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Transcript Exhibit(s)

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

Arizona Corporation Commission
DOCKETED
MAR 25 2016
DOCKETED BY

Exhibit #: AURA 1-5; Vote Solar 1-8; RUCO 1-6

Part 2 of 8

For Part 3, see Barcode 0000169258

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

SURREBUTTAL TESTIMONY
OF
SCOTT J. RUBIN
ON BEHALF OF
ARIZONA UTILITY RATEPAYER
ALLIANCE FEBRUARY 23, 2016

EXHIBIT
AURA-1
admitted

I INTRODUCTION

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND TELEPHONE NUMBER.

A. My name is Scott J. Rubin. My business address is 333 Oak Lane, Bloomsburg, PA 17815, and my phone number is 570-387-1893.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS MATTER?

A. I am testifying on behalf of the Arizona Utility Ratepayer Alliance ("AURA").

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am an independent consultant and an attorney. My practice is limited to matters affecting the public utility industry.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS CASE?

A. I have been asked by AURA to review the rebuttal testimony on rate design issues filed by UNS Electric Inc. ("UNSE").

Q. WHAT ARE YOUR QUALIFICATIONS TO PROVIDE THIS TESTIMONY IN THIS CASE?

A. I have testified as an expert witness before utility commissions or courts in the District of Columbia; the province of Nova Scotia; and the states of Alaska, Arizona, California, Connecticut, Delaware, Illinois, Kentucky, Maine, Maryland, Mississippi, New Hampshire, New Jersey, New York, Ohio, Pennsylvania, and West Virginia. I also have testified as an expert witness before various legislative committees. I also have served as a consultant to the staffs of state utility commissions, as well as to national utility trade associations, and state and local governments throughout the country. Prior to establishing my own consulting and law practice, I was employed by the Pennsylvania

Office of Consumer Advocate from 1983 through January 1994 in increasingly responsible positions. From 1990 until I left state government, I was one of two senior attorneys in that Office. Among my other responsibilities in that position, I had a major role in setting its policy positions on water and electric matters. In addition, I was responsible for supervising the technical staff of that Office. I also testified as an expert witness for that Office on rate design and cost of service issues.

Throughout my career, I developed substantial expertise in matters relating to the economic regulation of public utilities. I have published articles, contributed to books, written speeches, and delivered numerous presentations, on both the national and state level, relating to regulatory issues. I have attended numerous continuing education courses involving the utility industry. I also have participated as a faculty member in utility-related educational programs for the Institute for Public Utilities at Michigan State University, the American Water Works Association, and the Pennsylvania Bar Institute.

Q. HAVE YOU CONTRIBUTED TO ANY BOOKS ON THE TOPIC OF UTILITY RATE DESIGN?

A. Yes. I served on the editorial committee for the fifth edition of *Water Rates, Fees, and Charges* (Manual M1) published by the American Water Works Association in 2000. That book is the primary rate-setting manual for the water utility industry, including cost-of-service studies and rate design.

Q. HAVE YOU PUBLISHED ANY PAPERS ON THE TOPIC OF UTILITY RATE DESIGN?

A. Yes. In November 2015, I published a paper on this topic in *The Electricity Journal.* The paper is entitled "Moving Toward Demand-Based Residential Rates." In that paper, I discussed and analyzed several options for designing cost-based residential rates. A copy of the paper is provided as Exhibit SJR-1 accompanying this testimony.

Q. DO YOU HAVE ANY EXPERIENCE THAT IS PARTICULARLY RELEVANT TO THE ISSUES IN THIS CASE?

A. Yes, I do. I have testified on numerous occasions as a rate design and cost of service expert. For example, during the past three years, I have testified as a cost-of-service study and/or rate design expert in electric utility rate cases in Alaska (Chugach Electric and Municipality of Anchorage), Connecticut (United Illuminating), District of Columbia (Potomac Electric), Illinois (Commonwealth Edison and Ameren), Mississippi (Entergy), Ohio (Duke Energy, Dayton Power & Light, and the FirstEnergy companies), and Pennsylvania (Pike County Light & Power). My complete curriculum vitae is attached to this testimony as Appendix A.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. Yes, I testified as a rate design and cost-of-service study expert witness before this Commission in a rate case involving the former Citizens Utilities' water operations in 1996 (Docket Nos. E-1032-95-417, et al.).

II PURPOSE OF TESTIMONY

Q. WHAT IS THE SPECIFIC PURPOSE OF YOUR TESTIMONY IN THIS MATTER?

A. In its rebuttal testimony and exhibits, UNSE presents a new rate design for residential customers. UNSE claims that its new rate design, which includes demand charges for residential customers, more equitably recovers the cost of service than the rate design it proposed in its direct case. My testimony will evaluate UNSE's claim using data provided by UNSE as part of its rebuttal filing and workpapers.

III RATE DESIGN TESTIMONY

Q. WHAT DOES UNSE SPECIFICALLY CLAIM REGARDING ITS REVISED RATE DESIGN.

A. Four UNSE rebuttal witnesses claim that its new rate design would be fairer to all residential customers. Specifically, Mr. Hutchens states that UNSE "is attempting to modify its rates to (i) recover costs more equitably … [and] (iv) promote the efficient use of the Company's electric system." Hutchens rebuttal, p. 4, lines 14-17. Similarly, Mr. Dukes testifies in his rebuttal that "UNS Electric is trying to address *all* ratepayer subsidization in this case, by moving rates closer to cost-of-service." Dukes rebuttal, p. 19, lines 23-24 (emphasis in original). Mr. Jones's rebuttal testimony contains a similar claim, where he states: UNSE "is attempting to modify its rates to (i) reduce intra-class subsidization where possible, [and] (ii) promote fairness between like situated customers and recover costs from cost causers." Jones rebuttal, p. 1, lines 24-26. Finally, Dr. Overcast states that "a multi-part rate reflects cost causation more accurately [than an energy-only rate] and when unbundled will be consistent with the principles of cost causation and matching costs and revenues with a proper design." Overcast rebuttal, p. 8, lines 15-17.

Q. DID UNSE PROVIDE ANY ANALYSES TO SUPPORT ITS CONTENTION THAT THE CURRENT TWO-PART RATE DESIGN (CUSTOMER CHARGE AND ENERGY CHARGE) IS NOT CONSISTENT WITH THE COST OF SERVING RESIDENTIAL CUSTOMERS?

A. No.

Q. DID UNSE PROVIDE ANY ANALYSES TO SUPPORT ITS CONTENTION THAT ITS PROPOSED THREE-PART RATE DESIGN (CUSTOMER CHARGE, DEMAND CHARGE, AND ENERGY CHARGE) IS CONSISTENT WITH THE COST OF SERVING RESIDENTIAL CUSTOMERS?

A. No.

Q. HAS UNSE PROVIDED DATA THAT ALLOW SUCH ANALYSES TO BE PERFORMED?

A. Yes, at least in part. UNSE has provided a cost-of-service study ("COSS") from which the essential elements of the cost to serve each customer can be calculated. In addition, UNSE has provided hourly meter reading data for an entire 12-month period for a sample of 100 residential customers. While it would be ideal to have such data for all of UNSE's residential customers, I recognize that most residential customers did not have automated metering equipment installed for the entire test year.

Q. HAVE YOU PERFORMED AN ANALYSIS OF THE COST TO SERVE EACH OF THE 100 CUSTOMERS IN UNSE'S SAMPLE?

A. Yes.

Q. HAVE YOU ALSO COMPARED THE REVENUES THAT EACH OF THOSE 100 CUSTOMERS WOULD PROVIDE UNDER UNSE'S DIFFERENT RATE-DESIGN PROPOSALS?

A. Yes.

Q. BEFORE DISCUSSING THE RESULTS OF YOUR ANALYSES, PLEASE EXPLAIN HOW YOU ESTIMATED THE COST TO SERVE EACH CUSTOMER.

A. The best estimate we have of the cost to serve a customer is a COSS. I recognize that different COSS have been presented in this case, and I do not take a position on the various studies that have been presented. For purposes of consistency, I have used UNSE's most recent COSS provided in the file: *2015 UNSE Schedule G-COSS-R.xlsx*. I say that this is for consistency because I am evaluating UNSE's rate design proposals. So it is reasonable to compare those proposals to UNSE's COSS to test UNSE's claim that its rate design was developed to more closely track the results of its own analysis of the cost to serve customers.

UNSE's COSS includes four types of demand-related functions (production, transmission, distribution primary, and distribution secondary); one energy-related function (essentially fuel and purchased power); and four categories of customer-related functions (delivery, meter, billing and collections, and meter reading). UNSE's study develops a specific cost (a dollar amount) to provide each of these functions to the residential class of customers, each of which is based on a particular allocation methodology, as shown in the following table.

Function	**Cost of Service**	**Allocation to Residential**
Production demand	$20,709,455	Coincident peak (A&E/4CP)
Transmission demand	8,775,515	A&E/4CP
Distribution primary demand	10,625,712	Class Non-Coincident Peak (NCP)
Distribution secondary demand	1,173,823	NCP
Total demand-related costs	**$41,284,505**	
Energy	**$44,744,078**	Energy Usage (kWh)
Customer delivery	$ 7,991,033	Number of Customers
Customer meter	646,494	Number of Customers
Customer billing & collections	4,113,357	Number of Customers
Customer meter reading	942,211	Number of Customers
Total customer-related costs	**$13,693,095**	
Total residential cost of service	**$ 99,721,678**	

Source: File: *2015 UNSE Schedule G-COSS-R.xlsx*, Tab: *Functionalization_RES.*

Q. HOW IS THIS INFORMATION USED TO ESTIMATE THE COST TO SERVE A SPECIFIC CUSTOMER?

A. In utility rate cases, rate design and COSS experts (including me) are always talking about "cost causation." It is important to understand what that means. With the possible exception of very large customers under special rates, we do not attempt to determine the actual cost to serve each customer. Indeed, such an analysis would be impossible because each customer is slightly different. Some customers are closer to substations meaning that the distribution circuit serving them is shorter (usually meaning less expensive) than the circuit serving customers who are further from the substation. Some customers have underground service which usually is more expensive than overhead service. Some neighborhoods might have transformers that serve five or ten buildings, while others might have transformers that serve just one or two buildings. Some customers are located further from the street than others meaning that the cost of the service line connecting the distribution line to the premises would be different. I could go on and on. The point is that a cost-of-service study, and ratemaking in general, is designed to estimate the cost to serve the typical customer within a customer class or subclass. The principle of cost causation is not specific to each individual customer, but to customer classes that have certain characteristics in common.

For this reason, when we attempt to determine the cost to serve a particular customer, we are actually determining how a customer's use of the electric system affects the costs that are allocated to the customer's class. For example, secondary distribution costs are allocated among the customer classes based on the class's non-coincident peak ("NCP") demand. During the test year, the residential class's NCP demand occurred on July 24, 2014, in the hour from 4:00 pm to 5:00 pm (appearing in UNSE's data as the hour ending 17).[1] Thus, if we are trying to determine the secondary distribution cost to serve Jane Doe at 123 Any Street, we evaluate how much electricity she used on July 24, 2014, between 4:00 pm and 5:00 pm; that is, how much she contributed to the residential class's demand at the time of the class NCP.

Q. HOW DO YOU USE THIS UNDERSTANDING OF COST CAUSATION TO CONTINUE YOUR ANALYSIS?

A. The next step is to determine the unitized cost of each cost element. For example, as shown in the table above, the residential class has been allocated $13,693,095 of costs based on the number of customers in the class. The class has 82,607 customers.[2] So, each residential customer has "caused" UNSE to incur $165.76 per year in customer-related costs. The following table shows the unitized costs per year for each cost element. A more detailed calculation of these amounts is shown in my Exhibit SJR-2.

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[1] File: *UNSE RES LR Data.xlsx*, Tab: *Res Adj.*
[2] File: *2015 UNSE Schedule G-COSS-R.xlsx* Tab: *G-7 Allocations* Cell: J38

Function	Unitized Cost of Service
Production & transmission	\$108.17 per kW based on 4CP
Production & transmission	\$70.53 per kW based on average[3]
Distribution demand	\$44.13 per kW based on NCP
Energy	\$0.054304 per kWh
Customer costs	\$165.76 per customer

Q. WHAT DID YOU DO WITH THESE UNITIZED COSTS OF SERVICE?

A. I applied these unitized costs of service to the specific characteristics of each of the 100 customers in the sample provided by UNSE.[4] These specific characteristics are sometimes referred to as a customer's "units of service." That is, for each of the 100 customers in the sample, I determined the customer's demand (in kW) at the time of the system peak (based on the highest coincident peak in each of the four summer months (4CP)),[5] the customer's demand at the time of the class NCP, and the customer's annual energy consumption. In addition, each customer is equal to one customer for the purposes of determining customer-related costs. Each customer's units of service are then multiplied by the corresponding element of the unitized cost of service. When the results for a customer are summed, we have an estimate of the cost to serve each customer.

Q. CAN YOU PROVIDE AN EXAMPLE?

A. Yes. The following table shows these calculations for one customer in UNSE's sample.[6]

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[3] Average demand is equal to annual kilowatt-hour consumption divided by the number of hours in the year (8760 in the test year).

[4] The sample of 100 customers was provided as part of Mr. Dukes's rebuttal workpapers in the file: *UNSE Res Hrly 0713-0615.xlsx.*

[5] According to the file: *UNSE RES LR Data.xlsx*, Tab: *Res Adj* the system coincident peaks occurred on July 15, 2014 hour end 18, July 23, 2014 hour end 16, August 6, 2014 hour end 17, and September 2, 2014 hour end 17.

[6] The data are for the customer with the identifier 52657. Note that the figures in the table are rounded for ease of presentation. The more precise estimate of the cost to serve this customer, without rounding, is \$672.64.

Function	Unitized Cost of Service	Units of Service	Cost of Service
Production & transmission	$108.17 per kW 4CP	1.45 kW	$ 156.85
Production & transmission	$70.53 per kW avg.	0.46 kW	32.44
Distribution demand	$44.13 per kW NCP	2.25 kW	99.29
Energy	$0.054304 per kWh	4021.2 kWh	218.37
Customer costs	$165.76 per customer	1	165.76
Total cost of service			$ 672.71

Q. WHY IS THIS ESTIMATE OF THE COST TO SERVE EACH CUSTOMER IMPORTANT?

A. This estimate of the cost to serve each customer can be used to compare the revenues that would be collected from each customer under different rate design options. As I explain below, the difference between the costs and revenues under different options can then be compared to determine how well each rate design tracks the cost to serve customers.

Q. DO YOU USE ALL OF THE DATA IN THE ABOVE TABLE TO COMPARE RATE DESIGN OPTIONS?

A. I considered all of these data, but I found that including Energy costs in the analysis tends to mask important differences in rate design options. Approximately 45% of the residential class's cost of service is for energy costs. Those costs are allocated to the customer class based solely on energy consumption, and all of the rate designs (except one) collect these costs from customers using exactly the same factor (energy consumption in kWh). That is, there is essentially no difference among the rate design options in how they recover fuel, purchased power, and related costs. Because energy-related costs are such a large part of customers' bills and the cost of service, it was difficult to see the differences among different rate design options. The results that I discuss below, therefore, compare the distribution portion of customers' bills (all charges except the Base Power Supply Charge (BPSC) and the Purchased Power and Fuel

Adjustment Charge (PPFAC)) with distribution costs (unitized Demand costs and Customer costs from the COSS).

