of needed investment, open opportunities for new service providers to enter the market to provide services and products to enhance efficiency opportunities for customers, and enhancing competitive markets forces in the power sector. Just as important, and most ironically, it would also establish a pricing structure to enhance the long term prospects

of distributed solar generation far beyond the dubious prospects offered by the "chasing subsidies" business model currently being used by most solar DG developers.

**Q. DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?**

A. Yes.

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Before his current activities, Ashley Brown served as Commissioner of the Public Utilities Commission of Ohio, appointed twice by Governor Richard F. Celeste, first for a term from April 1983 to April 1988 and for a second term from April 1988 to April 1993. As Commissioner, he was of five members responsible for the regulation of the state's electricity, telecommunications, surface transport, water and sanitation, and natural gas sectors.

Prior to his appointment to the Commission, Mr. Brown was Coordinator and Counsel of the Montgomery County, Ohio, Fair Housing Center. From 1979-1981 he was Managing Attorney for the Legal Aid Society of Dayton, Inc. From 1977 to 1979 he was Legal Advisor of the Miami Valley Regional Planning Commission in Dayton. While practicing law, he specialized in litigation in federal and state courts, as well as before administrative bodies. He has served as an expert witness in litigation in the courts and administrative agencies In addition, Mr. Brown has extensive teaching experience in public schools and universities.

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Member, U.S. EPA Acid Rain Advisory Committee

Chair, Planning Section, National Governors' Association Task Force on Electric Transmission

Member, the Keystone Center Dialogue on Emissions Trading

Member, the Keystone Center Project on the Public Utility Holding Company Act of 1935

Member, The Keystone Center Project on State/Federal Regulatory Jurisdictional Issues Affecting Electricity Markets

Member, Policy Steering Group, The Keystone Center Project on Electricity Transmission

Member, Advisory Council of the Board of Directors of Nuclear Electric Insurance Limited

Member, Advisory Council of the Consumer Energy Council of America Project on Electricity

Member, Advisory Committee of the Consumer Energy Council of America Air Pollution Emissions Trading Project

Member, National Task Force on Low Income Energy Utilization and Conservation

Member, Board of Directors, Center for Clean Air Policy

Member, National Blue Ribbon Task Force on Allocating the Cost of New Transmission

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INTERNATIONAL EXPERIENCE

Member, Board of Director, Entegra Power Group

Member, U.S. Delegation of State Government Officials in the Center for Clean Air Policy/ German Marshall Fund Sponsored Exchange on Clean Air Issues to Germany, 1989

Member, U.S. Delegation to International Electric Research Exchange (IERE), Rio de Janeiro, Brazil, 1991

Consultant, Hungarian Ministry of Industry and Trade on Gas and Electric Regulatory policy, 1991-1992
*Advisor to Ministry of Trade and Industry on Writing New Laws Governing Electricity, Natural Gas, and Regulation*

Consultant, SNE, Costa Rican Regulatory Agency, on Transmission Access Issues, 1992
*Advisor on Development of Independent Power Producers and Transmission Access*

Consultant, World Bank Mission to Hungary Investigating the Financing of New Power Plants for MVM (Hungarian Electric Co.), 1992
*Preparation of Background Materials in Preparation of a World Bank loan to the Hungarian Power Sector*

Member, U.S. Delegation, in Conjunction with the U.S. Department of Energy, to the Argentina and United States Natural Gas and Electricity Regulatory Meetings, 1992

Consultant, ENARGAS, the Argentine gas regulatory agency, 1992
*Providing Training for ENARGAS Commissioners and Staff*

Consultant, USAID India Private Power Initiative Program on the Introduction of Private Generation and Competition into the Public Sector, 1993
*Preparation of a Report on Introducing and Promoting Private Investment in the Indian Power Sector*

Instructor, Regulatory Training Program of the National Regulatory Research Institute at Ohio State University and the Institute of Public Utilities at Michigan State University, Buenos Aires, Argentina, 1993
*Providing Training to Commissioners and Staff of ENARGAS*

Consultant, The Province of Salta, Argentina on infrastructure regulation, 1996
*Providing Training to Commissioners and Staff of the Regulatory Agency of the Province of Salta*

Consultant, USAID, Philippines Electric Sector Restructuring, 1994
*Preparation of Analysis and Report on Restructuring the Philippine Power Sector Including the Attraction of Private Capital in Generation, and Introduction of Competition*

Consultant, USAID, Russian Electric Sector Restructuring, 1994
*Preparation of Analysis and Report on Restructuring the Russian Power Sector Including the Attraction of Private Capital in Generation, and Introduction of Competition*

Participant, Harvard University's East Asian Electricity Restructuring Forum, 1994-1995
*Delivering a Series of Lectures in China, Indonesia, and Thailand on Reforming the Power Sector*

Consultant, Government of Ukraine on Electricity regulatory policy and industry restructuring, 1994-1995
*Advisor to the National Energy Regulatory Commission on the Structure, Processes and Substance of Electricity Regulation*

Consultant, Government of Brazil on Electric Sector Restructuring, 1995-1996
*Adviser to the Ministry of Mines and Energy on Various Issues Related to Privatization and Introduction of Competition in the Power Sector*

Consultant, Energy Regulatory Board of Zambia, 1997-2001
*Advisor to the Energy Regulatory Board on the Structure, Processes and Substance of Electricity Regulation*

Member, Brazil-U.S. Energy Summit, 1995-1996
*Preparation of a Report and Lecture on the Options for the Regulation of a Restructured Brazilian Power Sector*

Consultant, Nam Power, the electric utility in Namibia, 1998-1999
*Advisor on Development of Independent Power Project and on Restructuring of the Electric Distribution Sector*

Consultant, Government of Indonesia on electricity regulation, 1999
*Training Government and Industry Personnel on Electricity Regulation*

Consultant, Government of Mozambique on reform of the commercial code, 2000
*Advisor on Reformation and Rewriting of the Commercial Code*

Instructor, South Asia Forum for Infrastructure Regulation, 1999-present
*Annual Training Regulatory Personnel from Five South Asian Countries*

Consultant, Government of Tanzania on electricity regulation, 2002
*Advisor of Rewriting the Laws Governing Energy and Transport Regulation*

Consultant to Inter-American Development Bank on Sustainability of Sector Reform in Latin American energy markets, 2001-2002
*Preparation of a report and Analysis on the Sustainability of Power Sector and Regulatory Reform in Latin America, with Specific Focus on Colombia, Honduras, and Guatemala*

Consultant to Inter-American Development Bank, Brazilian Electric Restructuring, 2002
*Preparation of A Report and Analysis on Problems in the Privatization and Market Reform on the Brazilian Power Sector*

Consultant to World Bank on Brazilian energy regulation, 2002-2004
*Preparation of A Report and Analysis of Means for Improving Regulation of the Brazilian Power Sector.*

Consultant to the Brazilian Government on Redesign of Electricity Market, 2003-2004
*Advisor to Ministry of Mines and Energy on Electricity Market Design*

Consultant to Government of Dominican Republic on Electricity Regulation, 2004
*Delivery of a Series of Lectures on Problems in Restructuring and Privatization in Dominican Power Sector*

Consultant to Eskom, South Africa, 2004-2005
*Advisor on to Eskom on Restructuring of South African Electric Distribution Sector*

Consultant to World Bank on Regulation and Market Reform in Russian Power Sector, 2004-2005
*Preparation of Report and Lecture on Regulatory Issues in proposed New Market Design of Russian Power Sector, and Attraction of Private Capital*

Consultant to Government of Guinea-Bissau on Infrastructure Regulation, 2005
*Training Government and Industry Personnel on Infrastructure Regulation*

Consultant to the Government of Mozambique on Electricity Regulation, 2006-2007
*Assisting in the Re-Establishment of the Electricity Regulatory Agency*

Consultant to the Government of Equatorial Guinea, 2007
*Assisting in writing the country's electricity law*

Consultant to the Public Utilities Commission of Anguilla, 2008
*Report on Funding Regulatory Agencies*

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W. P. CAREY SCHOOL of BUSINESS
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# THE ECONOMIC IMPACT OF DISTRIBUTED SOLAR IN THE APS SERVICE TERRITORY, 2016-2035

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FINAL REPORT

February 16, 2016

# L. WILLIAM SEIDMAN RESEARCH INSTITUTE

*The L. William Seidman Research Institute serves as a link between the local, national, and international business communities and the W. P. Carey School of Business at Arizona State University (ASU).*

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*Working on behalf of government agencies, regulatory bodies, public or privately-owned firms, academic institutions, and non-profit organizations, Seidman specializes in studies at the city, county or state-wide level. Recent and current clients include:*

- *Arizona Commerce Authority (ACA)*
- *Arizona Corporation Commission (ACC)*
- *Arizona Department of Health Services (ADHS)*
- *Arizona Dept. Mines and Mineral Resources*
- *Arizona Hospital and Healthcare Association*
- *Arizona Investment Council (AIC)*
- *Arizona Mining Council*
- *Arizona Public Service Corporation (APS)*
- *Arizona School Boards Association*
- *Arizona Town Hall*
- *Arizona 2016 College Football Championship*
- *Banner Health*
- *BHP Billiton*
- *The Boeing Company*
- *The Boys & Girls Clubs of Metro Phoenix*
- *The Central Arizona Project (CAP)*
- *Chicanos Por La Causa*
- *The City of Phoenix Fire Department*
- *CopperPoint Mutual*
- *Curis Resources (Arizona)*
- *De Menna & Associates*
- *Dignity Health*
- *The Downtown Tempe Authority*
- *Environmental Defense Fund*
- *Epic Rides/The City of Prescott*
- *Excelsior Mining*
- *Executive Budget Office State of Arizona*
- *The Fiesta Bowl*
- *First Things First*
- *Freeport McMoRan*
- *Glendale Community College*
- *Greater Phoenix Economic Council*
- *HonorHealth*
- *Intel Corporation*
- *iState Inc.*
- *The McCain Institute*
- *Maricopa Community Colleges*
- *Maricopa Integrated Health System*
- *Navajo Nation Div. Economic Development*
- *The Pakis Foundation*
- *Phoenix Convention Center*
- *The Phoenix Philanthropy Group*
- *Phoenix Sky Harbor International Airport*
- *Protect the Flows*
- *Public Service New Mexico (PNM)*
- *Raytheon*
- *Republic Services, Inc.*
- *Rio Tinto*
- *Rosemont Copper Mine*
- *Salt River Project (SRP)*
- *Science Foundation Arizona (SFAZ)*
- *Tenet Healthcare*
- *The Tillman Foundation*
- *Turf Paradise*
- *Valley METRO Light Rail*
- *Tenet Healthcare*
- *Twisted Adventures Inc.*
- *Vote Solar Initiative*
- *Waste Management Inc.*
- *Yavapai County Jail District*

# Executive Summary

- This study examines the economic impact of three distributed (rooftop) solar deployment scenarios in the APS service territory for the study period 2016-2035, including the legacy effects of each scenario throughout the (assumed) 30 year economic life of distributed solar systems.[1]

- When considered in the round from a purely financial perspective, it concludes that all three potential distributed solar deployment scenarios will have a detrimental effect on the State of Arizona and Maricopa County economies, all other things being equal.

- Additional distributed solar is estimated to lower gross state product (GSP) by approximately $4.8 billion to $31.5 billion (2015 $), dependent on the scenario.

- Additional distributed solar deployment is also estimated to result in the net loss of 16,595 to 116,558 job years' private non-farm employment over the entire study period, dependent on the scenario.

- Any benefits emanating from each scenario are at best temporary, only coincident with the timing of the solar installations, and quickly counteracted by their long-run/legacy effects.

- In all three scenarios, the total amount of money paid by distributed generation and central station generation electricity consumers, 2016-2060, is greater than the amount which would have been paid had they all alternatively continued to draw electricity from the utility's central grid.

- That is, in each distributed solar scenario, electricity consumers as a whole will pay more for the same amount of electricity consumed, and therefore have less money to spend in other parts of the economy.

[1] The study assumes that the cost of a 2035 distributed solar installation will only be paid off in full in 2065, thereby accounting for legacy effects. If the economic life of an installation is less than 30 years, the negative economic consequences will be greater.

## LITERATURE REVIEW

- The study begins with a comprehensive literature review to assess state-of-the-art methods in economic impact analysis.

- Seidman's methodological approach is initially positioned in a 3 x 2 matrix classification of economic impact studies, illustrated below.

**Seidman's 3 x 2 Classification of Economic Impact Models**

| | | |
|---|---|---|
| **COUNT GROSS** | **PARTIAL GROSS** | **GENERAL GROSS** |
| **COUNT NET** | **PARTIAL NET** | **GENERAL NET** |

- ***Gross*** studies only consider the direct positive impacts of increased economic activity in a specific sector.

- ***Net*** studies represent a more thorough form of economic modeling as they also account for the trade-offs in the economy which result from incentivizing one specific sector.

- ***Counts*** are usually survey-based or theoretical capacity installation quantifications of the number of direct employees within one specific sector.

- ***Partial*** models consider the wider effects of levels of activity in one specific sector, including the indirect and induced effects of the direct change, but do not consider the feedback effects of changed levels of activity in that sector – for example, the effect on wages in the labor market.

- ***General*** models offer the most comprehensive economy-wide analysis, taking into account all of the economic interconnections and feedback effects. They also yield the most significant ***Gross*** and ***Net*** impacts.

- A critique of fourteen contemporary solar economic impact studies identifies only one example of a general equilibrium analysis – that is, Cansino, Cardenete, Gonzalez and Pablo-Romero's (2013) study of Andalusia. However, this is a gross, rather than net analysis, because the authors combine renewables and non-renewables as a single sector, thereby preventing any substitution between conventional and renewable forms of generation, and effectively only allowing for positive direct demand shocks in their modeling.

- Nine of the fourteen critiqued papers adopt the partial model approach, but six of these are gross, rather than net, studies.

**Positioning Seidman's Approach Relative to Fourteen Contemporary Economic Impact Studies**

| | Counts | Partial Models | General Models |
|---|---|---|---|
| **Gross** *Only positive or negative impacts* | • Pollin and Garrett-Peltier, 2009<br>• ETIC, 2016 | • AECOM, 2011<br>• Loomis, Jo & Alderman ,2013<br>• Motamedi & Judson, 2012<br>• VSI and Clean Energy Project Nevada, 2011<br>• VSI, 2013<br>• Comings et al. , 2014 | • Cansino et al. 2013 |
| **Net** *Both positive and negative impacts* | • Alvarez et al., 2009<br>• Frondel et al., 2009 | • NYSERDA, 2012<br>• Treyz et al., 2011<br>• Berkman et al.,2014<br>• **SEIDMAN 2016** | |

- In the absence of an existing CGE model for the State of Arizona, and taking into account time and cost constraints, Seidman implements a ***Partial Net*** REMI analysis of solar deployment in the APS service territory, 2016-2035, as the next best alternative.

**ECONOMIC IMPACT ANALYSIS**

- The capital costs and financing implications of each distributed solar deployment scenario are first estimated by APS, validated by Seidman, and allocated by economic sector using NREL's JEDI model for distributed solar installations throughout the supply chain in the State of Arizona.

- APS also supplied data describing the financial impact of each solar deployment scenario on its operating cash flow, future central station generation investments, and retail electricity rates.

- The changes in investment included in the economic impact model are:

  - The annual installed costs of distributed solar capacity, 2016-2035;[2] and
  - APS' deferred or avoided central station generation investments, 2016-2035.

- The long-term legacy costs of the investment included in the economic impact model are:

  - The customer financing costs of distributed solar installations, 2016-2060;[3] and
  - Consumer electricity rate savings, due to the deferred or avoided central station generation, 2016-2060.

- The results for each scenario take into account the direct, indirect and induced economic impacts of the distributed solar deployment, and the 30-year legacy effects reflecting the economic life of the solar installations and deferred central station generation.

- Using an Arizona-specific REMI model, the economic impact of the low case scenario, which assumes 1,300 $MW_{dc}$ of nameplate distributed solar PV installations by 2035 in the APS service territory, is as follows:[4]

| LOW CASE SCENARIO | Total Private Non-Farm Employment (Job Years)[5] | Gross State Product (Millions 2015 $) | Real Disposable Personal Income (Millions 2015 $) |
|---|---|---|---|
| **State of Arizona** | **-16,595** | **-$4,806.6** | **-$1,787.3** |
| ***Maricopa County*** | ***-15,685*** | ***-$4,491.8*** | ***-$1,862.4*** |

[2] APS assumes an initial $2.50 a watt.
[3] Based on the assumed 30 year economic life of the distributed system, the customer financing costs of solar installations, 2016-2035, will not be completed until 2065. The REMI model used currently only provides economic impact estimates up to and including 2060, but Seidman does not believe that this will materially affect the conclusions in the analysis. If the economic life of an installation is less than 30 years, the negative economic consequences are in all probability greater than the estimates presented in this study.
[4] Total effects for each economic measure may not tally due to rounding-up.
[5] A job year is equivalent to one person having a full-time job for exactly one year.

- If the low case distributed solar deployment scenario actually transpires, the State of Arizona is estimated to *lose* 16,595 job years of employment, plus over $4.8 billion gross state product, and $1.8 billion real disposable personal income (both 2015 $).

- The low case distributed solar scenario therefore estimates negative impacts for all three economic impact measures assessed for the study period, including legacy effects, in the State of Arizona and Maricopa County.

- The economic impact of the expected or medium case scenario, which assumes 5,000 $MW_{dc}$ of nameplate distributed solar PV installations by 2035 in the APS service territory, is as follows:[6]

| EXPECTED CASE SCENARIO | Total Private Non-Farm Employment (Job Years)[7] | Gross State Product (Millions 2015 $) | Real Disposable Personal Income (Millions 2015 $) |
|---|---|---|---|
| **State of Arizona** | **-76,308** | **-$21,613.3** | **-$7,956.4** |
| ***Maricopa County*** | ***-71,344*** | ***-$20,149.9*** | ***-$8,087.9*** |

- If the expected or medium case distributed solar deployment scenario actually transpires, the State of Arizona is estimated to *lose* 76,308 job years of employment, plus over $21.6 billion gross state product, and approximately $8 billion real disposable personal income (both 2015 $).

- The expected or medium case distributed solar scenario's negative impacts for all three economic measures are approximately 4.5 times greater than the low case scenario's impacts in the State of Arizona for the 2016-2035 study period, including legacy effects.

- The economic impact of the high case scenario, which assumes 7,600 $MW_{dc}$ of nameplate distributed solar PV installations by 2035 in the APS service territory, is as follows:[8]

[6] Total effects for each economic measure may not tally due to rounding-up.
[7] A job year is equivalent to one person having a full-time job for exactly one year.
[8] Total effects for each economic measure may not tally due to rounding-up.

| HIGH CASE SCENARIO | Total Private Non-Farm Employment (Job Years)[9] | Gross State Product (Millions 2015 $) | Real Disposable Personal Income (Millions 2015 $) |
|---|---|---|---|
| **State of Arizona** | **-116,558** | **-$31,454.4** | **-$11,901.4** |
| ***Maricopa County*** | ***-108,857*** | ***-$29,346.7*** | ***-$12,091.2*** |

- **If the high case distributed solar deployment scenario actually transpires, the State of Arizona is estimated to *lose* 116,558 job years of employment, plus $31.5 billion gross state product, and $11.9 billion real disposable personal income (both 2015 $).**

- **The high case distributed solar scenario's negative impacts for all three economic measures are 6.5 to 7 times greater than the low case scenario's impacts in the State of Arizona for the 2016-2035 study period, including legacy effects.**

- **The high case distributed solar scenario's negative impacts for all three economic measures are also 46% to 53% greater than the expected or medium case scenario's impacts in the State of Arizona for the 2016-2035 study period, including legacy effects.**

- **Seidman's APS study therefore clearly demonstrates that increased adoption of distributed solar generation represents a loss to the Arizona economy in the low, expected and high distributed solar deployment scenarios. This is because the overall cost of provision of electricity to the State of Arizona will rise when referenced against a base case where electricity continues to be provided by central station generation.**

[9] A job year is equivalent to one person having a full-time job for exactly one year.

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# 1.0 Introduction

The purpose of this study is to calculate the total (net) economic impact of an APS distributed solar NEM program in Arizona up to and including 2035.

## 1.1. Net Metering

Net metering (NEM) encourages consumers to invest in renewable energy technologies by crediting them for distributed generation at the same tariff they pay for purchasing centrally-generated power.

Originating in Idaho and Arizona in the early 1980s, this utility resource usage and payment scheme allows customer meters to effectively run backwards whenever their own generation is in excess of their level of consumption.

Customers use their generation to offset their consumption over an entire billing period, and only pay for their net power purchase per month: that is, the amount of electricity consumed minus the amount of electricity generated. NEM credits are, de facto, based on current centrally-generated power tariffs.

Some suggest that NEM unfairly passes on the fixed costs of building and operating a transmission grid used by participants to non-participating customers. This is because residential and small business' utility rates volumetrically recover all costs, including those that are fixed. Advocates typically counter this criticism by arguing that NEM customers bring benefits to the grid that equal or exceed the fixed costs they avoid paying for through self-generation, including job creation and other economic impacts.

NEM is currently available in Arizona for a wide range of distributed generation renewables, including solar PV, solar thermal, wind, biomass, biogas, hydroelectric, geothermal, combined heat and power, and fuel cell technologies. The Arizona Corporation Commission (ACC) has not set a firm kilowatt-based limit on system size capacity. It simply stipulates that a system size cannot exceed 125% of a customer's total connected load or electric service drop capacity. There is also no aggregate capacity limit for net-metered systems in Arizona. However, each utility is obliged to file an annual report listing the net metered facilities and their installed capacity for the previous calendar year. Approximately 38,000 of APS' current 1.2 million customer base have distributed solar.

## 1.2. Economic Impact Analysis

An economic impact analysis measures the effect of a policy, program, project, activity or event on a national, state or local economy, with particular emphasis on three types of effects or impacts. These are the *direct*, *indirect* and *induced* impacts:

- ***Direct*** impacts include the initial capital investment when a business, policy or program is launched, and the people directly employed to manufacture a product, provide a service or deliver a program.
- ***Indirect*** impacts are the economic growth or decline resulting from inter-industry transactions or supplier purchases, such as a distributed solar installation company's purchase of solar modules.
- ***Induced*** impacts occur when the workers either directly or indirectly associated with an organization, policy or program spend their incomes in the local economy, when suppliers place upstream demands on other producers, and when state and local governments spend new tax revenues.

The indirect and induced economic impacts are second order expenditures and jobs created as a result of the initial "injection" of expenditure and direct jobs. For example, a utility employee hired to administer a NEM program would represent a *direct* job. Purchases made by a utility are *indirect* impacts; and the income that the utility or supplier companies' employees spend in the local economy will in turn create revenues/income for a variety of other businesses, generating *induced* effects.

The second and later rounds of indirect and induced expenditure are not self-perpetuating in equal measure. Through time, they become smaller as more of the income/expenditures "leak" out of the examined economy.[10] The cumulative effect of the initial and latter rounds of expenditure is known as the multiplier effect. There is no one "magic" multiplier estimate for every conceivable scenario. Due to the inter-linked nature of the State of Arizona's economy and its links to the rest of the U.S. (and the world), the eventual ripple effects depend on numerous factors.[11]

A full understanding of the total impact that a specific energy policy will have on an economy is therefore rather more complex than just an extrapolation of direct impacts.

[10] For example, in the form of savings, or payments on goods and services produced outside of the state.
[11] In very simple terms, what matters is the size of the direct impact, where it occurs (that is, which county/state and which sector of the economy) and the duration of the impact.

## 1.3. Study Overview

To help position APS' service territory study and provide a context for its findings, Section 2 begins with an overview of economic impact modelling approaches to renewable energy, summarized in the form of a 3 x 2 matrix.

Fourteen published analyses drawn primarily, but not exclusively, from the U.S., and additional insights from Canada, Germany, and Spain (listed in Table 1) are reviewed by Seidman in Section 3, with a particular focus on assumptions, methods and conclusions.

Examining the varying magnitude of the employment and gross state product (GSP) impacts for each of the different types of study defined by the economic impact model matrix in Section 4, a clear rationale for Seidman's approach to assess the economic impact of distributed solar deployment in the APS service territory is also provided.

Sections 5 – 9 then examine the economic impact of three distributed (rooftop) solar deployment scenarios in the APS service territory for the study period 2016-2035 in the State of Arizona and Maricopa County. The analyses include the legacy effects of each scenario throughout the (assumed) 30 year economic life of the solar systems.[12]

Section 5 introduces the 3 solar deployment scenarios assessed for APS. These are:

- A low case scenario, which assumes 1,300 $MW_{dc}$ of nameplate distributed solar PV installations by 2035 in the APS service territory, which will increase APS' total number of distributed solar customers to approximately 150,000 accounts;
- An expected or medium case scenario, which assumes 5,000 $MW_{dc}$ of nameplate distributed solar PV installations by 2035 in the APS service territory, which will increase APS' total number of distributed solar customers to approximately 690,000 accounts; and

[12] Based on the assumed 30 year economic life of the distributed system, the customer financing costs of solar installations, 2016-2035, will not be completed until 2065. The REMI model used currently only provides economic impact estimates up to and including 2060, but Seidman does not believe that this will materially affect the conclusions in the analysis. If the economic life of an installation is less than 30 years, the negative economic consequences are in all probability greater than the estimates presented in this study.

- A high case scenario, which assumes 7,600 $MW_{dc}$ of nameplate distributed solar PV installations by 2035 in the APS service territory, which will increase APS' total number of distributed solar customers to approximately 1,050,000 accounts.

**Table 1: Economic Impact Analyses Critiqued as Part of Current Study**

| Geography | Title & Author(s) |
|---|---|
| California | *AECOM (July 2011)*<br>Economic and Fiscal Impact Analysis of Residential Solar Permitting Reform |
| California | *Vote Solar Initiative (April 2013)*<br>Economic and Job Creation Benefits of SB 43/AB 1014 |
| Illinois | *Loomis, Jo and Alderman (December 2013)*<br>Economic Impact Potential of Solar Photovoltaics in Illinois |
| Montana | *Comings, Fields, Takahashi and Keith (June 2014)*<br>Employment Effects of Clean Energy Investment in Montana |
| Montana | *Energy and Telecommunications Interim Committee (January 2016)*<br>Quantifying the Economic Impacts of Net Metering in Montana |
| Massachusetts | *Motamedi and Judson (March 2012)*<br>Modeling the Economic Impacts of Solar PV Development in Massachusetts |
| Missouri & U.S. | *Treyz, Nystrom and Cui (October 2011)*<br>A Multiregional Macroeconomic Framework for Analyzing Energy Policies |
| Nevada | *Vote Solar Initiative and Clean Energy Project (2011)*<br>Economic and Job Creation Benefits of the Nevada Solar Jobs Now Proposal of 2011 |
| New York | *NYSERDA (January 2012)*<br>New York Solar Study |
| Rhode Island | *Berkman, Lagos and Weiss (2014)*<br>Distributed Generation Contracts Standard Program and Renewables Energy Fund: Jobs, Economic and Environmental Impact Study |
| Andalusia | *Cansino, Cardenete, Gonzalez, and Pablo-Romero (2013)*<br>Economic Impacts of Solar Thermal Electricity Technology Deployment on Andalusian Productive Activities: A CGE Approach |
| Germany | *Frondel, Ritter, Schmidt and Vance (2009)*<br>Economic Impacts from the Promotion of Renewable Energy Technologies - The German Experience |
| Ontario | *Pollin and Garrett-Peltier (2009)*<br>Building the Green Economy: Employment Effects of Green Energy Investments for Ontario |
| Spain | *Alvarez, Jara, Julian and Bielsa (March 2009)*<br>Study of the Effects on Employment of Public Aid to Renewable Energy Sources |

Section 6 describes the simulation results for the low distributed solar deployment scenario.

Section 7 presents the simulation results for the expected distributed solar deployment scenario.

Section 8 describes the simulation results for the high distributed solar deployment scenario.

Conclusions are offered in Section 9.

## 2.0 Economic Impact Assessment Methods

There are a number of different approaches to an economic impact assessment. These are codified in Figure 1 below.

**Figure 1: Classification of Economic Impact Models**

| | | |
|---|---|---|
| COUNT GROSS | PARTIAL GROSS | GENERAL GROSS |
| COUNT NET | PARTIAL NET | GENERAL NET |

Figure 1 illustrates two key distinctions among economic impact studies.

The first distinction is between gross studies and net economic impact studies. Studies that are ***Gross*** in nature only consider the direct *positive* impacts of increased economic activity – in this case, solar generation. ***Net*** studies represent a more rounded form of economic assessment because they also account for the trade-offs in the economy which result from incentivizing one specific sector, such as the *negative* impacts on utilities and reduced spending and investment in other economic activities associated with increased solar activity.

For example, a gross study might consider the positive effects of the installation of 100MW utility-scale solar on the level of economic activity alone, while a net study of the same installation would additionally allow for the negative economic impacts such as the decreased use of conventional forms of generation if these were displaced, and the net changes in residential, commercial and industrial energy bills. Consider also the installation of a distributed solar system by a homeowner. To meet a $30,000 cost of installation, the homeowner will forego spending the same $30,000 on something else, such as perhaps a new or refurbished swimming pool at their property. There are obviously positive economic effects associated with the homeowner's investment in a distributed solar system, which would be captured in a gross economic study. However, in this example, there are also negative effects associated with the loss

of investment in the swimming pool, which are only ever considered alongside the positive benefits of the solar installation as part of a *net* study.

Nine gross and five net studies are examined in Section 3. The gross studies are:

- California: AECOM, 2011
- California: Vote Solar Initiative, 2013
- Illinois: Loomis, Jo & Alderman, 2013
- Massachusetts: Motamedi & Judson, 2012
- Montana: Comings, Fields, Takahashi and Keith (Synapse Energy Economics), 2014
- Montana: ETIC, (2016)
- Nevada: Vote Solar Initiative, 2011
- Andalusia: Cansino, Cardenete, Gonzalez and Pablo-Romero, 2013
- Ontario: Pollin and Garrett-Peltier, 2009

The net studies are:

- Missouri & U.S.: Treyz, Nystrom and Cui, 2011
- New York: NYSERDA, 2012
- Rhode Island: Berkman, Lagos and Weiss (the Bratton Group), 2014
- Germany: Frondel, Ritter, Schmidt and Vance, 2009
- Spain: Alvarez, Jara, Julian and Bielsa, 2009

The second key distinction is between simple counts, partial (equilibrium) modeling, and macroeconomic (or general equilibrium) modeling.

***Counts*** are typically tallies of direct measures of economic activities, such as jobs, investments, or sales, without any attempt to capture the impacts of the inter-relationships with other economic sectors. As a result, counts can be more or less extensive in terms of their reach. Some just concentrate on counting the number of direct employees or assessing the level of sales within a specific economic sector, while others seek information about a sector's entire supply chain. Counts can be made by surveys or by assessing theoretically the required inputs for the installation of defined amounts of solar capacity – for

example, the first part of a JEDI model which estimates the number of jobs created in the solar sector in a linear fashion based on the MW capacity of the solar installations. Studies examined in this report that use the counts method are:

- Montana: ETIC, 2016
- Germany: Frondel, Ritter, Schmidt and Vance, 2009
- Ontario: Pollin and Garrett-Peltier, 2009
- Spain: Alvarez, Jara, Julian and Bielsa, 2009

***Partial models*** consider the wider effects of levels of activity in a specific economic sector, and are one of the most common commercial approaches in economic impact modeling. In contrast to counts, which generally assess the direct impacts of a change in the economy, partial models also consider the indirect and induced effects of the direct changes within a particular geography. The one drawback with partial models is that they do not consider the feedback effects of changed levels of an investment or economic activity such as, for example, the effect of large solar projects on wages in the labor market. Studies examined in this report that use the partial model method are:

- California: AECOM 2011
- California: Vote Solar Initiative, 2013
- Illinois: Loomis, Jo & Alderman, 2013
- Massachusetts: Motamedi & Judson, 2012
- Missouri & U.S.: Treyz, Nystrom and Cui,, 2011
- Montana: Comings, Fields, Takahashi and Keith (Synapse Energy Economics), 2014
- New York: NYSERDA, 2012
- Nevada: Vote Solar Initiative and Clean Energy Project Nevada, 2011
- Rhode Island: Berkman, Lagos and Weiss (the Bratton Group), 2014

***General models*** consider the effects of levels of solar activity in an economy-wide context with reference to every economic interconnection and feedback effect. An example is computable general equilibrium (CGE) models. These model the entire economy and attempt to account for all of the impacts associated with a specific level of solar activity. Only one study examined in this report uses a general model to assess

impacts, due to the cost prohibitive nature of producing a CGE model for a state or a region. This is Cansino, Cardenete, Gonzalez and Pablo-Romero's (2013) study of Andalusia.

Figure 2 summarizes the studies examined in this report in terms of the method employed, and whether they consider positive impacts alone, or both positive and negative impacts.

**Figure 2: Classification of Studies Examined by Method**

| | Counts | Partial Models | General Models |
|---|---|---|---|
| **Gross** *Only positive or negative impacts* | • Pollin and Garrett-Peltier, 2009<br>• ETIC, 2016 | • AECOM, 2011<br>• Loomis, Jo & Alderman ,2013<br>• Motamedi & Judson, 2012<br>• VSI and Clean Energy Project Nevada, 2011<br>• VSI, 2013<br>• Comings et al. , 2014 | • Cansino et al. 2013 |
| **Net** *Both positive and negative impacts* | • Alvarez et al., 2009<br>• Frondel et al., 2009 | • NYSERDA, 2012<br>• Treyz et al., 2011<br>• Berkman et al., 2014 | |

## 3.0 Evaluation Framework and Review of Fourteen Economic Impact Analyses

To objectively critique fourteen contemporary analyses of the economic impact of solar PV/renewables, Seidman uses the following questions as an evaluation framework:

(a) What is the context for a study?
(b) What are the study's objectives?
(c) Which geography is being studied?
(d) What is the time-horizon of the study?
(e) Which economic modeling tool is used?
(f) What types of effects are modeled, with reference to Seidman's 3 x 2 classification of economic impact models?
(g) What are the key inputs and assumptions used in the modeling process, including the solar growth projection assumptions?
(h) What are the key findings?

The following tables in this Section provides Seidman's assessment of each of the fourteen contemporary studies.

Reference will also be made, where appropriate, when a particular study method is replicated in multiple geographies by the same authors.

| | |
|---|---|
| Title | **Economic and Fiscal Impact Analysis of Residential Solar Permitting Reform** |
| Author(s) | **AECOM, July 2011** |
| Background | Considers the impact of a 76% reduction in homeowner permitting costs for solar PV when scaled to the regional and state level, taking into account the projected growth in the industry through 2020. |
| Objective(s) | • Evaluate the economic and fiscal implications of a streamlined local government permitting system for installing residential solar PV. |
| Geography | California |
| Time Period | 2012-2020 |
| Modeling Tool | IMPLAN |
| Type of Effects Examined | • This is a ***Partial Gross*** analysis, as it lacks detail on negative impacts considered.<br>• Considers a few more factors than the VSI reports, such as the initial down payment for a solar system which is positioned as a loss to homeowner savings and a gain to the solar industry.<br>• It is at best a weak, borderline example of a net partial study as it does not:<br>o Explicitly consider non-solar energy sector losses;<br>o Take into account utility obligations from a transmission and distribution grid perspective in terms of savings, upgrades or modifications;<br>o Quantify the impact of a reduction in the demand for centralized power generation due to increased distributed generation;<br>o Remove the rebate dollars paid to homeowners and installers from the IMPLAN inputs; and<br>o Consider the administrative costs associated with changing permitting rules.<br>• Also questionably assumes that increased homeowner savings from reduced electricity bills will be spent in full in-state. |
| Model Assumptions | • Base case scenario uses California Solar Initiative's 2011 residential installation costs of $6.97 per watt decreasing to $3.63 per watt by 2020.<br>• Streamlined permitting would reduce annual costs by $0.38 per watt in 2020 (i.e. from $6.10 per watt in 2011 to $3.25 per watt in 2020).<br>• Investment Tax Credit of 30% is assumed to continue through 2020.<br>• Average size of residential solar systems was 5.6 kW, 2012-2020.<br>• All solar systems will be purchased in California, albeit region unknown.<br>• Assumes solar in both cases will appeal to homeowners whose annual electricity bills would be reduced by at least 5% post-installation.<br>• Value of residential solar only impacts property taxes when the home is sold.<br>• Buyers will pay on average 3.6% more for solar PV homes. |
| Solar Growth Projection Assumptions | • Projects 1,006,500 installations at 5 utilities' service areas for current permitting, 2012-2020; or an additional 131,500 installations for streamlined permitting.<br>• 332 MW installed 2007-2011; 2,668 MW installed 2012-2020 without streamlined permitting (BAU case). |
| Effects Scaled per Year (2015 $) | • Current permitting scenario assumes:<br>o 73.5 job years created per total MW installed, amounting to 196,020 job years in total for the entire 2012-2020 period;<br>o $1.24 million GSP per MW per year (2015 $); and<br>o $69.70 per MW per year increase in additional sales tax, property tax, and payroll tax (2015 $). |

| | |
|---|---|
| Title | **Economic and Job Creation Benefits of SB 43/AB 1014** |
| Author(s) | **The Vote Solar Initiative, April 2013** |
| Background | SB43 and AB 1014 are two shared renewable pilot programs to enable residential renters and commercial customers to subscribe via PG&E, SCE, and SDGE to an offsite renewable energy project and receive a utility bill credit in return. |
| Similar Studies | • VSI (2010) Colorado;<br>• VSI (2011) Nevada;<br>• VSI (2011) Iowa; and<br>• The Solar Foundation (2013) Colorado. |
| Objective(s) | • Estimate the number of jobs created under SB 43/AB 1014, and the increased dollars that will subsequently circulate throughout the California economy. |
| Geography | California |
| Time Period | 2014-2016 construction; 25 year lifetime O&M |
| Modeling Tool | JEDI (based on IMPLAN I-O) version January 3, 2013 |
| Type of Effects Examined | • This is a ***Partial Gross*** analysis of two shared renewable programs.<br>• Study does not consider net job creation. It simply details the cumulative employment benefits of both proposed shared renewable programs, without taking into account the potential loss of jobs in other energy sectors.<br>• State sales tax revenue and instate economic activity results are also exclusively considered from a shared renewable program perspective.<br>• Authors ignore the net changes that will in reality occur due to changes in other sectors of the state economy prompted by both programs, including the potential for higher energy bills. |
| Model Assumptions | • Crystalline Silicon – fixed mount commercial; single axis tracking utility scale.<br>• For both pilots, study assumes the following local purchases:<br>  o 100% of components for solar installations < 100 kW;<br>  o 50% of components for 100 kW to 1 MW installations; and<br>  o 30% of components for installations > 1 MW.<br>• For both pilots, it also assumes the following local manufacturing:<br>  o 10%-20% of components for installations < 1 MW; and<br>  o 5-10% of components for installations > 1 MW.<br>• This amounts to 546 MW local total purchases for the implementation of both pilot schemes, and 91.5 MW to 183 MW local manufacturing.<br>• 2014-2016 construction period.<br>• 25 year operational phase. |
| Solar Growth Projection Assumptions | • For SB 43, 53 MW installed in 2014, 161 MW installed in 2015, and 286 MW installed in 2016, resulting in a 500 MW pilot.<br>• For AB 1014, 65 MW installed in 2014, 285 MW installed in 2015, and 650 MW installed in 2016, resulting in a 1,000 MW pilot. |
| Effects Scaled per Year (2015 $) | • SB 43 is estimated to have a gross jobs impact of 26.7 job years/MW, $179,000 GSP per MW per year, and $5,291 sales tax revenue per MW per year (2015 $).<br>• AB 1014 is estimated to have a gross jobs impact of 24.0 job years/MW, $175,000 GSP per MW per year, and $5,331 sales tax revenue per MW per year (2015 $). |

| | |
|---|---|
| Title | **Economic Impact Potential of Solar Photovoltaics in Illinois** |
| Author(s) | **Loomis, Jo and Alderman, December 2013** |
| Background | Center for Renewable Energy (Illinois State University) study, supported by an Illinois Department of Commerce and Economic grant. |
| Objective(s) | Considers employment and output impacts for the construction and operations phases of 3 solar deployment scenarios, with 3 levels of in-state manufacturing. |
| Geography | Illinois |
| Time Period | 2014-2030 |
| Modeling Tool | JEDI PV Model (PVS4.5.13) |
| Type of Effects Examined | • This is a ***Partial Gross*** analysis.<br>• It exclusively considers renewable (solar) sector impacts, including supply chain.<br>• It does not consider corresponding impacts in other parts of the energy sector, or other economic sectors. |
| Model Assumptions | • Installations profile:<br>o 10% residential (80% retrofits, 20% new construction);<br>o 10% small commercial;<br>o 20% large commercial;<br>o 60% utility-scale.<br>• 100% local purchases:<br>o Labor and soft costs (permitting and business overhead); and<br>o Residential and small commercial materials and equipment.<br>• All materials and equipment for large commercial and utility-scale installations are purchased 100% out-of-state.<br>• Three levels of instate manufacturing per scenario – 0%, 5%, and 10%. |
| Solar Growth Projection Assumptions | • 2,292 MW, 2714 MW, or 11,265 MW by 2030. |
| Effects Scaled per Year (2015 $) | • For all 3 scenarios at 10% in-state manufacture:<br>o 12.2 gross job years per MW installed;<br>o Approximately $107,000 GSP per MW per year (2015 $); and<br>o Approximately $45,600 labor income per MW per year (2015 $). |

| | |
|---|---|
| Title | **Modeling the Economic Impacts of Solar PV Development in Massachusetts** |
| Author(s) | **Motamedi and Judson, March 28, 2012 (Unpublished PowerPoint)** |
| Background | REMI. commission for the New England Energy and Commerce Association Renewables and Distributed Generation Committee. |
| Objective(s) | • Assess the economic impact of the<br>o Construction of 305 MW of solar PV, 2012-2018; and<br>o Operation of solar PV installations, 2012-2025. |
| Geography | Massachusetts |
| Time Period | • 2012-2018 construction; and<br>• 2012-2025 operations. |
| Modeling Tool | REMI |
| Type of Effects Examined | • ***Partial Gross*** study, which generically describes, but does not state, the value of inputs used.[13]<br>• Energy cost savings are only considered from a solar savings perspective. |
| Model Assumptions | • Combination of residential, commercial, and utility-scale solar installations, with regional purchase coefficients of 0.629, 0.564, and 0.580 respectively.<br>• Construction phase uses total investment after federal and state tax credit cost reduction, including some consumer consumption reallocation and production costs, along with consumer electricity price, and business electricity fuel cost changes.<br>• Models locally supplied inputs as total construction spending.<br>• Consumer price of electricity, electricity fuel costs for businesses, and production cost to utilities are used to represent the energy cost savings; and analysis assumes no change to SREC market. |
| Solar Growth Projection Assumptions | • Additional 305 MW of PV, 2012-2018, taking total installation to 400 MW.<br>• Does not state the split between residential, commercial and utility-scale solar. |
| Effects Scaled per Year (2015 $) | • 20.1 job years created per MW installed.<br>• Approximately $122,000 GSP per MW per year (2015 $).<br>• Approximately $155,000 personal income per MW per year (2015 $). |

[13] Motamedi and Judson mention energy cost savings, implying some consideration of the negative economic impacts of solar deployment. However, their PowerPoint presentation does not include any obvious assessment of negative impacts, and the REMI output is not suggestive of their inclusion. As a result, Seidman has classified their approach as ***Partial Gross***.

| | |
|---|---|
| Title | **A Multiregional Macroeconomic Framework for Analyzing Energy Policies** |
| Author(s) | **Treyz, Nystrom and Cui, October 2011** |
| Background | REMI-authored study considering the local, regional and national economic impacts of Missouri's RPS, excluding environmental and social impacts. |
| Objective(s) | Compares effects of electricity price-cap mandate (Scenarios 1 and 2) and an alternative bond-funded cost-recovery strategy (Scenarios 3 and 4) to finance the subbing of wind and solar for coal. |
| Geography | Missouri and the U.S. |
| Time Period | • Construction impacts (RPS implementation), 2011-2021.<br>• Operational impacts, 2011-2035. |
| Modeling Tool | REMI |
| Type of Effects Examined | • ***Partial Net*** study. |
| Model Assumptions | • Baseline: No RPS implemented in Missouri.<br>• Scenario 1 = IOUs raise prices to statutory cap of 1% to recover low cost of subbing wind and solar for coal (cost fully recovered by 2023).<br>• Scenario 2 = IOUs raise prices to statutory cap of 1% to recover high cost of subbing wind and solar for coal (cost fully recovered by 2025).<br>• Scenario 3 = IOUs issue bonds with maturity of 15 years at 3.25% interest rates to raise funding needed for low cost infrastructure.<br>• Scenario 4 = IOUs issue bonds with maturity of 15 years at 3.25% interest rates to raise funding needed for high-cost infrastructure.<br>• In Scenarios 1 and 2:<br>  o 1% compound increase in commercial and industrial electricity prices;<br>  o 1% compound increase in residential electricity prices, with lower disposable income corresponding consumption reallocation.<br>• In Scenarios 3 and 4:<br>  o Utilities issue bonds at bank prime rate of 3.25% per year for 15 years;<br>  o Impacts greater in the 2020s when consumers have to pay higher prices to pay off bonds, compared to 2010s when consumers pay the costs up front in Scenarios 1 and 2.<br>• In Scenarios 1-4:<br>  o Solar panel purchase and O&M are treated as semiconductor manufacture exogenous final demand with corresponding consumption reallocation<br>  o IOU rebates accounted for in production cost and transfer payments;<br>  o Partial substitution of conventional electricity for solar electricity allows households to reduce conventional electricity consumption and expense, captured in consumption reallocation; and<br>  o Creation of a custom industry for commercial wind generation, to account for different intermediate demands. |
| Solar Growth Projection Assumptions | • RPS: Coal = 66%, Wind 14.7%, Solar 0.3% and Other 20% from 2021 onwards.<br>• Coal declines from 81% of electric production in 2010 to 66% by 2021; wind and solar from 0% to 15%. |
| Effects Scaled per Year (2015 $) | • Graphs rather than data tables are provided, creating difficulties for interpretation.<br>• A state RPS is assumed to cause a short-term decrease in local employment, real GDP and personal real disposable income per capita.<br>• Raising electricity prices is estimated to result in the loss of 4,000 to 5,000 job years by 2021 or 2025, before recovering to the same level as the 2010 baseline in 2031.<br>• A bond scheme is estimated to create an initial short term annual employment increase of up to 1,000 jobs, but the trend reverses upon completion of the RPS in 2021, |

[redacted]

decreasing by 2,000 to 3,000 jobs per year up until 2027, before recovering to a net decrease of 600-800 jobs by 2035.

- Real GDP would steadily decrease under the price-cap scenario, hitting a low of $350-$458 million loss in 2021 and 2025, before regaining some ground to a $102 million loss in 2035 (2015 $).
- The utility bond approach would have expand real GDP until 2021, peaking at $153-$204 million in 2019, fading to a decrease of $306-$408 million in 2027, before picking up to a loss of $153-244 million by 2035 (2015 $).

| | |
|---|---|
| Title | **Employment Effects of Clean Energy Investment in Montana** |
| Author(s) | **Comings, Fields, Takahashi and Keith (Synapse Energy Economics), 2014** |
| Background | Examines the employment impacts of hypothetical additions to Montana's renewable energy portfolio. |
| Objective(s) | • Estimate employment impacts of construction and O&M activities associated:<br>o Large-scale wind;<br>o Large-scale solar PV;<br>o Small-scale solar PV (rooftop), and<br>o Energy efficiency. |
| Geography | Montana |
| Time Period | • Installation of systems is assumed to take place in 2016-2017.<br>• Assumes 20 years of system operation. |
| Modeling Tool | IMPLAN in conjunction with capacity data from NREL's JEDI model. |
| Type of Effects Examined | • ***Partial Gross*** study of direct, indirect and induced employment impacts.<br>• Makes no attempt to consider net effects. Focused entirely on job impacts of solar installation and O&M spending and considers no other benefits of solar deployment. |
| Model Assumptions | • Develops solar spending patterns associated with rooftop and utility-scale installations using NREL's JEDI model with adjustments for local conditions.<br>• Estimates construction jobs in short-run and allocates them over 20 years together with O&M to obtain a 20 year cumulative job impact per average MW deployed. |
| Solar Growth Projection Assumptions | • No actual projections.<br>• Uses NREL's (2012) maximum hypothetical potential of 4,409 GW utility-scale and 2 GW rooftop solar PV for Montana. |
| Effects Scaled per Year | • Small PV – 9.2 job years per MW.<br>• Large PV – 5.0 job years per MW. |

| | |
|---|---|
| Title | **Quantifying the Economic Impacts of Net Metering in Montana** |
| Author(s) | **Energy and Telecommunications Interim Committee (ETIC), January 2016** |
| Background | Examines the historical economic development impact of net metering installations in 2014 and 2000-14 in Montana. |
| Objective(s) | • Evaluate economic development impacts of the installation of net metering systems in terms of the following benefits and costs:<br>o Bill savings of net metering customers;<br>o Residential property value increases;<br>o Revenue generated by installations;<br>o Employment from installations;<br>o Value of avoided carbon emissions;<br>o Costs of income tax credits; and<br>o Universal System Benefits (USB) renewable energy and Research & Development (R&D) allocations. |
| Geography | Montana |
| Time Period | 2000-2014 |
| Modeling Tool | Counts based on survey/modeling estimates from other states. |
| Type of Effects Examined | • This is in fact not an economic impact study or a normal assessment of economic development impacts.<br>• It's a partial ***Count Gross*** analysis that considers a limited set of costs and benefits associated with net metering system deployments.<br>• The tax revenue estimates are unclear, incomplete and based on very general assumptions. |
| Model Assumptions | • Based mostly on Montana Renewable Energy Association (MREA) survey data.<br>• Uses NREL models to assess installation sales revenue based total installations each year but no specifics of the nature of the system(s) installed are given.<br>• Employment outcomes are also based on survey work done by the Montana Environmental Information Center, Synapse Energy and the Sierra Club.<br>• It is lacking in a number of aspects. It needs to:<br>o Consider *full* indirect and the induced impacts of net metering;<br>o Use appropriate bespoke models for Montana reflective of local economic circumstances; and<br>o Not rely on very general rule of thumb estimates for jobs, revenues and taxes generated as base data.<br>• It double-counts historical property value and homeowner energy savings as separate benefits. |
| Solar Growth Projection Assumptions | • The extent of net metering systems installed in 2014 is stated as $4M (2014 $) but there is no statement of the extent of system additions or their capacity between 2010 and 2014. |
| Effects Scaled per Year | • There is no statement of installed capacity during the study period. There is also no statement of GSP, employment or tax revenue. It is thus impossible to calculate a jobs impact per MW, GSP per MW per year, or sales tax revenue per MW. |

| | |
|---|---|
| Title | **Economic and Job Creation Benefits of the Nevada Solar Jobs Now Proposal of 2011** |
| Author(s) | **Vote Solar Initiative and Clean Energy Project Nevada** |
| Background | Considers the economic impact of expanding Nevada's DG solar market from 35 MW to 400 MW between 2011 and 2020. |
| Similar Studies | • VSI (2010) Colorado;<br>• VSI (2011) Iowa;<br>• VSI (2013) California; and<br>• The Solar Foundation (2013) Colorado. |
| Objective(s) | • Evaluate the economic, job benefits and tax impacts of expansion of and changes to the incentive structure of Nevada's Solar Jobs Now proposal of 2011. |
| Geography | Nevada |
| Time Period | 2011-2020 |
| Modeling Tool | NREL's Jobs and Economic Impacts (JEDI) model. |
| Type of Effects Examined | • This is a very simplistic and rather opaque ***Partial Gross*** analysis since it lacks *any* consideration of the negative impacts of expansion.<br>• It is biased in terms of its assessment of economic impacts since it does not:<br>o Consider any non-solar energy sector losses;<br>o Take into account utility obligations from a transmission and distribution grid perspective in terms of savings, upgrades or modifications;<br>o Quantify the impact of a reduction in the demand for centralized power generation due to increased distributed generation;<br>o Consider the economic impacts of rebate dollars paid to DG homeowners and installers;<br>o Examine the economic impacts of reduced spending on other categories of expenditure throughout the expansion phase from capital expenditures on DG solar systems; and<br>o Consider the administrative costs associated with changing permitting rules. |
| Model Assumptions | • Base assumptions are drawn from a JEDI model specific to Nevada.<br>• Basic premise is a growth of 365 MW in residential and commercial DG solar.<br>• No specifics about system characteristics used in the JEDI model are outlined in the paper. |
| Solar Growth Projection Assumptions | • 365 MW installed 2011-2020. |
| Effects Scaled per Year (2015 $) | • Over the period 2011-2020, The Solar Jobs Now Proposal is estimated to have:<br>o A gross jobs impact of 28.5 job years/MW;<br>o $443,400 GSP per MW per year (2015 $); and<br>o $22,500 sales tax revenue per MW (2015 $). |

| | |
|---|---|
| Title | **New York Solar Study** |
| Author(s) | **New York State Energy Research & Development Authority (NYSERDA), January 2012** |
| Background | **Study required by The Power New York Act of 2011.** |
| Objective(s) | **Evaluate the cost-benefits of increasing solar PV in NY to 5,000 MW by 2025.** |
| Geography | **New York State** |
| Time Period | **2013-2049** |
| Modeling Tool | **REMI** |
| Type of Effects Examined | • ***Partial Net*** **study.**<br>• **Quantifies direct PV job impacts of each scenario, economy-wide net impacts, gross state product, retail rate impacts, and environmental impacts.**<br>• **Economy-wide net job analysis includes:**<br>o **Positive impacts such as the creation of new PV jobs, and ratepayer savings when electricity prices are suppressed by PV output; and**<br>o **Negative impacts, such as the cancellation of new power plants that are made unnecessary by the added PV capacity, or the additional costs of PV incentives, which reduce personal disposable income.**<br>• **Net retail impact of PV deployment includes:**<br>o **The above-market costs of PV;**<br>o **Net metering costs; and**<br>o **Savings generated by the suppression of wholesale electricity prices.**<br>• **Net environmental impacts include:**<br>o **Lower emissions via a reduction in the need for fossil fuel plants; and**<br>o **Land use changes from rooftop to ground-mounted over time.** |
| Model Assumptions | • Three scenarios:<br>o Low Cost Scenario, using DOE SunShot goal for PV cost reduction, assuming extension of the federal tax credit (FTC) through 2025;<br>o Base Case Scenario, using a DOE survey and moderate reduction of FTC beyond 2016, plus costs of $2.5 million/MW for large-scale and $3.1 million/MW for small-scale installations; and<br>o High Case Scenario, based on the national average annual PV system price decline over the past decade, with FTC reverting to a pre-federal stimulus level in 2016.<br>• 5% of solar components are manufactured in NY; the rest are imported.<br>• Incentive costs are recovered from ratepayers through their electricity bills.<br>• Quantified benefits of the 5000 MW by 2025 goal include a wholesale price suppression assumption, a reduction in energy lost to transmission and distribution inefficiencies, a reduction or deferral of the need to upgrade the utility distribution system, avoided RPS compliance costs, and a monetized carbon value of $15 per ton. |
| Solar Growth Projection Assumptions | • Achieve 5,000 MW solar PV deployment by 2025.<br>• Four policy options are analyzed to stimulate demand:<br>o Utilities obliged to purchase tradable solar renewable energy credits (SRECs) from spot market, supported by a price floor mechanism to provide greater degree of revenue certainty;<br>o Utilities manage a competitive procurement similar to CA in which they award long-term contracts to purchase renewable energy;<br>o Residential and commercial small PV system rebates, and larger systems incentives, provided centrally via competitive bidding; and<br>o Utilities incentives for larger projects through competitive long-term contracts, and a cents per kWh produced for smaller projects. |

| | |
|---|---|
| Effects Scaled per Year (2015 $) | • 4.7-6.3 gross job years created per MW installed, dependent on scenario, 2013-2025.<br>• 700 economy-wide jobs net gain (low) or 750 to 2,500 economy-wide jobs net loss (base and high), 2013-2049.<br>• $15,760 GSP per MW per year gain (low), or $16,930 to $58,386 GSP per MW per year loss (base and high), 2013-2049 (2015 $). |

| | |
|---|---|
| Title | **Distributed Generation Standard Contracts Program and Renewables Energy Fund: Jobs, Economic and Environmental Impact Study** |
| Author(s) | **Berkman, Lagos and Weiss (The Brattle Group), 2014** |
| Background | • Prepared for the Rhode Island Office of Energy Resources and Commerce as stipulated by the July 2013 Distributed Generation Standard Contracts (DGSC) Law. |
| Objective(s) | • Examine the potential economic, fiscal and environmental impacts of the Distributed generation Standard Contract (DGSC) and Renewable Energy Fund (REF) 20134-2038. |
| Geography | Rhode Island |
| Time Period | 2014-2038 |
| Modeling Tool | IMPLAN in conjunction with energy capacity planning and energy dispatch models |
| Type of Effects Examined | • A ***Partial Net*** study in terms of its economic impact assessment.<br>• Includes spending on installations as a gross addition to final demand.<br>• Does not net out the associated purchase/leasing costs which would likely swamp installation spending.<br>• Includes payments to DGSC/REF participants but no allows no countervailing reduction in non-DGC ratepayers' spending.<br>• Costs to ratepayers are assessed but not included in the economic impact assessment.<br>• Assess central generation capacity and operating costs with a capacity planning and economic dispatch model. |
| Model Assumptions | • Includes both wind and solar renewable energy.<br>• Operational life span of renewable resources assumed to be 25 years.<br>• Source metrics for with and without DGC and REF scenarios obtained from past studies.<br>• Use secondary sources to assess central generation and capacity costs using approximations rather than primary modeling.<br>• It is unclear how DGSC/REF capacity deletions/additions are assessed to affect central generation costs. |
| Solar Growth Projection Assumptions | • Three (assumed not forecast) scenarios above 2013 40 MW are assessed:<br>  o 160 MW (by 2019) with REF of $800,000 in solar installations;<br>  o 200 MW (by 2019) with REF of $800,000 in solar installations; and<br>  o 1,000 MW (by 2024) with REF of $1,600,000 in solar installations. |
| Effects Scaled per Year (2015 $) | • Average annual GSP per MW:<br>  o 160 MW DGC:$191,790 GSP per MW (2015 $);<br>  o 200 MW DGC: $182,216 GSP per MW (2015 $); and<br>  o 1,000 MW DGC: $135,290 GSP per MW (2015 $).<br>• Average annual job years per MW:<br>  o 160 MW DGC: 1.53 jobs;<br>  o 200 MW DGC: 1.465 jobs; and<br>  o 1,000 MW DGC: 1.095 jobs. |

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|---|---|
| Title | **Economic Impacts of Solar Thermal Electricity Technology Deployment on Andalusian Productive Activities: A CGE Approach** |
| Author(s) | **Cansino, Cardenete, Gonzalez and Pablo-Romero, 2013** |
| Background | Annals of Regional Science published paper estimating the impact on productive activities of increasing the production capacity of two types of solar thermal plant in Andalusia. |
| Objective(s) | • To quantify the gross direct and induced productivity impacts of a single parabolic trough solar collector power plant and a single solar tower plant for the Andalusian economy.<br>• To also quantify the gross direct and induced productivity impacts of both types of solar thermal technology based on the addition of 789 MW installed capacity by 2013 to comply with the Sustainable Energy Plan for Andalusia (PASENER). |
| Geography | Andalusia (Spain) |
| Time Period | • 2008-2013 installation; and 30 year estimated lifetime for each plant. |
| Modeling Tool | Static computable general equilibrium (CGE) model, consisting of 27 productive activities in the Andalusian economy. |
| Type of Effects Examined | • ***General Gross*** study.[14]<br>• Describes gross economic impacts by sector, based on an enlarged electricity sector which combines renewables and non-renewables and prevents any substitution. |
| Model Assumptions | • Walrasian notion of competitive equilibrium, extended to include producers, households, government, and foreign sectors.<br>• The single representative consumer maximizes a Cobb-Douglas utility function.<br>• Government maximizes a Leontief utility function.<br>• Foreign sector is modeled as a single sector that includes the rest of Spain, the European Union, and the rest of the world.<br>• Benchmark equilibrium scenario includes a perfect inelastic supply of capital and positive unemployment rate, and a fixed level of government and foreign sector activities which allows relative prices, activity levels, public deficit and foreign trade deficit to work as exogenous variables.<br>• Equilibrium is defined as an economic state in which the representative consumer maximizes his utility, the 27-sector productive activities maximize their profits after taxes, and public revenue is equal to the payments to the different economic agents.<br>• Does not consider if Andalusia's gross output gains are at the expense of other states' output – e.g. from the crowding-out effect of power generation. |
| Solar Growth Projection Assumptions | • For the single plant analysis:<br>  o 50 MW parabolic trough plant with 624 collectors; and<br>  o 17 MW solar tower plant with 2,750 heliostats.<br>• Estimated lifetime of each plant is 30 years.<br>• For the PASANER scenario, to meet the 800 MW target by 2013 (789 MW additions), the model assumes 80% parabolic trough and 20% solar tower. |
| Effects Scaled per Year | • Scenario 1 (single plant additions) is estimated to result in an economy-wide gross productivity increase of 0.75% for the parabolic trough plant, or a 0.68% economy-wide gross productivity increase for the solar tower plant.<br>• Scenario 2 (PASANER) is estimated to result in an economy-wide gross productivity increase of 35.37% over the 30-year lifetime of the parabolic trough and solar tower plant additions (30.81% parabolic trough; 4.57% solar tower). |

[14] Cansino et al. use a 27-sector CGE model that is a general modeling representation of the Spanish economy, allowing for both positive and negative feedback effects of increased levels of solar penetration in Andalusia. However, they model renewables and non-renewables as a single sector that does not allow for substitution between forms of generation, which means that they are effectively only allowing for positive direct demand shocks in their modeling. This is why Seidman classifies their approach as a *General Gross* model.

| | |
|---|---|
| Title | **Economic Impacts from the Promotion of Renewable Energy Technologies – The German Experience** |
| Author(s) | **Frondel, Ritter, Schmidt and Vance, 2009** |
| Background | Critically reviews cost and job implications of the Renewable Energy Sources Act (EEG) – the centerpiece of the German promotion of renewable energy. This guaranteed stable feed-in-tariffs (FITs) for up to 20 years, and also favorable conditions for investments in green electricity production for the long-term. |
| Objective(s) | To demonstrate the impact of government-backed renewable incentives for stimulating the economy |
| Geography | Germany |
| Time Period | 2000-2020 |
| Modeling Tool | Non-Applicable |
| Type of Effects Examined | • ***Count Net*** study which balances gross renewable sector gains with:<br>o The losses that result from the crowding out of cheaper forms of conventional energy generation; and<br>o The drain on economic activity precipitated by higher electricity prices, including a loss of consumer spending power, and lower total investments of industrial energy consumers.<br>• Also notes that:<br>o New green jobs are often filled by workers who were previously employed, leading to a further overestimate of gross jobs effects;<br>o Energy security benefits of solar PV are undermined by reliance of imported fossil fuel sources to meet technological demand; and<br>o Technological innovation is stifled via a subsidy that compensates an energy technology for its lack of competitiveness.<br>• Assesses real net present cost of solar subsidies, based on the volume of solar generation, the FIT, and conventional electricity prices.<br>• Specific net cost per kWh = difference between solar FIT and market prices at the power exchange. |
| Model Assumptions | • Utility central station generation costs of 2-7 cents/kWh<br>• Utilities obliged to accept delivery of power into their own grids from independent renewable producers<br>• Solar-specific FIT of 50.62 cents/kWh paid by utilities in 2000 falling to 43.01 cents/kWh in 2009.<br>• If solar subsidization ended in 2009, electricity consumers would still face charges until 2029.<br>• Assumes 2% annual inflation.<br>• Cost estimates for PV modules installed 2000-2008 are based on an overall solar electricity production of 96 billion kWh during 20 years of subsidization. |
| Solar Growth Projection Assumptions | • Germany had 5,311 MW installed PV capacity in 2008. |
| Effects Scaled per Year (2015 $) | • Net cost promoting Solar PV per MW installed: $3.18 million, 2000-2008 (2015 $).[15] |

[15] €2.2 million (2007 €) converted to US$ at a rate of US$1: €0.7687.

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|---|---|
| Title | **Building the Green Economy: Employment Effects of Green Energy Investments for Ontario** |
| Author(s) | **Pollin & Garrett-Peltier, 2009** |
| Background | University of Massachusetts-Amherst study sponsored by the Green Energy Act Alliance, Blue Green Canada, and World Wildlife Fund (Canada). |
| Objective(s) | • Considers the employment benefits of two Ontario green investment agendas:<br>o Baseline Integrated Power System Plan (IPSP): $18.6 BN investment over 10 years in conservation and demand management, hydroelectric, on-shore wind, bioenergy, waste energy recycling and solar power; and<br>o Expanded Green Energy Act Alliance (GEAA): $47.1 BN investment over 10 years in IPSP's 6 areas plus off-shore wind and smart grid electrical transmission system. |
| Geography | Ontario, Canada |
| Time Period | 10 years |
| Modeling Tool | • Author-modified provincial I-O tables for Ontario, combined with national I-O tables for Canada to construct wind, solar, biomass and building retrofitting as industries in their own right.<br>• Also uses U.S. data (BLS 2007 Occupational Employment Survey) to determine which occupations are likely to be in high demand for each of the 8 renewable energy areas considered. |
| Type of Effects Examined | • ***Count Gross*** study, addressing employment.<br>• No comparison is made with alternative, non-green investments.<br>• Neither do they consider if a green investment program is the most effective way to generate jobs in the region. |
| Model Assumptions | • Uses three factors to establish relative employment effects of alternative green investments:<br>o Labor intensity of spending – that is amount spent on workers rather than land, energy, or materials;<br>o Local content of spending; and<br>o Wage rates.<br>• 3% of baseline IPSP spending is allocated on an annual basis to solar.<br>• 16% of expanded GEAA spending is allocated on an annual basis to solar. |
| Solar Growth Projection Assumptions | • 88 MW of solar energy supplied over 10 years for baseline IPSP.<br>• 1,738 MW of solar energy supplied over 10 years for expanded GEAA. |
| Effects Scaled per Year | • IPSP: 89.7 gross job years per MW installed.<br>• GEAA: 68.7 gross job years per MW installed. |

| | |
|---|---|
| Title | **Study of the Effects on Employment of Public Aid to Renewable Energy Sources** |
| Author(s) | **Alvarez, Jara, Julian and Bielsa, March 2009** |
| Background | Universidad Rey Juan Carlos study part-funded by DG TREN (Energy & Transport) of the European Commission. |
| Objective(s) | To demonstrate the extent to which government support for green jobs in Europe has been economically counterproductive. |
| Geography | Spain |
| Time Period | 2000-2008 |
| Modeling Tool | Non-Applicable |
| Type of Effects Examined | • ***Count Net*** study.<br>• Compares average amount of subsidized investment needed to create a solar job with the average amount of capital needed for a job in the private sector.<br>• Also compares the average annual productivity that the solar job subsidy would have contributed to the economy had it not been consumed in public financing, with the average productivity of labor in the private sector that allows them to keep their job. |
| Model Assumptions | • The total subsidy to PV, wind, and hydro since 2000 is $36 billion.<br>• No additional solar plants have been constructed since December 2008.<br>• $12.1 billion has been committed for PV generation, 2000-2008. |
| Solar Growth Projection Assumptions | • Assumes that Spain has installed 2,934 MW solar PV by 2008. |
| Effects Scaled per Year | • For every renewable energy job financed by government, on average 2.2 jobs will be lost in the private sector.<br>• However, for every solar MW installed, 8.99 private jobs are destroyed as a result of "green jobs" mandates, subsidies and related regimes. |

## 4.0 Economic Impact Analyses – Magnitudes & Preferred Modeling Methods

Gross (positive impact only) studies clearly produce higher estimates of the economic impacts of solar enhancements than net studies, as demonstrated by the studies reviewed in Section 3. It is also important to note that gross studies are uniformly positive, while net studies are generally negative in terms of divined economic impact.

The principal effect of using a partial model approach rather than a count approach, or using a general (macroeconomic) modeling approach rather than a partial approach, is to reinforce the magnitude of the divined economic impacts. Thus, using a general (macroeconomic) model approach yields the most significant gross and negative studies.

Figure 3 summarizes the magnitude of impacts by type of economic impact study, based on the studies critiqued in Section 3.

Counts usually quantify the number of jobs. The Ontario ***Count Gross*** analysis reviewed in Section 3 estimated 68.7 to 89.7 gross (direct) job years are generated for every MW of wind and solar energy installed, which averages out at 69.74 for both renewable programs.

The Spanish ***Count Net*** analysis reviewed in Section 3 estimates that 8.99 private jobs are lost through "green jobs" mandates, subsidies and related regimes, for every 1 MW of solar installed.

Frondel et al. do not provide actual job counts for their German ***Count Net*** analysis. They simply conclude that "...any result other than a negative net balance of the German PV promotion would be surprising" (p. 17), based on a per capita subsidy of $257,400 in 2008, the EEG's crowding out effects, negative income effects and the unprecedented competition from cheaper Asian imports.[16]

Partial model estimates extend beyond a count to additionally estimate Gross State Product (GSP). The ***Partial Gross*** models reviewed in Section 3 estimated 5 to 73.5 gross job year gains per MW installed, and

[16] Frondel et al. report that in 2006 and 2007, almost half of Germany's PV demand was covered by imports, most notably from Japan and China.

a GSP gain of $106,800 to $1.24 million per MW installed per year (2015 $). The AECOM study appears to be something of an outlier, as the gross job year estimate for the three other studies ranges from 5 to 24.9 job years per solar MW installed. Four of the studies in this section estimate GSP contributions of $106,800 to $176,354 GSP per MW per year (all 2015 $). The two exceptions, estimating significantly higher GSP contributions per MW per year are VSI (2011) in Nevada, and the AECOM study.

NYSERDA's ***Partial Net*** model estimates a 700 economy-wide net gain in job years for their low case scenario, but a 750-2,500 economy-wide net loss for job years for their base and high case scenarios. Similarly NYSERDA estimate a $15,760 GSP net gain per MW installed per year for their low case scenarios, compared to net losses of $16,930 to $58,386 per MW installed per year for their base and high case scenarios (all 2015 $). Treyz et al. only present graphs, rather than actual data, which appear to show a net negative loss in both job years and GDP, 2011-2035.

**Figure 3: Magnitude of Economic Impacts**

| | Counts | Partial Models | General Models |
|---|---|---|---|
| **Gross**<br>*Only positive or negative impacts* | • 70 gross job years per MW | • Range of 5 to 73.5 gross job years per MW.<br>• Range of $106,830 to $1.24 million GSP per MW per year. | • $7,198 total production per MW installed per year for parabolic trough installations.[17]<br>• $4,265 total production per MW installed per year for solar tower installations.[18] |
| **Net**<br>*Both positive and negative impacts* | • -8.99 private jobs per MW per year | • Range of +750 to -2,500 net job years per MW, dependent on the scenario.<br>• Range of +$15,862 to -$58,386 GSP per MW installed per year, dependent on the scenario. | |

[17] This is based on the PASENER target, 80% of which would be met by parabolic trough.
[18] This is based on the PASENER target, 20% of which would be met by solar tower.

The ***General Gross*** model reviewed in Section 3 offers two solar-technology dependent estimates. These are a total gross productive increase of $7,075 per MW installed per year for parabolic trough; and $4,192 per MW installed per year for solar tower.[19]

Based on the 6-way matrix of economic impact studies initially presented in Section 2, the implementation of a ***General Net*** analysis of solar deployment in the APS service territory, 2016-2035 is the best methodological approach for the current study. However, to the research team's knowledge, a CGE model of this nature currently does not exist for the State of Arizona; and it would be cost prohibitive to test and develop a CGE model for the State of Arizona in a short time frame. As a result, the current study implements a ***Partial Net*** analysis of solar deployment in the APS service territory, 2016-2035, presented in Sections 5 - 8. Seidman expects the results presented in the subsequent Sections to be directionally correct, but possibly understated, compared to a ***General Net*** (CGE) approach.

[19] This uses an IRS 2013 dollar-euro annual currency exchange rate of US$1: €0.783. Source: IRS (2014), downloaded at www.irs.gov/Individuals/International-Taxpayers/Yearly-Average-Currency-Exchange-Rates. Value is then converted into 2015 $ using the Bureau of Labor Statistics CPI Inflation Calculator.

# 5.0 Economic Impact of Net Metering – Scenarios, Assumptions and Method

## 5.1. Scenarios and Assumptions

Three distributed (rooftop) solar deployment scenarios in the APS service territory are assessed for the study period 2016-2035, including the legacy effects of each scenario throughout the (assumed) 30 year economic life of the solar systems.[20] The solar deployment scenarios assessed for APS are:

- A low case scenario, which assumes 1,300 $MW_{dc}$ of nameplate distributed solar PV installations by 2035 in the APS service territory, which will increase APS' total number of distributed solar customers to approximately 150,000 accounts;
- An expected or medium case scenario, which assumes 5,000 $MW_{dc}$ of nameplate distributed solar PV installations by 2035 in the APS service territory, which will increase APS' total number of distributed solar customers to approximately 690,000 accounts; and
- A high case scenario, which assumes 7,600 $MW_{dc}$ of nameplate distributed solar PV installations by 2035 in the APS service territory, which will increase APS' total number of distributed solar customers to approximately 1,050,000 accounts.

Distributed solar deployment is assumed to take place throughout the period of study in each scenario – that is, up to and including 2035.

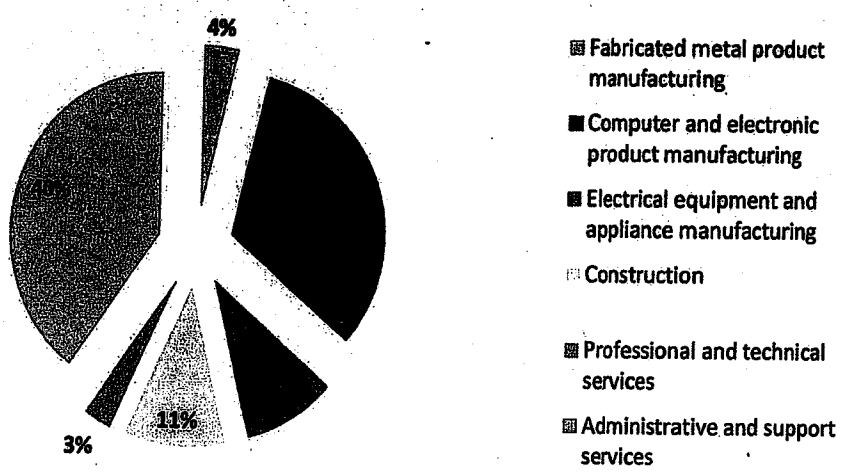
Approximately 86% of the solar installations are assumed to occur in Maricopa County, 5% in Pinal County, and 9% in Yuma County in each scenario.

