ORIGINAL

0000168411

BEFORE THE ARIZONA CORPORATION COMMISSION

RECEIVED

2016 FEB 23 P 1:21

AZ CORP COMMISSION
DOCKET CONTROL

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 RELATED APPROVALS.	DOCKET NO. E-04204A-15-0142

Arizona Corporation Commission
DOCKETED
FEB 23 2016
DOCKETED BY
KE

ARIZONA INVESTMENT COUNCIL'S NOTICE OF FILING

Arizona Investment Council ("AIC") hereby provides notice of filing the Surrebuttal Testimony of Gary Yaquinto and the Surrebuttal Testimony of Daniel G. Hansen in the above-referenced matter.

RESPECTFULLY SUBMITTED this 23 day of February, 2016.

OSBORN MALEDON, P.A.

By Meghan H. Grabel

Meghan H. Grabel
2929 North Central Avenue
Phoenix, Arizona 85012

Attorney for Arizona Investment Council

Original and 13 copies filed this 23rd day of February, 2016, with:

Docket Control
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007

Copies of the foregoing mailed this 23rd day of February, 2016, to:

All Parties of Record

Debra Huss

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

TABLE OF CONTENTS

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	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	82,455	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	168	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	$ 164	$ 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	$ 62,056	$ 15,031	$ (4,517)
$ (8,692)	$ 248	$ 867	$ 15,048	$ 3,468	$ (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

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
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

TABLE OF CONTENTS

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]

---

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]

---

[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

---

[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?

---

[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

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