Q. WHAT RATE DESIGNS DID YOU EVALUATE?

A. I evaluated existing rates and five rate design options under proposed rates. The rate design options are UNSE's originally proposed two-part rate, UNSE's originally proposed three-part rate, UNSE's rebuttal two-part rate (termed the "transition" rate design), UNSE's rebuttal three-part rate with no adjustment for load factor, and UNSE's rebuttal three-part rate based on a minimum load factor of 15% in each month.

Q. PLEASE DESCRIBE YOUR FIRST ANALYSIS AND WHAT CONCLUSIONS YOU REACHED FROM IT.

A. My first analysis is provided in Exhibit SJR-3. The solid black line on the graph represents equality between revenues (shown on the left or y axis) and the distribution cost of service (shown on the bottom or x axis). For ease of reference, I will call this the Equality Line. Points that lie above the Equality Line represent customers who are providing revenues in excess of their cost of service; points below the Equality Line are customers whose revenues are less than their cost of service.

The other line on the graph (the dashed line) is the trend (or regression) line. This line represents the best statistical relationship among the 100 points plotted on the graph. The closer this line is to the Equality Line, the better job the rate design does in tracking the customer-specific cost of service.

Three other factors are important to note here. First, the R-square of the trend line (shown below the graph) provides a numeric representation of how closely the trend line represents the individual customers. The closer the R-square is to 1.0, the better the trend line represents the customer data. The second important factor is the slope of the trend line (also shown below the graph). The slope is the change in the annual bill for each $1.00 increase in the cost of serving the customer. The closer the slope is to 1, the better the rate design does in increasing revenues by an amount equal to an increase in costs. Third, I calculate the average percentage difference between each customer's cost of service and revenues (using the absolute value). The smaller the average percentage difference, the closer the rate design comes to tracking each customer's cost of service.

Exhibit SJR-3 shows a comparison of the customer-specific distribution cost-of-service with annual distribution revenues under existing rates. UNSE has asked for a significant increase in distribution revenues, so it is not surprising that existing rates produce substantially less revenues than UNSE claims under proposed rates (that is, almost all points lie below the Equality Line). Thus, the average difference between revenues and costs is 36%. The existing slope is 0.607. This indicates that as costs increase, the existing rate design does not do a very good job of collecting the cost of service from higher-cost customers. Stated differently, higher-cost customers (those with larger demands) are paying a lower percentage of the cost to serve them than are lower-cost customers.

My analysis of existing rates shows that there certainly is room for improvement in the rate design. Not only do rates need to be increased (assuming for the sake of illustration, as I do throughout, that UNSE's revenue requirement claims are justified), but the rate design could be modified to do a better job of collecting revenues from higher-cost customers (that is, move the slope of the trend line closer to 1.0).

Q. PLEASE TURN NOW TO YOUR ANALYSIS OF UNSE'S RATE DESIGN PROPOSALS. WHAT IS SHOWN ON EXHIBIT SJR-4?

A. Exhibit SJR-4 shows UNSE's originally proposed rate design. This is a two-part rate consisting of a customer charge of $20.00 per month and a two-block consumption charge: 3.0810¢ per kWh for the first 400 kWh per month, and 5.0810¢ per kWh for all consumption in excess of 400 kWh per month.[7] My exhibit shows that this rate design constitutes an improvement over existing rates. The slope of the trend line is 0.846. This means that for every $100 by which the cost to serve a customer increases, this rate design collects $84.60 in additional revenues from the customer. This is an improvement over the existing rate design, but it still results in some higher-cost customers paying less than their cost of service.

The average difference between revenues and costs is 22% under this rate design. Once again, this is an improvement over the existing rates where customers' revenues differed from costs by 36%.

One troubling factor with this rate design is that the trend line starts above the Equality Line then crosses the Equality Line at about $800 in costs. In other words, lower-cost customers are paying more than the cost to serve them, while higher-cost customers are paying less than cost. It appears that this inequity is primarily due to the customer charge of $20 per month ($240 per year) which is substantially higher than the unitized customer cost of $165.76 per year. Simply, this rate design has a customer charge that is too high resulting in consumption charges that are too low. This leads to some lower-cost customers (those with lower demands) subsidizing some higher-cost customers (those with higher demands) under this rate design.

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[7] UNSE Schedule H-3 (Revised 6/3/2015), page 1.

Finally, the graph at the bottom of Exhibit SJR-4 (known as a histogram) shows the number of customers whose bills would increase by certain percentages compared to existing rates. Under this rate design, annual distribution bill increases range from 47% to 95%. The bill impacts are quite spread out, with most customers seeing increases in the range of 50% to 85%.

Q. PLEASE DESCRIBE EXHIBIT SJR-5.

A. Exhibit SJR-5 provides the same type of presentation as Exhibit SJR-4, but for UNSE's originally proposed residential three-part (demand) rate. I understand that UNSE originally presented this rate as an optional rate.

This original three-part rate consisted of a customer charge of $20 per month, a charge of $6.00 per kW for the first 7 kW of demand (measured as the maximum one hour during the month, regardless of day of week or time of day)[8] in a month, $9.95 per kW for demand in excess of 7 kW, and a consumption charge of 1.0¢ per kWh for all energy consumed.[9]

UNSE's original three-part rate is notably worse in reflecting the cost of service than UNSE's originally proposed two-part rate. The slope of the trend line is only 0.717 meaning that higher-cost customers would pay much less than the cost to serve them. Further, the average difference between revenues and costs is 35% compared to 22% under the original two-part rate. It also appears that this rate structure was not designed to be applicable to all customers because the total revenues that would be collected from these 100 customers would exceed the cost of serving the customers by more than $9,500 per year (15% more than the cost of service). Finally, this rate structure would have

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[8] Dukes direct testimony, p. 24, lines 8-9.
[9] UNSE Schedule H-3 (Revised 6/3/2015), p. 1.

enormous customer impacts, with more than 45% of customers seeing their annual distribution bills increase by more than 100%. In contrast, a few customers would have annual increases of less than 35%.

Simply stated, UNSE's original three-part rate design did a much worse job of tracking the cost of service than did UNSE's original two-part rate design. Based on the data in UNSE's sample of 100 customers, a two-block consumption charge came much closer to tracking the cost of serving customers than did a rate based on a customer's single monthly peak demand.

Q. WHAT IS SHOWN IN EXHIBIT SJR-6?

A. Exhibit SJR-6 provides a similar analysis of UNSE's rebuttal two-part rate, which UNSE called a "transition" rate. This rate design consists of a customer charge of $15 per month and it retains the existing three-block consumption charge: 3.2258¢ per kWh for the first 400 kWh per month, 4.2258¢ per kWh for the next 600 kWh per month, and 6.0258¢ per kWh for all consumption in excess of 1,000 kWh per month.[10]

UNSE's rebuttal transition rate does a very good job of having a customer's revenues track the cost of serving the customer. The slope of the trend line is 0.881 meaning that the rate design makes substantial progress toward having higher-cost customers provide higher-revenues. This rate design also has a lower average difference between revenues and costs, at 19%. It also can be seen that with a customer charge that is much closer to the customer-related cost of service ($180 per year in revenues compared to $165.76 in costs), lower-cost customers are not providing significant subsidies to higher-use customers. Finally, because this rate design is similar in structure to existing rates, the range of customer bill impacts is much tighter than in UNSE's originally proposed rates:

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[10] UNSE Exhibit CAJ-R-4, Schedule H-3, p. 4.

annual increases in distribution bills range from 42% to 56% for all customers in the sample group.

Q. DID YOU ALSO ANALYZE THE THREE-PART RESIDENTIAL RATE STRUCTURE UNSE PROPOSED IN ITS REBUTTAL?

A. Yes. In its rebuttal testimony, UNSE proposed a three-part rate that differs from its originally proposed demand rate structure in several respects. The new proposal contains a lower customer charge than the original proposal, and has only a single block demand rate instead of the two-block rate proposed initially. In addition, UNSE changed the measure of demand that would be used to bill customers. Its original demand charge was based on a customer's highest single-hour demand at any time during the month. UNSE's rebuttal proposal measures demand only during on-peak hours.[11]

Apparently because of concerns with bill impacts during the transition to a new rate structure, UNSE also proposed limiting the demand for billing purposes to no more than what the customer's demand would be if the customer had a 15% load factor during the month.[12]

For completeness, I analyzed UNSE's rebuttal three-part rate structure both with and without the 15% load factor limiter.

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[11] In the summer months of May through October, on-peak hours are Monday through Friday (excluding Memorial Day, Independence Day, and Labor Day) between 2 pm and 8 pm. In the other six months, on-peak hours are Monday through Friday (excluding Thanksgiving, Christmas Day, and New Year's Day) between 5 am and 9 am and 5 pm and 9 pm. See Dukes rebuttal testimony, p. 7, line 26 and Tariff RES-TOU (Sheet 102-1).

[12] Monthly load factor is the ratio of the customer's average demand to its maximum demand during the month. For example, if a customer uses 720 kWh in a month with 30 days (720 hours), the customer's average demand is 1.0 kW. If the customer's peak demand during the month is 3.0 kW, the customer's load factor would be 0.333.

Q. WHAT DID YOUR ANALYSIS SHOW CONCERNING UNSE'S REBUTTAL THREE-PART RESIDENTIAL RATE WITHOUT THE 15% LOAD FACTOR LIMITER?

A. Exhibit SJR-7 shows my analysis of the rebuttal demand rate without a limiter. The rate consists of a customer charge of $15.00 per month, a demand charge of $5.15 per kW (using on-peak demand as described above), and an energy charge of 1.6760¢ per kWh.[13]

UNSE's rebuttal three-part rate is notably worse in reflecting the cost of service than UNSE's rebuttal two-part rate (the "transition" rate). The slope of the trend line is only 0.636 meaning that higher-cost customers would pay much less than the cost to serve them. This is the worst result of any of UNSE's proposed rate designs, and dramatically worse than the transition rate which had a slope of 0.881. Further, the average difference between revenues and costs is 23% compared to 19% under the rebuttal two-part rate. Finally, this rate structure would have significant customer impacts, with more than 10% of customers seeing their annual distribution bills increase by more than 100% while another 10% of customers would see increases of 25% or less. Overall annual increases would range from 9% to 182%.

I would emphasize that these dramatic bill changes do not bring rates closer to tracking the cost of service. Indeed quite the opposite is true -- rates are further removed from cost, and the subsidies to higher-cost customers are greater, under the rebuttal three-part rate than they are under the rebuttal two-part rate. That is, contrary to the claims of several UNSE witnesses, the three-part rate proposed in rebuttal does not collect the cost of service from residential customers in a more equitable manner.

[13] UNSE Exh. CAJ-R-4, Schedule H-3, p. 4.

Q. DOES USING THE LOAD FACTOR LIMITER IMPROVE THE FAIRNESS OF UNSE'S REBUTTAL THREE-PART RATE?

A. Yes, but the improvement is very slight. Exhibit SJR-8 uses the same rates as I used in Exhibit SJR-7, but the billing units for demand are different because of the limitation that demand will not be higher than that which the customer would have with a 15% load factor. For example, if a customer used 720 kWh during a 30-day month, its average demand during the month would be 1.0 kW, as I discussed above. If the customer's highest demand during the month were 8.0 kW, its load factor would be 12.5%. UNSE's demand limiter would restate the maximum demand to 6.67 kW (1 / 6.67 = 15%) and use that lower amount for billing purposes in that month.

Exhibit SJR-8 shows that using the demand limiter reduces some of the highest bill impacts, but does little to improve the overall fairness of the rate design. Specifically, the highest bill increase has been reduced from 182% without the limiter to 113% with the limiter. That is still more than 10 times the percentage increase of the customer with the lowest bill impact.

Moreover, the limit does little to improve the overall fairness of this rate design. The slope of the trend line improves just slightly, from 0.636 to 0.657, meaning that higher-cost customers would provide revenues substantially less than the cost to serve them. Further, the average difference between a customer's revenues and the cost to serve the customer also improves just slightly, from 23% without the limiter to 21% with the limiter. Both of these results are worse than UNSE's two-part rebuttal rate, with a slope of 0.881 (enhanced recovery of costs from higher-cost customers) and an average cost-revenue differential of 19%.

Q. WHAT DO YOU CONCLUDE?

A. I conclude that the facts do not support the assertions of UNSE rebuttal witnesses that its proposed three-part rate design recovers costs more equitably, promotes fairness, and reduces intra-class subsidization. In fact, precisely the opposite is true. Compared to UNSE's rebuttal two-part rate design, its proposed rebuttal three-part rate design is less equitable, is unfair to lower-cost customers, and increases intra-class subsidization.

Q. IF SO MUCH OF THE COST OF SERVING RESIDENTIAL CUSTOMERS IS RELATED TO DEMAND, DOES IT MAKE SENSE TO YOU THAT A DEMAND-BASED RATE WOULD DO A WORSE JOB OF RECOVERING COSTS THAN A RATE WITHOUT A DEMAND COMPONENT?

A. Yes, it makes sense given the way these rates have been designed. UNSE's COSS allocates demand-related costs among the customer classes based on various measures of demand, nearly all of which are driven primarily by summer demand. Most demand-related costs are based on either the class non-coincident peak (which occurred on July 24 during the test year) or a demand allocator that uses a combination of non-coincident peak, average demand, and the four system coincident peaks during the months of June through September.

There is a relatively small average-demand component (average demand measures year-round energy consumption). On Exhibit SJR-2, line 25, I showed that the average demand component is \$6.6 million out of total demand-related costs of \$41.3 million (line 5 of Exhibit SJR-2), or about 16% of demand costs. In other words, approximately 84% of demand costs for the residential class are based on summer peak demands.

The logical question, then, is what type of rate design provides a better proxy for summer demands. Is it better to use each customer's monthly demand throughout the year or to use a customer's energy consumption throughout the year, weighted using inclining block rates?

Q. HAVE YOU PERFORMED ANY ANALYSIS TO TRY TO ANSWER THIS QUESTION?

A. Yes. In order to try to understand this relationship, I prepared a few simple regression analyses. First, on Exhibit SJR-9, I compared each customer's contribution to peak demands to the customer's average monthly billing demand (using the measure of billing demand in UNSE's rebuttal, including the demand limiter). This exhibit contains two graphs. The top graph shows the relationship between summer coincident peak demand and billing demand; the bottom graph shows class non-coincident peak demand and billing demand. These graphs show that there is some relationship between billing demand and summer coincident peak demand, but the R-square of 0.687 indicates that there is considerable variability in the relationship. The bottom graph shows a much weaker relationship between the customer's demand during the single non-coincident peak hour and the customer's annual billing demand. The R-square is 0.551, but simply looking at the data shows that customers with essentially the same contribution to NCP demand have vastly different monthly billing demands.

Exhibit SJR-10 provides similar comparisons, but instead of using monthly billing demand, I used weighted annual energy consumption. Specifically, I weighted energy usage by using the relative prices in the three rate blocks proposed by UNSE in its rebuttal transition rate design. In that rate design, the block 2 rate is 1.31 times the block 1 rate (4.2258¢ compared to 3.2258¢) and the block 3 rates is 1.87 times the block 1 rate (6.0258¢ compared to 3.2258¢). By weighting energy consumption in this manner, I developed an equivalent level of energy consumption that is used for billing purposes. The exhibit shows that for both summer coincident peaks and non-coincident peak, the weighted energy consumption used in UNSE's rebuttal two-part rate design bears a stronger relationship to peak demand allocators than does the monthly demand used in UNSE's three-part rebuttal demand rate. Specifically, the R-square is higher for each comparison using weighted energy than it is using billing demand (0.747 compared to 0.687 for CP demand and 0.588 compared to 0.551 for NCP demand).