The capital costs and financing implications of each solar deployment scenario is determined by examining the level of distributed generation as forecast by APS using generic assumptions about the costs of standard DG solar systems and financing parameters. NREL's JEDI model for solar installations is used to

[20] Based on the assumed 30 year economic life of the distributed system, the customer financing costs of solar installations, 2016-2035, will not be completed until 2065. The REMI model used currently only provides economic impact estimates up to and including 2060, but Seidman does not believe that this will materially affect the conclusions in the analysis. If the economic life of an installation is less than 30 years, the negative economic consequences are in all probability greater than the estimates presented in this study.

distribute the capital costs of the solar installations throughout the supply chain in the State of Arizona.[21] Figure 4 summarizes the breakdown of the JEDI model's solar system costs used in this analysis. This is based on national industry averages, and may not match Arizona's experience exactly, but is nevertheless widely accepted as a reasonable approximation. Administrative and support services account for an estimated 40% of solar system costs. This probably includes general administrative costs associated with state government permitting and federal rebates, and also local administrative costs in the solar industry.

**Figure 4: JEDI Model Exogenous Final Demand Categories**




*Source: Authors' Calculations*

APS has also supplied Seidman with an estimate of the financial impact of each solar deployment scenario on the utility's operating cash flow, future central station generation investments, and electricity retail rates. Approximately 70% of the deferred or cancelled central station generation investments occurring under the three distributed solar scenarios are assumed to occur in Maricopa County, with the balance in Pinal County.

The investment changes included in the economic impact model are:

- The annual installed costs of distributed solar capacity, 2016-2035; and

[21] NREL's JEDI models are an open-source, Excel-based, user-friendly tools that estimate the economic impacts of constructing and operating power generation and biofuel plants at the local and state levels. To find out more about the JEDI models, see http://www.nrel.gov/analysis/jedi/about_jedi.html

- APS' deferred or avoided central station generation investments, 2016-2035.

The long-term legacy costs included in the economic impact model are:

- The customer leasing costs of distributed solar installations, 2016-2060;[22] and
- Consumer electricity rate savings, 2016-2060, from the study period's deferred or avoided central station generation.

The timeframe of three of these elements extends beyond the last year of deployment (2035). This is because there are legacy effects associated with the deployment of distributed solar. For example, any customer installing a distributed solar PV system will have to meet the financial costs of that system for up to 30 years after the system has been installed on their roof. A utility is also required to recoup any investment in central station generation investments via retail electricity rates over the lifetime of that investment – again, usually 30 years. The legacy effects are therefore accounted for in the analysis.

The modelling elements are discussed in more detail in Section 5.2.

## 5.2. Study Method

Given the absence of a CGE model for the State of Arizona, Section 4 recommended the implementation of a ***Partial Net*** analysis of solar deployment in the APS service territory, 2016-2035. As a result, this study makes use of an Arizona-specific version of the REMI regional forecasting model, updated at the Seidman Research Institute, to produce partial net estimates of the impact on the Arizona economy of changes in the economic environment in the state.

REMI is especially useful when examining the economic impact associated with the launch or expansion of a new program, such as NEM, in a particular region, state or country. Through its dynamic modeling, REMI takes account of variations in the economic impact of a program as it moves from the establishment

[22] Based on the assumed 30 year economic life of the distributed system, the customer financing costs of solar installations, 2016-2035, will not be completed until 2065. The REMI model used currently only provides economic impact estimates up to and including 2060, but Seidman does not believe that this will materially affect the conclusions in the analysis. If the economic life of an installation is less than 30 years, the negative economic consequences are in all probability greater than the estimates presented in this study.

to operations phase, and also shows how estimates can vary through time. These estimated impacts are the difference between the baseline economy and the baseline economy augmented with the level of solar deployment assumed under each scenario. As a result, the analysis measures the Arizona economy up to 2035 *with* and *without* the existence of the new solar rooftop program.

The use of a county level model also enables a more detailed disaggregation of results to occur, estimating the "leakage" of economic impacts into other counties in Arizona.

Due to its overall flexibility, REMI allows for the examination of a whole host of different scenarios – different businesses and/or different construction and operations phases – while simultaneously providing estimates that are consistent across projects.

The method for estimating the economic impact involves four fundamental steps:

1. **Prepare a baseline forecast for the state and county economies:** This Business As Usual (BAU) case forecasts the future path of state and county economies based on a combination of an extrapolation of historic economic conditions and an exogenous forecast of relevant national economic variables.
2. **Develop a program or policy scenario:** This scenario describes the *direct* impacts that each distributed solar deployment scenario could generate in APS' service territory.
3. **Compare the baseline and policy scenario forecasts.**
4. **Produce the "delta" results**: Differences between the future values of each variable in the forecast results estimate the magnitude that each distributed solar deployment scenario could have on the state or county economies, relative to the baseline.

The baseline or counterfactual scenario employed in this study assumes that there are no additions to the current stock of distributed solar installations over the period 2016-2035 in APS' service territory. One consequence of this counterfactual scenario is that APS would need to add to both its central generation and transmission capacity, to cope with the increased load within its territory over the period. To cover the capital costs of the enhanced capacity and all subsequent operations and maintenance costs, APS would typically need to increase utility revenues over a 30-year period from the date of each investment. In isolation, this would manifest as a reduction in consumer spending, because utility customers would

collectively need to pay more for these new investments, and is also accounted for in the current study, up to and including 2060. In reality, some of this increased revenue will be provided by population growth which is creating the additional demand for new generation, and some will be offset by lower revenues for depreciating existing investments over time.

## 5.3. Solar Deployment Scenarios

Three distributed solar deployment scenarios are analyzed in this study. To represent the effects of increased penetrations of distributed solar, three key changes are included in the current study for the 2016-2035 time horizon. These are:

- The capital costs expended on rooftop solar systems purchased or leased by distributed generation customers, which are assumed to yield 20 years of construction-based benefits on the Arizona economy;
- The financial payments made by utility customers for leased solar systems for the economic life of their assets. This represents a reduction in spending on other goods and services and, as such, a likely reduction in economic activity in Arizona; and
- The reduction in revenue requirement for APS as a result of decreased net investment in centrally generated power. This represents a loss to the Arizona economy due to the reduction in central station generation construction and employment, offset by savings on fuel, O&M and financing costs over time.

Each scenario is modeled over a 20-year timeframe, starting in 2016 and ending in 2035, to estimate the employment, gross state product (GSP), and real disposable personal income (RDPI) for the State of Arizona and Maricopa County. However, there are also legacy effects associated with solar deployment and the deferral or cancellation of central station generation investments, which occur in the years immediately following an installation and last for the economic life of the solar installations. These legacy effects are therefore also included in the cumulative 2016-2035 estimate provided for each assessed economic measure, expressed in 2015 dollars (2015 $).[23]

[23] The legacy effects for any 2035 distributed solar installations should last until 2065, to reflect the economic life of the system. The current REMI model is unable to provide estimates after 2060, but Seidman does not believe that this will materially affect the conclusions in the analysis. If the economic life of an installation is less than 30 years, the negative economic consequences are in all probability greater than the estimates presented in this study.

## 6.0 Simulation Results: Low Distributed Solar Deployment Scenario

The low case scenario assumes that over $1.5 billion is invested in new distributed solar installations by 112,000 customers between 2016 and 2035, and the net deferral or cancellation of $85.5 million central station generation investments up to and including 2065 (all nominal $).[24]

Table 2 estimates the total employment impacts of the low case distributed solar scenario for the period 2016-2035. These are full-time (or equivalent) annual employment changes, applicable to all sectors and industries apart from government and farm workers. They include employees, sole proprietors and active partners, but exclude unpaid family workers and volunteers. The data is expressed in job years. The label "job year" is important and should not be simplified or abbreviated to "job". A "job year" is defined as one person having a full-time job for exactly one year. This means, for example, that one employee holding the same position at the same organization throughout 2016-2035 will account for 20 job years, but also only represent 1 job.

**Table 2: Total Private Non-Farm Employment Impacts 2016-2035 (including Legacy Effects to 2060)**

| Geography | Job Years[25] |
|---|---|
| State of Arizona | -16,595 |
| *Maricopa County* | *-15,685* |

*Source: Authors' Calculations*

Table 2 suggests that the low case distributed solar scenario could have a negative employment impact of 16,595 full-time (or equivalent) job years in the State of Arizona throughout the 2016-2035 period of study, including any legacy impacts up to 2060. This legacy effect accounts for the fact that the true effects of the distributed solar deployment are only experienced in full after the period of study (2016-2035), consistent with the economic life of each solar installation.[26]

In Maricopa County, there is a negative employment impact of 15,685 job years for the study period as a whole (including subsequent legacy effects).

[24] This simply reflects a deferral from the base case.
[25] A job year is equivalent to one person having a full-time job for exactly one year.
[26] The legacy effect should continue up to and including 2065. However, REMI currently does not allow for any analysis beyond 2060. If the economic life of an installation is less than 30 years, the negative economic consequences are in all probability greater than the estimates presented in this study.

Table 3 summarizes the industry sectors impacted the most by the low case distributed solar scenario.

**Table 3: Statewide Employment Impacts by Industry Sector (Job Years)[27]**

| Sector | Total Job Years, 2016-2060[28] |
|---|---|
| Forestry, Fishing, and Related Activities | -2 |
| Mining | -639 |
| Utilities | -2,025 |
| Construction | -2,549 |
| Manufacturing | -385 |
| Wholesale Trade | -548 |
| Retail Trade | -3,102 |
| Transportation and Warehousing | -514 |
| Information | -203 |
| Finance and Insurance | -845 |
| Real Estate and Rental and Leasing | -998 |
| Professional and Technical Services | -3,505 |
| Management of Companies and Enterprises | -89 |
| Administrative and Support Services | 5,447 |
| Educational Services | -440 |
| Health Care and Social Assistance | -3,210 |
| Arts, Entertainment, and Recreation | -406 |
| Accommodation and Food Services | -1,348 |
| Other Services, except Public Administration | -1,237 |
| **Total Net Change in Job Years** | **-16,595** |
| **Total Number of Job Years Lost in Non-Solar Industry Sectors[29]** | **22,042** |

*Source: Authors' Calculations*

The table suggests that administrative and support services could benefit from the low case distributed solar scenario in terms of employment created. However, all other sectors are estimated to experience job losses, resulting in the total net estimate of 16,595 job years lost statewide. The administrative gain probably originates to a large extent from the permitting of solar installations, and also business support functions within the solar industry. The sectors estimated to experience the biggest job losses (expressed

[27] A job year is equivalent to one person having a full-time job for exactly one year.
[28] Total job years may not tally due to rounding-up.
[29] This is a summation of the job years lost in non-solar industry sectors negatively impacted by the deployment of new distributed solar, 2016-2035.

in cumulative job years) during the study period in rank order are professional; scientific and technical services; health care and social assistance; retail trade; the construction industry; and utilities.

Table 4 estimates the cumulative gross state product (GSP) and real disposable personal income impacts (RDPI) associated with the low case distributed solar scenario for the period 2016-2035.

**Table 4: Total Gross State Product (GSP) and Real Disposable Personal Income Impacts (RDPI) 2016-2035 (including Legacy Effects to 2060)**

| Geography | Gross State Product Millions (2015 $) | Real Disposable Personal Income Millions (2015 $) |
|---|---|---|
| State of Arizona | -$4,806.6 | -$1,787.3 |
| *Maricopa County* | *-$4,491.8* | *-$1,862.4* |

*Source: Authors' Calculations*

Table 4 shows that in aggregate terms during the study period 2016-2035, and including legacy effects, total GSP could be cumulatively lower by over $4.8 billion (2015 $) in the State of Arizona. This includes an estimated $4.5 billion GSP lost in Maricopa County (2015 $).

Table 4 also shows that in aggregate terms during the study period 2016-2035, and including legacy effects, RDPI is estimated to be cumulatively lower by almost $1.8 billion (2015 $) in the State of Arizona. This includes an estimated fall in RDPI of over $1.86 billion in Maricopa County (2015 $).[30]

The employment, GSP, and RDPI losses associated with the low distributed solar deployment scenario are valid, because the total amount of money paid by distributed generation and central station generation electricity consumers over the relevant time period (which extends beyond 2035) is greater than the amount which would have been paid had they all instead continued to draw electricity from the utility's central grid. In short, electricity consumers are paying more for the same amount of electricity consumed under the low distributed solar deployment scenario, and therefore have less money to spend in other parts of the economy.

[30] Some of Maricopa County's estimated losses in RDPI will be offset by minor gains in other counties, thereby resulting in a negligibly smaller loss for the State as a whole.

## 7.0 Simulation Results: Expected Distributed Solar Deployment Scenario

The expected or medium case scenario assumes that approximately $8.9 billion in total is invested by 650,000 customers in distributed solar installations between 2016 and 2035, and the deferral or cancellation of $194 million central station generation investments (all nominal $).[31]

Table 5 estimates the total employment impacts of the expected or medium case distributed solar scenario for the period 2016-2035. These are full-time (or equivalent) annual employment changes, applicable to all sectors and industries apart from government and farm workers; and the data is again expressed in job years.

**Table 5: Total Private Non-Farm Employment Impacts 2016-2035 (including Legacy Effects to 2060)**

| Geography | Job Years[32] |
|---|---|
| State of Arizona | -76,308 |
| *Maricopa County* | *-71,344* |

*Source: Authors' Calculations*

Table 5 suggests that the expected or medium case distributed solar scenario would have a negative employment impact of 76,308 full-time (or equivalent) job years in the State of Arizona for the 2016-2035 period of study, including any legacy impacts up to 2060. This legacy effect accounts for the fact that the true effects of the distributed solar deployment are only experienced in full after the period of study (2016-2035), consistent with the economic life of each solar installation.[33]

In Maricopa County, there is a negative employment impact of 71,344 job years throughout the study period (including subsequent legacy effects).

Table 6 summarizes the industry sectors impacted the most by the expected or medium case distributed solar scenario.

[31] This simply reflects a deferral from the base case.
[32] A job year is equivalent to one person having a full-time job for exactly one year.
[33] The legacy effect should continue up to and including 2065. However, REMI currently does not allow for any analysis beyond 2060. If the economic life of an installation is less than 30 years, the negative economic consequences are in all probability greater than the estimates presented in this study.

**Table 6: Statewide Employment Impacts by Industry Sector (Job Years)[34]**

| Sector | Total Job Years, 2016-2060[35] |
|---|---|
| **Forestry, Fishing, and Related Activities** | **-18** |
| **Mining** | **-2,563** |
| **Utilities** | **-7,709** |
| **Construction** | **-11,098** |
| **Manufacturing** | **-1,504** |
| **Wholesale Trade** | **-2,691** |
| **Retail Trade** | **-15,762** |
| **Transportation and Warehousing** | **-2,472** |
| **Information** | **-943** |
| **Finance and Insurance** | **-4,558** |
| **Real Estate and Rental and Leasing** | **-4,948** |
| **Professional and Technical Services** | **-14,366** |
| **Management of Companies and Enterprises** | **-361** |
| **Administrative and Support Services** | **29,025** |
| **Educational Services** | **-2,336** |
| **Health Care and Social Assistance** | **-18,026** |
| **Arts, Entertainment, and Recreation** | **-2,231** |
| **Accommodation and Food Services** | **-6,886** |
| **Other Services, except Public Administration** | **-6,860** |
| **Total Net Change in Job Years** | **-76,308** |
| **Total Number of Job Years Lost in Non-Solar Industry Sectors[36]** | **105,333** |

*Source: Authors' Calculations*

The table again suggests that administrative and support services alone could benefit from the expected or medium case distributed solar scenario in terms of job years' employment created. However, all other sectors are estimated to experience job losses, resulting in the total net estimate of 76,308 job years lost statewide. The administrative gain again probably originates to a large extent from the permitting of solar installations and business functions within the solar industry. The sectors estimated to experience the biggest job losses (expressed in cumulative job years) during the study period in rank order are health care and social assistance; retail trade; professional; scientific and technical services; the construction industry; and utilities.

[34] A job year is equivalent to one person having a full-time job for exactly one year.
[35] Total job years may not tally due to rounding-up.
[36] This is a summation of the job years lost in non-solar industry sectors negatively impacted by the deployment of new distributed solar, 2016-2035.

Table 7 estimates the cumulative gross state product (GSP) and real disposable personal income impacts (RDPI) associated with the expected or medium case distributed solar scenario for the period 2016-2035.

**Table 7: Total Gross State Product (GSP) and Real Disposable Personal Income Impacts (RDPI) 2016-2035 (including Legacy Effects to 2060)**

| Geography | Gross State Product Millions (2015 $) | Real Disposable Personal Income Millions (2015 $) |
|---|---|---|
| **State of Arizona** | **-$21,613.3** | **-$7,956.4** |
| ***Maricopa County*** | ***-$20,149.9*** | ***-$8,087.9*** |

***Source: Authors' Calculations***

Table 7 shows that in aggregate terms during the study period 2016-2035, and including legacy effects, total GSP could be cumulatively lower by over $21.6 billion (2015 $) in the State of Arizona under the expected or medium case scenario. This includes an estimated $20.1 billion GSP lost in Maricopa County (2015 $).

Table 7 also shows that in aggregate terms during the study period 2016-2035, and including legacy effects, RDPI is estimated to be cumulatively lower by approximately $8 billion (2015 $) in the State of Arizona. This includes an estimated fall in RDPI of almost $8.1 billion in Maricopa County (2015 $).[37]

The employment, GSP, and RDPI losses associated with the expected distributed solar deployment scenario are valid, because the total amount of money paid by distributed generation and central station generation electricity consumers over the 2016-2060 time horizon is greater than the amount which would have been paid had they all continued to draw electricity from the utility's central grid. In short, electricity consumers are paying more for the same amount of electricity consumed under the expected distributed solar deployment scenario, and therefore have less money to spend in other parts of the economy.

[37] Some of Maricopa County's estimated losses in RDPI will be offset by minor gains in other counties, thereby resulting in a negligibly smaller loss for the State as a whole.

## 8.0 Simulation Results: High Distributed Solar Deployment Scenario

The high case scenario assumes that approximately $13.4 billion is invested by approximately 1 million customers in distributed solar installations between 2016 and 2035, and the deferral or cancellation of $194 million central station generation investments (both nominal $).[38]

Table 8 estimates the total employment impacts of the high case distributed solar scenario for the period 2016-2035. These are full-time (or equivalent) annual employment changes, applicable to all sectors and industries apart from government and farm workers; and the data is again expressed in job years.

**Table 8: Total Private Non-Farm Employment Impacts 2016-2035 (Including Legacy Effects to 2060)**

| Geography | Job Years[39] |
|---|---|
| State of Arizona | -116,558 |
| *Maricopa County* | *-108,857* |

*Source: Authors' Calculations*

Table8 suggests that the high case distributed solar scenario could have a negative employment impact of 116,558 full-time (or equivalent) job years in the State of Arizona for the 2016-2035 period of study, including any legacy impacts up to 2060. This legacy effect accounts for the fact that the true effects of the distributed solar deployment are only experienced in full after the period of study (2016-2035), consistent with the economic life of each solar installation.[40]

In Maricopa County, there is a negative employment impact of 108,857 job years throughout the study period (including subsequent legacy effects).

Table 9 summarizes the industry sectors impacted the most by the high case distributed solar scenario.

[38] This simply reflects a deferral from the base case.
[39] A job year is equivalent to one person having a full-time job for exactly one year.
[40] The legacy effect should continue up to and including 2065. However, REMI currently does not allow for any analysis beyond 2060. If the economic life of an installation is less than 30 years, the negative economic consequences are in all probability greater than the estimates presented in this study.

**Table 9: Statewide Employment Impacts by Industry Sector (Job Years)[41]**

| Sector | Total Job Years, 2016-2060[42] |
|---|---|
| Forestry, Fishing, and Related Activities | -30 |
| Mining | -3,496 |
| Utilities | -10,632 |
| Construction | -14,220 |
| Manufacturing | -2,074 |
| Wholesale Trade | -4,318 |
| Retail Trade | -25,645 |
| Transportation and Warehousing | -3,847 |
| Information | -1,505 |
| Finance and Insurance | -7,489 |
| Real Estate and Rental and Leasing | -7,892 |
| Professional and Technical Services | -20,701 |
| Management of Companies and Enterprises | -538 |
| Administrative and Support Services | 45,650 |
| Educational Services | -3,898 |
| Health Care and Social Assistance | -29,486 |
| Arts, Entertainment, and Recreation | -3,668 |
| Accommodation and Food Services | -11,364 |
| Other Services, except Public Administration | -11,405 |
| **Total Net Change in Job Years** | **-116,558** |
| **Total Number of Job Years Lost in Non-Solar Industry Sectors[43]** | **162,208** |

*Source: Authors' Calculations*

Consistent with the previous two scenarios, the table suggests that administrative and support services could benefit alone from the high case distributed solar scenario in terms of job years employment created. The administrative gain again probably originates to a large extent from the permitting of solar installations, and also business support functions within the solar industry. All other sectors are estimated to experience job losses, resulting in the total net estimate of 116,558 job years lost statewide. The sectors estimated to experience the biggest job losses (expressed in cumulative job years) during the study period in rank order are health care and social assistance; retail trade; professional; scientific and technical services; the construction industry; and other services (excluding public administration).

[41] A job year is equivalent to one person having a full-time job for exactly one year.
[42] Total job years may not tally due to rounding-up.
[43] This is a summation of the job years lost in non-solar industry sectors negatively impacted by the deployment of new distributed solar, 2016-2035.

Table 10 estimates the cumulative gross state product (GSP) and real disposable personal income impacts (RDPI) associated with the high case distributed solar scenario for the period 2016-2035.

**Table 10: Total Gross State Product (GSP) Impacts 2016-2035 (including Legacy Effects to 2060)**

| Geography | Gross State Product Millions (2015 $) | Real Disposable Personal Income Millions (2015 $) |
|---|---|---|
| **State of Arizona** | **-$31,454.4** | **-$11,901.4** |
| ***Maricopa County*** | ***-$29,346.7*** | ***-$12,091.2*** |

***Source: Authors' Calculations***

Table 10 shows that in aggregate terms during the study period 2016-2035, and including legacy effects, total GSP could be cumulatively lower by $31.5 billion (2015 $) in the State of Arizona under the high case scenario. This includes an estimated $29.3 billion GSP lost in Maricopa County (all 2015 $).

Table 10 also shows that in aggregate terms during the study period 2016-2035, and including legacy effects, RDPI is estimated to be cumulatively lower by $11.9 billion (2015 $) in the State of Arizona. This includes an estimated fall in RDPI of almost $12.1 billion in Maricopa County (2015 $).[44]

The employment, GSP, and RDPI losses associated with the high distributed solar deployment scenario are valid, because the total amount of money paid by distributed generation and central station generation electricity consumers over the 2016-2060 time horizon is greater than the amount which would have been paid had they all continued to draw electricity from the utility's central grid. In short, electricity consumers are paying more for the same amount of electricity consumed under the high distributed solar deployment scenario, and therefore have less money to spend in other parts of the economy.

[44] Some of Maricopa County's estimated losses in RDPI will be offset by minor gains in other counties, thereby resulting in a negligibly smaller loss for the State as a whole.

## 9.0 Conclusions

The goal of this study is to assess the impact of three distributed solar deployment scenarios in the APS service territory on economic activity in the State of Arizona and Maricopa County. The results of the analysis are influenced to an extent by the choice of economic impact model implemented.

Economic impact analyses can generally be classified in one of 6 ways, represented in Figure 5.

**Figure 5: Seidman's 3 x 2 Classification of Economic Impact Models**

| | | |
|---|---|---|
| COUNT GROSS | PARTIAL GROSS | GENERAL GROSS |
| COUNT NET | PARTIAL NET | GENERAL NET |

***Gross*** studies only consider the direct positive impacts of increased economic activity in a specific sector, whereas ***Net*** studies represent a more thorough form of economic modeling as they also account for the trade-offs in the economy which result from incentivizing one specific sector,

***Counts*** are usually survey-based or theoretical capacity installation quantifications of the number of direct employees within a specific economic sector, which can extend to that sector's entire supply chain.

***Partial*** models consider the wider effects of levels of activity in a specific economic sector, including the indirect and induced effects of the direct sectoral change. Frequently assessed via input-output models such as IMPLAN and REMI, partial models do not consider the feedback effects of changed levels of activity in a specific sector, such as the effect of large solar projects on wages in the labor market.

***General*** models offer the most comprehensive economy-wide analysis, taking into account all of the economic interconnections and feedback effects. Of the fourteen contemporary solar economic impact studies critiqued by Seidman, only one uses a general equilibrium model. This is Cansino, Cardenete, Gonzalez and Pablo-Romero's (2013) study of Andalusia. However, this is a gross, rather than net analysis, because the authors combine renewables and non-renewables as a single sector, thereby preventing any

substitution between conventional and renewable forms of generation, and effectively only allowing for positive direct demand shocks in their modeling.

The principal effect of using a ***Partial*** model approach rather than a ***Count*** approach, or using a ***General*** modeling approach rather than a ***Partial*** approach, is *generally* to reinforce the magnitude of the divined economic impacts. Thus, using a ***General*** model approach yields the most significant ***Gross*** and ***Net*** impacts.

However, to the research team's knowledge, a CGE model currently does not exist for the State of Arizona; and it would be cost prohibitive to test and develop a CGE model for the State of Arizona in a short time frame.

Seidman has therefore implemented a ***Partial Net*** REMI analysis of solar deployment in the APS service territory, 2016-2035, for the current study. This is the next best alternative from a methodological standpoint; and it is consistent, for example, with the approach taken by Berkman, Lagos and Weiss (2014), NYSERDA (2012), and Treyz et al. (2011), critiqued in Section 3. Figure 6 positions Seidman's approach relative to the fourteen critiqued studies

**Figure 6: Classification of Seidman's 2016 Approach for APS Relative to Fourteen Contemporary Economic Impact of Solar/Renewables Studies**

| | Counts | Partial Models | General Models |
|---|---|---|---|
| **Gross**<br>***Only positive or negative impacts*** | • Pollin and Garrett-Peltier, 2009<br>• ETIC, 2016 | • AECOM, 2011<br>• Loomis, Jo & Alderman ,2013<br>• Motamedi & Judson, 2012<br>• VSI and Clean Energy Project Nevada, 2011<br>• VSI, 2013<br>• Comings et al. , 2014 | • Cansino et al. 2013 |
| **Net**<br>***Both positive and negative impacts*** | • Alvarez et al., 2009<br>• Frondel et al., 2009 | • NYSERDA, 2012<br>• Treyz et al., 2011<br>• Berkman et al., 2014<br>• **SEIDMAN 2016** | |

The economic impacts of all three distributed solar deployment scenarios are assessed in terms of private non-farm employment, gross state product, and real disposable personal income.

The study clearly demonstrates that increased adoption of distributed solar generation represents a *loss* to the Arizona economy as a whole in all three scenarios. This is because the overall cost of provision of electricity to the State of Arizona will rise when referenced against a base case where electricity continues to be provided by central station generation.

If the low case distributed solar deployment scenario actually transpires, the State of Arizona is cumulatively estimated to lose:

- 16,595 job years private non-farm employment;
- Over $4.8 billion gross state product (2015 $); and
- $1.8 billion real disposable personal income (2015 $).

This takes into account both the solar installation study period (2016-2035) and the legacy effects of those installations to reflect the estimated 30 year economic life of the solar systems and deferred central station generation.[45]

If the expected or medium case distributed solar deployment scenario actually transpires, the State of Arizona is cumulatively estimated to lose:

- 76,308 job years private non-farm employment;
- Over $21.6 billion gross state product (2015 $); and
- Almost $8 billion real disposable personal income (2015 $).

This also takes into account both the solar installation study period (2016-2035) and the legacy effects of those installations, to reflect the estimated 30 year economic life of the solar systems and deferred central station generation.

If the high case distributed solar deployment scenario actually transpires, the State of Arizona is cumulatively estimated to lose:

[45] The legacy effects of any 2035 distributed solar installation or deferred central station generation will continue until 2065. However, the REMI model used currently only provides economic impact estimates up to and including 2060, but Seidman does not believe that this will materially affect the conclusions in the analysis. If the economic life of an installation is less than 30 years, the negative economic consequences are in all probability greater than the estimates presented in this study.

- 116,558 job years private non-farm employment;
- Approximately $31.5 billion gross state product (2015 $); and
- $11.9 billion real disposable personal income (2015 $).

This again takes into account both the solar installation study period (2016-2035) and the legacy effects of those installations, to reflect the estimated 30 year economic life of the solar systems and deferred central station generation.

The implications of these findings are potentially far-reaching, as they challenge a sometimes expressed claim that an aggressive distributed solar initiative will have a significant positive impact on the state and county economies in the State of Arizona.

In short, and wholly based on the financial implications of solar installations from a customer, utility and supplier perspective, this study estimates that any benefits emanating from the three distributed solar deployment scenarios are at best temporary and only coincident with the timing of those solar installations. This is because the lasting legacy effects of each distributed solar scenario, which reflect the economic life of the installed systems and deferred central station generation, are negative. That is, in all three scenarios, the total amount of money paid by distributed generation and central station generation electricity consumers over the relevant time period (2016-2060) is greater than the amount which would have been paid had they all alternatively continued to draw electricity from the utility's central grid. In each distributed solar scenario, electricity consumers as a whole are being asked to pay more for the same amount of electricity consumed, and therefore have less money to spend in other parts of the economy.

Thus, when considered in the round from a purely financial perspective, the economic impact of all three potential solar deployed scenarios in the APS service territory are estimated to have a detrimental effect on both the State of Arizona and Maricopa County economies, all other things being equal.

# Appendix

## A.1. The REMI Model

REMI is an economic-demographic forecasting and simulation model developed by Regional Economic Models, Inc. REMI is designed to forecast the impact of public policies and external events on an economy and its population. The REMI model is recognized by the business and academic community as the leading regional forecast/simulation tool available.

Unlike most other regional economic impact models, REMI is a dynamic model that produces integrated multiyear forecasts and accounts for dynamic feedbacks among its economic and demographic variables. The REMI model is also an "open" model in that it explicitly accounts for trade and migration flows in and out of the state. A complete explanation of the model and discussion of the empirical estimation of the parameters/equations can be found at www.remi.com.

The operation of the REMI model has been developed to facilitate the simulation of policy changes, such as a tax increase for example, or many other types of events – anything from the opening of a new business to closure of a military base to a natural disaster. The model's construction includes a large set of policy variables that are under the control of the model's operators. To simulate the impact of a policy change or other event, a change in one or more of the policy variables is entered into the model and a new forecast is generated. The REMI model then automatically produces a detailed set of simulation results showing the differences in the values of each economic variable between the control and the alternative forecast.

The specific REMI model used for this analysis was Policy Insight Model Version PI$^{+}$ version 1.7.2 of the Arizona economy (at the county level) leased from Regional Economic Models Inc. by a consortium of State agencies, including Arizona State University, for economic forecasting and policy analysis.

## A.2. Effects Not Incorporated into the Analysis

No major financial impacts were left out.

# Glossary

**Gross State Product (GSP):** The dollar value of all goods and services produced in Arizona for final demand/consumption.

**Job Year:** A job year is equivalent to one person having a full-time job for exactly one year.

**Real Disposable Personal Income:** The household income that is available to be spent after tax payments. Technically speaking, real disposable personal income is the sum of wage and salary disbursements, supplements to wages and salaries, proprietors' income, rental income of persons, personal dividend income, personal interest income, and personal current transfer receipts, less personal taxes and contributions for government social insurance.

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# ATTACHMENT A

EXHIBIT
APS-2
admitted

## DISCLAIMER

## POSSIBLE FUTURE RULES and/or RATE CHANGES AFFECTING YOUR PHOTOVOLTAIC (PV) SYSTEM

The following is a supplement to the Grid-Tied Residential Solar Electric PV Application you signed with UNS Electric, Inc. (UNSE).

1. Your PV system is subject to the current rates, rules and regulations established by the Arizona Corporation Commission (Commission). The Commission may alter its rules and regulations and/or change rates in the future. If this occurs, your PV system is subject to those changes and you will be responsible for paying any future increases to electricity rates, charges or service fees from UNSE.

2. UNSE's electricity rates, charges and service fees are determined by the Commission and are subject to change based upon the decision of the Commission. These future adjustments may positively or negatively impact any potential savings or the value of your PV system.

3. Any future electricity rate projections which may be presented to you are not produced, analyzed or approved by UNSE or the Commission. They are based on projections formulated by external third parties not affiliated with UNSE or the Commission.

Initials _____

**In its pending rate case that was filed on May 5,2015, UNSE has asked the Commission for approval to change the retail customer credit for excess energy placed on the grid and to eliminate the monthly energy carryover (banked credits). These changes, if approved by the Commission, may affect your bill. Other parties participating in the rate case may recommend different proposals that may affect your bill in other ways. The Commission is not bound by any party's proposal and may accept, reject, or modify any proposed rate, charge or term of service.**

Initials _____

By signing below, you acknowledge that you have read and understand the above disclaimer. Please return to UNSE.

_____ _____
Main Customer's Printed Name Main Customer's Signature

_____
Installation Address

_____
Date

Rev. 12312015

# ATTACHMENT B

## System Qualifications, Electric Service Requirements and Interconnection Requirements

**The installed PV system must at all times meet the system qualification requirements for residential and grid-connected PV systems as set forth in the current "Electric Service Requirements", "Distributed Generation Interconnection Requirements" (DGIRs), and UNSE's "Rules and Regulations", as amended from time to time, the terms of which are fully incorporated herein by reference (PV systems are defined as "Generating Facility" in the DGIRs). Complete copies of the "Electric Service Requirements" and "Distributed Generation Interconnection Requirements" conformed to ACC Docket No. E-00000A-99-0431 are located at https://www.uesaz.com/customer/construction/electric under the "Customer Care" - "Construction Services" tab. UNSE's "Rules and Regulations" dated July 1, 2013 are located at https://www.uesaz.com/customer/rates/electric under the "Rules and Regulations" tab. Customer acknowledges that it has adequate notice of and access to these online documents, has read the documentation, and waives any objection thereto. Hard copies will be provided upon request.**

Main UNSE Customer's Printed Name

Main UNSE Customer's Signature

Installation Address

Date

Installer

**DIRECT TESTIMONY OF AHMAD FARUQUI**

**On Behalf of Arizona Public Service Company**

**Docket No. E-04204A-15-0142**

EXHIBIT
APS-3
admitted

December 9, 2015

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**DIRECT TESTIMONY OF AHMAD FARUQUI**
**ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY**
**(Docket No. E-04204A-15-0142)**

## I. INTRODUCTION

**Q. PLEASE STATE YOUR NAME, JOB TITLE, BUSINESS ADDRESS AND PARTY FOR WHOM YOU ARE FILING TESTIMONY.**

A. My name is Ahmad Faruqui. I am a Principal with The Brattle Group. My business address is 201 Mission Street, Suite 2800, San Francisco, California 94105. I am filing testimony on behalf of Arizona Public Service Company ("APS").

**Q. PLEASE DESCRIBE YOUR PROFESSIONAL BACKGROUND AND EXPERIENCE.**

A. I have 35 years of consulting and research experience in the utility industry. During my career, I have advised some one hundred and twenty five electric and gas utilities, regulatory commissions, government agencies, transmission system operators, private energy companies, equipment manufacturers, and IT companies. Besides the United States, my clients have been located in Australia, Canada, Chile, Egypt, Hong Kong, Jamaica, Philippines, Saudi Arabia, South Africa, and Vietnam. I have advised them on a wide range of issues including: rate design, load forecasting, demand response, energy efficiency, distributed energy resources, cost-benefit analysis of emerging technologies, integration of retail and wholesale markets, and integrated resource planning. I have testified or appeared before a dozen state and provincial regulatory commissions and legislative bodies. I have authored or co-authored more than one hundred papers on energy economics and co-edited three books on electricity pricing and customer choice.

More details regarding my professional background and experience are set forth in my Statement of Qualifications, included as Attachment Faruqui Direct-1.

**Q. WHAT ARE YOUR RESPONSIBILITIES AS A PRINCIPAL WITH THE BRATTLE GROUP?**

A. I lead the firm's practice in understanding and managing the changing needs of energy consumers.

**Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE ARIZONA CORPORATION COMMISSION ("COMMISSION")?**

A. No, I have not formally testified before the Commission. However, I was invited to speak at a technical workshop before the Commission on the 20th of March, 2014. I gave a presentation that discussed the impact of changing customer energy use patterns on utilities. The workshop was entitled, "In the Matter of the Commission's Inquiry into Potential Impacts to the Current Utility Model Resulting from Innovation and Technological Developments in Generation and Delivery of Energy."[1]

## II. OVERVIEW AND ORGANIZATION OF TESTIMONY

**Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY IN THIS PROCEEDING?**

A. The purpose of my testimony is to evaluate the merits of UNS Electric's proposal to offer three-part rates to residential customers, including new net metering distributed generation ("DG") customers with rooftop photovoltaic ("PV") panels.[2]

**Q. PLEASE SUMMARIZE YOUR TESTIMONY.**

A. My testimony begins with a discussion of ratemaking principles and the merits of a three-part rate design. An overriding principle of electric rate design is that of cost causation—those who create costs should be responsible for paying those costs. Yet the standard residential rate design in the United States does not follow this principle. Fixed costs are most often recovered through volumetric rates (expressed in cents/kWh). The result is that customers might reduce the volume of electricity they consume but not reduce the demand they place on the grid, thereby lowering their load factor. As a result, some of the fixed costs required to meet their demand can go unpaid. The cost-causers do not pay for all the costs they create, and those costs are instead shifted to customers who use more volume of electricity and have higher load factors.

[1] Docket No.E-00000J-13-0375, Substantive Workshop No. 1(a) Special Open Meeting, March 20, 2014.

[2] Throughout my testimony I refer to these customers as "DG PV" customers.

The cost shift from lower load factor customers to higher load factor customers is a structural inefficiency that should be addressed through a rate design that includes three parts: a fixed charge, a demand charge, and a volumetric charge. With a three-part rate design, customers can more efficiently use the electric grid in a way that reduces the cost shift. In addition, demand rates provide a price signal to technologies that reduce demand. If policy-makers wish to encourage innovative distributed technologies, demand rates offer an efficient and equitable method of doing so.

My testimony concludes by evaluating UNS Electric's rate proposal in light of these principles. UNS Electric has proposed the deployment of three-part rates. Based on my review, the proposed rates appear to be based on well-established principles of rate design and would send a better price signal to customers that will encourage adoption of new technologies that are most beneficial to the power system. Given the benefits of these new three-part rate designs, as UNS Electric proceeds with the deployment of automated metering, it would be reasonable to eventually make a demand charge a feature of the rate for all residential customers.

**Q. HOW IS YOUR TESTIMONY ORGANIZED?**

A. It is organized into several sections. Section III reviews the principles of rate design. Section IV summarizes UNS Electric's rate design proposal and evaluates the proposal in light of the generally accepted ratemaking principles and the opportunities offered by three-part rates. Section V concludes the testimony.

**Q. ARE YOU SPONSORING ANY ATTACHMENTS TO YOUR TESTIMONY?**

A. Yes, I sponsor the following attachment to my testimony: Attachment Faruqui Direct-1: Statement of Qualifications.

## III. PRINCIPLES OF RATE DESIGN

**Q. PLEASE PROVIDE A HISTORICAL PERSPECTIVE ON THE THEORY OF ELECTRIC RATE DESIGN.**

A. The principles that guide electric rate design have evolved over time. Many authorities have contributed to their development, beginning with the legendary British rate engineer John Hopkinson in the late 1800's.[3] Hopkinson introduced demand charges into electricity rates. Subsequently, Henry L. Doherty proposed a three-part tariff, consisting of a fixed service charge, a demand charge and an energy charge.[4] The demand charge was based on the maximum level of demand which occurred during the billing period. Some versions of the three-part tariff also feature seasonal or time-of-use ("TOU") variations corresponding to the variations in the costs of energy supply.[5]

In the decades that followed, a number of British, French and U.S. economists and engineers made further enhancements to the original three-part rate design.[6] In 1961, Professor James C. Bonbright coalesced their thinking in his canon, *Principles of Public Utility Rates*,[7] which was reissued in its second edition in 1988. Some of these ideas were further expanded upon by Professor Alfred Kahn in his treatise, *The Economics of Regulation*.[8]

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[3] John R. Hopkinson, "On the Cost of Electricity Supply," *Transactions of the Junior Engineering Society*, Vol. 3, No. 1 (1892), pp.1-14

[4] Henry L. Doherty, *Equitable, Uniform and Competitive Rates,* Proceedings of the National Electric Light Association (1900), pp.291-321

[5] *See, for example*, Michael Veall, "Industrial Electricity Demand and the Hopkinson Rate: An Application of the Extreme Value Distribution," *Bell Journal of Economics*, Vol. 14, Issue No. 2 (1983).

[6] The most notable names include Maurice Allais, Marcel Boiteux, Douglas J. Bolton, Ronald Coase, Jules Dupuit, Harold Hotelling, Henrik Houthakker, W. Arthur Lewis, I. M. D. Little, James Meade, Peter Steiner and Ralph Turvey.

[7] James C. Bonbright, Albert L. Danielsen, and David R. Kamerschen, *Principles of Public Utility Rates,* 2d ed. (Arlington, VA: Public Utility Reports, 1988).

[8] Alfred Kahn, *The Economics of Regulation: Principles and Institutions*, rev. ed. (MIT Press, June 1988).

**Q. WHAT ARE THE GENERALLY ACCEPTED RATE DESIGN PRINCIPLES?**

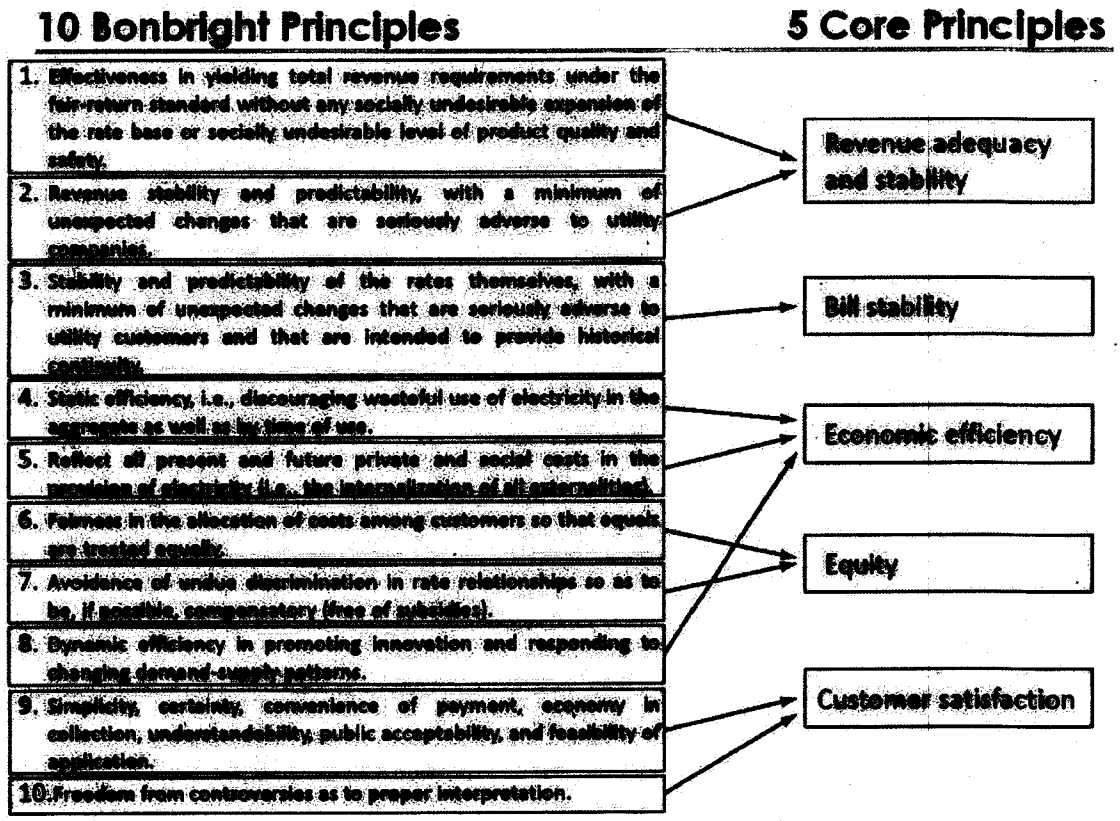
A. Professor Bonbright propounded ten principles of rate design that are widely used as a foundation for designing rates. For ease of exposition, I have grouped these into five core principles that fully encompass the concepts established by Professor Bonbright.

1. Economic Efficiency. The price of electricity should convey to the customer the cost of producing it, ensuring that resources consumed in the production and, delivery of electricity, are not wasted. If the price is set equal to the cost of providing a kWh, customers who value the kWh more than the cost of producing it will use the kWh and customers who value the kWh less will not. This will encourage the development and adoption of energy technologies that are capable of providing the most valuable services to the power grid.
2. Equity. There should be no unintentional subsidies between customer types. A classic example of the violation of this principle occurs under flat rate pricing structures (i.e., cents/kWh). Since customers have different load profiles, "peaky" customers, who use more electricity when it is most expensive, are subsidized by less "peaky" customers who overpay for cheaper off-peak electricity. Note that equity is not the same as social justice, which is related to inequities in socioeconomic status rather than cost. The pursuit of one is not necessarily the pursuit of the other, and vice versa.
3. Revenue adequacy and stability. Rates should recover the authorized revenues of the utility and should promote revenue stability. Theoretically, all rate designs can be implemented to be revenue neutral within a class, but this would require perfect foresight of the future. Changing technologies and customer behaviors make load forecasting more difficult and increase the risk of the utility either under-recovering or over-recovering costs when rates are not cost reflective.

4. Bill stability. Customer bills should be stable and predictable while striking a balance with the other ratemaking principles. Rates that are not cost reflective will tend to be less stable over time, since both costs and loads are changing over time. For example, if fixed infrastructure costs are spread over a certain number of kWh in Year 1, and the number of kWh halves in Year 2, then the price per kWh in Year 2 will double even though there is no change in the underlying infrastructure cost of the utility.
5. Customer satisfaction. Rates should enhance customer satisfaction. Because most residential customers devote relatively little time to reading their electric bills, rates need to be relatively simple so that customers can understand them and perhaps respond to the rates by modifying their energy use patterns. Giving customers meaningful cost-reflective rate choices helps enhance customer satisfaction.

Figure 1 illustrates my grouping of Bonbright's original 10 principles.

**Figure 1: Deriving the 5 Core Principles of Rate Design**




**Q. DID PROFESSOR BONBRIGHT DISCUSS THE CONCEPT OF COST CAUSATION IN DESIGNING RATES?**

A. Yes. In the first edition, an entire chapter is devoted to this topic. It is entitled: "Cost of Service as the Basic Standard of Reasonableness." In the chapter he states: "One standard of reasonable rates can fairly be said to outrank all others in the importance attached to it by experts and public opinion alike – the standard of cost of service, often qualified by the stipulation that the relevant cost is necessary cost or cost reasonably or prudently incurred."[9] Later he states that: "The first support for the cost-price standard is concerned with the consumer-rationing function when performed under the principle of consumer sovereignty."[10] He also cites another benefit of the cost-price standard

[9] James C. Bonbright, *Principles of Public Utility Rates*, (Columbia University Press: 1961) 1st Edition, Chapter IV, p. 67.
[10] Op. cit., p. 69.

when he says that "an individual with a given income who decides to draw upon the producer, and hence on society, for a supply of public utility services should be made to "account" for this draft by the surrender of a cost-equivalent opportunity to use his cash income for the purchase of other things."[11] Later in Chapter XVI, where he discusses the "criteria of a sound rate structure," he says that a purely volumetric rate assumes that the total costs of the utility vary directly with the changes in the kWh output of energy. He calls this "a grossly false assumption" and says such a rate "violates the most widely accepted canon of fair pricing, the principle of service at cost." Later, while discussing the Hopkinson rate, he says that such a "rate distinguishes between the two most important cost functions of an electric-utility system: between those costs that vary with changes in the system's output of energy, and those costs that vary with plant capacity and hence with the maximum demands on the system (and subsystems) that the company must be prepared to meet in planning its construction program."[12]

**Q. PLEASE DISCUSS FURTHER HOW THE CONCEPT OF COST CAUSATION IS IN ACCORD WITH THE BONBRIGHT PRINCIPLES.**

A. The Bonbright principles of economic efficiency and equity in particular embody the concept of cost causation. Economic efficiency is achieved by having cost-reflective prices. This ensures that products are only consumed by those customers who value them at more than they cost to produce. Pricing below cost is wasteful because customers will purchase and consume products that they would not choose to consume if faced with the full cost. Similarly pricing above cost is wasteful because customers, who would get a net benefit from consuming the product over its cost of production, lose out on that benefit. Respecting the equity principle requires that the tariff's design not result in unintended cross-subsidies between customers. This differs from a public policy that seeks to intentionally subsidize certain customers through the tariff. Prices

[11] Op. cit., p. 70.
[12] Op. cit., p. 310.

that are cost reflective minimize unintentional subsidies. Cost causation may need to be balanced against the other core principles such as customer satisfaction or bill stability.

**Q. GIVEN BONBRIGHT'S EMPHASIS ON COST CAUSATION, WHY DOES HIS FIFTH PRINCIPLE CALL FOR REFLECTING SOCIAL COSTS (OR EXTERNALITIES) IN ELECTRIC RATES?**

A. Each of Professor Bonbright's principles should be read in conjunction with the others. Reading a single principle in isolation from the others ensures that it will be taken out of context, resulting in a misinterpretation of his rate design philosophy. The fact is that the cost of service is Professor Bonbright's *basic standard* for designing rates, and it is clear from his writings that above all, rates should be cost-based. This is easily squared with the principle of reflecting social costs in the provision of electricity. If a price has been assigned to a certain externality, in other words, if it has been internalized, and that price is part of the utility's cost structure, then it is economically efficient to reflect the price of that externality in rates for all customers. However, it would violate the core principles of ratemaking if only certain customers or technologies were charged or compensated for their impact on those externalities. For instance, compensating owners of only one specific technology for reductions in emissions would lead to inefficient levels of investment in that technology when there may be other options which, if similarly compensated, would provide even greater environmental benefits. All technologies and customers should be on a level playing field when developing residential rate design.

**Q. WHAT IS THE STANDARD RATE STRUCTURE FOR RESIDENTIAL CUSTOMERS?**

A. The standard rate structure for residential customers in much of the U.S., and in fact in much of the globe, consists of two parts, a monthly service charge and a volumetric (kWh) energy charge. Most of the revenue is collected from the volumetric charge.

**Q. HOW DOES THE COLLECTION OF COSTS ON A VOLUMETRIC BASIS COMPARE TO THE NATURE OF UTILITY COSTS?**

A. The collection of utility costs through volumetric charges is at odds with the underlying cost structure of providing electricity to customers. Most of the costs do not vary with the volume of electricity that is produced and delivered to the customer, but vary with maximum demand or are otherwise fixed. In order to provide electricity to a customer, a utility must bear—directly or indirectly—costs related to energy, generation, transmission, distribution, metering, and customer service. It is true that generation energy costs generally vary with kWh electricity consumption. But generation capacity costs vary with system peak demand. Similarly, transmission costs also vary with system peak demand while distribution and transmission costs vary with maximum demand that is more local in nature. Metering, billing, customer care services, and other connection/hookup costs are a fixed cost per each customer of a particular class. Some of these costs vary across time. Generation costs will vary from hour to hour depending on the marginal generation source. Distribution and transmission networks, while used year round, are generally sized to meet class and system peak demand, respectively.

**Q. WHAT IS THE CONSEQUENCE OF FIXED CHARGES BEING COLLECTED THROUGH VOLUMETRIC RATES?**

A. This mismatch between cost structure and rate structure creates an inevitable and indisputable cost shift from customers with lower load factors to customers with higher load factors. Customers might reduce their load factor if, for instance, they install rooftop solar. With a lower load factor, customers paying for electricity under a volumetric rate design contribute less to the electric grid's fixed costs. Inevitably, customers with high load factors, paying for electric service under a volumetric rate design, wind up paying more for comparable service.

**Q. HOW SHOULD THESE COSTS TRANSLATE INTO RATES?**

A. According to the notion of cost causation, the rate structure should reflect the nature of the costs. Fixed costs, such as metering, billing, and customer service, should be

collected through a fixed monthly service charge. Demand-driven costs, such as capacity costs, should be collected through a demand charge. Variable costs, such as fuel and power grid operations and maintenance (O&M), should be collected through a variable charge (also known as an energy charge).

To address the deficiencies of current two-part rates, I support the institution of a three-part rate design, consisting of a monthly service charge, a demand charge, and a volumetric charge. The fixed charge should be designed to cover the fixed costs such as metering, billing, and customer care. Sometimes it also covers the cost of the line drop and the associated transformer. The demand charge should be designed to cover demand-driven costs, such as transmission, distribution, and generation capacity. It is typically applied to the individual customer's maximum demand, either during a defined on-peak period, or regardless of time of occurrence, or based on a combination of the two. While the concept of demand is instantaneous, in implementation demand is usually measured over 15-minute, 30-minute or 60-minute intervals. The energy charge covers the cost of the fuels that are used to generate electricity. The demand charge and the energy charge might vary with the time of use of electricity and have different seasonal and/or peak/off-peak charges. Such three-part rates align the rate design with costs, a fundamental tenet of rate design.

**Q. DID PROFESSOR BONBRIGHT SUPPORT THE USE OF THREE-PART RATES?**

A. Yes, he did. Their usage is discussed in several places in Bonbright's canon.[13] Bonbright cites the earlier text by the British engineer D. J. Bolton,[14] who states: "More accurate costing has shown that, on the average, only one-quarter of the total costs of electricity supply are represented by coal[15] or items proportional to energy, while three-

[13] James C. Bonbright, *Principles of Public Utility Rates*, (Columbia University Press: 1961).
[14] Bonbright says that "On many technical issues, no American treatise on electric utility rates can equal that by the distinguished British rate engineer D. J. Bolton," p. 289, n. 3.
[15] Coal was the dominant fuel for generating electricity in the United Kingdom in 1938 when the book by Bolton was first published.

quarters are represented by fixed costs or items proportional to power, etc. If therefore only one rate is to be levied it would appear more logical to charge for power and neglect the energy, were it not for certain practical difficulties of which the following are two. In the first place, the effective power demand on the system made by any particular consumer is extremely difficult to estimate and is very different from the individual maximum demand metered at the consumer's terminals. Secondly, a purely power tariff would probably lead to a waste of energy to a greater extent than a purely energy tariff leads to waste of power."[16]

Of course, with the arrival of smart meters, customer demand at times of system and distribution peak can be accurately recorded. And the choice is no longer a binary one of imposing either a demand-only rate or an energy-only rate. It is possible now to deploy a three-part pricing structure for residential customers that better reflects the cost of providing electric services. When Bonbright discusses a two-part rate structure, he is referring to what he characterizes as "the two most important cost functions of an electric-utility system"[17] -- demand and energy charges. When he moves into a discussion of three-part rate structures, he adds truly fixed charges, customer charges, to the two-part rate concept. Three-part rates are discussed at length in Bonbright's canon, beginning on page 346.[18]

**Q. HOW HAS THE PRINCIPLE OF COST CAUSATION AND THREE-PART RATES BEEN APPLIED IN PRACTICE?**

A. Most medium and large commercial and industrial customers across the U.S. are served under the more cost-reflective three-part rate structures. And those structures have been the norm for these customer classes for decades in much of the U.S.

[16] D. J. Bolton, *Costs and Tariffs in Electricity Supply*, (Chapman & Hall Ltd.: 1951) p. 59.
[17] Bonbright, p. 310.
[18] Bonbright, 2nd Edition, p. 401, credits Doherty with extending the Hopkinson two-part rate into a three part rate. Henry L. Doherty, *Equitable, Uniform and Competitive Rates*, Proceedings of the National Electric Light Association (1900), pp. 291-321.

**Q. HAVE THESE COST CAUSATION PRINCIPLES BEEN APPLIED TO RESIDENTIAL CUSTOMERS?**

A. Historically, these principles have rarely been fully applied to residential customers. Most residential customers in the U.S. are on two-part rates, with some or all of the fixed and demand-driven charges being recovered through a variable charge.

**Q. WHAT HAS PREVENTED THREE-PART RATES FROM BEING BROADLY DEPLOYED TO RESIDENTIAL CUSTOMERS?**

A. Until recently, metering technology for residential customers has been a significant limiting factor. The traditional electromechanical meters that most customers had installed at their homes measured only cumulative electricity consumption and not demand. Without the ability to meter demand, utilities could not cost-effectively offer three-part rates to these customers. Advances in metering technology have changed this situation.

**Q. HOW HAVE ADVANCES IN METERING TECHNOLOGY CHANGED THE UTILITY'S ABILITY TO OFFER THREE-PART RATES?**

A. With the deployment of automated meters (sometimes also referred to as advanced metering infrastructure or AMI), consumption can be recorded in intervals of an hour or less. This allows the utility to collect the consumption data necessary to incorporate demand charges into rates. It has removed a large barrier to the wider dissemination of cost-reflective rates to residential customers. Given these technological developments, rate structures for residential customers should be changed.

**Q. SHOULD UTILITIES UTILIZE THREE-PART RATES?**

A. Yes. Now is the time to take advantage of this opportunity to make cost-reflective three-part rates a standard offering for all residential customers. These rates will recover costs from customers in an equitable manner by more accurately charging customers for their use of the power grid. A more cost-reflective rate will also encourage the adoption of emerging energy technologies and changes in energy consumption behavior that will lead to more efficient use of power grid infrastructure and resources.

**Q. HOW WOULD A THREE-PART RATE ENCOURAGE THE ADOPTION OF EMERGING ENERGY TECHNOLOGIES?**

A. By providing customers with a price signal that includes a component for demand, a three-part rate would encourage the adoption of technologies that are designed to smooth out a customer's load profile. Behind-the-meter battery storage, for example, could be used to release electricity during hours of high electricity demand and store electricity during hours of low electricity demand. Load control technologies, such as programmable communicating thermostats, demand limiters, and smart appliances could also help customers manage their electricity demand. If a customer took service under a three-part rate, the use of battery storage, or other demand-reducing technologies, would reduce the customer's bill. This reduction in the customer's bill is an economic value that forms the basis of the price signal created by three-part rates.

**Q. ASIDE FROM TRANSMITTING PRICE SIGNALS THAT ENCOURAGE TECHNOLOGICAL INNOVATION, WOULD THREE-PART RATES PROVIDE OTHER BENEFITS TO RESIDENTIAL CUSTOMERS?**

A. Three-part rates will incentivize customers to smooth their energy consumption profile even if they are not equipped with enabling technologies. More than 40 pilot studies and full-scale rate deployments involving over 200 rate offerings over roughly the past dozen years have found that customers respond to new price signals by changing their energy consumption pattern.[19]

Further, there is some evidence that customers respond not just to changes in the rate structure generally, but specifically to demand charges. The following studies arrived at this conclusion:

[19] Some of these studies are summarized in Ahmad Faruqui and Sanem Sergici, "Arcturus: International Evidence on Dynamic Pricing," *The Electricity Journal*, (August/September 2013). Similar results were obtained from an earlier generation of 14 pricing pilots that were funded in the late seventies and early eighties by the U.S. Federal Energy Administration (later part of the Department of Energy). There were also early studies producing similar results. *See* Ahmad Faruqui and Bob Malko, "The Residential Demand for Electricity by Time-of-Use: A Survey of Twelve Experiments with Peak Load Pricing," *Energy*, Vol. 8, No. 10, (1983).

- Stokke, A., Doorman, G., Ericson, T., 2009, January. "An Analysis of a Demand Charge Electricity Grid Tariff in the Residential Sector," Discussion Paper 574, Statistics Norway Research Department.

- Taylor, T., Schwartz, P., 1986, April. "A residential demand charge: evidence from the Duke Power time-of-day pricing experiment." *Energy Journal*. (2), 135–151.

- Caves, D., Christensen, L., Herriges, J., 1984. "Modeling alternative residential peak-load electricity rate structures." *J. Econometrics*.

- Thomas N. Taylor, 1982. "Time-of-Day Pricing with a Demand Charge: Three-Year Results for a Summer Peak." Award Papers in Public Utility Economics and Regulation, Michigan State University Institute of Public Utilities, Michigan.

**Q. HAVE THREE-PART RATES BEEN OFFERED TO RESIDENTIAL CUSTOMERS IN OTHER U.S. JURISDICTIONS?**

A. Yes. There are at least 18 utilities in 14 states that offer a three-part rate to residential customers, including APS which has over 100,000 of its customers on a three-part rate. In most cases, the rates are available to all customers on an opt-in basis. In the case of Salt River Project ("SRP"), a three-part rate is mandatory for all residential customers who choose to install a new grid-connected DG PV system.[20]

## IV. UNS ELECTRIC'S RATE PROPOSAL

**Q. WHAT ARE UNS ELECTRIC'S CURRENT RATES FOR RESIDENTIAL CUSTOMERS, AND HOW ARE THEY DESIGNED?**

A. My understanding is that UNS Electric's current residential rate offerings include Residential Service ("RES-01"), Residential Service Time-of-Use ("RES-01 TOU"), and Residential Service Time-of-Use Super Peak ("RES-01 TOU SP"). All three are two-part rates with a fixed monthly service charge and a volumetric charge. The

[20] SRP website: http://www.srpnet.com/prices/home/customergenerated.aspx.

Residential Service option includes a $10 fixed monthly service charge and a tiered volumetric charge with a price of 8.4 cents/kWh for the first 400 kWh per month, 9.9 cents/kWh for the next 600 kWh per month, and 10.3 cents/kWh for all remaining kWh per month. The other two options include a slightly higher fixed monthly service charge and a volumetric rate that is time-varying.

**Q. HOW IS UNS ELECTRIC PROPOSING TO REDESIGN ITS RESIDENTIAL RATES?**

A. UNS Electric has proposed four specific changes to its residential rate offering: (1) increasing the fixed monthly service charge, (2) reducing the number of tiers in the inclining block rate, (3) modifying the net metering payment policy for excess generation from DG PV, and (4) introducing two three-part rate options. The focus of my testimony is on the three-part rates that are being proposed.

**Q. PLEASE DESCRIBE THE THREE-PART RATES THAT UNS ELECTRIC HAS PROPOSED.**

A. UNS Electric has proposed two rates, one called "RES-01 Demand" and a second rate called "RES-01 Demand TOU." DG PV customers would have the option of enrolling in one of these two rates. Other residential customers would have these as options in addition to the standard residential rate options described previously (subject to the additional rate design changes that have been proposed by UNS Electric).

My understanding is that the RES-01 Demand rate includes a tiered demand charge with a price of $6/kW on the first 7 kW of monthly demand and a price of $9.95/kW on demand in excess of 7 kW. The rate also includes a fixed monthly service charge of $20/month and a variable energy charge of approximately 5.9 cents/kWh.[21] Demand is measured as the customer's maximum one-hour demand in the billing month. The "RES-01 Demand TOU" rate has the same demand and fixed monthly service charges, but a time-varying energy charge which is approximately 11.1 cents/kWh during the

[21] Direct Testimony of Craig A. Jones on Behalf of UNS Electric, Inc., May 5, 2015, Exhibit CAJ-3, Docket No. E-04204A-15-0142.

peak period and 4.4 cents/kWh during the off-peak period in the summer, and approximately 10.9 cents/kWh during the peak period and 4.4 cents/kWh during the off-peak period in the winter. Summer is defined as May through October and the summer peak period is from 2 pm to 8 pm, excluding weekends and holidays. Winter is from November through April and the winter peak period is from 5 am to 9 am and from 5 pm to 9 pm, excluding weekends and holidays. The off-peak period is all other hours. These rates are summarized in Table 1 below.

**Table 1: Summary of UNS Electric's Proposed Three-Part Rates for DG PV Customers**

| | RES-01 Demand | RES-01 Demand TOU |
|---|---|---|
| **Basic service charge ($/month)** | 20.00 | 20.00 |
| | | |
| **Energy charge (cents/kWh)** | | |
| Summer on-peak | 5.9260 | 11.1110 |
| Summer off-peak | 5.9260 | 4.3900 |
| Winter on-peak | 5.9260 | 10.8960 |
| Winter off-peak | 5.9260 | 4.3579 |
| | | |
| **Demand charge ($/kW)** | | |
| First 7 kW | 6.00 | 6.00 |
| Over 7 kW | 9.95 | 9.95 |

Source: Direct Testimony of Craig A. Jones on Behalf of UNS Electric, Inc., May 5, 2015, Exhibit CAJ-3, Docket No. E-04204A-15-0142.

Note: Energy charge includes both delivery services charge and power supply charges

**Q. ARE UNS ELECTRIC'S PROPOSED THREE-PART RATES CONSISTENT WITH THE RATEMAKING PRINCIPLE OF EQUITY?**

A. Yes. Each customer imposes costs on the system some of which are fixed and the rest of which demand-driven and energy driven. Under purely volumetric tariffs, customers with high demand but low monthly consumption would not be paying their fair share of the cost of maintaining, upgrading, and expanding the utility's generation, transmission and distribution system. Instead, lower-demand customers would be covering the deficit and paying more than their fair share. UNS Electric's proposed three-part rates more

closely match demand, fixed, and variable costs with demand, fixed, and variable charges and will reduce this inequity so that all customers will pay their fair share of the costs associated with the generation of electricity, its delivery through utility's transmission and distribution system, and customer service.

**Q. ARE UNS ELECTRIC'S PROPOSED THREE-PART RATES CONSISTENT WITH THE RATEMAKING PRINCIPLE OF ECONOMIC EFFICIENCY?**

A. Yes. As I discussed previously, the cost-based price signals in the three-part rates proposed by UNS Electric provide customers with the financial incentive to make investments in technologies or otherwise change their behavior in ways that are most beneficial to the system. Technologies and behaviors that reduce a customer's demand should ultimately lead to a more efficient use of the grid, reduced costs, and lower bills.

**Q. ARE UNS ELECTRIC'S PROPOSED THREE-PART RATES CONSISTENT WITH THE RATEMAKING PRINCIPLE OF CUSTOMER SATISFACTION?**

A. Yes. UNS Electric is proposing to offer new rate options to residential customers. Having a choice of cost-based pricing products is a benefit to customers. Three-part rates send customers a more accurate price signal than traditional two-part rate structures, which then allows customers to properly assess and, where appropriate, adopt technologies that can help them manage their bills.

**Q. ARE UNS ELECTRIC'S PROPOSED THREE-PART RATES CONSISTENT WITH THE RATEMAKING PRINCIPLE OF BILL STABILITY?**

A. For the residential class as a whole, there will be no change in electric bills. That would also be true for customers whose load profile is similar to that of the class. Customers whose load factors are higher than the class average will experience lower bills. As for customers whose load factor is worse than the class average, since they have been subsidized for years by the customers whose load factor was higher than the class average, and the change in rates will remove that subsidy, they will experience higher bills. However, they will have an opportunity to lower their bills by reducing their demand. And that would also be true for customers who are automatically seeing lower

bills. They will have an opportunity to further lower their bills by reducing their demand.

**Q. ARE UNS ELECTRIC'S PROPOSED THREE-PART RATES CONSISTENT WITH THE RATEMAKING PRINCIPLE OF REVENUE ADEQUACY AND STABILITY?**

A. Yes. The introduction of a three-part rate will not change the utility's revenues. All other things being equal, a properly designed three-part rate will be revenue neutral for the class as a whole and therefore collect the same revenue as the otherwise applicable two-part rates. The main reason for moving to three-part rates is the ability to more accurately recover costs from those customers who are imposing costs on the system, and to provide customers with an incentive to consume electricity in a more efficient manner.

## V. CONCLUSION

**Q. WHAT ARE YOUR CONCLUSIONS ABOUT UNS ELECTRIC'S THREE-PART RATE DESIGN PROPOSALS?**

A. The two-part rate which is presently employed throughout the industry must give way to three-part rates. Not only are two-part rates ineffective at providing the proper pricing signals, as discussed above, they do not facilitate the integration of distributed energy resources with the grid, nor do they stimulate the deployment of other innovative technologies such as customer-sited battery storage and plug-in electric vehicles.

UNS Electric proposes to begin replacing its legacy two-part rate with three-part rates that are reasonable, cost-based, efficient, and equitable. In sum, they are consistent with well-established principles of rate design. In addition, UNS Electric's proposed three-part rates better align costs with prices. In so doing, the proposed rates will provide a more accurate price signal to customers, promote the efficient use of energy around-the-clock, and encourage the development of new, demand-reducing technologies. I would recommend that UNS Electric make the demand charge a feature of the rate for all

residential customers as it proceeds with the deployment of automated metering to all its customers.

**Q. DOES THIS CONCLUDE YOUR TESTIMONY?**

A. Yes, it does.

**Ahmad Faruqui**
Principal

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**Dr. Ahmad Faruqui** leads a consulting practice focused on understanding and managing the way customers use energy. His clients include utilities, commissions, equipment manufacturers, technology developers, and energy service companies. The practice encompasses a wide range of activities:

- **Rate design.** The recent decline in electricity sales has generated an entire crop of new issues that utilities must address in order to remain profitable. A key issue is the under-recovery of fixed costs and the creation of unsustainable cross-subsidies. To address these issues, we are creating alternative rate designs, testing their impact on customer bills, and sponsoring testimony to have them implemented. We are currently undertaking a large-scale project for a large investor-owned utility to estimate marginal costs, design rates, and produce a related software tool, working in close coordination with their internal executives. We have created a Pricing Roundtable which serves as virtual think tank on addressing the risks of under-recovery in the face of declining growth. About 18 utilities are a part of the think tank.

- **Demand forecasting.** We help utilities to identify the reasons for the slowdown in sales growth, which include utility energy efficiency programs, governmental codes and standards, distributed general, and fuel switching brought on by falling natural gas prices and the weak economic recovery. We present widely on the issue and are researching new methods for forecasting peak demand, such as the use of quantile regression.

- **Demand response.** For several clients in the United States and Canada, we are studying the impact of dynamic pricing. We have completed similar studies for a utility in the Asia-Pacific region and a regulatory body in the Middle East. We also conduct program design studies, impact evaluation studies, and cost-benefit analysis, and design marketing programs to maximize customer enrollment. Clients include utilities, regulators, demand response providers, and technology firms.

- **Energy efficiency.** We are studying the potential role of combined heat and power in enhancing energy efficiency in large commercial and industrial facilities. We are also carrying out analyses of behavioral programs that use social norming to induce change in the usage patterns of households.

- **New product design and cost-benefit analysis of emerging customer-side technologies.** We analyze market opportunities, costs, and benefits for advanced digital meters and associated infrastructure, smart thermostats, in-home displays, and other devices. This includes product design, such as proof-of-concept assessment, and a comparison of the costs and benefits of these new technologies from several vantage points: owners of that technology, other electricity customers, the utility or retail energy provider, and society as a whole.

In each of these areas, the engagements encompass both quantitative and qualitative analysis. Dr. Faruqui's reports, and derivative papers and presentations, are often widely cited in the media. The Brattle Group often sponsors testimony in regulatory proceedings and Dr. Faruqui has testified or appeared before a dozen state and provincial commissions and legislative bodies in the United States and Canada.

Dr. Faruqui's survey of the early experiments with time-of-use pricing in the United States is referenced in Professor Bonbright's treatise on public utilities. He managed the integration of results across the top five of these experiments in what was the first meta-analysis involving innovative pricing. Two of his dynamic experiments have won professional awards, and he was named one of the world's Top 100 experts on the smart grid by Greentech Media.

He has consulted with more than 50 utilities and transmission system operators around the globe and testified or appeared before a dozen state and provincial commissions and legislative bodies in the United States and Canada. He has also advised the Alberta Utilities Commission, the Edison Electric Institute, the Electric Power Research Institute, FERC, the Institute for Electric Efficiency, the Ontario Energy Board, the Saudi Electricity and Co-Generation Regulatory Authority, and the World Bank. His work has been cited in publications such as *The Economist*, *The New York Times*, and *USA Today* and he has appeared on Fox News and National Public Radio.

Dr. Faruqui is the author, co-author or editor of four books and more than 150 articles, papers, and reports on efficient energy use, some of which are featured on the websites of the Harvard Electricity Policy Group and the Social Science Research Network. He has taught economics at San Jose State University, the University of California at Davis and the University of Karachi. He holds a an M.A. in agricultural economics and a Ph. D. in economics from The University of California at Davis, where he was a Regents Fellow, and B.A. and M.A. degrees in economics from The University of Karachi, where he was awarded the Gold Medal in economics.

**AREAS OF EXPERTISE**

- *Innovative pricing.* He has identified, designed and analyzed the efficiency and equity benefits of introducing innovative pricing designs such as dynamic pricing, time-of-use pricing and inclining block rates.

+ demand charge

- *Regulatory strategy.* He has helped design forward-looking programs and services that exploit recent advances in rate design and digital technologies in order to lower customer bills and improve utility earnings while lowering the carbon footprint and preserving system reliability.
- *Cost-benefit analysis of advanced metering infrastructure.* He has assessed the feasibility of introducing smart meters and other devices, such as programmable communicating

thermostats that promote demand response, into the energy marketplace, in addition to new appliances, buildings, and industrial processes that improve energy efficiency.

- *Demand forecasting and weather normalization.* He has pioneered the use of a wide variety of models for forecasting product demand in the near-, medium-, and long-term, using econometric, time series, and engineering methods. These models have been used to bid into energy procurement auctions, plan capacity additions, design customer-side programs, and weather normalize sales.
- *Customer choice.* He has developed methods for surveying customers in order to elicit their preferences for alternative energy products and alternative energy suppliers. These methods have been used to predict the market size of these products and to estimate the market share of specific suppliers.
- *Hedging, risk management, and market design.* He has helped design a wide range of financial products that help customers and utilities cope with the unique opportunities and challenges posed by a competitive market for electricity. He conducted a widely-cited market simulation to show that real-time pricing of electricity could have saved Californians millions of dollars during the Energy Crisis by lowering peak demands and prices in the wholesale market.
- *Competitive strategy.* He has helped clients develop and implement competitive marketing strategies by drawing on his knowledge of the energy needs of end-use customers, their values and decision-making practices, and their competitive options. He has helped companies reshape and transform their marketing organization and reposition themselves for a competitive marketplace. He has also helped government-owned entities in the developing world prepare for privatization by benchmarking their planning, retailing, and distribution processes against industry best practices, and suggesting improvements by specifying quantitative metrics and follow-up procedures.
- *Design and evaluation of marketing programs.* He has helped generate ideas for new products and services, identified successful design characteristics through customer surveys and focus groups, and test marketed new concepts through pilots and experiments.
- *Expert witness.* He has testified or appeared before state commissions in Arkansas, California, Colorado, Connecticut, Delaware, the District of Columbia, Illinois, Indiana, Iowa, Kansas, Michigan, Maryland, Ontario (Canada) and Pennsylvania. He has assisted

clients in submitting testimony in Georgia and Minnesota. He has made presentations to the California Energy Commission, the California Senate, the Congressional Office of Technology Assessment, the Kentucky Commission, the Minnesota Department of Commerce, the Minnesota Senate, the Missouri Public Service Commission, and the Electricity Pricing Collaborative in the state of Washington. In addition, he has led a variety of professional seminars and workshops on public utility economics around the world and taught economics at the university level.

## EXPERIENCE

### Innovative Pricing

- **Report examining the costs and benefits of dynamic pricing in the Australian energy market.** For the Australian Energy Market Commission (AEMC), developed a report that reviews the various forms of dynamic pricing, such as time-of-use pricing, critical peak pricing, peak time rebates, and real time pricing, for a variety of performance metrics including economic efficiency, equity, bill risk, revenue risk, and risk to vulnerable customers. It also discusses ways in which dynamic pricing can be rolled out in Australia to raise load factors and lower average energy costs for all consumers without harming vulnerable consumers, such as those with low incomes or medical conditions requiring the use of electricity.

- **Whitepaper on emerging issues in innovative pricing.** For the Regulatory Assistance Project (RAP), developed a whitepaper on emerging issues and best practices in innovative rate design and deployment. The paper includes an overview of AMI-enabled electricity pricing options, recommendations for designing the rates and conducting experimental pilots, an overview of recent pilots, full-deployment case studies, and a blueprint for rolling out innovative rate designs. The paper's audience is international regulators in regions that are exploring the potential benefits of smart metering and innovative pricing.

- **Assessing the full benefits of real-time pricing.** For two large Midwestern utilities, assessed and, where possible, quantified the potential benefits of the existing residential real-time pricing (RTP) rate offering. The analysis included not only "conventional" benefits such as avoided resource costs, but under the direction of the state regulator was

expanded to include harder-to-quantify benefits such as improvements to national security and customer service.

- **Pricing and Technology Pilot Design and Impact Evaluation for Connecticut Light & Power (CL&P).** Designed the Plan-It Wise Energy pilot for all classes of customers and subsequently evaluated the Plan-It Wise Energy program (PWEP) in the summer of 2009. PWEP tested the impacts of CPP, PTR, and time of use (TOU) rates on the consumption behaviors of residential and small commercial and industrial customers.
- **Dynamic Pricing Pilot Design and Impact Evaluation: Baltimore Gas & Electric.** Designed and evaluated the Smart Energy Pricing (SEP) pilot, which ran for four years from 2008 to 2011. The pilot tested a variety of rate designs including critical peak pricing and peak time rebates on residential customer consumption patterns. In addition, the pilot tested the impacts of smart thermostats and the Energy Orb.
- **Impact Evaluation of a Residential Dynamic Pricing Experiment: Consumers Energy (Michigan).** Designed the pilot and carried out an impact evaluation with the purpose of measuring the impact of critical peak pricing (CPP) and peak time rebates (PTR) on residential customer consumption patterns. The pilot also tested the influence of switches that remotely adjust the duty cycle of central air conditioners.
- **Impact Simulation of Ameren Illinois Utilities' Power Smart Pricing Program.** Simulated the potential demand response of residential customers enrolled to real- time prices. Results of this simulation were presented to the Midwest ISO's Supply Adequacy Working Group (SAWG) to explore alternative ways of introducing price responsive demand in the region.
- **The Case for Dynamic Pricing: Demand Response Research Center.** Led a project involving the California Public Utilities Commission, the California Energy Commission, the state's three investor-owned utilities, and other stakeholders in the rate design process. Identified key issues and barriers associated with the development of time-based rates. Revisited the fundamental objectives of rate design, including efficiency and equity, with a special emphasis on meeting the state's strongly-articulated needs for demand response and energy efficiency. Developed a score-card for evaluating competing rate designs and applied it to a set of illustrative rates that were created for four customer classes using actual utility data. The work was reviewed by a national peer-review panel.

- **Developed a Customer Price Response Model: Consolidated Edison.** Specified, estimated, tested, and validated a large-scale model that analyzes the response of some 2,000 large commercial customers to rising steam prices. The model includes a module for analyzing conservation behavior, another module for forecasting fuel switching behavior, and a module for forecasting sales and peak demand

- **Design and Impact Evaluation of the Statewide Pricing Pilot: Three California Utilities.** Working with a consortium of California's three investor-owned utilities to design a statewide pricing pilot to test the efficacy of dynamic pricing options for mass-market customers. The pilot was designed using scientific principles of experimental design and measured changes in usage induced by dynamic pricing for over 2,500 residential and small commercial and industrial customers. The impact evaluation was carried out using state-of-the-art econometric models. Information from the pilot was used by all three utilities in their business cases for advanced metering infrastructure (AMI). The project was conducted through a public process involving the state's two regulatory commissions, the power agency, and several other parties.

- **Economics of Dynamic Pricing: Two California Utilities.** Reviewed a wide range of dynamic pricing options for mass-market customers. Conducted an initial cost-effectiveness analysis and updated the analysis with new estimates of avoided costs and results from a survey of customers that yielded estimates of likely participation rates.

- **Economics of Time-of-Use Pricing: A Pacific Northwest Utility.** This utility ran the nation's largest time-of-use pricing pilot program. Assessed the cost-effectiveness of alternative pricing options from a variety of different perspectives. Options included a standard three-part time-of-use rate and a quasi-real time variant where the prices vary by day. Worked with the client in developing a regulatory strategy. Worked later with a collaborative to analyze the program's economics under a variety of scenarios of the market environment.

- **Economics of Dynamic Pricing Options for Mass Market Customers - Client: A Multi-State Utility.** Identified a variety of pricing options suited to meet the needs of mass-market customers, and assessed their cost-effectiveness. Options included standard three-part time-of-use rates, critical peak pricing, and extreme-day pricing. Developed plans for implementing a pilot program to obtain primary data on customer acceptance and load shifting potential. Worked with the client in developing a regulatory strategy.

- **Real-Time Pricing in California - Client: California Energy Commission.** Surveyed the national experience with real-time pricing of electricity, directed at large power customers. Identified lessons learned and reviewed the reasons why California was unable to implement real-time pricing. Catalogued the barriers to implementing real-time pricing in California, and developed a program of research for mitigating the impacts of these barriers.

- **Market-Based Pricing of Electricity - Client: A Large Southern Utility.** Reviewed pricing methodologies in a variety of competitive industries including airlines, beverages, and automobiles. Recommended a path that could be used to transition from a regulated utility environment to an open market environment featuring customer choice in both wholesale and retail markets. Held a series of seminars for senior management and their staffs on the new methodologies.

- **Tools for Electricity Pricing - Client: Consortium of Several U.S. and Foreign Utilities.** Developed Product Mix, a software package that uses modern finance theory and econometrics to establish a profit-maximizing menu of pricing products. The products range from the traditional fixed-price product to time-of-use prices to hourly real-time prices, and also include products that can hedge customers' risks based on financial derivatives. Outputs include market share, gross revenues, and profits by product and provider. The calculations are performed using probabilistic simulation, and results are provided as means and standard deviations. Additional results include delta and gamma parameters that can be used for corporate risk management. The software relies on a database of customer load response to various pricing options called StatsBank. This database was created by metering the hourly loads of about one thousand commercial and industrial customers in the United States and the United Kingdom.

- **Risk-Based Pricing - Client: Midwestern Utility.** Developed and tested new pricing products for this utility that allowed it to offer risk management services to its customers. One of the products dealt with weather risk; another one dealt with risk that real-time prices might peak on a day when the customer does not find it economically viable to cut back operations.

**Demand Response**

- **National Action Plan for Demand Response: Federal Energy Regulatory Commission.** Led a consulting team developing a national action plan for demand response (DR). The national action plan outlined the steps that need to be taken in order to maximize the amount of cost-effective DR that can be implemented. The final document was filed with U.S. Congress in June 2010.
- **National Assessment of Demand Response Potential: Federal Energy Regulatory Commission.** Led a team of consultants to assess the economic and achievable potential for demand response programs on a state-by-state basis. The assessment was filed with the U.S. Congress in 2009, as required by the Energy Independence and Security Act of 2007.
- **Evaluation of the Demand Response Benefits of Advanced Metering Infrastructure: Mid-Atlantic Utility.** Conducted a comprehensive assessment of the benefits of advanced metering infrastructure (AMI) by developing dynamic pricing rates that are enabled by AMI. The analysis focused on customers in the residential class and commercial and industrial customers under 600 kW load.
- **Estimation of Demand Response Impacts: Major California Utility.** Worked with the staff of this electric utility in designing dynamic pricing options for residential and small commercial and industrial customers. These options were designed to promote demand response during critical peak days. The analysis supported the utility's advanced metering infrastructure (AMI) filing with the California Public Utilities Commission. Subsequently, the commission unanimously approved a $1.7 billion plan for rolling out nine million electric and gas meters based in part on this project work.

**Smart Grid Strategy**

- **Development of a smart grid investment roadmap for Vietnamese utilities.** For the five Vietnamese power corporations, developed a roadmap to guide future smart grid investment decisions. The report identified and described the various smart grid investment options, established objectives for smart grid deployment, presented a multi-phase approach to deploying the smart grid, and provided preliminary recommendations regarding the best investment opportunities. Also presented relevant case studies and an assessment of the current state of the Vietnamese power

grid. The project involved in-country meetings as well as a stakeholder workshop that was conducted by *Brattle* staff.

- **Cost-Benefit Analysis of the Smart Grid: Rocky Mountain Utility.** Reviewed the leading studies on the economics of the smart grid and used the findings to assess the likely cost-effectiveness of deploying the smart grid in one geographical location.
- **Modeling benefits of smart grid deployment strategies.** Developed a model for assessing benefits of smart grid deployment strategies over a long-term (e.g., 20-year) forecast horizon. The model, called iGrid, is used to evaluate seven distinct smart grid programs and technologies (e.g., dynamic pricing, energy storage, PHEVs) against seven key metrics of value (e.g., avoided resource costs, improved reliability).
- **Smart grid strategy in Canada.** The Alberta Utilities Commission (AUC) was charged with responding to a Smart Grid Inquiry issued by the provincial government. Advised the AUC on the smart grid, and what impacts it might have in Alberta.
- **Smart grid deployment analysis for collaborative of utilities.** Adapted the iGrid modeling tool to meet the needs of a collaborative of utilities in the southern U.S. In addition to quantifying the benefits of smart grid programs and technologies (e.g., advanced metering infrastructure deployment and direct load control), the model was used to estimate the costs of installing and implementing each of the smart grid programs and technologies.
- **Development of a smart grid cost-benefit analysis framework.** For the Electric Power Research Institute (EPRI) and the U.S. DOE, contributed to the development of an approach for assessing the costs and benefits of the DOE's smart grid demonstration programs.
- **Analysis of the benefits of increased access to energy consumption information.** For a large technology firm, assessed market opportunities for providing customers with increased access to real time information regarding their energy consumption patterns. The analysis includes an assessment of deployments of information display technologies and analysis of the potential benefits that are created by deploying these technologies.

- **Developing a plan for integrated smart grid systems.** For a large California utility, helped to develop applications for funding for a project to demonstrate how an integrated smart grid system (including customer-facing technologies) would operate and provide benefits.

**Demand Forecasting**

- **Comprehensive Review of Load Forecasting Methodology: PJM Interconnection.** Conducted a comprehensive review of models for forecasting peak demand and re-estimated new models to validate recommendations. Individual models were developed for 18 transmission zones as well as a model for the RTO system.
- **Analyzed Downward Trend: Western Utility.** We conducted a strategic review of why sales had been lower than forecast in a year when economic activity had been brisk. We developed a forecasting model for identifying what had caused the drop in sales and its results were used in an executive presentation to the utility's board of directors. We also developed a time series model for more accurately forecasting sales in the near term and this model is now being used for revenue forecasting and budgetary planning.
- **Analyzed Why Models are Under-Forecasting: Southwestern Utility.** Reviewed the entire suite of load forecasting models, including models for forecasting aggregate system peak demand, electricity consumption per customer by sector and the number of customers by sector. We ran a variety of forecasting experiments to assess both the ex-ante and ex-post accuracy of the models and made several recommendations to senior management.
- **U.S. Demand Forecast: Edison Electric Institute.** For the U.S. as a whole, we developed a base case forecast and several alternative case forecasts of electric energy consumption by end use and sector. We subsequently developed forecasts that were based on EPRI's system of end-use forecasting models. The project was done in close coordination with several utilities and some of the results were published in book form.
- **Developed Models for Forecasting Hourly Loads: Merchant Generation and Trading Company.** Using primary data on customer loads, weather conditions, and economic activity, developed models for forecasting hourly loads for residential, commercial,

and industrial customers for three utilities in a Midwestern state. The information was used to develop bids into an auction for supplying basic generation services.

- **Gas Demand Forecasting System - Client: A Leading Gas Marketing and Trading Company, Texas.** Developed a system for gas nominations for a leading gas marketing company that operated in 23 local distribution company service areas. The system made week-ahead and month-ahead forecasts using advanced forecasting methods. Its objective was to improve the marketing company's profitability by minimizing penalties associated with forecasting errors.

**Demand Side Management**

- **The Economics of Biofuels.** For a western utility that is facing stringent renewable portfolio standards and that is heavily dependent on imported fossil fuels, carried out a systematic assessment of the technical and economic ability of biofuels to replace fossil fuels.
- **Assessment of Demand-Side Management and Rate Design Options: Large Middle Eastern Electric Utility.** Prepared an assessment of demand-side management and rate design options for the four operating areas and six market segments. Quantified the potential gains in economic efficiency that would result from such options and identified high priority programs for pilot testing and implementation. Held workshops and seminars for senior management, managers, and staff to explain the methodology, data, results, and policy implications.
- **Likely Future Impact of Demand-Side Programs on Carbon Emissions - Client: The Keystone Center.** As part of the Keystone Dialogue on Climate Change, developed scenarios of future demand-side program impacts, and assessed the impact of these programs on carbon emissions. The analysis was carried out at the national level for the U.S. economy, and involved a bottom-up approach involving many different types of programs including dynamic pricing, energy efficiency, and traditional load management.
- **Sustaining Energy Efficiency Services in a Restructured Market - Client: Southern California Edison.** Helped in the development of a regulatory strategy for implementing energy efficiency strategies in a restructured marketplace. Identified the various players that are likely to operate in a competitive market, such as third-party energy service companies (ESCOS) and utility affiliates. Assessed their

objectives, strengths, and weaknesses and recommended a strategy for the client's adoption. This strategy allowed the client to participate in the new market place, contribute to public policy objectives, and not lose market share to new entrants. This strategy has been embraced by a coalition of several organizations involved in the California PUC's working group on public purpose programs.

- **Organizational Assessments of Capability for Energy Efficiency - Client: U.S. Agency for International Development, Cairo, Egypt.** Conducted in-depth interviews with senior executives of several energy organizations, including utilities, government agencies, and ministries to determine their goals and capabilities for implementing programs to improve energy end-use efficiency in Egypt. The interviews probed the likely future role of these organizations in a privatized energy market, and were designed to help develop U.S. AID's future funding agenda.

- **Enhancing Profitability Through Energy Efficiency Services - Client: Jamaica Public Service Company.** Developed a plan for enhancing utility profitability by providing financial incentives to the client utility, and presented it for review and discussion to the utility's senior management and Jamaica's new Office of Utility Regulation. Developed regulatory procedures and legislative language to support the implementation of the plan. Conducted training sessions for the staff of the utility and the regulatory body.

**Advanced Technology Assessment**

- **Competitive Energy and Environmental Technologies - Clients: Consortium of clients, led by Southern California Edison, Included the Los Angeles Department of Water and Power and the California Energy Commission.** Developed a new approach to segmenting the market for electrotechnologies, relying on factors such as type of industry, type of process and end use application, and size of product. Developed a user-friendly system for assessing the competitiveness of a wide range of electric and gas-fired technologies in more than 100 four-digit SIC code manufacturing industries and 20 commercial businesses. The system includes a database on more than 200 end-use technologies, and a model of customer decision making.

- **Market Infrastructure of Energy Efficient Technologies - Client: EPRI.** Reviewed the market infrastructure of five key end-use technologies, and identified ways in which the infrastructure could be improved to increase the penetration of these

technologies. Data was obtained through telephone interviews with equipment manufacturers, engineering firms, contractors, and end-use customers

## TESTIMONY

### California

Rebuttal Testimony before the Public Utilities Commission of the State of California, Pacific Gas and Electric Company Joint Utility on Demand Elasticity and Conservation Impacts of Investor-Owned Utility Proposals, in the Matter of Rulemaking 12-06-013, October 17, 2014.

Prepared testimony before the Public Utilities Commission of the State of California on behalf of Pacific Gas and Electric Company on rate relief, Docket No. A.10-03-014, summer 2010.

Qualifications and prepared testimony before the Public Utilities Commission of the State of California, on behalf of Southern California Edison, Edison SmartConnect™ Deployment Funding and Cost Recovery, exhibit SCE-4, July 31, 2007.

Testimony on behalf of the Pacific Gas & Electric Company, in its application for Automated Metering Infrastructure with the California Public Utilities Commission. Docket No. 05-06-028, 2006.

### Colorado

Rebuttal testimony before the Public Utilities Commission of the State of Colorado in the Matter of Advice Letter No. 1535 by Public Service Company of Colorado to Revise its Colorado PUC No.7 Electric Tariff to Reflect Revised Rates and Rate Schedules to be Effective on June 5, 2009. Docket No. 09al-299e, November 25, 2009.

Direct testimony before the Public Utilities Commission of the State of Colorado, on behalf of Public Service Company of Colorado, on the tariff sheets filed by Public Service Company of Colorado with advice letter No. 1535 – Electric. Docket No. 09S-__E, May 1, 2009.

### Connecticut

Testimony before the Department of Public Utility Control, on behalf of the Connecticut Light and Power Company, in its application to implement Time-of-Use , Interruptible Load Response, and Seasonal Rates-Submittal of Metering and Rate Pilot Results- Compliance Order No. 4, Docket no. 05-10-03RE01, 2007.

### District of Columbia

Direct testimony before the Public Service Commission of the District of Columbia on behalf of Potomac Electric Power Company in the matter of the Application of Potomac Electric Power Company for Authorization to Establish a Demand Side Management Surcharge and an Advance Metering Infrastructure Surcharge and to Establish a DSM Collaborative and an AMI Advisory Group, case no. 1056, May 2009.

## Ahmad Faruqui

### Illinois

Direct testimony on rehearing before the Illinois Commerce Commission on behalf of Ameren Illinois Company, on the Smart Grid Advanced Metering Infrastructure Deployment Plan, Docket No. 12-0244, June 28, 2012.

Testimony before the State of Illinois – Illinois Commerce Commission on behalf of Commonwealth Edison Company regarding the evaluation of experimental residential real-time pricing program, 11-0546, April 2012.

Prepared rebuttal testimony before the Illinois Commerce Commission on behalf of Commonwealth Edison, on the Advanced Metering Infrastructure Pilot Program, ICC Docket No. 06-0617, October 30, 2006.

### Indiana

Direct testimony before the State of Indiana, Indiana Utility Regulatory Commission, on behalf of Vectren South, on the smart grid. Cause no. 43810, 2009.

### Kansas

Direct testimony before the State Corporation Commission of the State of Kansas, on behalf of Westar Energy, in the matter of the Application of Westar Energy, Inc. and Kansas Gas and Electric Company to Make Certain Changes in Their Charges for Electric Service, Docket No. 15-WSEE-115-RTS, March 2, 2015.

### Maryland

Direct testimony before the Public Service Commission of Maryland, on behalf of Potomac Electric Power Company and Delmarva Power and Light Company, on the deployment of Advanced Meter Infrastructure. Case no. 9207, September 2009.

Prepared direct testimony before the Maryland Public Service Commission, on behalf of Baltimore Gas and Electric Company, on the findings of BGE's Smart Energy Pricing ("SEP") Pilot program. Case No. 9208, July 10, 2009.

### Minnesota

Rebuttal testimony before the Minnesota Public Utilities Commission State of Minnesota on behalf of Northern States Power Company, doing business as Xcel Energy, in the matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in Minnesota, Docket No. E002/GR-12-961, March 25, 2013.

Direct testimony before the Minnesota Public Utilities Commission State of Minnesota on behalf of Northern States Power Company, doing business as Xcel Energy, in the matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in Minnesota, Docket No. E002/GR-12-961, November 2, 2012.

**Nevada**

Prepared direct testimony before the Public Utilities Commission of Nevada on behalf of Nevada Power Company d/b/a NV Energy, in the matter of the application for approval of a cost of service study and net metering tariffs, Docket No. 15-07, July 31, 2015.

**New Mexico**

Direct testimony before the New Mexico Regulation Commission on behalf of Public Service Company of New Mexico in the matter of the Application of Public Service Company of New Mexico for Revision of its Retail Electric Rates Pursuant to Advice Notice No. 507, Case No. 14-00332-UT, December 11, 2014.

**Pennsylvania**

Direct testimony before the Pennsylvania Public Utility Commission, on behalf of PECO on the Methodology Used to Derive Dynamic Pricing Rate Designs, Case no. M-2009-2123944, October 28, 2010.

## REGULATORY APPEARANCES

**Arkansas**

Presented before the Arkansas Public Service Commission, "The Emergence of Dynamic Pricing" at the workshop on the Smart Grid, Demand Response, and Automated Metering Infrastructure, Little Rock, Arkansas, September 30, 2009.

**Delaware**

Presented before the Delaware Public Service Commission, "The Demand Response Impacts of PHI's Dynamic Pricing Program" Delaware, September 5, 2007.

**Kansas**

Presented before the State Corporation Commission of the State of Kansas, "The Impact of Dynamic Pricing on Westar Energy" at the Smart Grid and Energy Storage Roundtable, Topeka, Kansas, September 18, 2009.

**Ohio**

Presented before the Ohio Public Utilities Commission, "Dynamic Pricing for Residential and Small C&I Customers" at the Technical Workshop, Columbus, Ohio, March 28, 2012.

**Texas**

Presented before the Public Utility Commission of Texas, "Direct Load Control of Residential Air Conditioners in Texas," at the PUCT Open Meeting, Austin, Texas, October 25, 2012.

## PUBLICATIONS

### Books

"Making the Most of the No Load Growth Business Environment," with Dian Grueneich. *Distributed Generation and Its Implications for the Utility Industry.* Ed. Fereidoon P. Sioshansi. Academic Press, 2014. 303-320.

"*Arcturus:* An International Repository of Evidence on Dynamic Pricing," with Sanem Sergici. *Smart Grid Applications and Developments, Green Energy and Technology.* Ed. Daphne Mah, Ed. Peter Hills, Ed. Victor O. K. Li, Ed. Richard Balme. Springer, 2014. 59-74.

"Will Energy Efficiency make a Difference," with Fereidoon P. Sioshansi and Gregory Wikler. *Energy Efficiency: Towards the end of demand growth.* Ed. Fereidoon P. Sioshansi. Academic Press, 2013. 3-50.

"The Ethics of Dynamic Pricing." *Smart Grid: Integrating Renewable, Distributed & Efficient Energy.* Ed. Fereidoon P. Sioshansi. Academic Press, 2012. 61-83.

*Electricity Pricing in Transition.* Co-editor with Kelly Eakin. Kluwer Academic Publishing, 2002.

*Pricing in Competitive Electricity Markets.* Co-editor with Kelly Eakin. Kluwer Academic Publishing, 2000.

*Customer Choice: Finding Value in Retail Electricity Markets.* Co-editor with J. Robert Malko. Public Utilities Inc. Vienna. Virginia: 1999.

*The Changing Structure of American Industry and Energy Use Patterns.* Co-editor with John Broehl. Battelle Press, 1987.

*Customer Response to Time of Use Rates: Topic Paper I,* with Dennis Aigner and Robert T. Howard, Electric Utility Rate Design Study, EPRI, 1981.

### Technical Reports

*Quantifying the Amount and Economic Impacts of Missing Energy Efficiency in PJM's Load Forecast,* with Sanem Sergici and Kathleen Spees, prepared for The Sustainable FERC Project, September 2014.

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EXHIBIT

APS-4

admitted

**SURREBUTTAL TESTIMONY OF AHMAD FARUQUI**

**On Behalf of Arizona Public Service Company**

**Docket No. E-04204A-15-0142**

February 23, 2016

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**SURREBUTTAL TESTIMONY OF AHMAD FARUQUI**
**ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY**
**(Docket No. E-04204A-15-0142)**

I. INTRODUCTION

**Q. PLEASE STATE YOUR NAME, JOB TITLE, BUSINESS ADDRESS AND PARTY FOR WHOM YOU ARE FILING TESTIMONY.**

A. My name is Ahmad Faruqui. I am a Principal with The Brattle Group. My business address is 201 Mission Street, Suite 2800, San Francisco, California 94105. I am filing testimony on behalf of Arizona Public Service Company.

**Q. HAVE YOU PREVIOUSLY TESTIFIED IN THIS PROCEEDING?**

A. Yes, I filed Direct Testimony on December 9, 2015.

II. SUMMARY AND ORGANIZATION OF SURREBUTTAL TESTIMONY

**Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY IN THIS PROCEEDING?**

A. The purpose of my Surrebuttal Testimony is to rebut some of the points made in the direct testimony of several intervenors in this proceeding, including, TASC witness Fulmer, Vote Solar witness Kobor, WRA witness Wilson, and RUCO witness Huber. In addition, I will comment on some of the points raised by Staff witness Solganick.

**Q. PLEASE SUMMARIZE YOUR SURREBUTTAL TESTIMONY.**

A. Several intervenors have mischaracterized demand charges and three-part rates in general. Demand charges are an appropriate price signal that closely relates the design of the rate to the costs it is recovering. Through this close alignment with costs, in addition to improving economic efficiency and equity/fairness, three-part rates will provide an incentive for customers to adopt emerging energy management technologies that reduce power system costs for all customers. Customers are likely to be able to understand the concept of demand and respond to a demand charge by reducing their maximum demand through behavioral changes or adoption of the aforementioned technologies. In fact, while some customers' bills will go down and others will go up

with the new rate design, demand charges will provide all customers - including those with limited income - with three opportunities to reduce their electricity bill: First, by managing their demand, second by conserving energy, and third by shifting usage to off-peak periods. In my Surrebuttal Testimony, I elaborate on these points.

**Q. HOW IS YOUR SURREBUTTAL TESTIMONY ORGANIZED?**

A. My Surrebuttal Testimony is organized around the following issues: the appropriateness of demand charges as a price signal; the role of demand charges in promoting advanced energy technologies; customer understanding and acceptance of demand charges; the impact of demand charges on bills and electricity consumption; the impact of three-part rates on customer bills; and how to make the transition to demand charges.

**Q. ARE YOU SPONSORING ANY ATTACHMENTS TO YOUR SURREBBUTTAL TESTIMONY?**

A. No.

III. THE APPROPRIATENESS OF DEMAND CHARGES AS A PRICE SIGNAL

**Q. DO YOU AGREE WITH THE ASSERTION THAT DEMAND CHARGES ARE NOT AN APPROPRIATE PRICE SIGNAL?**

A. No. As I indicated throughout my Direct Testimony, three-part rates, which include a demand charge as well as a fixed charge and an energy charge, do a much better job of reflecting the cost structure of generating and delivering electricity than two-part rates, which recover costs almost entirely through a volumetric charge.[1] Two-part rates over-collect costs from larger-than-average customers and under-recover costs from smaller-than-average customers. Not only do three-part rates improve equity in rate design; they also encourage technological innovation by incentivizing the adoption of newly emerging energy technologies and by bringing about changes in energy consumption behavior that lead to more efficient use of power grid infrastructure and resources.

[1] *See* Decision No. 51472 (Oct. 21, 1980).

**Q. WHY ARE THREE-PART RATES AN IMPROVEMENT OVER TWO-PART RATES?**

A. Some intervenors have argued that while three-part rates may do a better job of reflecting costs in the short run, they do not do so in the long run.[2] They argue that two-part rates send a better price signal than three part rates.[3] Precisely the opposite is true. In the long run, transmission, distribution, and generation capacity costs are directly driven by peak demand. Thus, increases in demand translate into a need for more capacity in the long run. Reductions in demand reduce the need for new capacity. By virtue of being tied specifically to a measure of a customer's maximum demand, demand charges capture this relationship between demand and infrastructure investment requirements.

The view that three-part rates are an improvement in rate design is supported by the testimony of ACC Staff. Staff witness Solganick, for instance, indicates that rate design should recognize the concepts of customer, demand, and energy costs, and the time-and season-differentiated nature of these costs.[4] Staff witness Solganick further notes that three-part rates are the norm for medium and large commercial and industrial (C&I) customers, and thus set a precedent in Arizona.[5] Indeed, in much of the country, three-part rates are the norm for commercial and industrial customers and have been the norm for the better part of the past century.

**Q. SOME INTERVENORS WHO OPPOSE THE INTRODUCTION OF A DEMAND CHARGE HAVE PROPOSED ALTERNATIVE RATE DESIGNS. PLEASE SUMMARIZE YOUR UNDERSTANDING OF THOSE PROPOSED DESIGNS.**

A. Two alternative rate designs are mentioned in intervenor testimony. One is a minimum bill, in which each customer would pay a fixed minimum amount for electricity each

[2] Direct Testimony of Mark Fulmer, p. 19.
[3] Direct Testimony of Briana Kobor, p. 34-35.
[4] Direct Testimony of Howard Solganick, p. 10.
[5] *Id.*, p. 13.

month, even if their net consumption (net of any self-generation) was very low.[6] The second is a time-of-use (TOU) rate in which the volumetric charge varies by time of day, with a higher price during peak hours of the day and a lower price during off-peak hours.[7]

**Q. DO YOU AGREE WITH EITHER OF THESE ALTERNATIVE DESIGNS?**

A. No, I do not believe either of these is a suitable replacement for the three-part rate that has been proposed by UNSE. These alternatives will not solve the cost-shift issue that is attendant to the two-part design that is currently in place. Neither will they adequately reflect cost of service or incent adoption of new technology. I expand on these points below.

**Q. WHY IS A MINIMUM BILL NOT A SUITABLE ALTERNATIVE TO A THREE-PART RATE WITH A DEMAND CHARGE?**

A. There are two reasons why it is not a suitable alternative.

First, minimum bills must be set at a very high level in order to sufficiently recover capacity costs from rooftop solar customers. Second, minimum bills by themselves do not reward reductions in demand or improvements in load factor. Thus, there is no incentive to do either.

**Q. WHY IS A TOU RATE NOT A SUITABLE ALTERNATIVE TO A THREE-PART RATE WITH A DEMAND CHARGE?**

A. Since infrastructure costs do not vary with electricity consumption, they cannot be recovered adequately through a volumetric (kWh) rate, TOU or otherwise. From a cost-causation standpoint, the most efficient way to represent kilowatt-based costs is through a kilowatt-based charge, i.e., through a demand charge. That is why demand charges are part of the standard tariff for most commercial and industrial customers.

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[6] Direct Testimony of Kenneth Wilson, p. 11-12.
[7] *Id.*, p. 13, Fulmer Direct, p. 23.

TOU rates are an appropriate method for recovering energy costs if they vary by time-of-use but not for recovering capacity costs. Thus, they are a good complement to a demand charge; not a substitute. Offering a rate with both a demand charge and a time-varying energy charge may be the best option.

## IV. THE ROLE OF DEMAND CHARGES IN PROMOTING ADVANCED ENERGY TECHNOLOGIES

**Q. WOULD THE INTRODUCTION OF DEMAND CHARGES IMPACT ADOPTION OF DISTRIBUTED ENERGY RESOURCES (DER)?**

A. A change in rate design will affect the economics of DER. Adoption of the technologies is driven in part by their economic attractiveness,[8] thus the inclusion of demand charges in rate design should affect their adoption levels. Some intervenors have suggested that demand charges would curtail the adoption of distributed generation (DG), rooftop solar in particular.[9] However, this technology-specific perspective takes too narrow a view on the impacts of demand charges on energy technology adoption.

**Q. WHY IS A FOCUS ON THE IMPACT OF DEMAND CHARGES ON ROOFTOP SOLAR PV TOO NARROW OF A PERSPECTIVE?**

A. A three-part rate will foster technological innovation by encouraging customers to adopt technologies that enable peak demand reductions and also reduce their energy consumption. Examples of such technologies include battery storage, smart thermostats, demand controllers, and energy information displays. The use of these technologies to reduce demand will not only reduce customer bills but will also reduce the utility's costs, thus benefitting all customers.

In the same vein, introducing a demand charge and reducing the volumetric charge would decrease the economic attractiveness of energy technologies that cannot provide

[8] Other factors beyond economics also drive consumer buying decisions, such as a desire to be "green" or to have more control over energy consumption or simply to buy the newest technologies.
[9] Kobor Direct, p. 4, Fulmer Direct, p. 17.

energy savings during those peak hours when the energy reductions are most valuable to the system. This simply means that the three-part rate structure is encouraging adoption of those technologies that are most beneficial to the power grid and to customers. It is important to take this broader view of energy technologies to avoid overstating the importance of one particular option that may not be the most beneficial.

**Q. HOW WILL DEMAND CHARGES IMPACT OWNERS OF ELECTRIC VEHICLES?**

A. WRA witness Wilson has suggested that ownership of an electric vehicle (EV) would lead to a "peakier" consumption profile, resulting in an increase in the cost of charging the vehicle with a demand charge.[10] This is not necessarily correct. If the vehicle is charged during nighttime hours when the household is otherwise using relatively little electricity, then charging the electric vehicle would not necessarily create a new peak. Additionally, smart charging equipment would allow the EV owner to manage his or her charging to reduce the possibility of setting a new peak.

It is also important to note that, while off-peak load building is beneficial to the power system by reducing average costs, the simultaneous charging of several EVs on a capacity constrained feeder could lead to a need for distribution system upgrades. Demand charges should help to send a price signal that encourages flatter load profiles throughout the day and reduces this possibility.

## V. CUSTOMER UNDERSTANDING AND ACCEPTANCE OF DEMAND CHARGES

**Q. DO YOU AGREE WITH THOSE INTERVENORS WHO HAVE SUGGESTED THAT CUSTOMERS WILL NOT UNDERSTAND DEMAND CHARGES?**

A. No, I don't agree with TASC witness Fulmer and WRA witness Wilson, for example, who have suggested that residential customers will not be able to understand demand

[10] Wilson Direct, p. 10.

charges.[11,12] I believe there are several reasons why customers will be able to understand demand charges, if they are explained properly to them.

**Q. WHY DO YOU BELIEVE THAT CUSTOMERS CAN UNDERSTAND A DEMAND CHARGE?**

A. First, 117,000 customers of Arizona Public Service ("APS") have elected to take service on voluntary demand charges. APS has been offering these rates to its residential customers since the very early 1980s. In other words, long before the advent of advanced metering infrastructure ("AMI"), there is evidence that customers were able to comprehend the notion of demand and recognize the benefits of being on such a rate.

Second, just about every customer has encountered the concept of electricity demand in daily life, perhaps without knowing what demand was. It would be hard to find a residential customer who is not familiar with a light bulb. When buying or installing a light bulb, the customer had to choose a bulb that would project a certain amount of light. It was then that the customer would have encountered the power of the bulb expressed in watts.[13] The wattage would have been expressed as 40 watts, 60 watts, 75 watts or 100 watts (or their equivalent, if the bulb was a compact fluorescent or LED bulb). Some wattages would have been higher, for three-way bulbs, such as 50, 100, and 150; or 100, 200 and 250. Thus, it would be difficult to find a customer who has not encountered the concept of watts. Further, if the customer had purchased a high wattage hair dryer and a high wattage electric iron, and decided to run both at the same time, they may have tripped the circuit breaker, requiring a trip to the garage or basement to reset it after one of the two devices had been unplugged. That is yet another way through which customers would have become familiar by experience with the concept of demand or capacity.

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[11] Fulmer Direct, p. 18.
[12] Wilson Direct, p. 5.
[13] Watts is the industry-accepted unit of power or demand.

Third, customers do not need to know the precise definition of a kilowatt in order to be able to respond to a demand rate. Simple messages encouraging customers to avoid the simultaneous use of electricity-intensive appliances can convey this concept in easy-to-understand terms without even using the word "kilowatt."

Fourth, all of this would apply even with greater force to customers with rooftop solar. They would have encountered the concept of watts (or kilowatts) once again when they purchased or leased their solar panels since that is the measure in which the size and cost of the panels are expressed. Demand rates for rooftop PV customers, therefore, would convey prices in terms in units that they are already familiar with.

**Q. DO YOU AGREE THAT A DEMAND CHARGE WILL FUNCTION AS AN ADDITIONAL FIXED CHARGE FOR MOST CUSTOMERS?**

A. No, I do not agree with Vote Solar witness Kobor who states that a demand charge will "likely function as an additional fixed charge for most residential and small commercial customers because they lack the tools and understanding to effectively respond to the demand charge price signal."[14] Demand charges are significantly different than fixed charges in that customers can, and are likely to, reduce their demand charge by lowering their demand. Conversely, customers are not able to take any behavioral actions to reduce their fixed charges.

**Q. HOW ARE DEMAND CHARGES DIFFERENT THAN FIXED CHARGES?**

A. Importantly, demand charges vary with a customer's demand for electricity. Customers with high maximum demand will be charged more than customers with low maximum demand. The result is that customers are charged in a manner that is proportional to their use of the power grid. Fixed charges, on the other hand, charge each customer the

[14] Kobor Direct, p. 36

same amount regardless of their use of the power grid. Referring to a demand charge as a fixed charge ignores this important distinguishing feature of demand charges.

Additionally, with a demand charge, customers have the ability to reduce their bill by changing the way they consume electricity. Fixed charges, on the other hand, are not under the customer's control. In my Direct Testimony, I cited four studies that found that customers respond to demand charges by reducing their maximum demand. Additionally, the Direct Testimony of APS witness Miessner stated that 60% of a sample of APS's customers on a three-part rate reduced their demand after switching to the three-part rate, with those who actively manage their demand achieving demand savings of 10% to 20% or more.[15]

**Q. DO THE INTERVENORS OFFER ANY EVIDENCE THAT CUSTOMERS CANNOT UNDERSTAND A DEMAND CHARGE?**

A. TASC witness Fulmer and Vote Solar witness Kobor cite a study in California by Hiner and Partners ("Hiner") to suggest that customers could not understand a demand charge.[16] However, for several reasons this study does not support the conclusion that customers cannot understand a demand charge.

**Q. WHY IS IT INCORRECT TO USE THE HINER STUDY TO SUPPORT A CONCLUSION THAT CUSTOMERS CANNOT UNDERSTAND A DEMAND CHARGE?**

A. There are several problems with Mr. Fulmer's and Mr. Kobor's use of the Hiner study in their testimony. In his testimony, Mr. Fulmer states the following in support of his claim that customers will not understand demand charges: "The survey found 'Possible that concept was confusing and respondents did not understand that it varies based on

[15] Direct Testimony of Charles Miessner, p. 7.
[16] Fulmer Direct, p. 18, Kobor Direct, p. 36.

kW demand levels, which made demand charges appear low relative to monthly service fee.'"[17]

Based on careful inspection of the study, at no stage was customer understanding of demand charges even investigated. Mr. Fulmer selectively quotes extracts from commentary by the study authors and presents this information as a finding of the survey. The reality is that in a conjoint analysis, investigating relative preferences for various rates, the study found that the existence of demand charges was relatively unimportant in rate plan selection. Rather the presence of a "monthly service fee had more influence on rate choice than any other attribute," followed by "the price per kWh associated with different rate structures rather than by the rate structure itself."[18] To explain this result, the study authors speculated, "[It is] possible that [the] concept [of demand charges] was confusing and respondents did not understand that it varies based on kW demand levels, which made demand charges appear low relative to [a] monthly service fee."[19] This is speculative commentary, not fact, and only one possible explanation of many for why demand charges seemed to have little impact on rate plan selection.

Additionally, Mr. Fulmer indicates that the survey identified the following as surveyed customers' preferred features in a solar rate: "57% stated save money, 39% said simple, and 34% said 'fits my habits and lifestyle.'"[20] Mr. Fulmer fails to mention, however, that the same study says that the advantages of demand charges are that they can, "save money (through changing behavior), gives control over the bill."[21] Moreover the study listed "confusing" as a negative attribute of all four of the rates examined in the study--a

[17] Fulmer Direct, p. 18.
[18] Hiner & Partners, Inc. "RROIR Customer Survey – Key Finding," April (2013), slide 18.
[19] *Id.*, slide 22.
[20] Fulmer Direct, p. 19.
[21] Hiner & Partners, "Final Report: Solar (NEM) Rate Preferences Survey Results" (June 2015), slide 8.

feed in tariff; a demand charge, a solar capacity charge and a panel rate (where you are billed by the size of circuit panel for delivery).[22] In fact when one looks at how customers rated the four plans on simplicity ("Does not require a lot of effort to understand how my energy use will affect my bill."), there is very little variation in the results.[23] Twenty-eight percent of customers found the feed in tariff plan (which involves only kWh) to be simple, 26% found the installed capacity charge and the panel rate to be simple and 24% found the demand charge to be simple.[24] In sum, the Hiner study does not prove that customers would not understand or not be interested in a rate with a demand charge. The assertion by the intervenors that it does is an unsupported generalization.

**Q. IS ANY OTHER EVIDENCE OFFERED TO SUGGEST THAT CUSTOMERS WOULD NOT WANT OR UNDERSTAND A DEMAND CHARGE?**

A. Vote Solar witness Kobor claims that APS's 10% enrollment level in its voluntary three-part rate is evidence that customers do not want three-part rates.[25] It is inherently difficult to get customers to voluntarily sign up for new energy programs. Many demand response programs have participation of around 10%. When new rate designs are introduced on a voluntary basis they rarely achieve enrollment levels in excess of 20% to 30%.[26] This has been the experience with time-varying rates. New rates typically must be offered on a mandatory or default basis to achieve significantly higher enrollment levels.[27]

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[22] *Id.*
[23] *Id.*, slides 22, 26, 30, 34.
[24] *Id.*
[25] Kobor Direct, p. 38
[26] For information on residential demand response program participation, see FERC reports on advanced metering and demand response: http://www.ferc.gov/industries/electric/indus-act/demand-response/dem-res-adv-metering.asp
[27] Ahmad Faruqui, Ryan Hledik, and Neil Lessem, "Smart by Default," *Public Utilities Fortnightly*, August 2014.

**Q. IS CUSTOMER ACCEPTANCE THE ONLY CRITERION THAT SHOULD BE CONSIDERED WHEN EVALUATING THE MERITS OF A THREE-PART RATE?**

A. While customer acceptance of and satisfaction with the new rate design is certainly a consideration, it is not the only criterion that should be taken into account. It is only one of the ten Bonbright criteria. In fact, if customer acceptance were the only principle that mattered, one could argue that customers should simply be given free electricity, as they would certainly be more satisfied with free electricity than with paying for it. Rather, as I discussed throughout my direct testimony, a demand rate which more closely aligns the structure of the rate with underlying costs improves fairness in rate design and can have significant benefits for customers. Factors such as cost causation, equity/fairness, and the impact of the rate on emerging energy technology adoption are all critical considerations beyond a having only narrow focus on customer acceptance.

**Q. REGARDING THE ISSUE OF EQUITY, DO YOU AGREE WITH THOSE INTERVENORS WHO HAVE SUGGESTED THAT MANY CROSS-SUBSIDIES ARE EMBEDDED IN CURRENT RATES AND THAT WE THEREFORE SHOULD NOT FOCUS ON JUST ADDRESSING A CROSS-SUBSIDY RELATED TO THE ADOPTION OF DISTRIBUTED GENERATION?**

A. No, I do not agree with the argument made by AURA witness Alston that it is inappropriate to address DG-related cross-subsidies without addressing all subsidies embedded in today's rates.[28] First, demand charges better align rates with costs. Therefore, the introduction of a demand charge does more than just address the DG-related cross subsidy. It also addresses the subsidization of customers with peak (i.e., costly) consumption patterns by those with flat (i.e., beneficial) consumption patterns. If deployed to all customers, this amounts to the removal of a significant cross-subsidy and one not just limited to DG-related issues.

[28] Direct Testimony of Thomas Alston, p. 3

Second, while DG market penetration may be relatively low today, it is the trajectory of adoption that matters. PV costs continue to decline rapidly, and Congress just extended the income tax credit by five years. It is better to get in front of this issue now, before it becomes a bigger problem and while grandfathering of current rooftop solar customers under the current rate is still a feasible policy option.

## VI. THE IMPACT OF DEMAND CHARGES ON BILLS AND ELECTRICITY CONSUMPTION

**Q. SOME INTERVENORS SUGGEST THAT DEMAND CHARGES WILL INCREASE BILLS FOR LIMITED INCOME CUSTOMERS. IS THERE ANY EVIDENCE TO SUPPORT THIS CLAIM?**

A. I have not come across any empirical evidence from the intervenors which shows that limited income customers will be made worse off overall with a three-part rate. Whether or not a three-part rate will cause a customer's bill to increase or decrease is not determined by the customer's income or even their monthly consumption. The bill impact is driven by the customer's load factor. If the customer has a high load factor (i.e., a relatively flat electricity consumption profile), then his or her bill is likely to decrease. If the customer has a low load factor (i.e., a "peaky" consumption profile), the bill is likely to increase. A common mistake is to equate the impact of a demand charge on a customer's bill with the customer's total monthly consumption. Demand charges do not automatically increase bills for small users, because a small user could have a higher load factor than the class average.

**Q. COULD DEMAND CHARGES PROVIDE LIMITED INCOME CUSTOMERS WITH AN OPPORTUNITY TO REDUCE THEIR ELECTRICITY BILL?**

A. Yes, demand charges could provide limited income customers with a new opportunity to save money on their electricity bills. Whereas the existing two-part rate provides only one opportunity to save money - by reducing one's total consumption - the three-part rate also provides an opportunity to save through both reductions in total consumption and reductions in maximum demand. Certain actions which would not provide material

bill savings under the two-part rate, such as staggering the use of electricity intensive appliances, would yield a bill reduction under the three-part rate.

**Q. WILL DEMAND CHARGES REDUCE THE INCENTIVE TO CONSERVE ENERGY?**

A. I don't agree with WRA witness Wilson's and TASC witness Fulmer's suggestion that the lowering of the volumetric rate will reduce the incentive to conserve.[29] As I indicated earlier in my Surrebuttal Testimony, a three-part rate gives customers an additional option for reducing their electricity bill - they can reduce total consumption and/or maximum demand. Rather than removing a customer's incentive to conserve, demand charges encourage a different and/or more efficient type of conservation - that is, conservation at peak times when it is most valuable to the power system. In his Direct Testimony, APS witness Miessner indicates that customers on APS's demand rate have not only reduced their demand but their total electricity consumption as well.[30] Demand charges are therefore not implicitly going to impair energy efficiency efforts; they will simply guide those efforts toward the most beneficial efficiency initiatives.

## VII. TRANSITIONING TO DEMAND CHARGES

**Q. DO YOU AGREE WITH STAFF, WHO HAS SUGGESTED THAT CUSTOMERS NEED EDUCATION AND INFORMATION IN THE TRANSITION TO A THREE-PART RATE?**

A. Yes. Staff witness Solganick indicates throughout his testimony that customers will need education and information about demand charges in order to successfully make the transition to a three-part rate. I agree with this and believe that a transition plan should be developed when making significant changes to rate design in order to facilitate a smooth introduction of the new rate.

**Q. WHAT DO YOU CONSIDER TO BE IMPORTANT ELEMENTS OF A RATE TRANSITION PLAN?**

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[29] Wilson Direct, p. 9, Fulmer Direct, pp. 21 and 24
[30] Miessner Direct, pp. 7-8.

A. The transition plan should be tailored to the specific needs of the utility and its customers. As such, it will vary from one jurisdiction to the next. In other words, there is not a "one size fits all" approach to the rate transition. Still, there are several examples of elements that I would consider to be useful options to consider in the plan. As I described above, one is a customer education plan that includes the provision of general information about the new rate and opportunities to mitigate potential bill impacts, as well as targeted outreach and education for those customers who are most likely to experience bill changes under the new rate.

## VIII. CONCLUSION

**Q. WHAT DO YOU CONCLUDE, BASED ON YOUR REVIEW OF THE INTERVENOR TESTIMONY?**

A. The intervenors' objections to the three-part rate are not supported by evidence. For several reasons, I believe that a three-part rate would be a significant improvement over the current two-part rate. It would do a much better job of reflecting the cost structure of generating and delivering electricity. The rate would simultaneously improve economic efficiency while promoting equity and fairness in rate design -arguably the two most important principles in rate design. It would provide customers with new opportunities to save money on their electricity bills. Finally, it would foster innovation by improving the economics of a range of emerging energy technologies that can reduce demand and, as a result, infrastructure costs.

**Q. DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?**

A. Yes, it does.

EXHIBIT
APS-5
admitted

# SURREBUTTAL TESTIMONY OF CORY WELCH

**On Behalf of Arizona Public Service Company**

**Docket No. E-04204A-15-0142**

February 23, 2016

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**SURREBUTTAL TESTIMONY OF CORY WELCH**
**ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY**
**(Docket No. E-04204A-15-0142)**

I. INTRODUCTION

**Q. PLEASE STATE YOUR NAME, JOB TITLE, BUSINESS ADDRESS AND THE PARTY FOR WHOM YOU ARE FILING TESTIMONY.**

A. My name is Cory Welch. I am a Director in the Energy Practice at Navigant Consulting, Inc. My business address is 1375 Walnut Street, Boulder, CO. Today, I will be filing testimony on behalf of Arizona Public Service Company.

**Q. PLEASE DESCRIBE YOUR PROFESSIONAL BACKGROUND AND EXPERIENCE.**

A. I have a Master of Science in Mechanical Engineering from Massachusetts Institute of Technology (MIT) and a Master of Business Administration (MBA) from MIT's Sloan School of Management, in addition to a BS in Mechanical Engineering from Cornell University. I have been working in the clean energy industry for the last 15 years, including a 4-year position at the National Renewable Energy Laboratory. For the last eight years I have worked in renewable energy and energy efficiency at Navigant. My clients include both utilities and utility regulatory agencies on issues related to modeling the economics and cost-effectiveness of energy efficiency and renewable energy, forecasting market adoption of efficient and renewable technologies, and quantifying the energy and peak demand impacts of efficient and renewable technologies. A copy of my curriculum vitae is attached as Attachment CJW-1SR.

**Q. WHAT ARE YOUR RESPONSIBILITIES AT NAVIGANT?**

A. I am currently a Director in Navigant's Energy Practice, focusing on quantitative modeling associated with renewable and energy efficient technologies. I have developed several of Navigant's proprietary financial and market adoption models for renewable energy and energy efficiency technologies, including Navigant's Renewable Energy

Market Simulator (RE-Sim™) model, which was used for the analysis I'll be discussing today.

**Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE ARIZONA CORPORATION COMMISSION?**

A. No, I have not.

**Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?**

A. The purpose of my testimony is to respond to portions of Direct Testimony submitted by Briana Kobor on behalf of Vote Solar on December 9, 2015.

## II. SUMMARY OF TESTIMONY AND STUDY FINDINGS

**Q. PLEASE SUMMARIZE YOUR SURREBUTTAL TESTIMONY.**

A. I am presenting analysis that suggests solar providers have headroom to respond to some rate changes in Arizona, based on the results of a study recently conducted by Navigant Consulting, Inc. for Arizona Public Service Company (APS). The Vote Solar testimony to which I am responding suggests on page 51 that "growth of DG on the UNS system would most certainly be reduced," and on page 55 that rate changes could "destroy the solar market." I am calling into question the inevitability implied by these and similar statements. Recent federal policy changes, combined with recently observed lease rate increases by solar providers in Arizona, reveal that third-party-owned (TPO) solar provider project returns on invested capital have increased relative to what they had been throughout 2015. Navigant's analysis suggests that it is not inevitable that any adjustments to variable charges or fixed and demand related charges would necessarily affect solar adoption. Depending on the magnitude of the ultimate rate changes, I conclude it is also possible that rate changes would simply result in lowering solar TPO provider project returns. In other words, the recently observed increased solar TPO provider project returns could simply go back to levels prior to favorable federal policy changes and solar TPO lease rate increases.

**Q. ARE YOU SPONSORING ANY ATTACHMENTS TO YOUR TESTIMONY?**

A. Yes. I am sponsoring an attachment entitled "Solar Project Return Analysis for Third Party Owned Solar Systems," dated February 19, 2016, which contains the findings and results of the Navigant study, which I oversaw, and forms the basis for my opinions here. The study is attached as Attachment CJW-2SR and incorporated into my testimony by this reference.

**Q. BRIEFLY EXPLAIN THE FINDINGS AND CONCLUSIONS OF THE SOLAR PROJECT RETURN ANALYSIS FOR THIRD PARTY OWNED SOLAR SYSTEMS.**

A. Key findings of the analysis include the following:

- Navigant's research indicates that solar providers who offer a TPO leasing model (the dominant business model for residential systems in Arizona) tend to compete in jurisdictions where they can maximize their return by undercutting utility offset rates.[1,2,3]

- Solar TPO providers appear to be tracking utility offset rates and pricing accordingly, evidenced by higher observed lease prices in jurisdictions with higher offset rates. These higher lease prices cannot be fully accounted for by variations in system cost, solar production, and tax rates across service territories.

- Navigant's analysis found that solar TPO providers' project returns vary by utility service territory, with higher project returns calculated in service territories having higher utility offset rates.

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[1] Utility offset rates ($/kWh) are defined as the dollar value of a customer's bill reduction for each kWh generated by the customer's solar system. It is the amount of their bill that is "offset" for each kWh generated (hence the term). In other words, it is the amount a customer saves on their utility bill.

[2] In Arizona, solar TPO leases are the dominant contract vehicle. Leases typically involve a monthly dollar payment for a minimum guaranteed solar production (in kWh). One can therefore calculate an "effective lease rate" (lease rate) on a $/kWh basis.

[3] For the purpose of this analysis, Navigant refers to all solar TPO rates as lease rates.

- Federal incentives such as the Investment Tax Credit (ITC), accelerated depreciation, and bonus depreciation have a significant impact on project return. The solar TPO business model is able to maximize the benefits of these federal incentives, which are amplified considerably by the TPO's ability to use a system "value", which is higher than the system cost, as the basis for the tax credit and asset depreciation.

- Navigant's research found that despite continuing declines in solar system costs and recent favorable policy decisions (e.g., re-introduction of bonus depreciation), solar lease rates have recently *increased* in certain locations, including in UNS Electric, Inc. (UNSE) service territory, where a 9% increase was observed in SolarCity's TPO lease rates. In 2015, SolarCity in UNSE territory experienced an estimated 40 percent project return to TPO providers, which is expected to increase to around 80 percent in 2016, due to an observed lease rate increase from $0.087/kWh to $0.095/kWh between 2015 and 2016 and the re-introduction of the 50 percent bonus depreciation allowance, which came into effect in December of 2015.

I conclude that solar TPO providers have headroom to adjust to some changes in rate structures while maintaining project returns. The amount of the headroom relative to the new offset rates that would result from proposed UNSE rates in the residential sector has not been specifically analyzed.

## III. METHODOLOGY AND ASSUMPTIONS

**Q. BRIEFLY DESCRIBE THE METHODOLOGY AND ASSUMPTIONS USED IN THE STUDY.**

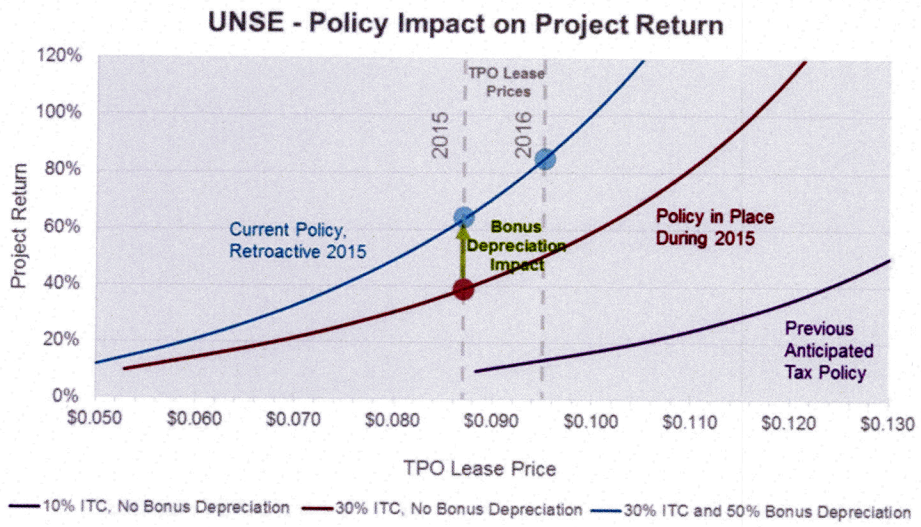
A. The analysis focused on solar systems installed using a third-party-ownership model, which is the dominant residential sales model for solar in Arizona and throughout the country. SolarCity is the dominant solar TPO provider in Arizona with around 51% market share of residential installations in 2015. The study obtained lease price estimates through their public website and focused on analysis of project returns

assuming lease prices offered by SolarCity are reasonably indicative of the Arizona market.

We then conducted a discounted cash flow analysis of a typical residential solar PV system installation, including all relevant project costs and other cash flow streams. As a benchmark, we calculated project return on invested capital (project return) for systems installed in UNSE territory in 2015. Our estimates indicated that project return was around 40% at observed lease rates in UNSE territory of $0.087/kWh. We then re-calculated estimated project return in UNSE service territory after incorporating two changes. First, we accounted for the reinstated bonus depreciation benefit of 50% (which expired at the end of 2014, but was re-introduced in December of 2015 and applies retroactively to 2015 projects). Second, we accounted for an observed lease rate increase in UNSE service territory from $0.087/kWh in December 2015 to $0.095/kWh in January 2016. As we note in our attached report, rate increases are consistent with statements made by SolarCity to correspond with increases in utility rates and shift its focus less on growth and more on near-term profitability. We also found that solar lease rates increased in four out of the six service territories analyzed in our report. Incorporating these two changes into the analysis resulted in increased project returns from 40% to 80%. This result alone suggests that there is headroom for solar providers in UNSE service territory to adjust to some rate changes through compression of project return. We offer additional evidence in the attached report.

The figure below, which is excerpted from Figure 8 of the attached report, illustrates the impact on project return of the re-introduction of bonus depreciation and the recently observed lease rate increases by SolarCity in the UNSE service territory. During 2015, estimated project return was 40% at a $0.087/kWh lease rate (the red dot on the red line, on which it is estimated SolarCity was operating). After re-introduction of 50% bonus depreciation (which applies retroactively to 2015 installations) and after increasing lease

rates to $0.095/kWh in UNSE service territory, SolarCity is estimated to achieve an 80% project return (the higher blue dot) and is estimated to be operating on the blue line. For context, we estimate that solar TPO providers would have been operating on the purple line as of January 1, 2017, prior to the extension of the Federal ITC and re-introduction of 50% bonus depreciation.




There are of course many assumptions underlying this analysis, all of which is detailed in the attached report in the interest of transparency. The assumptions draw upon publicly available and credible sources, including SolarCity's own website, cost roadmap, and public reports. The analysis also benchmarks the assumptions against statements from other publicly traded companies, third-party market reports, as well as reports from the Department of Energy and the National Renewable Energy Laboratory.

The analysis goes on to compare observed lease rates in other jurisdictions with those calculated to result in the same 40% project return as estimated in UNSE service territory, accounting for variations in factors such as labor costs, solar insolation, and tax rates, which can differ across jurisdictions. This comparative analysis illustrated that solar TPO provider lease rates and project returns tend to increase with higher utility

offset rates, without direct cost causation. In other words, solar TPO providers benefit from higher project returns in jurisdictions with higher utility rates.

**Q. ARE THE ASSUMPTIONS USED IN THE STUDY CONSERVATIVE, AND IF SO, HOW?**

A. The analysis uses several conservative assumptions that would actually tend to understate, rather than overstate, true TPO solar project returns. These conservative assumptions include:

- **Cost of debt**: The analysis uses a cost of debt of 6 percent throughout the analysis. Some sources indicate that this cost of debt could be as low as 5 percent.[4]
- **Lease term and residual value**: The analysis uses a 20 year contract term with no residual value for contract renewal and no residual value for the system at the end of life. The typical system life is longer than 20 years and the system is expected to have a residual value at the end of the lease term.
- **Markup assumed for the ITC and depreciation basis**: The analysis used a 35 percent markup on system cost for calculating the value of the ITC and system depreciation. This would effectively result in a solar TPO developer reporting system value of $3.74-3.87/W-DC to the Internal Revenue Service, which is lower than observed system sales prices typically ranging from 4.20-4.75.[5,6,7,8] The ability of PV providers to markup cost to something more akin to a price, or system value, when calculating tax credits and depreciation is a key driver in the favorable economics for solar TPO providers.

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[4] UBS Solar, US Alternative Energy & YieldCos, 4Q15 Playbook: Giving Solar 'Credit,' January 2014.
[5] Deutsche Bank Market Research, SolarCity, Analyst Day Recap, December 15, 2015.
[6] "A Survey of State and Local PV Program Response to Financial Innovation and Disparate Federal Tax Treatment in the Residential PV Sector," Lawrence Berkeley National Laboratory, June 2015.
[7] SolarCity Company Analyst Day, December 2015.
[8] Deutsche Bank Market Research, SolarCity, Analyst Day Recap, December 15, 2015.

## IV. CONCLUSIONS

**Q. WHAT KEY CONCLUSIONS DO YOU DRAW FROM YOUR ANALYSIS?**

A. The primary conclusion I draw from the analysis is that solar TPO providers likely have headroom to adjust to some rate changes in Arizona, including in UNSE service territory. Depending on the magnitude of the rate changes, it is possible that adequate project returns could be maintained while incorporating a reduction in utility offset rates due to adjustment of variable charges or introduction of fixed and demand related charges.

**Q. DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?**

A. Yes.

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## Professional Summary

Cory Welch is a Director in the Energy Practice of Navigant Consulting, Inc.. He has 20 years of complex system modeling, project management, and engineering experience in fields including fuel cell development, energy efficiency, renewable energy, energy R&D portfolio and policy analysis, and power plant engineering. Mr. Welch brings expertise in renewable energy economics and market adoption, financial analysis, efficiency portfolio evaluation, efficiency potential estimation, system dynamics, stochastic analysis, discrete choice analysis, optimization, and statistics, which he has applied to various analysis projects for utility clients, regulatory agencies, and the U.S. Department of Energy. Mr. Welch is the lead developer of many of Navigant's proprietary renewable energy and energy efficiency models. Mr. Welch holds an SM in Mechanical Engineering from Massachusetts Institute of Technology (MIT), an MBA from MIT's Sloan School of Management, and a BS in Mechanical Engineering from Cornell University. Additionally, he completed a rigorous 6-month graduate-level curriculum in mechanical and nuclear engineering while serving as an officer in the U.S. Navy.

## Professional Experience

- Developed Navigant's Renewable Energy Market Simulator (RE-Sim™) model. Applied this model in strategic advisory engagements with six major electric utilities looking to better understand the economics, dynamics and drivers of adoption of distributed solar PV. This model includes a rigorous discounted cash flow optimization model, which is used to understand solar PV project economics. It fully accounts for the economics of third-party-ownership, a dominant business model in distributed PV. The RE-Sim model also forecasts market adoption of solar PV using an enhanced version of the Bass diffusion algorithm, implemented in a System Dynamics framework. Calibrated back-casting is used to develop diffusion coefficients. The model can forecast adoption under a wide variety of policy, costs, and rate regimes, providing a rigorous and robust platform for understanding likely dynamics of solar PV adoption.

- Developed a highly transparent, web-capable model for Pacific Gas & Electric to estimate the impact on customers and utility economics of changes to Net Energy Metering policies in California. The model analyzed probability distributions of historic payback times for solar PV installations under various NEM grandfathering and rate scenarios.

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## Professional Experience (Continued)

- Developed Navigant Consulting's Demand Side Management Simulator (DSMSim™) to simulate the adoption of energy-efficient technologies in efficiency potential studies and program design. DSMSim™ is a bottom-up technology diffusion model grounded in the principles of System Dynamics (stock/flow modeling). Led projects estimating energy-efficiency potential analyses for ten electric/gas utilities. Acted as senior modeling advisor on potential studies for eleven additional utilities, including the four large IOUs in California.

- Led the re-development of a nonlinear stochastic optimization model for the Northwest Power and Conservation Council. This model calculates optimal electric generation and demand side management resource strategies with explicit consideration of uncertainty and risk. It is currently being used in the Council's creation of its seventh power plan for the NW region

- Managed a $6M project to evaluate the energy efficiency savings achieved from five Maryland electric utilities.

- Developed the optimization portion of an energy-efficiency portfolio optimization tool for DTE Energy. The model used linear programming techniques to maximize energy savings for target cost levels under various constraints including low-income participation, low-income spending, maximum and minimum measure-level participation, sector spending targets, etc.

- Managed a $4M portfolio impact evaluation for five Maryland utilities to estimate kW and kWh savings from their energy efficiency programs and to permit bidding peak demand reductions achieved through efficiency programs into the PJM forward capacity market.

- Acted as the deputy project manager for the evaluation of 56 Local Government Partnership energy efficiency programs for the California Public Utility Commission (CPUC), a multi-year, multi-million dollar portfolio impact evaluation.

- Developed a stochastic model estimating the probabilistic benefits and costs of Smart-Grid technologies for Bonneville Power Administration. This model is currently being used to shape Smart-Grid policy and strategy in the Northwest U.S.

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## Professional Experience (Continued)

- Developed a nonlinear optimization model for NV Energy to optimize dispatch of Demand Response (DR) resources and to forecast DR savings. Provided model to the client with a user-friendly graphical user interface.
- Estimated the remaining useful life of residential appliances for a California utility using established Weibull regression methods as well as a novel method involving a stock/flow model using System Dynamics.
- Assessed the market potential for Demand Response in the Con Edison service territory (New York City). Developed Navigant Consulting's Demand Response Simulator (DRSim™) model to assist in evaluating DR market potential, including assessment of market risk using Monte Carlo techniques.
- Guided development of a smart-grid benefit/cost model for Tendril networks. Provided model to the client with a user-friendly graphical user interface and trained Tendril staff in its use.
- Developed a model evaluating the pricing of power purchase agreements for a large renewable installation in Southern California.
- Developed a model simulating the dispatch of a gas turbine for purposes of assessing the market value of improved startup times and reduced startup emissions.
- Developed a model simulating the supply/demand balance in the LA Basin load pocket for the California Energy Commission. This model considered environmental and transmission constraints and facilitated scenario analysis associated with shutting down once-through cooling plants due to environmental concerns.

## Work History

- Navigant Consulting, Inc. – Director
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- National Renewable Energy Laboratory – Senior Energy Analyst
- UTC Fuel Cells – Program Manager
- Lieutenant, United States Navy – Naval Nuclear Propulsion Headquarters

## Certifications, Memberships, and Awards

- Association of Energy Service Professionals
- Systems Dynamics Society

## Education

- MS, Mechanical Engineering, Massachusetts Institute of Technology
- MBA, Massachusetts Institute of Technology's Sloan School of Management
- BS, Mechanical Engineering, Cornell University (with distinction)

## Publications

- Welch, C. and Richerson-Smith, D. "Incentive Scenarios in Potential Studies: A Smarter Approach" Peer reviewed paper presented at American Council for an Energy Efficient Economy (ACEEE) Summer Study on Energy Efficiency in Buildings. August, 2012. Pacific Grove, CA.
- Welch, C. and Rogers, B. "Estimating the Remaining Useful Life of Residential Appliances." Peer reviewed paper presented at American Council for an Energy Efficient Economy (ACEEE) Summer Study on Energy Efficiency in Buildings. August, 2010. Pacific Grove, CA.
- Welch, C. and Stern, F. "Simulation the Adoption of Energy Efficient Technologies." Poster presented at American Council for an Energy Efficient Economy (ACEEE) Summer Study on Energy Efficiency in Buildings. August, 2010. Pacific Grove, CA.

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http://www1.eere.energy.gov/hydrogenandfuelcells/analysis/pdfs/scenario_analysis_welch1_07.pdf

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- Welch, C., Wipke, K., Gronich, S., and Garbak, J. "Hydrogen Fleet and Infrastructure Demonstration and Validation Project: Data Analysis Overview." Paper (http://www.nrel.gov/hydrogen/pdfs/37845.pdf) and presentation (http://www.nrel.gov/hydrogen/pdfs/37811.pdf) prepared for the National Hydrogen Association Conference, Washington, DC., March 2005.

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- Wipke, K., Welch, C., Thomas, H., Sprik, S., Gronich, S., and Garbak, J. "Controlled Hydrogen Fleet and Infrastructure Demonstration and Validation Project—Initial Fuel Cell Efficiency and Durability Results." Paper (http://www.nrel.gov/hydrogen/pdfs/40921.pdf) prepared for the World Electric Vehicle Association Journal, Vol. 1, 2007., December 2006.

# Solar Project Return Analysis for Third Party Owned Solar Systems

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# EXECUTIVE SUMMARY

## 1.1 UNDERSTANDING THE SITUATION

Navigant conducted an analysis to evaluate the Third-Party Owned (TPO) solar PV (solar) leasing business model, which has emerged as the dominant business model in Arizona (AZ) and throughout the country. Customers with solar TPO systems receive solar-generated power without the high up-front cost of purchasing a system or the responsibility of system monitoring or maintenance. Solar electricity is delivered to the customer at a contracted fixed or escalating effective solar TPO lease rate (lease rate)[1] for the term of the agreement.[2] The emergence of the solar TPO business model has allowed TPO providers to present customers with a comparison between two rates, the first-year solar lease rate and the customer's retail electricity rate. Our analysis focuses on quantifying solar TPO providers' project returns in utility service territories across AZ and California (CA).

## 1.2 KEY FINDINGS

Key findings include the following:

- Navigant's research indicates that solar TPO providers choose to operate in jurisdictions where they can maximize their return by undercutting utility offset rates.[3]
- Solar TPO providers appear to be tracking utility rates and pricing accordingly, evidenced by higher observed lease prices in jurisdictions with higher utility rates. These higher lease prices cannot be fully accounted for by variations in system cost, solar production, and tax rate (locational factors).
- Navigant's analysis found that solar TPO providers' project returns vary by utility service territory, with higher project returns calculated in service territories having higher utility offset rates.
- Federal incentives such as the Investment Tax Credit (ITC), accelerated depreciation, and bonus depreciation have a significant impact on project return. The solar TPO business model is able to maximize the benefits of these federal incentives, which are amplified considerably by the TPO's ability to use a system "value", which is higher than the system cost, as the basis for the tax credit and asset depreciation.
- Navigant's research found that despite continuing declines in solar system costs and favorable policy decisions (e.g., re-introduction of bonus depreciation), lease rates have recently increased in certain locations, consistent with public disclosures from leading solar players and indicating higher project returns for solar TPO providers. In 2015, UNS Electric, Inc. (UNSE) solar TPO providers experienced an estimated 40 percent project return, which is expected to increase to around 80 percent in 2016, due to the lease rate increase from $0.087/kWh to $0.095/kWh between 2015 and 2016 and the re-introduction of the 50 percent bonus depreciation allowance (see Figure 8 on page 13).
- We conclude that solar TPO providers have headroom to adjust to some changes in rate structures while maintaining project returns.

[1] For the purpose of this analysis, Navigant refers to all solar TPO rates as lease rates.

[2] In AZ, solar TPO leases are the dominant contract vehicle. Leases typically involve a monthly dollar payment for a minimum guaranteed solar production (in kWh). One can therefore calculate an "effective lease rate" (lease rate) on a $/kWh basis.

[3] Utility offset rates ($/kWh) are defined as the dollar value of a customer's bill reduction for each kWh generated by the customer's solar system. It is the amount of their bill that is "offset" for each kWh generated (hence the term). In other words, it is the amount a customer saves on their utility bill.

# 2. SOLAR PROJECT RETURN ANALYSIS

## 2.1 THIRD-PARTY OWNED SOLAR BUSINESS MODEL

Third-Party Owned solar systems, as compared with customer owned systems, has emerged as the dominant distributed solar business model throughout the country. Solar TPO providers offer customers the option to adopt solar power with no upfront costs. Customers sign a long term contract for solar electricity and the solar TPO provider owns and maintains the system. Solar electricity is delivered to the customer at a contracted fixed or escalating effective solar lease rate[4] for the term of the agreement.[5]

The emergence of the solar TPO business model has allowed TPO providers to present customers with a comparison between two rates, the first-year solar lease rate and the customer's retail electricity rate.

## 2.2 ARIZONA SOLAR MARKET

Navigant obtained data from ArizonaGoesSolar.org[6] and used those data to characterize the 2015 residential solar market. The data revealed that the solar TPO business model dominates the Arizona market with a handful of large national players comprising the majority of the solar market share. For UNSE, the market is dominated by one national player, SolarCity, and a handful of regional companies. Navigant observed the same trends in other service territories – dominance of the solar TPO business model and SolarCity followed by other national and regional players.

### 2.2.1 Arizona 2015 Solar Data

Since not all utilities report data to ArizonaGoesSolar.org denoting whether a system is solar TPO or a customer purchased system, Navigant looked at data from APS, the utility with the largest residential solar market, to quantify the market share of solar TPO systems in the overall residential market. In 2015, APS territory comprised 81 percent of the solar PV installations across the Arizona utility territories examined in this report (UNSE, Arizona Public Service (APS), Sulphur Springs Valley Electric Cooperative (SSVEC), and Tucson Electric Power (TEP)). Given the large percentage of solar PV installations in APS's service territory, relative to other Arizona utilities, Navigant assumed the ownership type split in APS's service territory reasonably represents the Arizona market. These data indicate that solar TPO is the dominant business model in the residential sector. Figure 1 shows that 72 percent of systems 10 kilowatts and smaller installed in the APS service territory in 2015 were TPO. This aligns with the U.S. Solar Market Insight Q3 2015 report, which reported that third party providers owned 77-80 percent of new residential installations in Arizona in 2015.[7]

[4] For the purpose of this analysis, Navigant refers to all solar TPO rates as lease rates.

[5] In AZ, solar TPO leases are the dominant contract vehicle. Leases typically involve a monthly dollar payment for a minimum guaranteed solar production (in kWh). One can therefore calculate an "effective lease rate" (lease rate) on a $/kWh basis.