These relationships show why UNSE's two-part rate design does a better job of reflecting the cost of service and reducing intra-class subsidies than does UNSE's three-part (demand) rate design. Just because a rate uses something called "demand" does not mean that it bears a better relationship to the types of demand measures used in allocating costs in a cost-of-service study.

The essential task of rate design is to try to find understandable, and readily measurable, proxies for each component of the cost of service so that bills can be rendered that fairly reflect each customer's contribution to the cost of service. No method will be perfect, but based on the available data UNSE's rate structure using three consumption blocks (with inclining rates in each block) is a reasonable proxy for class non-coincident demand and system coincident demand. My cost analyses and my demand analyses show that UNSE's rate design with three consumption blocks with inclining block rates is superior to its rate designs that use monthly billing demand.

Q. WHAT DO YOU RECOMMEND?

A. I recommend that the Commission reject UNSE's unsupported assertion that its proposed three-part residential demand rates are superior to a rate structure based on a two-part rate with inclining consumption block rates. My analyses of the available data show that precisely the opposite is true. I further recommend, therefore, that the Commission adopt UNSE's so-called rebuttal "transition" rate design for residential customers who do not elect time-of-use rates. (Of course, the actual rates need to be adjusted based on the final revenue requirement determined by the Commission.) This rate design is structured in the same manner as existing rates which should minimize any issues with customer understanding, ease of administration, or metering technology. The rate design also is superior to UNSE's other proposed rate designs in its ability to fairly collect the cost of service from each customer and minimize the level of intra-class subsidies. Finally, of all of the rate designs put forth by UNSE, this rate design also has the fairest impact on customers, with all customers in the sample having annual bills for distribution service increase by a fairly consistent percentage.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

Appendix A

Scott J. Rubin
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Current Position

Public Utility Attorney and Consultant. 1994 to present. I provide legal, consulting, and expert witness services to various organizations interested in the regulation of public utilities.

Previous Positions

Lecturer in Computer Science, Susquehanna University, Selinsgrove, PA. 1993 to 2000.

Senior Assistant Consumer Advocate, Office of Consumer Advocate, Harrisburg, PA. 1990 to 1994. I supervised the administrative and technical staff and shared with one other senior attorney the supervision of a legal staff of 14 attorneys.

Assistant Consumer Advocate, Office of Consumer Advocate, Harrisburg, PA. 1983 to 1990.

Associate, Laws and Staruch, Harrisburg, PA. 1981 to 1983.

Law Clerk, U.S. Environmental Protection Agency, Washington, DC. 1980 to 1981.

Research Assistant, Rockville Consulting Group, Washington, DC. 1979.

Current Professional Activities

Member, American Bar Association, Public Utility Law Section.

Member, American Water Works Association.

Admitted to practice law before the Supreme Court of Pennsylvania, the New York State Court of Appeals, the United States District Court for the Middle District of Pennsylvania, the United States Court of Appeals for the Third Circuit, and the Supreme Court of the United States.

Previous Professional Activities

Member, American Water Works Association, Rates and Charges Subcommittee, 1998-2001.

Member, Federal Advisory Committee on Disinfectants and Disinfection By-Products in Drinking Water, U.S. Environmental Protection Agency, Washington, DC. 1992 to 1994.

Chair, Water Committee, National Association of State Utility Consumer Advocates, Washington, DC. 1990 to 1994; member of committee from 1988 to 1990.

Member, Board of Directors, Pennsylvania Energy Development Authority, Harrisburg, PA. 1990 to 1994.

Member, Small Water Systems Advisory Committee, Pennsylvania Department of Environmental Resources, Harrisburg, PA. 1990 to 1992.

Member, Ad Hoc Committee on Emissions Control and Acid Rain Compliance, National Association of State Utility Consumer Advocates, 1991.

Member, Nitrogen Oxides Subcommittee of the Acid Rain Advisory Committee, U.S. Environmental Protection Agency, Washington DC. 1991.

Education

J.D. with Honors, George Washington University, Washington, DC. 1981.

B.A. with Distinction in Political Science, Pennsylvania State University, University Park, PA. 1978.

Publications and Presentations (* denotes peer-reviewed publications)

1. "Quality of Service Issues," a speech to the Pennsylvania Public Utility Commission Consumer Conference, State College, PA. 1988.

2. K.L. Pape and S.J. Rubin, "Current Developments in Water Utility Law," in *Pennsylvania Public Utility Law* (Pennsylvania Bar Institute). 1990.

3. Presentation on Water Utility Holding Companies to the Annual Meeting of the National Association of State Utility Consumer Advocates, Orlando, FL. 1990.

4. "How the OCA Approaches Quality of Service Issues," a speech to the Pennsylvania Chapter of the National Association of Water Companies. 1991.

5. Presentation on the Safe Drinking Water Act to the Mid-Year Meeting of the National Association of State Utility Consumer Advocates, Seattle, WA. 1991.

6. "A Consumer Advocate's View of Federal Pre-emption in Electric Utility Cases," a speech to the Pennsylvania Public Utility Commission Electricity Conference. 1991.

7. Workshop on Safe Drinking Water Act Compliance Issues at the Mid-Year Meeting of the National Association of State Utility Consumer Advocates, Washington, DC. 1992.

8. Formal Discussant, Regional Acid Rain Workshop, U.S. Environmental Protection Agency and National Regulatory Research Institute, Charlotte, NC. 1992.

9. S.J. Rubin and S.P. O'Neal, "A Quantitative Assessment of the Viability of Small Water Systems in Pennsylvania," *Proceedings of the Eighth NARUC Biennial Regulatory Information Conference*, National Regulatory Research Institute (Columbus, OH 1992), IV:79-97.

10. "The OCA's Concerns About Drinking Water," a speech to the Pennsylvania Public Utility Commission Water Conference. 1992.

11. Member, Technical Horizons Panel, Annual Meeting of the National Association of Water Companies, Hilton Head, SC. 1992.

12. M.D. Klein and S.J. Rubin, "Water and Sewer -- Update on Clean Streams, Safe Drinking Water, Waste Disposal and Pennvest," *Pennsylvania Public Utility Law Conference* (Pennsylvania Bar Institute). 1992.

13. Presentation on Small Water System Viability to the Technical Assistance Center for Small Water Companies, Pa. Department of Environmental Resources, Harrisburg, PA. 1993

14. "The Results Through a Public Service Commission Lens," speaker and participant in panel discussion at Symposium: "Impact of EPA's Allowance Auction," Washington, DC, sponsored by AER*X. 1993.

15. "The Hottest Legislative Issue of Today -- Reauthorization of the Safe Drinking Water Act," speaker and participant in panel discussion at the Annual Conference of the American Water Works Association, San Antonio, TX. 1993.

16. "Water Service in the Year 2000," a speech to the Conference: "Utilities and Public Policy III: The Challenges of Change," sponsored by the Pennsylvania Public Utility Commission and the Pennsylvania State University, University Park, PA. 1993.

17. "Government Regulation of the Drinking Water Supply: Is it Properly Focused?," speaker and participant in panel discussion at the National Consumers League's Forum on Drinking Water Safety and Quality, Washington, DC. 1993. Reprinted in *Rural Water*, Vol. 15 No. 1 (Spring 1994), pages 13-16.

18. "Telephone Penetration Rates for Renters in Pennsylvania," a study prepared for the Pennsylvania Office of Consumer Advocate. 1993.

19. "Zealous Advocacy, Ethical Limitations and Considerations," participant in panel discussion at "Continuing Legal Education in Ethics for Pennsylvania Lawyers," sponsored by the Office of General Counsel, Commonwealth of Pennsylvania, State College, PA. 1993.

20. "Serving the Customer," participant in panel discussion at the Annual Conference of the National Association of Water Companies, Williamsburg, VA. 1993.

21. "A Simple, Inexpensive, Quantitative Method to Assess the Viability of Small Water Systems," a speech to the Water Supply Symposium, New York Section of the American Water Works Association, Syracuse, NY. 1993.

22. * S.J. Rubin, "Are Water Rates Becoming Unaffordable?," *Journal American Water Works Association*, Vol. 86, No. 2 (February 1994), pages 79-86.

23. "Why Water Rates Will Double (If We're Lucky): Federal Drinking Water Policy and Its Effect on New England," a briefing for the New England Conference of Public Utilities Commissioners, Andover, MA. 1994.

24. "Are Water Rates Becoming Unaffordable?," a speech to the Legislative and Regulatory Conference, Association of Metropolitan Water Agencies, Washington, DC. 1994.

25. "Relationships: Drinking Water, Health, Risk and Affordability," speaker and participant in panel discussion at the Annual Meeting of the Southeastern Association of Regulatory Commissioners, Charleston, SC. 1994.

26. "Small System Viability: Assessment Methods and Implementation Issues," speaker and participant in panel discussion at the Annual Conference of the American Water Works Association, New York, NY. 1994.

27. S.J. Rubin, "How much should we spend to save a life?," *Seattle Journal of Commerce*, August 18, 1994 (Protecting the Environment Supplement), pages B-4 to B-5.

28. S. Rubin, S. Bernow, M. Fulmer, J. Goldstein, and I. Peters, *An Evaluation of Kentucky-American Water Company's Long-Range Planning*, prepared for the Utility and Rate Intervention Division, Kentucky Office of the Attorney General (Tellus Institute 1994).

29. S.J. Rubin, "Small System Monitoring: What Does It Mean?," *Impacts of Monitoring for Phase II/V Drinking Water Regulations on Rural and Small Communities* (National Rural Water Association 1994), pages 6-12.

30. "Surviving the Safe Drinking Water Act," speaker at the Annual Meeting of the National Association of State Utility Consumer Advocates, Reno, NV. 1994.

31. "Safe Drinking Water Act Compliance -- Ratemaking Implications," speaker at the National Conference of Regulatory Attorneys, Scottsdale, AZ. 1995. Reprinted in *Water*, Vol. 36, No. 2 (Summer 1995), pages 28-29.

32. S.J. Rubin, "Water: Why Isn't it Free? The Case of Small Utilities in Pennsylvania," *Utilities, Consumers & Public Policy: Issues of Quality, Affordability, and Competition, Proceedings of the Fourth Utilities, Consumers and Public Policy Conference* (Pennsylvania State University 1995), pages 177-183.

33. S.J. Rubin, "Water Rates: An Affordable Housing Issue?," *Home Energy*, Vol. 12 No. 4 (July/August 1995), page 37.

34. Speaker and participant in the Water Policy Forum, sponsored by the National Association of Water Companies, Naples, FL. 1995.

35. Participant in panel discussion on "The Efficient and Effective Maintenance and Delivery of Potable Water at Affordable Rates to the People of New Jersey," at The New Advocacy: Protecting Consumers in the Emerging Era of Utility Competition, a conference sponsored by the New Jersey Division of the Ratepayer Advocate, Newark, NJ. 1995.

36. J.E. Cromwell III, and S.J. Rubin, *Development of Benchmark Measures for Viability Assessment* (Pa. Department of Environmental Protection 1995).

37. S. Rubin, "A Nationwide Practice from a Small Town in Pa.," *Lawyers & the Internet – a Supplement to the Legal Intelligencer and Pa. Law Weekly* (February 12, 1996), page S6.

38. "Changing Customers' Expectations in the Water Industry," speaker at the Mid-America Regulatory Commissioners Conference, Chicago, IL. 1996, reprinted in *Water* Vol. 37 No. 3 (Winter 1997), pages 12-14.

39. "Recent Federal Legislation Affecting Drinking Water Utilities," speaker at Pennsylvania Public Utility Law Conference, Pennsylvania Bar Institute, Hershey, PA. 1996.

40. "Clean Water at Affordable Rates: A Ratepayers Conference," moderator at symposium sponsored by the New Jersey Division of Ratepayer Advocate, Trenton, NJ. 1996.

41. "Water Workshop: How New Laws Will Affect the Economic Regulation of the Water Industry," speaker at the Annual Meeting of the National Association of State Utility Consumer Advocates, San Francisco, CA. 1996.

42. * E.T. Castillo, S.J. Rubin, S.K. Keefe, and R.S. Raucher, "Restructuring Small Systems," *Journal American Water Works Association*, Vol. 89, No. 1 (January 1997), pages 65-74.

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44. "Capacity Development – More than Viability Under a New Name," speaker at National Association of Regulatory Utility Commissioners Winter Meetings, Washington, DC. 1997.

45. * E. Castillo, S.K. Keefe, R.S. Raucher, and S.J. Rubin, *Small System Restructuring to Facilitate SDWA Compliance: An Analysis of Potential Feasibility* (AWWA Research Foundation, 1997).

46. H. Himmelberger, *et al.*, *Capacity Development Strategy Report for the Texas Natural Resource Conservation Commission* (Aug. 1997).

47. Briefing on Issues Affecting the Water Utility Industry, Annual Meeting of the National Association of State Utility Consumer Advocates, Boston, MA. 1997.

48. "Capacity Development in the Water Industry," speaker at the Annual Meeting of the National Association of Regulatory Utility Commissioners, Boston, MA. 1997.

49. "The Ticking Bomb: Competitive Electric Metering, Billing, and Collection," speaker at the Annual Meeting of the National Association of State Utility Consumer Advocates, Boston, MA. 1997.

50. Scott J. Rubin, "A Nationwide Look at the Affordability of Water Service," *Proceedings of the 1998 Annual Conference of the American Water Works Association*, Water Research, Vol. C, No. 3, pages 113-129 (American Water Works Association, 1998).

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52. Scott J. Rubin, "Effects of Electric and Gas Deregulation on the Water Industry," *Pennsylvania Public Utility Law Conference*, Vol. I, pages 139-146 (Pa. Bar Institute, 1998).

53. Scott J. Rubin, *The Challenges and Changing Mission of Utility Consumer Advocates* (American Association of Retired Persons, 1999).

54. "Consumer Advocacy for the Future," speaker at the Age of Awareness Conference, Changes and Choices: Utilities in the New Millennium, Carlisle, PA. 1999.

55. Keynote Address, $1 Energy Fund, Inc., Annual Membership Meeting, Monroeville, PA. 1999.

56. Scott J. Rubin, "Assessing the Effect of the Proposed Radon Rule on the Affordability of Water Service," prepared for the American Water Works Association. 1999.

57. Scott J. Rubin and Janice A. Beecher, The Impacts of Electric Restructuring on the Water and Wastewater Industry, *Proceedings of the Small Drinking Water and Wastewater Systems International Symposium and Technology Expo* (Phoenix, AZ 2000), pp. 66-75.

58. American Water Works Association, *Principles of Water Rates, Fees, and Charges, Manual M1 – Fifth Edition* (AWWA 2000), Member, Editorial Committee.

59. Janice A. Beecher and Scott J. Rubin, presentation on "Special Topics in Rate Design: Affordability" at the Annual Conference and Exhibition of the American Water Works Association, Denver, CO. 2000.

60. Scott J. Rubin, "The Future of Drinking Water Regulation," a speech at the Annual Conference and Exhibition of the American Water Works Association, Denver, CO. 2000.