[6] Arizonagoessolar.org, http://arizonagoessolar.org/UtilityIncentives/ArizonaPublicService.aspx, Accessed January 12, 2016.

[7] GTM Research and Solar Energy Industries Association, U.S. Solar Market Insight, Q3 2015, December 2015.

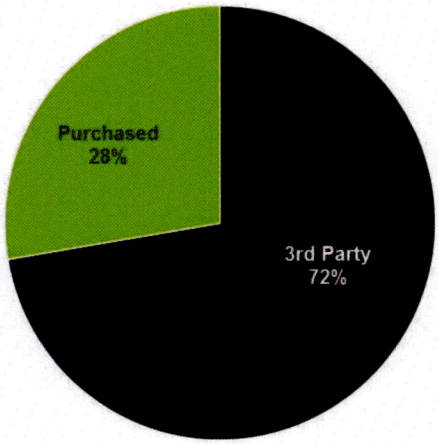
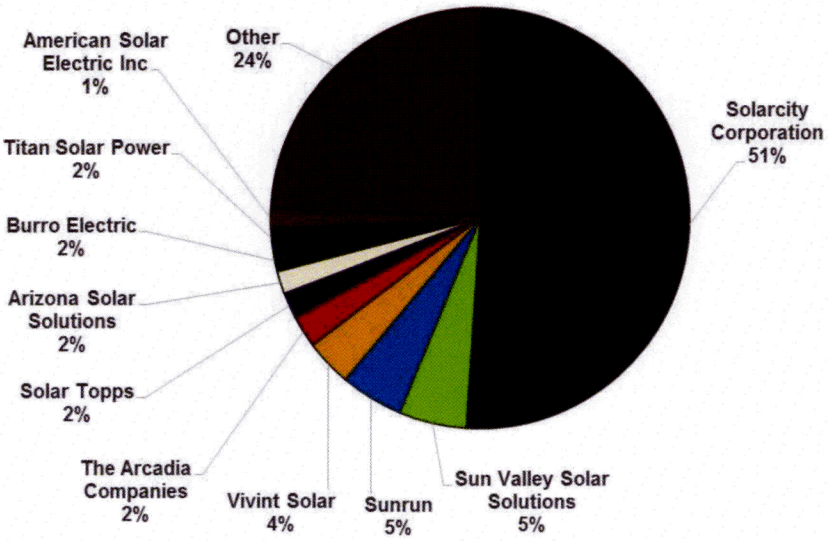



**Figure 1. Arizona Residential Solar APS 2015 Ownership Type[8]**

ArizonaGoesSolar.org data indicate that SolarCity is the dominant solar player across all Arizona utilities, comprising approximately 50 percent of the residential market in 2015, as shown in Figure 2. SolarCity is also the dominant player in UNSE territory with around 32 percent of total installed residential systems in 2015.




* Other includes all other installers in the Arizona examined service territories.

**Figure 2. Arizona (APS, TEP, UNSE, and SSVEC) Residential Solar Market Share, Leading Installers[9]**

Based on the dominance of solar TPO and SolarCity, Navigant used solar TPO and SolarCity data to represent the Arizona solar market.

[8] APS market share installation data for systems <10kW in 2015, as other utilities do not report ownership type.
[9] Installation data for systems <10kW in 2015.

## 2.3 LEASE PRICING VS. UTILITY OFFSET RATES

Navigant obtained lease data from leading solar TPO companies in states with high penetration of distributed solar PV, benchmarking this information through industry interviews and market research. Solar TPO providers reported that their residential lease rates are typically 5 to 20 percent below residential retail rates.[10] Navigant's research indicates that third party providers choose to operate in jurisdictions where they can undercut utility offset rates. Further, Navigant's research found that the solar TPO pricing strategy is such that jurisdictions with higher offset rates are likely to see higher solar TPO lease prices without direct cost-causation. Table 1 lists the lease rates and utility offset rates used for this analysis.

**Table 1. Lease Rates and Utility Offset Rates[11]**

| State | APS | UNSE | TEP | SSVEC | PG&E | SMUD |
|---|---|---|---|---|---|---|
| Observed Lease Rate (Year-1) – Jan 2016 ($/kWh) | 0.105 | 0.095 | 0.093 | 0.110 | 0.162 | 0.109 |
| Observed Lease Rate (Year-1) – Dec 2015 ($/kWh) | 0.105 | 0.087 | 0.090 | 0.105 | 0.150 | 0.109 |
| Lease Rate Annual Escalation | 2.90% | 2.90% | 2.90% | 2.90% | 2.90% | 2.90% |
| Utility Offset Rate ($/kWh) | 0.133 | 0.103 | 0.108 | 0.122 | 0.234 | 0.137 |

### 2.3.1 Lease Rate Pricing

In AZ, solar TPO leases are the dominant contract vehicle. Leases typically involve a monthly dollar payment for a minimum guaranteed solar production in kWhs. One can therefore calculate an "effective lease rate" (lease rate) on a $/kWh basis. In other jurisdictions, the contract might entail a rate directly specified on a $/kWh basis, often referred to as a power purchase agreement (PPA) rate. For simplicity, we refer throughout this document to the lease rate, as though it is analogous to a PPA rate. Residential customers usually enter 20-year lease agreements with the solar TPO provider that often include a year-one lease rate and an annual escalator.

Navigant accessed publicly available lease rate pricing data for the six utilities listed in Table 1 from SolarCity's website and benchmarked them through interviews and market research. In some utilities, lease rates have increased from 2015 to 2016, consistent with public disclosures and comments from leading players such as SolarCity and SunRun.

- SolarCity reported on its Q3 2015 earnings call that in 2016 the company would focus on cost reduction and value, with less emphasis on growth. They reported that pricing would increase in Q1 of 2016 to correspond with escalation in utility rates.[12]

[10] Navigant interviews with industry experts.

[11] Sources: Energy Information Administration Average Utility Rates, System Advisor Model – National Renewable Energy Laboratory, SolarCity website https://go.solarcity.com/#/my-home/zip-nearme, Navigant Modeling (Rates: APS: Residential TOU ET2; SSVEC: Residential Service; TEP: R-01; UNSE: Residential-RES-01; PG&E: E-6 TOU Region R; Residential TOU Option 1)

[12] SolarCity Corp (SCTY) Earnings Report: Q3 2015 Conference Call Transcript, http://www.thestreet.com/story/13345540/1/solarcity-corp-scty-earnings-report-q3-2015-conference-call-transcript.html, Accessed January 28, 2016.

- SunRun reported on its Q3 2015 call that cost structure improvements are a primary focus. For a significant portion of their current markets, SunRun is currently pricing on a per kilowatt hour basis at 25 percent or more below utility rates, even before anticipating future increases in utility rates. They reported that because of strong consumer demand, they have begun to and will selectively raise prices.[13]

### 2.3.2 Utility Offset Rates

Utility offset rates ($/kWh) are defined as dollar value reduction to a customer's utility bill for each kWh generated by the customer's solar system. In other words, it is the amount of their utility bill that is "offset" for each kWh of solar generated. Navigant calculated the offset rate for each utility using residential tiered rates and time of use rates. Consistent with net metering rules, Navigant sized the system to meet 80 percent of customer load over the course of the year, such that the system never over generates on an annual basis and generation exported to the grid is credited to the customer at a retail rate rather than a wholesale rate.

Navigant benchmarked these offset rates using National Renewable Energy Laboratory's (NREL) System Advisor Model (SAM) and the average residential rates published by the Energy Information Administration (EIA). Both the Navigant and NREL SAM models rely on TMY3 weather data and OpenEI data for average hourly residential building load profiles.

### 2.3.3 Rate Comparison

Consistent with the findings from the 2015 Lawrence Berkeley National Laboratory (LBNL) Tracking the Sun VIII report, Navigant found that solar TPO vendors pursue value-based pricing strategies by undercutting the utility offset rate, which is evidenced by the positive correlation between lease pricing and the offset rate.[14] Figure 3 shows that offset rate increases across utility territories correspond with lease rate increases.

[13] Transcript of SunRun earnings conference call or presentation 12-Nov-15, http://finance.yahoo.com/news/edited-transcript-run-earnings-conference-032845202.html, Accessed January 28, 2016.

[14] "Tracking the Sun VIII: The Installed Price of Residential and Non-Residential Photovoltaic Systems in the United States," Lawrence Berkeley National Laboratory, 2015. https://emp.lbl.gov/sites/all/files/lbnl-188238_1.pdf

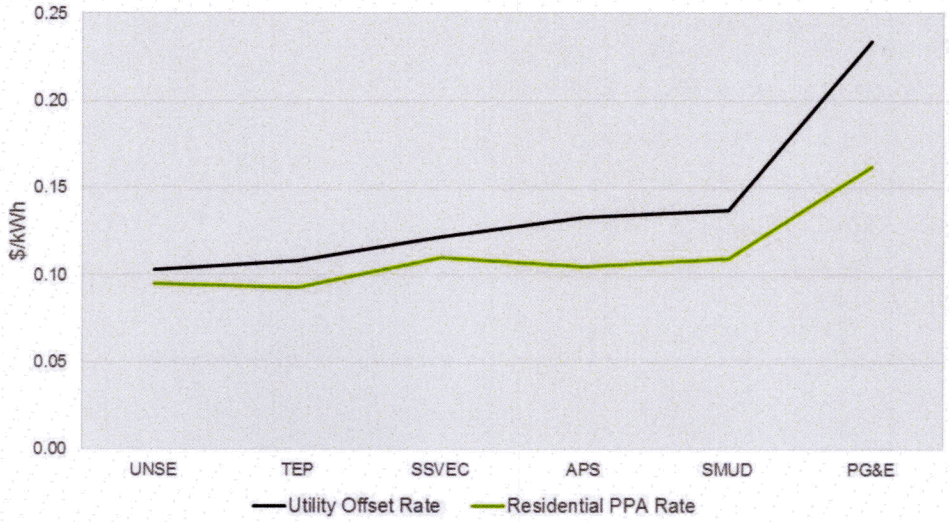



**Figure 3. Utility Offset Rate vs. Lease Rate – Line Graph**

In Figure 4, the dashed grey line represents the points at which the residential solar lease rate equals the utility offset rate. Along this line customers would be paying the same for grid and solar generated electricity. Points below the line indicate where lease rates are undercutting utility offset rates. However, while solar TPO providers are undercutting utility offset rates, the analysis needs to consider the impact of locational factors such as solar insolation, installed system cost, state income tax rates and state incentives to correctly compare lease rates across different service territories and locations. We will present these jurisdiction specific factors in the following section.

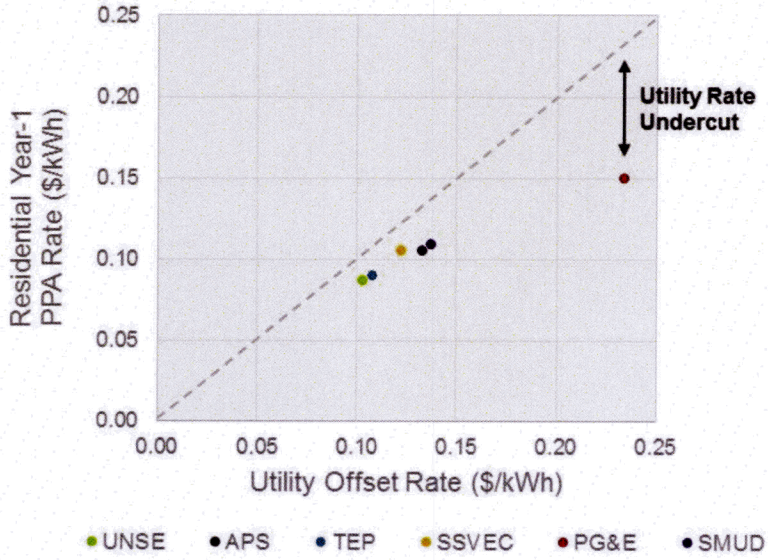



**Figure 4. Utility Offset Rate vs. Lease Rate – Scatter Plot**

## 2.4 PROJECT RETURN ANALYSIS

### 2.4.1 Project Return

This section presents Navigant's jurisdiction-specific analysis of solar TPO lease pricing. Navigant used its proprietary Renewable Energy Market Simulator (RE-Sim™) discounted cash-flow analysis model to calculate a leveraged project return on invested capital on a project-specific basis.

Consistent with standard economic practice, we define the project return on invested capital (project return), sometimes referred to as an internal rate of return or economic rate of return, as the discount rate at which the net present value of all cash flow streams is equal to zero. Navigant's analysis estimates the project return assuming a solar TPO provider both owns and installs the system, consistent with the dominant solar PV business model. We calculate total project return independent of the breakdown of possible recipients of the project return (i.e., whether an equity investor, a tax equity investor, or the third-party provider itself is the recipient of the project return on invested capital).

In this report, Navigant defines the *project return on invested capital* (project return), sometimes referred to as an internal rate of return or economic rate of return, as the discount rate at which the net present value of all cash flow streams is equal to zero.

The cash flow streams accounted for in this analysis include:

- Initial capital outlay, inclusive of all system component costs, installation costs, and an allocation of overhead costs
- Operation and maintenance (O&M) costs, inclusive of inverter replacement
- Debt-financing cash inflow and interest payments
- Federal Investment Tax Credit (ITC) benefits
- Incentives (where applicable)
- Accelerated depreciation for tax purposes (MACRS and Bonus Depreciation)
- Federal and State corporate income taxes
- Lease revenue, including lease rate escalation and accounting for system output degradation

Navigant's model is a discounted-cash-flow optimization model, whose objective function is to minimize the lease rate, a decision variable in the optimization, subject to constraints on the input project return and minimum debt service coverage ratio.[15] Another decision variable in the optimization is the debt ratio, which is an output of the optimization rather than an assumed input, as with some more simplistic analyses. The reason we calculate the debt ratio rather than assume a debt ratio is that higher lease rates afford the opportunity for a provider to have greater leverage (i.e., a higher debt ratio), while still being able to service its debt. Having greater leverage offers the potential for higher project returns on invested capital, since for a given revenue stream the required capital outlay is lower. As such, a rigorous analysis must calculate the debt ratio rather than take it as an input.

[15] Navigant's model can also calculate the effective project return given an input lease rate.

### 2.4.2 Financial Assumptions

As described above, Navigant conducted a discounted cash flow analysis to calculate the project return for projects across various service territories in AZ and CA. While several assumptions were fixed across utility territories, as detailed in the Appendix, locational assumptions varied by service territory where applicable. Locational assumptions that varied by service territory include: the installed system cost ($/Watt), capacity factor, PV production, local taxes, and incentives. These locational assumptions are detailed in Table 1 and Table 2 and are explained in the following sections.

**Table 2. Locational Financial Assumptions**

| | APS | UNSE | TEP | SSVEC | PG&E | SMUD |
|---|---|---|---|---|---|---|
| Installed Cost ($/W-DC) | 2.76 | 2.76 | 2.77 | 2.77 | 2.87 | 2.88 |
| First Year PV Production (kWh/kW-DC) | 1,684 | 1,718 | 1,718 | 1,692 | 1,591 | 1,469 |
| State Income Tax Rate | 6.00% | 6.00% | 6.00% | 6.00% | 8.84% | 8.84% |
| Incentives | - | - | - | - | - | $500/system |

#### *2.4.2.1 PV System Costs*

Navigant developed detailed cost estimates for residential solar PV systems installed in 2015 based on a system size of 7.00 kW. As displayed in Figure 5, Navigant's bottom-up estimate for the national average installed system cost in 2015 is $2.82/W. Navigant adjusted installed system costs for each utility service territory accounting for changes in key cost components such as direct labor and sales tax.

While some components of the installed system costs can vary significantly by location, the overall impact of locational cost differences is small. For example, direct labor is a leading cost component that changes by location. Navigant adjusted direct labor costs by utility service territory and, while costs may differ by as much as 30-35 percent between high cost locations in CA and low cost locations in AZ, the overall impact on the total installed system cost is relatively low, as direct labor costs only account for around 10-15 percent of the total installed system costs.[16,17]

[16] Quarterly Census of Employment and Wages - Bureau of Labor Statistics
[17] Electrical Cost Data - RSMeans

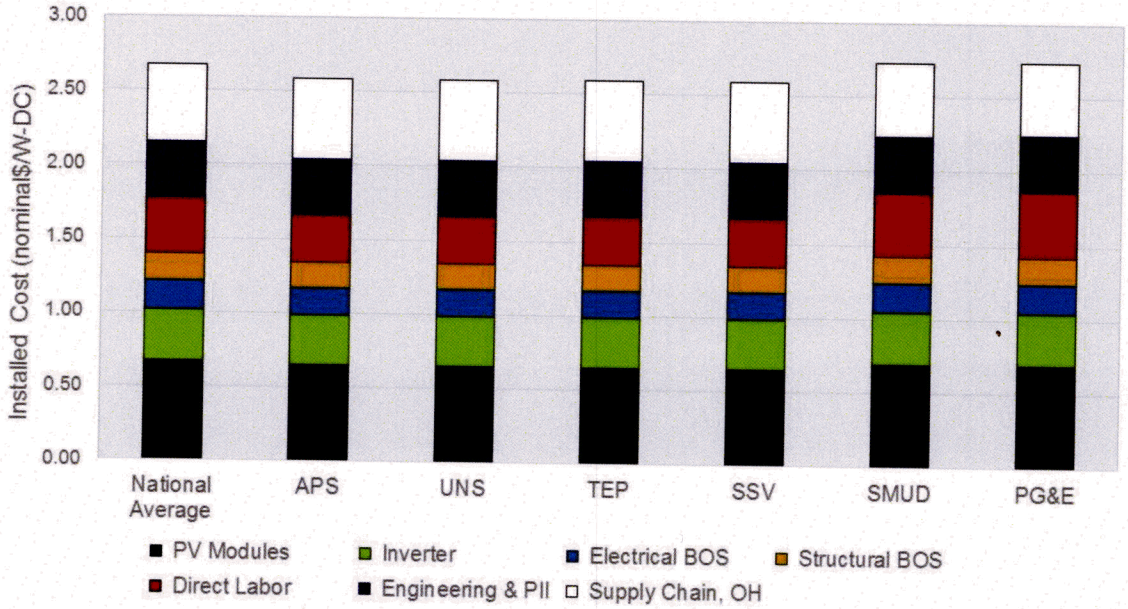



**Figure 5. 2015 Installed System Costs, Residential**

Over the coming years, system costs are expected to decline further as published in the solar market leaders' three-four year cost reduction roadmaps. In December 2015, SolarCity reiterated its cost goal of $2.25/W by mid-2017 and $2.00/W by 2019.[18] This cost reduction roadmap is part of a broader initiative by SolarCity to improve profitability over focusing on pure growth. Key elements of the cost reduction roadmap include: the use of higher efficiency panels, hardware cost reductions and sales and operations cost reduction. Other industry leaders have also published cost reduction roadmaps. For example, SunRun is projecting 2016 cost declines to follow 2015 cost decline trends.[19]

#### *2.4.2.2 Solar Resource*

Navigant used NREL's SAM model to calculate system performance across all regions. System design assumptions were fixed, though the solar resource assumptions changed for each service territory. This methodology accounted for the variance in locational solar resource, and therefore capacity factor and system generation, while keeping system design constant.

### 2.4.3 Policy Adjustments

Solar project economics are currently driven by federal incentives including the investment tax credit (ITC), accelerated depreciation, and bonus depreciation. During 2015, federal incentives included the ITC and accelerated depreciation, as bonus depreciation had expired at the end of 2014. However, in December 2015, the ITC benefit was extended through 2022. Additionally, bonus depreciation was also extended

[18] SolarCity 2015 Analyst Day, December 15 2015. http://files.shareholder.com/downloads/AMDA-14LQRE/1426590891x0x866739/D20C11BF-C791-4BCB-B49B-2F78B0A6FFB7/SCTY_Analyst_Day_FNL-12AM-3.compressed-min.pdf

[19] SunRun Q3 2015 Q3 Earnings Conference Call Presentation, November 12, 2015. http://investors.sunrun.com/phoenix.zhtml?c=254007&p=irol-calendar

through 2019, retroactively impacting 2015 project economics. [20,21] Federal incentives currently driving the solar market include:

- **Investment Tax Credit**: The ITC has recently been extended allowing solar system owners to take advantage of this benefit until 2022. The revised policy allows for 30 percent ITC through 2019, 26 percent in 2020, 22 percent in 2021, and 10 percent in 2022, after which the ITC is set to remain at 10 percent.[20] The ITC benefits solar TPO providers by directly reducing providers' tax liability in the form of a tax credit, effectively reducing the cost of acquiring the asset.[22]
- **Accelerated depreciation:** Qualifying solar energy equipment is eligible for an accelerated cost recovery period of five years.[23] This accelerated depreciation is a significant benefit to solar TPO providers compared with normal depreciation of a capital asset for tax purposes, which would require depreciating an asset over its useful lifetime (e.g., 20-30 years). Since depreciating an asset reduces a firm's tax liability, accelerating the depreciation improves a firm's after-tax income in the early years. Since a dollar today is worth more than a dollar tomorrow, due to the time value of money, this benefits solar TPO providers and/or investors.[24]
- **Bonus depreciation:** The bonus depreciation benefit has been re-introduced and is currently 50 percent through 2017, after which it is reduced to 40 percent in 2018, 30 percent in 2019, and zero percent from 2020 onward.[21] The benefits of bonus depreciation are similar to those described for accelerated depreciation, except that they result in even greater depreciation of an asset in the first year of a capital investment. For instance, with a 50 percent bonus depreciation, one can essentially depreciate an additional 50 percent of the asset's value in the first year.

### 2.4.4 Locational Adjustments

As described above, observed variations in residential solar lease rates alone do not determine project return, as factors such as PV production and systems costs, among others, also need to be considered in the calculation. In our analysis, Navigant used the lowest project return calculated as a comparative benchmark for project returns by solar TPO providers in other jurisdictions. For the six utilities analyzed in 2015, UNSE service territory had the lowest observed lease rate of $0.087/kWh and a project return around 40 percent.

Navigant then made adjustments to account for key drivers such as solar production, system costs, incentives, and tax rates to calculate a lease rate required to achieve the same 40 percent return in other service territories, as presented in Figure 6.

In PG&E's service territory, a 40 percent project return would result in a calculated lease rate around $0.10/kWh, which is about 33 percent lower than the observed $0.15/kWh lease rate in PG&E territory in 2015. In APS's service territory, a 40 percent return would result in a calculated lease rate around

[20] HOUSE AMENDMENT #1 TO THE SENATE AMENDMENT TO H.R. 2029, MILITARY CONSTRUCTION AND VETERANS AFFAIRS AND RELATED AGENCIES APPROPRIATIONS ACT, 2016; Sec 303

[21] HOUSE AMENDMENT #1 TO THE SENATE AMENDMENT TO H.R. 2029, MILITARY CONSTRUCTION AND VETERANS AFFAIRS AND RELATED AGENCIES APPROPRIATIONS ACT, 2016; Sec 143

[22] A tax credit is a dollar-for-dollar reduction in the income taxes that a solar TPO would otherwise have to pay the federal government.

[23] SEIA, Depreciation of Solar Energy Property in MACRS, http://www.seia.org/policy/finance-tax/depreciation-solar-energy-property-macrs, Accessed February 1, 2016.

[24] The significant tax benefits from the ITC, accelerated, and bonus depreciation require a "tax appetite" to monetize these benefits (i.e., one must have sufficient tax liability to take advantage of these tax breaks). Thus, it is not surprising that tax equity investors (which can provide the tax appetite required) constitute a substantial portion of solar TPO providers' financing.

$0.090/kWh, yet observed lease rates in APS service territory in 2015 were around $0.105 (Figure 6). This shows the calculated project return in one service territory vastly differs from the project return in other service territories.

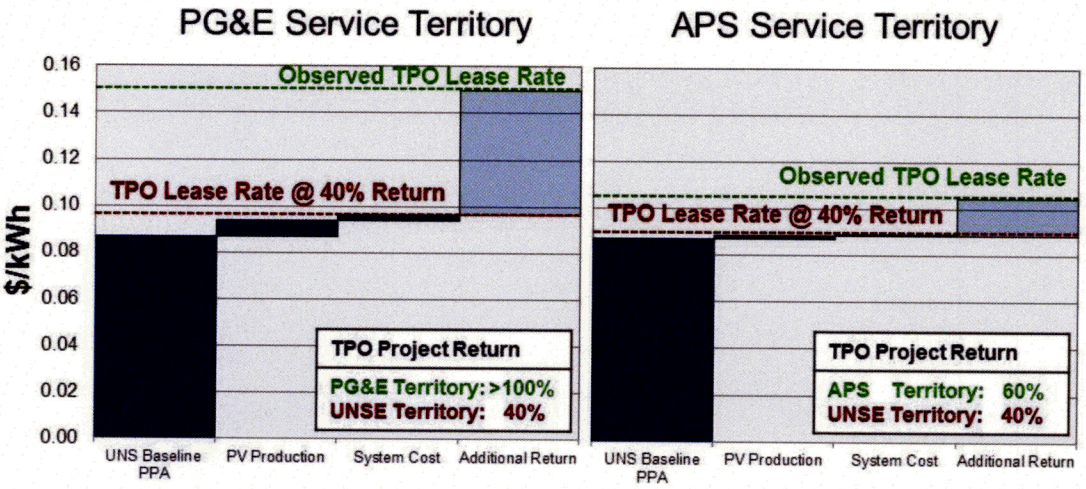



**Figure 6. Impact of Locational Factors on Solar TPO Project Return, 2015[25]**

Figure 7 plots the observed solar TPO lease rates in each of six jurisdictions in AZ and CA (represented by the green dots) on the same graph as what lease rates would be if instead solar TPO providers achieved a benchmark 40 percent project return in those jurisdictions, accounting for locational differences (represented by the red dots). These red and green dots on Figure 7 correspond with the red and green dotted lines in Figure 6, respectively. The positive difference between the observed solar TPO lease rates and the TPO lease rates at 40 percent project return, shown as the green shaded area in Figure 7, represents an opportunity for solar TPO providers to achieve "additional return" in those service territories.

As is evident in Figure 7, solar TPO project returns increase with increasing utility rates, which cannot be accounted for by variations in locational factors. In other words, calculated project returns vary by utility and are positively correlated with the utility rates.

[25] Prior to retroactive bonus depreciation.

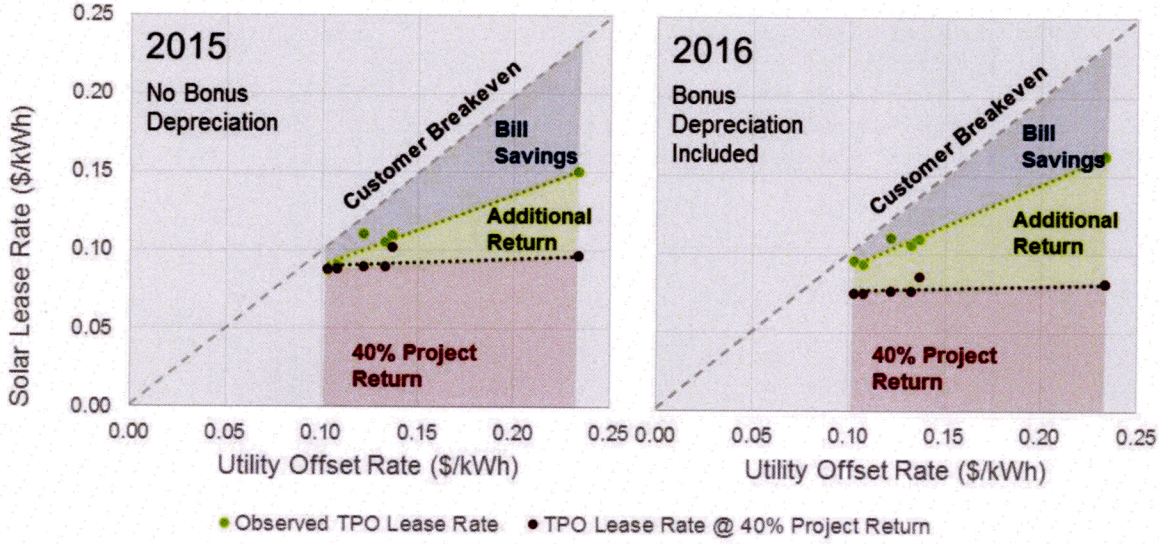



**Figure 7. Project Value Analysis across six utility service territories in AZ and CA**

Navigant conducted this analysis for lease rates in 2015 and 2016. We found that in four out of the six utility service territories analyzed, SolarCity, for example, increased their lease rates in 2016. This occurred despite declining system costs and favorable policy re-introducing the 50 percent bonus depreciation allowance. The chart above clearly illustrates that solar TPO providers have headroom in many jurisdictions, including UNSE's service territory, to reduce solar TPO rates while still achieving project returns at or above those achieved in UNSE's service territory in 2015 (when lease rates were lower, and when bonus depreciation had not yet been re-introduced, as is discussed in further detail in the next section).

### 2.4.5 Impact of Policy

Figure 8 shows how the ITC and bonus depreciation policy impact project returns in UNSE and APS territories for various solar TPO lease prices. Throughout 2015 bonus depreciation did not exist for solar systems. However, in December 2015, bonus depreciation was reintroduced and retroactively applies to all 2015 projects. [26] In Figure 8, the red line reflects policy in place during 2015, which has been replaced by current policy (blue line) as of December 2015 and applies retroactively to 2015 projects. Following the favorable bonus depreciation change, solar TPO project returns increased significantly. For example, if lease rates were held constant at $0.087/kWh, project return in UNSE service territory for systems installed in 2015 would have retroactively increased from 40 percent to 60 percent. Similarly, solar TPO providers in APS's service territory experienced project return increases from 60 to 110 percent for systems installed in 2015 due solely to the re-introduction of bonus depreciation.

Simultaneously, UNSE customers have seen increases in lease rates from 2015 to 2016. These lease rate increases are consistent with multiple residential solar players announcing plans to raise lease prices at the end of 2015.[31] As shown in Figure 8, UNSE customers have seen a 9 percent increase in solar TPO lease rates, representing a further project return increase from 60 percent in 2015 to 80 percent in 2016.

[26] UBS, Global Research – "SolarCity Corp, Getting a Bigger Policy Boost", 16 December, 2015

In contrast, the purple line reflects previously anticipated 2017 policy -- 10 percent ITC and no bonus depreciation. Before these recent policy changes, solar companies would have had to compete along the purple line as of Jan 1st, 2017, yet now they are operating along the blue line.

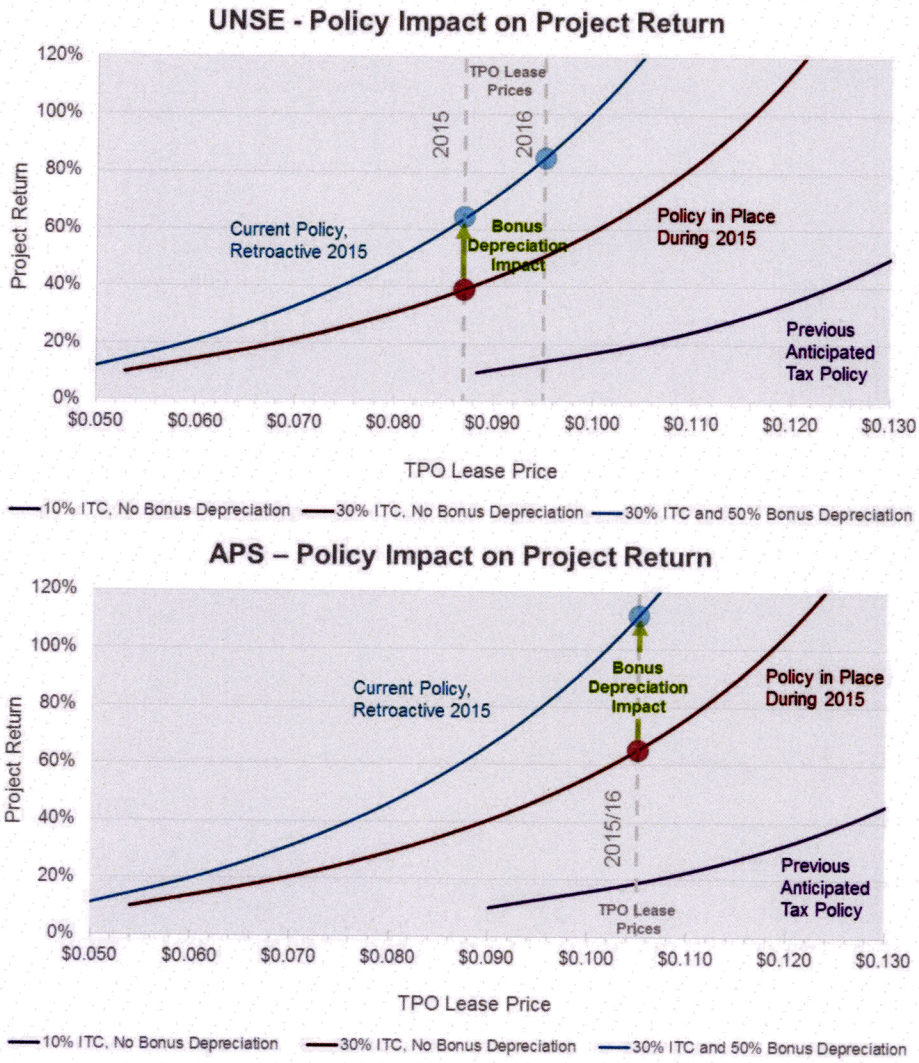



**Figure 8. Incentive Impact on Project Return, APS and UNSE Service Territories**

The analysis above suggests that the combined impacts of the re-introduction of bonus depreciation and the increase of lease rates from 2015 to 2016 offer headroom for solar TPO providers to reduce lease rates and adjust to changing rate structures while still enjoying the same project returns achieved in 2015. For instance, in 2015 in UNSE's territory, SolarCity, the leading solar TPO provider, could earn a project return of 40 percent with solar TPO prices set at $0.087/kWh. With the re-introduction on bonus depreciation, this should permit SolarCity, the leading solar TPO provider in UNSE service territory, to earn 40 percent return with lease rates of about $0.075/kWh, which differs substantially from current observed lease rates of $0.095/kWh. The headroom available in other service territories appears to be even greater, based on our analysis indicating that service territories with higher offset rates tend to have larger project returns. The above analysis is presented in a slightly different format below in Table 3.

**Table 3. Policy Impact of Project Returns, 2015 and 2016[27]**

| | 2015 policy in place through Dec 2015 | | 2015 retroactive change to bonus depreciation in place after Dec 2015 | | 2016 policy in place after Dec 2015 | |
|---|---|---|---|---|---|---|
| | 2015 Solar Lease Rate ($/kWh) | Project Return | 2015 Solar Lease Rate ($/kWh) | Project Return | 2016 Solar Lease Rate ($/kWh) | Project Return |
| UNSE | 0.087 | 40% | 0.087 | 60% | 0.095 | 80% |
| APS | 0.105 | 60% | 0.105 | 110% | 0.105 | 110% |

Navigant notes that project return calculations can be sensitive to certain input assumptions. Since project returns grow exponentially as lease rates increase (see Figure 8), this sensitivity is most notable when lease rates and corresponding project returns are high. The robustness of this analysis is in its *comparative* nature, such that minor uncertainties in inputs are applied equally across all jurisdictions, and across comparative policy and lease price changes. As a result, the conclusions of this analysis are driven primarily by the relative values of the calculated project returns across service territories and over time. Furthermore, Navigant makes no assertions regarding whether any individual project return is deemed to be acceptable, too high, or too low.

Although these calculated project returns are high, we note that we have made several conservative assumptions in our analysis that would actually tend to understate, rather than overstate, true project returns. These conservative assumptions include:

- **Cost of debt**: Our analysis used a cost of debt of 6 percent throughout the analysis. Some sources indicate that this cost of debt could be as low as 5 percent.[28]
- **Lease term and residual value**: The analysis uses a 20 year contract term with no residual value for contract renewal and no residual value for the system at the end of life. The typical system life is longer than 20 years and the system is expected to have a residual value at the end of the lease term.
- **Markup assumed for the ITC and depreciation basis**: We used a 35 percent markup on system cost to calculate the value of the system for the purpose of ITC and system depreciation benefits. This value is also known as the fair market value (FMV). Using FMV as the basis for tax credits and depreciation benefits would effectively result in a solar TPO developer reporting a system value of $3.74-3.87/W-DC to the Internal Revenue Service, which is still lower than observed system sales prices that typically range from $4.20-$4.75.[29,30,31] The ability of PV providers to

[27] Project returns are influenced by several key factors including: installed system cost, ITC, bonus depreciation, accelerated depreciation.

[28] UBS Solar, US Alternative Energy & YieldCos, 4Q15 Playbook: Giving Solar 'Credit,' January 2014.

[29] Deutsche Bank Market Research, SolarCity, Analyst Day Recap, December 15, 2015.

[30] "A Survey of State and Local PV Program Response to Financial Innovation and Disparate Federal Tax Treatment in the Residential PV Sector", Lawrence Berkeley National Laboratory, June 2015

[31] SolarCity 2015 Analyst Day, December 15 2015. http://files.shareholder.com/downloads/AMDA-14LQRE/1426590891x0x866739/D20C11BF-C791-4BCB-B49B-2F78B0A6FFB7/SCTY_Analyst_Day_FNL-12AM-3.compressed-min.pdf

markup cost to something more akin to a price, or system value, when calculating tax credits and depreciation is a key driver in the favorable economics for solar TPO providers. [32, 33]

## 2.5 KEY FINDINGS

Key findings include the following:

- Navigant's research indicates that solar TPO providers choose to operate in jurisdictions where they can maximize their return by undercutting utility offset rates.[34]
- Solar TPO providers appear to be tracking utility rates and pricing accordingly, evidenced by higher observed lease prices in jurisdictions with higher utility rates. These higher lease prices cannot be fully accounted for by variations in system cost, solar production, and tax rate (locational factors).
- Navigant's analysis found that solar TPO providers' project returns vary by utility service territory, with higher project returns calculated in service territories having higher utility offset rates.
- Federal incentives such as the Investment Tax Credit (ITC), accelerated depreciation, and bonus depreciation have a significant impact on project return. The solar TPO business model is able to maximize the benefits of these federal incentives, which are amplified considerably by the TPO's ability to use a system "value", which is higher than the system cost, as the basis for the tax credit and asset depreciation.
- Navigant's research found that despite continuing declines in solar system costs and favorable policy decisions (e.g., re-introduction of bonus depreciation), lease rates have recently increased in certain locations, consistent with public disclosures from leading solar players and indicating higher project returns for solar TPO providers. In 2015, UNS Electric, Inc. (UNSE) solar TPO providers experienced an estimated 40 percent project return, which is expected to increase to around 80 percent in 2016, due to the lease rate increase from $0.087/kWh to $0.095/kWh between 2015 and 2016 and the re-introduction of the 50 percent bonus depreciation allowance (see Figure 8 on 13).
- We conclude that solar TPO providers have headroom to adjust to some changes in rate structures while maintaining project returns.

[32] "Evaluating Cost Basis for Solar Photovoltaic Properties", U.S. Treasury Department. https://www.treasury.gov/initiatives/recovery/Documents/N%20Evaluating_Cost_Basis_for_Solar_PV_Properties%20final.pdf

[33] "Valuation of Solar Generating Assets", Solar Energy Industries Association, http://www.seia.org/sites/default/files/Valuation-of-Solar-Generation-Assets.pdf

[34] Utility offset rates ($/kWh) are defined as dollar value of a customer's bill reduction for each kWh generated by the customer's solar system. In other words, it is the amount of their bill that is "offset" for each kWh generated (hence the term).

# APPENDIX A.

| Financial Assumptions | | |
|---|---|---|
| **System Specifications** | Asset life/investment horizon (Years) | 20 |
| | Installed cost ($/W-DC) | Varies by location |
| | Total asset size (kW) | 7.00 |
| | Annual capacity factor (%) | Varies by location |
| | Annual degradation (%/year) | 0.50%/year |
| | Fixed O&M ($/kW-year)* [35,36] | 20.00 |
| | Fixed O&M escalator | 1.90% |
| **Financing** | Cost of equity | Model output |
| | Cost of debt | 6.00% |
| | Percentage of cap structure – equity | Model output |
| | Percentage of cap structure – debt | Model output |
| | Debt amortization period (Years) | 20 |
| | Residual Value | $0.00 |
| | Target Debt Service Coverage Ratio | 1.30 |
| **Taxes and Incentives** | Federal income tax | 35.00% |
| | State income tax | CA: 8.84%; AZ: 6.00% |
| | Investment Tax Credit | 30.00% |
| | Depreciation type | MACRS, Bonus where applicable |
| | Discounting convention | Mid-year[37] |
| | System Cost Markup for Tax and Depreciation | 35.00% |
| | State incentives | None |
| | Local incentives | None (SMUD: $500/system) |
| **Other** | Lease rate | Varies by location |
| | Lease escalation rate | 2.90% |

*O&M costs include all O&M components as well as inverter replacement.

[35] National Renewable Energy Laboratory, U.S. Residential Photovoltaic (PV) System Prices, Q4 2013 Benchmarks: Cash Purchase, Fair Market Value, and Prepaid Lease Transaction Prices, Oct. 2014.

[36] National Renewable Energy Laboratory, Distributed Generation Renewable Energy Estimate of Costs, http://www.nrel.gov/analysis/tech_lcoe_re_cost_est.html, Accessed February 1, 2016.

[37] A mid-year discounting convention is a standard assumption about when cash flows occur throughout the year for the purposes of a discounted cash flow analysis. The problem with an end-of-year discounting convention is that it discounts the future value too much. It assumes that the entire cash flow for a given year comes at the very end of that year, and therefore should be discounted accordingly. This is often inaccurate, since cash flows typically occur in each month of the year. The mid-year discounting convention better represents the time-value of these monthly cash flows than an end-of-year convention. The mid-year convention assumes that all the cash comes in halfway through the year, which averages out the time differences between the individual monthly cash flows. http://www.wallstreetoasis.com/finance-dictionary/what-is-mid-year-discount

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admitted

**DIRECT TESTIMONY OF CHARLES A. MIESSNER**

**On Behalf of Arizona Public Service Company**

**Docket No. E-04204A-15-0142**

December 9, 2015

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**DIRECT TESTIMONY OF CHARLES A. MIESSNER**
**ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY**
**(Docket No. E-04204A-15-0142)**

I. INTRODUCTION

**Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

A. Charles A. Miessner, 400 North Fifth Street, Phoenix, Arizona 85004.

**Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?**

A. I am the Manager of Rates for Arizona Public Service Company ("APS").

**Q. WHAT ARE YOUR PROFESSIONAL QUALIFICATIONS?**

A. My qualifications are provided in Attachment Miessner Direct-1, Statement of Qualifications.

II. PURPOSE OF TESTIMONY

**Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY IN THIS PROCEEDING?**

A. The purpose of my testimony is to evaluate the residential rate designs proposed by UNS Electric Company ("UNSE") in their efficiency and appropriateness for recovering costs and for setting an effective platform to incent new technologies in the home. I will specifically comment on the proposed three-part rate that incorporates a service charge, energy charge, and demand charge.

III. SUMMARY OF TESTIMONY

**Q. PLEASE SUMMARIZE YOUR TESTIMONY.**

A. In my Direct Testimony, I explain that the current residential rates at UNSE, although typical of electric utilities across the country, are based on decades-old designs that were developed when metering equipment was limited and customers had few, if any, options to invest in (what is now referred to as) distributed technologies. I discuss that these old rate designs do not adequately reflect the costs or even the services that utilities provide. These services include basic services for accessing the grid and receiving electrical service each month, a demand or capacity service for the grid infrastructure investments like power plants, transmission lines, substations, and local distribution equipment

necessary to serve the customer's load, and an energy service for the fuel and other variable costs for the actual electricity consumed in a month. I further discuss how the grid infrastructure is sized to accommodate the customer's maximum electrical draw or "demand" in any hour, as measured in kW, not the total monthly energy consumption, which is measured in kWh. I explain that these old two-part rate structures that include a monthly service charge and a kWh charge are misaligned with the utility's costs to serve customers because they recover all of the grid investment costs and some of the basic service costs with volumetric kWh energy charges, instead of kW demand charges and monthly service fees. By doing so, the charges on the bill do not accurately reflect either the services provided to the customer or the cost of those services. In addition, the two-part rate only provides one opportunity for customers to save on their bill – by reducing their total kWh consumption. In contrast, a three-part rate rewards customers for reducing both their energy and their demand. Furthermore, under the three-part rate, the bill savings for the demand and energy charges will be linked to reductions in both the utility's grid costs and energy costs and thus will minimize any adverse impacts on other customers. Conversely, under a two-part rate the customer's bill savings are not linked to the utility's total cost savings, but only to the energy savings, which results in unfunded grid costs that are shifted to other customers in the form of higher rates.

In short, the old two-part rate designs are economically inefficient, ineffective in reducing a utility's total costs to serve, and ultimately unfair to customers. They are inefficient because they do not provide the right price signals for when and how customers use electricity. Nor do they provide the correct incentives for customers desiring to invest in distributed technologies because such technologies will not be rewarded for, or focused on, reducing demand-related grid costs. Both of these issues will result in the inefficient use of, and inadequate funding for, the grid. In addition, for similar reasons, the two-part rates are also ineffective in reducing a utility's overall costs because they do not effectively incent customers to lower their monthly demand. As a

result, the rates would likely only reduce the utility's energy-related costs, like fuel, and not the demand-related costs, which include all of the extensive grid investment costs. The two-part rates are also ultimately unfair because they can result in grid costs that are caused by one customer to be paid by others, as discussed earlier. This is a direct result of the three utility services - basic services, demand-related grid services, and energy-related services - being billed with two charge types instead of three. I conclude that residential rates should be reformed and modernized to better align rates with costs, provide appropriate price signals to customers, and improve the efficient use of, and funding for, the grid and other necessary infrastructure.

I next summarize APS's extensive experience with residential three-part demand rates and explain that customers on these rates can and do understand the demand concept and manage their monthly demand on their bill. APS has offered a three-part demand rate to residential customers for decades and is currently serving approximately 117,000 on the rate. When customers switch to the rate, they typically reduce both their demand and energy consumption, and some 90% save on their monthly bill.

I then review UNSE's current cost of service, rates and proposed revisions. I note that its costs to serve residential customers include: basic service costs such as meters, point of delivery equipment, transformers, and billing and customer care costs; demand-related costs such as capital infrastructure investments for power plants and the transmission and distribution grid; and energy-related costs such as fuel and purchased power. However, UNSE's current residential rates recover some of the basic service costs and all of the demand costs through kWh energy charges, rather than monthly service charges and kW demand charges, respectively.

I also evaluate UNSE's proposed revisions to the residential rates and conclude that its proposals are consistent with the types of rate reform discussed in my testimony. UNSE improves the recovery of basic service costs through the monthly service charge, rather

than through a kWh energy charge; it reduces the tail block kWh charge in the inclining block rate to better reflect cost of service; it introduces a three-part rate that recovers basic services with a monthly service charge, demand services with a kW demand charge, and energy services with a kWh energy charge.

## IV. RESIDENTIAL RATE REFORM

**Q. WHY MUST RESIDENTIAL RATES BE REFORMED?**

A. Today most, if not all, electric utilities have residential rates that are not aligned with the types of costs necessary to serve the customers. Rather they reflect old, outmoded designs that may have made sense in the past when metering technology was limited and customers had no interest or options to invest in distributed technologies. However, today's Automated Metering Infrastructure ("AMI") offers significant flexibility in residential rate design and allows energy usage information to be integrated with home controls and smart appliances. Also today, customers have meaningful opportunities to invest in distributed generation, energy storage, electric vehicles, smart thermostats and appliances, home energy controls, advanced HVAC systems and other new technologies.

So it is imperative that we have new rate designs that incent the right type of technologies; provide accurate price signals for incenting how and when customers use electricity; accurately reflect the types of services provided by the utility and the costs for those services; and provide opportunities for customers to save on their bills without shifting costs to other customers. All of these factors will result in the improved use of, and funding for, the electrical grid.

**Q. HOW ARE TYPICAL RESIDENTIAL RATES AND COSTS CURRENTLY MISALIGNED?**

A. Residential rates and costs are currently misaligned because they rely on volumetric kWh energy charges to recover grid investment costs – wires, poles, transformers, and generating plants, which are by far the predominant costs to serve residential customers.

In contrast, these grid costs are recovered through kW demand charges and/or monthly service charges for most non-residential customers like businesses, schools, colleges, hospitals, fast-food restaurants and government buildings.

**Q. WHAT IS THE DIFFERENCE BETWEEN DEMAND AND ENERGY?**

A. Energy is the total consumption of electricity over a billing month, measured in kWh (1,000 Watt-hours). Demand is the instantaneous electrical draw of a customer's load at a single point in time, measured in kW (1,000 Watts). If you turned on ten 100-Watt lightbulbs at the same time they would draw (or demand) 1 kW at that instant. If you left them all on for 5 hours they would consume 5 kWh of energy (1 kW used over 5 hours).

**Q. WHY IS THIS DISTINCTION IMPORTANT?**

A. Demand and energy reflect different costs of service, both of which are necessary to serve customers. The size of the grid necessary to serve the home is driven by the home's kW demand. This includes infrastructure investments in power plant capacity, wires, poles, substations, transformers and other capital equipment. For example, a home that draws a maximum load of 8.0 kW in one hour requires 8.0 kW of grid investment to serve it, regardless of the overall energy consumption during the month.

Other costs, such as fuel and variable operation and maintenance costs are driven by a customer's total kWh energy consumption during the month. In this same home, the customer's average load over all of the hours in a month may be more like 2.5 kW per hour, which would equate to 1,825 kWh (2.5 kW times 730 hours in a month).

Suppose the customer goes on vacation for two weeks and reduces their monthly kWh energy consumption, but still drew 8.0 kW demand sometime during the other two weeks. What costs would they reduce? They would certainly reduce the fuel and other variable costs needed to serve them because of the reduction in monthly kWh consumed. However, they would still require 8.0 kW of grid services for the home because they still

drew 8.0 kW demand in some hour before or after the vacation. Stated another way, the fixed infrastructure costs don't go away just because the customer leaves for a couple of weeks.

**Q. HOW DOES THIS TRANSLATE TO THE RATES?**

A. In a sense, the utility provides the customer with three types of services: basic services for connection to the grid each month, kWh energy, and kW demand. Business customers, except for extremely small accounts, are charged separately for these services through a three-part rate. The customer pays for basic services through a monthly service charge, energy services through a kWh energy charge, and demand services through a kW demand rate. In contrast, residential customers are typically billed through a two-part energy rate, where the energy services, demand services, and some of the basic services are billed with a kWh energy charge, and a portion of the basic services with a monthly service charge.

V. <u>APS'S RESIDENTIAL THREE-PART DEMAND RATES</u>

**Q. WHAT IS APS'S EXPERIENCE WITH RESIDENTIAL DEMAND RATES?**

A. APS has significant experience with residential three-part demand rates. We currently have about 117,000 customers, or 11% of our total customers, on a demand rate.

**Q. HOW LONG HAS APS OFFERED THESE RATES?**

A. APS has offered residential demand rates for nearly 35 years.

**Q. WHY WERE DEMAND RATES FIRST ADOPTED?**

A. APS's earliest three-part demand rates date back to 1981. In approving the rate at that time, the Arizona Corporation Commission ("ACC") stated that a residential rate based primarily on each customer's kWh energy consumption "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."[1] The Commission further recognized that including a demand component in residential customers' bills would provide "an

[1] Decision No. 51472 (Oct. 21, 1980) at Finding of Fact 1.

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."[2]

**Q. CAN CUSTOMERS UNDERSTAND AND MANAGE DEMAND?**

A. Yes. While the experience varies for each customer, we have found that customers can and do understand and manage demand. Some customers maximize their experience and bill savings by actively managing their demand through investments in home energy controls, efficient appliances, HVAC systems and other devices. Others are generally aware of the new charge on their bill and try to reduce it by changing their energy usage behavior and patterns, such as avoiding using major appliances at the same time to lower the home's maximum electrical draw. There are some customers who are not interested in any of the specific components of the electric bill, including the demand charge; they are only concerned that the total seems to be reasonable and comports to some typical expected amount. These customers may have a more limited knowledge of demand, energy, or even the service charge component of the bill, and may not try to actively manage any of them. However, some of these customers end up saving on their bill under a demand rate because their electrical usage patterns naturally benefit from a demand charge. For example, they may have a lower maximum kW draw in any hour in relation to their monthly kWh energy consumption.

**Q. WHAT KIND OF DEMAND SAVINGS HAVE CUSTOMERS ACHIEVED?**

A. Again, it varies by home. 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%

[2] *See id.* at Finding of Fact 3.

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.

**Q. HAVE CUSTOMERS ON DEMAND RATES SAVED ON THEIR BILL?**

A. Typically, yes. Looking at this same sample of customers we found that over 90% of the customers that switched to the demand rate saved on their monthly bill. The average bill savings was 9%, and the top 25% saved over 20% on average (excluding taxes and adjustments).

**Q. WHAT CAUSES THESE BILL SAVINGS?**

A. The three-part rate structure rewards customers for reducing both their demand and energy. And because it's also a time-of-use rate, it also provides savings for shifting usage to the off-peak hours. In essence, APS's three-part rate provides customers three opportunities to save on their bill. In comparison, our two-part inclining block rate only provides one opportunity to save – namely, reducing the total monthly kWh energy usage.

**Q. BUT IS THIS A WIN-WIN SITUATION OR ARE THESE BILL SAVINGS SHIFTED TO OTHER CUSTOMERS?**

A. It's a win-win situation. As discussed earlier, when customers reduce their demand and energy, they reduce both the grid investment costs and the fuel and other variable costs necessary to serve them. Because the bill savings from the reduced demand and energy charges are directly aligned with the demand-related and energy-related costs to serve the customer, there are fewer costs shifted to other customers. Simply stated, the bill savings customers achieve on three-part rates better match APS's cost savings so there are only minimal spillover effects to other customers.

In contrast, a two-part rate only incents customers to reduce their monthly kWh consumption, not their demand. Thus, under a two-part rate, only the fuel and other variable costs are reduced, typically not the grid investment costs. But customers are rewarded as if they had reduced both types of costs.

## VI. UNSE'S RESIDENTIAL RATES AND COST RECOVERY

**Q. PLEASE DESCRIBE UNSE'S RESIDENTIAL RATES.**

A. UNSE's current residential rates are based on the two-part rate, which include a monthly service charge and kWh energy charges. The service charge is a flat amount per month. The kWh energy charges have two varieties – an inclining block and time-of-use structure. Most UNSE customers are on the inclining block rate.

**Q. WHAT ARE UNSE'S COSTS TO SERVE RESIDENTIAL CUSTOMERS?**

A. The cost of service study provided in standard filing requirement "G Schedules" and other relevant information show that UNSE's costs to serve residential customers include power supply and fuel costs, transmission infrastructure investments and ancillary services, local grid infrastructure cost for delivering the energy to the home and hookup costs such as some secondary service costs, meters, meter reading, billing and customer care.

**Q. ARE UNSE'S CURRENT RESIDENTIAL RATE STRUCTURES ALIGNED WITH THEIR COST OF SERVICE?**

A. While the overall proposed level of cost recovery for each residential rate class appears to be generally consistent with the class cost of service, the current residential rate structures do not align rates with the costs to serve individual customers as well as they could with three-part rates. Specifically, UNSE's two-part rate structure recovers grid infrastructure investments through volumetric kWh charges, even though the costs are determined by the size of the home's electrical draw (or demand), not the monthly kWh consumption. Likewise, even some of the basic service costs also are recovered through kWh charges.

**Q. WHAT CHANGES DOES UNSE PROPOSE IN THIS RATE CASE?**

A. UNSE proposes to (1) increase the monthly service charge, (2) revise the kWh charges in the inclining block rate, and (3) offer a new three-part rate with a demand charge.

**Q. DO YOU BELIEVE THESE CHANGES WILL IMPROVE THE ALIGNMENT OF UNSE'S RESIDENTIAL RATES WITH COSTS?**

A. Absolutely.

**Q. PLEASE EXPLAIN.**

A. I believe UNSE's proposed revisions to its residential rates will result in substantial improvements in aligning the rate structures with costs and to the services provided. For example, the proposed rate revisions increase the amount of the basic service costs that are recovered through the monthly service charge, rather than through a kWh energy charge, for all residential rates. They also reduce the tail block kWh charge in the inclining block rate to better reflect cost of service. And they introduce a three-part rate consistent with the type of design that I detailed in the rate reform discussion. This new rate recovers basic services with a monthly service charge, demand services with a kW demand charge, and energy services with a kWh energy charge, which results in bills that are more aligned with the costs and services provided.

**Q. WHAT ARE THE BENEFITS OF THESE PROPOSED CHANGES?**

A. As discussed above, rate structures that are better aligned with costs will provide more accurate price signals for customers that wish to invest in distributed technologies, smart appliances and energy controls in their home, and result in a more efficient use of, and funding for, the grid. In particular, the three-part rate will provide an opportunity for customers to save on both the demand and energy components on their bill. And these bill savings will be aligned with a reduction in UNSE's demand and energy-related costs, which will mitigate potential adverse impact on the rates of other customers.

**Q. WHAT IS APS RECOMMENDING THAT THE COMMISSION DO?**

A. APS recommends that the Commission approve UNSE's proposed residential rate design.

**Q. DOES THAT CONCLUDE YOUR DIRECT TESTIMONY?**

A. Yes.

**Charles Miessner**
**Statement of Qualifications**

Charles Miessner has over 30 years experience in the electric utility industry in the areas of pricing, planning, and business development for both utilities and private energy companies. He currently serves as Manager of Rates at Arizona Public Service. Prior to joining Arizona Public Service he served in management and leadership positions for Progress Energy, Tucson Electric Power, AES - New Energy, New West Energy and The Salt River Project. His accomplishments include: developing, implementing and evaluating retail rates; developing integrated resource planning methods and models; and directing strategic planning. Charles has appeared before regulators and legislators on energy issues in Arizona, California, Nevada and New Mexico. He serves on the national rates committee for the Edison Electric Institute. Charles has a B.S. in Economics from Arizona State University and has completed all requirements, excluding dissertation, towards a PH.D. in Economics from the University of North Carolina.

ARS-7

# SURREBUTTAL TESTIMONY OF CHARLES A. MIESSNER

**On Behalf of Arizona Public Service Company**

**Docket No. E-04204A-15-0142**

February 23, 2016

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**SURREBUTTAL TESTIMONY OF CHARLES A. MIESSNER**
**ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY**
**(Docket No. E-04204A-15-0142)**

I. INTRODUCTION

**Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

A. Charles A. Miessner, 400 North Fifth Street, Phoenix, Arizona 85004.

**Q. DID YOU PROVIDE TESTIMONY EARLIER IN THIS DOCKET?**

A. Yes, I provided Direct Testimony on behalf of Arizona Public Service Company (APS).

**Q. DID YOU REVIEW THE REBUTTAL TESTIMONY OF UNSE AND THE DIRECT TESTIMONY OF STAFF AND OTHER INTERVENORS?**

A. Yes, I did.

**Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTTAL TESTIMONY?**

A. The purpose of my Surrebuttal Testimony is to respond to certain assertions and claims made by other intervenors that relate to my Direct Testimony and to assess their recommendations made in this proceeding. I will also address UNSE's proposal for a buy-back rate for customers with rooftop solar and Staff's proposal for a transition period to three-part rates.

II. SUMMARY

**Q. WILL YOU PLEASE SUMMARIZE YOUR SURREBUTTAL TESTIMONY?**

A. In my Surrebuttal Testimony, I respond to the objections to three-part demand rates made by various intervenors. Specifically, I address five key points:

- Demand charges;
- Minimum bills;
- Time of use (TOU) rates;
- Complexity for residential customers; and
- Impacts on energy efficiency.

**Demand charges.** Contrary to the objections made by TASC and Vote Solar, APS believes demand charges appropriately reflect the cost of service and recover the right amount of revenue.

**Minimum bills.** Minimum bills are not a viable alternative to three-part demand rates as asserted by TASC, WRA, and other intervenors. Minimum bills would have to be both very large and tiered for small, medium, and large homes to have any beneficial effect. Specifically, the minimum bill would have to be significantly larger than the amounts typically discussed by these parties, $10 to $25, to address the cost recovery issue for any but the smallest energy users. For example, minimum bills for medium-sized and large-sized homes would likely need to be in the range of $70 to $150 per month.

**Time-of-Use (TOU) rates.** Two-part time-of-use ("TOU") energy rates are not a viable alternative to three-part demand rates as asserted by TASC, WRA, and other intervenors. TOU kWh rates, while having advantages over other two-part kWh rate designs, still do not and cannot adequately reflect cost of service because they inherently recover infrastructure costs through variable kWh charges. What's more, neither minimum bills nor TOU kWh rates incent customers to invest in home technologies that actually reduce the utility's infrastructure costs. While TOU kWh rates provide a higher incentive to reduce energy during the on-peak hours, if this response is not consistent throughout the entire month, these rates will have either a limited impact or no impact at all on the demand-related infrastructure costs.

**Complexity for residential customers.** I rebut the contention made by TASC, WRA, and Vote Solar that residential customers will not be able to understand or manage demand. As discussed extensively in my Direct Testimony, APS's existing three-part demand rate has shown just the opposite; a significant number of APS customers have already accepted the demand-rate concept and can and do manage their demand.

**Impacts on energy efficiency.** I also respond to claims made by TASC, WRA, and other intervenors that three-part demand rates will hurt energy efficiency. These parties claims are wrong. A demand rate will incent energy efficiency programs that are refocused on opportunities that can reduce both energy and demand, which would be much more valuable to the electrical system and other customers because they could result in both savings in future fuel costs and savings from avoiding or deferring the need to build additional power plants.

In addition, APS supports the general direction proposed by UNSE to replace net metering with a solar purchase rate arrangement for the excess power. While the best rate is avoided cost, the purchase rates proposed by UNSE could provide a reasonable method to value excess energy exported to the grid. Certainly, the purchase rate should be no higher than the purchase price for grid-scale PV solar power.

For these reasons, APS recommends that the Commission approve three-part demand rates for UNSE residential customers. This is consistent with the proposals made by Staff and agreed to by UNSE in their rebuttal testimony. In that respect, APS also supports Staff's recommendation for a transition period combined with customer education. APS further supports adoption of UNSE's net metering proposal.

## III. MISSTATEMENTS ABOUT APS DEMAND RATES

**Q. DOES APS HAVE EXTENSIVE EXPERIENCE WITH THREE-PART DEMAND RATES FOR RESIDENTIAL CUSTOMERS?**

A. Yes. As detailed in my Direct Testimony APS has several decades of experience with residential demand rates. We currently have more than 117,000 residential customers on a demand rate, which is approximately 11% of our total residential customer base. In addition, all of our business customers served under our small to extra-large rates are billed with a demand charge.

**Q. HAVE APS'S RESIDENTIAL DEMAND RATES BEEN SUCCESSFUL?**

A. Yes. While Vote Solar witness Kobor considers an 11% adoption rate to be low and indicates that not many customers desire a demand rate, it is actually quite impressive for a rate that is voluntary and competed with as many as four residential two-part TOU rates (now just two). In fact, APS has the highest participation in residential demand rates in the country. Vote Solar claims that APS's current three-part demand rate does not produce any demand reduction – the participants are only high-use customers who naturally save on the rate. Both parts of this assertion are untrue. I have provided substantial information in my Direct Testimony concerning the demand and energy reductions achieved by customers currently on the demand rate, which are significant. *See also* APS's response to RUCO Data Request 1.6, which is attached as Attachment CAM-1SR and incorporated into my Surrebuttal Testimony by this reference.

## IV. INTERVENORS' OBJECTIONS TO DEMAND RATES ARE UNFOUNDED

**Q. WHAT OBJECTIONS DO SOME INTERVENORS HAVE TO THREE-PART DEMAND RATES?**

A. Certain intervenors testified that they object to three-part rates for residential customers because they have asserted:

- Demand charges do not reflect long-run cost of service;
- Demand charges will somehow recover too much revenue because of customer diversity;
- Minimum bills and TOU rates are better alternatives;
- Customers won't understand or manage demand; and
- Demand charges will disincent energy efficiency.

**Q. DO DEMAND CHARGES REFLECT COST OF SERVICE?**

A. Yes. In fact, demand charges correct the misalignment between a customer's cost of service and their bill inherent in two-part energy rates that rely on a monthly service

charge and kWh energy charges to recover the utility's infrastructure investment necessary to serve the home. I included a detailed explanation of this issue in my Direct Testimony in this proceeding and therefore will refer the reader to that testimony rather than repeating that information here. However, the highlights are:

- A significant portion of the cost to serve residential customers is comprised of infrastructure investments;
- These costs are indisputably driven by the kW demand of the home, not the monthly kWh consumption; and
- A kW demand charge is the most appropriate and accurate way of recovering these costs.

**Q. BUT AREN'T ALL COSTS VARIABLE IN THE LONG RUN?**

A. Not in the sense that some intervenors are referring. Utilities typically face higher fuel costs, higher customer-related costs like meters and billing systems, and higher infrastructure costs as they build new power plants, transmission lines, and distribution facilities over time. However, once an infrastructure investment is made it is not variable over its useful life, which can be several decades. Therefore, this notion of fluctuating costs over time can lead to a somewhat common misconception about fixed versus variable costs articulated by TASC witness Fulmer in his direct testimony. Fulmer claims that kWh charges, which he correctly characterizes as a variable charge, are a better reflection of cost of service because all costs are variable in the long run. Hence variable charges for variable costs.

The problem with this reasoning is that the increases in customer-related costs and infrastructure investment are not driven by increased kWh consumption, but rather the increased number of customers and increased kW demand, respectively, over time. All costs and charges can and do change over time, but that doesn't change the fundamental need for a direct nexus between rate design and cost of service. Increased fuel and

variable operating and maintenance costs ("O&M"), which vary with kWh production, should be recovered through higher kWh charges; increased customer-related costs should be recovered through higher monthly service charges; and increased infrastructure costs should be recovered through higher demand charges.

**Q. WILL DEMAND CHARGES OVERRECOVER INFRASTRUCTURE COSTS DUE TO CUSTOMER DIVERSITY AS CLAIMED BY WRA?**

A. No. That's not how the rate making process works. APS has been billing residential and business customers on demand rates for decades and has established those charges in numerous rate cases. The diversity issue was appropriately reflected and adjusted for as a part of this process. There simply is no double counting.

Let me explain with an example. The monthly demand for APS's residential customers, i.e., the hour when the electrical load in each home is at its peak, typically occurs between 5 p.m. and 9 p.m. in both summer and winter months, although there are always exceptions to this usual pattern. However, the precise hour of this demand will vary for each home – some will peak at 6 p.m., others at 7 p.m. and so on. That is what is called diversity.

Consider a simple example with 5 residential customers, each with an individual monthly peak demand of 6 kW for their home and lower kW loads in other hours. The sum of the individual demands for the 5 homes would be 30 kW (6 kW times 5 customers). As illustrated in Table 1 below, in this example the combined load of all 5 homes, taken as a group, peaks at 7 p.m., which only adds up to 26 kW because not all of the homes are that their maximum load at that time. This combined maximum hourly load for the group is referred to as the class peak. In addition, suppose the utility also serves some business customers and the combined peak for all customer classes occurs at 6 p.m., which is referred to as the system peak. The residential load in this example is 23 kW at the system peak hour.

Table 1.

Illustrative Hourly kW loads for 5 Customers

| Customer | 5:00 PM kW | System Peak 6:00 PM kW | Class Peak 7:00 PM kW | 8:00 PM kW | Individual Demand kW |
|---|---|---|---|---|---|
| 1 | 4 | 4 | 6 | 4 | 6 |
| 2 | 4 | 4 | 6 | 4 | 6 |
| 3 | 4 | 5 | 6 | 4 | 6 |
| 4 | 6 | 5 | 4 | 4 | 6 |
| 5 | 4 | 5 | 4 | 6 | 6 |
| Total | 22 | 23 | 26 | 22 | 30 |

So what's the issue? There's a mistaken notion that because the utility bills each of the 5 customers according to their individual demand, the 6 kW, even though the infrastructure costs are driven by the combined peak of all the homes at the time of the system peak, the 23 kW, they will over recover these costs – they will charge for an aggregate of 30 kW, but only incur costs for 23 kW.

**Q. IS THIS NOTION CORRECT?**

A. No, it's not, and for two reasons. First of all, not all of the utility's infrastructure costs are driven by the system peak. For example, the costs for some equipment like the pad mounted transformer in front of the home are driven by the diversified peak of the homes served off of that transformer (5 homes, and 26 kW in this illustrative example), not the system peak. Similarly, the cost for the local substation that serves the home is driven by the neighborhood or class peak, not the system peak. Infrastructure costs that are farther "upstream" from the home and serve a much wider group of customers, such as power plant costs, are primarily driven by the system peak.

Second and more importantly, irrespective of the cost drivers, diversity does not result in any double counting or over recovery. This is because of the way the demand charge is derived in the rate-making process.

**Q. PLEASE EXPLAIN.**

A. In the rate-making process the demand charge is calculated in two steps: (1) the allocation of demand-related costs to a specific customer class and (2) the derivation of the monthly demand charge using the allocated costs and the class billing determinants (i.e. the total customer kW that will be billed each month).

In the first step, the utility's infrastructure costs are allocated or assigned to each customer class based on the cost drivers discussed above. This step establishes the total infrastructure cost to be recovered through rates from the specific class. Continuing with the same example of 5 residential customers, assume that the various infrastructure costs associated with the three cost drivers (individual demand, class peak, and system peak) are as shown in Table 2 below. These costs are allocated to the residential class according to the kW specific to each driver: the cost related to the kW of the individual homes is allocated at 30 kW (5 homes at 6 kW peak demand per home); the cost related to the class peak kW is allocated at 26 kW; and the costs related to the system peak are allocated at 23 kW. This allocation process results in $3,780 per year of total infrastructure costs to be recovered in rates from residential customers. Importantly, this allocated cost fully reflects the appropriate level of diversity for each type of cost.

Table 2.

Illustrative Cost Allocation and Demand Charge Derivation

Step 1. Cost Allocation

| Cost Driver | Unit Cost $-kW | Units kW | Allocated Cost |
|---|---|---|---|
| Individual Demand | 30 | 30 | $ 900 |
| Class Peak | 40 | 26 | $ 1,040 |
| System Peak | 80 | 23 | $ 1,840 |
| Total | | | $ 3,780 |

Step 2. Derivation of Demand Charge

| | | | |
|---|---|---|---|
| Total Allocated Cost | $ | 3,780 | |
| Total Billed kW (12 months of kW) | | 360 | (30 kW X 12 months) |
| Monthly Demand Charge ($-kW) | $ | 10.50 | ($3,780 / 360 kW) |
| Revenue from Demand Charge | $ | 3,780 | ($10.50 X 360 kW) |

In the second step of the process, the monthly demand charge is derived by dividing the $3,780 annual cost by the total kW that will be billed for all 5 customers, which in this case is 360 kW (5 customers times 6 kW per month times 12 months). The resulting demand charge is $10.50 per kW. This step also ensures that there is no double counting or overrecovery of costs because the kW used to derive the charge (30 kW per month, 360 kW per year) are the same kW that will be billed customers. In other words, the utility's annual revenue from the demand charge in this example is $3,750 ($10.50 per kW times 30 kW per month times 12 months), which is exactly the same as the infrastructure costs allocated to the residential class.

In recap, the cost allocation process ensures that the right amount of costs are recovered in rates by appropriately reflecting the customer load diversity in the allocated costs for each customer class. The rate derivation process ensures that the demand charge will be designed to recover this allocated cost by calculating the charge using the same

"undiversified" kW that customers will be billed on – and that the utility must have the local infrastructure in place to support. Expanding the example from five customers to a million complicates the math a bit, but would not change the result.

**Q. WHY IS A MINIMUM BILL NOT A VIABLE ALTERNATIVE TO A THREE-PART DEMAND RATE?**

A. A minimum bill is not a viable alternative to a three-part demand rate both from a cost-of-service perspective and a practical standpoint. Conceptually, a minimum bill would have to address two potential situations - a customer whose kWh and kW drop significantly in a particular month, e.g., the customer is absent from the house for two weeks out of the month, and a situation where a customer's kWh drops significantly, but their kW remains at or near the normal level for the home.

A sufficiently sized minimum bill could be somewhat useful for the first situation where both the kWh and kW usage drop significantly. In this case the minimum bill could help recover infrastructure costs that are: (1) sized for and reserved for a home's electrical service; (2) are not recovered through the monthly service charge; (3) are not used by the customer or otherwise paid for in the absent month; and (4) cannot be used to temporarily serve other customers, and charged to them.

In this case the customer isn't paying for or using the demand-related facilities in the vacation month. Nonetheless, the unused facilities may not be available to serve another customer because they are not suitably fungible, or the facilities are needed to serve the customer in a subsequent month and therefore cannot be shifted to someone else, or the absence occurs in a month with low system loads. Therefore, the facilities are not needed to serve anyone else.

In this case, where a customer significantly, but temporarily, reduces their kW demand, a large minimum bill could help pay for these infrastructure facilities, e.g. substations, wires, poles, transformers, and power plants. However, the minimum charge couldn't

be one-size-fits-all. Undoubtedly, the dedicated but unused facilities will be much higher for a large home versus a small apartment. For example, a large home with a monthly bill of $500 may have $350 of infrastructure costs per month (e.g. 70%), while a small apartment with a $60 bill may have $40 of monthly infrastructure costs. A minimum facilities charge of $30, the $20 service charge, plus $10 for the dedicated demand-related facilities may be reasonable for the small apartment, but it does not come close to recovering any reasonable portion of the $350 infrastructure cost for the large home.

Therefore, any minimum bill would have to be tiered to the normal kW demand for the home – a higher minimum bill for the higher kW needed to serve the larger home and a lower minimum for the lower kW needed to serve the small apartment. In addition, the levels of minimum bills would have to be significantly higher than the amounts currently proposed by solar companies, residential advocates, or other proponents of this concept. Finally, because the minimum bill would need to be tiered by the home's kW, the minimum bill concept provides little to no advantage over a demand charge with a minimum billed kW.

**Q. WHAT IF A CUSTOMER REDUCES THEIR MONTHLY KWH, BUT NOT THEIR KW DEMAND?**

A. The minimum bill concept is even more troubling when the customer significantly reduces the kWh energy but not the kW demand for their home. In this case the customer continues to consume the monthly kW, but not pay for it if they are served under a two-part rate. Thus, there are no unused facilities that could theoretically be used to serve another home. As a result, no realistic minimum bill concept could adequately replace a demand charge for recovering these infrastructure costs.