61. Janice A. Beecher and Scott J. Rubin, "Deregulation Impacts and Opportunities," a presentation at the Annual Conference and Exhibition of the American Water Works Association, Denver, CO. 2000.

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64. Scott J. Rubin, Methods for Assessing, Evaluating, and Assisting Small Water Systems, NARUC Annual Regulatory Studies Program, East Lansing, MI. 2000.

65. Scott J. Rubin, Consumer Issues in the Water Industry, NARUC Annual Regulatory Studies Program, East Lansing, MI. 2000.

66. "Be Utility Wise in a Restructured Utility Industry," Keynote Address at Be UtilityWise Conference, Pittsburgh, PA. 2000.

67. Scott J. Rubin, Jason D. Sharp, and Todd S. Stewart, "The Wired Administrative Lawyer," *5th Annual Administrative Law Symposium*, Pennsylvania Bar Institute, Harrisburg, PA. 2000.

68. Scott J. Rubin, "Current Developments in the Water Industry," *Pennsylvania Public Utility Law Conference*, Pennsylvania Bar Institute, Harrisburg, PA. 2000.

69. Scott J. Rubin, "Viewpoint: Change Sickening Attitudes," *Engineering News-Record*, Dec. 18, 2000.

70. Janice A. Beecher and Scott J. Rubin, "Ten Practices of Highly Effective Water Utilities," *Opflow*, April 2001, pp. 1, 6-7, 16; reprinted in *Water and Wastes Digest*, December 2004, pp. 22-25.

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74. Scott J. Rubin, Impacts of Deregulation on the Water Industry, NARUC Annual Regulatory Studies Program, East Lansing, MI. 2001.

75. Scott J. Rubin, "Economic Characteristics of Small Systems," *Critical Issues in Setting Regulatory Standards*, National Rural Water Association, 2001, pp. 7-22.

76. Scott J. Rubin, "Affordability of Water Service," *Critical Issues in Setting Regulatory Standards*, National Rural Water Association, 2001, pp. 23-42.

77. Scott J. Rubin, "Criteria to Assess the Affordability of Water Service," White Paper, National Rural Water Association, 2001.

78. Scott J. Rubin, Providing Affordable Water Service to Low-Income Families, presentation to Portland Water Bureau, Portland, OR. 2001.

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85. Scott J. Rubin, "Thinking Outside the Hearing Room," *Pennsylvania Public Utility Law Conference*, Pennsylvania Bar Institute, Harrisburg, PA. 2002.

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87. Scott J. Rubin, *Understanding Telephone Penetration in Pennsylvania*, Council on Utility Choice, Harrisburg, PA. 2003.

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89. Scott J. Rubin, What Price Safer Water? Presentation at Annual Conference of National Association of Regulatory Utility Commissioners, Atlanta, GA. 2003.

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93. Scott J. Rubin, Buying and Selling a Water System – Ratemaking Implications, *Pennsylvania Public Utility Law Conference*, Pennsylvania Bar Institute, Harrisburg, PA. 2005.

94. *Thinking Outside the Bill: A Utility Manager's Guide to Assisting Low-Income Water Customers*, American Water Works Association. 2005; Second Edition published in 2014

95. * Scott J. Rubin, "Census Data Shed Light on US Water and Wastewater Costs," *Journal American Water Works Association*, Vol. 97, No. 4 (April 2005), pages 99-110, reprinted in Maxwell, *The Business of Water: A Concise Overview of Challenges and Opportunities in the Water Market.*, American Water Works Association, Denver, CO. 2008.

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97. * Robert S. Raucher, et al., *Regional Solutions to Water Supply Provision*, American Water Works Association Research Foundation, Denver, CO. 2007.

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100. Scott J. Rubin, "Current State of the Water Industry and Stimulus Bill Overview," in *Pennsylvania Public Utility Law* (Pennsylvania Bar Institute). 2009.

101. Scott J. Rubin, Best Practice in Customer Payment Assistance Programs, webcast presentation sponsored by Water Research Foundation. 2009.

102. * Scott J. Rubin, How Should We Regulate Small Water Utilities?, National Regulatory Research Institute. 2009.

103. * John Cromwell III, et al., *Best Practices in Customer Payment Assistance Programs*, Water Research Foundation, Denver, CO. 2010.

104.* Scott J. Rubin, What Does Water Really Cost? Rate Design Principles for an Era of Supply Shortages, Infrastructure Upgrades, and Enhanced Water Conservation, , National Regulatory Research Institute. 2010.

105. Scott J. Rubin and Christopher P.N. Woodcock, Teleseminar: Water Rate Design, National Regulatory Research Institute. 2010.

106. David Monie and Scott J. Rubin, Cost of Service Studies and Water Rate Design: A Debate on the Utility and Regulatory Perspectives, Meeting of New England Chapter of National Association of Water Companies, Newport, RI. 2010.

107. * Scott J. Rubin, A Call for Water Utility Reliability Standards: Regulating Water Utilities' Infrastructure Programs to Achieve a Balance of Safety, Risk, and Cost, National Regulatory Research Institute. 2010.

108.* Raucher, Robert S.; Rubin, Scott J.; Crawford-Brown, Douglas; and Lawson, Megan M. "Benefit-Cost Analysis for Drinking Water Standards: Efficiency, Equity, and Affordability Considerations in Small Communities," *Journal of Benefit-Cost Analysis*: Vol. 2: Issue 1, Article 4. 2011.

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110. Scott J. Rubin, Current Topics in Water: Rate Design and Reliability. Presentation to the Water Committee of the National Association of Regulatory Utility Commissioners, Washington, DC. 2011.

111. Scott J. Rubin, Water Reliability and Resilience Standards, *Pennsylvania Public Utility Law Conference* (Pennsylvania Bar Institute). 2011.

112. Member of Expert Panel, Leadership Forum: Business Management for the Future, Annual Conference and Exposition of the American Water Works Association, Washington, DC. 2011.

113. Scott J. Rubin, Evaluating Community Affordability in Storm Water Control Plans, *Flowing into the Future: Evolving Water Issues* (Pennsylvania Bar Institute). 2011.

114. Invited Participant, Summit on Declining Water Demand and Revenues, sponsored by The Alliance for Water Efficiency, Racine, WI. 2012.

115. *Scott J. Rubin, Evaluating Violations of Drinking Water Regulations, *Journal American Water Works Association*, Vol. 105, No. 3 (Mar. 2013), pp. 51-52 (Expanded Summary) and E137-E147. Winner of the AWWA Small Systems Division Best Paper Award.

116. *Scott J. Rubin, Structural Changes in the Water Utility Industry During the 2000s, *Journal American Water Works Association*, Vol. 105, No. 3 (Mar. 2013), pp. 53-54 (Expanded Summary) and E148-E156.

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Testimony as an Expert Witness

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2. *Pa. Public Utility Commission v. Shenango Valley Water Co.*, Pa. Public Utility Commission, Docket R-00922420. 1992. Concerning cost allocation, on behalf of the Pa. Office of Consumer Advocate

3. *Pa. Public Utility Commission v. Pennsylvania Gas and Water Co. - Water Division*, Pa. Public Utility Commission, Docket R-00922482. 1993. Concerning rate design, on behalf of the Pa. Office of Consumer Advocate

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6. *West Penn Power Co. v. State Tax Department of West Virginia*, Circuit Court of Kanawha County, West Virginia, Civil Action No. 89-C-3056. 1993. Concerning regulatory policy and the effects of a taxation statute on out-of-state utility ratepayers, on behalf of the Pa. Office of Consumer Advocate

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15. *Winter Harbor Water Company, Proposed Schedule Revisions to Introduce a Readiness-to-Serve Charge*, Maine Public Utilities Commission, Docket No. 95-271. 1995 and 1996. Concerning standards for, and the reasonableness of, imposing a readiness to serve charge and/or exit fee on the customers of a small investor-owned water utility, on behalf of the Maine Public Advocate.

16. *In the Matter of the 1995 Long-Term Electric Forecast Report of the Cincinnati Gas & Electric Company*, Public Utilities Commission of Ohio, Case No. 95-203-EL-FOR, and *In the Matter of the Two-Year Review of the Cincinnati Gas & Electric Company's Environmental Compliance Plan Pursuant to Section 4913.05, Revised Cost*, Case No. 95-747-EL-ECP. 1996. Concerning the reasonableness of the utility's long-range supply and demand-management plans, the reasonableness of its plan for complying with the Clean Air Act Amendments of 1990, and discussing methods to ensure the provision of utility service to low-income customers, on behalf of the Office of the Ohio Consumers' Counsel..

17. *In the Matter of Notice of the Adjustment of the Rates of Kentucky-American Water Company*, Kentucky Public Service Commission, Case No. 95-554. 1996. Concerning rate design, cost of service, and sales forecast issues, on behalf of the Kentucky Office of Attorney General.

18. *In the Matter of the Application of Citizens Utilities Company for a Hearing to Determine the Fair Value of its Properties for Ratemaking Purposes, to Fix a Just and Reasonable Rate of Return Thereon, and to Approve Rate Schedules Designed to Provide such Rate of Return*, Arizona Corporation Commission, Docket Nos. E-1032-95-417, *et al.* 1996. Concerning rate design, cost of service, and the price elasticity of water demand, on behalf of the Arizona Residential Utility Consumer Office.

19. *Cochrane v. Bangor Hydro-Electric Company*, Maine Public Utilities Commission, Docket No. 96-053. 1996. Concerning regulatory requirements for an electric utility to engage in unregulated business enterprises, on behalf of the Maine Public Advocate.

20. *In the Matter of the Regulation of the Electric Fuel Component Contained within the Rate Schedules of Monongahela Power Company and Related Matters*, Public Utilities Commission of Ohio, Case No. 96-106-EL-EFC. 1996. Concerning the costs and procedures associated with the implementation of the Clean Air Act Amendments of 1990, on behalf of the Ohio Consumers' Counsel.

21. *In the Matter of the Regulation of the Electric Fuel Component Contained within the Rate Schedules of Cleveland Electric Illuminating Company and Toledo Edison Company and Related Matters*, Public Utilities Commission of Ohio, Case Nos. 96-107-EL-EFC and 96-108-EL-EFC. 1996. Concerning the costs and procedures associated with the implementation of the Clean Air Act Amendments of 1990, on behalf of the Ohio Consumers' Counsel.

22. *In the Matter of the Regulation of the Electric Fuel Component Contained within the Rate Schedules of Ohio Power Company and Columbus Southern Power Company and Related Matters*, Public Utilities Commission of Ohio, Case Nos. 96-101-EL-EFC and 96-102-EL-EFC. 1997. Concerning the costs and

procedures associated with the implementation of the Clean Air Act Amendments of 1990, on behalf of the Ohio Consumers' Counsel.

23. *An Investigation of the Sources of Supply and Future Demand of Kentucky-American Water Company (Phase II)*, Kentucky Public Service Commission, Docket No. 93-434. 1997. Concerning supply and demand planning, on behalf of the Kentucky Office of Attorney General, Public Service Litigation Branch.

24. *In the Matter of the Regulation of the Electric Fuel Component Contained within the Rate Schedules of Cincinnati Gas and Electric Co. and Related Matters*, Public Utilities Commission of Ohio, Case No. 96-103-EL-EFC. 1997. Concerning the costs and procedures associated with the implementation of the Clean Air Act Amendments of 1990, on behalf of the Ohio Consumers' Counsel.

25. *Bangor Hydro-Electric Company Petition for Temporary Rate Increase*, Maine Public Utilities Commission, Docket No. 97-201. 1997. Concerning the reasonableness of granting an electric utility's request for emergency rate relief, and related issues, on behalf of the Maine Public Advocate.

26. *Testimony concerning H.B. 1068 Relating to Restructuring of the Natural Gas Utility Industry*, Consumer Affairs Committee, Pennsylvania House of Representatives. 1997. Concerning the provisions of proposed legislation to restructure the natural gas utility industry in Pennsylvania, on behalf of the Pennsylvania AFL-CIO Gas Utility Caucus.

27. *In the Matter of the Regulation of the Electric Fuel Component Contained within the Rate Schedules of Cleveland Electric Illuminating Company and Toledo Edison Company and Related Matters*, Public Utilities Commission of Ohio, Case Nos. 97-107-EL-EFC and 97-108-EL-EFC. 1997. Concerning the costs and procedures associated with the implementation of the Clean Air Act Amendments of 1990, on behalf of the Ohio Consumers' Counsel.

28. *In the Matter of the Petition of Valley Road Sewerage Company for a Revision in Rates and Charges for Water Service*, New Jersey Board of Public Utilities, Docket No. WR92080846J. 1997. Concerning the revenue requirements and rate design for a wastewater treatment utility, on behalf of the New Jersey Division of Ratepayer Advocate.

29. *Bangor Gas Company, L.L.C., Petition for Approval to Furnish Gas Service in the State of Maine*, Maine Public Utilities Commission, Docket No. 97-795. 1998. Concerning the standards and public policy concerns involved in issuing a certificate of public convenience and necessity for a new natural gas utility, and related ratemaking issues, on behalf of the Maine Public Advocate.

30. *In the Matter of the Investigation on Motion of the Commission into the Adequacy of the Public Utility Water Service Provided by Tidewater Utilities, Inc., in Areas in Southern New Castle County, Delaware*, Delaware Public Service Commission, Docket No. 309-97. 1998. Concerning the standards for the provision of efficient, sufficient, and adequate water service, and the application of those standards to a water utility, on behalf of the Delaware Division of the Public Advocate.

31. *In the Matter of the Regulation of the Electric Fuel Component Contained within the Rate Schedules of Cincinnati Gas and Electric Co. and Related Matters*, Public Utilities Commission of Ohio, Case No. 97-103-EL-EFC. 1998. Concerning fuel-related transactions with affiliated companies and the appropriate ratemaking treatment and regulatory safeguards involving such transactions, on behalf of the Ohio Consumers' Counsel.

32. *Olde Port Mariner Fleet, Inc. Complaint Regarding Casco Bay Island Transit District's Tour and Charter Service*, Maine Public Utilities Commission, Docket No. 98-161. 1998. Concerning the standards and requirements for allocating costs and separating operations between regulated and unregulated operations of a transportation utility, on behalf of the Maine Public Advocate and Olde Port Mariner Fleet, Inc.

33. *Central Maine Power Company Investigation of Stranded Costs, Transmission and Distribution Utility Revenue Requirements, and Rate Design*, Maine Public Utilities Commission, Docket No. 97-580. 1998. Concerning the treatment of existing rate discounts when designing rates for a transmission and distribution electric utility, on behalf of the Maine Public Advocate.

34. *Pa. Public Utility Commission v. Manufacturers Water Company*, Pennsylvania Public Utility Commission, Docket No. R-00984275. 1998. Concerning rate design on behalf of the Manufacturers Water Industrial Users.

35. *In the Matter of Petition of Pennsgrove Water Supply Company for an Increase in Rates for Water Service*, New Jersey Board of Public Utilities, Docket No. WR98030147. 1998. Concerning the revenue requirements, level of affiliated charges, and rate design for a water utility, on behalf of the New Jersey Division of Ratepayer Advocate.

36. *In the Matter of Petition of Seaview Water Company for an Increase in Rates for Water Service*, New Jersey Board of Public Utilities, Docket No. WR98040193. 1999. Concerning the revenue requirements and rate design for a water utility, on behalf of the New Jersey Division of Ratepayer Advocate.