This point is demonstrated through the following example, which is typical for customers with solar generation. The assumptions and results are provided below in Table 3.

Table 3.

Minimum Bill Example for Typical Residential Customer

Medium Size Home

| | kW Used | kWh Used | Service Charge | Demand Charge | Energy Charge | Total Bill |
|---|---|---|---|---|---|---|
| Typical Monthly Electrical Load | | | | | | |
| Cost of Service | 6 | 1200 | 20 | $36 | $72 | $128 |
| Bill 2-part rate | 6 | 1200 | 20 | 0 | $108 | $128 |
| Bill 3-part rate | 6 | 1200 | 20 | $36 | $72 | $128 |
| Minimum Bill | | | | | | $25 |
| Same Demand, 75% Lower Energy | | | | | | |
| Cost of Service | 6 | 300 | $20 | $36 | $18 | $74 |
| Bill 2-part rate | 6 | 300 | $20 | 0 | $27 | $47 |
| Bill 3-part rate | 6 | 300 | $20 | $36 | $18 | $74 |
| Minimum Bill | | | | | | $25 |

This home consumes 6.0 kW demand and 1,200 kWh of energy per month. The customer's monthly bill is $128 per month without taxes or adjustor rates. This is based on a $20 service charge, $6 per kW demand charge and $0.06 per kWh energy charge for the demand rate and $20 service charge and $0.09 per kWh for the two-part rate, which are similar to the charges proposed by UNSE. The $128 bill is the same whether it's computed under a two-part energy rate or a three-part demand rate, and the cost to provide service is also $128 per month.

But what happens when the customer reduces their monthly kWh energy consumption by 75%, from 1,200 to 300 kWh, and their monthly demand usage remains at 6.0 kW.

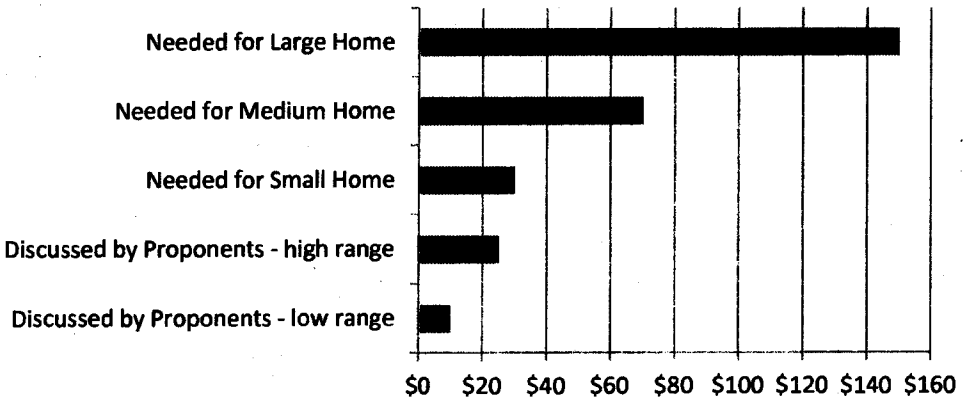
The cost of service is assumed to be reduced from $128 to $74, if the $0.06 kWh rate truly reflected variable energy costs, because the utility avoided $54 in variable costs ($0.06 * 900 kWh) such as fuel and variable O&M. For APS's residential customers this variable cost of energy service would be closer to $0.04 per kWh, not $0.06. But because UNSE provides most of its generation through power purchases rather than their own power plants, the higher variable cost number might not be unreasonable. The bill under the three-part demand rate is also reduced to $74. Thus, the rate structure is aligned with the cost of service, and the UNS customer received the right price signal for reducing the kWh energy, namely, the variable cost of energy service. However, the bill under the two-part energy rate is reduced to $47, which is significantly less than the cost of service. The two part rate is not aligned with cost of service because the customer received $0.09 per kWh to reduce their energy consumption when the variable cost was only $0.06 per kWh; while the customer still "demanded" (i.e. needed) 6.0 kW of capacity at some point during the billing month, and the utility needed to have the infrastructure in place to meet that demand, irrespective of the overall reduction in kWh.

What does a minimum bill do to correct the deficiency in this scenario? The answer – nothing. A minimum bill of $25, which is around the high range proponents are discussing, has absolutely no effect at all. In fact, even for this medium size home the minimum bill would have to be at least $47 a month - the $20 service charge plus the $27 variable cost for the kWh still consumed by the home - to make any contribution towards the infrastructure costs that are still used, but not paid for. In this case, the correct minimum bill for a medium-size home would be $74, the amount resulting from a three-part demand rate. The minimum amount would include $20 for the monthly service costs, $36 for the demand-related infrastructure costs, and $18 for the fuel costs associated with the 300 kWh of usage, which would be included in the minimum. As in the first case, the minimum bill would have to be tiered to the home's kW load, and

would have to be at a level that is significantly higher than that proposed by proponents of the concept, to be effective at all in recovering infrastructure costs.

Figure 1.

Minimum Bills Likely Needed for Small, Medium and Large Homes Versus Levels Proposed by Proponents




In summary, a minimum bill, as proposed by various intervenors is not a viable alternative to a three-part demand rate to recover infrastructure costs. To be effective and fair, the minimum bill could not be one-size-fits-all – it would have to be tiered to the usual demand needed to serve each home. It would also have to be much higher than the service charge and the variable costs for any kWh consumed in the month to have any contribution towards fixed cost recovery. The minimum bill would also have to distinguish between customers that have both low kWh and low kW usage in a given month from those that reduce their kWh energy consumption but not their kW demand. In either case, the levels of minimum bill amount would have to be much higher than even the highest range discussed or proposed by proponents of the concept. Minimum bills of $30 for small homes, $70 for medium-size homes, and $150 for large homes would be the range of possibilities for a minimum bill to be a viable alternative to a three-part demand rate.

**Q. UNDER A MINIMUM BILL, DOES A CUSTOMER HAVE AN OPPORTUNITY TO REDUCE THEIR BILL BELOW THE MINIMUM AMOUNT?**

A. No. A minimum bill acts like an "adder" to the basic service charge. A customer would not have any opportunity to reduce their bill below this amount. In this example, if the minimum bill was $74 per month for a medium-size home, which includes 300 kWh of consumption, the customer would have no opportunity to reduce the bill below the $74 minimum. In contrast, under a three-part rate the customer would have an opportunity to substantially reduce the bill, in that a demand rate affords a customer who does in fact reduce their demand to reduce their bill – the very alignment and price signal that is desired and not attainable with a minimum bill. It is also worth noting that a minimum bill does not send any effective price signal for customers to invest in home energy technologies

**Q. ARE TOU ENERGY RATES A BETTER ALTERNATIVE THAN THREE-PART DEMAND RATES?**

A. No. WRA, and TASC assert that two-part TOU energy rates are a better alternative to three-part demand rates. They assert that the TOU rates are easier for customers to understand and are as effective in recovering infrastructure costs as the demand rates. But this is incorrect.

**Q. PLEASE EXPLAIN.**

A. TOU rates can have an important role in aligning rates with costs, but by themselves they are not a viable alternative to a three-part demand rate, which can also have a time-of-use structure. While TOU kWh rates have advantages over other two-part kWh rate structures, they still do not and cannot adequately reflect cost of service because they inherently recover infrastructure costs through variable kWh charges. Even though TOU kWh rates provide an incentive to reduce energy during the on-peak hours, which is helpful from a resource perspective, if this response is not consistent throughout the

entire month, it will have minimal impact on the demand-related infrastructure costs necessary to serve the home.

For example, if a customer reduces their kWh energy usage during half of the on-peak hours in a month, let's say every other day, the utility would not likely be able to reduce the infrastructure investment needed for the home very much, if at all – certainly not anywhere near 50%. Just because the customer reduces their electrical demand on Monday, but requires the usual electrical demand on Tuesday, doesn't mean the utility can permanently downsize the grid infrastructure, such as transformers, poles, wires, and other equipment needed to serve their home. In this example, the utility would not be able to downsize the grid at all. However, the customer would be overcompensated through the avoided higher on-peak energy charges.

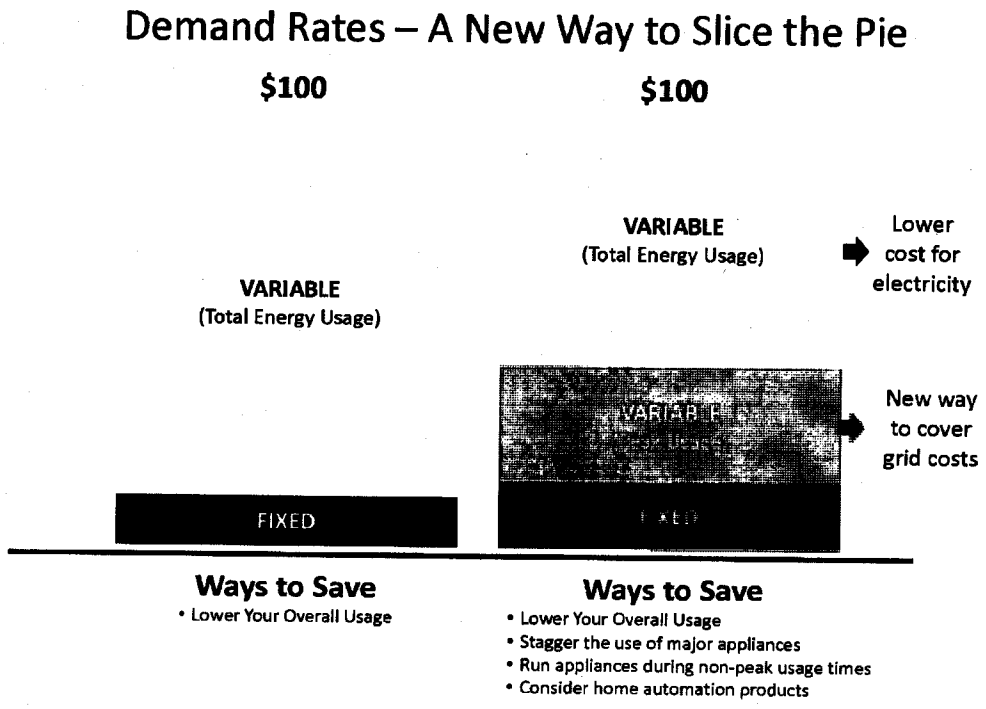
Theoretically, these sporadic energy reductions could have some beneficial impacts at the system peak level, which in turn drives utility's power plant capacity costs. But this would require enough participants in the TOU rate with a sufficient diversity of sporadic energy reductions at different times of the day, and days of the year, to provide a combined energy reduction that is somewhat more consistent across the utility's critical peak hours. However, even in this hypothetical case, the combined diversified impact on system peak would almost certainly be far less than the sum of the impacts for the individual homes.

In any event, a two-part TOU energy rate would not be likely to incent the type of technology or electrical appliance choices that are focused on reducing the home's electrical infrastructure requirements. For example, some electrical appliance choices, such as instantaneous water heaters, may use a high level of demand, but lower kWh's during the month, compared to alternatives. These devices can reduce the utility's fuel costs to serve the home, but also require significantly more infrastructure investment from the utility. Two-part kWh rates, including TOU rates, would incent the customer to

invest in the latter choice, with the higher demand but lower energy requirements. Other home energy technologies would also be incented to focus on, and be rewarded for, reducing on-peak energy but not necessarily demand, under a two-part TOU rate.

From a customer's perspective, a three-part TOU rate provides three ways to save on their bill – shifting kWh energy usage to off-peak hours, reducing overall kWh energy usage, and reducing the on-peak demand, while a two-part TOU rate only provides the first two ways to save, as illustrated in Figure 2 below. In addition, these three ways to save are much better aligned with the utility's cost of service, which creates a win-win situation where the customer's bill savings result in similar utility cost savings.

Figure 2.




**Q. WHAT ABOUT APPLYING THE DEMAND ONLY TO ON-PEAK HOURS?**

A. Some parties including Staff, RUCO, and WRA have proposed that demand charges should only apply to on-peak hours for residential customers. APS believes this

argument involves the inherent tension between theoretical precision and practical application. In general, APS supports applying the demand charge to the on-peak hours for residential customers, but only under certain circumstances. And this opinion is driven more by practical considerations than by theoretical precision.

**Q. PLEASE EXPLAIN.**

A. All utility charges are a mix of theoretical precision and practical application. The perfect charges, whether they are demand charges, energy charges or something else, would likely be too complex and expensive to implement. For example, the best demand charge would likely be two demand charges – an untimed (non-time-of-use) demand charge to recover distribution costs that vary with the size of the home and are driven by the neighborhood peak, rather than the system peak, and an on-peak demand charge to recover power plant infrastructure costs that are driven by system peak hours. This could also be accomplished through separate on-peak and off-peak demand charges that would differ by the power plant capacity costs.

However, APS believes that this structure would be complex, at least initially, and therefore more appropriate for business customers than residential customers. Therefore, APS believes that an on-peak demand charge is a viable option for recovering the costs of both power lines and power plants if the following conditions are met: (1) the monthly service charge recovers the grid costs from the meter, point of delivery, service drop to the home, and the distribution transformer (along with the other customer-related costs such as meter reading, billing, and customer care); and (2) the on-peak period is defined to include the hours that typically drive the design peaks for residential feeders and substations as well as the system-peak hours that drive power plant costs.

As a practical matter, a uniform un-timed demand charge could work because residential customers largely peak on the system peak. Under this scenario an un-timed demand

charge would reasonably reflect the infrastructure costs for each home, without unduly complicating the bill.

**Q. SHOULD THE DEMAND CHARGE ONLY BE APPLIED TO SUMMER MONTHS?**

A. No. The demand charges could be somewhat higher in the summer months compared with the winter, but APS does not recommend only applying the demand charge to one month or one season. From a theoretic standpoint, as discussed above, not all infrastructure costs are driven by system peak months or hours. For example, the distribution grid, while typically sized for summer load, is needed to serve homes throughout the year. And while it may be cost justified to apply a significant portion of power plant costs only to the core summer months, from a practical standpoint residential customers already face high summer bills, and this option would exacerbate that issue.

**Q. WILL THREE-PART DEMAND RATES HURT ENERGY EFFICIENCY?**

A. No, it will refocus energy efficiency and turn it into a better resource for the utility and provide means by which customers can exercise greater control over their utility bill through demand management.

**Q. PLEASE EXPLAIN.**

A. As discussed in my Direct Testimony, APS believes that home technology investments can be an important resource for meeting future power needs – if the investments are properly incented and focused on reducing the costs for both building and running power plants in the future. Currently, the two-part kWh rates focus energy efficiency programs on investments that reduce operating costs, such as fuel and variable O&M, but not the costs of the power plants themselves, which are more significant. A three-part demand rate incents home technologies and energy efficiency investments that can reduce both of these costs.

Concerning the customer's potential bill savings, a three-part demand rate will have a lower kWh charge compared with a two-part kWh rate. But, under the three-part demand rate, the demand charge will provide the customer an additional incentive and opportunity to save on their bill. Therefore, APS believes that three-part demand rates can result in viable opportunities for energy efficiency programs, and those programs will have a much higher value to the electric system because of the potential increased utility cost savings compared with those that are primarily focused on energy savings.

**Q. WHAT WERE VOTE SOLAR'S REMARKS CONCERNING ENERGY EFFICIENCY AT MINGUS HIGH SCHOOL?**

A. Vote Solar witness Kobor testified that Mingus Union High School District ("Mingus") was harmed because APS implemented a demand charge to their bill after the customer invested more than $1 million in energy efficiency. Because the estimated bill savings from the energy efficiency project was apparently targeted at reducing kWh energy and not kW demand, the actual bill savings were much lower than expected, which reduced the investment's net benefits.

**Q. DO YOU AGREE WITH VOTE SOLAR'S TESTIMONY REGARDING THE ENERGY EFFICIENCY INVESTMENTS MADE BY MINGUS?**

A. No.

**Q. PLEASE EXPLAIN.**

A. In 2013 and 2014, Mingus implemented energy efficiency projects apparently targeted at reducing kWh energy and not kW demand. As a result, the actual bill savings were much lower than expected, which reduced the investment's net benefits. Mingus – along with all business customers with loads greater than 20 kW – has been subject to a three-part demand rate for decades. Therefore, contrary to Vote Solar's testimony the demand charge was in place many years before the energy efficiency investment took place. An adjustment to how the demand charge is calculated during a low-load month was approved in our last general rate case and effective in July 2012, which was also

well before the energy efficiency measures were installed. Unfortunately, it appears that either Mingus or their third-party vendor may have miscalculated the anticipated savings from its investment in energy efficiency.

APS is sympathetic to our customer for this situation. We know that utility bills are especially important to our schools because of relatively tight overall funding and limited control over significant portions of their operating budgets such as teacher's salaries. As such, we also know it is critical that the investments they make in energy efficiency, solar and other technologies produce sufficient savings in utility bills or other operating costs to justify their cost.

While APS does not know precisely how the savings miscalculation occurred for the project, a plausible reason is that Mingus (or their third-party vendor) may have overestimated the savings by dividing the total bill by the monthly kWh to get an average savings per kWh, rather than calculating specific expected savings for the demand and energy components of the bill, as they should have. Had the estimated bill savings included both the demand and energy components, the actual bill savings would have been more in line with or even surpassed their expectations. As a result, the estimated bill savings from the reduction in monthly kWh were overstated compared to the actual bill reduction.

## V. STAFF'S RECOMMENDATION FOR CUSTOMER EDUCATION ON THREE-PART RATES

**Q. DO YOU AGREE WITH STAFF THAT CUSTOMER EDUCATION IS AN IMPORTANT PART OF IMPLEMENTING THREE-PART RATES?**

A. Yes. APS believes that it is important to educate customers about all components of their bill, how the bill is calculated and the actions they can take to save and mitigate potential impacts from rate changes. This education can emphasize that under a three-part time-of-use rate, for example, the customer would have three ways to save on their

bill – lower their overall monthly energy use (or kWh), shift energy to the off-peak hours, and lower their monthly peak usage (kW demand) during a specific on-peak period.

Customer education would also focus on the use of modern technologies such as home energy monitors and controls, smart thermostats, advanced air-conditioners, battery storage, and smart inverters. These devices help manage and reduce peak usage, thus allowing customers to better manage and reduce their bills.

**Q. DOES THIS EDUCATION HAVE TO BE HIGHLY COMPLICATED AS SUGGESTED BY TASC?**

A. No. Not at all. We have found that the demand charge concept and strategies to save can be, and should be, explained very simply for the general customer group. Customers don't need an energy engineer in their home, as suggested by TASC in a Salt River Project proceeding, to understand either. Additional detailed information can be made available on the utility's website, or through other education channels, for the customers that are interested in learning about further specific details.

**Q. DOES APS HAVE ANY EXAMPLES OF THIS EDUCATION MATERIAL?**

A. Yes. Attachment CAM-2SR is a sample draft customer education piece we are currently developing as we contemplate proposing an expansion of our three-part rate program. The piece is not yet complete. However, APS thought it could be helpful to provide examples of education concepts. *See also* APS's response to RUCO Data Request 1.6, which is attached as Attachment CAM-3SR and incorporated into my Surrebuttal Testimony by this reference. This material includes information used for our current three-part rate program.

## VI. UNSE'S PROPOSAL FOR A SOLAR PURCHASE RATE

**Q. WHAT DOES UNSE PROPOSE CONCERNING A SOLAR PURCHASE RATE?**

UNSE proposes that excess power from rooftop solar that flows back to the grid be purchased by the utility at a solar purchase rate and credited on the bill each month. Their proposed solar purchase rate reflects the purchase price from a large grid-scale solar plant, which would be revised from time to time.

**Q. WHAT IS APS'S POSITION?**

A. APS believes that the best rate for excess power would be an avoided cost rate. UNSE's proposed purchase price from a grid-scale solar plant could be reasonable, but should be the maximum considered for purchase of excess generation from rooftop solar.

## VII. CONCLUSION

**Q. PLEASE SUMMARIZE YOUR CONCLUSIONS.**

A. APS recommends that the Commission approve three-part demand rates for UNSE residential customers. This is consistent with the proposals made by Staff and UNSE in their Rebuttal Testimony. APS also recommends that the Commission adopt Staff's recommendation for a transition period combined with customer education. APS further recommends adoption of UNSE's net metering proposal.

**Q. DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?**

A. Yes.

# 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

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

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
Page 2 of 2

**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)**

| % Customers | Total kWh | On-Pk kWh | Off-Pk kWh | On-Pk kW | % Total kWh | % On-Pk kWh | % Off-Pk kWh | % On-Pk kW | Summer Bill [1] $ 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% |

**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 % Customers | Total kWh | On-Pk kWh | Off-Pk kWh | On-Pk kW | % Total kWh | % On-Pk kWh | % Off-Pk kWh | % On-Pk kW | Annual Bill [1] $ 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**

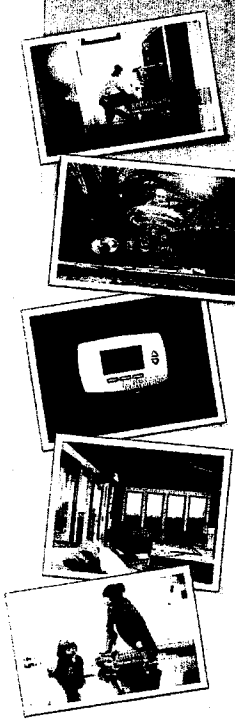
**Three-part Demand Rate (Time-of-use)**
**ECT-2 Average Monthly Bill [1]**

| % 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.



If you're able to make slight changes to when and how you use energy, you can lower your energy bill and save. Here are some simple suggestions.

**1) Stagger the use of major appliances (AC, oven, dryer, electric water heater).**
When possible, wait to do laundry until later in the evening after you are done cooking dinner.

**2) Run appliances during non-peak usage times**
Set your dishwasher to run on a delay cycle and put your pool pump on a timer.

**3) Consider home automation products**
Programmable thermostats and load controllers are a great way to reduce your peak usage without giving it a second thought. Set your parameters, and the products do all the managing for you.

**4) Lower your overall usage**
Take advantage of some basic energy-efficiency programs, tips and tools – turning off lights and fans when leaving a room, setting your thermostat a few degrees higher in the summer and lower in the winter, switching to LEDs, and taking our Energy Analyzer online survey, to name just a few.

Back Cover
(Illustrative draft materials – Rev 4)



# Lower Your Peak Usage and Save Money

Cover
(Illustrative draft materials – Rev 4)

## Understanding [illegible]

Simply put, peak usage is [illegible] greatest on weekdays when [illegible] – not just one moment in time. And [illegible] energy use.

Let's take a look at an example of two customers – with identical appliances – who have different peak usage numbers based on how many appliances they're using **at the same time**:

### STEVE

Steve, who puts a priority on comfort and convenience, comes home from work and…

- Turns his AC down to **75°**
- Cooks dinner
- Starts a few loads of laundry
- Has the TV on

**STEVE'S HOME**

| | | |
|---|---|---|
| Air Conditioner | On | 3.8 kW |
| Oven | On | 1.3 kW |
| Washer | On | 0.4 kW |
| Dryer | On | 1.9 kW |
| Television | On | 0.1 kW |
| **Peak Usage** | | **7.5 kW** |

### JAMIE

Jamie, who is more concerned with cost-savings, comes home from work and…

- Turns her AC down to **79°**
- Cooks dinner
- Has the TV on

**JAMIE'S HOME**

| | | |
|---|---|---|
| Air Conditioner | On | 2.5 kW |
| Oven | On | 1.3 kW |
| Washer | Off | 0.0 kW |
| Dryer | Off | 0.0 kW |
| Television | On | 0.1 kW |
| **Peak Usage** | | **3.9 kW** |

(Examples are based on 1,800 sq. ft. homes during a typical summer evening)

## Who Will Save More Money?

It's no surprise that Jamie's peak usage is almost half that of Steve's since she is not running all her major appliances at once. So while Steve will pay his typical bill amount, **Jamie will save approximately $20 on her bill.** Why? Because the lower your peak usage, the greater your savings.

# 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 1.6: APS'S Residential Three-Part Demand Charge Based Rates - What programs, tools, or customer support does APS provide for customers on their demand charge based rates? Please explain how APS currently educates customers who switch to a demand charge based rate? Does APS see their education strategy changing over time?

Response: APS customers receive information on available rate plans, including the Company's three-part residential demand rate, in several ways.

Customers calling APS requesting to set up a new account are asked a set of questions about lifestyle choices and property characteristics designed to assist both the customer and the call center associate to determine which rate plan might be the most beneficial to the customer (for example: Do you have gas service at your home? Does your home have a pool? Are you at home during daytime hours?).

Call center associates also provide a description of how APS's three-part residential demand rate works when an existing customer contacts APS through the call center to inquire about changing rate plans. In addition, customers that request additional information will be directed to aps.com or, if the customer cannot access the website, a letter can be sent that explains each of the available residential rate plans (this letter is attached to this response as APS15759).

In each of the Company's customer service offices brochures are available to residential customers that discuss each of the available rate plans to assist customers in determining which plan might be appropriate for their circumstances. This brochure is attached as APS15760.

The above information is also available at aps.com for customers to review at any time. In addition, to assist customers in choosing an appropriate rate plan, the Company offers a rate comparison tool for existing customers that will use the customer's actual energy usage history to provide an overview of each available rate plan. This information is accessed through each customer's individual online account. Screenshots of this tool are attached as APS15761.

APS provides customers with information regarding rate plans and rate plan options on an ongoing basis and will continue to assess new education strategies.

Witness: Charles Miessner

January 6, 2016

JOE & MARY SMITH
400 N 5TH ST
PHOENIX AZ

Dear Joe & Mary Smith:

Thank you for contacting APS regarding our residential service plan options. We recognize that when it comes to energy usage, different people have different needs. That's why we offer several electric service plans - so you can find the one that is most convenient for your lifestyle and saves you the most money. Please see the detailed information that is included in this letter for more information.

Additionally, you can find complete information on our Web site at www.aps.com/rates, and can also perform a comparison and find out about other options such as Green Choice rates.

If you have any questions regarding this or need additional information, please feel free to contact our Customer Care Center at (602)371–7171 or (800)253–9405. Associates are available 24-hours-a-day. Or, visit us online at www.aps.com.

We appreciate your business and the opportunity to serve you.

Sincerely,

*Bernard*

Bernard
APS Customer Care Center

## Standard

This plan helps those who use less energy save money. It doesn't make any difference what time of day electricity is used. This plan may be best for you if:

- You generally use 1,000 kWh or less each month due to the size of your home and type of appliances.
- You live in a home, mobile home, condominium or apartment that is 1,100 square feet or less.
- You do not have a swimming pool or spa that is electrically heated.

Here's how it works:

- In the summer (May-October) you are billed at different costs per kilowatt hour (kWh) depending on your energy usage;
  - The first 400 are billed at about 9.7¢
  - The next 400 are billed at about 13.7¢
  - The next 2,200 are billed at about 16.3¢
  - All remaining kWh are billed at about 17.4¢
- In the winter (November-April) the cost is about 9.4¢ per kWh used.

## Time Advantage 7 p.m.-Noon

This plan is best for those who have minimal energy usage during on-peak periods (Noon-7 p.m., Monday-Friday), especially during the summer months. This plan may be best for you if:

- You generally use 1,000 kWh or more each month due to the size of your home and type of appliances.
- You are not home during the day or have low daytime energy use.
- You are able to use your dishwasher, dryer, washer and range more during off-peak hours.
- You are able to operate your major electric appliances such as the water heater, pool pump and spa heater during off-peak hours.
- You have a programmable thermostat or can set your air conditioning to a warmer temperature during on-peak hours.

Here's how it works:

- The plan is billed on an off-peak and on-peak basis.
- Off-peak hours are weekdays from 7 p.m. to Noon and all day Saturday and Sunday, as well as six major holidays*. Electricity used during off-peak hours is billed at a lower rate.
- On-peak hours are Monday through Friday from Noon to 7 p.m. and are billed at a higher rate.
- In the summer (May-October) you are billed at about 24.4¢ per kWh used on-peak, and 6.1¢ per kWh used off-peak.
- In the winter (November-April) you are billed at about 19.8¢ per kWh used on-peak, and 6.1¢ per kWh used off-peak.
  - *Note: The APS meter readers must have safe, unassisted access to physically touch the meter each month.*

## Combined Advantage 7 p.m.-Noon

This plan is best for those who have minimal energy usage during peak periods (Noon-7 p.m., Monday-Friday). You can save on your bill by adjusting when you use energy and how much you use at one time. This plan works just like the Time Advantage 7 p.m.-Noon plan, with one main difference:

- This plan has a Demand component, which is the largest portion of the bill and is billed in addition to the charge for on-peak and off-peak kilowatt hours used.
    - The Demand (kW) is the one on-peak 60-minute period of the billing cycle when you use the most electricity.

This plan may be best for you if:

- You are able to spread out your use of major appliances during on-peak hours, so you are not using them all at once.
- You are able to operate your major electric appliances such as the water heater, pool pump and spa heater during off-peak hours.

Here's how it works:

- The plan is billed on an off-peak and on-peak basis, with an on-peak demand component.
    - Off-peak hours are weekdays from 7 p.m. to Noon and all day Saturday and Sunday, as well as six major holidays*.
    - On-peak hours are Monday through Friday from Noon to 7 p.m. and are billed at a higher rate.
    - The Demand is the one on-peak 60-minute period of the billing cycle when you use the most electricity. It is also the largest component of the bill.
- The chart below shows the costs for the different timeframes and components of the bill:

| **Summer** (May-October billing cycle) | **Cost** |
|---|---|
| Demand charge (kW) | $13.404 per kW |
| On-peak kWh used | 8.845¢ per kWh |
| Off-peak kWh used | 4.363¢ per kWh |

| **Winter** (November-April billing cycle) | **Cost** |
|---|---|
| Demand charge (kW) | $9.203 per kW |
| On-peak kWh used | 5.815¢ per kWh |
| Off-peak kWh used | 4.273¢ per kWh |

- To save money, it is important for you to use more energy on weekends and weekday mornings before Noon or evenings after 7 p.m., since electricity used during off-peak hours costs less. It is also important to limit the number of appliances that you use at one time during on-peak hours in order to minimize the demand charge.
    - *Note: The APS meter readers must have safe, unassisted access to physically touch the meter each month.*

# Time Advantage Super Peak 7 p.m.-Noon

This plan is best for those who can significantly limit energy usage during peak (Noon-7 p.m., Monday-Friday) and Super Peak periods (3 p.m.-6 p.m. Monday-Friday, summer only). A smart meter must be installed at your home to select this rate. This plan works just like the Time Advantage 7p.m.-Noon plan, with one main difference:

- You are able to use more of your energy during off-peak hours, and can significantly limit your energy use during the summer between the hours of 3 p.m. and 6 p.m, Monday through Friday in the billing months of June through August.

Here's how it works:

- The plan is billed on an off-peak and on-peak basis, with a Super peak period in the summer billing months of June through August.
  - Off-peak hours are weekdays from 7 p.m. to Noon and all day Saturday and Sunday, as well as six major holidays*.
  - On-peak hours are Monday through Friday from Noon to 7 p.m. and are billed at a higher rate.
  - Super-peak hours are Monday through Friday from 3 p.m.-6 p.m. in the billing months of June through August and are billed at the most expensive cost per kWh on this plan.
- The chart below shows the costs per kWh for the different timeframes:

| Off-peak | Nov-Apr Per kWh | May, Sep, Oct Per kWh | Jun-Aug Per kWh |
|---|---|---|---|
| 7 p.m.-Noon, Mon-Fri | 5.253¢ | 5.254¢ | 5.254¢ |
| All day Sat-Sun and six holidays | 5.253¢ | 5.254¢ | 5.254¢ |

| On-peak (Mon-Fri) | Nov-Apr Per kWh | May, Sep, Oct Per kWh | Jun-Aug Per kWh |
|---|---|---|---|
| Noon-3 p.m. | 19.825¢ | 24.445¢ | 24.445¢ |
| 3 p.m.-6 p.m. | 19.825¢ | 24.445¢ | 49.445¢ |
| 6 p.m.-7 p.m. | 19.825¢ | 24.445¢ | 24.445¢ |

- To save money, it is important for you to use more energy on weekends and weekday mornings before Noon or evenings after 7 p.m., since electricity used during off-peak hours costs less.

***Holidays for 7 p.m.-Noon Rate Plans:**
New Year's Day (January 1)
Memorial Day (last Monday in May)
Independence Day (July 4)
Labor Day (first Monday in September)
Thanksgiving Day (fourth Thursday in November)
Christmas Day (December 25)

NOTE: If these holidays fall on a Saturday, the preceding Friday will be off-peak. If they fall on a Sunday, the following Monday will be off-peak.

### Time Advantage
### 7 p.m. – Noon

This plan is best if you use more energy during off-peak times (7 p.m. to Noon Monday – Friday, weekends all day and select holidays). Consider this plan if you:

- Use 1,000 kWh or more each month and don't use much energy during on-peak periods (Noon to 7 p.m., Monday – Friday).
- Use your dishwasher, washing machine, dryer and range more during off-peak hours.
- Use other major electric appliances such as water heater, pool pump and spa heater during off-peak hours.
- Have a programmable thermostat or can set your AC to a warmer temperature during on-peak hours.

### Combined Advantage
### 7 p.m. – Noon

This plan is best if you use more energy during off-peak times (7 p.m. to Noon Monday – Friday, weekends all day and select holidays). Consider this plan if you:

- Use 1,000 kWh or more each month.
- Use your dishwasher, washing machine, dryer and range more during off-peak hours.
- Use more energy during off-peak hours and use a timer to run major appliances (water heater, pool pump, spa heater).
- Have a programmable thermostat or can set your AC to a warmer temperature during on-peak hours.
- Can stagger your use of major appliances during on-peak hours so you're not using them simultaneously.

### Time Advantage Super Peak
### 7 p.m. – Noon

If you can reduce your energy usage by 20% or more during super peak hours of 3 p.m. and 6 p.m. during weekdays, June through August and use most of your energy during off-peak hours this plan may be best for you. Consider this plan if you:

- Use 1,000 kWh or more each month.
- Use your dishwasher, washing machine, dryer and range more during off-peak hours.
- Use your major appliances (water heater, pool pump, spa heater) during off-peak hours.
- Have a programmable thermostat or can set your AC to a warmer temperature during on-peak and super-peak hours.

### APS Peak Time Rebate

Our Peak Time Rebate program is designed to help you save energy and money. By participating in this unique program, you can actually earn money by reducing your energy use during peak time events—times when energy demand is at its highest.

- We will designate from 6 to 18 peak time events from June through September.
- Events will not take place on weekends or holidays.
- Each event will last for five hours between 2 p.m. and 7 p.m.

For additional information about our Peak Time Rebate program, call us at (602) 371-3660 (metro-Phoenix) or (800) 659-8148 (other areas).

## APS Service Plans to fit your lifestyle

aps.com/plans

aps

APS15760
Page 1 of 2

## Find the Service Plan that's right for you

Not everyone uses energy the same way. To help you manage your usage and save money on your energy bill, APS offers a variety of service plans. To find the plan that's right for your lifestyle, visit aps.com/compare and use the Rate Comparison tool. You'll see how energy costs on your current plan compare to estimated costs on other plans. Check it out today.

## The Standard Plan

The Standard Plan helps you save if you have a small home and your energy use is low. And it doesn't make any difference what time of day you use the electricity. Your bill will simply depend on the total amount of electricity you used, not when you used it.

Consider this plan if you:

- Live in a home or apartment that is 1,100 square feet or less.
- Generally use 1,000 kilowatt-hours or less each month; and
- Do not have a swimming pool or electrically heated spa.

## How the Standard Plan helps you save

Designed to encourage customers to conserve energy, the Standard Plan price goes up as your use increases—giving you an incentive to use less electricity per month.

- May through October – the cost per kWh increases after 400 kWhs and again after 800 kWhs.
- November through April – there is just one price per kWh.
- Learn more at aps.com/plans.

## Time-of-Use (TOU) Service Plans

On a TOU plan, you pay a lower price for electricity during off-peak hours, but pay a higher price during on-peak hours. To save money, it is important to shift more of your energy use to off-peak hours. Learn more at aps.com/plans.

## Off-Peak holidays for Time-of-Use Plans

The following six holidays are considered off-peak times all day long: New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day.

If one of these holidays falls on a Saturday, the preceding Friday will be off-peak. If it falls on a Sunday, the following Monday will be off-peak.

## What's a kilowatt hour (kWh)?

A kilowatt-hour (kWh) is a unit of measurement for electricity, just as a gallon is a unit of measurement for gasoline or water. A kWh is 1,000 watts of electricity used for one hour. For example, the amount of electricity that ten 100-watt light bulbs use during one hour is one kWh (ten 100-watt bulbs X one hour equates to one kWh).

APN#00127169 (8/2015) CS#1508087

**Login with username and password**

my account | logout

aps | search

my bill | my energy | my rebates & renewables | my profile & preferences | help & support

my account

your payment of $100.00 is past due as of january 05, 2016 | total amount due : $100.00

what do you want to do today?

see more
+-

## summary of what you owe

for service at:
plan: combined advantage 7pm - noon

bill date: december 24, 2015
view bill | print page

| previous bill | last payment | balance forward | new charges | total amount due |
|---|---|---|---|---|
| $403.39 | ($100.48) on dec 28, thank you | $101.68 | $100.00 | $100.00 due date: jan 05 |
| billing history | payment history | daily & hourly usage | usage history | |

## property details

download property data

| address and plan type | total electricity used (kWh) | on-peak | off-peak | other peak | demand | total electric charges |
|---|---|---|---|---|---|---|
| | 768 | 164 | 604 | | 3.6 | $100.00 |
| plan: combined advantage 7pm - | usage history | | | | | charge breakdown |

**Select my energy > compare service plans**

my account | logout

aps | search

my bill | my rebates & renewables | my profile & preferences | help & support

my ac

total amount due : $100.00

what do

## summary of what you owe

for service at:
plan: combined advantage 7pm - noon

bill date: december 24, 2015
view bill | print page

my account | logout

aps

search

my bill | my energy | my rebates & recognition | my profile & preferences | help & support

residential service plans

home

last payment of $100.00 received on december 21, 2016

equalizer payment due : $0.00

# residential service plan compare

for service at:
plan: combined advantage 7pm - noon

plan comparison tool

The results of your service plan comparison are listed below. The rate comparison tool provides a forecast of your energy costs and usage for the next 12 months. This data is based on our current pricing and your usage history.

Based on your usage history, the Time Advantage 7pm-noon may be better suited to you. Projections are based on estimated on-peak usage. Your costs may vary depending on your ability to shift usage to off-peak hours.

If you feel another plan may better suit your lifestyle, you can request a service plan change.

For additional information regarding our service plans please review our service plan pricing and details.

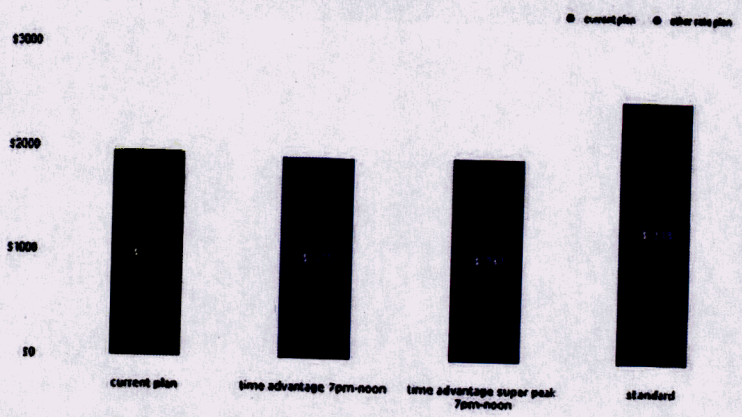
We encourage our customers to perform a comparison each year to ensure they are still on the best service plan. If you have decided you would like to change your rate plan, please proceed.

APS does not make adjustments or refunds based on this information.

Please take a moment to complete a brief survey about your recent visit to aps.com. We value your feedback.

## your cost summary forecast for the next 12 months

based on your energy usage, you may save money on another rate plan.



**Recommended plan overview popup**

## plan: time advantage 7pm-noon

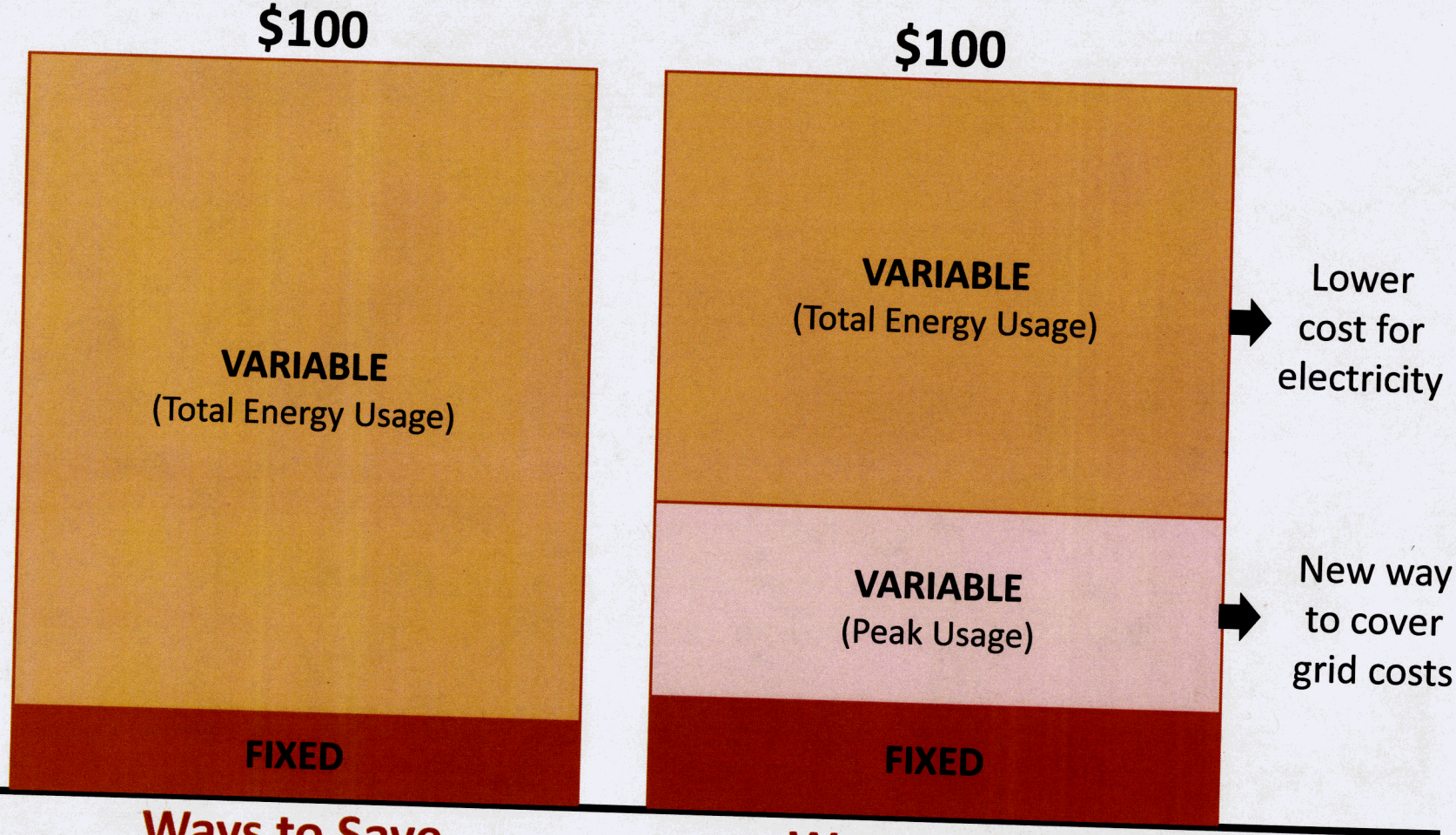
This plan is best if you don't use much energy during on-peak periods (noon – 7 pm, Monday - Friday).

best if you

- use 1,000 kWh or more each month
- aren't home during the day or don't use much energy during on-peak periods
- use your dishwasher, washing machine, dryer and range more during off-peak hours
- use your major electric appliances (water heater, pool pump, spa heater) during off-peak hours
- have a programmable thermostat or can set your AC to a warmer temperature during on-peak hours

EXHIBIT
APS-8
admitted

# Demand Rates: A New Way to Slice the Pie



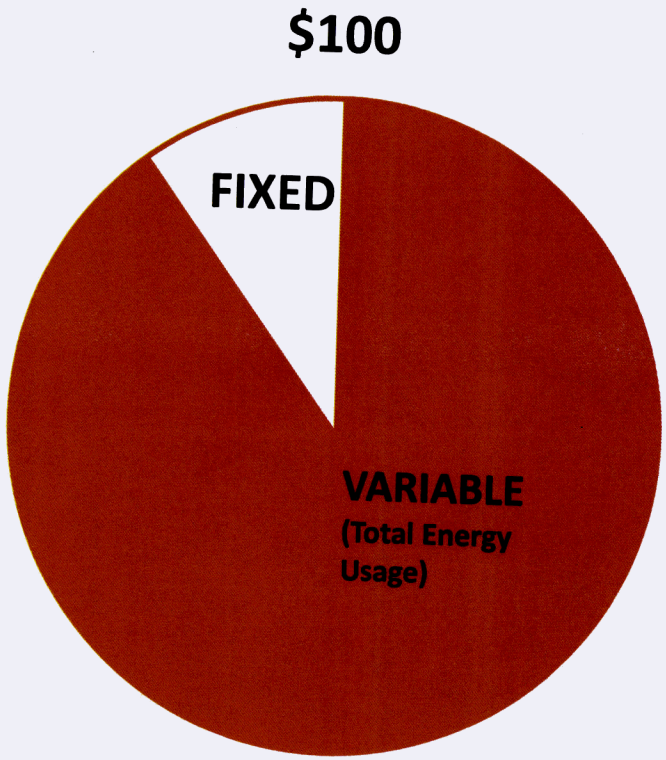

## Ways to Save

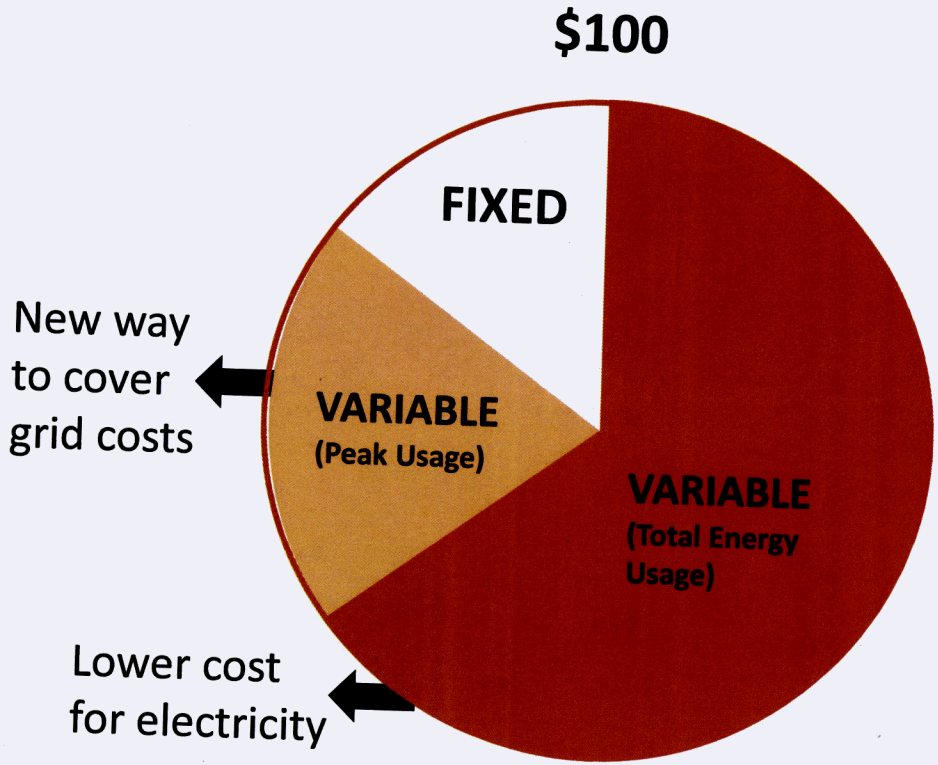
- Lower Your Overall Usage

## Ways to Save

- Lower Your Overall Usage
- Stagger the use of major appliances (AC, oven, dryer, electric water heater)
- Run appliances during non-peak usage times
- Consider home automation products

# Demand Rates: A New Way to Slice the Pie




## Ways to Save

- Lower Your Overall Usage

## Ways to Save

- Lower Your Overall Usage
- Stagger the use of major appliances (AC, oven, dryer, electric water heater)
- Run appliances during non-peak usage times
- Consider home automation products

# How to Manage Your Peak Usage and Save

If you're able to make slight changes to when and how you use energy, you can lower your energy bill and save. Here are some simple suggestions.

1) **Stagger the use of major appliances (AC, oven, dryer, electric water heater)**
When possible, wait to do laundry until later in the evening after you are done cooking dinner.

2) **Run appliances during non-peak usage times**
Set your dishwasher to run on a delay cycle and put your pool pump on a timer.

3) **Consider home automation products**
Programmable thermostats and load controllers are a great way to reduce your peak usage without giving it a second thought. Set your parameters, and the products do all the managing for you.

4) **Lower your overall usage**
Take advantage of some basic energy-efficiency programs, tips and tools – turning off lights and fans when leaving a room, setting your thermostat a few degrees higher in the summer and lower in the winter, switching to LEDs, and taking our Energy Analyzer online survey, to name just a few.

Back Cover
(Illustrative draft materials – Rev 4)

# Lower Your Peak Usage and Save Money

Cover
(Illustrative draft materials – Rev 4)

## Understanding How Peak Usage Impacts Your Bill

Simply put, peak usage is your **highest one hour** of energy use during times when there is already a lot of demand for energy; Energy demand is at its greatest on weekdays when Arizonans are coming home from school or work. Your peak usage is averaged over an entire hour – a full 60 minutes – not just one moment in time. And since there's a direct tie between your peak usage and your bill amount, you can save money by managing your energy use.

Let's take a look at an example of two customers – with identical appliances – who have different peak usage numbers based on how many appliances they're using **at the same time**.

### STEVE

Steve, who puts a priority on comfort and convenience, comes home from work and…

- Turns his AC down to **75°**
- Cooks dinner
- Starts a few loads of laundry
- Has the TV on

**STEVE'S HOME**

| | | |
|---|---|---|
| Air Conditioner | On | 3.8 kW |
| Oven | On | 1.3 kW |
| Washer | On | 0.4 kW |
| Dryer | On | 1.9 kW |
| Television | On | 0.1 kW |
| **Peak Usage** | | **7.5 kW** |

### JAMIE

Jamie, who is more concerned with cost-savings, comes home from work and…

- Turns her AC down to **79°**
- Cooks dinner
- Has the TV on

**JAMIE'S HOME**

| | | |
|---|---|---|
| Air Conditioner | On | 2.5 kW |
| Oven | On | 1.3 kW |
| Washer | Off | 0.0 kW |
| Dryer | Off | 0.0 kW |
| Television | On | 0.1 kW |
| **Peak Usage** | | **3.9 kW** |

(Examples are based on 1,800 sq. ft. homes during a typical summer evening)

## Who Will Save More Money?

It's no surprise that Jamie's peak usage is almost half that of Steve's since she is not running all her major appliances at once. So while Steve will pay his typical bill amount, **Jamie will save approximately $20 on her bill**. Why? Because the lower your peak usage, the greater your savings.

EXHIBIT
APS-9
admitted

# ARISEIA Energy Forum
# APS Residential Rate Design

A Brief History and What's Next for Arizona?
November 7, 2015

Leland Snook
Director,
Rates and Rate Strategy

aps

# Arizona Public Service Company

## Arizona's largest and longest-serving electric utility

**Customers:** 1.2 million (89% residential)

**Service Territory:**

- 34,646 square miles
- 11 of the 15 Arizona counties

**2015 Peak Demand:** 7,031 MW

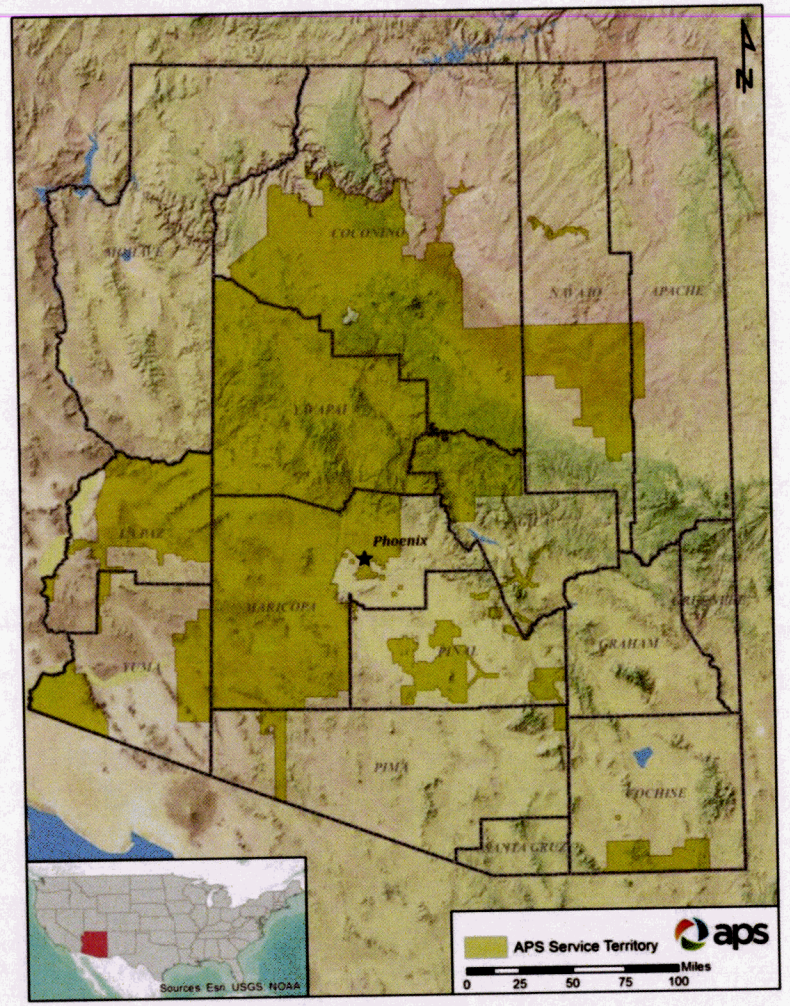
- All time high of 7,256 in July 2009

**Generation Capacity:** Over 6,400 MW of owned or leased capacity (~9,400 MW with long-term contracts)

- Including 29.1% interest in Palo Verde Nuclear Generating Station, the largest in the U.S.

**Transmission & Distribution:** 34,937 miles

- Transmission: 5,958 miles
- Distribution: 28,979 miles



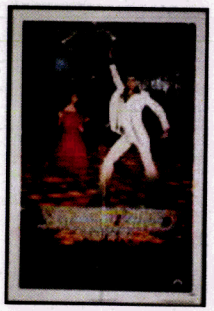
# APS's TOU & Demand Rate Evolution

## Mid 1970's

Residential use of **central air conditioning (AC)** flourishes in the Phoenix area – begins to **drive system peak** demand

## Late 1970's

APS requests approval of a mandatory residential **demand rate** for any new home with **central air conditioning** - charges based on 1) the highest kW demand in a single hour; 2) kWh energy consumed; and 3) a basic service charge



## Early 1980's

APS implements **inclining block** and **TOU** rates and demand rate becomes voluntary

## Early 1990's

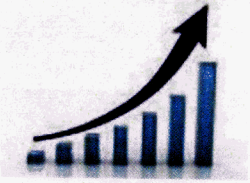
Almost all TOU Adoption is demand based

## Early 2000's

TOU Adoption exceeds **40% and demand adoption ebbs to just over 7%**

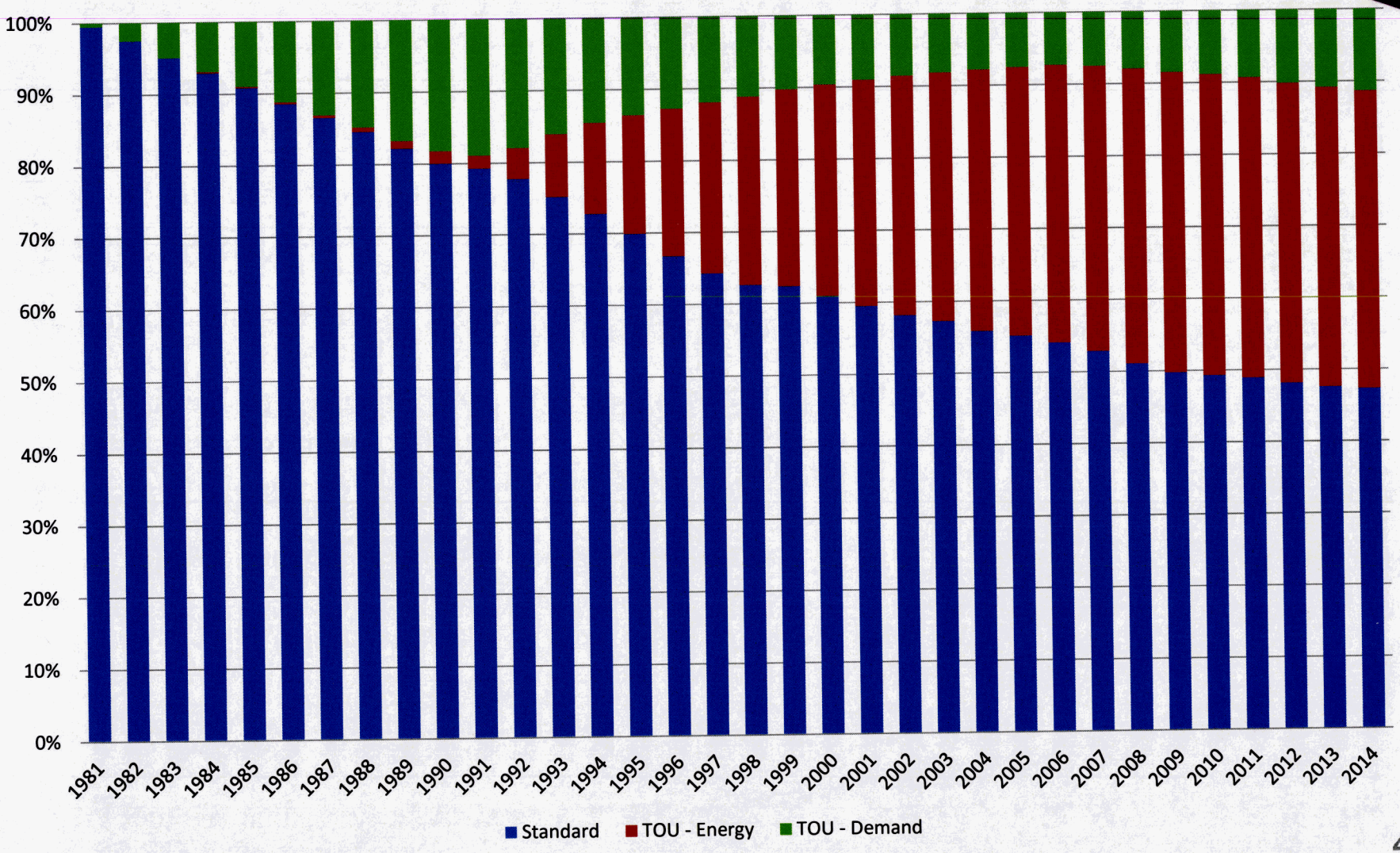
## Today

**Over 11% (117,000)** of residential customers are on a **demand rate** and TOU adoption is approximately **53%**



# APS

## Historic Customer Count Percentage
## Standard vs. Time of Use



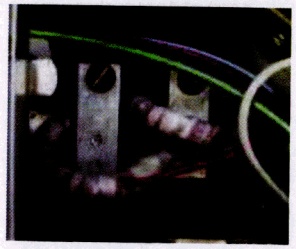
# How did APS reach 53% TOU and 11% demand rate adoption?

## Point of Sale

**Leverage** the new service process to **educate** customers on their rate options and the **best rate fit**

## Technology Enhancements

Initially, residential demand rates were marketed with **load control technology** that would limit peak demand, for example, by **limiting** an electric clothes dryer or electric water heater **from turning on at the same time** as an air conditioning unit



## Rate Calculator and Customer Lifestyle

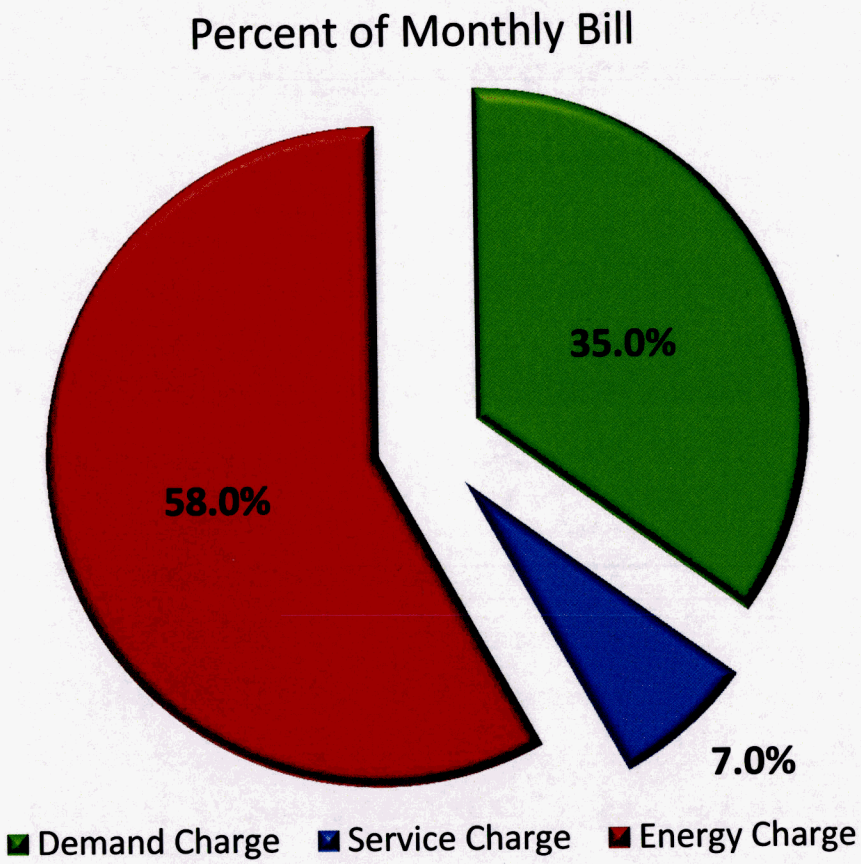
Average monthly consumption is very different for each rate family:

Inclining Block Rate = **700 kWh**

Energy Only TOU = **1,300 kWh**

Demand Based TOU = **2,000 kWh**

# Today's Residential TOU-Demand Rate




**Service Charge ($ per Month)**

| | | |
|---|---|---|
| All Service Amps | $ | 16.91 |

**Demand Charges ($ per kW)** [1]

| | | |
|---|---|---|
| Summer | $ | 13.50 |
| Winter | $ | 9.30 |

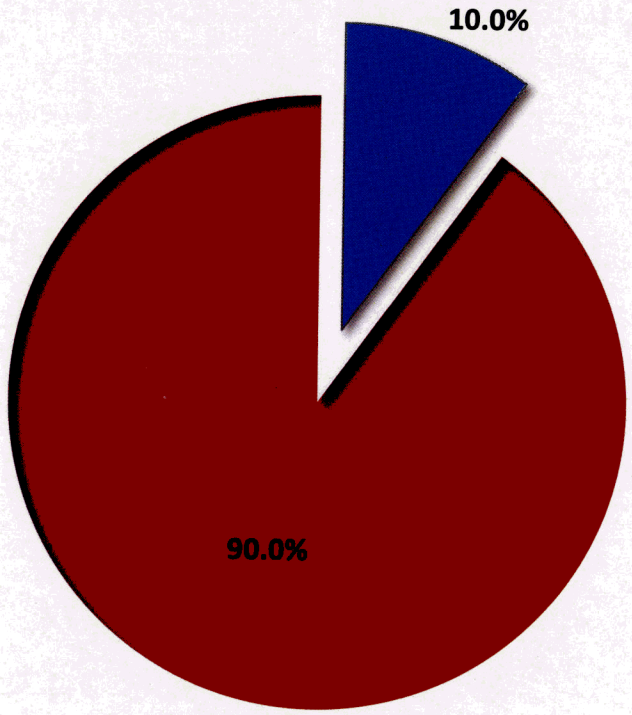
**Energy Charges ($ per kWh)**

| | Peak [2] | Off Peak |
|---|---|---|
| Summer | 0.08867 | 0.04417 |
| Winter | 0.05747 | 0.04107 |

1. Demand is based on the highest one-hour kW read during on-peak hours in a billing month.
2. On peak hours are 12 noon to 7 pm, excluding weekends and holidays.

# Today's Residential TOU-Energy Rate

Percent of Monthly Bill




Service Charge  Energy Charge

**Service Charge ($ per Month)**

| | |
|---|---|
| All Service Amps | **$ 16.91** |

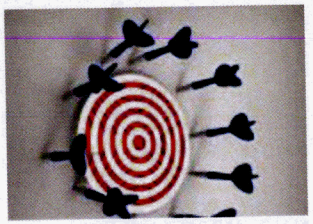
**Energy Charges ($ per kWh)**

| | Peak [1] | Off Peak |
|---|---|---|
| Summer | **0.24477** | **0.06118** |
| Winter | **0.19847** | **0.06116** |

1. On peak hours are 12 noon to 7 pm, excluding weekends and holidays.

# APS TOU & demand lessons learned

## Should be based on cost



Price signals drive behavior - **poor price signals** will potentially lead to **bad results**

## Designs should be adaptable and flexible

**Update peak periods** as peaks shift over time **and update price signals** as market costs evolve

## Customers respond to price signals

TOU energy customers reduce their peak by **5%** on average

TOU Demand customers further reduce their peak by **4-5%**

## Demand rates have become more essential

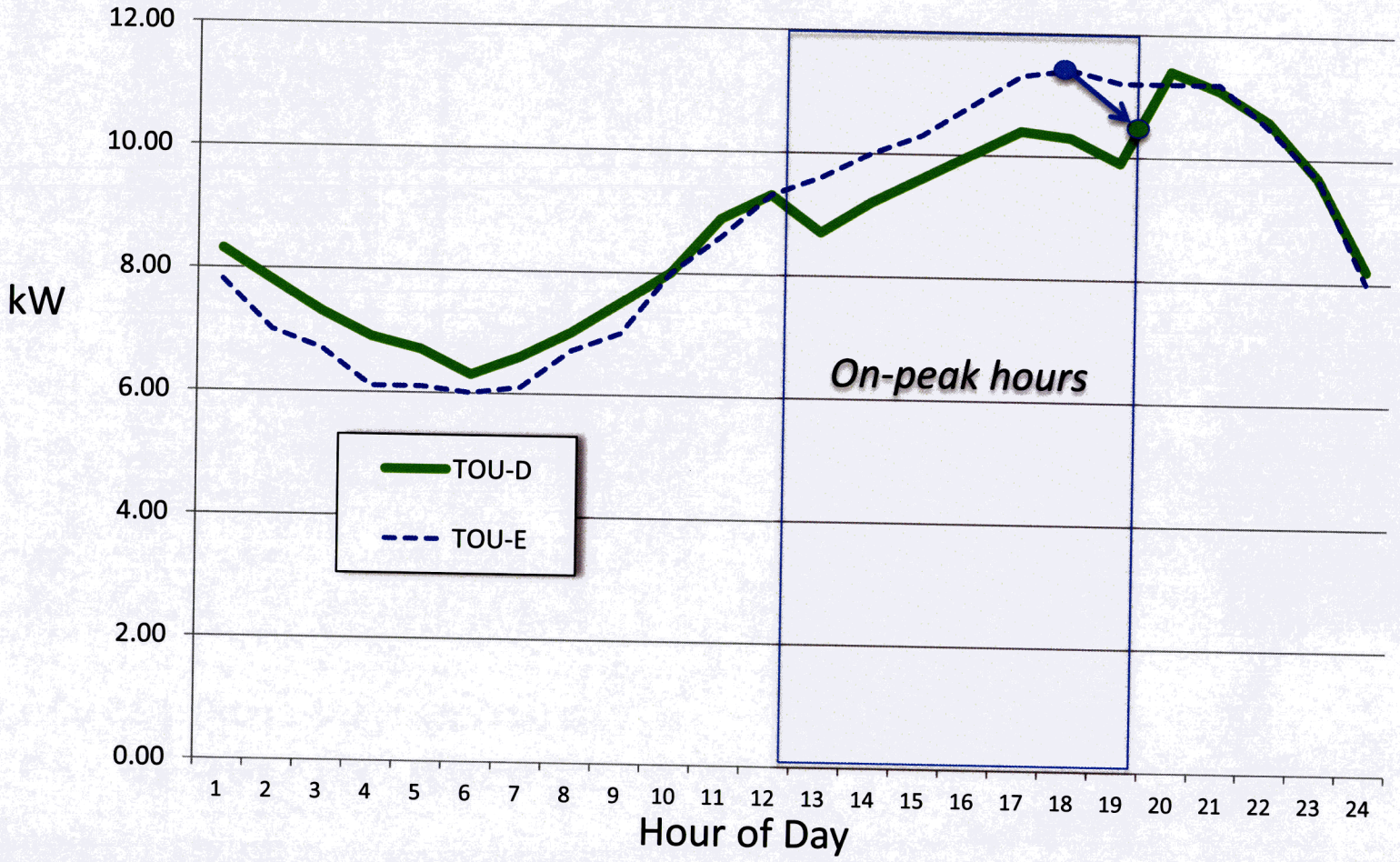
Better **price signals** to customers so they can make **informed decisions**

## Technology removes barriers

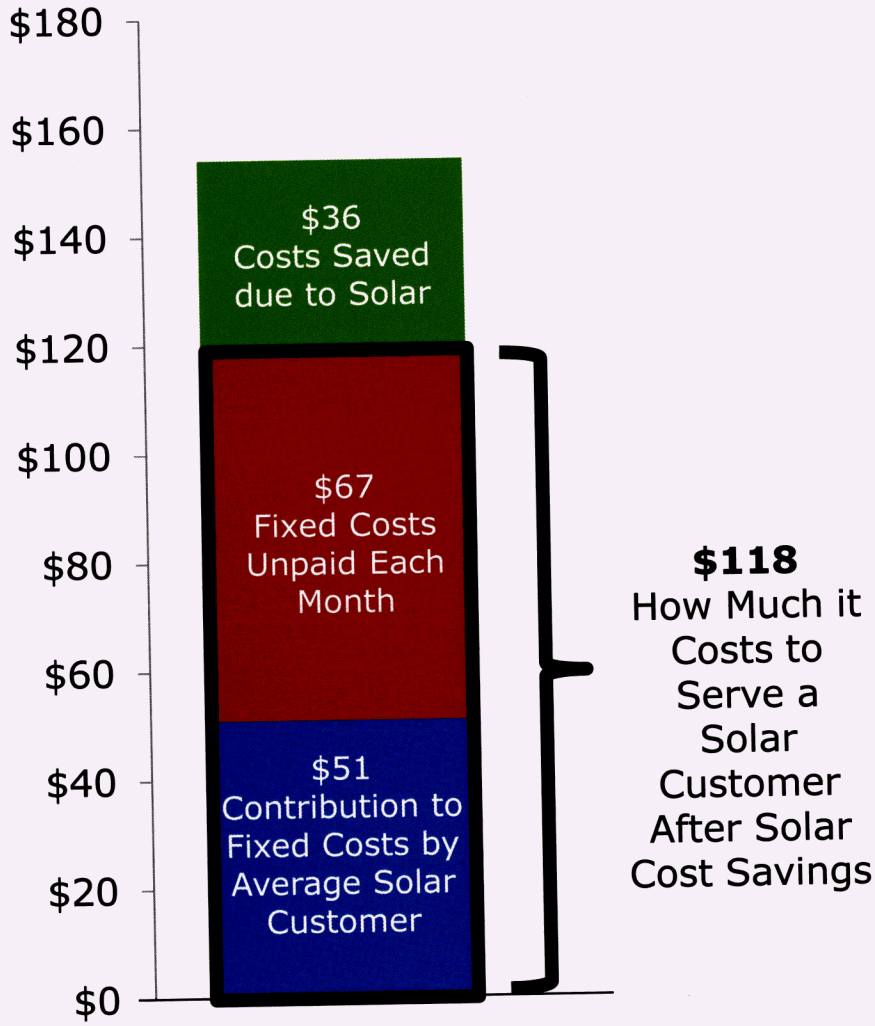
Today's metering devices allow us to more precisely **match cost recovery** with the **costs to provide service**

# Peak Day Load Shapes

## TOU-Demand, TOU-Energy
## kW per hour of day, July peak day

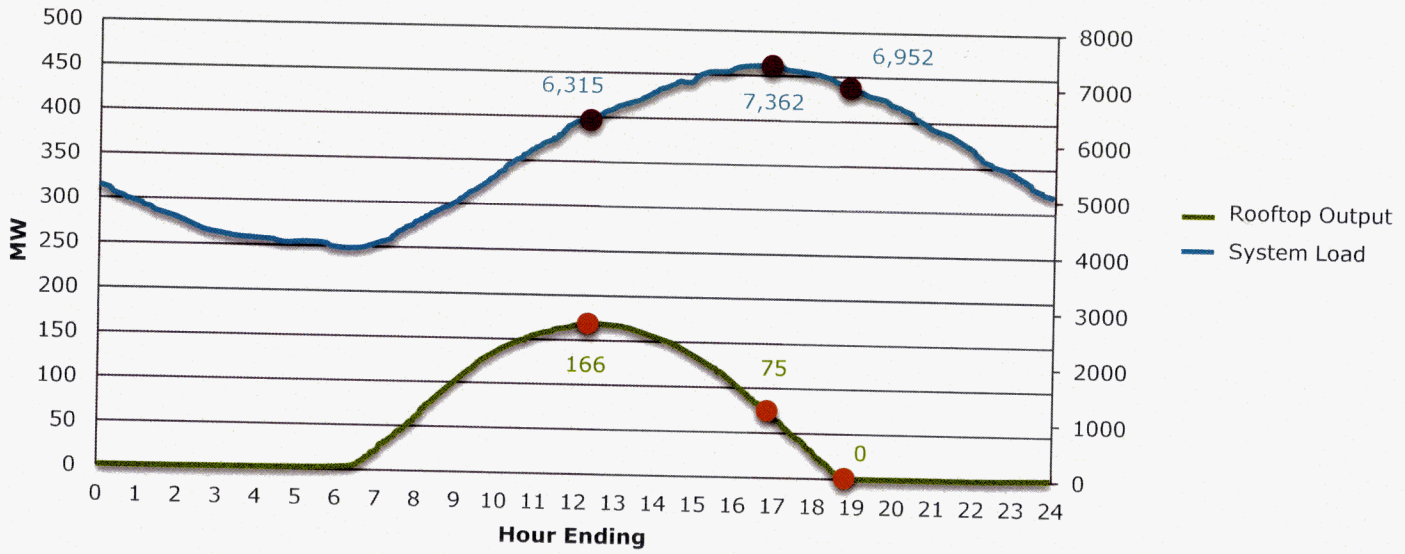


# Cost of Service Results for A Typical Solar Customer




- APS had over 27,000 solar customers on energy rates and almost 1,200 on demand rates in 2014
- Study includes both the costs and the benefits of rooftop solar
- Solar customers were only allocated cost for the portion of system they used
- Study used actual 2014 load and solar production data to analyze how solar systems produced at the time of system and class peaks
- APS System peaks occurred from 5 to 6 pm, but system peak is broad and persists from 3 to 10 pm
- Residential customers peak around 7 pm, with a broad class peak that persists from 3 to 10 pm
- Solar generation energy credit at actual fuel cost for 100% of solar production
- Solar generation capacity credit based on system and class peaks ~ residential solar offset about 19% of peak demand
- Transmission allocation/savings based on system peak
- Distribution allocation/savings based on class peaks

On August 15, 2015 the temperature in Phoenix reached 115 degrees. APS customers hit their peak demand, using more than 7,300 megawatts of electricity at approximately 5 PM. How did rooftop solar perform?