37. *In the Matter of the Regulation of the Electric Fuel Component Contained within the Rate Schedules of Ohio Power Company and Columbus Southern Power Company and Related Matters*, Public Utilities Commission of Ohio, Case Nos. 98-101-EL-EFC and 98-102-EL-EFC. 1999. Concerning the costs and procedures associated with the implementation of the Clean Air Act Amendments of 1990, on behalf of the Ohio Consumers' Counsel.

38. *In the Matter of the Regulation of the Electric Fuel Component Contained within the Rate Schedules of Dayton Power and Light Company and Related Matters*, Public Utilities Commission of Ohio, Case No. 98-105-EL-EFC. 1999. Concerning the costs and procedures associated with the implementation of the Clean Air Act Amendments of 1990, on behalf of the Ohio Consumers' Counsel.

39. *In the Matter of the Regulation of the Electric Fuel Component Contained within the Rate Schedules of Monongahela Power Company and Related Matters*, Public Utilities Commission of Ohio, Case No. 99-106-EL-EFC. 1999. Concerning the costs and procedures associated with the implementation of the Clean Air Act Amendments of 1990, on behalf of the Ohio Consumers' Counsel.

40. *County of Suffolk, et al. v. Long Island Lighting Company, et al.*, U.S. District Court for the Eastern District of New York, Case No. 87-CV-0646. 2000. Submitted two affidavits concerning the calculation and collection of court-ordered refunds to utility customers, on behalf of counsel for the plaintiffs.

41. *Northern Utilities, Inc., Petition for Waivers from Chapter 820*, Maine Public Utilities Commission, Docket No. 99-254. 2000. Concerning the standards and requirements for defining and separating a natural gas utility's core and non-core business functions, on behalf of the Maine Public Advocate.

42. *Notice of Adjustment of the Rates of Kentucky-American Water Company*, Kentucky Public Service Commission, Case No. 2000-120. 2000. Concerning the appropriate methods for allocating costs and designing rates, on behalf of the Kentucky Office of Attorney General.

43. *In the Matter of the Petition of Gordon's Corner Water Company for an Increase in Rates and Charges for Water Service*, New Jersey Board of Public Utilities, Docket No. WR00050304. 2000. Concerning the revenue requirements and rate design for a water utility, on behalf of the New Jersey Division of Ratepayer Advocate.

44. *Testimony concerning Arsenic in Drinking Water: An Update on the Science, Benefits, and Costs*, Committee on Science, United States House of Representatives. 2001. Concerning the effects on low-income households and small communities from a more stringent regulation of arsenic in drinking water.

45. *In the Matter of the Application of The Cincinnati Gas & Electric Company for an Increase in Gas Rates in its Service Territory*, Public Utilities Commission of Ohio, Case No. 01-1228-GA-AIR, *et al.* 2002. Concerning the need for and structure of a special rider and alternative form of regulation for an accelerated main replacement program, on behalf of the Ohio Consumers' Counsel.

46. *Pennsylvania State Treasurer's Hearing on Enron and Corporate Governance Issues*. 2002. Concerning Enron's role in Pennsylvania's electricity market and related issues, on behalf of the Pennsylvania AFL-CIO.

47. *An Investigation into the Feasibility and Advisability of Kentucky-American Water Company's Proposed Solution to its Water Supply Deficit*, Kentucky Public Service Commission, Case No. 2001-00117. 2002. Concerning water supply planning, regulatory oversight, and related issue, on behalf of the Kentucky Office of Attorney General.

48. *Joint Application of Pennsylvania-American Water Company and Thames Water Aqua Holdings GmbH*, Pennsylvania Public Utility Commission, Docket Nos. A-212285F0096 and A-230073F0004. 2002. Concerning the risks and benefits associated with the proposed acquisition of a water utility, on behalf of the Pennsylvania Office of Consumer Advocate.

49. *Application for Approval of the Transfer of Control of Kentucky-American Water Company to RWE AG and Thames Water Aqua Holdings GmbH*, Kentucky Public Service Commission, Case No. 2002-00018. 2002. Concerning the risks and benefits associated with the proposed acquisition of a water utility, on behalf of the Kentucky Office of Attorney General.

50. *Joint Petition for the Consent and Approval of the Acquisition of the Outstanding Common Stock of American Water Works Company, Inc., the Parent Company and Controlling Shareholder of West Virginia-American Water Company*, West Virginia Public Service Commission, Case No. 01-1691-W-PC. 2002. Concerning the risks and benefits associated with the proposed acquisition of a water utility, on behalf of the Consumer Advocate Division of the West Virginia Public Service Commission.

51. *Joint Petition of New Jersey-American Water Company, Inc. and Thames Water Aqua Holdings GmbH for Approval of Change in Control of New Jersey-American Water Company, Inc.*, New Jersey Board of Public Utilities, Docket No. WM01120833. 2002. Concerning the risks and benefits associated with the proposed acquisition of a water utility, on behalf of the New Jersey Division of Ratepayer Advocate.

52. *Illinois-American Water Company, Proposed General Increase in Water Rates*, Illinois Commerce Commission, Docket No. 02-0690. 2003. Concerning rate design and cost of service issues, on behalf of the Illinois Office of the Attorney General.

53. *Pennsylvania Public Utility Commission v. Pennsylvania-American Water Company,* Pennsylvania Public Utility Commission, Docket No. R-00038304. 2003. Concerning rate design and cost of service issues, on behalf of the Pennsylvania Office of Consumer Advocate.

54. *West Virginia-American Water Company,* West Virginia Public Service Commission, Case No. 03-0353-W-42T. 2003. Concerning affordability, rate design, and cost of service issues, on behalf of the West Virginia Consumer Advocate Division.

55. *Petition of Seabrook Water Corp. for an Increase in Rates and Charges for Water Service*, New Jersey Board of Public Utilities, Docket No. WR3010054. 2003. Concerning revenue requirements, rate design, prudence, and regulatory policy, on behalf of the New Jersey Division of Ratepayer Advocate.

56. *Chesapeake Ranch Water Co. v. Board of Commissioners of Calvert County*, U.S. District Court for Southern District of Maryland, Civil Action No. 8:03-cv-02527-AW. 2004. Submitted expert report concerning the expected level of rates under various options for serving new commercial development, on behalf of the plaintiff.

57. *Testimony concerning Lead in Drinking Water*, Committee on Government Reform, United States House of Representatives. 2004. Concerning the trade-offs faced by low-income households when drinking water costs increase, including an analysis of H.R. 4268.

58. *West Virginia-American Water Company,* West Virginia Public Service Commission, Case No. 04-0373-W-42T. 2004. Concerning affordability and rate comparisons, on behalf of the West Virginia Consumer Advocate Division.

59. *West Virginia-American Water Company,* West Virginia Public Service Commission, Case No. 04-0358-W-PC. 2004. Concerning costs, benefits, and risks associated with a wholesale water sales contract, on behalf of the West Virginia Consumer Advocate Division.

60. *Kentucky-American Water Company,* Kentucky Public Service Commission, Case No. 2004-00103. 2004. Concerning rate design and tariff issues, on behalf of the Kentucky Office of Attorney General.

61. *New Landing Utility, Inc.,* Illinois Commerce Commission, Docket No. 04-0610. 2005. Concerning the adequacy of service provided by, and standards of performance for, a water and wastewater utility, on behalf of the Illinois Office of Attorney General.

62. *People of the State of Illinois v. New Landing Utility, Inc.,* Circuit Court of the 15th Judicial District, Ogle County, Illinois, No. 00-CH-97. 2005. Concerning the standards of performance for a water and wastewater utility, including whether a receiver should be appointed to manage the utility's operations, on behalf of the Illinois Office of Attorney General.

63. *Hope Gas, Inc. d/b/a Dominion Hope*, West Virginia Public Service Commission, Case No. 05-0304-G-42T. 2005. Concerning the utility's relationships with affiliated companies, including an appropriate level of revenues and expenses associated with services provided to and received from affiliates, on behalf of the West Virginia Consumer Advocate Division.

64. *Monongahela Power Co. and The Potomac Edison Co.*, West Virginia Public Service Commission, Case Nos. 05-0402-E-CN and 05-0750-E-PC. 2005. Concerning review of a plan to finance the construction of pollution control facilities and related issues, on behalf of the West Virginia Consumer Advocate Division.

65. *Joint Application of Duke Energy Corp., et al., for Approval of a Transfer and Acquisition of Control*, Case Kentucky Public Service Commission, No. 2005-00228. 2005. Concerning the risks and benefits associated with the proposed acquisition of an energy utility, on behalf of the Kentucky Office of the Attorney General.

66. *Commonwealth Edison Company proposed general revision of rates, restructuring and price unbundling of bundled service rates, and revision of other terms and conditions of service,* Illinois Commerce Commission, Docket No. 05-0597. 2005. Concerning rate design and cost of service, on behalf of the Illinois Office of Attorney General.

67. *Pennsylvania Public Utility Commission v. Aqua Pennsylvania, Inc.*, Pennsylvania Public Utility Commission, Docket No. R-00051030. 2006. Concerning rate design and cost of service, on behalf of the Pennsylvania Office of Consumer Advocate.

68. *Central Illinois Light Company d/b/a AmerenCILCO, Central Illinois Public Service Company d/b/a AmerenCIPS, and Illinois Power Company d/b/a AmerenIP, proposed general increases in rates for delivery service*, Illinois Commerce Commission, Docket Nos. 06-0070, et al. 2006. Concerning rate design and cost of service, on behalf of the Illinois Office of Attorney General.

69. *Grens, et al., v. Illinois-American Water Co.*, Illinois Commerce Commission, Docket Nos. 5-0681, et al. 2006. Concerning utility billing, metering, meter reading, and customer service practices, on behalf of the Illinois Office of Attorney General and the Village of Homer Glen, Illinois.

70. *Commonwealth Edison Company Petition for Approval of Tariffs Implementing ComEd's Proposed Residential Rate Stabilization Program*, Illinois Commerce Commission, Docket No. 06-0411. 2006. Concerning a utility's proposed purchased power phase-in proposal, in behalf of the Illinois Office of Attorney General.

71. *Illinois-American Water Company, Application for Approval of its Annual Reconciliation of Purchased Water and Purchased Sewage Treatment Surcharges Pursuant to 83 Ill. Adm. Code 655*, Illinois Commerce Commission, Docket No. 06-0196. 2006. Concerning the reconciliation of purchased water and sewer charges, on behalf of the Illinois Office of Attorney General and the Village of Homer Glen, Illinois.

72. *Illinois-American Water Company, et al.*, Illinois Commerce Commission, Docket No. 06-0336. 2006. Concerning the risks and benefits associated with the proposed divestiture of a water utility, on behalf of the Illinois Office of Attorney General.

73. *Joint Petition of Kentucky-American Water Company, et al.*, Kentucky Public Service Commission, Docket No. 2006-00197. 2006. Concerning the risks and benefits associated with the proposed divestiture of a water utility, on behalf of the Kentucky Office of Attorney General.

74. *Aqua Illinois, Inc. Proposed Increase in Water Rates for the Kankakee Division*, Illinois Commerce Commission, Docket No. 06-0285. 2006. Concerning various revenue requirement, rate design, and tariff issues, on behalf of the County of Kankakee.

75. *Housing Authority for the City of Pottsville v. Schuylkill County Municipal Authority*, Court of Common Pleas of Schuylkill County, Pennsylvania, No. S-789-2000. 2006. Concerning the reasonableness and uniformity of rates charged by a municipal water authority, on behalf of the Pottsville Housing Authority.

76. *Application of Pennsylvania-American Water Company for Approval of a Change in Control*, Pennsylvania Public Utility Commission, Docket No. A-212285F0136. 2006. Concerning the risks and benefits associated with the proposed divestiture of a water utility, on behalf of the Pennsylvania Office of Consumer Advocate.

77. *Application of Artesian Water Company, Inc., for an Increase in Water Rates*, Delaware Public Service Commission, Docket No. 06-158. 2006. Concerning rate design and cost of service, on behalf of the Staff of the Delaware Public Service Commission.

78. *Central Illinois Light Company, Central Illinois Public Service Company, and Illinois Power Company: Petition Requesting Approval of Deferral and Securitization of Power Costs*, Illinois Commerce Commission, Docket No. 06-0448. 2006. Concerning a utility's proposed purchased power phase-in proposal, in behalf of the Illinois Office of Attorney General.

79. *Petition of Pennsylvania-American Water Company for Approval to Implement a Tariff Supplement Revising the Distribution System Improvement Charge*, Pennsylvania Public Utility Commission, Docket No. P-00062241. 2007. Concerning the reasonableness of a water utility's proposal to increase the cap on a statutorily authorized distribution system surcharge, on behalf of the Pennsylvania Office of Consumer Advocate.

80. *Adjustment of the Rates of Kentucky-American Water Company*, Kentucky Public Service Commission, Case No. 2007-00143. 2007. Concerning rate design and cost of service, on behalf of the Kentucky Office of Attorney General.

81. *Application of Kentucky-American Water Company for a Certificate of Convenience and Necessity Authorizing the Construction of Kentucky River Station II, Associated Facilities and Transmission Main*, Kentucky Public Service Commission, Case No. 2007-00134. 2007. Concerning the life-cycle costs of a planned water supply source and the imposition of conditions on the construction of that project, on behalf of the Kentucky Office of Attorney General.

82. *Pa. Public Utility Commission v. Pennsylvania-American Water Company*, Pennsylvania Public Utility Commission, Docket No. R-00072229. 2007. Concerning rate design and cost of service, on behalf of the Pennsylvania Office of Consumer Advocate.

83. *Illinois-American Water Company Application for Approval of its Annual Reconciliation of Purchased Water and Purchased Sewage Treatment Surcharges*, Illinois Commerce Commission, Docket No. 07-0195. 2007. Concerning the reconciliation of purchased water and sewer charges, on behalf of the Illinois Office of Attorney General.

84. *In the Matter of the Application of Aqua Ohio, Inc. to Increase Its Rates for Water Service Provided In the Lake Erie Division*, Public Utilities Commission of Ohio, Case No.07-0564-WW-AIR. 2007. Concerning rate design and cost of service, on behalf of the Office of the Ohio Consumers' Counsel.

85. *Pa. Public Utility Commission v. Aqua Pennsylvania Inc.*, Pennsylvania Public Utility Commission, Docket No. R-00072711. 2008. Concerning rate design, on behalf of the Masthope Property Owners Council.

86. *Illinois-American Water Company Proposed increase in water and sewer rates*, Illinois Commerce Commission, Docket No. 07-0507. 2008. Concerning rate design and demand studies, on behalf of the Illinois Office of Attorney General.

87. *Central Illinois Light Company, d/b/a AmerenCILCO; Central Illinois Public Service Company, d/b/a AmerenCIPS; Illinois Power Company, d/b/a AmerenIP: Proposed general increase in rates for electric delivery service*, Illinois Commerce Commission Docket Nos. 07-0585, 07-0586, 07-0587. 2008. Concerning rate design and cost of service studies, on behalf of the Illinois Office of Attorney General.

88. *Commonwealth Edison Company: Proposed general increase in electric rates*, Illinois Commerce Commission Docket No. 07-0566. 2008. Concerning rate design and cost of service studies, on behalf of the Illinois Office of Attorney General.

89. *In the Matter of Application of Ohio American Water Co. to Increase Its Rates*, Public Utilities Commission of Ohio, Case No. 07-1112-WS-AIR. 2008. Concerning rate design and cost of service, on behalf of the Office of the Ohio Consumers' Counsel.