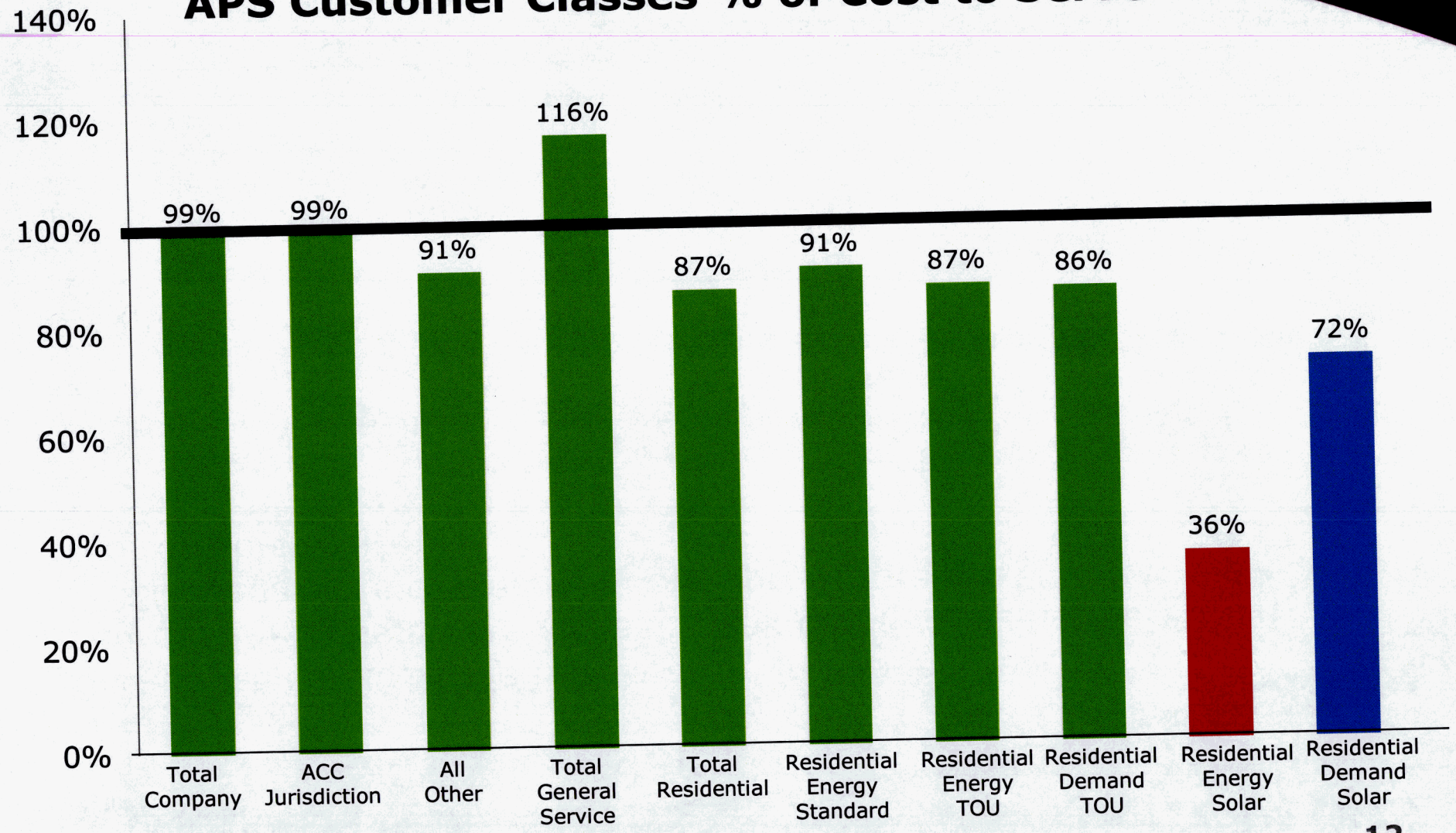



At noon, when customer demand is still increasing, rooftop solar peaks and begins to decline.

By 5 PM, when customer demand peaked, rooftop units had declined to only 38% of their power.

At 7 PM, rooftop output dropped to zero, but customers still needed 6,900 MW of power.

# APS Customer Classes % of Cost to Serve



# Where is APS headed in residential rate design?

- The evolving grid with two-way power flows is driving the need for updated pricing structures
  - Today's metering technology has enabled a new level of sophisticated rate offerings
- Residential demand charges can work
  - APS started in 1981 and today, over 117,000 customers have voluntarily selected the rate
- Residential demand charges can be understood by residential customers
  - APS helps customers select the best rate at the time of new service or through website rate comparison tool
- Residential demand charges can reduce a customer's peak demand and result in a win for both the customer and the utility
- Technology can help simplify the customer experience and improve results
  - Such as smart thermostats, load control technology and battery storage

# Where is APS headed in residential rate design?

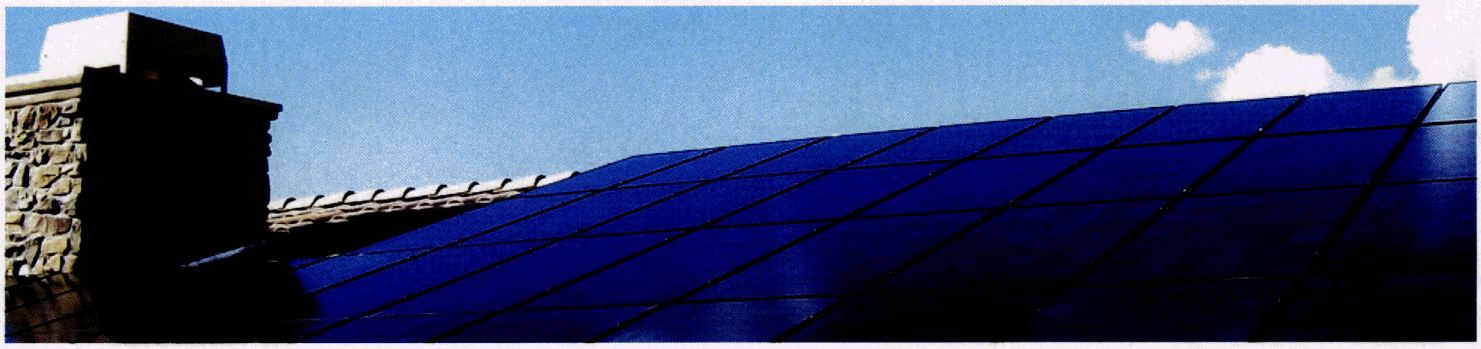
- APS wants to provide meaningful rate choices and will streamline its residential rate offerings
  - Replace current offerings with a new suite of offerings rather than freezing current rate plans
  - Need to be thoughtful in developing new rates for a relatively smooth transition
- APS is evaluating kW demand rates broadly for residential customers to modernize residential rate design
  - Better align rate offerings with costs and provide better price signals to customers
  - Demand measured over the on-peak period, even for non-TOU rates
- Update on-peak and off-peak time periods
- Update energy pricing
  - Inclining block rates - less tiers and more modest incline
  - TOU rates - reduced on-peak to off-peak ratio
- New suite of rates will likely include:
  - Inclining block option with demand
  - One or more TOU options with demand
  - A transitional extra-small customer rate without demand
  - Need thoughtful consideration of grandfathering for existing solar customers

# Where is APS headed in residential rate design – how would demand rates affect solar adoption?

- Demand rates would create opportunities
  - Shift the focus from energy savings to a combination of demand and energy savings
  - Expand the opportunities for suites of solutions, resulting in a more sustainable energy future
- Demand rates would drive a more holistic approach to behind-the-meter technology (BTM) and energy efficiency
  - Depending on customer lifestyle, it may require additional strategies to manage energy and demand (e.g. pairing pool pump run time with solar production)
  - Load management (technology to manage when energy is used by major appliances and air conditioning)
  - Pre-cooling strategy to manage early evening peak demand (smart thermostats)
- Demand rates would stimulate other innovative BTM technology
  - Energy storage
  - Smart appliances
  - Apps that manage the home in tandem with meaningful price signals

EXHIBIT
APS-10
admitted

**Call us today: 480.689.5000 | 888.5.SOLARUP**
**SOLAR ELECTRICITY FOR HOME AND BUSINESS**

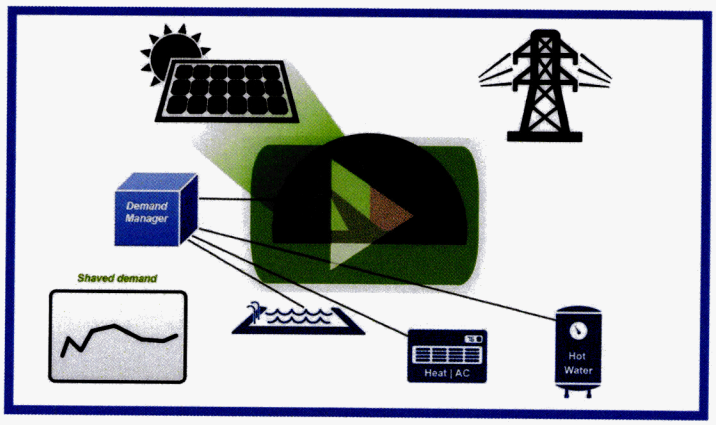


# SUN VALLEY SOLAR SOLUTIONS BRINGS SOLAR BACK TO SRP

Posted on March 10, 2016 by Kyle Ritland

**Sun Valley Solar Solutions is pleased to announce a new system that fully optimizes SRP's new solar rate plan, and allows customers to once again realize considerable savings when going solar in SRP territory.**

***"The rates rolled out by SRP last year include new demand fees for solar customers when their energy consumption exceeds their solar production during on-peak hours,"*** **explains**




Russ Patzer, CEO of Sun Valley Solar Solutions. "*Because these new charges are based on possible energy 'peaks' from future usage, it's difficult for solar providers like us toaccurately calculate a clear ROI with traditional solar.*"

Patzer continued, "*Our new solution relies on a proven demand management system that works in conjunction with rooftop solar to help homeowners better control SRP's new demand fees and avoid the additional charges.*"

At the core of Sun Valley Solar Solutions' new offering is a demand manager module that uses sophisticated software to monitor a home's energy use during SRP's on-peak hours of 1 pm to 8 pm weekdays in the summer, and 5 to 9 weekday mornings and evenings during the winter. When activated, the demand manager stabilizes a home's overall energy consumption for better alignment with solar production during those critical timeframes. This helps smooth out energy peaks that can result in costly demand fees.

Jennifer Holtzman of Gilbert was one of the first to install Sun Valley Solar's new smart solar system for SRP customers.

"*I had a very clear energy goal in mind, and so far the system is delivering exactly as promised,*" stated Holtzman. "*I've received two bills since installation. Both were more than 50% lower than the previous year. I'm so pleased that I'm already looking to expand the system to accommodate a new pool and additional outdoor living space.*"

Since late last year, Sun Valley Solar Solutions has installed more than a dozen smart solar systems with demand management throughout SRP territory. Positive results have been reported from all locations.

"*We're back in the business of helping SRP customers save money, and that's the best part,*" concluded Patzer. "*We're confident in the tools we now have to make good on that promise, and we're ready to work with any SRP homeowner who thought solar was no longer a viable option for them.*"

Watch the video and learn more about smart solar with demand management.

If you have any questions regarding this article, please contact Kyle Ritland at (480) 689-5027 or kyle.ritland@svssolutions.com.

Tagged News, Sun Valley Solar Solutions

EXHIBIT
AEC/HS-1
Architect

# 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 |

## Direct Testimony of Kevin C. Higgins

**on behalf of**

**Freeport Minerals Corporation,**

**Arizonans for Electric Choice & Competition and**

**Noble Americas Energy Solutions LLC**

**Rate Design**

**December 9, 2015**

## DIRECT TESTIMONY OF KEVIN C. HIGGINS

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KCH-1 ..... AECC/Noble Solutions Recommended Unbundled Rate Design

# DIRECT TESTIMONY OF KEVIN C. HIGGINS

## INTRODUCTION

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

A. Kevin C. Higgins, 215 South State Street, Suite 200, Salt Lake City, Utah, 84111.

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

A. I am a Principal in the firm of Energy Strategies, LLC. Energy Strategies is a private consulting firm specializing in economic and policy analysis applicable to energy production, transportation, and consumption.

**Q. On whose behalf are you testifying in this proceeding?**

A. My testimony is being sponsored by Freeport Minerals Corporation, Arizonans for Electric Choice and Competition ("AECC") and Noble Americas Energy Solutions LLC ("Noble Solutions"). AECC is a business coalition that advocates on behalf of retail electric customers in Arizona.[1] Noble Solutions is a retail energy supplier that serves over 15,000 commercial and industrial end-use customers in 16 states, the District of Columbia, and Baja California, Mexico, and supplies power to Arizona Public Service Company ("APS") that serves Experimental Rate Rider AG-1 ("AG-1") customers on the APS system.

**Q. Please describe your professional experience and qualifications.**

A. My academic background is in economics, and I have completed all coursework and field examinations toward the Ph.D. in Economics at the

[1] Henceforth in this testimony, Freeport Minerals Corporation and AECC collectively will be referred to as "AECC."

University of Utah. In addition, I have served on the adjunct faculties of both the University of Utah and Westminster College, where I taught undergraduate and graduate courses in economics. I joined Energy Strategies in 1995, where I assist private and public sector clients in the areas of energy-related economic and policy analysis, including evaluation of electric and gas utility rate matters.

Prior to joining Energy Strategies, I held policy positions in state and local government. From 1983 to 1990, I was economist, then assistant director, for the Utah Energy Office, where I helped develop and implement state energy policy. From 1991 to 1994, I was chief of staff to the chairman of the Salt Lake County Commission, where I was responsible for development and implementation of a broad spectrum of public policy at the local government level.

**Q. Have you testified before the Arizona Corporation Commission ("Commission") in other dockets?**

A. Yes. I have testified in approximately twenty proceedings before this Commission, including the generic proceeding on retail electric competition (1998),[2] the hearings on APS 1999 Settlement Agreement (1999),[3] the hearings on the Tucson Electric Power ("TEP") 1999 Settlement Agreement (1999),[4] the AEPCO transition charge hearings (1999),[5] the Commission's Track A proceeding (2002),[6] the APS adjustment mechanism proceeding (2003),[7] the

[2] Docket No. RE-00000C-94-0165.
[3] Docket Nos. RE-00000C-94-0165, E-01345A-98-0471, and E-01345A-98-0473.
[4] Docket Nos. RE-00000C-94-0165, E-01933A-97-0772, and E-01933A-97-0773.
[5] Docket No. E-01773A-98-0470.
[6] Docket Nos. E-00000A-02-0051; E-01345A-01-0822; E-00000A-01-0630; E-01933A-02-0069; E-01933A-98-0471.
[7] Docket No. E-01345A-02-0403.

Arizona ISA proceeding (2003),[8] the APS 2004 rate case (2004),[9] the Trico 2004 rate case (2005),[10] the TEP 2004 rate review (2005),[11] the APS 2006 interim rate proceeding (2006),[12] the APS 2006 rate case (2006),[13] TEP's request to amend Decision No. 62103 (2007),[14] the TEP 2007 rate case (2008),[15] the APS 2008 rate case (2008),[16] the APS 2011 rate case (2011-12),[17] the TEP 2011 Energy Efficiency Plan (2012),[18] the TEP 2012 rate case (2012),[19] and the APS Four Corners Rate Rider proceeding (2014).[20]

**Q. Have you testified before utility regulatory commissions in other states?**

A. Yes. I have testified in approximately 180 other proceedings on the subjects of utility rates and regulatory policy before state utility regulators in Alaska, Arkansas, Colorado, Georgia, Idaho, Illinois, Indiana, Kansas, Kentucky, Michigan, Minnesota, Missouri, Montana, Nevada, New Mexico, New York, North Carolina, Ohio, Oklahoma, Oregon, Pennsylvania, South Carolina, Texas, Utah, Virginia, Washington, West Virginia, and Wyoming. I have also participated in various Pricing Processes conducted by the Salt River Project Board and have filed affidavits in proceedings at the Federal Energy Regulatory Commission ("FERC").

[8] Docket No. E-00000A-01-0630.
[9] Docket No. E-01345A-03-0437.
[10] Docket No. E-01461A-04-0607.
[11] Docket No. E-01933A-04-0408.
[12] Docket No. E-01345A-06-0009.
[13] Docket No. E-01345A-05-0816.
[14] Docket No. E-01933A-05-0650.
[15] Docket No. E-01933A-07-0402.
[16] Docket No. E-01345A-08-0172.
[17] Docket No. E-01345A-11-0224.
[18] Docket No. E-01933A-11-0055.
[19] Docket No. E-01933A-12-0291.
[20] Docket No. E-01345A-11-0224.

1 **OVERVIEW AND CONCLUSIONS**

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

3 A. My testimony addresses the following topics in response to the general
4 rate case filing made by UNS Electric, Inc. ("UNSE" or the "Company"): (1) rate
5 spread, (2) cost of service, (3) the buy-through tariff presented by the Company
6 (Experimental Rider 14, Alternative Generation Service), and (4) unbundled rate
7 design for larger commercial and industrial customers.

8 Relative to the wide scope of this general rate proceeding, my testimony is
9 concentrated on a limited number of issues. Absence of comment on my part
10 regarding a particular issue does not signify support (or opposition) toward the
11 Company's filing with respect to a non-discussed issue.

12 **Q. What are your primary conclusions and recommendations?**

13 A. I offer the primary conclusions and recommendations:

14 (1) UNSE's proposed rate spread, or revenue apportionment, among
15 customer classes is generally reasonable. Even though UNSE's proposal results
16 in considerable cross subsidies remaining in rates, the Company is taking a step in
17 the direction of achieving a better alignment of class revenue requirement and
18 class cost of service while remaining consistent with the principles of gradualism.

19 (2) If a reduction to UNSE's proposed revenue requirement is approved
20 by the Commission I recommend that it be apportioned 50% to the subsidy-
21 paying classes (in proportion to their respective base revenue requirements) and
22 50% to the subsidy receiving classes (in proportion to their respective base
23 revenue requirements). Further, I recommend that the first $908 thousand of
24 revenue requirement reduction apportioned to the subsidy-paying classes should

be used to support the Experimental Rider 14 buy-through program, as discussed later in my testimony.

(3) I recommend adoption of the Average and Excess Demand method used by UNSE to allocate production cost, as this method is both well-accepted and fundamentally reasonable.

(4) I recommend adoption of a buy-through program that is as similar as reasonably possible to the AG-1 program approved for APS. A buy-through program provides commercial, industrial, and public sector customers with the opportunity to gain experience with market transactions and potentially reduce their energy costs, which enhances the economic development climate of the service territory and in the state generally. I recommend adopting some of the features of the buy-through program presented by UNSE, but modifying other features to make the program open to a wider variety of customers and to make it a more viable offering. Specifically, I recommend changes to program eligibility, pricing, terms for return to standard generation service, and the mechanics of fixed generation cost recovery. In particular:

(a) I recommend retaining the proposed 10 MW cap on participation proposed by UNSE, but broadening the range of eligible customers by allowing customers to participate with a minimum load size of 1 MW (peak demand) and allowing aggregation of smaller loads in the Medium and Large General Service classes owned by the same corporate entity to achieve that 1 MW threshold. I recommend that the term of the program be clarified to indicate that the buy-through program will continue at least until the start of the first rate-effective

period (following a general rate case) occurring no less than four years from the starting date of the buy-through program.

(b) The monthly management fee of $0.004/kWh for buy-through service proposed by UNSE is unreasonable and should be reduced to $0.0006/kWh, which is the management fee charged by APS for AG-1 service.

(c) Under the UNSE program, for the first twelve months of service under the rider, the generation-related component of the Demand Charge would continue to apply to 100% of the customer's billed demand, with this proportion decreasing to 25% after twelve months. While some assignment of cost for generation reserves may be appropriate, the UNSE proposal goes well beyond such a threshold and is more comparable to a stranded cost charge. The stranded cost approach should be rejected unless the customers are being provided with an opportunity to transition permanently to market pricing. Absent such an option, the going-forward charges for generation-related services should be limited to a charge for reserve capacity applied to 15% of the customer's billed demand priced at the unbundled generation demand charge, which is based on UNSE's planning reserve margin and is comparable to the AG-1 reserve capacity charge levied by APS.

In addition, I recommend that the first $908 thousand of any revenue requirement reduction apportioned to the subsidy-paying classes – which under my proposal are also the classes eligible for the buy-through program – be used to absorb UNSE's revenue deficiency ascribed to the loss of fixed generation revenues from buy-through customers. In this way, both UNSE and the customer

classes not eligible to participate in the program would be held harmless from adoption of the buy-through provision.

(d) If, prior to the end of the planned four-year term of the program, and absent Commission termination of the program, a buy-through customer seeks to return to standard generation service and does not provide one-year's notice, UNSE proposes to charge the returning customer the Dow Jones Electricity Palo Verde Daily Index price for the power delivery date plus $20 per MWh until the Company is reasonably able to integrate the customer back into the Company's generation planning. While I agree that this general approach is reasonable, I believe the proposed $20 per MWh mark-up is excessive and should be eliminated or significantly reduced to no greater than $4 per MWh.

(5) UNSE's unbundled rate design is seriously flawed in that the Company is improperly attempting to recover fixed generation-related costs in the unbundled Local Delivery component of the demand charge, contrary to the fundamentals of proper unbundled rate design. For this reason I recommend that UNSE's proposed relationship between delivery demand charges and generation capacity demand charges in its unbundled tariff for Medium General Service, Large General Service, and Large Power Service be rejected. Instead, I recommend that the unbundled rate design presented in Exhibit KCH-1 attached to my testimony should be adopted (at the UNSE revenue requirement for these classes).

## RATE SPREAD

**Q. Please describe the rate increase and spread of rates proposed by UNSE.**

A. UNSE is proposing a base rate increase of $22.6 million, which is an average base rate increase of 11.9%. However, $4.3 million of this base rate increase consists of the transfer into base rates of revenues currently recovered in the Transmission Cost Adjustor ("TCA"). In addition, a large portion of the proposed increase is offset by a $14.9 million reduction in the Base Fuel Rate. When these offsets are netted out, the net revenue increase proposed by UNSE is $3.6 million, or 2.5%. The net increase to the UNSE customer classes is shown in Table KCH-1 below.

**Table KCH-1**

**Summary of UNSE Proposed Revenue Spread by Customer Class**

| Customer Class | Current Adjusted Test Year Base Revenue | UNSE Proposed Base Dollar Change | UNSE Proposed Base Percent Change | UNSE Proposed Net Dollar Change | UNSE Proposed Net Percent Change |
|---|---|---|---|---|---|
| Residential | $73,653,026 | $20,556,648 | 27.9% | $7,507,747 | 10.2% |
| Small General Service | $11,905,151 | $2,664,336 | 22.4% | $1,185,904 | 10.0% |
| Medium/Large General Service | $53,699,953 | $26,345 | 0.0% | ($3,485,442) | -6.5% |
| Large Power Service | $7,375,505 | ($771,829) | -10.5% | ($1,672,387) | -22.7% |
| Lighting | $543,010 | $75,592 | 13.9% | $75,046 | 13.8% |
| Total | $147,176,645 | $22,551,092 | 15.3% | $3,610,868 | 2.5% |

**Q. What are your observations regarding UNSE's proposed rate spread?**

A. UNSE's proposed rate spread, or revenue apportionment, shows a dispersed rate change by customer class, with some classes receiving increases in the range of 10.0% – 13.8%, with others receiving net rate decreases.

**Q. What general guidelines should be employed in spreading any change in rates?**

A. In determining rate spread it is important to align rates with cost causation, to the greatest extent practicable. Properly aligning rates with the costs caused by each customer group is essential for ensuring fairness, as it minimizes cross subsidies among customers. It also sends proper price signals, which improves efficiency in resource utilization.

At the same time, it can be appropriate to mitigate the impact of moving immediately to cost-based rates for customer groups that would experience significant rate increases from doing so. This principle of ratemaking is known as "gradualism." When employing this principle, it is important to adopt a long-term strategy of moving in the direction of cost causation, and to avoid schemes that result in permanent cross-subsidies from other customers.

**Q. How does the spread of rates proposed by UNSE relate to class recovery of cost of service?**

The final rates proposed by UNSE contain considerable interclass subsidies, which are summarized in Table KCH-2, below. The largest subsidy goes to the Residential class, which under-recovers its allocated costs by $8.2 million at UNSE's proposed revenue requirement. Small General Service also receives a subsidy of just over $900 thousand. The large majority of the subsidy is paid by the Medium General Service ("MGS") and Large General Service ("LGS") classes, which together over-recover their costs by $8.2 million. In addition, Large Power Service ("LPS") pays a subsidy of nearly $900 thousand.

1 **Table KCH-2**

**Subsidies Included in UNSE's Proposed Revenue Spread by Customer Class**

| Customer Class | Current Adjusted Test Year Base Revenue | Revenue Change Required to Achieve COS | UNSE Proposed Base Dollar Change | UNSE Proposed Subsidy (Paid)/ Subsidy Received |
|---|---|---|---|---|
| **Residential** | $73,653,026 | $28,730,078 | $20,556,648 | $8,173,429 |
| **Small General Service** | $11,905,151 | $3,578,296 | $2,664,336 | $913,959 |
| **Medium/Large General Service** | $53,699,953 | ($8,183,024) | $26,345 | ($8,209,369) |
| **Large Power Service** | $7,375,505 | ($1,667,982) | ($771,829) | ($896,153) |
| **Lighting** | $543,010 | $93,725 | $75,592 | $18,134 |
| **Total** | $147,176,645 | $22,551,092 | $22,551,092 | $0 |

2 **Q. What is your assessment of UNSE's proposed rate spread?**

3 A. I believe that UNSE's proposed rate spread is generally reasonable, even
4 though it results in considerable cross subsidies remaining in rates. UNSE is
5 proposing to increase the rates of those classes that are relatively under-
6 recovering their allocated costs and to reduce the rates of those classes that are
7 relatively over-recovering their costs. In proposing these actions, the Company is
8 taking a step in the direction of achieving a better alignment of class revenue
9 requirement and class cost of service while remaining consistent with the
10 principles of gradualism.

11 **Q. How should UNSE's proposed rate spread be modified if the approved**
12 **revenue requirement is reduced from what the Company has requested?**

13 A. It is highly plausible that some reduction from what UNSE has requested
14 will be required. For example, Staff has proposed that UNSE's proposed revenue

requirement increase be reduced by $4.5 million[21] and RUCO is recommending a reduction of $10.35 million.[22] If a reduction to UNSE's proposed revenue requirement is approved by the Commission I recommend that it be apportioned 50% to the subsidy-paying classes (in proportion to their respective base revenue requirements) and 50% to the subsidy receiving classes (in proportion to their respective base revenue requirements). Further, I recommend that the first $908 thousand of revenue requirement reduction apportioned to the subsidy-paying classes should be used to support the Experimental Rider 14 buy-through program. The mechanism for doing so is discussed later in my testimony.

## COST OF SERVICE

**Q. What method has UNSE used for allocating production costs to customer classes?**

A. UNSE uses the Average and Excess Demand - 4CP method. As described in the Electric Utility Cost Allocation Manual published by the National Association Regulatory Utility Commissioners ("NARUC"), the Average and Excess Demand method uses an average demand or total energy allocator to allocate that portion of the utility's generating capacity that would be needed if all customers used energy at a constant 100 percent load factor.[23] The cost of capacity above average demand is then allocated in proportion to each class's excess demand, where excess demand is measured as the *difference* between each

[21] See direct testimony of Donna H. Mullinax, p. 8.
[22] See direct testimony of Jeffrey M. Michlik, Schedule JMM-1.
[23] NARUC Electric Utility Cost Allocation Manual, January 1992, p. 49.

1 class's individual peak demand[24] and its average demand. In this manner, the
2 incremental amount of production plant that is required to meet loads that are
3 above average demand is assigned to the users who create the need for the
4 additional capacity. The 4CP variant of the Average and Excess method used by
5 UNSE utilizes each class's demand during the utility's four highest monthly
6 coincident peaks (or "4CP") to measure excess demand, whereas the conventional
7 version uses class non-coincident peak for this purpose. The 4CP variant of
8 Average and Excess is also used in Colorado and Texas.

9 **Q. Do you have any comments regarding UNSE's use of the Average and Excess**
10 **Demand method to allocate production costs?**

11 A. Yes. I believe the use of the Average and Excess Demand method is
12 reasonable and should be adopted for cost allocation in this case. The Average
13 and Excess Demand method is a well-accepted method for allocating production
14 costs. It has been used by APS for many years and I am aware of this method
15 being approved by regulatory commissions in Colorado, New Mexico, Texas,
16 Virginia, and Kentucky.

17 **Q. Why do you believe the Average and Excess Demand method produces**
18 **reasonable results?**

19 A. The Average and Excess Demand method addresses a fundamentally
20 important question in production cost allocation: once we've accounted for the
21 capacity needed to serve the average demand on the system, how should we fairly
22 assign the responsibility for the *additional* (or excess) capacity that is needed to

[24] A class's individual peak demand is often referred to as "Class Non-Coincident Peak Demand" or "Class NCP."

meet the various capacity requirements put on the system by each customer class? The Average and Excess Demand method makes an objective and reasonable attempt to answer this question.

## BUY-THROUGH TARIFF

**Q. Please provide an overview of the buy-through tariff presented by UNSE in this proceeding.**

A. UNSE has submitted a buy-through tariff in this proceeding pursuant to the settlement agreement approved by the Commission in the proceeding concerning the acquisition of UNS Energy by Fortis, Inc.[25] However, UNSE is opposed to the implementation of this tariff, contending that it will result in costs being passed on to the remaining customers, while allowing certain large customers to "cherry pick" currently available capacity in the market.[26]

As described in the Direct Testimony of Craig A. Jones, Experimental Rider 14, Alternative Generation Service, is designed as an optional program to provide an alternative generation arrangement for participating LPS customers.

**Q. How would this alternative generation arrangement operate?**

A. According to Mr. Jones' direct testimony, the participating customer would select a wholesale generation service provider with whom to contract to sell power to the Company on the customer's behalf. The power would be delivered to the Company's point(s) of delivery, and the Company would provide

[25] Docket Nos. E-04230A-14-0011 and E-01933A-14-0011, Settlement Agreement Attachment A, Condition 31, approved by the Commission in Decision No. 74689.
[26] Direct Testimony of Craig A. Jones, p. 56.

1 transmission and delivery services under the customer's current retail rate
2 schedule.[27]

3 The Company would purchase and manage this generation for the
4 customer for a management fee of $0.0040 per kWh.[28] The Company would also
5 serve as the scheduling coordinator and would provide Imbalance Service
6 according to the Company's Open Access Transmission Tariff, with Imbalance
7 Energy based on the generation service provider's portfolio of customer loads.
8 Customers would be charged for Imbalance Service at a rate greater than $0.00
9 per kWh and less than or equal to the rate charged to the generation service
10 provider by UNSE. The Company would bill the customer for the generation
11 service provider's charged amounts for Generation Service and Imbalance
12 Service.[29]

13 The customer would also be subject to all of the charges and adjustments
14 in its retail rate schedule with the exception of the Base Power Charge, the
15 unbundled generation-related components of the Demand Charge and the
16 Delivery Services Energy Charge,[30] and the Purchased Power and Fuel
17 Adjustment Clause ("PPFAC"). However, for the first twelve months of service
18 under the rider, the generation-related component of the Demand Charge would
19 continue to apply to 100% of the customer's billed demand, with this proportion

[27] Id., pp. 56-57.
[28] Exhibit CAJ-3, (Experimental Rider-14 proposed tariff), Original Sheet No. 714-2. Note: the Direct Testimony of Craig A. Jones contained a typographical error of $0.0060/kWh. See UNSE Response to STF 2.116.
[29] Exhibit CAJ-3 (Experimental Rider-14 proposed tariff), Original Sheet No. 714-2.
[30] While the proposed tariff indicates that buy-through customers would be exempt from the unbundled Generation component in the Delivery Services Energy Charge, there *is no such charge* under the proposed tariff, although the current tariff does have such a component. See also Footnote 31.

1 decreasing to 25% after twelve months.[31] The customer would also be subject to
2 the historical component of the PPFAC for the first twelve months. In addition,
3 the customer would be responsible for the hedging cost associated with the
4 customer's standard generation service at the time the customer takes service
5 under the rider.[32]

6 **Q. Please describe the buy-through program size, eligibility requirements, and**
7 **program term as designed by UNSE.**

8 A. The total program would be limited to 10 MW of peak load, and would be
9 available to customers in the LPS and LPS-TOU rate classes with peak demands
10 of 2,500 kW or more. Eligible customers could apply during the initial
11 enrollment period, and if the total MW of peak load from the applications
12 exceeded the program maximum, customers would be selected through a lottery
13 process to be developed by UNSE.[33] The Company proposes that the program be
14 available for no more than four years from the effective date of new rates in this
15 docket.[34]

16 **Q. What would happen if the generation service provider defaults or the**
17 **customer wants to return to standard generation service?**

18 A. If the generation service provider cannot meet its contractual obligations,
19 the customer must notify the Company and select another generation service

[31] Note: The proposed tariff also indicates these provisions would apply to the unbundled Generation component of the Energy Charge for Delivery Services. However, as I indicate in Footnote 30, there is no such unbundled Generation component in the Delivery Services Energy Charge under the proposed tariff, although the current tariff does have such a component. Therefore, for purposes of this discussion, I will treat UNSE's proposal to recover all or a portion of the unbundled Generation component of the Energy Charge for Delivery Services from buy-through customers as moot.
[32] Exhibit CAJ-3 (Experimental Rider-14 proposed tariff), Original Sheet Nos. 714-1 through 714-2.
[33] Direct Testimony of Craig A. Jones, p. 57, lns. 14-23.
[34] Id., p. 56, lns. 21-22.

provider within 60 days. The Company would supply power to the customer prior to execution of the new power contract at the Dow Jones Electricity Palo Verde Daily Index price plus $20 per MWh.

If the customer wishes to return to standard generation service without providing one year notice to the Company and prior to program termination, the Company would supply power to the customer at the Dow Jones Electricity Palo Verde Daily Index price plus $20 per MWh until the Company is able to integrate the customer back into its generation planning and provide power at standard retail rates.[35]

**Q. How does UNSE propose to recover the remaining fixed generation costs that are not recovered from buy-through customers?**

A. As I explained above, according to the Company's proposal, subsequent to the first year of service under the rider, buy-through customers would not be subject to the generation-related component of the Demand Charge for 75% of the buy-through customers' billing demands.[36] The Company proposes that any "lost revenues" resulting from the buy-through program should be recovered through the Lost Fixed Cost Recovery Mechanism ("LFCR") and paid for by all the customers subject to this charge.[37]

**Q. What is your assessment of the buy-through program presented by UNSE?**

A. A buy-through program provides customers with the opportunity to gain experience with market transactions and potentially reduce their energy costs, thereby enhancing the economic development climate of the UNSE service

[35] Exhibit CAJ-3 (Experimental Rider-14 proposed tariff), Original Sheet No. 714-3.
[36] See also Footnotes 30 and 31.
[37] Direct Testimony of Craig A. Jones, p. 59, lns. 1-7.

1 territory and of the state generally. I recommend adoption of a buy-through
2 program that is as similar as reasonably possible to the AG-1 program approved
3 for APS. This would mean adopting some of the features of the buy-through
4 program presented by UNSE, but modifying other features to make the program
5 open to a wider variety of customers and to make it a more viable option.
6 Specifically, I recommend changes to program eligibility, pricing, terms of return
7 to standard generation service, and the mechanics of fixed generation cost
8 recovery. I also recommend a clarification to the program term.

9 **Q. What is your recommended clarification to the program term?**

10 A. I do not disagree with UNSE's proposal to target a four-year period for the
11 term of the program. However, I believe it is important for consideration of
12 program extension or modifications to be considered in the context of a future
13 general rate case prior to the termination of the program. Therefore I recommend
14 that the term of the program be restated to indicate that the buy-through program
15 will continue at least until the start of the first rate-effective period (following a
16 general rate case) occurring no less than four years from the starting date of the
17 buy-through program.

18 **Q. Please describe the changes to program eligibility that you are**
19 **recommending.**

20 A. While I would retain the proposed 10 MW cap on participation proposed
21 by UNSE, I recommend broadening the range of the customers that would be
22 eligible to participate. Specifically, I recommend allowing customers to
23 participate with a minimum load size of 1 MW (peak demand) and allowing
24 aggregation of smaller loads in the MGS/LGS classes owned by the same

1 corporate entity to achieve that 1 MW threshold. Each single site aggregated to
2 reach the 1 MW threshold should have experienced a billing demand of at least
3 200 kW in the past year to be eligible.

4 **Q. Why do you recommend broadening the range of eligible customers?**

5 A. The APS buy-through program reserved 50% of the initial capacity for
6 customers on Schedule 32-L, which roughly corresponds to the UNSE MGS and
7 LGS classes. The APS program allows Schedule 32-L (and in some cases
8 smaller) customers to aggregate their single site loads to achieve the 10 MW
9 minimum size required to participate in the AG-1 program. Experience with the
10 AG-1 program demonstrates that there is keen interest on the part of commercial
11 and public sector customers in participating in the market for electric power. This
12 opportunity should be available to similarly-situated UNSE customers.

13 **Q. You state that the APS AG-1 program allows aggregation but requires a 10**
14 **MW minimum aggregated load size. Why are you recommending a 1 MW**
15 **aggregated load size for UNSE?**

16 A. APS is a much larger service territory than UNSE, so there is greater
17 potential to aggregate smaller loads up to a 10 MW threshold. Indeed, the APS
18 non-residential retail load is about 20 times larger than that of UNSE. My
19 recommended 1 MW threshold for aggregated loads in the UNSE service territory
20 simply scales back the APS aggregate threshold to take into account the smaller
21 UNSE service territory, while balancing the need for sufficient critical mass for
22 each participant in this experimental program.

23 **Q. Are there aspects of buy-through program pricing proposed by UNSE that**
24 **you agree are reasonable?**

1 A. Yes. UNSE's proposal that the buy-through customer be subject to the
2 historical component of the PPFAC for one year is reasonable because it relates to
3 service the customer would have received prior to switching to buy-through
4 service. In addition, UNSE's proposal to assign a pro rata share of previously-
5 incurred hedging costs is reasonable in *concept.* I note, however, that the
6 reasonableness of the specific calculations that UNSE intends to apply has yet to
7 be demonstrated.

8 **Q. What changes to buy-through program pricing are you recommending?**

9 A. I am recommending changes to the proposed monthly management fee as
10 well as to the continuation of certain generation demand charges proposed by
11 UNSE.

12 **Q. What change to the monthly management fee are you recommending?**

13 A. UNSE is proposing a monthly management fee of $0.004/kWh for buy-
14 through service. While I agree that some management fee cost is appropriate, the
15 fee proposed by UNSE is more than six times greater than the $0.0006/kWh
16 management fee charged by APS for AG-1 service. It thus strikes me as
17 unreasonable and exorbitant. A management fee of $0.0006/kWh, comparable to
18 the AG-1 charge, is more reasonable.

19 **Q. What changes to UNSE's proposed generation charges for buy-through**
20 **customers are you recommending?**

21 A. As I discussed above, under the UNSE program, the generation-related
22 component of the Demand Charge would continue to apply to 100% of the buy-
23 through customer's billed demand for the first twelve months, with this proportion
24 decreasing to 25% for the subsequent three years. Ostensibly, these charges are

for reserve capacity. While some assignment of cost for reserves capacity may be appropriate, the UNSE proposal goes well beyond such a threshold.

The proper basis for charging for reserve capacity is the utility's planning reserve margin. A planning reserve margin is used in the resource planning process to compensate for uncertainty surrounding future load forecast changes and resource contingencies such as generation or transmission forced outages. The planning reserve margin is calculated as the amount of firm peak resource capacity in excess of projected retail demand as a percentage of total demand. The planning reserve margin used by UNSE in the Company's Integrated Resource Plan ("IRP") is 15%.[38]

Significantly, under the AG-1 tariff, the monthly reserve capacity charge is applied to 15% of the customer's billed demand priced at APS's cost-based rate for generation capacity filed at FERC, consistent with APS's planning reserve margin of 15%.[39]

UNSE's proposal to retain fixed generation charges for services that the buy-through customer would not utilize are pricing features that do not exist in the APS AG-1 program. I recommend that these charges <u>not</u> be introduced into the UNSE buy-through program. Instead, the going-forward charges for generation-related services should be limited to a charge for reserve capacity applied to 15% of the customer's billed demand priced at the unbundled generation demand charge for the customer's rate schedule. This pricing

[38] See UNSE 2014 IRP, p. 33.
[39] See APS 2014 IRP, p. 93.

1 approach ties the charge for reserve capacity to UNSE's planning reserve margin
2 in the Company's IRP and is comparable to APS's AG-1 charge for reserve
3 capacity.

4 **Q. Why do you recommend against adoption of UNSE's generation pricing**
5 **proposal?**

6 A. As I stated above, UNSE's proposed generation charges are for services
7 (e.g., fixed generation cost) that the buy-through customer would not utilize while
8 acquiring market power through UNSE. The charges proposed by UNSE beyond
9 a 15% charge for reserve capacity are in effect stranded cost charges that are
10 typically levied by utilities when direct access service is being offered. A critical
11 distinction with respect to retail choice programs is that in exchange for the
12 customer's payment of stranded cost charges for a period of time (e.g., five years)
13 the customer is allowed to migrate *permanently* to market participation with no
14 further stranded cost obligation. That is not the case with the proposed buy-
15 through program. When the term of the customer's participation in the buy-
16 through program has expired the customer is presumed to have no continued right
17 to market procurement unless the program is extended and the customer is able to
18 regain a slot. In short, if the participating customer is required to pay a stranded
19 cost charge as proposed by UNSE, then a more permanent shopping option,
20 accompanied by a timetable for cessation of stranded cost obligations, should be
21 on offer.

22 In addition, the Year 1 charge of 100% of fixed generation costs proposed
23 by UNSE strikes me as a being a potentially significant barrier to participation, as

1 the buy-through participant would have to pay both this charge and purchase
2 100% of its power in the marketplace.

3 **Q. If the pricing features proposed by UNSE are not adopted, how should the**
4 **Company's revenue deficiency associated with the buy-through program be**
5 **recovered?**

6 A. In my discussion of rate spread, above, I recommended that the first $908
7 thousand of any revenue requirement reduction apportioned to the subsidy-paying
8 classes be used to support the Experimental Rider 14 buy-through program. The
9 subsidy-paying classes (MGS, LGS, and LPS) are also the classes that I
10 recommend be eligible for the buy-through program. ,

11 This funding mechanism would work as follows. The first $908 thousand
12 of revenue requirement reduction apportioned to MGS, LGS and LPS
13 (collectively) would <u>not</u> be applied to a change in rates per se. Rather, this $908
14 thousand would be used to absorb UNSE's revenue deficiency that is attributed to
15 the reduction in fixed generation revenues from buy-through customers. In this
16 way, UNSE is able to recover its approved revenue requirement and the customer
17 classes not eligible to participate in the program are held harmless from adoption
18 of the buy-through provision.

19 **Q. Why is it reasonable to recover the fixed generation costs from the classes**
20 **eligible to participate in the program rather than by directly assigning the**
21 **cost recovery to the buy-through participants?**

22 A. As I discussed previously, directly assigning stranded cost charges might
23 be appropriate if participants were being offered a more permanent shopping
24 option. Further, the opportunity to participate in the program provides a potential

1 value-added option for the members of the eligible classes. It strikes me as more
2 reasonable to recover the fixed generation costs of the buy-through program
3 through a foregone rate reduction from the eligible classes rather than relying on a
4 combination of direct assignment to participants and the LFCR mechanism as
5 proposed by UNSE.

6 **Q. Why are you estimating that the revenue required to fund the buy-through**
7 **program is around $908 thousand per year?**

8 A. UNSE has estimated that the revenue required for a 10 MW program
9 under its proposed parameters is $331,200 per year for Years 2 through 4.[40]
10 However, that estimate assumes a 25% direct assignment of fixed generation costs
11 to participants in Years 2 through 4. In addition, as I will discuss in the next
12 section of my testimony, UNSE's unbundled charge for fixed generation cost is
13 grossly understated as a share of the Company's charges for fixed cost recovery
14 (and its unbundled delivery demand charge is grossly overstated). Correcting this
15 rate design relationship and reducing the 25% direct assignment charge to a 15%
16 reserve capacity charge will increase the revenue requirement to support the
17 program to around $908 thousand per year, assuming fully-subscribed
18 participation.[41]

19 To the extent that program initiation is delayed and does not coincide with
20 the start of the rate-effective period in this case, then there should be a downward
21 adjustment to the annual imputed cost of the program prorated over the planned

[40] See UNSE Response to Staff Data Request 2.118.
[41] If all buy-through participants are in the LPS class, the cost would be $878 thousand per year. Similarly, if all buy-through participants are in LGS class the cost would be $989 thousand per year and if all buy-through participants are in the MGS class the cost would be $857 thousand per year. My estimate of $908 thousand is the simple average of this range.

1 four-year term of the program, to account for the over-recovery of revenues from
2 eligible classes during the delayed start-up.

3 **Q. What do you recommend if the buy-through program is not fully**
4 **subscribed?**

5 A. If the buy-through program is not fully subscribed then the revenues set
6 aside to fund the program and which turn out to be superfluous should be deferred
7 and returned to the eligible classes through a suitable rate mechanism, perhaps
8 through the PPFAC.

9 **Q. What do you recommend in the event that the Commission does not order a**
10 **revenue requirement reduction relative to UNSE's proposed revenue**
11 **increase that is sufficient to fund the buy-through requirements?**

12 A. In that event, although it appears unlikely, I recommend that the program
13 costs be funded out of the revenue requirement reductions proposed by UNSE for
14 the eligible classes.

15 **Q. Please explain your proposed change to the return to general service**
16 **provision.**

17 A. If, prior to the end of the planned four-year term of the program, and
18 absent Commission termination of the program, a buy-through customer seeks to
19 return to standard generation service and does not provide one-year's notice,
20 UNSE proposes to charge the returning customer the Dow Jones Electricity Palo
21 Verde Daily Index price for the power delivery date plus $20 per MWh until the
22 Company is reasonably able to integrate the customer back into the Company's
23 generation planning. While I agree that this general approach is reasonable, I
24 believe the proposed $20 per MWh mark-up is excessive. In comparison, APS's

AG-1 program also requires that an "early" returning buy-through customer pay market rates for up to one year, but without an additional mark-up. I believe the $20per MWh mark-up proposed by UNSE should be eliminated or significantly reduced to no greater than $4 per MWh.

**Q. Are you aware of whether any AG-1 customers have sought to return to APS standard generation service prior to the planned term of the AG-1 program?**

A. To the best of my knowledge, no AG-1 customers have sought to return to APS standard generation service prior to the planned term of the AG-1 program.

## UNBUNDLED RATE DESIGN

**Q. What aspects of UNSE's proposed rate design are you addressing in your testimony?**

A. My testimony addresses the rate design for UNSE's *unbundled* demand charges for the MGS, LGS, and LPS classes. My absence of comment on other aspects of UNSE's rate design should not be interpreted as support for (or opposition to) UNSE's proposed rate design generally.

**Q. By way of background, please explain the significance of an unbundled tariff.**

A. An unbundled tariff is one in which utility rates are separated according to function, in particular, generation, transmission, and distribution (or delivery service). The Commission's rules carefully prescribe the requirements for filing an unbundled tariff.[42] The fundamental requirement in any well-designed unbundled tariff is that each unbundled component should only recover costs associated with its specific function. That is, the unbundled delivery service

[42] See AAC R14-2-1606.C.2.

charge should only recover delivery-services-related costs (and not generation costs), the unbundled generation charge should only recover generation-related costs, and the unbundled transmission charge should only recover transmission-related costs.

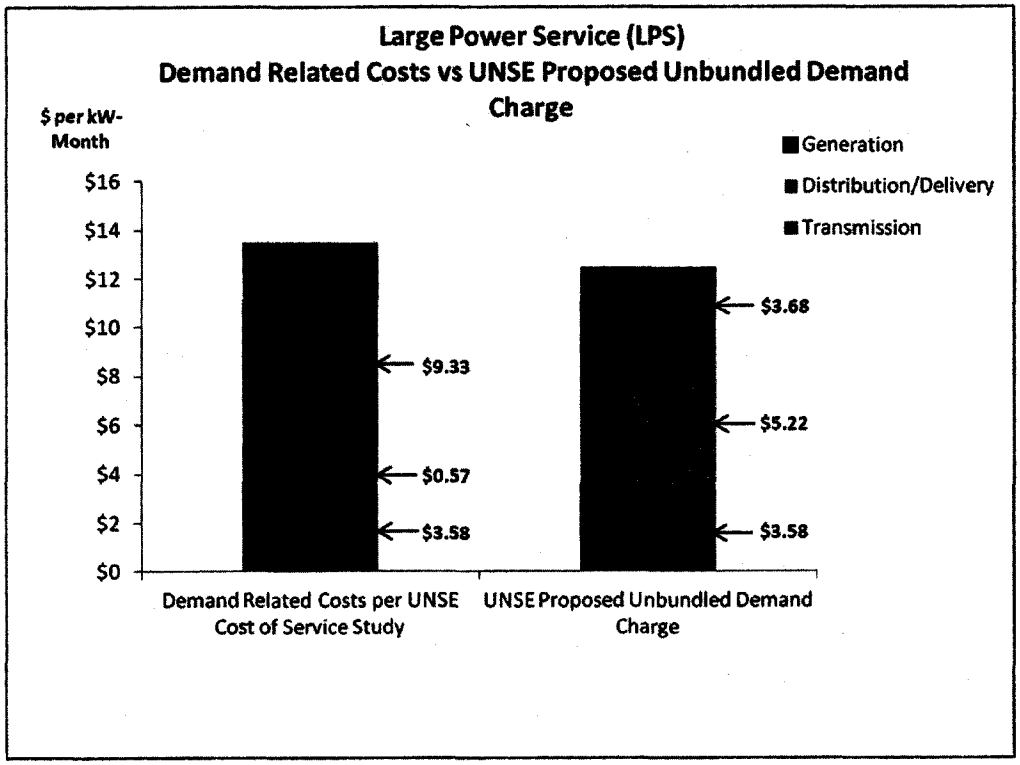
A well-designed unbundled tariff is essential to implement a buy-through program because customers in such a program purchase their generation service from third parties and thus the rates they pay the utility must accurately distinguish the avoidable generation costs from the other components in the rate schedule.

As required by Commission rules, UNSE's rate schedules show rates both on a bundled and unbundled basis.

**Q. Do you have concerns with the rate design of UNSE's unbundled tariff?**

A. Yes. UNSE's unbundled rate design is seriously flawed in that the Company is attempting to recover fixed generation-related costs in the Local Delivery component of the demand charge, contrary to the fundamentals of proper unbundled rate design. This problem is illustrated for the LPS rate schedule in Figure KCH-1, below.

**Figure KCH-1**




**Q. Please describe Figure KCH-1.**

A. Figure KCH-1 compares the unbundled demand *cost* of serving the LPS class with the proposed unbundled demand *charges* for these customers. For LPS customers, the proposed bundled demand charge of $12.48 per kW-month is shown in the bar graph on the right-hand side of Figure KCH-1. This charge is disaggregated into three unbundled components, also illustrated: (1) an unbundled Transmission demand charge of $3.58 per kW-month, (2) an unbundled Local Delivery demand charge of $5.22 per kW-month, and (3) an unbundled Generation Capacity demand charge of $3.68 per kW-month.

The corresponding demand-related *costs* are shown on the left-hand side of the figure. These costs are taken directly from the UNSE cost-of-service study.

Figure KCH-1 shows that the unbundled transmission costs and charges are fully aligned, but the unbundled Local Delivery demand charge and unbundled Generation Capacity demand charge are entirely inconsistent with the results of UNSE's cost-of-service study. That study indicates that generation demand costs for the LPS class to be $9.33 per kW-month and distribution demand costs to be just $0.57 per kW-month.[43] In other words, the cost-of-service study UNSE performed shows that generation demand costs are more than 16 times as great as distribution demand costs for the LPS class, yet UNSE proposes to price generation demand more cheaply than distribution demand! This is a serious problem. A similar problem exists for the MGS and LGS classes.

**Q. Why is this a serious problem?**

A. It is a serious problem because the fundamental economic proposition in a buy-through rate is that the buy-through customer is able to bypass either all, or a significant portion of, the unbundled generation charges. If the utility's unbundled rate design shifts cost recovery from generation charges to distribution (or delivery) charges, then the avoidable generation costs will be underpriced and unavoidable distribution charges will be overpriced. As a result, the ability of customers to shop for buy-through power will be thwarted. Indeed, that is exactly what is likely to occur if UNSE's unbundled rate design is accepted.

To appreciate this point, we can return to Figure KCH-1. UNSE has in effect re-packaged the aggregate *costs* of G + D shown on the left into the aggregate *charges* of G + D on the right. In so doing, a large portion of the G cost

[43] See UNSE Schedule G-6-1 workpaper. Note that this UNSE workpaper indicates that the bundled demand cost for LPS is $13.47 per kW-month, whereas the bundled demand charge for LPS is proposed to be $12.48/kW-month. The difference between these two amounts is largely recovered in the power factor adjustment charge for this rate schedule.

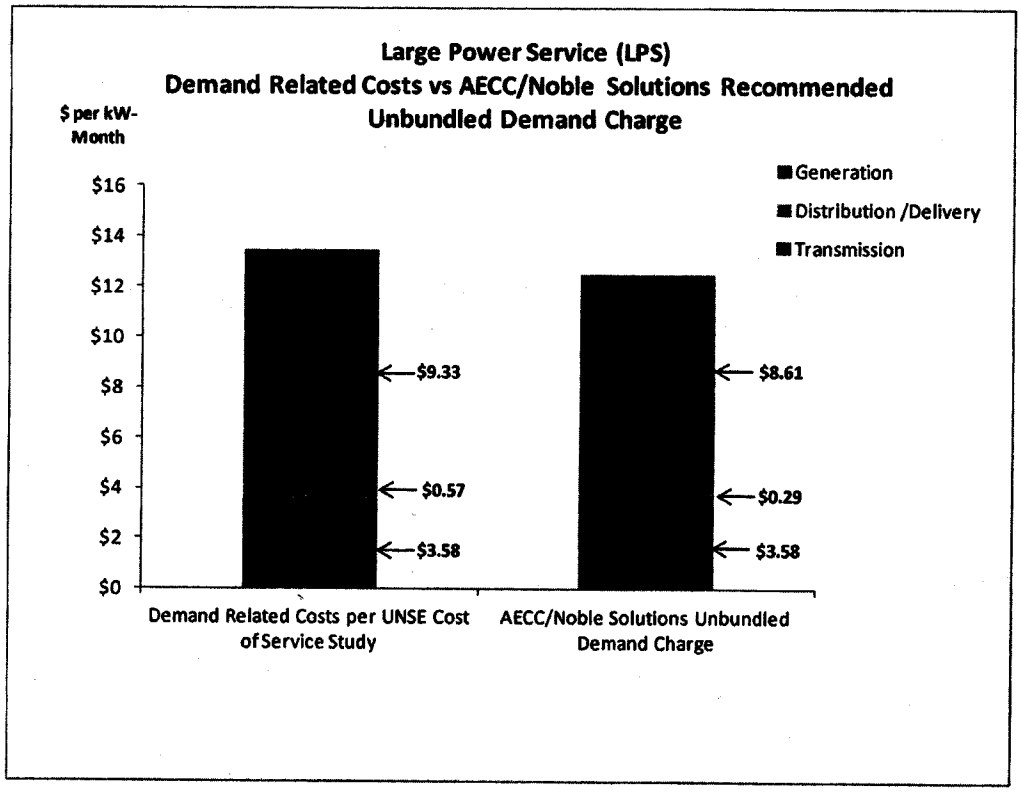
is shifted into the unbundled D charge. This is plainly evident by comparing the two bar graphs. When we consider that the unbundled D charge is *unavoidable* for the buy-through customer, it is obvious that shifting G-related costs into the D charge will hinder the buy-through customer's ability to avoid paying for G-related costs when the buy-through customer contracts for third-party generation service. This situation will significantly and unduly undermine the economics of acquiring generation service in the power market. Indeed, shifting generation-related costs into the distribution (or delivery) charge is contrary to the very purpose of unbundling rates. It also appears to be contrary to the requirements of AAC R14-2-1606.H.2 which states that rates for unbundled services "shall reflect the costs of providing the services."

**Q. Have you calculated alternative unbundled rates for the LPS, MGS, and LGS classes?**

A. Yes. I have calculated a set of alternative unbundled rates that produce the same bundled demand charge as proposed by UNSE for each of these customer classes, but with unbundled rate components that are aligned with the functional costs identified in UNSE's cost-of-service study. These calculations are presented in Exhibit KCH-1.[44] I have also illustrated the relationship between my proposed unbundled demand charge components for LPS with the underlying cost components in Figure KCH-2, below.

[44] Note that UNSE appears to have inadvertently reversed the Meter Services and Meter Reading unit costs in its workpapers and consequently has accidentally reversed the unbundled charges for these services. I have corrected this error in my proposed unbundled rates in Exhibit KCH-1.

**Figure KCH-2**




**Q. Referring to Figure KCH-2, please explain why your recommended unbundled generation demand charge for LPS is less than the unbundled generation demand cost.**

A. As I indicated above, I have designed my recommended unbundled demand charges using the same *bundled* demand charge that UNSE has proposed; given this constraint, my recommended unbundled demand components sum to the $12.48 per kW-month bundled demand charge proposed by UNSE. The difference between the unbundled generation demand cost and my recommended unbundled generation demand charge is recovered in the power factor adjustment charge for this rate schedule proposed by UNSE.

1 **Q. Also referring to Figure KCH-2, please explain why your recommended**
2 **unbundled delivery service demand charge for LPS is less than the**
3 **unbundled delivery service demand cost.**
4 A. UNSE's current and proposed rate design recovers a portion of
5 distribution/delivery service costs in a delivery service energy charge. While I
6 generally do not agree with recovering distribution/delivery service costs in an
7 energy charge, I have elected not to challenge this aspect of UNSE's rate design
8 in this case. Therefore, the difference between the distribution/delivery service
9 demand costs and my recommended unbundled distribution/delivery service
10 demand charge is recovered in the delivery service energy charge proposed by
11 UNSE.
12 **Q. What is your recommendation to the Commission on this issue?**
13 A. UNSE's proposed relationship between delivery demand charges and
14 generation capacity demand charges in its unbundled tariff should be rejected.
15 Instead, I recommend that the unbundled rate design presented in Exhibit KCH-1
16 should be adopted at the UNSE revenue requirement for these classes. If the
17 revenue requirement for these classes is modified, then the underlying
18 relationship among the unbundled components of the demand charges in Exhibit
19 KCH-1 should be retained in any new bundled demand charges.
20 **Q. Does this conclude your direct testimony?**
21 A. Yes, it does.

# EXHIBIT KCH-1

## AECC/Noble Solution Recommended Unbundled LPS & LPS-TOU Rates
## (at UNSE's Requested Revenue Requirement)

| Line No. | Description | UNSE Unit Cost @ Proposed Rates[1] | UNSE Proposed[2] | AECC/ Noble Solutions Recommended |
|---|---|---|---|---|
| 1 | Basic Service Charge Components ($/Cust./Mo.): | | | |
| 2 | Meter Services[3] | $260.68 | $101.86 | $145.57 |
| 3 | Meter Reading[3] | $182.42 | $145.57 | $101.86 |
| 4 | Billing & Collection | $808.82 | $451.63 | $451.63 |
| 5 | Customer Delivery | $896.57 | $500.94 | $500.94 |
| 6 | Total | $2,148.50 | $1,200.00 | $1,200.00 |
| 7 | Demand Charge Components ($/kW): | | | |
| 8 | Local Delivery | $0.57 | $5.22 | $0.29 |
| 9 | Generation Capacity | $9.33 | $3.68 | $8.61 |
| 10 | Transmission | $3.58 | $3.58 | $3.58 |
| 11 | Total | $13.47 | $12.48 | $12.48 |
| 12 | Energy Charge Components ($/kWh): | | | |
| 13 | Local Delivery | NA | $0.00052 | $0.00052 |
| 14 | Power Supply Charges ($/kWh): | | | |
| 15 | Base Power Supply (LPS) | $0.045099 | $0.048410 | $0.048410 |
| 16 | Base Power Supply Summer On-Peak - (LPS-TOU) | | $0.122510 | $0.122510 |
| 17 | Base Power Supply Summer Off-Peak - (LPS-TOU) | | $0.032110 | $0.032110 |
| 18 | Base Power Supply Winter On-Peak - (LPS-TOU) | | $0.092110 | $0.092110 |
| 19 | Base Power Supply Winter Off-Peak - (LPS-TOU) | | $0.030910 | $0.030910 |
| 20 | PPFAC (%) (see Rider-1 for current rate) | NA | Varies | Varies |

Notes:
1. Data Source: UNSE Schedule G-6-1, Sheet 1 of 1.
2. Data Source: UNSE Witness Craig Jones Exhibit CAJ-3, Original Sheet 301-2 & 302-3.
3. UNSE's workpapers appear to reverse the Meter Services and Meter Reading unit costs. AECC/Noble Solutions recommended unbundled charges correct this error.

## AECC/Noble Solution Recommended Unbundled LGS, LGS-TOU & LGS-TOU-S Rates
## (at UNSE's Requested Revenue Requirement)

| Line No. | Description | UNSE Unit Cost @ Proposed Rates[1] | UNSE Proposed[1] | AECC/ Noble Solutions Recommended |
|---|---|---|---|---|
| 1 | Basic Service Charge Components ($/Cust./Mo.): | | | |
| 2 | Meter Services[2] | $32.27 | $5.01 | $31.32 |
| 3 | Meter Reading[2] | $5.16 | $31.32 | $5.01 |
| 4 | Billing & Collection | $22.82 | $22.15 | $22.15 |
| 5 | Customer Delivery | $248.80 | $241.52 | $241.52 |
| 6 | Total | $309.05 | $300.00 | $300.00 |
| 7 | Demand Charge Components ($/kW): | | | |
| 8 | Demand Delivery | $3.93 | $8.29 | $0.96 |
| 9 | Generation Capacity | $6.47 | $2.37 | $9.70 |
| 10 | Transmission | $2.30 | $2.30 | $2.30 |
| 11 | Total | $12.70 | $12.96 | $12.96 |
| 12 | Energy Charge Components ($/kWh): | | | |
| 13 | Local Delivery | NA | $0.00540 | $0.00540 |
| 14 | Power Supply Charges ($/kWh): | | | |
| 15 | Base Power Supply (LGS) | $0.048536 | $0.048400 | $0.048400 |
| 16 | Base Power Supply Summer On-Peak - (LGS-TOU) | | $0.145510 | $0.145510 |
| 17 | Base Power Supply Summer Off-Peak - (LGS-TOU) | | $0.034510 | $0.034510 |
| 18 | Base Power Supply Winter On-Peak - (LGS-TOU) | | $0.124510 | $0.124510 |
| 19 | Base Power Supply Winter Off-Peak - (LGS-TOU) | | $0.032910 | $0.032910 |
| 20 | Base Power Supply Summer On-Peak - (LGS-TOU-S) | | $0.150210 | $0.150210 |
| 21 | Base Power Supply Summer Off-Peak - (LGS-TOU-S) | | $0.039210 | $0.039210 |
| 22 | Base Power Supply Winter On-Peak - (LGS-TOU-S) | | $0.129210 | $0.129210 |
| 23 | Base Power Supply Winter Off-Peak - (LGS-TOU-S) | | $0.037610 | $0.037610 |
| 24 | PPFAC (%) (see Rider-1 for current rate) | | Varies | Varies |

Notes:
1. Data Source: UNSE Schedule G-6-1, Sheet 1 of 1.
2. Data Source: UNSE Witness Craig Jones Exhibit CAJ-3, Original Sheet 220-2 & 221-2 & 222-2.
3. UNSE's workpapers appear to reverse the Meter Services and Meter Reading unit costs. AECC/Noble Solutions recommended unbundled charges correct this error.

## AECC/Noble Solution Recommended Unbundled MGS, MGS-TOU & MGS-TOU-S Rates
## (at UNSE's Requested Revenue Requirement)

| Line No. | Description | UNSE Unit Cost @ Proposed Rates[1] | UNSE Proposed[1] | AECC/ Noble Solutions Recommended |
|---|---|---|---|---|
| 1 | Basic Service Charge Components ($/Cust./Mo.): | | | |
| 2 | Meter Services[2] | $32.27 | $1.67 | $10.44 |
| 3 | Meter Reading[2] | $5.16 | $10.44 | $1.67 |
| 4 | Billing & Collection | $22.82 | $7.38 | $7.38 |
| 5 | Customer Delivery | $248.80 | $80.51 | $80.51 |
| 6 | Total | $309.05 | $100.00 | $100.00 |
| 7 | Demand Charge Components ($/kW): | | | |
| 8 | Demand Delivery | $3.93 | $8.38 | $2.26 |
| 9 | Generation Capacity | $6.47 | $2.37 | $8.40 |
| 10 | Transmission | $2.30 | $2.30 | $2.30 |
| 11 | Total | $12.70 | $13.05 | $12.96 |
| 12 | Energy Charge Components ($/kWh): | | | |
| 13 | Local Delivery | NA | $0.00550 | $0.00550 |
| 14 | Power Supply Charges ($/kWh): | | | |
| 15 | Base Power Supply (MGS) | $0.048536 | $0.048440 | $0.048440 |
| 16 | Base Power Supply Summer On-Peak - (MGS-TOU) | | $0.145510 | $0.145510 |
| 17 | Base Power Supply Summer Off-Peak - (MGS-TOU) | | $0.034510 | $0.034510 |
| 18 | Base Power Supply Winter On-Peak - (MGS-TOU) | | $0.124510 | $0.124510 |
| 19 | Base Power Supply Winter Off-Peak - (MGS-TOU) | | $0.032910 | $0.032910 |
| 20 | Base Power Supply Summer On-Peak - (MGS-TOU-S) | | $0.150210 | $0.150210 |
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| 22 | Base Power Supply Winter On-Peak - (MGS-TOU-S) | | $0.129210 | $0.129210 |
| 23 | Base Power Supply Winter Off-Peak - (MGS-TOU-S) | | $0.037610 | $0.037610 |
| 24 | PPFAC (%) (see Rider-1 for current rate) | | Varies | Varies |

Notes:

1. Data Source: UNSE Schedule G-6-1, Sheet 1 of 1.
2. Data Source: UNSE Witness Craig Jones Exhibit CAJ-3, Original Sheet 210-2 & 211-2 & 212-2.
3. UNSE's workpapers appear to reverse the Meter Services and Meter Reading unit costs. AECC/Noble Solutions recommended unbundled charges correct this error.

# 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 of Kevin C. Higgins

**on behalf of**

**Freeport Minerals Corporation,**

**Arizonans for Electric Choice & Competition and**

**Noble Americas Energy Solutions LLC**

**Rate Design**

**February 23, 2015**

# DIRECT TESTIMONY OF KEVIN C. HIGGINS

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KCH-SR-2 ..... APS Experimental Rate Rider AG-1
KCH-SR-3 ..... AECC/Noble Solutions Recommended Unbundled Rates

1 **SURREBUTTAL TESTIMONY OF KEVIN C. HIGGINS**

2

3 **INTRODUCTION**

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

5 A. Kevin C. Higgins, 215 South State Street, Suite 200, Salt Lake City, Utah,

6 84111.

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

8 A. I am a Principal in the firm of Energy Strategies, LLC. Energy Strategies

9 is a private consulting firm specializing in economic and policy analysis

10 applicable to energy production, transportation, and consumption.

11 **Q. Are you the same Kevin C. Higgins who previously filed direct testimony in**

12 **this case on behalf of Freeport Minerals Corporation, Arizonans for Electric**

13 **Choice and Competition ("AECC")** [1] **and Noble Americas Energy Solutions**

14 **LLC ("Noble Solutions")?**

15 A. Yes, I am.

16 **Q. What is the purpose of your surrebuttal testimony?**

17 A. My surrebuttal testimony responds to certain arguments advanced by

18 UNSE Energy ("UNSE") witness Craig A. Jones in his rebuttal testimony, and

19 Staff witness Howard Solganick in his direct testimony, regarding revenue

20 allocation and the proposed Experimental Rider 14 buy-through program. I also

21 briefly discuss the rebuttal testimony of UNSE witness David G. Hutchens

22 regarding the proposed Economic Development Rider ("EDR").

[1] Freeport Minerals Corporation and AECC collectively will be referred to as "AECC."

AECC witness Michael D. McElrath responds in his surrebuttal testimony to the direct testimony of Arizona Investment Council witness Gary Yaquinto on the subject of the buy-through program. I concur with Mr. McElrath's response to Mr. Yaquinto.

**Q. What are the primary conclusions and recommendations in your surrebuttal testimony?**

A. With respect to revenue allocation, or rate spread, I continue to support the revenue allocation proposed by UNSE in its **direct** testimony, and I continue to recommend that any reduction to UNSE's proposed revenue requirement be apportioned 50% to the subsidy-paying classes and 50% to the subsidy receiving classes. I also recommend that the first $908 thousand of revenue requirement reduction apportioned to the subsidy-paying classes should be used to support the Experimental Rider 14 buy-through program.

I also continue to recommend adoption of a buy-through program that is as similar as reasonably possible to the AG-1 program approved for Arizona Public Service Company ("APS"). In my surrebuttal testimony I respond to the criticisms of my recommendations by UNSE in the Company's rebuttal filing.

Finally, I note that my criticisms of UNSE's unbundled rate design for the Medium General Service ("MGS"), Large General Service ("LGS") and Large Power Service ("LPS") rate schedules has not been refuted by UNSE. I recommend that the Commission adopt the unbundled rate design I proposed in my direct testimony for these rate schedules, with minor modifications to account for the reduced revenue requirement accepted by UNSE in its rebuttal filing.

## RATE SPREAD

**Q. In your direct testimony you supported the revenue allocation, or rate spread, proposed by UNSE in its direct filing. Has UNSE modified its recommended revenue allocation in response to the testimony of other parties?**

A. Yes. As discussed in the rebuttal testimony of UNSE witness Mr. Jones, UNSE has modified the Company's proposed revenue allocation to shift more cost recovery to larger customers and less to residential and small general service customers. UNSE has also updated its proposed revenue allocation for a revised, lower revenue requirement in response to adjustments proposed by Staff. UNSE's new proposed rate spread is designed to recover a non-fuel revenue requirement increase of $18.5 million[2] rather than the $22.6 million that UNSE proposed in its direct filing. UNSE's rebuttal revenue allocation proposal is summarized in table KCH-SR-1 below.

**Table KCH-SR-1**
**Summary of UNSE Proposed Rebuttal Revenue Spread by Customer Class**

| Customer Class | UNSE Rebuttal Current Adjusted Test Year Base Revenue | UNSE Proposed Base Dollar Change | UNSE Proposed Base Percent Change | UNSE Net Dollar Change (Year 2) | UNSE Net Percent Change (Year 2) |
|---|---|---|---|---|---|
| (a) | (b) | (c) | (d) | (e) | (f) |
| **Residential** | $78,169,265 | $15,928,289 | 20.4% | $6,606,441 | 8.5% |
| **Small General Service** | $12,461,200 | $1,816,538 | 14.6% | $909,374 | 7.3% |
| **Medium/Large General Service** | $56,334,006 | $1,236,675 | 2.2% | $2,257,929 | 4.0% |
| **Large Power Service** | $7,446,668 | ($669,871) | -9.0% | $189,131 | 2.5% |
| **Lighting** | $547,038 | $75,592 | 13.8% | $79,050 | 14.5% |
| **Total** | $154,958,178 | $18,387,223 | 11.9% | $10,041,924 | 6.5% |

[2] This $18.5 million consists of $18.4 million in base revenues plus $0.1 million in other revenues.

1 **Q. Please explain the difference between the UNSE proposed "base" change and**
2 **the "net" change in Table KCH-SR-1.**
3 A. The proposed base change is limited to the proposed change in non-fuel
4 rates. The net change takes into account the projected reduction in fuel costs and
5 also takes into account the absorption of the Transmission Cost Adjustor ("TCA")
6 charge into base rates.
7 **Q. Why are the net changes expressed as "Year 2" changes in Table KCH-SR-**
8 **1?**
9 A. UNSE is proposing a temporary Year 1 credit to the purchased power and
10 fuel adjustment clause to pass through deferred savings associated with the
11 acquisition of the Gila River power plant, a proposal that I support as reasonable.
12 But to understand the underlying revenue allocation absent the temporary effect
13 of the credit, it is necessary to examine the Year 2 effects.
14 **Q. Why does your presentation of the net revenue change differ from what**
15 **UNSE shows in UNSE Exhibit CAJ-4-R, Schedule H-1?**
16 A. In the depiction of the net revenue change resulting from UNSE's
17 proposed revenue allocation shown in UNSE Schedule H-1, the *kilowatt-hours*
18 associated with Test Year Present Net Revenue, Adjusted Test Year Revenue, and
19 Proposed Net Revenue are each different. The difference in kilowatt-hours is
20 attributable to a number of causes, including load growth for some classes, loss of
21 load for other classes, and UNSE-proposed class restructuring. These differences
22 in kilowatt-hours among these categories make it very problematic to interpret the
23 net revenue changes for each class as depicted in UNSE Schedule H-1. For
24 example, the Schedule H-1 entry for LPS shows a $14.8 million reduction

revenues in the column entitled "Net Change." This reduction includes the revenue effects of load that has disappeared due to large customer shut-downs as well as load that is migrated to other rate schedules. Schedule H-1 is simply not a useful representation of the true rate impacts on customer classes and cannot be used to assess the reasonableness of UNSE's revenue allocation proposal.

In contrast, Table KCH-SR-1 holds each class's kilowatt-hours constant when determining the net revenue change relative to adjusted base revenues. This approach provides a more meaningful depiction of the true rate impact on the customers in each class than does UNSE Schedule H-1. Table KCH-SR-1 also includes the full effect of absorbing pro forma TCA revenues into base rates, whereas Schedule H-1 only shows the absorption of the much lower TCA revenues that were in effect during calendar year 2014.

**Q. Do the kilowatt-hour differences in UNSE Schedule H-1 affect classes other than LPS?**

A. Yes. For the Residential class, UNSE Schedule H-1 includes the effects of Residential load *growth*. Thus, the "Net Change" of $10.2 million in revenues for the Residential class in Schedule H-1 includes the effect of 1.1% load growth. Interestingly, UNSE projects a net reduction in base fuel costs for Residential customers in total of $5.2 million, *including* the increased fuel usage for growth. This means that the effective fuel cost *reduction* impact on Residential *rates* is even *greater*, after accounting for the effects of load growth. My presentation in Table KCH-SR-1 accurately captures this effect.

**Q. Turning back to UNSE's proposed revenue allocation, do you agree with UNSE's revised proposal to shift more cost recovery to larger customers?**

1 A. No. As I discussed in my direct testimony, I believe that UNSE's initial
2 proposal strikes the proper balance in allocating revenue responsibility among
3 customer classes.

4 **Q. What explanation does UNSE offer for its revised revenue allocation?**

5 A. According to Mr. Jones, UNSE's modification is "along the lines
6 suggested by Staff,"[3] although UNSE does not shift as many costs to MGS, LGS,
7 and LPS as Staff advocates.

8 **Q. Do you agree with the revenue allocation recommendations offered by Staff?**

9 A. No. Staff's revenue allocations are presented by Mr. Solganick, who
10 advocates for a long-term movement toward cost-based rates, but in smaller steps
11 than proposed by UNSE in the Company's direct filing. Mr. Solganick proposes
12 that the Commission should use UNSE's class cost of service study as a general
13 guideline, but should rely on gradualism to determine the final revenue allocation
14 in this case.[4] Staff's proposed revenue allocation is presented in Table KCH-SR-
15 2, below. Staff presented its proposed allocation in terms of the base percentage
16 change, Column (d), below.

[3] Rebuttal testimony of Craig A. Jones, p. 8.
[4] Direct testimony of Howard Solganick, p. 21.

**Table KCH-SR-2**
**Summary of Staff Proposed Revenue Spread by Customer Class**

| Customer Class | UNSE Direct Current Adjusted Test Year Base Revenue | Staff Proposed Base Dollar Change | Staff Proposed Base Percent Change |
|---|---|---|---|
| (a) | (b) | (c) | (d) |
| **Residential** | $73,653,026 | $10,563,000 | 14.34% |
| **Small General Service** | $11,905,151 | $1,328,500 | 11.16% |
| **Medium/Large General Service** | $53,699,953 | $5,435,055 | 10.12% |
| **Large Power Service** | $7,375,505 | $746,486 | 10.12% |
| **Lighting** | $543,010 | $54,959 | 10.12% |
| **Total** | $147,176,645 | $18,128,000 | 12.32% |

**Q. Do you disagree with applying the principle of gradualism in this case?**

A. No. I do not disagree with applying the principle of gradualism, so long as it is part of a genuine strategy of moving rates meaningfully in the direction of cost causation, and is not merely a device for institutionalizing permanent cross-subsidies from other customers. UNSE's original proposal – which I support – adheres to the principle of gradualism as it provides approximately $9 million in cross subsidies from MGS, LGS, and LPS customers to Residential and Small General Service ("SGS") customers while still moving in the direction of cost-based rates.[5] Staff's proposal dampens the movement to cost-based rates by increasing this cross subsidy to nearly $11.9 million. The subsidies incorporated into Staff's proposal are shown in Table KCH-3-SR, below.[6]

[5] Direct Testimony of Kevin C. Higgins, pp. 9-10.
[6] The subsidies in Table KCH-3-SR are derived from Staff Exhibit HS-4.

**Table KCH-3-SR**
**Subsidies Included in Staff's Proposed Revenue Spread by Customer Class**

| Customer Class | UNSE Rebuttal Current Adjusted Test Year Base Revenue | Revenue Change Required to Achieve COS | Staff Proposed Base Dollar Change | Staff Proposed Subsidy (Paid)/ Subsidy Received |
|---|---|---|---|---|
| (a) | (b) | (c) | (d) | (e) |
| **Residential** | $78,169,265 | $21,126,000 | $10,563,000 | $10,563,000 |
| **Small General Service** | $12,461,200 | $2,657,000 | $1,328,500 | $1,328,500 |
| **Medium/Large General Service** | $56,334,006 | ($4,752,900) | $5,435,055 | ($10,187,955) |
| **Large Power Service** | $7,446,668 | ($957,900) | $746,486 | ($1,704,386) |
| **Lighting** | $547,038 | $55,800 | $54,959 | $841 |
| **Total** | $154,958,178 | $18,128,000 | $18,128,000 | $0 |

**Q. What is the basis for Staff's revenue allocation proposal?**

A. In articulating the principles that he has used in allocating class revenue responsibility, Mr. Solganick states that "There should be an upper bound of 150 percent for any class' percentage increase in revenue compared to the overall percentage increase in revenue."[7] However, Mr. Solganick actually does not structure his revenue allocation proposal using this mitigation mechanism. If he had, Staff's recommended (non-fuel) increase for Residential customers would be 18.48% (12.32% x 1.5), not 14.34% (as Staff is actually proposing), and the subsidy paid to Residential customers would be around $3 million less than Staff is proposing.[8]

[7] Direct testimony of Howard Solganick, p. 22.
[8] $73,653,026 x .1848 = $13,611,079, which is $3,048,079 more than the base revenue increase for the Residential class that Staff is proposing.

1 Instead, Staff's proposal is to increase the Residential and SGS rates by
2 half of the increase that would be required to move these classes to full cost of
3 service (or parity).[9]

4 **Q. Why do you object to this approach?**

5 A. Simply setting the increase to selected classes to half of what is required to
6 attain parity – without linking that concept to other measurements such as the
7 system average increase or the relationship to the increase levied on the subsidy-
8 paying classes – is arbitrary. Staff's approach provides no assurance that UNSE
9 rates would even be taking a *small* step in the *direction* of parity consistent with
10 Staff's stated long-term objectives.

11 The unreasonable outcome that obtains from such an approach is evident
12 when examining the results for the SGS class under Staff's proposal. According
13 to Mr. Solganick's Exhibit HS-4, the system average non-fuel increase under
14 Staff's proposed revenue requirement is 12.32%. To attain parity (or full cost-of-
15 service) SGS would require an increase of 22.32% – which is 10 percentage
16 points *above* the system average. Under Staff's proposal to increase SGS by only
17 half of what is needed to attain parity, SGS winds up with a non-fuel increase of
18 11.16% – which is *below* the system average. By itself, this is a red flag, because
19 if 12.32% is an acceptable increase for customers as a whole, it is difficult to
20 understand why a class that is receiving a subsidy should be getting a better-than-
21 average deal. Further, in order to fund the subsidies to the Residential and SGS
22 classes, the MGS/LGS grouping, which warrants a non-fuel rate *reduction* of

[9] Direct Testimony of Howard Solganick, p. 24.

8.85% to attain parity,[10] winds up with a non-fuel increase of 10.12% – an increase that is just below the increase proposed for SGS. Staff's revenue allocation formulation is demonstrably unreasonable in part because it results in a subsidy-receiving class (SGS) receiving a below-average increase – and one that is very similar to the increase proposed for the class that is funding its subsidy (MGS/LGS). When this occurs, classes are not moving toward parity in a meaningful way.

**Q. Do you have any other observations regarding Staff's revenue allocation proposal?**

A. Yes. The framework presented by Staff in support of its revenue allocation proposal appears in Staff Exhibit HS-4. This presentation focuses exclusively on the relative class increases in non-fuel rates, without taking into consideration that a big driver behind the non-fuel rate increase is UNSE's investment in the Gila River generating plant and that the investment in that plant is expected to bring base fuel costs down. By focusing on the relative rate changes in non-fuel costs in isolation, and without factoring in the associated reduction in base fuel costs to customers, and the absorption of the TCA into base rates, Staff's depiction of the class rate impacts tells only part of the story.

To gain insight into these effects, I have updated the net rate impacts from Staff's proposed revenue allocation using updated test year base revenue and fuel costs, which are now reflected in UNSE's rebuttal filing. This update is shown in Table KCH-SR-4, below. This update changes the percentages in Column (d), but not the dollar amounts proposed by Staff in Column (c). I have also added

[10] See Staff Exhibit HS-4, line 37, Column (E).

Columns (e) and (f) to show the net change in rates implicit in Staff's proposal, using the adjusted test year base revenue presented by UNSE and the Company's projected change in fuel costs in its rebuttal filing, adjusted to keep kilowatt-hour sales for each class constant and to take into account the absorption of the TCA revenues into base rates, as I described above.

**Table KCH-SR-4**
**Summary of Staff Proposed Revenue Spread by Customer Class**

| Customer Class | UNSE Rebuttal Current Adjusted Test Year Base Revenue | Staff Proposed Base Dollar Change | Staff Proposed Base Percent Change | Staff Net Dollar Change (Year 2) | Staff Net Percent Change (Year 2) |
|---|---|---|---|---|---|
| (a) | (b) | (c) | (d) | (e) | (f) |
| **Residential** | $78,169,265 | $10,563,000 | 13.51% | $1,241,152 | 1.6% |
| **Small General Service** | $12,461,200 | $1,328,500 | 10.66% | $421,336 | 3.4% |
| **Medium/Large General Service** | $56,334,006 | $5,435,055 | 9.65% | $6,456,308 | 11.5% |
| **Large Power Service** | $7,446,668 | $746,486 | 10.02% | $1,605,487 | 21.6% |
| **Lighting** | $547,038 | $54,959 | 10.05% | $58,417 | 10.7% |
| **Total** | $154,958,178 | $18,128,000 | 11.70% | $9,782,701 | 6.3% |

The proposed net changes to each class's revenue requirement under Staff's proposal are presented in the final two columns of Table KCH-SR-4, above. This shows that the net rate impacts on the subsidy-receiving classes are dramatically lower than the impacts of the non-fuel increases that Staff focused on in isolation. Moreover, the net increases for both of the subsidized classes under Staff's proposal are significantly lower than the net increases for the subsidy-paying classes. This is a strong further indication that Staff's proposed revenue allocation and increased cross-subsidization is unreasonable.

**Q. In your direct testimony you supported the revenue allocation proposed by UNSE in its direct testimony and further recommended that if a reduction to UNSE's proposed revenue requirement is approved by the Commission that it be apportioned 50% to the subsidy-paying classes and 50% to the subsidy-receiving classes. Is this still your recommendation?**

A. Yes. I also recommended that the first $908 thousand of revenue requirement reduction apportioned to the subsidy-paying classes should be used to support the Experimental Rider 14 buy-through program.

**Q. Given UNSE's stipulated agreement to reduce its proposed non-fuel revenue requirement increase from $22.6 million to $18.5 million, what revenue allocation results from your recommended approach?**

A. My recommended revenue allocation at UNSE's lower non-fuel revenue requirement is presented in Exhibit KCH-SR-1 and summarized in Table KCH-5-SR, below.

**Table KCH-5-SR**

**Summary of AECC/Noble Solutions Proposed Surrebuttal Revenue Spread by Customer Class**

| Customer Class | UNSE Rebuttal Current Adjusted Test Year Base Revenue | AECC/ Noble Solutions Proposed Base Dollar Change | AECC/ Noble Solutions Proposed Base Percent Change | AECC/ Noble Solutions Net Dollar Change (Year 2) | AECC/ Noble Solutions Net Percent Change (Year 2) |
|---|---|---|---|---|---|
| (a) | (b) | (c) | (d) | (e) | (f) |
| Residential | $78,169,265 | $18,819,863 | 24.1% | $9,498,015 | 12.2% |
| Small General Service | $12,461,200 | $2,345,477 | 18.8% | $1,438,312 | 11.5% |
| Medium/Large General Service | $56,334,006 | ($1,020,943) | -1.8% | $310 | 0.0% |
| Large Power Service | $7,446,668 | ($898,475) | -12.1% | ($39,473) | -0.5% |
| Lighting | $547,038 | $49,303 | 9.0% | $52,761 | 9.6% |
| Sub-Total | $154,958,178 | $19,295,224 | 12.5% | $10,949,925 | 7.1% |
| Experimental Rider 14 Reserve | | ($908,000) | | ($908,000) | |
| Total | $154,958,178 | $18,387,224 | 11.9% | $10,041,925 | 6.5% |

My recommended approach allows all customer classes to benefit from the stipulated $4.2 million reduction in non-fuel revenues. My approach also adheres to the principle of gradualism, as substantial subsidies to the Residential and SGS classes are built into the starting revenue allocation from which the rate reductions arc applied.[11] Finally, it provides for complete recovery of UNSE's revenue deficiency that is attributed to the reduction in fixed generation revenues from potential buy-through customers. Under my proposal, UNSE is able to recover its approved revenue requirement and the customer classes not eligible to participate in the program are held harmless from adoption of the buy-through provision. Moreover, non-participating customers in the buy-through-eligible classes are also held harmless – and indeed are in an improved position – relative to UNSE's initial filing.

## BUY-THROUGH TARIFF

**Q. Does Staff address the buy-through tariff in its direct testimony?**

A. Yes. Mr. Solganick comments on the buy-through tariff. He states:

> Because the Company is not supporting this concept, there is no record describing the benefits to non-participating customers. Staff looks forward to testimony in support of the "Buy-Through". Staff does not object to a "Buy-Through" mechanism if there are no adverse impacts and no costs to all other customers. Staff opposes recouping any allegedly lost Buy-Through revenue in the LFCR and likewise opposes any deferral of allegedly lost Buy-Through revenue.[12]

[11] As explained on pp. 9-10 of my direct testimony, the interclass subsidies in the revenue allocation proposed in UNSE's direct filing, which is the starting point for my surrebuttal revenue allocation, amount to approximately $9.1 million, the large majority of which benefits the Residential class.
[12] Direct Testimony of Howard Solganick, p. 48.

1 **Q. Do you believe your recommended modifications to UNSE's buy-through**
2 **program parameters meet the requirements identified by Mr. Solganick to**
3 **warrant Staff non-opposition to the buy-through program?**
4 A. Yes, I do. My modifications to UNSE's program parameters remove any
5 funding through the Lost Fixed Cost Recovery Mechanism ("LFCR") and ensure
6 that the customer classes not eligible to participate in the program would be held
7 harmless from adoption of the buy-through provision. In addition, my proposed
8 revenue allocation relating to the $4.2 million reduction in base rates accepted by
9 UNSE ensures that non-participating customers in the buy-through-eligible
10 classes are also held harmless – and indeed are in an improved position – relative
11 to UNSE's initial filing. Finally, my proposal does not require any cost deferrals,
12 another condition identified by Staff to warrant non-opposition.
13 **Q. Has UNSE responded to your direct testimony regarding the buy-through**
14 **program?**
15 A. Yes. UNSE witness Craig Jones generally disagrees with my
16 recommendations. Specifically, Mr. Jones responds to the following elements of
17 my testimony:[13]
18 • Mr. Jones disagrees with my proposal to reduce the minimum load size for
19 participation and to allow load aggregation;
20 • Mr. Jones disagrees with my proposal to reduce UNSE's proposed
21 management fee;
22 • Mr. Jones disagrees with my recommended reductions to UNSE's proposed
23 assignment of fixed generation costs to buy-through customers;

[13] See Rebuttal Testimony of Craig A. Jones, pp. 45-51.

- Mr. Jones disagrees with my proposal for funding the UNSE revenue deficiency that is attributed to the reduction in fixed generation revenues from buy-through customers;
- Mr. Jones disagrees with my recommendation to reduce the mark-up proposed by UNSE for customers that seek to return to the standard rate schedule; and
- Mr. Jones disagrees with my proposal to clarify that the buy-through program will continue at least until the start of the first rate-effective period of a general rate case following the proposed four-year term.

I will respond to each of these items in turn.

**Q. On what grounds does UNSE oppose your proposal to reduce the minimum load size for participation and to allow load aggregation?**

A. In advancing my proposal to allow aggregation and to allow premises with billing demands of 200 kW or greater to participate (if they can aggregate up to 1000 kW), I pointed out that the APS AG-1 program permits aggregation and allows smaller premises to participate than UNSE proposes. Mr. Jones responds that APS is a much larger utility than UNSE and has greater economies of scale. He also argues that APS Schedule 32-L (which qualifies for AG-1) "in no way corresponds" to UNSE's MGS rate schedule. Mr. Jones also states that UNSE's obligation to propose a buy-through program is limited to the LPS class. [14]

**Q. What is your response to Mr. Jones on these points?**

A. I do not disagree with Mr. Jones that APS is a much larger utility than UNSE. I recognized the difference in scale between the two utilities in my direct testimony when I accepted UNSE's proposal for a 10 MW cap on buy-through

[14] Id., p. 47.

1 participation, which is only 5% of the 200 MW participation allowed under the
2 APS program.

3 Yet, within this smaller program scope, it is reasonable and in the public
4 interest for the opportunities to participate in the buy-through program to be
5 broader than just the LPS class. According to UNSE's filing, this class would
6 have only <u>four</u> customers in it. Eligibility for the buy-through program should not
7 be limited to such a small number of customers. Experience with the AG-1
8 program demonstrates that there is keen interest on the part of commercial and
9 public sector customers in participating in the market for electric power. This
10 opportunity should be available to similar UNSE customers as well.

11 Regarding the comparability of the APS 32-L rate schedule to the UNSE
12 MGS rate schedule, I note that my proposal requires a minimum size of 200 kW,
13 which is reasonably comparable to the 400 kW minimum size for 32-L. I believe
14 a smaller minimum size for the UNSE buy-through program is appropriate given
15 the smaller scale of the UNSE system.

16 Finally, I recognize that UNSE is not *obligated* under the Fortis settlement
17 agreement to propose a program with eligibility that is broader than the LPS class.
18 The proposal to broaden the eligibility in this proceeding is that of AECC and
19 Noble Solutions. The question before the Commission at this time is what type of
20 buy-through program might be appropriate for UNSE and its customers, when
21 considered on the merits. I believe that the expanded buy-through program
22 discussed in my direct and this surrebuttal testimony is in the public interest and
23 merits Commission approval.

1 **Q. On what grounds does Mr. Jones disagree with your proposal to reduce**
2 **UNSE's proposed management fee from $0.004/kWh to $0.0006/kWh?**
3 A. In my direct testimony I pointed out that UNSE's proposed management
4 charge was more than six times the size of the comparable charge for the AG-1
5 program. Mr. Jones responds by citing to APS's larger scale and also asserts that
6 APS has indicated that the "net impact of the AG-1 program has been losses in
7 the range of $10 million annually." Mr. Jones suggests that an inadequate
8 management fee is partly responsible for the alleged losses.[15]
9 **Q. What is your response to Mr. Jones on these points?**
10 A. I acknowledge that APS has larger scale than UNSE. However, UNSE
11 provides no analysis supporting its much larger charge. Indeed, UNSE has made
12 it clear that the Company opposes the buy-through program. Proposing a
13 burdensome administrative charge is consistent with such opposition. Further,
14 there is no independent evidentiary support for Mr. Jones's assertion that the AG-
15 1 program has incurred net losses in the range of $10 million annually for APS.
16 Absent evidence from UNSE that a $0.004/kWh administrative charge is
17 cost-justified, the more reasonable approach is to set this charge in a range similar
18 to the AG-1 program.
19 **Q. How does Mr. Jones respond to your recommended reductions to UNSE's**
20 **proposed assignment of fixed generation costs to buy-through customers?**
21 A. Mr. Jones disputes that the assignment of 100% of fixed generation costs
22 to buy-through customers is comparable to a stranded cost charge, as I maintain.

[15] Id., p. 48.

However, he does not offer an argument as to why the charge should be greater than the 15% planning reserve margin that I propose.

**Q. Do you continue to recommend that, absent an opportunity to transition permanently to market pricing, the going-forward charges for generation-related services to buy-through customers should be limited to a charge for reserve capacity applied to 15% of the customer's billed demand priced at the unbundled generation demand charge?**

A. Yes. This is a reasonable fixed generation cost charge for a customer that would not be using UNSE's generation service as part of a pilot program, such as a buy-through customer.

**Q. How does Mr. Jones respond to your proposal for funding any UNSE revenue deficiency that is attributed to the reduction in fixed generation revenues from buy-through customers?**

A. In my direct testimony I proposed that the first $908 thousand of any revenue requirement reduction apportioned to the subsidy-paying classes – which under my proposal are also the classes eligible for the buy-through program (MGS, LGS, and LPS) – be used to absorb UNSE's revenue deficiency ascribed to the loss of fixed generation revenues from buy-through customers. In this way, both UNSE and the customer classes not eligible to participate in the program would be held harmless from adoption of the buy-through provision. In my surrebuttal testimony, I have applied my proposal to the $4.2 million base revenue requirement reduction accepted by UNSE in its rebuttal filing, as presented above in Table KCH-5-SR.

In his rebuttal testimony, Mr. Jones acknowledges that my proposal is "innovative on the surface," then simply reiterates that UNSE is opposed to the buy-through concept in any form.[16]

**Q. Do you continue to recommend that the first $908 thousand of any revenue requirement reduction apportioned to the subsidy-paying classes be used to absorb UNSE's revenue deficiency ascribed to the loss of fixed generation revenues from buy-through customers?**

A. Yes. My proposal limits the funding of this revenue requirement to the classes eligible for the program. My approach avoids both the burdensome fixed generation charges proposed by UNSE for buy-through customers as well as recovery of deemed lost revenues from other customers through the LFCR as proposed by UNSE.

Further on this point, I note that UNSE witness David G. Hutchens indicates in his rebuttal testimony that any lost non-fuel revenues resulting from discounts provided through the proposed EDR would be absorbed by the Company.[17] This position contrasts sharply with UNSE's position regarding the buy-through tariff, which is also an economic development tool. In the case of the EDR, UNSE is willing to absorb lost non-fuel revenues from discounts related to the sale of full requirements service, but in the case of the buy-through tariff, UNSE proposes to load fixed generation costs onto customers who would not even be buying generation service from the Company.

[16] Id., p. 49.
[17] Rebuttal Testimony of David G. Hutchens, pp. 15-16.

I believe my proposal strikes a reasonable balance, as it does not even require UNSE to absorb margins as the Company indicates it would do for an EDR contract, nor does my proposal impact customer classes that are not eligible to participate in the buy-through program.

**Q. On what grounds does Mr. Jones oppose your recommendation to reduce the mark-up proposed by UNSE for customers that seek to return to the standard rate schedule?**

A. If, prior to the end of the planned four-year term of the program, and absent Commission termination of the program, a buy-through customer seeks to return to standard generation service and does not provide one-year's notice, UNSE proposes to charge the returning customer the Dow Jones Electricity Palo Verde Daily Index price for the power delivery date plus $20 per MWh until the Company is reasonably able to integrate the customer back into the Company's generation planning. In my direct testimony, I agreed that this general approach is reasonable, but argued that the proposed $20 per MWh mark-up is excessive. I pointed out that APS's AG-1 program also requires that an "early" returning buy-through customer pay market rates for up to one year, but without an additional mark-up. I recommended that the $20 per MWh mark-up proposed by UNSE should be eliminated or significantly reduced to no greater than $4 per MWh.

In rebuttal, Mr. Jones argues that the AG-1 tariff provides for a $10 per MWh mark-up over the Dow Jones Palo Verde Index for a returning customer. He also argues that this return charge is intended to be a "penalty" and states that

"UNS Electric wants to protect itself and its customers from the types of losses that APS has experienced as a result of the AG-1 program."[18]

**Q. What is your response to Mr. Jones on these points?**

A. Mr. Jones misinterprets the AG-1 tariff, which I have attached as Exhibit KCH-SR-2. As is clear in the Section entitled "Return to Company's Standard Generation Service," on page 3 of the AG-1 tariff, APS does not charge a returning customer a mark-up over the market index rate. Rather, APS will charge the customer a market price until APS is reasonably able to integrate the customer back into its generation planning, at which time the customer may take service at the applicable retail rate.

The $10 per MWh referenced by Mr. Jones appears in a different section of the AG-1 tariff, "Default of the Third Party Generation Provider." This section is not intended for customers returning to standard offer service, as Mr. Jones indicates, but rather customers who are "in between" third-party generation providers. This product is clearly intended as a temporary bridge for a customer whose generation provider has defaulted and is in the process of finding a new market supplier.

Further, Mr. Jones's concerns that UNSE must be "protected" from a returning customer are misplaced. Under my proposal, UNSE experiences no unrecovered revenue deficiency from the buy-through program; thus there is no harm from which UNSE and customers must be "protected." Moreover, if a returning customer is charged a market price that is passed through from UNSE, the Company continues to be held harmless. The $4 per MWh mark-up over the

[18] Rebuttal testimony of Craig A. Jones, p. 50.

1 market price that I suggested in my direct testimony is intended to provide
2 reasonable compensation to UNSE for undertaking the market transaction for the
3 returning customer. A $20 per MWh penalty is unnecessary and unwarranted.

4 **Q. On what grounds does Mr. Jones disagree with your proposal to clarify that**
5 **the buy-through program will continue at least until the start of the first**
6 **rate-effective period of a general rate case following the proposed four-year**
7 **term?**

8 A. Mr. Jones asserts that AECC "seems to want the best of both worlds" with
9 my recommendation.

10 **Q. What is your response to Mr. Jones on this point?**

11 A. My proposal is merely intended to avoid a "stub period" in which the pilot
12 program terminates prior to its future being considered in a general rate case.
13 Recently, the AG-1 program was extended by the Commission after parties
14 realized that it was scheduled to terminate prior to its future being considered in a
15 general rate case. My proposal is simply intended to line up the terminal date of
16 the initial pilot to the start date of the rate-effective period of the rate case in
17 which the program's future would be decided. This is not attempt to achieve the
18 "best of both worlds," but simply a recommendation in the interest of
19 administrative efficiency.

20

21 **UNBUNDLED RATE DESIGN**

22 **Q. In your direct testimony you challenged UNSE's unbundled rate design for**
23 **MGS, LGS, and LPS rate schedules. Has UNSE responded in its rebuttal**

**testimony to your criticism and your recalculation of UNSE's unbundled rates?**

A. No. In my direct testimony, I pointed out that UNSE's unbundled rate design is seriously flawed in that the Company is attempting to recover fixed generation-related costs in the Local Delivery component of the demand charge, contrary to the fundamentals of proper unbundled rate design. UNSE has not responded to my criticism, which I believe is irrefutable.

**Q. Have you updated your recommended unbundled rate design for the MGS, LGS, and LPS rate schedules to reflect the reduced revenue requirement in your surrebuttal revenue allocation?**

A. Yes. My updated unbundled rates are presented in Exhibit KCH-SR-3. My proposed non-fuel revenue requirement for LPS represents a reduction of $126,646 relative to UNSE's (and my) direct testimony to reflect this rate schedule's share of the $4.2 million overall non-fuel revenue requirement reduction accepted by UNSE in its rebuttal filing. I pass this reduction through to the bundled demand charges and energy delivery charges for this rate schedule on a pro rata basis. Within the bundled demand charge, I reflect the reduction on an equal percentage basis between the Demand Delivery and Generation Capacity unbundled charges, as shown on page 1 of the exhibit.

My proposed non-fuel revenue requirement for MGS/LGS represents a reduction of $1,047,288 relative to UNSE's (and my) direct testimony to reflect this group's share of the $4.2 million overall non-fuel revenue requirement reduction accepted by UNSE in its rebuttal filing. I pass this reduction through to the bundled demand charges and energy delivery charges for these rate schedules

1 on a pro rata basis. Within the bundled demand charges, I reflect the reduction on
2 an equal percentage basis between the Demand Delivery and Generation Capacity
3 unbundled charges, as shown on pages 2-3 of the exhibit.

4 **Q. In your direct testimony, you *accepted* the *bundled* demand charges proposed**
5 **by UNSE, but you proposed significantly different unbundled components.**
6 **Are you no longer accepting UNSE's bundled demand charges as your**
7 **starting point for unbundled rates?**

8 A. That is correct. I am no longer accepting UNSE's bundled demand
9 charges as the starting point for unbundled rates because UNSE has changed its
10 revenue allocation unreasonably to the disadvantage of the MSG, LGS, and LPS
11 rate schedules. Even though UNSE has accepted an overall lower revenue
12 requirement in its rebuttal filing, each of these three rate schedules is *worse off* in
13 UNSE's rebuttal filing than in the Company's direct filing. In contrast, I am
14 recommending that each rate schedule be made better off relative to UNSE's
15 direct filing to reflect the $4.2 million reduction in revenue requirement that
16 UNSE has accepted.

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

18 A. Yes, it does.

KCH-SR-1

## Summary of AECC/Noble Solutions Proposed Surrebuttal Revenue Spread by Customer Class

| Line No. | Description (a) | Amount (b) |
|---|---|---|
| 1 | UNSE Direct Filing Requested Revenue Increase = | $22,621,008 |
| 2 | UNSE Rebuttal Filing Requested Revenue Increase = | $18,457,140 |
| 3 | UNSE Reduction in Requested Revenue Increase = | ($4,163,868) |
| | **AECC/Noble Solutions Recommended Distribution of Reduction in Reqeusted Revenue Increase:** | |
| 5 | 50% Applied to Subsidy Receiving Class = | ($2,081,934) |
| 6 | 50% Applied to Subsidy Paying Classes = | ($2,081,934) |
| 7 | Reduction of Subsidy Paying Classes Amount Applied to Experimantal Rider 14 Costs[1] = | $908,000 |
| 8 | Net Reduction Applied to Subsidy Paying Classes = | ($1,173,934) |

**Note 1: This amount would be used to recover any reduction in fixed generation revenues that arise from implementation of the Experimental Rider 14. Any unused funds would be returned to MGS/LGS/LPS customers in a future regulatory proceeding.**

## AECC/Noble Solutions Recommended Spread of UNSE's Requested Rebuttal Revenue Increase

| | | Current Adjusted Test Year Margin Revenue | Percentages for Spreading Revenue Reduction[2] | UNSE As-Filed Base Dollar Change | Spread of Reduction in Revenue Increase | AECC Recommended Base Dollar Change |
|---|---|---|---|---|---|---|
| 9 | Residential | 33,425,187 | 13.4% | $20,556,648 | ($1,736,785) | $18,819,863 |
| 10 | Small General Service | 6,136,594 | 13.3% | $2,664,336 | ($318,860) | $2,345,477 |
| 11 | Medium/Large General Service | 26,394,695 | 89.2% | $26,345 | ($1,047,288) | ($1,020,943) |
| 12 | Large Power Service | 3,191,840 | 10.8% | ($771,829) | ($126,646) | ($898,475) |
| 13 | Lighting | 505,944 | 1.5% | $75,592 | ($26,289) | $49,303 |
| 14 | Sub-Total | 69,654,260 | | 22,551,092 | (3,255,868) | 19,295,224 |
| 15 | Experimental Rider 14 Reserve | | | | (908,000) | ($908,000) |
| 16 | Total | | | | (4,163,868) | 18,387,224 |

**Note 2: Shaded cell percentages apply to AECC/Noble reduction (see Ln. 5) for subsidy receiving classes. Non-shaded cells percentages apply to AECC/Noble reduction (see Ln. 8) for subsidy paying classes.**

## Summary of AECC/Noble Solutions Proposed Surrebuttal Revenue Spread by Customer Class

| | Customer Class (a) | UNSE Rebuttal Current Adjusted Test Year Base Revenue (b) | AECC/ Noble Solutions Proposed Base Dollar Change (c) | AECC/ Noble Solutions Proposed Base Percent Change (d) | AECC/ Noble Solutions Net Dollar Change (Year 2) (e) | AECC/ Noble Solutions Net Percent Change (Year 2) (f) |
|---|---|---|---|---|---|---|
| 17 | Residential | $78,169,265 | $18,819,863 | 24.1% | $9,498,015 | 12.2% |
| 18 | Small General Service | $12,461,200 | $2,345,477 | 18.8% | $1,438,312 | 11.5% |
| 19 | Medium/Large General Service | $56,334,006 | ($1,020,943) | -1.8% | $310 | 0.0% |
| 20 | Large Power Service | $7,446,668 | ($898,475) | -12.1% | ($39,473) | -0.5% |
| 21 | Lighting | $547,038 | $49,303 | 9.0% | $52,761 | 9.6% |
| 22 | Sub-Total | $154,958,178 | $19,295,224 | 12.5% | $10,949,925 | 7.1% |
| 23 | Experimental Rider 14 Reserve | | ($908,000) | | ($908,000) | |
| 24 | Total | $154,958,178 | $18,387,224 | 11.9% | $10,041,925 | 6.5% |

KCH-SR-2

# Exhibit KCH-SR-2

# APS Experimental Rate Rider Schedule AG-1

# EXPERIMENTAL RATE RIDER SCHEDULE AG-1
# ALTERNATIVE GENERATION
# GENERAL SERVICE

## AVAILABILITY

This experimental rate rider schedule is available in all territories served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the sites served.

## APPLICATION

This rate rider schedule is available for Standard Offer customers who have an Aggregated Peak Load of 10 MW or more and are served under Rate Schedules E-34, E-35, E32-L, or E-32 TOU L. An aggregated group may also include metered accounts that are served under Rate Schedules E-32 M or E-32 TOU M, if the accounts are located on the same premises and served under the same name as an otherwise eligible Customer.

Customers must have interval metering, Advanced Metering Infrastructure, or an alternative in place at all times of service under this schedule. If the Customer does not have such metering, the Company will install the metering equipment at no additional charge. However, the customer will be responsible for providing and paying for any communication requirements associated with the meter, such as a phone line.

All provisions of the customer's applicable rate schedule will apply in addition to this Schedule AG-1, except as modified herein. This rate rider schedule is available for existing AG-1 customers served under the rider as of November 25, 2015 and will remain available until further order of the Arizona Corporation Commission, in accordance with Commission Decision No. 75322. Total program participation shall be limited to 200 MW of customer load, 100 MW of which shall be initially reserved for Customers served under Rate Schedule E-32 L.

## DEFINITIONS

Aggregated Peak Load: The sum of the maximum metered kW for each of the Customer's aggregated metered accounts over the previous 12 months, as determined by the Company and measured at the Customer's meter(s) at the time of application for service under this rate rider schedule.

Standard Generation Service: Power provided by the Company to a retail customer in conjunction with transmission and delivery services, at terms and prices according to a retail rate schedule other than Schedule AG-1.

Customer: A metered account or set of aggregated metered accounts that meet the eligibility requirements for service and enrollment as an aggregated load for service, under this rate rider schedule.

Generation Service Provider: A third party entity that provides wholesale power to the Company on behalf of a Customer. This entity must be legally capable of selling and delivering wholesale power to the Company.

Generation Service: Wholesale power delivered to APS by a Generation Service Provider.

Imbalance Energy: For each Generation Service Provider, Imbalance Energy will be calculated by the Company as the difference between the hourly delivered energy from the Generation Service Provider and the actual hourly metered load for each Customer for all Customers that have selected the Generation Service Provider under this rate rider schedule.

Imbalance Service: Calculating and managing the hourly deviations in energy supply for imbalance energy.

Total Load Requirements: The Customer's hourly load including losses from the point of delivery to the Company's transmission system to the Customer's sites for the duration of the contract.

CUSTOMER ENROLLMENT

The Company shall establish an initial enrollment period during which Customers can apply for service under this rate rider schedule. If the applications for service are greater than the program maximum amount, then Customers shall be selected for enrollment through a lottery process as detailed in the program guidelines, which may be revised from time-to-time during the term of this rate rider schedule.

AGGREGATION

Eligible customers may be aggregated if they have the same corporate name, ownership, and identity. In addition, (1) an eligible franchisor customer may be aggregated with eligible franchisees or associated corporate accounts, and (2) eligible affiliate customers may be aggregated if they are under the same corporate ownership, even if they are operating under multiple trade names.

DESCRIPTION OF SERVICES AND OBLIGATIONS

The Customer shall apply for service under this rate rider schedule.

The Company shall conduct the enrollment process in accordance with the provisions of this rate rider schedule.

The Customer shall select a Generation Service Provider to provide Generation Service in accordance with the timeline specified in the program guidelines

The Company shall enter into a contract with the Generation Service Provider to receive delivery and title to the power on the Customer's behalf.

The Generation Service Provider shall provide to the Company on behalf of the Customer firm power sufficient to meet the Customer's Total Load Requirements for each of the specified metered accounts, and will attest in its contract with the Company that this condition is met. For the purposes of this rate schedule, "firm power" refers to generation resources identified in Western System Power Pool Schedule C or a reasonable equivalent as determined by the Company.

The Company shall provide transmission, delivery and network services to the Customer according to normal retail electric service.

The Company will settle with the Generation Service Provider for Imbalance Service and other relevant costs on a monthly basis according to the program guidelines.

The Generation Service Provider shall bill the Company the monthly billed amounts for each customer for Generation Service and Imbalance Service according to the program guidelines.

The Company shall bill the customer for the Generation Service Provider's charged amounts and remit the amounts to the Generation Service provider.

The customer will be responsible for paying for the cost of the power provided by the Generation Service Provider, as specified in the contract and this rate rider schedule.

DELIVERY OF POWER TO THE COMPANY'S SYSTEM

Power provided by the Generation Service Provider must be firm power as defined above and delivered to the Company at the Palo Verde network delivery point, or other point of delivery as agreed to by the Company. The Generation Service Provider is responsible for the cost of transmission service to deliver the power to the Company's delivery point.

SCHEDULING

The Company shall serve as the scheduling coordinator. The Generation Service Provider shall provide monthly schedules of hourly loads along with day-ahead hourly load deviations from the monthly schedule to the Company according to the program guidelines. Line losses, in the amount of 7%, from the point of delivery to the Customer's sites shall be either scheduled or financially settled.

IMBALANCE SERVICE

The Company will provide Imbalance Service according to the terms and provisions in the Company's Open Access Transmission Tariff, Schedule 4. Imbalance Energy will be based on the Generation Service Provider's portfolio of Customer loads.

POWER SUPPLY ADJUSTER AND HEDGE COST TRUE-UP

The customer will be subject to the power supply adjustment – historical component for the first twelve months of service under this rate rider schedule. The customer will also pay for the hedge cost associated with the customer's Standard Generation Service at the time the customer takes service under this rate rider schedule. For the purpose of this rate rider schedule, the Company will determine the applicable pro rata hedge cost based on the market price for hedge costs at the time the customer takes service under this rate rider schedule.

DEFAULT OF THE THIRD PARTY GENERATION PROVIDER

In the event that the Generation Service Provider is unable to meet its contractual obligations, the customer must notify the Company and select another Generation Service Provider within 60 days. Prior to execution of any new power contract, the Company shall provide the required power to the customer, which will be charged at the Dow Jones Electricity Palo Verde Hourly Index price for the power delivery date plus $10 per MWh. In addition, all other provisions of this rate rider schedule will continue to apply.

If the Customer is unable to select another Generation Service Provider within sixty days, the customer will automatically return to Standard Generation Service, and be subject to the conditions below.

RETURN TO COMPANY'S STANDARD GENERATION SERVICE

Customer may return to the Company's Standard Generation Service under their applicable retail rate schedule without charge if: (1) they provide six months notice (or longer) to the Company; or (2) if the Commission terminates the program. Absent one of these conditions, the Company will provide the customer with generation service at the market index rate provided in the Company's Open Access Transmission Tariff until the Company is reasonably able to integrate the customer back into their generation planning and provide power at the applicable retail rate schedule. This transition will be at the Company's determination but no longer than 1 year. The returning customer must remain with the Company's Standard Generation Service for at least 1 year.

RATES

All provisions, charges and adjustments in the customer's applicable retail rate schedule will continue to apply except as follows:

1. The generation charges will not apply;
2. Adjustment Schedule PSA-1will not apply, except that the Historical Component will apply for the first twelve months of service under this rate rider schedule;
3. Adjustment Schedule EIS will not apply; and
4. The applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder shall be applied to the customer's bill.

Schedule AG-1 charges determined and billed by the Company include:

1. A monthly management fee of $0.00060 per kWh applied to the customer's metered kWh;
2. A monthly reserve capacity charge applied to 15% of the customer's billed kW (on-peak for Rate Schedules E-35 and E-32 TOU L) at the Company's applicable cost-based rate filed at the Federal Energy Regulatory Commission and revised from time to time, which is currently $6.985 per kW month;
3. An initial charge or credit for fuel hedging costs, as described herein;
4. Returning Customer charge, where applicable, as described herein;
5. Generation Service Provider Default charge, where applicable, as described herein.

Schedule AG-1 Generation Service and Imbalance Service charges billed by the Company include:

1. Generation Service charges shall be charged at a rate within the minimum and maximum limits as follows:

    a. When the contract provides for pricing that reflects a specific index price, the minimum price will be the specified index minus 35% and the maximum price will be the specified index plus 35%. The determination that a contract is consistent with this provision will be based on the specified index price applicable on the date the contract is executed.
    b. When the contract provides for a fixed price supply for the term of the contract, the minimum price will be the generation rate of the Customer's applicable retail rate schedule minus 35%, and the maximum price shall be the generation rate of the Customers applicable retail schedule plus 35%. If the Customer has more than one otherwise applicable retail rate schedule, the highest applicable retail rate schedule will be used for purposes of the consistency determination. The determination that a contract is consistent with this provision will be based on the Customer's otherwise applicable retail rate schedule in effect on the date the contract is executed.
    c. Losses from the delivery point to the Customer's meters and any charges assessed by the Company on the Customer, including charges for transmission and distribution, Capacity Reservation Charge, the Management Fee, Imbalance Service charges, PSA balance and hedging costs, and Returning Customer Charges, shall not be included in the Generation Service charge for purposes of determining whether the contract is consistent with the minimum and maximum price provisions of this rate rider schedule.

2. Imbalance Service charges shall be charged at a rate greater than $0.00 per kWh and less than or equal to the rate that the Company charges the Generation Service Provider for Imbalance Service as specified herein.

## CONTRACT TERM AND REQUIREMENTS

The term of the contract with the Generation Service Provider shall be for not less than one year and shall not exceed four years.

The Generation Service Provider and Customer will enter into a contract or contracts with the Company, stating the pertinent details of the transaction with the Generation Service Provider, including but not limited to the scheduling of power, location of delivery and other terms related to the Company's management of the generation resource.

## CREDIT REQUIREMENTS

A Generation Service Provider or its parent company must have at least an investment grade credit rating or demonstrate creditworthiness in the form of either a 3rd-party guarantee from an investment grade rated company, surety bond, letter of credit, or cash in accordance with the Company's standard credit support rules

KCH-SR-3

**AECC/Noble Solutions' Recommended Unbundled LPS & LPS-TOU Rates**
**(at UNSE's Rebuttal Revenue Requirement)**

| Line No. | Description | UNSE Proposed Bundled Rates (Rebuttal)[1] | AECC/ Noble Solutions Recommended Rates (Direct) | AECC/ Noble Solutions Recommended Rates (Rebuttal) |
|---|---|---|---|---|
| 1 | Basic Service Charge Components ($/Cust./Mo.): | | | |
| 2 | Meter Services | | $145.57 | $145.57 |
| 3 | Meter Reading | | $101.86 | $101.86 |
| 4 | Billing & Collection | | $451.63 | $451.63 |
| 5 | Customer Delivery | | $500.94 | $500.94 |
| 6 | Total | $1,500.00 | $1,200.00 | $1,200.00 |
| 7 | Demand Charge Components ($/kW): | | | |
| 8 | Local Delivery | | $0.29 | $0.26 |
| 9 | Generation Capacity | | $8.61 | $7.93 |
| 10 | Transmission | | $3.58 | $3.57 |
| 11 | Total | $13.00 | $12.48 | $11.76 |
| 12 | Energy Charge Components ($/kWh): | | | |
| 13 | Local Delivery | $0.000500 | $0.000520 | $0.000489 |
| 14 | Power Supply Charges ($/kWh): | | | |
| 15 | Base Power Supply (LPS) | $0.049332 | $0.048410 | $0.049332 |
| 16 | Base Power Supply Summer On-Peak - (LPS-TOU) | $0.125155 | $0.122510 | $0.125155 |
| 17 | Base Power Supply Summer Off-Peak - (LPS-TOU) | $0.033410 | $0.032110 | $0.033410 |
| 18 | Base Power Supply Winter On-Peak - (LPS-TOU) | $0.092110 | $0.092110 | $0.092110 |
| 19 | Base Power Supply Winter Off-Peak - (LPS-TOU) | $0.030410 | $0.030910 | $0.030410 |
| 20 | PPFAC (%) (see Rider-1 for current rate) | Varies | Varies | Varies |

Notes:
1. Data Source: UNSE Exhibit CAJ-R-4, Schedule H-3, p. 6 of 8.

## AECC/Noble Solutions' Recommended Unbundled LGS, LGS-TOU & LGS-TOU-S Rates (at UNSE's Rebuttal Revenue Requirement)

| Line No. | Description | UNSE Proposed Bundled Rates (Rebuttal)[1] | AECC/ Noble Solutions Recommended Rates (Direct) | AECC/ Noble Solutions Recommended Rates (Rebuttal) |
|---|---|---|---|---|
| 1 | Basic Service Charge Components ($/Cust./Mo.): | | | |
| 2 | Meter Services | | $31.32 | $31.32 |
| 3 | Meter Reading | | $5.01 | $5.01 |
| 4 | Billing & Collection | | $22.15 | $22.15 |
| 5 | Customer Delivery | | $241.52 | $241.52 |
| 6 | Total | $300.00 | $300.00 | $300.00 |
| 7 | Demand Charge Components ($/kW): | | | |
| 8 | Demand Delivery | | $0.96 | $0.91 |
| 9 | Generation Capacity | | $9.70 | $9.20 |
| 10 | Transmission | | $2.30 | $2.30 |
| 11 | Total | $13.35 | $12.96 | $12.41 |
| 12 | Energy Charge Components ($/kWh): | | | |
| 13 | Local Delivery | $0.005470 | $0.005400 | $0.005167 |
| 14 | Power Supply Charges ($/kWh): | | | |
| 15 | Base Power Supply (LGS) | $0.053290 | $0.048400 | $0.053290 |
| 16 | Base Power Supply Summer On-Peak - (LGS-TOU) | $0.143771 | $0.145510 | $0.143771 |
| 17 | Base Power Supply Summer Off-Peak - (LGS-TOU) | $0.038600 | $0.034510 | $0.038600 |
| 18 | Base Power Supply Winter On-Peak - (LGS-TOU) | $0.139880 | $0.124510 | $0.139880 |
| 19 | Base Power Supply Winter Off-Peak - (LGS-TOU) | $0.034927 | $0.032910 | $0.034927 |
| 20 | Base Power Supply Summer On-Peak - (LGS-TOU-S) | $0.148471 | $0.150210 | $0.148471 |
| 21 | Base Power Supply Summer Off-Peak - (LGS-TOU-S) | $0.043300 | $0.039210 | $0.043300 |
| 22 | Base Power Supply Winter On-Peak - (LGS-TOU-S) | $0.144580 | $0.129210 | $0.144580 |
| 23 | Base Power Supply Winter Off-Peak - (LGS-TOU-S) | $0.039627 | $0.037610 | $0.039627 |
| 24 | PPFAC (%) (see Rider-1 for current rate) | Varies | Varies | Varies |

Notes:
1. Data Source: UNSE Exhibit CAJ-R-4, Schedule H-3, p. 6 & 7 of 8.

**AECC/Noble Solutions' Recommended Unbundled MGS, MGS-TOU & MGS-TOU-S Rates**
**(at UNSE's Rebuttal Revenue Requirement)**

| Line No. | Description | UNSE Proposed Bundled Rates (Rebuttal)[1] | AECC/ Noble Solutions Recommended Rates (Direct) | AECC/ Noble Solutions Recommended Rates (Rebuttal) |
|---|---|---|---|---|
| 1 | Basic Service Charge Components ($/Cust./Mo.): | | | |
| 2 | Meter Services | | $10.44 | $10.44 |
| 3 | Meter Reading | | $1.67 | $1.67 |
| 4 | Billing & Collection | | $7.38 | $7.38 |
| 5 | Customer Delivery | | $80.51 | $80.51 |
| 6 | Total | $100.00 | $100.00 | $100.00 |
| 7 | Demand Charge Components ($/kW): | | | |
| 8 | Demand Delivery | | $2.26 | $2.16 |
| 9 | Generation Capacity | | $8.40 | $8.04 |
| 10 | Transmission | | $2.30 | $2.30 |
| 11 | Total | $13.95 | $12.96 | $12.50 |
| 12 | Energy Charge Components ($/kWh): | | | |
| 13 | Local Delivery | $0.005500 | $0.005500 | $0.005263 |
| 14 | Power Supply Charges ($/kWh): | | | |
| 15 | Base Power Supply (MGS) | $0.053290 | $0.048440 | $0.053290 |
| 16 | Base Power Supply Summer On-Peak - (MGS-TOU) | $0.114886 | $0.109900 | $0.114886 |
| 17 | Base Power Supply Summer Off-Peak - (MGS-TOU) | $0.033500 | $0.033500 | $0.033500 |
| 18 | Base Power Supply Winter On-Peak - (MGS-TOU) | $0.101047 | $0.089900 | $0.101047 |
| 19 | Base Power Supply Winter Off-Peak - (MGS-TOU) | $0.031690 | $0.031600 | $0.031690 |
| 20 | Base Power Supply Summer On-Peak - (MGS-TOU-S) | $0.120586 | $0.115600 | $0.120586 |
| 21 | Base Power Supply Summer Off-Peak - (MGS-TOU-S) | $0.039200 | $0.039200 | $0.039200 |
| 22 | Base Power Supply Winter On-Peak - (MGS-TOU-S) | $0.106747 | $0.095600 | $0.106747 |
| 23 | Base Power Supply Winter Off-Peak - (MGS-TOU-S) | $0.037390 | $0.037300 | $0.037390 |
| 24 | PPFAC (%) (see Rider-1 for current rate) | Varies | Varies | Varies |

Notes:
1. Data Source: UNSE Exhibit CAJ-R-4, Schedule H-3, p. 5 & 7 of 8.

**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 of Michael D. McElrath**

**on behalf of**

**Freeport Minerals Corporation and**

**Arizonans for Electric Choice & Competition**

**Rate Design**

**February 23, 2016**

1 **Q. PLEASE STATE YOUR NAME, AND BUSINESS ADDRESS.**

2 A. Michael D. McElrath, 333 North Central Avenue, Phoenix Arizona.

3 **Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?**

4 A. I am employed by Freeport Minerals Corporation ("Freeport") as its Director of
5 Energy Services.

6 **Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?**

7 A. Arizonans for Electric Choice and Competition ("AECC"), of which Freeport is a
8 member.

9 **Q. PLEASE DESCRIBE YOUR PROFESSIONAL EXPERIENCE AND**
10 **QUALIFICATIONS.**

11 A. I have over 40 years of experience in the energy field beginning with 16 years with
12 a natural gas utility with increasing responsibilities in 3 different states. I have
13 worked in the mining industry for 28 years dealing with energy matters for 3
14 different mining companies. Today, I am responsible for the power and natural gas
15 supplies for Freeport's mines in North America, South America and Africa.

16 **Q. HAVE YOU TESTIFIED BEFORE THE ARIZONA CORPORATION**
17 **COMMISSION (THE "COMMISSION") IN OTHER DOCKETS?**

18 A. Yes. I have testified in a number of dockets before the Commission beginning in
19 1994.

20 **Q. HAVE YOU TESTIFIED BEFORE ANY OTHER PUBLIC UTILITY**
21 **COMMISSION?**

22 A. Yes, I have testified before the Public Utility Regulatory Board in El Paso, Texas,
23 the Public Utility Commission of Colorado and the Federal Energy Regulatory
24 Commission in various dockets over the years.

25 **Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS**
26 **PROCEEDING?**

A. The purpose of my testimony is to respond to the Direct Testimony of Mr. Gary Yaquinto, Director of the Arizona Investment Council ("AIC"), concerning UNS Electric, Inc.'s ("UNSE") proposed Experimental Rider 14 ("buy-through") Tariff.

**Q. WHAT IS YOUR PRIMARY CONCLUSION AFTER REVIEWING MR. YAQUINTO'S DIRECT TESTIMONY CONCERNING THE PROPOSED BUY-THROUGH TARIFF?**

A. Mr. Yaquinto's opposition to the buy-through tariff is based primarily on the AIC's desire to maximize profits for the state's investor-owned utility investors it represents, despite claiming on the organization website that "Arizona investment strategies must be approached from a statewide perspective, with coordination among key leaders within the ***business***, investment and government communities…." and that "it is critical that Arizona establish a climate that will support and encourage investment."[1]

**Q. WHAT SUPPORTS YOUR GENERAL CONCLUSION THAT MR. YAQUINTO'S TESTIMONY CONFLICTS WITH ONE OF AIC'S STATED MISSION GOALS OF ENCOURAGING ECONOMIC INVESTMENT IN ARIZONA?**

A. Mr. Yaquinto claims that the proposed buy-through tariff represents a "free ride" for a few existing customers, and would enable a handful of "elite" corporate entities to take advantage of market opportunities, making them "a select group of privileged, large customers." Using such "loaded" terms to describe Freeport and other members of the AECC – all of which help to drive Arizona's economy and provide jobs in UNSE's service territory and throughout the state – does not lend itself to establishing a collaborative climate that will support and encourage

[1] Exhibit 1: History and Mission Statement, AIC Website

investment.

**Q. DO YOU BELIEVE THAT IF THE BUY-THROUGH TARIFF IS APPROVED, ANY CUSTOMER PARTICIPATING IN THE PROGRAM WOULD BE RECEIVING A "FREE RIDE" AS MR. YAQUINTO SUGGESTS?**

**A.** Absolutely not. Mr. Yaquinto freely admits that a major thrust of this rate proceeding is for UNSE to modernize its rate design in a way that moves customer classes closer to their actual cost of service. Industrial and commercial customers like Freeport and other members of AECC have historically paid electricity rates that more than reflect their true cost of service, and will very likely continue to subsidize other customer classes who do not pay their true cost of service after the conclusion of this proceeding.

**Q. HOW DO YOU RESPOND TO MR. YAQUINTO'S ASSERTION THAT THE COMMISSION SHOULD CONSIDER THE RESULTS OF ANOTHER "EXPERIMENTAL" PROGRAM ("AG-1" TARIFF), PREVIOUSLY APPROVED FOR ARIZONA PUBLIC SERVICE COMPANY ("APS"), BEFORE APPROVING AN EXPERIMENTAL PROGRAM FOR UNSE?**

**A.** APS' AG-1 program thus far has provided material cost savings for Freeport and other large customers without any detrimental impact to APS' other customer classes. As for his assertion that the Commission should wait and evaluate the results of the AG-1 program before approving a buy-through mechanism for UNSE, Mr. Yaquinto clearly does not recognize the benefit that approval of the buy-through tariff would have on continued economic investment in UNSE's service territory and throughout Arizona.

**Q. WHY IS FREEPORT INTERESTED IN SUPPORTING A BUY-THROUGH TARIFF IN THIS PROCEEDING?**

A. Even though Freeport's electric load in UNSE's service territory is minimal at this time, as a member of AECC, Freeport believes that the buy-through tariff proposal represents an important policy decision for the Commission as to whether to provide market options or choice in generation services for high-load industrial and commercial customers, not only in UNSE's service territory, but on a state-wide basis in areas served by Commission jurisdictional entities. As the AIC itself notes, investment strategies must be approached from a state-wide perspective, and that same reasoning applies to Freeport and other member of AECC.

In that regard, Freeport is a multinational corporation with operations in several continents and countries throughout the world. Given the current weak commodity price environment, Freeport has taken aggressive actions to enhance its financial position implementing significant reductions in capital spending, production curtailments at certain North and South America mines (including curtailments at the Sierrita and Miami operations in Arizona) and actions to reduce operating, exploration and administrative costs. Other AECC members face similar choices. This is the nature of having to compete in a competitive market. In considering the options, several factors come into play, and in Freeport's experience, those jurisdictions that provide market options for the purchase of electricity can be superior climates for continued investment compared to those that do not. If the Commission were to reject UNSE's buy-through tariff proposal in this proceeding, it would send a negative signal to the business community at large that the prospect of market purchases for electricity – even on a limited basis – is unlikely to materialize long-term in UNSE's service territory and throughout the state.

**Q. DO YOU BELIEVE THAT THE PROPOSED BUY-THROUGH TARIFF, AS WELL AS SIMILAR MECHANISMS FOR OTHER INVESTOR-OWNED UTILITIES, COULD BENEFIT UNSE BY PROVIDING A MEANS BY**

**WHICH TO INCENT LARGE CUSTOMERS TO KEEP THEIR OPERATIONS IN ITS SERVICE TERRITORY?**

A. Yes. There are significant advantages in having industrial and commercial customers located within UNSE' service territory that benefit the community at large, such as job creation, a higher tax base and corporate sponsorship of community and civic events. These benefits disappear if a corporation decides to curtail, shut down or completely move its operations from the local community as a result of market conditions.

Q. **UNSE HAS ALSO PROPOSED AN ECONOMIC DEVELOPMENT RATE, WHICH OTHER INVESTOR-OWNED UTILITIES ARE LIKELY TO EMULATE IF APPROVED IN THIS PROCEEDING. DO YOU SUPPORT AN ECONOMIC DEVELOPMENT RATE AS PART OF UNSE'S OVERALL RATE DESIGN PROPOSAL?**

A. Customer choice of generation supply would be the best form of economic development rate, inasmuch as customers could tailor the generation supply and pricing mechanism to best meet their needs. For example, a customer could choose to purchase 100% of its power from renewable sources. A customer like Freeport, which has historically not hedged its energy prices, could choose to purchase its power on an hourly, daily, monthly or annual basis as it wished. Absent customer choice, I believe that an economic development rate is yet another tool that UNSE and other investor-owned utilities can employ to attract economic development within the state. However, that should not preclude adoption of the proposed buy-through tariff as another tool or option for attracting or keeping large customers on the local system. The major difference is that the proposed economic development rate will only apply to an expansion of existing operations, or the location of new operations, within UNSE's service territory. By contrast, the proposed buy-

through tariff and others like it would allow existing large and commercial customers (such as Nucor and Walmart) to calculate potential cost savings for existing operations in deciding whether to curtail, shut down or relocate their businesses elsewhere.

Further to this point, I note that in Mr. Hutchens' rebuttal testimony, he clarified that UNSE will not seek recovery of any lost non-fuel revenues associated with the economic development rate in future rate case proceedings, because "The long-term benefits of attracting or retaining large, high load factor customers greatly outweigh the short-term costs."[2] I believe that same reasoning can be applied to the buy-through tariff proposal, recognizing that whatever the mechanism, UNSE and its investors' willingness to pay the short-term costs will be outweighed by the long-term benefits of not only attracting, but ***retaining*** high load-factor customers within its service territory.

**Q. DOES THIS CONCLUDE YOUR TESTIMONY?**

**A.** Yes.

11336986/023040.0041

[2] Rebuttal Testimony of David Hutchens at p. 16.

# EXHIBIT 1

aic
ARIZONA INVESTORS COUNCIL

Building economic foundations through energy, water and communications infrastructure. Our mission is to maximize the influence of utility investors on public policies and governmental actions and to support the infrastructure development in the State of Arizona.



**Utility Regulators Spar Over APS Political Spending**
Thursday, 11 February 2016

**Commission Calls Supreme Court Decision to Put Clean Air Plan Enforcement on Hold a Win**
Wednesday, 10 February 2016

**Corporation Commission Seeks to Dismiss Text-Messages Case**
Thursday, 04 February 2016

**New Arizona Corporation Commissioner "Nervous" About Conflict fo Interest**
Wednesday, 03 February 2016

**Arizona Corporation Commission Names Doug Little New Chairman**
Tuesday, 02 February 2016

**AG Won't Seek the Removal of Utility Regulator Robert Burns**
Monday, 01 February 2016

**Utility Regulator Robert Burns Launches Investigation of APS Political Spending**
Friday, 29 January 2016

**The Arizona Corporation Commission Weighs In on Federal Court Declining Request for Stay of Clean Power Rule**

Current Utility News

**Current News**

History and Mission

Originally formed in 1994 to maximize the influence of utility investors on public policies and governmental actions that may have an impact the well-being of investors and their utility investments, the Arizona Utility Investors Association (AUIA) was renamed the Arizona Investment Council (AIC) in April 2007 and given an expanded vision and mission. AIC's new, expanded mission extends to the support of infrastructure development in the State of Arizona. It is our belief that the well-being of investors in Arizona's utilities and businesses is closely linked with the capacity of Arizona's business leaders and policymakers to plan for the future. As Arizona faces the challenge of being the nation's fastest growing state, AIC is helping ensure we have a strong and sustainable infrastructure for this growth – today and tomorrow. We do this by working with Arizona's policymakers, regulators and business community to resolve the critical infrastructure needs in the areas of energy, water, and communications.

## Why is An Organization Like Arizona Investment Council Important?

Over the next 25 years, Arizona's population is projected to double, reaching 13 million people by 2032. As a community, we need to ask questions today about what investments in backbone infrastructure, such as electricity generation and transmission, natural gas distribution and storage, water supply, and communications systems will be needed over the next 25 years to sustain our economy and lifestyle. We must also assess how we will pay for these investments and ensure that our utility companies have access to capital markets. Arizona's investment strategies must be approached from a statewide perspective, with coordination among key leaders within the business, investment and government communities and with input from citizens. Most important, it is critical that Arizona establish a climate that will support and encourage investment.

Additionally, a new generation of issues is bringing tremendous change to the utility industry. Changing technologies are redefining utility markets and services. Government policies and economic conditions are thrusting traditional monopolies into competition. Environmental concerns over climate change could lead to new laws, regulations and additional costs on utility companies and other businesses, and result in price increases to consumers. Utility regulators and policymakers face conflicting pressures from consumer, environmental and industry advocates. And governments at all levels are seeking financial resources through taxation to fund projects and programs. These issues can have a major impact on utility company finances and the return on your investments.

It's important that public officials and those who elect them understand the relationship between utility companies and the economic and environmental arenas in which they operate. This is particularly critical in our state, where rapid growth requires large investments in infrastructure. As an investor, it's important to understand the issues that affect your investments.

Currently, there are 41 state-funded utility consumer agencies operating across the country. Our government hears regularly from these agencies. But our government works best in this country when policies are made with input from all concerned parties. Regulators, legislators and other policymakers should also hear from investors – those individuals whose investments make utility services possible. With AIC, Arizona is one of approximately 10 other states providing a voice for utility investors at legislatures and regulatory agencies.

## Our Objectives

AIC's activities are aimed at establishing a favorable investment climate in Arizona. We do so through active participation in public venues where investment in infrastructure and utilities is discussed and debated. AIC also gives high priority to public education in the areas of utility economics, service choices, new technologies, economic and environmental regulations and policies, infrastructure requirements and consumer and investor interests.

Arizona Investment Council focuses on these activities:

- Intervention and participation in regulatory and administrative proceedings
- Participating and speaking at community programs and public forums on issues of investment, infrastructure and the utility industry
- Educating regulators, legislators and other policymakers on issues on investment and infrastructure

AIC Briefs

**AIC Letter Supporting CenturyLink**
Tuesday, 02 February 2016

**AIC'S Oppostiion to AURA's Motion to Extend Procedural Schedule**
Thursday, 28 January 2016

**AIC Amicus Brief to AZ Supreme Court re: RUCO v ACC**
Tuesday, 15 December 2015

**AIC Testimony in UNS Electric Rate Case**
Wednesday, 9 December 2015

**AIC Legal Memo Response to TASC**
Friday, 02 October 2015

**Deregulation Responsive Comments**
Thursday, 17 October 2013

**Deregulation Comments**
Wednesday, 9 October 2013

Conferences

Click the links below to watch the upcoming debate or watch the archived debated.

Reports and Newsletters

***Connect* - December 23, 2015**

***Connect* - October 8, 2015**

***Connect* - July 23, 2015**

***Connect* - March 11, 2015**

***Connect* - December 23, 2014**

***Connect* - November 7, 2014**

**2015 Annual Report**

**2014 Annual Report**

**Study of Studies: Economic Impacts of GHG Regulation**

**Carbon Controls Fact Sheet**

**Economic Impact of Carbon Controls in Arizona (full report)**

**Infrastructure Needs and Funding Alternatives For Arizona: 2008-2032 (Full Report)**

**Infrastructure Needs and Funding Alternatives For Arizona: 2008-2032 (Executive Summary)**

**Streamlining Administrative & Ratemaking Processes of the ACC**

## History and Mission

Organizing and sponsoring public forums and seminars on topics relating to investment, infrastructure and the utility industry

Providing news media with the investor's point of view

Issuing newsletters, legislative alerts and bulletins

Coordinating grassroots activities for investors throughout Arizona

Conducting research and issuing position papers in the areas of investment, regulatory process and policies and infrastructure

Participating in shareholder meetings of investor companies

**css** **xhtml**

## Summary of AECC/Noble Solutions Proposed Late-Filed Revenue Spread by Customer Class

| Line No. | Description (a) | Amount (b) | |
|---|---|---|---|
| 1 | UNSE Direct Filing Requested Revenue Increase = | $22,621,008 | |
| 2 | UNSE Rejoinder Filing Requested Revenue Increase = | $15,099,716 | |
| 3 | UNSE Reduction in Requested Revenue Increase = | ($7,521,292) | = Ln 2 - Ln 1 |
| | **AECC/Noble Solutions Recommended Distribution of Reduction in Requested Revenue Increase:** | | |
| 5 | 50% Applied to Subsidy Receiving Class = | ($3,760,646) | = 50% x Ln 3 |
| 6 | 50% Applied to Subsidy Paying Classes = | ($3,760,646) | = 50% x Ln 3 |
| 7 | Reduction of Subsidy Paying Classes Amount Applied to Experimantal Rider 14 Costs [1] = | $908,000 | |
| 8 | Net Reduction Applied to Subsidy Paying Classes = | ($2,852,646) | = Ln 6 + Ln 7 |

**Note 1: This amount would be used to recover any reduction in fixed generation revenues that arise from implementation of the Experimental Rider 14. Any unused funds would be returned to MGS/LGS/LPS customers in a future regulatory proceeding.**

## AECC/Noble Solutions Recommended Spread of UNSE's Requested Rejoinder Revenue Increase

| | Customer Class (a) | Current Adjusted Test Year Margin Revenue (b) | Percentages for Spreading Revenue Reduction[2] (c) | UNSE As-Filed Base Dollar Change (d) | Spread of Reduction in Revenue Increase (e) | AECC/ Noble Recommended Base Dollar Change (f) |
|---|---|---|---|---|---|---|
| 9 | Residential | 33,425,187 | 83.4% | $20,556,648 | ($3,137,196) | $17,419,453 |
| 10 | Small General Service | 6,136,594 | 15.3% | $2,664,336 | ($575,964) | $2,088,373 |
| 11 | Medium/Large General Service | 26,394,695 | 89.2% | $26,345 | ($2,544,898) | ($2,518,553) |
| 12 | Large Power Service | 3,191,840 | 10.8% | ($771,829) | ($307,748) | ($1,079,577) |
| 13 | Lighting | 505,944 | 1.3% | $75,592 | ($47,487) | $28,105 |
| 14 | Sub-Total | 69,654,260 | | 22,551,092 | (6,613,292) | 15,937,800 |
| 15 | Experimental Rider 14 Reserve | | | | (908,000) | ($908,000) |
| 16 | Total | | | | (7,521,292) | 15,029,800 |

**Note 2: Shaded cell percentages apply to AECC/Noble reduction (see Ln. 5) for subsidy receiving classes. Non-shaded cells percentages apply to AECC/Noble reduction (see Ln. 8) for subsidy paying classes.**

## Summary of AECC/Noble Solutions Proposed Late-Filed Revenue Spread by Customer Class

| | Customer Class (a) | UNSE Rebuttal Current Adjusted Test Year Base Revenue (b) | AECC/ Noble Solutions Proposed Base Dollar Change (c) | AECC/ Noble Solutions Proposed Base Percent Change (d) | AECC/ Noble Solutions Net Dollar Change (Year 2) (e) | AECC/ Noble Solutions Net Percent Change (Year 2) (f) |
|---|---|---|---|---|---|---|
| 17 | Residential | $78,169,265 | $17,419,453 | 22.3% | $8,097,604 | 10.4% |
| 18 | Small General Service | $12,461,200 | $2,088,373 | 16.8% | $1,181,208 | 9.5% |
| 19 | Medium/Large General Service | $56,334,006 | ($2,518,553) | -4.5% | ($1,497,300) | -2.7% |
| 20 | Large Power Service | $7,446,668 | ($1,079,577) | -14.5% | ($220,575) | -3.0% |
| 21 | Lighting | $547,038 | $28,105 | 5.1% | $31,563 | 5.8% |
| 22 | Sub-Total | $154,958,178 | $15,937,800 | 10.3% | $7,592,501 | 4.9% |
| 23 | Experimental Rider 14 Reserve | | ($908,000) | | ($908,000) | |
| 24 | Total | $154,958,178 | $15,029,800 | 9.7% | $6,684,501 | 4.3% |

AECC/NS-5

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

**STF 2.118**

Buy Through: Please provide a worksheet with all supporting information that calculates the cost of the impact to the LFCR of the Buy-Through provision assuming the 10 MW was fully subscribed. [Jones 59:1]

**RESPONSE:**

Please see **STF 2.118 Rider 14 AGS-Gen Rev Loss.xlsx.**

**RESPONDENT:**

Rick Bachmeier

**WITNESS:**

Craig Jones

EXHIBIT
AECC/NS-5
ADMITTED

**UNS Electric Proposed LPS Rate**

*Unbundled Generation Components*

| | | |
|---|---|---|
| Demand-Generation Capacity ($/kW) | $ | 3.68 |

Note: Unbundled LPS TOU Generation components are the same as above.

| | |
|---|---|
| Prescribed Load Limit (MW) | 10.00 |

**Billing Determinants**

| | |
|---|---|
| Annual Billing Demand (kW) | 120,000 |

| | | |
|---|---|---|
| **Total Generation Capacity Revenue** | $ | 441,600.00 |

**Lost Generation Revenue from Rider-14 AGS**

| Year | Percent at Risk | Lost Generation Revenue ($) |
|---|---|---|
| 1 | 0.0% | $ - |
| 2 | 75.0% | $ 331,200.00 |
| 3 | 75.0% | $ 331,200.00 |
| 4 | 75.0% | $ 331,200.00 |
| | **Total** | $ 993,600.00 |

2014 ANNUAL REPORT

EXHIBIT
NS
AECC-6
admitted

# FOLLOW A LEADER

PINNACLE WEST CAPITAL CORPORATION

## PINNACLE WEST CAPITAL CORPORATION COMBINES A SOLID FOUNDATION AND A CLEAR STRATEGY TO BUILD SHAREHOLDER VALUE...

*Superior reliability and operating performance across our business*
*Excellent customer satisfaction and deep community involvement · Affordable electricity rates*
*A balanced, high-performing power generation portfolio · A constructive regulatory environment*
*Targeted investments in new technologies · Solid financial results*

---

## ...WITH A SHARPENED FOCUS ON OUR CORE UTILITY BUSINESS.

### THE APS VISION

*Creating a sustainable energy future for Arizona*

### THE APS MISSION

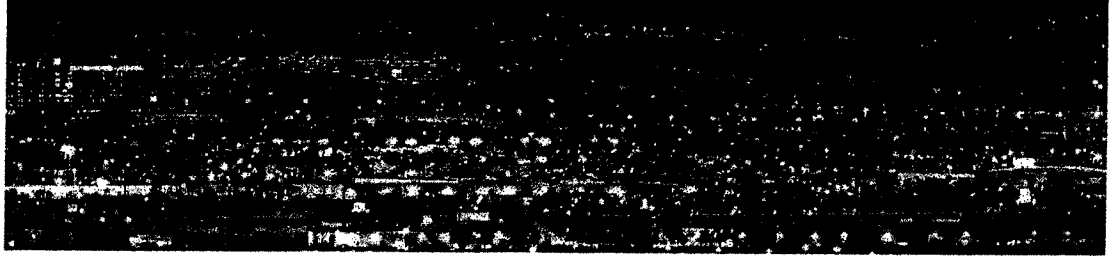
*We safely and efficiently generate and deliver reliable electric power and related services to our customers.*

# $2B

*Pinnacle West's total shareholder value increased $2 billion in 2014.*

# $5B

*Pinnacle West's total shareholder value increased $5 billion over the last five years.*



# CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

*(dollars in millions)*

| | 2014 | 2013 | 2012 |
|---|---|---|---|
| *Year Ended December 31,* | | | |
| **CONDENSED CONSOLIDATED STATEMENTS OF INCOME** | | | |
| Operating revenues | $ 3,492 | $ 3,455 | $ 3,302 |
| Fuel and purchased power | (1,180) | (1,096) | (995) |
| Other operating expenses | (1,501) | (1,513) | (1,455) |
| Operating income | 811 | 846 | 852 |
| Net other income | 19 | 11 | 4 |
| Interest expense | (185) | (187) | (200) |
| Income taxes | (221) | (230) | (237) |
| Income from continuing operations | 424 | 440 | 419 |
| Loss from discontinued operations - net of tax | – | – | (6) |
| Net income | 424 | 440 | 413 |
| Less: Net income attributable to noncontrolling interests | 26 | 34 | 31 |
| Net income attributable to common shareholders | $ 398 | $ 406 | $ 382 |
| *December 31,* | | | |
| **CONDENSED CONSOLIDATED BALANCE SHEETS** | | | |
| *Assets* | | | |
| Current assets | $ 974 | $ 1,044 | $ 1,006 |
| Investments and other assets | 786 | 727 | 669 |
| Property, plant and equipment - net | 11,194 | 10,889 | 10,397 |
| Deferred debits | 1,360 | 849 | 1,308 |
| Total assets | $ 14,314 | $ 13,509 | $ 13,380 |
| *Liabilities and Equity* | | | |
| Current liabilities, excluding current maturities of long-term debt | $ 1,176 | $ 1,078 | $ 961 |
| Long-term debt | 3,415 | 3,337 | 3,322 |
| Deferred credits and other | 5,204 | 4,753 | 4,995 |
| Total equity | 4,519 | 4,341 | 4,102 |
| Total liabilities and equity | $ 14,314 | $ 13,509 | $ 13,380 |
| *Year Ended December 31,* | | | |
| **CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS** | | | |
| Cash and cash equivalents at beginning of year | $ 10 | $ 26 | $ 34 |
| Net cash flow provided by operating activities | 1,100 | 1,153 | 1,171 |
| Net cash flow used for investing activities | (923) | (1,009) | (873) |
| Net cash flow used for financing activities | (179) | (160) | (306) |
| Cash and cash equivalents at end of year | $ 8 | $ 10 | $ 26 |

*Complete audited consolidated financial statements are included in our Annual Report on Form 10-K.*

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Wed, Mar 2, 2016, 12:48pm EST - US Markets close in 3 hrs and 12 mins Report an Issue

Dow ↓0

KNOW MORE 500 commission-free trades charles SCHWAB

Scottrade UP TO $2,000 + 50 FREE TRADES Restrictions Apply

TD Ameritrade Pump up your portfolio

**Pinnacle West Capital Corporation (PNW)** - NYSE ★ Watchlist

Like 6

**68.27** ↑0.35(0.52%) 12:48PM EST - NYSE Real Time Price

## Historical Prices

Get Historical Prices for: GO

**Set Date Range**

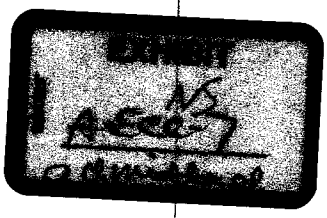
Start Date: Jun 1 2012 Eg. Jan 1, 2010

End Date: Mar 1 2016

○ Daily
○ Weekly
◉ Monthly
○ Dividends Only

Get Prices

EXHIBIT NS A-Ecc-7 Admitted



First | Previous | Next | Last

**Prices**

| Date | Open | High | Low | Close | Avg Vol | Adj Close* |
|---|---|---|---|---|---|---|
| Mar 1, 2016 | 69.20 | 69.44 | 67.83 | 67.92 | 3,121,600 | 67.92 |
| Feb 1, 2016 | 66.24 | 71.40 | 66.02 | 68.83 | 1,308,900 | 68.83 |
| Jan 28, 2016 | | | 0.625 Dividend | | | |
| Jan 4, 2016 | 64.31 | 66.49 | 62.51 | 66.31 | 947,900 | 66.31 |
| Dec 1, 2015 | 63.33 | 65.51 | 60.70 | 64.48 | 973,200 | 63.85 |
| Nov 2, 2015 | 63.47 | 65.45 | 61.02 | 63.36 | 1,097,700 | 62.74 |
| Oct 29, 2015 | | | 0.625 Dividend | | | |
| Oct 1, 2015 | 64.16 | 67.02 | 62.43 | 63.51 | 944,700 | 62.89 |
| Sep 1, 2015 | 59.02 | 64.21 | 57.33 | 64.14 | 886,600 | 62.90 |
| Aug 3, 2015 | 61.72 | 65.23 | 58.95 | 59.53 | 1,000,700 | 58.38 |
| Jul 30, 2015 | | | 0.595 Dividend | | | |
| Jul 1, 2015 | 57.03 | 62.63 | 56.77 | 61.71 | 1,032,000 | 60.52 |
| Jun 1, 2015 | 61.04 | 61.34 | 56.01 | 56.89 | 888,400 | 55.25 |
| May 1, 2015 | 60.95 | 61.88 | 58.37 | 60.92 | 873,000 | 59.16 |
| Apr 30, 2015 | | | 0.595 Dividend | | | |
| Apr 1, 2015 | 63.76 | 64.95 | 60.78 | 61.20 | 766,700 | 59.43 |
| Mar 2, 2015 | 63.93 | 65.43 | 61.53 | 63.75 | 823,500 | 61.32 |
| Feb 2, 2015 | 70.18 | 70.71 | 63.81 | 64.08 | 1,082,700 | 61.64 |
| Jan 29, 2015 | | | 0.595 Dividend | | | |
| Jan 2, 2015 | 68.58 | 73.31 | 67.69 | 70.18 | 1,002,300 | 67.51 |
| Dec 1, 2014 | 62.85 | 71.11 | 62.60 | 68.31 | 1,244,500 | 65.16 |
| Nov 3, 2014 | 61.75 | 63.50 | 60.61 | 63.23 | 772,000 | 60.32 |
| Oct 30, 2014 | | | 0.595 Dividend | | | |
| Oct 1, 2014 | 54.70 | 61.56 | 54.59 | 61.47 | 835,700 | 58.64 |
| Sep 2, 2014 | 57.04 | 57.74 | 54.13 | 54.64 | 925,100 | 51.60 |
| Aug 1, 2014 | 53.51 | 56.97 | 52.13 | 56.95 | 987,200 | 53.79 |
| Jul 30, 2014 | | | 0.568 Dividend | | | |
| Jul 1, 2014 | 57.72 | 57.95 | 53.29 | 53.49 | 1,013,800 | 50.52 |
| Jun 2, 2014 | 55.45 | 58.06 | 53.04 | 57.84 | 728,900 | 54.08 |
| May 1, 2014 | 55.62 | 57.09 | 53.81 | 55.42 | 987,300 | 51.81 |
| May 1, 2014 | | | 0.568 Dividend | | | |
| Apr 1, 2014 | 54.66 | 57.31 | 53.71 | 55.95 | 1,023,900 | 51.78 |
| Mar 3, 2014 | 55.42 | 55.78 | 53.29 | 54.66 | 1,014,000 | 50.58 |
| Feb 3, 2014 | 52.63 | 55.99 | 51.15 | 55.65 | 1,199,600 | 51.50 |
| Jan 30, 2014 | | | 0.568 Dividend | | | |

| | | | | | | |
|---|---|---|---|---|---|---|
| Jan 2, 2014 | 53.00 | 53.81 | 51.37 | 52.63 | 884,600 | 48.71 |
| Dec 2, 2013 | 53.33 | 53.97 | 52.32 | 52.92 | 1,037,600 | 48.44 |
| Nov 1, 2013 | 56.08 | 56.72 | 52.81 | 53.36 | 1,069,800 | 48.84 |
| Oct 31, 2013 | | | 0.568 Dividend | | | |
| Oct 1, 2013 | 54.90 | 58.70 | 53.84 | 56.03 | 1,062,900 | 51.28 |
| Sep 3, 2013 | 54.53 | 56.12 | 52.03 | 54.74 | 910,400 | 49.61 |
| Aug 1, 2013 | 59.28 | 59.98 | 53.86 | 54.27 | 647,400 | 49.18 |
| Jul 30, 2013 | | | 0.545 Dividend | | | |
| Jul 1, 2013 | 55.85 | 60.33 | 54.02 | 58.90 | 599,000 | 53.38 |
| Jun 3, 2013 | 56.49 | 58.13 | 51.56 | 55.47 | 1,150,000 | 49.81 |
| May 1, 2013 | 60.82 | 61.89 | 55.60 | 56.48 | 831,300 | 50.72 |
| Apr 29, 2013 | | | 0.545 Dividend | | | |
| Apr 1, 2013 | 57.89 | 61.09 | 57.41 | 60.90 | 763,400 | 54.69 |
| Mar 1, 2013 | 55.90 | 57.96 | 55.56 | 57.89 | 585,400 | 51.52 |
| Feb 1, 2013 | 53.58 | 56.01 | 52.95 | 55.94 | 732,800 | 49.78 |
| Jan 30, 2013 | | | 0.545 Dividend | | | |
| Jan 2, 2013 | 51.72 | 53.62 | 51.50 | 53.38 | 828,800 | 47.50 |
| Dec 3, 2012 | 51.58 | 52.46 | 50.12 | 50.98 | 653,900 | 44.91 |
| Nov 1, 2012 | 53.32 | 53.36 | 48.73 | 51.46 | 749,400 | 45.33 |
| Oct 31, 2012 | | | 0.545 Dividend | | | |
| Oct 1, 2012 | 52.85 | 54.20 | 52.35 | 52.97 | 503,800 | 46.66 |
| Sep 4, 2012 | 51.50 | 53.99 | 51.39 | 52.80 | 711,000 | 46.03 |
| Aug 1, 2012 | 53.68 | 54.56 | 51.19 | 51.37 | 532,200 | 44.78 |
| Jul 30, 2012 | | | 0.525 Dividend | | | |
| Jul 2, 2012 | 52.06 | 54.66 | 51.50 | 53.54 | 795,900 | 46.67 |
| Jun 1, 2012 | 49.44 | 52.30 | 48.37 | 51.74 | 832,600 | 44.67 |

* Close price adjusted for dividends and splits.