90. *In the Matter of the Application of The East Ohio Gas Company d/b/a Dominion East Ohio for Authority to Increase Rates for its Gas Service*, Public Utilities Commission of Ohio, Case Nos. 07-829-GA-AIR, et al. 2008. Concerning the need for, and structure of, an accelerated infrastructure replacement program and rate surcharge, on behalf of the Office of the Ohio Consumers' Counsel.

91. *Pa. Public Utility Commission v. Pennsylvania American Water Company*, Pennsylvania Public Utility Commission, Docket No. R-2008-2032689. 2008. Concerning rate design, cost of service study, and other tariff issues, on behalf of the Pennsylvania Office of Consumer Advocate.

92. *Pa. Public Utility Commission v. York Water Company*, Pennsylvania Public Utility Commission, Docket No. R-2008-2023067. 2008. Concerning rate design, cost of service study, and other tariff issues, on behalf of the Pennsylvania Office of Consumer Advocate.

93. *Northern Illinois Gas Company d/b/a Nicor Gas Company,* Illinois Commerce Commission, Docket No. 08-0363. 2008. Concerning rate design, cost of service, and automatic rate adjustments, on behalf of the Illinois Office of Attorney General.

94. *West Virginia American Water Company,* West Virginia Public Service Commission, Case No. 08-0900-W-42T. 2008. Concerning affiliated interest charges and relationships, on behalf of the Consumer Advocate Division of the Public Service Commission of West Virginia.

95. *Illinois-American Water Company Application for Approval of its Annual Reconciliation of Purchased Water and Purchased Sewage Treatment Surcharges*, Illinois Commerce Commission, Docket No. 08-0218. 2008. Concerning the reconciliation of purchased water and sewer charges, on behalf of the Illinois Office of Attorney General.

96. *In the Matter of Application of Duke Energy Ohio, Inc. for an Increase in Electric Rates*, Public Utilities Commission of Ohio, Case No. 08-0709-EL-AIR. 2009. Concerning rate design and cost of service, on behalf of the Office of the Ohio Consumers' Counsel.

97. *The Peoples Gas Light and Coke Company and North Shore Gas Company Proposed General Increase in Rates for Gas Service*, Illinois Commerce Commission, Docket Nos. 09-0166 and 09-0167. 2009. Concerning rate design and automatic rate adjustments on behalf of the Illinois Office of Attorney General, Citizens Utility Board, and City of Chicago.

98. *Illinois-American Water Company Proposed Increase in Water and Sewer Rates*, Illinois Commerce Commission, Docket No. 09-0319. 2009. Concerning rate design and cost of service on behalf of the Illinois Office of Attorney General and Citizens Utility Board.

99. *Pa. Public Utility Commission v. Aqua Pennsylvania Inc.*, Pennsylvania Public Utility Commission, Docket No. R-2009-2132019. 2010. Concerning rate design, cost of service, and automatic adjustment tariffs, on behalf of the Pennsylvania Office of Consumer Advocate.

100. *Apple Canyon Utility Company and Lake Wildwood Utilities Corporation Proposed General Increases in Water Rates*, Illinois Commerce Commission, Docket Nos. 09-0548 and 09-0549. 2010. Concerning parent-company charges, quality of service, and other matters, on behalf of Apple Canyon Lake Property Owners' Association and Lake Wildwood Association, Inc.

101. *Application of Aquarion Water Company of Connecticut to Amend its Rate Schedules*, Connecticut Department of Public Utility Control, Docket No. 10-02-13. 2010. Concerning rate design, proof of revenues, and other tariff issues, on behalf of the Connecticut Office of Consumer Counsel.

102. *Illinois-American Water Company Annual Reconciliation Of Purchased Water and Sewage Treatment Surcharges*, Illinois Commerce Commission, Docket No. 09-0151. 2010. Concerning the reconciliation of purchased water and sewer charges, on behalf of the Illinois Office of Attorney General.

103. *Pa. Public Utility Commission v. Pennsylvania-American Water Co.*, Pennsylvania Public Utility Commission, Docket Nos. R-2010-2166212, et al. 2010. Concerning rate design and cost of service study for four wastewater utility districts, on behalf of the Pennsylvania Office of Consumer Advocate.

104. *Central Illinois Light Company d/b/a AmerenCILCO, Central Illinois Public Service Company d/b/a AmerenCIPS, Illinois Power Company d/b/a AmerenIP Petition for accounting order*, Illinois Commerce Commission, Docket No. 10-0517. 2010. Concerning ratemaking procedures for a multi-district electric and natural gas utility, on behalf of the Illinois Office of Attorney General.

105. *Commonwealth Edison Company Petition for General Increase in Delivery Service Rates*, Illinois Commerce Commission Docket No. 10-0467. 2010. Concerning rate design and cost of service study, on behalf of the Illinois Office of Attorney General.

106. *Pa. Public Utility Commission v. City of Lancaster Bureau of Water*, Pennsylvania Public Utility Commission, Docket No. R-2010-2179103. 2010. Concerning rate design, cost of service, and cost allocation, on behalf of the Pennsylvania Office of Consumer Advocate.

107. *Application of Yankee Gas Services Company for Amended Rate Schedules*, Connecticut Department of Public Utility Control, Docket No. 10-12-02. 2011. Concerning rate design and cost of service for a natural

gas utility, on behalf of the Connecticut Office of Consumers' Counsel.

108. *California-American Water Company*, California Public Utilities Commission, Application 10-07-007. 2011. Concerning rate design and cost of service for multiple water-utility service areas, on behalf of The Utility Reform Network.

109. *Little Washington Wastewater Company, Inc., Masthope Wastewater Division*, Pennsylvania Public Utility Commission Docket No. R-2010-2207833. 2011. Concerning rate design and various revenue requirements issues, on behalf of the Masthope Property Owners Council.

110. *In the matter of Pittsfield Aqueduct Company, Inc.*, New Hampshire Public Utilities Commission Case No. DW 10-090. 2011. Concerning rate design and cost of service on behalf of the New Hampshire Office of the Consumer Advocate.

111. *In the matters of Pennichuck Water Works, Inc. Permanent Rate Case and Petition for Approval of Special Contract with Anheuser-Busch, Inc.*, New Hampshire Public Utilities Commission Case Nos. DW 10-091 and DW 11-014. 2011. Concerning rate design, cost of service, and contract interpretation on behalf of the New Hampshire Office of the Consumer Advocate.

112. *Artesian Water Co., Inc. v. Chester Water Authority*, U.S. District Court for the Eastern District of Pennsylvania Case No. 10-CV-07453-JP. 2011. Concerning cost of service, ratemaking methods, and contract interpretation on behalf of Chester Water Authority.

113. *North Shore Gas Company and The Peoples Gas Light and Coke Company Proposed General Increases in Rates for Gas Service*, Illinois Commerce Commission, Docket Nos. 11-0280 and 11-0281. 2011. Concerning rate design and cost of service on behalf of the Illinois Office of Attorney General, the Citizens Utility Board, and the City of Chicago.

114. *Ameren Illinois Company: Proposed general increase in electric delivery service rates and gas delivery service rates*, Illinois Commerce Commission, Docket Nos. 11-0279 and 11-0282. 2011. Concerning rate design and cost of service for natural gas and electric distribution service, on behalf of the Illinois Office of Attorney General and the Citizens Utility Board.

115. *Pa. Public Utility Commission v. Pennsylvania-American Water Co.*, Pennsylvania Public Utility Commission, Docket No. R-2011-2232243. 2011. Concerning rate design, cost of service, sales forecast, and automatic rate adjustments on behalf of the Pennsylvania Office of Consumer Advocate.

116. *Aqua Illinois, Inc. Proposed General Increase in Water and Sewer Rates*, Illinois Commerce Commission, Docket No. 11-0436. 2011. Concerning rate design and cost of service on behalf of the Illinois Office of Attorney General.

117. *City of Nashua Acquisition of Pennichuck Corporation*, New Hampshire Public Utilities Commission, Docket No. DW 11-026. 2011. Concerning the proposed acquisition of an investor-owned utility holding company by a municipality, including appropriate ratemaking methodologies, on behalf of the New Hampshire Office of Consumer Advocate.

118. *An Application by Heritage Gas Limited for the Approval of a Schedule of Rates, Tolls and Charges*, Nova Scotia Utility and Review Board, Case NSUARB-NG-HG-R-11. 2011. Concerning rate design and

cost of service, on behalf of the Nova Scotia Consumer Advocate.

119.*An Application of Halifax Regional Water Commission for Approval of a Cost of Service and Rate Design Methodology,* Nova Scotia Utility and Review Board , Case NSUARB-W-HRWC-R-11. 2011. Concerning rate design and cost of service, on behalf of the Nova Scotia Consumer Advocate.

120.*National Grid USA and Liberty Energy Utilities Corp.*, New Hampshire Public Utilities Commission, Docket No. DG 11-040. 2011. Concerning the costs and benefits of a proposed merger and related conditions, on behalf of the New Hampshire Office of Consumer Advocate.

121.*Great Northern Utilities, Inc., et al.*, Illinois Commerce Commission, Docket Nos. 11-0059, et al. 2012. Concerning options for mitigating rate impacts and consolidating small water and wastewater utilities for ratemaking purposes, on behalf of the Illinois Office of Attorney General.

122.*Pa. Public Utility Commission v. Aqua Pennsylvania, Inc.,* Pennsylvania Public Utility Commission, Docket No. R-2011-2267958. 2012. Concerning rate design, cost of service, and automatic rate adjustment mechanisms, on behalf of the Pennsylvania Office of Consumer Advocate.

123.*Golden State Water Company*, California Public Utilities Commission, Application 11-07-017. 2012. Concerning rate design and quality of service, on behalf of The Utility Reform Network.

124.*Golden Heart Utilities, Inc. and College Utilities Corporation*, Regulatory Commission of Alaska, Case Nos. U-11-77 and U-11-78. 2012. Concerning rate design and cost of service, on behalf of the Alaska Office of the Attorney General.

125.*Illinois-American Water Company*, Illinois Commerce Commission, Docket No. 11-0767. 2012. Concerning rate design, cost of service, and automatic rate adjustment mechanisms, on behalf of the Illinois Office of Attorney General.

126.*Application of Tidewater Utilities, Inc., for a General Rate Increase in Water Base Rates and Tariff Revisions*, Delaware Public Service Commission, Docket No. 11-397. 2012. Concerning rate design and cost of service study, on behalf of the Staff of the Delaware Public Service Commission.

127.*In the Matter of the Philadelphia Water Department's Proposed Increase in Rates for Water and Wastewater Utility Services*, Philadelphia Water Commissioner, FY 2013-2016. 2012. Concerning rate design and related issues for storm water service, on behalf of Citizens for Pennsylvania's Future.

128.*Corix Utilities (Illinois) LLC, Hydro Star LLC, and Utilities Inc. Joint Application for Approval of a Proposed Reorganization*, Illinois Commerce Commission, Docket No. 12-0279. 2012. Concerning merger-related synergy savings and appropriate ratemaking treatment of the same, on behalf of the Illinois Office of Attorney General.

129.*North Shore Gas Company and The Peoples Gas Light and Coke Company*, Illinois Commerce Commission, Docket Nos. 12-0511 and 12-0512. 2012. Concerning rate design, cost of service study, and automatic rate adjustment tariff on behalf of the Illinois Office of Attorney General.

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CrossMark

Moving Toward Demand-Based Residential Rates

The widespread use of automated metering infrastructure in the electricity distribution industry is generating increasing discussion of residential demand charges. An analysis of six types of residential rate designs shows that designing residential rates with seasonal consumption charges might make significant progress toward a more efficient rate design. Seasonal usage rates are understandable to customers, avoid many of the problems with demand-based rates, do not require significant implementation expenditures, and may avoid the extreme bill impacts of some demand-based rate options.

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I. Background

The widespread use of automated metering infrastructure (AMI) in the electricity distribution industry is generating increasing discussion of residential demand charges. Conferences are being held where pro-demand-charge consultants (Ryan Hledik, 2015) square off against anti-demand-charge consultants (Barbara Alexander, 2015); interest groups are posting blogs about the desirability of residential demand charges (Rocky Mt. Institute, 2015); and articles are being published in this *Journal* to try to elucidate points on both sides of the issue (Blank and Gegax, 2014; Hledik, 2014).

1040-6190/ http://dx.doi.org/10.1016/j.tej.2015.09.021

Both sides make valid points. On the one hand, every electricity distribution cost-of-service study (COSS) recognizes that a substantial portion of distribution costs are demand-related. Most utilities, however, have residential rates that contain a customer charge and one or more rates based on energy consumption (rates per kilowatt-hour). Residential demand charges are rare. Where they exist, they are nearly always optional. This means that most residential customers continue to pay demand-related costs through a combination of a flat-rate customer charge and per-kWh charges, rates that may not precisely mirror a customer's demand.

On the other side are those who suggest that residential demand charges are fraught with problems, not the least of which are the need for substantial consumer education and difficulties with tariff administration (including reprogramming utility billing systems and training customer service personnel). Those on the "anti" side of the debate also note that there are important rate design concerns other than strict adherence to the results of a COSS. These include understandability, efficiency, gradualism, revenue stability, and affordability.

With AMI the industry has an unprecedented opportunity to better understand the relationship between peak demand and energy consumption on a very granular level – that is, that of the individual customer. The challenge will be to use this information to move toward a residential rate design that is more efficient (that is, improves the collection of demand-related costs from residential customers who cause the demand), yet remains understandable, affordable, and easy to administer.

Any potential rate design must represent a compromise involving a series of trade-offs.

II. Advantages and Disadvantages of Different Rate Designs

Before discussing any specific analyses, it is worth remembering that there is no "perfect" rate design. The rate design process involves developing averages and groupings for thousands, or even millions, of customers. No rate design will exactly capture the actual cost to serve an individual residential customer, but the goal is to have a rate design that treats all customers fairly within the confines of the averaging and grouping process.

Thus, any potential rate design must represent a compromise involving a series of trade-offs. Prof. Bonbright taught that among the factors to be evaluated in a rate design are fairness (including relationship of the rates to cost), encouraging the wise use of the service, understandability, ease of administration, non-discrimination, revenue stability, and gradualism (Bonbright, 1961).

Billing based on annual demand has a certain theoretical appeal, but the annual demand is not known until the end of the peak season. A summer-peaking utility might experience its peak in July or August, or even in September during an unusual weather event. Similarly, a winter-peaking utility could reach its peak in December, January, or February. Moreover, a utility whose peak fluctuates (winter peaking some years, summer peaking in others) might not know its annual peak until an entire year passes. In any event, billing based on the annual peak always will be based on some event in the past, often many months before, that the customer can no longer control. When a customer moves during the year or a new home is added to the service territory, there also could be a serious question about the fairness of the billing determinant that will be used for the new account.

Further, the customer's ability to control its peak-period usage might be limited, or simply the

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result of luck (good or bad). For instance, if a customer happens to be on vacation during the peak day, her contribution to the annual peak might be unusually low compared to her normal seasonal consumption. Similarly, if a customer happens to have the bad luck of having visitors on the peak day, her contribution to the peak might be unusually high compared to her normal seasonal usage.

Other events also could hamper a customer's ability to control consumption during the precise peak hour, especially because the time of the peak is not knowable when energy is being consumed. These might include appliance cycling during the day (how the refrigerator was cycling during the peak hour), whether the customer has a medical device (such as an oxygen concentrator) that was required to work during the peak hour, whether the peak hour occurred during the work day or after the customer returned home from work, and so on.

Rates based on billing (that is, monthly) demand would eliminate some of the temporal shift involved when annual demand is used, but there is a question about the relationship between a customer's monthly peak demands and his contribution to the annual system peak. This is particularly the case for customers who peak off-season, such as space-heating customers in a summer-peaking utility.

Similarly, billing based on annual energy consumption has some advantages (it is easy to understand and administer, and it spreads the utility's revenues throughout the year), but it may not be fair to consumers who use electricity efficiently (that is, high-load-factor customers who control their peak usage). Such a rate also can send the incorrect price signal that the cost of electricity distribution is the same throughout the year, regardless of the time of day or season of consumption.

From a utility's perspective, having most distribution costs collected in the peak season could create concerns with revenue stability.

Collecting demand costs partially through customer charges also can be problematic. Implicitly, this type of rate design assumes that all customers contribute equally to peak demand, which is rarely the case. It also assumes that there are no differences in distribution facilities based on a customer's peak demand. This ignores the fact that transformers and other facilities might be sized differently depending on the expected demands from connected customers. For example, why should a customer in an apartment without air conditioning pay the same amount for demand-related costs as a customer in a large, air-conditioned home where the thermostat is set to 70 °F? Per-customer billing of demand-related costs also fails to send any price signal to a customer about the longer-term costs the customer's energy usage patterns cause to the system.

Seasonal billing also can create problems, both for the utility and for customers. For example, high summer charges essentially give space-heating customers a "free ride" on the distribution network. While heating customers may not "cause" the system peak, heating customers certainly use wires, poles, transformers, and other distribution facilities that were sized to meet summer peak demands. Setting a non-summer distribution charge very low, therefore, could be unfair to customers.

Finally, from a utility's perspective, having most distribution costs collected in the peak season could create concerns with revenue stability, particularly if weather happens to be unusual (a summer that is much cooler than normal, for example). Such seasonal pricing certainly would change the cash flows of electric distribution utilities, making the cash-flow patterns similar to those experienced by natural gas distribution utilities (very high

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peak-season revenues) that may require a utility to have a significant line of credit to provide adequate off-season cash flows.

III. Previous Research

In 2014, Blank and Gegax (Blank and Gegax, 2014), working with a small data set (43 households), used linear regression analysis to show that annual energy consumption (kWh) was positively but somewhat weakly correlated with a customer's contribution to peak demand (expressed in kilowatts). Their regression analysis showed that while the result was statistically significant ($\rho < 0.001$) annual kWh explained only 38 percent of the variability in peak demand (kW).

That study also posited that a regression through the origin (that is, an intercept equal to zero) might do a better job of explaining the relationship between kWh and kW. Given the different measurements involved in linear regression analyses with and without an intercept term, Eisenhauer explains that the *R*-squared cannot be used to compare results; rather, results using the two approaches must be evaluated by comparing the standard errors of the analyses (the lower the standard error, the closer the correlation between the variables) (Eisenhauer, 2003). On this basis, the analyses of Blank and Gegax show that the regression with an intercept term is superior (a standard error of 1.96 compared to the regression without an intercept's standard error of 3.06).

Blank and Gegax also suggested that a rate that divided demand charge recovery between the customer charge and the kWh charge might enhance fairness. They did not develop any analyses, however, that would evaluate this hypothesis.

Blank and Gegax suggested that a rate that divided demand charge recovery between the customer charge and the kWh charge might enhance fairness.

IV. Methods

This article expands on the Blank and Gegax approach to evaluate the ability of different residential rate designs. Rate designs are compared for their ability to collect demand-related costs in a manner that might be fairer to customers and consistent with other important rate design principles and goals.

In particular, linear regression analysis is used on a data set containing monthly energy consumption and annual contribution to the system peak demand for 77,675 residential accounts. The data set contains data for a portion of the service area of an electric distribution utility in U.S. Department of Energy climate zone 5 (U.S. Department of Energy, 2013). Some customers in the data set use electricity for space heating in the winter, but most do not. Many (but not all) non-heating customers have summer peak usage evidencing energy usage for air conditioning or other seasonal space cooling. Prior to developing the final data set, some outliers were eliminated (such as accounts with highly atypical usage or demand profiles, those with missing data, etc.).

Hledik (2014) notes that some residential demand charges are developed using billing demand (that is, each customer's maximum demand in each billing period), rather than contribution to annual peak demand. In order to evaluate a rate design using billing demand, it is necessary to have the monthly peak demand for each customer. The data set does not contain those monthly demands, so monthly demands were estimated for each customer using the base, low, and high usage load profiles developed by the U.S. Department of Energy (DOE) for a city within the utility's service area.

Specifically, the "low" load profile was used for accounts with annual usage less than 7,500 kWh; the "base" profile was used for accounts using between 7,500 and 12,500 kWh during the year; and

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the "high" profile was used for accounts using more than 12,500 kWh in the year. From each load profile, the peak demand was determined for each month. From that monthly peak demand, a monthly load factor (ratio of average demand to peak demand) was calculated for each month. The July load factor from the applicable load profile was then compared to the actual July load factor (July was the month when the peak occurred in the data set) for each customer to calibrate the results. For example, if a customer had a load factor in July of 0.50 but the applicable DOE load profile had a July load factor of 0.45, the actual load factor for the month was 11 percent higher than the profile. It was assumed, therefore, that the load factor would be 11 percent higher than the applicable DOE profile in all other months. The monthly load factor was then used to calculate the monthly billing demand. The following equation shows the calculation of May billing demand for a customer in the "base" group (using between 7,500 and 12,500 kWh in the year).

$$kW_{May} = \frac{kWh_{May}/744}{BLF_{May} \times [(kWh_{Jul}/744)/(kW_{Annual}/BLF_{Jul})]}$$

where kW = Peak kW demand in a period (month or Annual); kWh = kWh consumption in a period; BLF = Load factor calculated from DOE Base profile in a period; 744 = Number of hours in a 31-day month.

Illustrative rates were then calculated for six different rate design options, as described in **Table 1**. The rates are based on the customer cost ($13.25 per month per customer) and demand charge ($4.93 per kW per month based on annual peak demand) used by Blank and Gegax. Applying those rates to the customers in the data set produces revenues of approximately $27.7 million. All other rate design options were designed to collect the same amount of revenues.

For purposes of these analyses, it is assumed that the existing rate design is the All kWh design. Thus, the existing rate has a customer charge that collects customer-related costs of $13.25 per month. All other costs (to simplify, it is assumed that all other distribution costs are demand-related) are collected through a flat charge of 1.52¢ per kWh throughout the year.

The second assumption is that the Annual Demand rate represents the cost to serve each customer. That is, this rate collects all customer-related costs in an equal amount per customer and all demand-related costs based solely on each customer's contribution to the annual peak demand. This also makes the

Table 1: Rate Design Options.

Option	Description	Customer Charge (per month)	Demand Charge (per kW per month)	Summer Energy (per kWh)	Non-Summer Energy (per kWh)
Annual Demand	Per kW charge based on annual peak	$13.25	$4.93	– 0 –	– 0 –
Billing Demand	Per kW charge based on monthly peak	$13.25	$5.55	– 0 –	– 0 –
All kWh	All demand costs per kWh	$13.25	– 0 –	1.52¢	1.52¢
Split	Demand costs 60% per kWh; 40% in customer charge	$19.84	– 0 –	0.91¢	0.91¢
All Summer	All demand costs per summer (Jun–Sep) kWh	$13.25	– 0 –	4.79¢	– 0 –
Seasonal	Summer kWh charge is 2 times non-summer charge	$13.25	– 0 –	2.31¢	1.15¢

 1040-6190/, http://dx.doi.org/10.1016/j.tej.2015.09.021

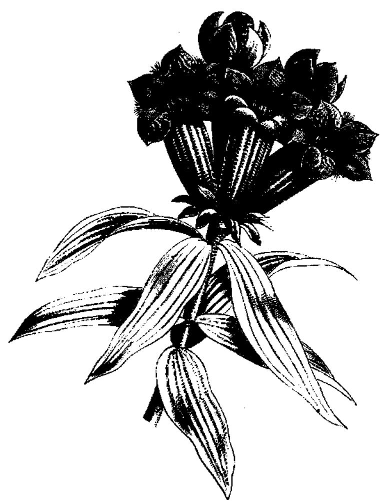
simplifying assumption that all demand-related costs are allocated to customer classes based solely on a single coincident peak (that is, each class's contribution to the single hour of the year with the highest system demand).

Thus, the assumed cost to serve each customer (the Annual Demand rate) can be compared to the charges under other rate designs to assess the relationship between the cost of service and revenues for each customer. Rather than comparing demand (measured in kW) against charges (measured in dollars per year), the analyses compare the customer-specific cost of service (in dollars per year) against charges under other rate design options (also in dollars per year for each customer). Because of the existence of a fixed customer charge, bills will never approach zero, which avoids one of the analytical issues raised by Blank and Gegax in their analyses that compared demand (kW) to energy (kWh).

V. Results

Initially, the characteristics of the cost of service are examined. The data show that the cost to serve customers varies from a low of $159.35 per year (a customer with almost no contribution to peak demand) to $750.48 per year (the highest-demand customer), with an average of $356.79 per year (standard deviation of 103.78).

Next, the existing rate (All kWh) is compared to the cost of service. While the cost of service indicated a maximum cost of $750.48, the existing rates result in a maximum annual bill that is substantially higher: $919.00. While the average annual bill is essentially the same as the cost of service ($356.75 versus $356.79), the existing rates' standard deviation is higher (127.77 versus 103.78), providing an initial indication that there is a meaningful difference between revenues and costs for many customers.



A linear regression analysis provides further evidence that the existing rate does not ideally track the cost of service for many customers. The analysis shows that the existing rate is positively but modestly correlated with the cost of service, and the relationship is statistically significant ($\rho < 0.001$). Specifically, both the intercept (169.200) and slope (0.526) are positive, indicating that the relationship is logical (customers with higher costs pay higher rates). The R-squared, however, is 0.419, which indicates that there is a substantial unexplained variance between the cost of service and customers' annual bills.

The next stage in the analysis is to evaluate each rate design option in two ways. First, the option is compared to the cost of service with a linear regression analysis. Second, the magnitude of rate change (compared to the existing All kWh rate) is described to indicate whether this type of rate design change might create unacceptable customer impacts. The results of these analyses are shown in Tables 2 and 3.

Several points are noteworthy in these results. First, to move immediately to rates based on annual demand (even if other obstacles could be overcome) would result in dramatic rate changes, ranging from a 76 percent decrease to a 162 percent increase. Ten percent of customers would experience annual bill decreases of 29 percent or less, while another 10 percent of customers would face annual bill increases of 32 percent or more, as shown in Fig. 1. It is unlikely that a revenue-neutral rate design change having changes of this magnitude would be consistent with the rate design criteria of public acceptability and gradualism. The difference from existing (kWh-based) rates is simply too severe.

Interestingly, adopting a rate design based on billing demand

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Table 2: Results of Linear Regression Analyses Compared to Cost (All Demand).

Option	Intercept	Slope	R-squared	Significance
All kWh	169.200	0.526	0.419	$\rho < 0.001$
Billing Demand	178.876	0.499	0.426	$\rho < 0.001$
Split	43.695	0.878	0.419	$\rho < 0.001$
All Summer	60.580	0.830	0.846	$\rho < 0.001$
Seasonal	125.856	0.648	0.550	$\rho < 0.001$

Table 3: Bill Changes from Rate Design Options Compared to Existing Bills (All kWh).

Option	Average % Change	Min/Max % Change	10th/90th Percentile	% Bills Increased
Annual Demand	4.4%	−76%/+162%	−29%/+32%	62%
Billing Demand	0.6%	−40%/+183%	−14%/+16%	43%
Split	4.6%	−25%/+49%	−14%/+24%	60%
All Summer	3.0%	−76%/+74%	−26%/+26%	63%
Seasonal	0.7%	−19%/+18%	−6%/+6%	61%

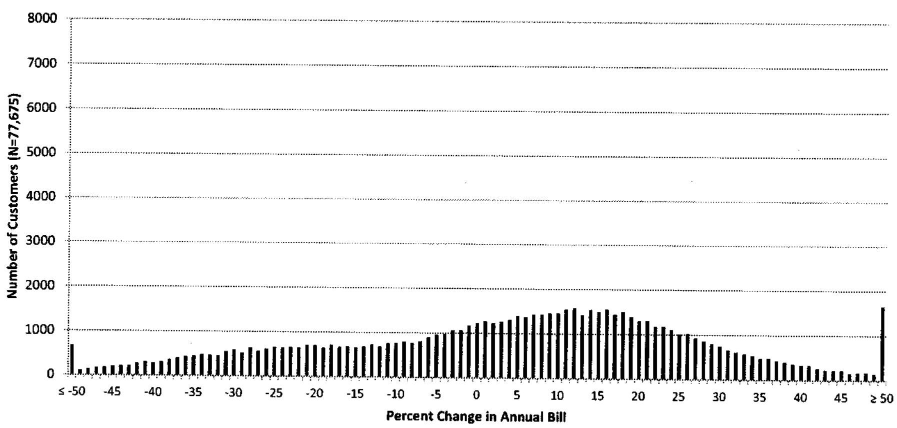

Fig. 1: Distribution of Rate Increases Required to Move from All kWh Rates to Rates Based on Annual Demand

(that is, the customer's peak demand in each billing month) would make almost no progress toward aligning rates with the cost of service. Specifically, this option (Billing Demand) has an R-squared of just 0.426 (compared to existing rates' R-squared of 0.419) when compared to the cost of service. While this option would have a less severe rate impact than moving to the Annual Demand option, there are still sizeable rate dislocations, with some customers experiencing increases even higher than those experienced under the Annual Demand option (as high as 183 percent). Most customers, however, would experience increases in the range of ±15% (Fig. 2), which is somewhat more acceptable than the ±30% range under the Annual Demand option. Further, this is the only rate design option evaluated that has more customers receiving annual bill decreases than increases (43 percent receive increases, compared to the other options where more than 60 percent of customers receive increases).