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*Attorneys for Fresh Produce Association of the Americas*

**BEFORE THE ARIZONA CORPORATION COMMISSION**

**COMISSIONERS:**
**SUSAN BITTER SMITH, Chairperson**
**BOB STUMP**
**BOB BURNS**
**DOUG LITTLE**
**TOM FORESE**

| | |
|---|---|
| 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 ELECRIC, INC., DEVOTED TO ITS OPERATIONS THROUGHT THE STATE OF ARIZONA AND FOR RELATED APPROVALS | DOCKET NO. E-04204A-15-0142<br><br>**NOTICE OF FILING DIRECT TESTIMONY OF LANCE S. JUNGMEYER ON BEHALF OF FRESH PRODUCE ASSOCIATION OF THE AMERICAS** |

The Fresh Produce Association of the Americas ("FPAA"), through its undersigned counsel, hereby provides notice that it has this day filed the attached direct testimony of Lance S. Jungmeyer.

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Arizona Corporation Commission
DOCKETED
DEC 09 2015
DOCKETED BY

DATED this 9th day of December, 2015.

MOYES SELLERS & HENDRICKS

Jason Y. Moyes
Jay I. Moyes

*Attorneys for Fresh Produce Association of the Americas*

ORIGINAL and 13 COPIES of the foregoing filed this 9th day of December, 2015 with:

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Phoenix, AZ 85007

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## I. EXECUTIVE SUMMARY

Lance S. Jungmeyer is the President of the Fresh Produce Association of the Americas ("FPAA"). Mr. Jungmeyer describes FPAA's concerns regarding the use of ratcheted demands by UNSE in the existing large general service class, which has caused a significant financial burden on FPAA members.

FPAA has over 100 member companies involved in the importation and distribution of fresh produce from Mexico. Mr. Jungmeyer describes the cyclical seasonal operations of FPAA members, which includes a dormant late summer season. Mr. Jungmeyer proposes that FPAA members' lack of use of the system is likely a benefit to UNSE during the late summer months when utilities struggle to deliver power.

Mr. Jungmeyer is requesting UNSE and this Commission to reconsider the current rate design and use of ratcheted demands.

## II. INTRODUCTION

Q. **PLEASE STATE YOUR NAME, ADDRESS AND OCCUPATION.**

A. My name is Lance Jungmeyer. My business address is P.O. Box 848, Nogales, AZ 85628. I am the President of the Fresh Produce Association of the Americas ("FPAA"), an association focused on critical business objectives that ensure the health and viability of the produce industry.

Q. **HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?**

A. No.

Q. **WHAT IS THE PURPOSE OF YOUR TESTIMONY TODAY?**

A. The purpose of my testimony is to describe the FPAA and its interest as an Intervenor in this case. In particular, as the policy witness for Intervenor FPAA, I am describing FPAA's operations and economic contributions to the Santa Cruz valley. I am also describing the FPAA's concerns with the current and proposed UniSource Energy

Services ("UNSE") rate design for medium and large general service customers, in particular the use of ratchet demand rates, and their financial impact on FPAA members.

**Q. PLEASE DESCRIBE THE FRESH PRODUCE ASSOCIATION OF THE AMERICAS.**

A. The FPAA was founded by produce distributors in 1944. Today the FPAA has over 100 member companies involved in the importation and distribution of fresh produce from Mexico. The members of the FPAA consist of U.S. distributors and associate members. Distributors directly import fresh produce from growing operations in Mexico. Associate members consist of a variety of companies, from unique buyers procuring product from distributors to industry-associated companies such as custom-house brokers, seed companies, packaging providers, trucking firms, financial institutions, insurance companies and more.

The Nogales produce industry imports approximately 5.5 billion pounds of produce at a value of approximately $3 billion each year. Nearly all of this produce crosses through the Mariposa Port of Entry in Nogales, Arizona and is held in commercial warehouses located in Santa Cruz County. Mexico represents 39 percent of all imported fruits and vegetables consumed in North America annually. Arizona accounts for about 40 percent of all Mexican produce imported into the U.S. by volume.

**Q. CAN YOU BRIEFLY DESCRIBE THE ECONOMIC BENEFITS THAT FPAA MEMBERS PROVIDE TO SANTA CRUZ COUNTY?**

A. Yes. A recent University of Arizona study[1] highlighting the economic impacts of the fresh produce import industry in Santa Cruz County reached the following conclusions:

[1] The 2013 study was conducted by The University of Arizona (Eller College of Management, Economic & Business Research Center, and the College of Agriculture & Life Sciences) and made possible by a grant from the US Economic Development Authority, administered by Nogales Community Development. The study can be viewed at: http://www.azmc.org/wp-content/uploads/2014/06/fresh_produce_and_production_sharing_Nogales_Santa_Cruz_County_Arizona_9_25_13.pdf

- Fresh produce imports account for $437.7 million in direct and secondary economic output in Santa Cruz County (this is more than 1/3 of the county's economic output).
- Fresh produce imports account for $45 million in tax revenues to the state and county.
- Fresh produce imports account for about 4,000 direct and secondary jobs, representing $190 million in wages (representing more than 22% of total jobs and nearly 25% of total wages).
- There is a multiplier effect from the fresh produce import industry, benefitting more than 80 local services, from commercial equipment and packaging to legal and insurance services.
- Arizona is poised to benefit from expanding fresh produce imports. From 2002-2012, Mexican produce imports have grown 42% -- from 8 billion pounds to more than 14 billion pounds -- according to the United States Department of Agriculture.
- More than 85% of the 750,000 annual commercial truck crossings between Arizona and Mexico flow through the Mariposa Port of Entry in Nogales, Arizona.

**Q. DOES FPAA HAVE AN OPINION REGARDING UNSE'S USE OF RATCHET DEMAND RATES.**

A. Yes. FPAA members provide refrigeration services for fresh produce primarily from October through June, and facilities go nearly entirely dormant during the July through September period. During the dormant portion of the summer, our facilities require very little electrical service from UNSE. Since UNSE began the use of a ratcheted demand rate effective January 1, 2014, our Members have experienced significant financial hardship from the ratcheted demand charges being imposed during the dormant periods when the facilities are non-operational. More importantly, our members are providing zero or minimal refrigeration and distribution service sales during the dormant

months; therefore, little to no revenues are being collected that could be used by our members to help cover the cost burden caused by the ratcheted demand charges. It would seem that our members actually offer a material, involuntary "demand-side-management" ("DSM") benefit to UNSE by significantly reducing their demand during the hottest months of the year when Arizona utilities generally face the most difficulty and expense meeting their customers' peak demands. We believe UNSE should incentivize the DSM-like benefits implicit in our members' counter-cyclical demand reductions, rather than penalizing them with an imputed demand via the ratchet. I am requesting UNSE and this Commission to reconsider the current rate design and use of ratcheted demands.

**Q. IF THIS COMMISSION DOES NOT SUPPORT RATE RELIEF FOR FPAA MEMBERS, WHAT OTHER OPTIONS MIGHT FPAA HAVE?**

A. Texas economic development groups have hosted meetings in Nogales to lure away importers. They offer considerable concessions in the form of tax breaks, more permissive building codes, utility rate policies, and economic improvement zones. Some members of the FPAA have already left the Santa Cruz Valley, and others are considering leaving.

**Q. DOES THIS CONCLUDE YOUR TESTIMONY IN THIS CASE?**

A. Yes.

# Lance S. Jungmeyer

■ ljungmeyer72@yahoo.com ■ 520.398.5803 (home) ■ 520.903.4314 (cell) ■ Sahuarita, AZ

## EXPERIENCE

■ **Fresh Produce Association of the Americas, Nogales, AZ**

**MAY 2010 – PRESENT, PRESIDENT**

Serves as chief executive for association representing U.S.-based importers of Mexican fruits and vegetables. In Arizona alone, the FPAA represents more than $2.5 billion in imported fruits and vegetables. As President of FPAA, engages in government relations at the local, state and federal levels. Administers a budget of $1 million a year. Oversees a staff of six persons. In this capacity, is part of the following industry and civic groups:

- Greater Nogales/Santa Cruz Port Authority
- Government Relations Council of the United Fresh Produce Association
- Supply Chain Logistics Council of the United Fresh Produce Association
- Produce Traceability Initiative Association Interest Group
- North American Trade Task Force, a committee of the Canadian Produce Marketing Association

■ **EnvironmentalLeader.com**

**FEBRUARY 2009 – MAY, 2010, EDITOR**

Served as chief editor for leading Web site for business executives, with topics including corporate energy efficiency, renewable energy and sustainability. Researched and wrote in-depth case studies on corporate use of solar and wind energy, and related state and federal incentives.

■ **Missouri Department of Conservation**

**JULY 2008 – DECEMBER 2008, DIGITAL COMMUNICATIONS MANAGER**

Directed all digital content for mdc.mo.gov and related public sites. Supervised Web and video content teams.

■ **The Packer**, published by the food360° division of Vance Publishing Corp., Lenexa, Ks.

**MAY 2005 – JULY 2008, EDITOR**

Led top-rated weekly newspaper covering the $100 billion fresh fruit and vegetable industry. Managed a staff of 20 reporters and editors. Directed two annual books — *Fresh Trends*, a consumer research report, and *The Guide*, an A-to-Z desk reference. Started Spanish-language industry Web site.

**APRIL 2003 – MAY 2005, MANAGING EDITOR**

Developed and executed a $1.5 million budget. Added *The Packer 25*, an annual profile of industry leaders. Traveled to China to write a 3-part series on the garlic export industry.

**MAY 1999 – APRIL 2003, NEWS EDITOR**

Directed 14 writers for print and Web. Traveled to Cuba to examine post-Castro agricultural potential.

**APRIL 1997 – MAY 1999, ASSISTANT NEWS EDITOR**

Directed more than 120 enterprise sections a year. Supervised five writers.

**AUGUST 1995 – APRIL 1997, STAFF WRITER**

■ ***Mexico City Business Journal***

**JANUARY 1995 – JULY 1995, PRODUCTION DIRECTOR, COPY EDITOR & WRITER**

## EDUCATION

■ **University of Missouri**, Bachelor of Science in Journalism, with honors

## AWARDS

■ **Best opinion column** — 2007 Vance Editorial Awards

■ **Finalist** — Best B2B Web site under 100,000 unique visitors, 2007 American Business Media Neal Awards

## OTHER

■ **Customs and Border Protection Citizens Academy** — In 2010, was part of first-ever class in the nation to educate citizens about the role of Customs in protecting the border and facilitating commerce.

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*Attorneys for Intervenor Fresh Produce Association of the Americas*

**BEFORE THE ARIZONA CORPORATION COMMISSION**

**COMISSIONERS:**
**SUSAN BITTER SMITH, Chairperson**
**BOB STUMP**
**BOB BURNS**
**DOUG LITTLE**
**TOM FORESE**

| | |
|---|---|
| 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 ELECRIC, INC., DEVOTED TO ITS OPERATIONS THROUGHT THE STATE OF ARIZONA AND FOR RELATED APPROVALS | DOCKET NO. E-04204A-15-0142<br><br>**NOTICE OF FILING DIRECT TESTIMONY OF KENT R. SIMER ON BEHALF OF FRESH PRODUCE ASSOCIATION OF THE AMERICAS** |

The Fresh Produce Association of the Americas ("FPAA"), through its undersigned counsel, hereby provides notice that it has this day filed the attached direct testimony of Kent R. Simer.

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Arizona Corporation Commission
DOCKETED
DEC 09 2015
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DATED this 9th day of December, 2015.

MOYES SELLERS & HENDRICKS

Jason Y. Moyes
Jay I. Moyes

*Attorneys for Fresh Produce Association of the Americas*

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## I. EXECUTIVE SUMMARY

The Fresh Produce Association of the Americas ("FPAA") is comprised of over 100 member companies involved in the importation and distribution of fresh produce from Mexico. The FPAA is focused on critical business objectives that ensure the health and viability of the produce industry. Trucks from Mexico cross the border carrying already sorted, packaged and palletized produce, and these trucks offload the produce into U.S. refrigerated warehouses. As a counter-seasonal business by nature, the produce warehouses tend to use more electricity during the months of October through June, and largely are dormant or operating well below capacity during the summer months of July through September.

Mr. Simer provides testimony that addresses specific changes in rate design that have resulted in a rate impact that is greater than was intended in the past rate case. Mr. Simer testifies on the use of ratcheted demands in rate design and the unintended impacts that ratcheted demands can have on certain customer types; namely seasonal, low load factor, and off-peak consumers. Mr. Simer provides examples of tools implemented by other Utility Commissions to address these shortcomings.

Mr. Simer explains that it is important for the Commission and UniSource Energy Services ("UNSE") to recognize the unique operating characteristics of FPAA members and evaluate whether the existing ratchet demand imposed on large general service customers is appropriate for FPAA members. Mr. Simer believes UNSE should provide additional review of its methodology for determining the current ratchet demand, and evaluate the possibility of establishing a separate rate class for counter-seasonal agricultural customers that recognizes the unique operating characteristics and system benefits these customers provide. Mr. Simer encourages the Commission to explore any options that might lessen the financial impacts imposed on FPAA members.

## II. INTRODUCTION

**Q. PLEASE STATE YOUR NAME, ADDRESS AND OCCUPATION.**

A. My name is Kent R. Simer. My business address is 160 N. Pasadena, Suite 101, Mesa, Arizona. I am a Utility Rate Consultant for K. R. Saline & Associates, PLC, a firm that provides electrical engineering services, management consulting, and ongoing business operational services primarily to wholesale public electric utilities.

**Q. PLEASE DESCRIBE YOUR PROFESSIONAL QUALIFICATIONS AND EXPERIENCE.**

A. I have been employed at K. R. Saline & Associates, PLC for the past seventeen years, providing various services to our clients. For the past ten years my primary responsibilities have included performing cost-of-service and rate design, economic analyses and computer-aided modeling for power supply planning, load forecasting, financial forecasting, and cost/benefit analysis for various municipal, tribal and public utilities throughout Arizona.

I have a Bachelor's Degree in Interdisciplinary Studies in Business and Communications from Arizona State University. Additionally I have completed the American Public Power Association basic and advanced Utility Cost of Service and Retail Rate Design courses and coursework towards a Master's Degree in Business Administration.

**Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?**

A. Yes. I provided testimony in Docket W-01303A-10-0448 and W-01303A-09-0343.

**Q. ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?**

A. I am appearing on behalf of the Fresh Produce Association of the Americas

("FPAA").

## III. PURPOSE

**Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY TODAY?**

A. The purpose of my testimony is to introduce the FPAA and its economic contributions to Santa Cruz County, as well as describe the power usage profile of this large group of UNSE customers. On behalf of the FPAA, I will be requesting rate relief for FPAA members who currently are receiving service under the UNSE large general service tariff and will be subject to the terms of the proposed medium general service tariff. Specifically, my testimony will address the impacts that the demand ratchet has had on FPAA's members due to their unique, counter-seasonal operations. Because of the FPAA's unique operating characteristics, UNSE's ratchet rate design is punitive in nature and has the potential to cause a loss of this large and important customer base, which would not be in the public interest. Finally, I discuss how UNSE's proposed rate design and allocation methodology will only further increase the financial burdens faced by FPAA members.

## IV. FRESH PRODUCE ASSOCIATION OF THE AMERICAS

**Q. CAN YOU PLEASE DESCRIBE THE FRESH PRODUCE ASSOCIATION OF THE AMERICAS?**

A. The FPAA was founded by produce distributors in 1944. Today the FPAA has over 100 member companies involved in the importation and distribution of fresh produce from Mexico. The FPAA is focused on critical business objectives that ensure the health and viability of the produce industry. The members of the FPAA consist of U.S. distributors and associate members. Distributors directly import fresh produce from growing operations in Mexico. Associate members are a variety of companies, from unique buyers procuring product from distributors to industry-associated companies such

as custom-house brokers, seed companies, packaging providers, trucking firms, financial institutions, insurance companies, and more.

The FPAA reports that a recent study conducted revealed that fresh produce imports account for $437.7 million in direct and secondary economic output in Santa Cruz County, $45 million in tax revenues to the state and county, and approximately 4,000 direct and secondary jobs, representing $190 million in wages. FPAA's members have a significant presence and economic influence in the Santa Cruz Valley, with the industry's direct and secondary impacts accounting for more than one-third of the county's economic output.

**Q. HOW ARE FPAA OPERATIONS UNIQUE COMPARED TO OTHER COMMERCIAL AND INDUSTRIAL CUSTOMERS?**

A. Trucks from Mexico cross the border carrying already sorted, packaged and palletized produce, and these trucks offload the produce into U.S. warehouses. The produce is held in these refrigerated warehouses until it is loaded onto U.S. trucks that carry it to buyers across the United States and Canada.

A majority of the volume crosses **counter-seasonally** to production times in the U.S. The major commodities imported include tomatoes, watermelons, bell peppers, cucumbers, eggplant, squash, green beans, melons, and more. The produce season typically begins in October with light volume, reaches peak volumes in January and February continuing through to April and May, and winds down with a focus on grape production in May, June, and July. As a counter-seasonal business by nature, the produce warehouses tend to use more electricity during these winter, fall and spring months, and **are largely dormant or operating well below capacity during the hottest summer months of July through September.**

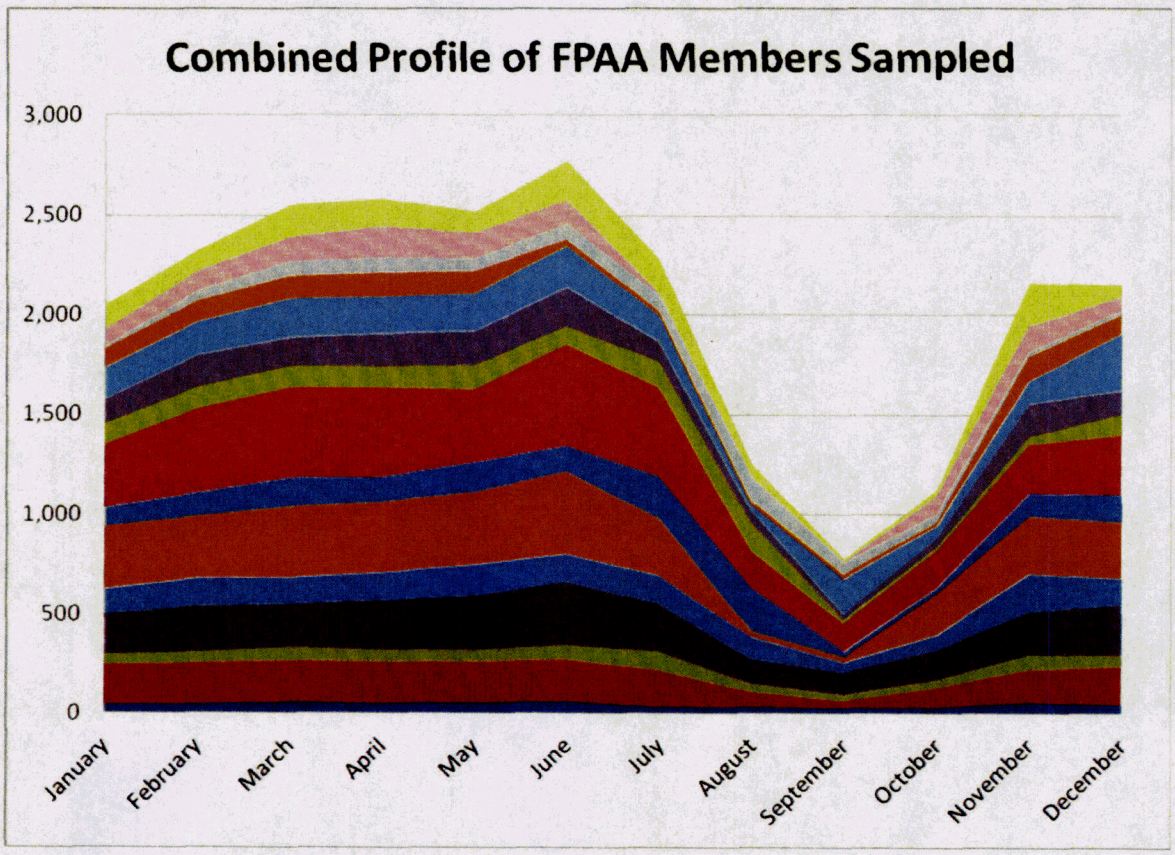


**Figure 1 – 12 Month profile of metered demands for sample of 15 FPAA members.**

From an electrical demand standpoint, during the dormant months, customer loads related to the storage and refrigeration of produce drop significantly and remain low until the next season begins. The facilities being shut off by a typical FPAA member during this time can equate to as much as a 200 kW drop in load. Looking at the FPAA as a group, the load drop-off becomes much more apparent. Provided above in Figure 1 is a sample 12-month profile of metered demands for a small portion[1] of the FPAA members requesting rate relief. Figure 1 demonstrates the unique operational characteristics of typical FPAA members. For the 15 samples included in the chart, there is a nearly 2,000 kW drop-off from the peak to the trough. Based on my preliminary analysis, the inclusion

[1] The FPAA has not been able to thoroughly analyze the load characteristic of *every* individual FPAA member. However, Figure 1 is typical of the load characteristics of FPAA members providing refrigeration services for counter-seasonal produce imports. Additionally, FPAA members represent only 50 to 60 percent of the total produce import industry in Santa Cruz County and it is likely that many, if not most, other non-member refrigeration providers demonstrate similar operating characteristics as those illustrated in Figure 1.

of all of its refrigeration members would amount to a total kilowatt drop-off during these dormant months of more than 5 MW. A 5MW load curtailment in the late monsoon summer months provides additional benefit to UNSE that is currently not being recognized and attributed to FPAA members through the existing rate design.

Typical industrial and general service customers have a more level demand month-to-month, or mirror the system load profile that is representative of Arizona's climate. That is to say, long hot summers that last into late October and drive cooling related loads. In Arizona, general service customers who do not operate from August to October, such as FPAA members, are uncommon and certainly offer a beneficial form of load diversity to the system.

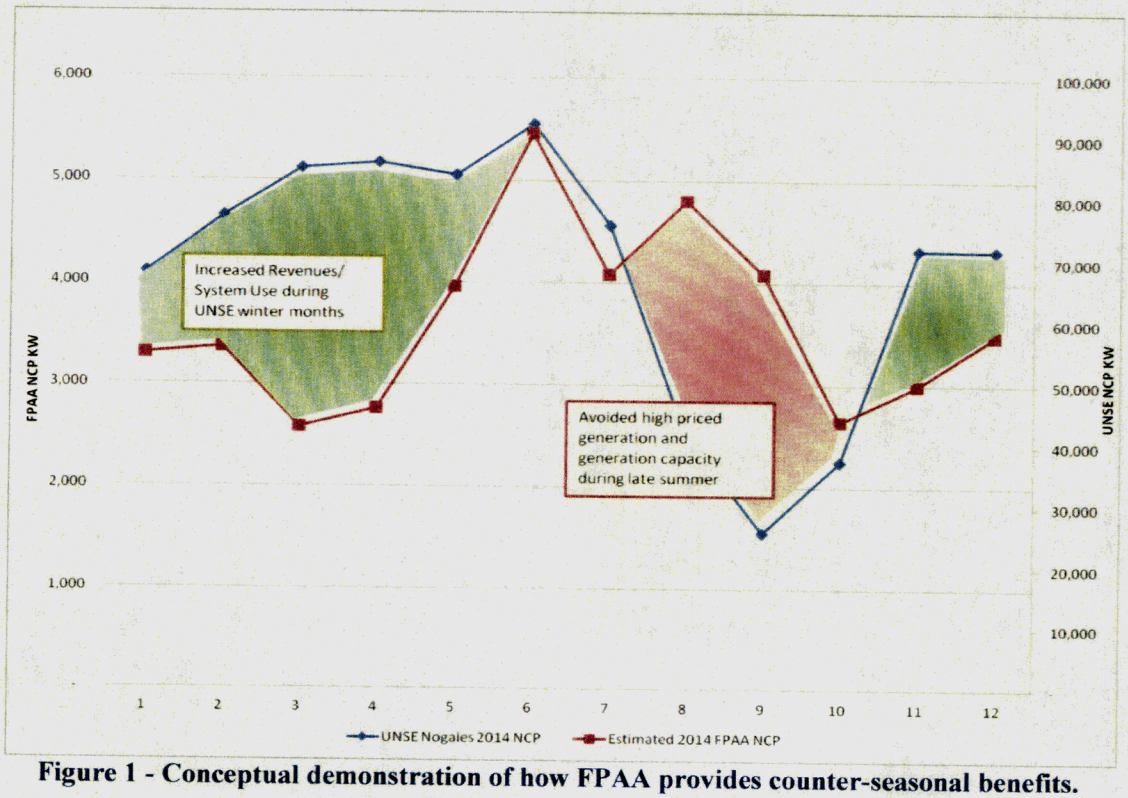


**Figure 1 - Conceptual demonstration of how FPAA provides counter-seasonal benefits.**

When you compare FPAA's unique operating characteristics to the local system use in the Nogales area, FPAA members provide additional revenues and system use during the winter months when UNSE system sales are down. In the late summer months they provide benefits via periods of avoided use, and therefore, avoided purchases of higher priced power and generation capacity. The current rate design does not take into consideration these unique benefits.

**Q. WHY ARE FPAA MEMBERS SEEKING RATE RELIEF NOW?**

A. In Decision 74235[2] the Commission, in addition to approving a 9% increase over adjusted test year revenue, approved a new large general service tariff for UNSE, which included a ratcheted demand provision that would adjust the monthly billing demand to the maximum of either the monthly metered demand or 75% of the greatest demand in the preceding 11 months. Due to the unique operations of FPAA members, essentially turning their facilities off for several months, the ratchet demand has had a very significant and detrimental economic impact. Since the rates approved by Decision 74235 went into effect on January 1, 2014, many FPAA customers have experienced a rate impact of 20% or more as a direct result of the demand ratchet mechanism. This rate impact is greater than was intended by the rate design approved by the Commission in Decision 74235. In the present case pending before the Commission, UNSE proposes additional increases in customer charges and demand charges, as well as a new cost-allocation methodology, which will only serve to further exacerbate the problems being faced by FPAA members.

**Q. DOES THE PROPOSED RATE DECREASE FOR GENERAL SERVICE CUSTOMERS PROVIDE ADEQUATE RATE RELIEF?**

A. No. Under the proposed rate design, FPAA members will be included in the new Medium General Service rate class and will receive a 9.67% rate decrease. The rate

[2] Decision 74235, Docket No. E-04204A-12-0504, December 31, 2013.

decrease is occurring solely via an adjustment to the base fuel charge; meanwhile, the basic service charge, the demand charge, and the energy delivery charges are all increasing. Though the adjustment to the base fuel charge will create an immediate rate decrease, it is highly unlikely that fuel costs will remain at today's low prices. It will not take a significant increase in fuel supply pricing to offset the proposed rate decrease through an increased purchase power and fuel adjustor. The increases in the non-fuel rate components however, will result in a rate increase of 2-5% for the typical FPAA member. This increase in the customer and demand rates, combined with the last rate case's increase, will be greatly felt during the period in which the customers operations go dormant and minimal energy is consumed.

The continued use of the current ratcheted demand and the proposed changes to rates and cost allocation methods will increase the financial impact imposed on FPAA members. In my opinion, the Commission should support changes to UNSE's rate tariffs that will recognize the unique operations of the FPAA members and the benefits they provide to UNSE's system.

## V. RATCHETED DEMANDS

**Q. CAN YOU BRIEFLY DESCRIBE RATCHETED DEMANDS?**

A. Certainly. A ratcheted demand is a rate design tool that is intended to help provide revenue stability and to distribute cost responsibility equitably among the general service rate class according to the costs that each member of the class generates. The ratcheted demand benefits the serving utility by setting a minimum billing demand (e.g. 75% of the prior 11 month peak) for a customer, which in turn provides revenue stability. Conceptually, by establishing a minimum billing demand across the rate class, each customer bears an equitable share of revenue responsibility based on their proportionate size compared to the class. Of course, this assumes that the actual demands of all

customers across the rate class are somewhat proportional throughout the year.

Q. **WHAT ARE SOME DRAWBACKS OF RATCHETED DEMANDS?**

A. Ratcheted demands assume that the cost-causation level for each customer is relative to their annual peak non-coincident demand. However, this does not hold true for all customers. Low load-factor, seasonal, and off-peak users may not have incurred the same cost responsibility as their counterparts and, especially in the case of FPAA, are imposing a lower average capacity requirement during the four coincident peak summer months. By assigning them the same cost responsibility, low load-factor, seasonal, and off-peak users may experience a significant financial hardship for their off-peak use of the system, which equates to an intra-class subsidy for other customers.

Additionally, ratcheted demands incentivize unnecessary consumption during a customer's non-peak demand period. For instance, FPAA members could elect to just leave their refrigerators on, even if they are not storing produce, simply because they are already paying a majority of the costs through their ratchet billing demand. Rate policy that incentivizes unnecessary consumption seems to be in opposition to general energy efficiency goals supported by the Commission.

Q. **HOW HAVE OTHER COMMISSIONS DEALT WITH THE DRAWBACKS OF RATCHETED DEMANDS?**

A. Texas, as a state, has recognized the significant drawbacks and financial harm that can result from the use of ratcheted demands. Both the State of Texas and the Public Utility Commission of Texas have dealt with both low load factor and seasonal customers on different occasions, the most significant of which is HB1064. In 2011, Texas signed into law HB1064 of the 82nd Legislature, Regular Session, which required transmission and distribution owning utilities to "waive the application of demand ratchet provisions for each nonresidential secondary service customer that has a maximum load

factor equal to or below a factor set by commission rule."[3]

Subsequently, The Public Utility Commission of Texas adopted ruling §25.244 that waived demand ratchet provisions for nonresidential secondary service customers that had a maximum load factor equal to or below 25 percent. That Commission held that such a rule:

> **Strikes a balance between a threshold that is high enough to provide demand ratchet relief to low-load-factor customers with primarily off-peak usage, but not so high as to affect customers with a large degree of on-peak usage or interfere with a utility's ability to reasonably recover the costs of providing distribution service while avoiding significant intra-class subsidization.**[4]

Additionally, in Order 40 in Docket No. 22344, the Public Utility Commission of Texas "acknowledged the unique characteristics of seasonal agricultural customers" and granted an exception from demand ratchet provisions and an option to recover distribution charges without the use of a demand ratchet.

The Public Utility Commission of Texas has shown significant support to seasonal agricultural customers and has recognized that significant financial impacts are imposed on low load-factor, seasonal, and off peak customers when ratcheted demands are used.

**Q. WHY IS THE PUBLIC UTILITY COMMISSION OF TEXAS RELEVANT?**

A. The Public Utility Commission of Texas is relevant for two reasons. One, it illustrates the degree of flexibility that Commissions have in determining the appropriate use and applicability of ratcheted demands across various customer classes and types.

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[3] Texas Utility Code §36.009.

[4] Order Adopting §25.244, Project No. 39829, Public Utility Commission of Texas. May 18, 2012. Pg.21.

Texas has recognized that seasonal, low load factor, and off peak system users face significant financial burdens when ratchet demands are imposed and have shown a willingness to carve out exceptions to lessen those burdens.

Secondly, and more importantly, the **Arizona-based produce importers are increasingly under pressure to relocate their businesses to Texas**. Indeed, Texas has grown its market share considerably. According to the Eller College of Economics and Business at the University of Arizona, Nogales generated $2.8 billion in trade in 2010, while Pharr, Texas generated $1.3 billion in trade. That year, Nogales had 57.1 percent of the Mexican fresh produce import market share compared to Pharr's 26.5 percent. In 2014, Nogales' lead in market share had shrunk significantly. Nogales had $2.9 billion of fresh produce trade compared to $2.5 billion for Pharr. Nogales had 41.4 percent of the market share while Pharr had increased to 35.7 percent.

According to representatives of the FPAA, Texas economic development groups have hosted meetings in Nogales to lure away importers. They offer considerable concessions in the form of tax breaks, more permissive building codes, and economic improvement zones. Combined with the policy being set by the Public Utility Commission of Texas, the incentives begin to stack up to support the moving of operations from the Santa Cruz Valley to southern Texas. **Should FPAA members opt to relocate, this would likely have a compounding effect as the loss of major local employment opportunity would likely lead to the loss of other associated businesses and UNSE customers.**

**Q. SHOULD THIS COMMISSION CONSIDER SIMILAR POLICY TO HELP REMEDY THE IMPACT EXPERIENCED BY FPAA MEMBERS?**

A. It would help. This Commission should recognize the unique seasonality of FPAA members' operations and the significant financial burden imposed by the ratchet

demand during this period. Through development of seasonal and low load factor exceptions, the Commission could lessen the financial hardship and still not "interfere" with a utility's ability to reasonably recover its costs. However, the Commission can also require UNSE to evaluate the appropriateness of the use of ratchet demands, the applicability to the customers within the medium and large general service classes and the appropriate ratchet level to be applied.

Q. **WHEN IS THE USE OF RATCHETS APPROPRIATE?**

A. In general, ratchets used in rate design should be representative of class load characteristics to minimize intra-class subsidization. Class characteristics are usually compared to system characteristics to establish appropriate ratchets and billing demands for a customer class. If a class has a class coincidence factor of 80%, than an 80% ratchet may be appropriate. As a customer's load factor increases, so does their coincidence factor. Ratchet demands are most commonly applied to large and industrial customers with high load factors. FPAA members' consumption patterns only equate to an approximate 45% load factor during operating months, and less than 20% during the dormant months. It is quite likely the FPAA members do not share the same load characteristics as other customers in the proposed medium and large general service classes. In my opinion, the existing ratchet may not be appropriate at all for FPAA members, or is set too high, leading to intra-class subsidization at FPAA member's expense.

Q. **HOW DID UNSE DETERMINE THE APPROPRIATENESS OF THE CURRENT RATCHET?**

A. It is unclear how UNSE came to their ratchet determination. UNSE originally requested a 100% ratchet demand and only settled on a 75% ratchet as a result of settlement negotiations. UNSE should provide data that supports their justification for the use and level of ratchet demands. UNSE should also review if it is more appropriate

to establish a class specifically for the produce refrigerators, recognizing that their unique load characteristics may be materially different than other medium and large general service customers and may in fact may provide a benefit to UNSE with increased usage in the spring, winter and fall when utility revenues are depressed, and reduced usage in late summer when system-wide demands are generally at peak.

## VI. OTHER ISSUES

**Q. PLEASE DESCRIBE THE CHANGES IN COST ALLOCATION THAT UNSE IS PROPOSING.**

A. UNSE is proposing in this case to change how it allocates demand costs from a Peaks and Average methodology to an Average & Excess methodology. As illustrated in the Direct Testimony of Craig Jones[5] in this Docket, the proposed change in allocation methodology will cause an additional $1,652,648 in demand related costs to be allocated to the newly proposed medium general service rate class, than would have otherwise been allocated under the historically used Peaks and Average methodology. This increases the return on rate base for medium and large general service customers from 9.84% to 12.96%.

**Q. IS THE CHANGE IN COST ALLOCATION METHODOLOGY APPROPRIATE AT THIS TIME?**

A. No. UNSE has not sufficiently demonstrated the need for a change in the cost allocation methodology. More importantly, UNSE has stated they strive to achieve rate parity, where customer classes generate sufficient revenues to earn a return on plant that matches the overall return on invested capital. The proposed change in allocation methodology will actually move rates further away from rate parity for the proposed medium and large general service rate classes. It appears that, should UNSE adopt the

[5] Direct Testimony of Craig A. Jones, pg. 25.

Average & Excess cost allocation methodology, UNSE would be earning a greater rate of return for this customer class then has been previously allowed or currently being requested.

Q. **HAVE YOU HAD THE OPPORTUNITY TO ANALYZE THE COST ALLOCATION METHODS USED IN THE COST OF SERVICE STUDY?**

A. No. Due to our late intervention in early November, and general procedural issues, I have not received a copy or been able to readily access the Cost of Service study to make my own evaluations. Additional examples and supporting exhibits may be provided when surrebuttal testimonies are provided.

Q. **ARE THERE ANY OTHER ISSUES YOU WOULD LIKE TO ADDRESS AT THIS TIME?**

A. NO.

Q. **DOES THIS CONCLUDE YOUR TESTIMONY?**

A. Yes.

# STATEMENT OF QUALIFICATIONS
# OF
# KENT R. SIMER

## EDUCATION

BIS, Business and Communication, Arizona State University. 2003
MBA, (Coursework toward), University of Phoenix

## CERTIFICATIONS & TRAINING

American Public Power Association – Basic Utility Cost of Service and Retail Rate Design (2005)
American Public Power Association – Advanced Utility Cost of Service and Retail Rate Design (2005)
American Public Power Association – Rate and Utility Management Seminars (Ongoing)

## TESTIMONY BEFORE REGULATORY COMMISSIONS

Arizona Corporation Commission, Docket No. W-01303A-10-0448: Application of Arizona-American Water for a determination of the current fair value of its utility plant and property and for increases in its rates and charges based thereon for utility service by its Agua Fria Water District, Havasu Water District, and Mohave Water District .

Arizona Corporation Commission, Docket No. W-01303A-09-0343: Application of Arizona-American Water for a determination of the current fair value of its utility plant and property and for increases in its rates and charges based thereon for utility service by its Anthem Water District and its Sun City Water District

## RELEVANT WORK EXPERIENCE

Electrical District No. 3 – Annual Cost of Service and Rate Design Analysis (Since 2003)
San Carlos Irrigation Project – Annual Cost of Service and Rate Design Analysis (Since 2005)
Electrical District No. 3 – Load Forecast (Annually)
Imperial Irrigation District – Annual Load Forecast (2001-2008)
Town of Thatcher – Electric Utility Unbundled Cost of Service and Rate Design Study (2004)
San Carlos Irrigation Project – Electric Utility Unbundled Cost of Service and Rate Design Study (2006)
City of Safford – Electric Utility Unbundled Cost of Service and Rate Design Study (2007)
City of Safford – Gas Utility Unbundled Cost of Service and Rate Design Study (2007)
Town of Wickenburg - Electric Utility Unbundled Cost of Service and Rate Design Study (2007)
Electrical District No. 4 – Load Forecast (2008)
Navajo Tribal Utility Authority – Power Requirements Study (2008)
San Carlos Irrigation Project – Electric Unbundled Utility Cost of Service and Rate Design Study (2011)
Multiple Electric Utilities –Revenue Requirement Forecasting / Planning (Ongoing)

Mr. Simer is a rate consultant for K. R. Saline & Associates, PLC. ("KRSA"), which provides ongoing consulting and engineering services for numerous irrigation and electrical districts, municipal utilities and tribal utilities located throughout the Southwest. Many of KRSA's clients were created to bring electrical service to rural areas to facilitate groundwater pumping for agricultural purposes. Over time these clients have extended their electrical service offerings to residential and commercial customers, and have seen their agricultural wells repurposed for commercial pumping and potable water development. Mr. Simer provides various consulting services for these clients.

Employed since 1998, Mr. Simer's experience in the utility industry includes economic analyses and computer-aided modeling for power supply planning, load forecasting, financial forecasting, cost/benefit analysis and rate studies. Mr. Simer participates with several regional public power organizations that

seek to find the balance between environmental and cultural stewardship of water resources and federal project power development on the Colorado River. Mr. Simer assists in analysis of Western Area Power Administration rate filings and participates in Public Information Forums and Public Comment Forums for federal rate making for Parker-Davis Project power rates, Parker-Davis Project transmission rates, Pacific NW-SW Intertie transmission rates, Boulder Canyon Project power rates, and Salt Lake City Area Integrated Projects power and transmission rates.

Ongoing Consulting Services Include:

Project: Financial and Economic Studies
Project Description: Economic analysis of operations, financial modeling, forecasting, cash management analyses and electric rate studies, including cost-of-service and bundled and unbundled rate design.

Project: Load Forecasting
Project Description: Long range load forecasting based on econometric and time series techniques that incorporated regional economic, demographic, and climatological data to develop independent energy forecasts for the various customer classes and the peak demand for the total system. Forecasts of energy and demand were developed for low and mid-range as well as high range expectations of future economic conditions.

Project: Integrated Resource Plans.
Project Description: Conservation and Renewable Energy programs, Integrated Resource Plans, evaluation of long-term and short-term power supply alternatives, demand-side planning and special resource pooling and resource integration arrangements.

Special Projects Include:

Project: Standard Market Design Study
Project Description: Investigating the effects of Standard Market Design and the implementation of Locational Marginal Pricing methodologies. This included development of a generation cost data database, simulation of powerflow models under existing and proposed scenarios, and analysis of the data created from the simulations.

Project: Solar Feasibility Study
Project Description: Developed a twenty-year utility rate model based on forecasted commercial load. Load profile was analyzed for its suitability under existing available time-of-use and net metering rate tariffs to determine the most financially beneficial solution. Model included development of utility rate increase assumptions, net metering determination, and calculation of applicable fees and taxes. Feasibility analysis included reviewed of current utility renewable incentives, federal and state tax implications, and project capital planning. Feasibility package included all necessary data and materials to aid customer in making their solar decision.

EXHIBIT
FPAA 3
admitted

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**BEFORE THE ARIZONA CORPORATION COMMISSION**

**COMISSIONERS:**
**SUSAN BITTER SMITH, Chairperson**
**BOB STUMP**
**BOB BURNS**
**DOUG LITTLE**
**TOM FORESE**

| | |
|---|---|
| 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 ELECRIC, INC., DEVOTED TO ITS OPERATIONS THROUGHT THE STATE OF ARIZONA AND FOR RELATED APPROVALS | DOCKET NO. E-04204A-15-0142<br><br>**NOTICE OF FILING SURREBUTTAL TESTIMONY OF KENT R. SIMER ON BEHALF OF FRESH PRODUCE ASSOCIATION OF THE AMERICAS** |

The Fresh Produce Association of the Americas ("FPAA"), through its undersigned counsel, hereby provides notice that it has this day filed the attached surrebuttal testimony of Kent R. Simer.

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Arizona Corporation Commission
DOCKETED
FEB 22 2016
DOCKETED BY

DATED this 22dn day of February 2016.

MOYES SELLERS & HENDRICKS

Jason Y. Moyes
Jay I. Moyes

*Attorneys for Fresh Produce Association of the Americas*

ORIGINAL and 13 COPIES of the foregoing filed this 22nd day of February 2016 with:

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Docket Control
Arizona Corporation Commission
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Phoenix, AZ 85007

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All Parties of Record

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## INTRODUCTION

**Q. PLEASE STATE YOUR NAME, ADDRESS AND OCCUPATION.**

A. My name is Kent R. Simer. My business address is 160 N. Pasadena, Suite 101, Mesa, Arizona. I am a Utility Rate Consultant for K. R. Saline & Associates, PLC, a firm that provides electrical engineering services, management consulting, and ongoing business operational services primarily to wholesale public electric utilities.

**Q. DID YOU PREVIOUSLY FILE DIRECT TESTIMONY IN THIS PROCEEDING?**

A. Yes, I filed Direct Testimony on rate design on December 9, 2015.

**Q. ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?**

A. My Surrebuttal Testimony is filed on behalf of the Fresh Produce Association of the Americas ("FPAA").

**Q. WHAT WAS THE MAIN PURPOSE OF YOUR DIRECT TESTIMONY?**

A. The purpose of my Direct Testimony was to introduce the FPAA and its economic contributions to Santa Cruz County, as well as describe the power usage profile of this large group of UNSE customers. Specifically, my testimony addressed the impacts that the demand ratchet has had on FPAA's members due to their unique, counter-seasonal operations. Because of the FPAA's unique operating characteristics, UNSE's ratchet rate design is punitive in nature and has the potential to cause a loss of this large and important customer base, which would not be in the public interest. FPAA is seeking rate relief for its members and

similar seasonal agricultural customers through a smaller or eliminated demand ratchet.

**Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY TODAY?**

A. The purpose of my Surrebuttal Testimony is to respond to the Rebuttal Testimony of UNSE witness Craig Jones and, in particular, the existing 75% ratchet "compromise" by recommending a solution that FPAA believes would be an acceptable compromise that better follows the rate setting practice of tying cost-causation to causers.

**Q. PLEASE SUMMARIZE MR. JONES' POSITION REGARDING FPAA'S REQUEST TO LOWER OR ELIMINATE THE DEMAND RATCHET FOR SEASONAL AGRICULTURAL CUSTOMERS.**

A. In his Rebuttal Testimony, Mr. Jones offers that the current 75% ratchet design implemented for Large General Service ("LGS") customers and proposed for Medium General Service ("MGS") customers offers a "compromise and moves the rates in the direction that improves the allocation and cost recovery from customers within the rate class"[1]. Mr. Jones believes FPAA's request is contrary to the desires of UNSE's goal of designing rates that allocate cost recovery to the cost causer.

**Q. DO YOU AGREE WITH MR. JONES THAT A 75% DEMAND RATCHET IS AN ACCEPTABLE COMPROMISE?**

A. I do not. I believe the demand ratchet recommended for the new MGS rate class is unnecessary. While Mr. Jones' assertion that a 75% ratchet moves rates in the direction that improves allocation and cost recovery is true, it does not justify a

[1] Rebuttal Testimony of Craig Jones, Page 36.

75% ratchet. The 75% ratchet was a compromise reached through settlement discussions in the previous rate case and no other justification was relied upon. The MGS rate customer group is being proposed in this proceeding for the first time; therefore, it is appropriate for this Commission to consider whether the 75% is appropriate for the MGS customers. Given the general rate design of the MGS customer group, UNSE's lack of justification for how they set a demand ratchet, energy conservation goals generally accepted by this Commission, and annual system load characteristics, I believe that a ratchet is neither not justified nor needed.

**Q. MR. JONES STATES THAT A DEMAND RATCHET IS A "COMMON METHOD OF ASSIGNING THE ACTUAL DEMAND THAT A CUSTOMER PLACES ON THE SYSTEM." DOES THE DEMAND RATCHET DO THIS?**

A. No it does not. As Nucor Steel witness Dr. Jay Zarnikau correctly points out, "the tariffs that UNS Electric applies to its largest customers apply a complicated set of alternatives that distort the connection between how and why the utility's demand costs are incurred and how the demand costs are paid by these customers."[2] The 75% demand ratchet being proposed for MGS customers only serves to further distort how customers are charged and obscures their actual demand on the system. Though the 75% demand ratchet does give customers some level of credit for system diversity at the time of the system's coincident peak, it does not correlate to what the customer's actual contribution is to the system peak.

[2] Direct Testimony of Nucor witness Dr. Jay Zarnikau, pg 10.

**Q. IS THERE A COMPROMISE SOLUTION THAT FPAA MEMBERS COULD SUPPORT?**

A. I believe that a demand ratchet is not necessary for FPAA members and other similar seasonal agricultural customers in Santa Cruz County on the basis that system characteristics do not justify the need. However, any compromise solution that includes a demand ratchet should justify the ratchet percentage. The sample data discussed in my direct testimony indicated that FPAA members' summer loads (*i.e.*, four summer coincident peaks) are approximately 51% of the FPAA members' annual peak load. Any compromise ratchet should not exceed the ratio of the four summer coincident peaks to annual peak load or 51%, if my sample data is representative of the entire group.[3]

**Q. WHAT IS THE JUSTIFICATION FOR ELIMINATING THE DEMAND RATCHET?**

A. The first test for determining the need for a demand ratchet is an evaluation of the system load profile to see if there are substantial load swings being experienced by the utility. UNSE is unique to Arizona in that it is the only electric utility in the state that is bifurcated into separate, non-contiguous service territories. FPAA members and similar produce distributors, who demonstrate a unique counter-seasonal power usage profile, are situated in the Santa Cruz County/Nogales portion of the UNSE service territory. Reviewing the system usage information in UNSE's response to RUCO's informal data request[4], the Nogales portion of UNSE's system only averages a load variance of approximately 10 MW between the summer and winter seasons. In other words, the average load experienced

[3] FPAA Customer Sample Data Exhibit KRS-2.
[4] RUCO's Informal Data Requests 02 – 11-17-2015.

during their winter months, over the last 5 years, has been roughly 85% of the average of the summer loads. This particular portion of the system, which has the most cost-causation relevancy to FPAA members, does not demonstrate significant swings in monthly demands at a level that would justify the need for a demand ratchet. Furthermore, as illustrated in exhibit KRS-1, the annual load factor for the Nogales area is higher than its Northern counterpart. The higher load factor combined with the minimal seasonal variance in the Nogales area illustrates that the demand ratchet is unnecessary, or should be lowered for these customers since the system is more efficiently used in Nogales. Under a ratchet rate design, the difference between load factors in the service territories indicates that customers located in the Nogales area are subsidizing customers in the Kingman/Havasu areas. The load data demonstrates that the counter-seasonal power profile of FPAA produce distributors' operations likely brings unique load diversity to the Nogales system and improves system efficiency.

**Q. HOW COULD UNSE ELIMINATE THE DEMAND RATCHET AND STILL ASSURE FULL COST RECOERY?**

A. FPAA customers reside in the Nogales area and there is not a demonstrated need for a demand ratchet in the area. It would be appropriate for UNSE to create a new customer class for seasonal agricultural customers which would assign costs to cost-causers in a more localized manner, while still maintaining the uniform nature of UNSE's service territories.

Q. **WHAT JUSTIFICATION IS THERE FOR CREATING A SEPARATE RATE CLASS FOR SEASONAL AGRICULTURAL CUSTOMERS?**

A. The justification for developing a separate rate class for seasonal agricultural customers is the same as the reasoning upon which UNSE relies to create the MGS customer class. In his rebuttal testimony[5], Mr. Jones specifically states:

> "the main purpose of creating the additional MGS rate class was to establish classes of service that contained a more **homogeneous grouping of customers** based on similar usage habits." [Emphasis added]

Mr. Jones continues by saying:

> "the Company has attempted to propose rate design and conditions relating to providing services to our customers that move toward treating **like-situated customers** in a similar manner." [Emphasis added]

As a group, FPAA members have similar counter-seasonal power requirements, generally similar load factors and share the same geographically specific cost drivers that create a more like-situated, homogenous grouping of customers than those of a much larger MGS customer group that encompasses many different load types across the separate geographic areas to which UNSE provides service. If this Commission decides that a demand ratchet is still appropriate, cost allocated based on Average and Excess 4CP methods would better tie cost causation to causers if FPAA members and similar counter-seasonal agricultural customers were in their own customer grouping.

[5] Rebuttal Testimony of Craig Jones, Pages 16-17.

**Q. HOW COULD UNSE APPLY A REDUCED DEMAND RATCHET?**

A. In lieu of a separate rate class, the MGS class being proposed as a newly designed rate class would include all FPAA member loads and the loads of like companies in Santa Cruz County. A demand ratchet that is lower than the LGS customer group could be established for this new MGS class.

**Q. DO YOU AGREE WITH MR. JONES' ASSERTION THAT MODIFYING THE DEMAND RATCHET OR RATES FOR FPAA MEMBERS WOULD CREATE A COST SHIFT TO OTHER CUSTOMERS?**

A. Yes; but it does not follow that such a cost shift is unjustified. UNSE has communicated the desire to move towards cost-based rates and a more levelized rate-of-return across customer groups. Though UNSE's proposed rate design in this docket does move toward this goal, the proposal still shows MGS customers providing a significant subsidy to other customer groups. Even though a cost shift may occur, the return earned would be more in line with other rate classes and the overall Rate of Return ("ROR"). I believe the changes I am recommending will result in appropriate cost shifts that are in line with UNSE's goals.

**Q. WHAT BENEFITS MAY RESULT IF UNSE ACCEPTS YOUR RATE RECCOMENDATION?**

A. The produce distribution industry is poised to expand in the coming years. Should UNSE deploy rate design strategies that are better suited for the unique operations of seasonal agricultural customers and that are competitive with Texas regulatory practices, UNSE can help incentivize new produce distribution operations to locate in the Nogales area and direct them away from establishing in other southern border states. This would be in line with UNSE's economic development goals,

while still being based on sound rate-making principles that result in just and reasonable rates.

Q. **WHAT IS THE RISK TO UNSE IF YOUR RATE RECCOMENDATION IS NOT ACCEPTED?**

A. Unfortunately, the rate design proposed by UNSE in this proceeding is eliminating all potential methods of rate mitigation for FPAA members. By instituting a demand ratchet on the proposed MGS customer group, they are limiting or eliminating customer savings opportunities that can be made through investments in distributed generation, demand response, or energy efficiency technologies. The time of day in which many of these technologies may be most advantageous may not be coincident with when the customer registers its peak load. A demand ratchet, therefore, would be prohibitive to potential capacity savings. Additionally, some FPAA members have sought to enroll in UNSE's interruptible program as a way to lessen the impact of the demand ratchet. This can provide a level of rate relief; however, not all FPAA members would qualify and there may not be adequate time for FPAA members to sign up before a potential change to the interruptible program occurs as a result of this rate proceeding. Any rate relief from the interruptible program would also be short-lived as UNSE is proposing to lessen the benefit of this program in the immediate case and has made clear that it is supportive of eliminating the program in its entirety in its next filed rate case. Finally, FPAA member operations are dictated by the requirements of the seasonal produce they distribute; and, like many other seasonal customers, have little ability or incentive to further manage their power requirements.

Absent a reduced or eliminated demand ratchet, FPAA members are therefore

limited in their cost mitigation abilities and are left with evaluating the option of relocating to an alternative service territory. As I mentioned in my Direct Testimony, the imported Mexican produce distribution industry exists primarily in Arizona and Texas. Texas has been actively lobbying Arizona companies to make the move and has created a utility regulatory environment that has shown to be flexible and supportive of seasonal agricultural customers. FPAA members are considering moving their operations, and associated employment, out of the state as a possible cost-mitigation option. Loss of FPAA members would only serve to further the decline of UNSE loads and reduce system efficiency through the loss of the unique counter-seasonal operations of this customer group.

**Q. DOES THIS CONCLUDE YOUR TESTIMONY?**

A. YES.

Calculation of Regional Load Factors 2011-2014

| Nogales Area | MWh | MW | Hours | LF |
|---|---|---|---|---|
| 2011 | 340,322 | 79 | 8,760 | 49.2% |
| 2012 | 337,549 | 77 | 8,784 | 49.9% |
| 2013 | 322,696 | 77 | 8,760 | 47.8% |
| 2014 | 320,717 | 72 | 8,760 | 50.8% |
| | | 4-Year Average | | 49.4% |

| Kingman/Havasu Area Only | MWh | MW | Hours | LF |
|---|---|---|---|---|
| 2011 | 1,606,448 | 369 | 8,760 | 49.7% |
| 2012 | 1,494,585 | 368 | 8,784 | 46.2% |
| 2013 | 1,460,999 | 373 | 8,760 | 44.7% |
| 2014 | 1,420,247 | 361 | 8,760 | 44.9% |
| | | 4-Year Average | | 46.4% |

| Total System | MWh | MW | Hours | LF |
|---|---|---|---|---|
| 2011 | 1,946,770 | 438 | 8,760 | 50.8% |
| 2012 | 1,832,134 | 437 | 8,784 | 47.7% |
| 2013 | 1,783,695 | 434 | 8,760 | 46.9% |
| 2014 | 1,740,964 | 428 | 8,760 | 46.5% |
| | | 4-Year Average | | 48.0% |

Sample FPAA Data Set

| Metered KW | January | February | March | April | May | June | July | August | September | October | November | December | Peak | 4 CP | 4CP/Peak |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Customer 1 | 204 | 234 | 222 | 252 | 277 | 323 | 243 | 125 | 117 | 151 | 217 | 259 | 323 | 202 | 0.63 |
| Customer 2 | 314 | 311 | 356 | 355 | 364 | 415 | 284 | 31 | 28 | 208 | 288 | 280 | 415 | 190 | 0.46 |
| Customer 3 | 159 | 169 | 199 | 187 | 190 | 208 | 133 | 29 | 176 | 60 | 114 | 285 | 285 | 137 | 0.48 |
| Customer 4 | 124 | 106 | 164 | 139 | 108 | 194 | 170 | 61 | 13 | 30 | 214 | 61 | 214 | 110 | 0.51 |
| Customer 5 | 72 | 74 | 61 | 77 | 76 | 114 | 54 | 42 | 22 | 22 | 11 | 47 | 114 | 58 | 0.51 |
| Customer 6 | 122 | 161 | 141 | 164 | 171 | 197 | 99 | 65 | 31 | 49 | 166 | 119 | 197 | 98 | 0.50 |
| Customer 7 | 126 | 138 | 131 | 136 | 152 | 134 | 139 | 106 | 46 | 73 | 189 | 129 | 189 | 106 | 0.56 |
| Customer 8 | 95 | 106 | 111 | 120 | 112 | 34 | 22 | 23 | 23 | 18 | 123 | 97 | 123 | 26 | 0.21 |
| Customer 9 | 49 | 51 | 61 | 54 | 58 | 65 | 36 | 37 | 33 | 35 | 60 | 48 | 65 | 43 | 0.66 |
| Customer 10 | 317 | 421 | 451 | 448 | 365 | 507 | 445 | 187 | 142 | 189 | 246 | 298 | 507 | 320 | 0.63 |
| Customer 11 | 85 | 100 | 125 | 161 | 134 | 123 | 13 | 8 | 8 | 90 | 132 | 68 | 161 | 38 | 0.24 |
| Customer 12 | 117 | 144 | 124 | 149 | 127 | 212 | 217 | 28 | 31 | 115 | 139 | 93 | 217 | 122 | 0.56 |
| Customer 13 | 47 | 51 | 62 | 58 | 55 | 70 | 91 | 39 | 27 | 37 | 72 | 53 | 91 | 57 | 0.62 |
| Customer 14 | 107 | 109 | 107 | 122 | 92 | 131 | 138 | 15 | 14 | 38 | 106 | 103 | 138 | 75 | 0.54 |
| Customer 15 | 200 | 206 | 208 | 208 | 206 | 210 | 185 | 77 | 36 | 100 | 166 | 194 | 210 | 127 | 0.61 |
| | | | | | | | | | | | | | | | 0.51 |

| Ratchet BKW | January | February | March | April | May | June | July | August | September | October | November | December | Peak | 4 CP |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Customer 1 | 204 | 239 | 239 | 252 | 277 | 323 | 243 | 242 | 242 | 242 | 242 | 259 | 323 | 263 |
| Customer 2 | 314 | 311 | 356 | 355 | 364 | 415 | 284 | 257 | 257 | 257 | 288 | 280 | 415 | 303 |
| Customer 3 | 159 | 237 | 237 | 237 | 237 | 208 | 178 | 178 | 178 | 178 | 178 | 285 | 285 | 186 |
| Customer 4 | 194 | 194 | 194 | 194 | 194 | 194 | 170 | 146 | 146 | 146 | 214 | 98 | 214 | 164 |
| Customer 5 | 72 | 74 | 61 | 77 | 76 | 114 | 85 | 85 | 85 | 85 | 58 | 58 | 114 | 92 |
| Customer 6 | 122 | 186 | 186 | 186 | 186 | 197 | 148 | 148 | 148 | 148 | 166 | 148 | 197 | 160 |
| Customer 7 | 142 | 142 | 142 | 142 | 152 | 142 | 142 | 142 | 142 | 142 | 189 | 142 | 189 | 142 |
| Customer 8 | 95 | 106 | 111 | 120 | 112 | 92 | 92 | 92 | 92 | 92 | 123 | 97 | 123 | 92 |
| Customer 9 | 49 | 51 | 61 | 54 | 58 | 65 | 49 | 49 | 49 | 49 | 60 | 49 | 65 | 53 |
| Customer 10 | 317 | 421 | 451 | 448 | 365 | 507 | 445 | 380 | 380 | 380 | 380 | 298 | 507 | 428 |
| Customer 11 | 85 | 100 | 125 | 161 | 134 | 128 | 121 | 121 | 121 | 121 | 132 | 121 | 161 | 123 |
| Customer 12 | 123 | 144 | 124 | 149 | 127 | 212 | 217 | 163 | 163 | 123 | 139 | 123 | 217 | 189 |
| Customer 13 | 59 | 59 | 62 | 59 | 59 | 70 | 91 | 68 | 68 | 59 | 72 | 59 | 91 | 74 |
| Customer 14 | 107 | 109 | 107 | 122 | 107 | 131 | 138 | 104 | 104 | 107 | 107 | 107 | 138 | 119 |
| Customer 15 | 200 | 206 | 208 | 208 | 206 | 210 | 185 | 185 | 157 | 157 | 166 | 194 | 210 | 184 |

| Metered KWh | January | February | March | April | May | June | July | August | September | October | November | December | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Customer 1 | 73,800 | 84,360 | 68,040 | 82,200 | 97,560 | 119,880 | 38,160 | 19,200 | 17,880 | 23,520 | 64,800 | 86,880 | 776,280 |
| Customer 2 | 129,920 | 141,440 | 129,120 | 175,360 | 157,280 | 178,560 | 31,040 | 10,080 | 12,000 | 11,360 | 114,880 | 124,640 | 1,215,680 |
| Customer 3 | 35,400 | 64,680 | 59,040 | 60,360 | 52,440 | 63,600 | 7,320 | 7,680 | 7,800 | 7,440 | 16,800 | 18,000 | 400,560 |
| Customer 4 | 33,960 | 33,000 | 53,160 | 41,040 | 28,440 | 59,400 | 61,200 | 4,680 | 2,760 | 2,880 | 3,720 | 15,960 | 340,200 |
| Customer 5 | 20,320 | 24,800 | 12,640 | 20,480 | 19,840 | 26,880 | 2,560 | 1,600 | 1,200 | 2,240 | 640 | 2,480 | 135,680 |
| Customer 6 | 47,280 | 65,920 | 53,760 | 58,960 | 60,560 | 51,360 | 14,320 | 8,800 | 8,960 | 10,160 | 31,280 | 42,000 | 453,360 |
| Customer 7 | 57,480 | 59,760 | 58,080 | 59,880 | 55,680 | 56,040 | 55,200 | 30,960 | 13,920 | 15,360 | 47,880 | 49,800 | 560,040 |
| Customer 8 | 33,040 | 32,720 | 32,000 | 42,080 | 22,800 | 6,160 | 4,560 | 4,160 | 4,240 | 3,520 | 6,960 | 18,400 | 210,640 |
| Customer 9 | 18,640 | 20,960 | 19,520 | 20,960 | 22,720 | 21,360 | 12,560 | 13,520 | 9,440 | 12,640 | 17,440 | 15,360 | 205,120 |
| Customer 10 | 116,800 | 93,440 | 99,520 | 104,800 | 78,560 | 118,240 | 91,840 | 40,640 | 26,880 | 24,640 | 48,000 | 81,920 | 925,280 |
| Customer 11 | 15,360 | 24,840 | 28,440 | 30,720 | 33,840 | 7,320 | 2,400 | 2,280 | 2,520 | 3,120 | 26,400 | 8,880 | 186,120 |
| Customer 12 | 42,080 | 43,360 | 34,640 | 49,840 | 45,440 | 56,480 | 41,680 | 1,840 | 1,280 | 13,200 | 39,920 | 28,720 | 398,480 |
| Customer 13 | 18,880 | 18,000 | 18,080 | 15,000 | 15,520 | 11,840 | 15,440 | 5,520 | 5,280 | 6,560 | 18,480 | 11,840 | 160,440 |
| Customer 14 | 38,760 | 38,040 | 34,360 | 44,200 | 28,720 | 41,760 | 36,480 | 1,800 | 1,720 | 2,440 | 33,240 | 22,400 | 323,920 |
| Customer 15 | 71,760 | 93,480 | 87,960 | 87,960 | 72,960 | 73,320 | 47,760 | 20,880 | 9,240 | 27,720 | 41,760 | 61,920 | 696,720 |

| LF | January | February | March | April | May | June | July | August | September | October | November | December | Annual |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Customer 1 | 49% | 54% | 41% | 45% | 47% | 52% | 21% | 21% | 21% | 21% | 41% | 45% | 27% |
| Customer 2 | 56% | 68% | 49% | 69% | 58% | 60% | 15% | 44% | 59% | 7% | 55% | 60% | 33% |
| Customer 3 | 30% | 57% | 40% | 45% | 37% | 42% | 7% | 36% | 6% | 17% | 20% | 8% | 16% |
| Customer 4 | 37% | 47% | 43% | 41% | 35% | 42% | 48% | 10% | 29% | 13% | 2% | 35% | 18% |
| Customer 5 | 38% | 50% | 28% | 37% | 35% | 33% | 6% | 5% | 7% | 14% | 8% | 7% | 14% |
| Customer 6 | 52% | 61% | 51% | 50% | 48% | 36% | 19% | 18% | 40% | 28% | 26% | 47% | 26% |
| Customer 7 | 61% | 65% | 60% | 61% | 49% | 58% | 53% | 39% | 42% | 28% | 35% | 52% | 34% |
| Customer 8 | 47% | 46% | 39% | 49% | 27% | 25% | 27% | 24% | 26% | 26% | 8% | 26% | 20% |
| Customer 9 | 52% | 61% | 43% | 54% | 53% | 46% | 46% | 49% | 40% | 48% | 40% | 43% | 36% |
| Customer 10 | 50% | 33% | 30% | 32% | 29% | 32% | 28% | 29% | 26% | 18% | 27% | 37% | 21% |
| Customer 11 | 24% | 37% | 31% | 27% | 34% | 8% | 24% | 36% | 42% | 5% | 28% | 17% | 13% |
| Customer 12 | 48% | 45% | 37% | 47% | 48% | 37% | 26% | 9% | 6% | 15% | 40% | 42% | 21% |
| Customer 13 | 54% | 52% | 39% | 36% | 38% | 23% | 23% | 19% | 27% | 24% | 36% | 30% | 20% |
| Customer 14 | 49% | 52% | 43% | 50% | 42% | 44% | 35% | 16% | 17% | 9% | 43% | 29% | 27% |
| Customer 15 | 48% | 68% | 57% | 59% | 48% | 49% | 35% | 36% | 36% | 37% | 35% | 43% | 38% |