It also is interesting to note that the Split option that collects 60 percent of demand-related costs through a kWh charge and 40 percent through the customer charge, does nothing to better align costs and revenues. The R-squared under this option is identical to the R-squared of existing rates at 0.419. In this

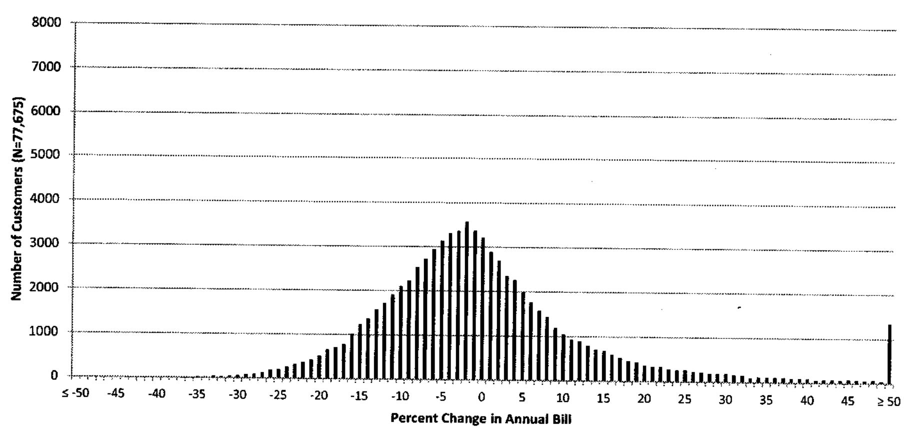

Fig. 2: Distribution of Rate Increases Required to Move from All kWh Rates to Rates Based on Billing Demand

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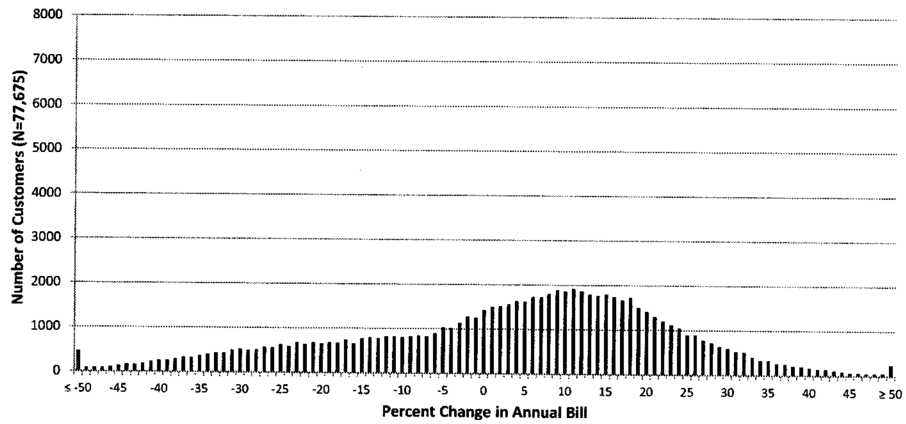

Fig. 3: Distribution of Rate Increases Required to Move from All kWh Rates to Rates Based on Summer kWh

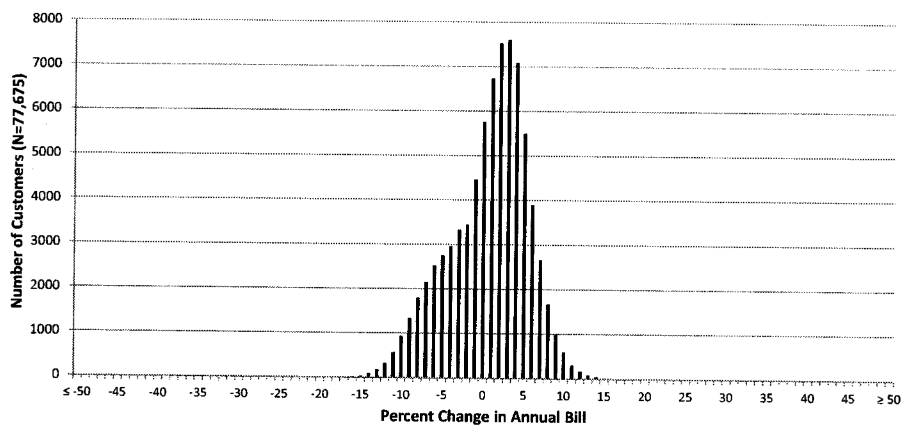

Fig. 4: Distribution of Rate Increases Required to Move from All kWh Rates to Seasonal kWh Rates

example, this option represents a classic case of a rate design that creates winners and losers but does nothing to improve the overall efficiency of the rate design (that is, the rate design's ability to more closely track the cost of service).

The last two options evaluated represent cases that may achieve some of the benefits of demand-based rates without using a kW billing determinant. The rate design that collects all demand-related costs through peak-season (summer) kWh charges comes much closer to tracking the cost of service, with an *R*-squared of 0.846. This type of rate could avoid the educational and implementation problems of a demand-based rate while better aligning rates with costs. This type of rate design, however, does have theoretical problems, as discussed above (particularly the problems of revenue stability and off-season customers getting the free use of the distribution network). Moving to this type of rate design also would create significant annual bill changes for customers. Most customers would experience increases in the range of ±26%, with the highest and lowest increases of approximately ±75% (Fig. 3).

The final option evaluated has a summer kWh charge that is double the non-summer kWh charge. This might represent an incremental change in the rate design that does not involve the issues associated with demand-based billing, but moves closer toward cost-based rates in a gradual manner that considers customer impacts. This type of rate design makes meaningful movement toward tracking the cost of service (*R*-squared of 0.550 compared to the existing rate design's 0.419), but without the drastic changes in annual bills that the other rate design options would engender. Under this option, most customers would see bills change within the range of ±6%, with no customer experiencing a change outside the range of ±19%, as shown in Fig. 4.

VI. Conclusion

The illustrative rate design options evaluated in this article contain some important results. For example, shifting costs between consumption and customer charges may do nothing to improve the efficiency of the

  http://dx.doi.org/10.1016/j.tej.2015.09.021

rate design, even though customers experience dramatic changes in their annual bills. Similarly, while one might expect monthly billing demands to be closely correlated with annual peak demand, that is not the case in this data set. In fact, using monthly billing demands does very little to improve the efficiency of the rate design compared to a simple kWh-based rate design. Once again, while winners and losers are created, the overall rate design is no better at tracking the cost of serving customers than a consumption-based design.

From these examples, it appears that designing residential electric distribution rates with seasonal consumption charges (higher peak-season charges) might make significant progress toward a more efficient rate design. Seasonal kWh rates are understandable to customers, avoid many of the problems with demand-based rates (such as the "lucky" customer who happens to be away from home on the day of the annual peak), do not require significant implementation expenditures, and may avoid the extreme bill impacts of some demand-based rate options.

There are a limitless number of rate design options available to utilities and regulators. With the wide-scale deployment of AMI, data will be available that will allow analysts to develop rate design options that improve the efficiency of the rate design (that is, its ability to have a customer's revenues collect the cost of serving the customer) while also evaluating the impacts of the rate design change on customers. This article has highlighted some of the statistical and comparative techniques that should be helpful in the development of such rates. It is hoped that analysts and researchers will further explore these topics with more extensive data sets, other rate design options, and different statistical techniques for evaluating the ability to improve rate design efficiency while remaining sensitive to other longstanding rate design principles and goals.■

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 1040-6190/, http://dx.doi.org/10.1016/j.tej.2015.09.021

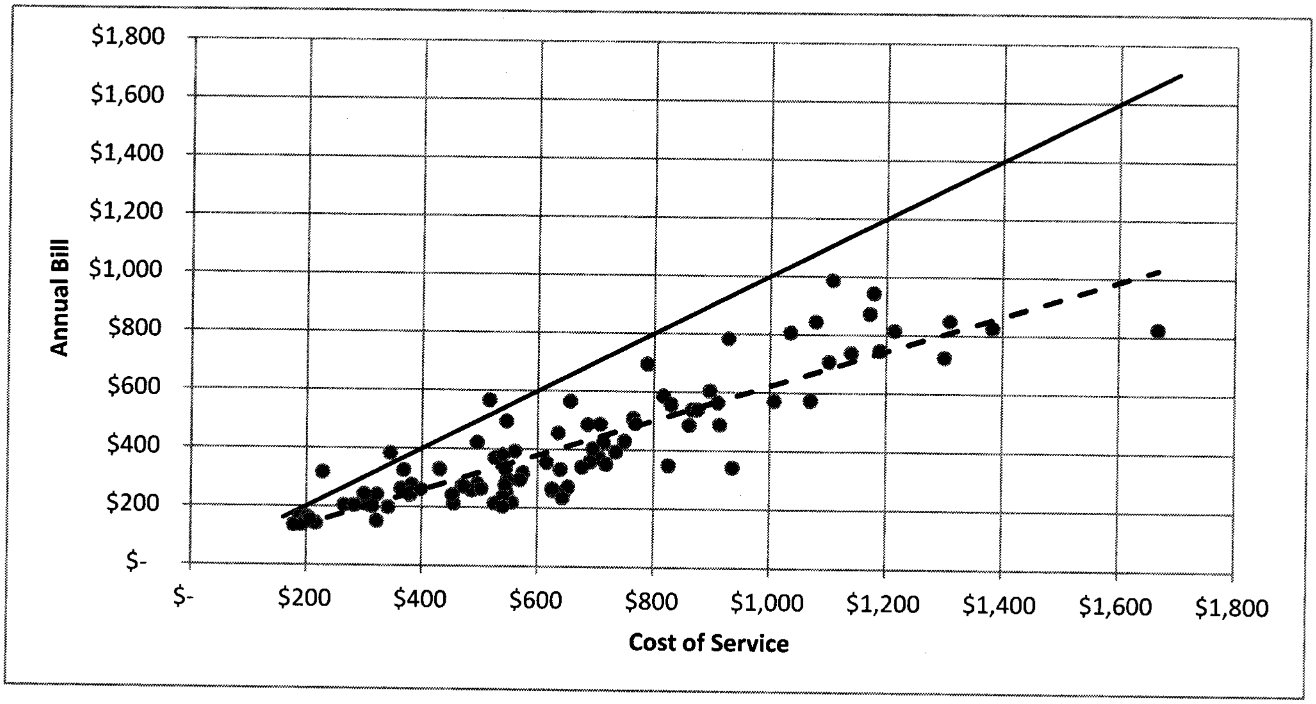
UNS Electric Inc.
Arizona Corp. Comm'n Docket No. E-04204A-15-0142

Exhibit SJR-2

Residential Cost of Service, Units of Service, and Unit Cost
(All data from: 2015 UNSE Schedule G-COSS-R.xlsx)

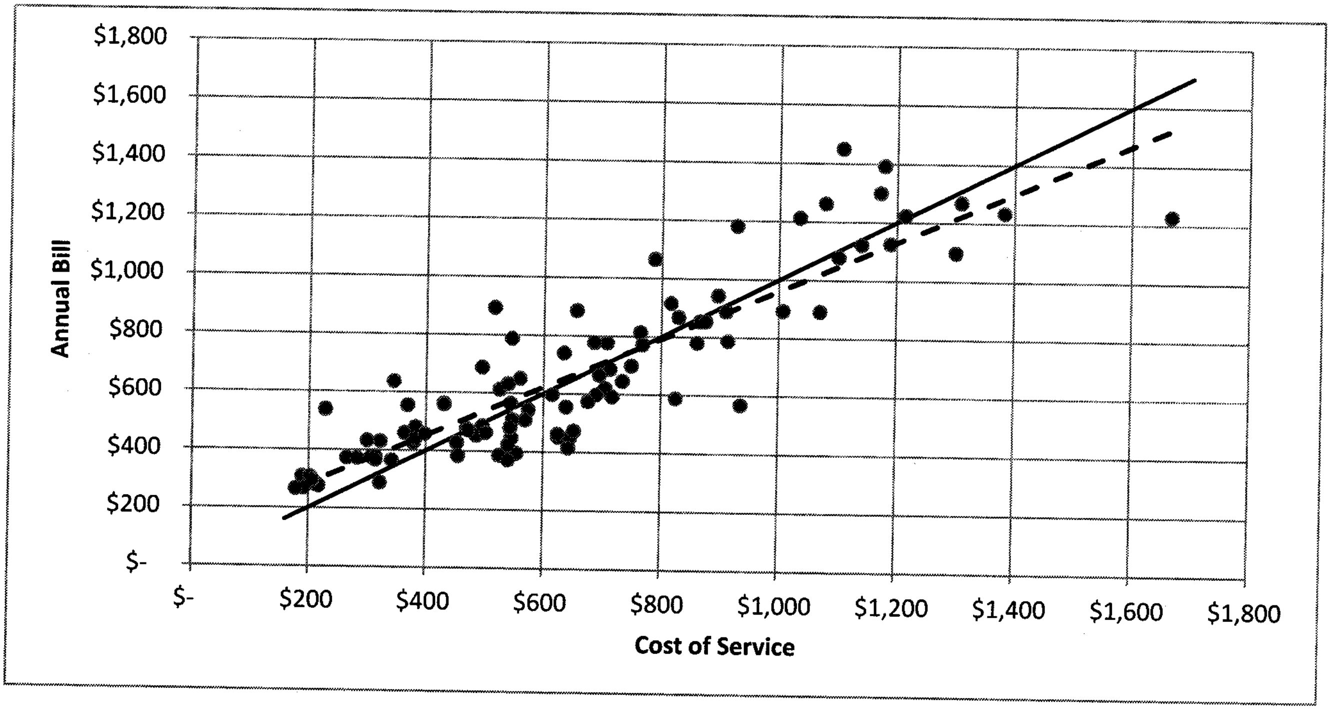
	Cost of Service				
1	Production demand	$	20,709,455	A&E/4CP	Data from the Functionalization_RES tab
2	Transmission demand		8,775,515	A&E/4CP	
3	Distribution primary demand		10,625,712	NCP	
4	Distribution secondary demand		1,173,823	NCP	
5	Total demand	$	41,284,505		
6	Energy	$	44,744,078	KWH	
7	Customer delivery	$	7,991,033	Customers	
8	Customer meter		646,494	Customers	
9	Customer billing & collections		4,113,357	Customers	
10	Customer meter reading		942,211	Customers	
11	Total customer	$	13,693,095		
	Units of Service				
12	Residential customers		82,607		G-7 Allocations tab, J38
13	Residential sales		823,953,185	kWh	G-7 Allocations tab, I32
14	Residential NCP		267,360	kW	NCP tab, C65
15	Residential CP		211,252	kW	NCP tab, C60
	For calculation purposes, simplify the A&E/4CP allocator to				
16	Average demand		22.50%		Calculated in Work copy of COSS
17	4 CP		77.50%		
18	Equals		184,883.48	kW	(line 13 / 8760 x line 16) + (line 15 x line 17)
	Annual Unit Costs				
19	Production demand	$	112.01	per kW (A&E/4CP)	line 1 / line 18
20	Transmission demand	$	47.47	per kW (A&E/4CP)	line 2 / line 18
21	Distribution primary demand	$	39.74	per kW (NCP)	line 3 / line 14
22	Distribution secondary demand	$	4.39	per kW (NCP)	line 4 / line 14
23	Energy	$	0.054304	per kWh	line 6 / line 13
24	Customer-related costs	$	165.76	per customer	line 11 / line 12
	Restated Annual Unit Costs				
	Average demand:				
25	22.50% of A&E/4CP costs	$	6,634,118		(line 1 + line 2) x line 16
26	Average demand		94,059	kW	line 13 / 8760
27	Average demand-related	$	70.53	per kW @ avg.	line 25 / line 26
28	Convert to cost per kWh	$	0.008052	per kWh	line 27 / 8760
29	Energy costs	$	44,744,078		line 6
30	Energy costs per kWh	$	0.054304	per kWh	line 29 / line 13
31	**Energy-related unit cost**	**$**	**0.062356**	**per kWh**	line 28 + line 30
	4 CP related:				
32	77.50% of A&E/4CP costs	$	22,850,852		line 1 + line 2 - line 25
33	**4 CP related unit cost**	**$**	**108.17**	**per kW @ 4 CP**	line 32 / line 15
34	**NCP related unit cost**	**$**	**44.13**	**per kW @ NCP**	line 21 + line 22
35					
32	**Customer related unit cost**	**$**	**165.76**	**per customer**	line 24

Sample of 100 Residential Customers
Comparison of Cost of Service and Present Distribution Bill

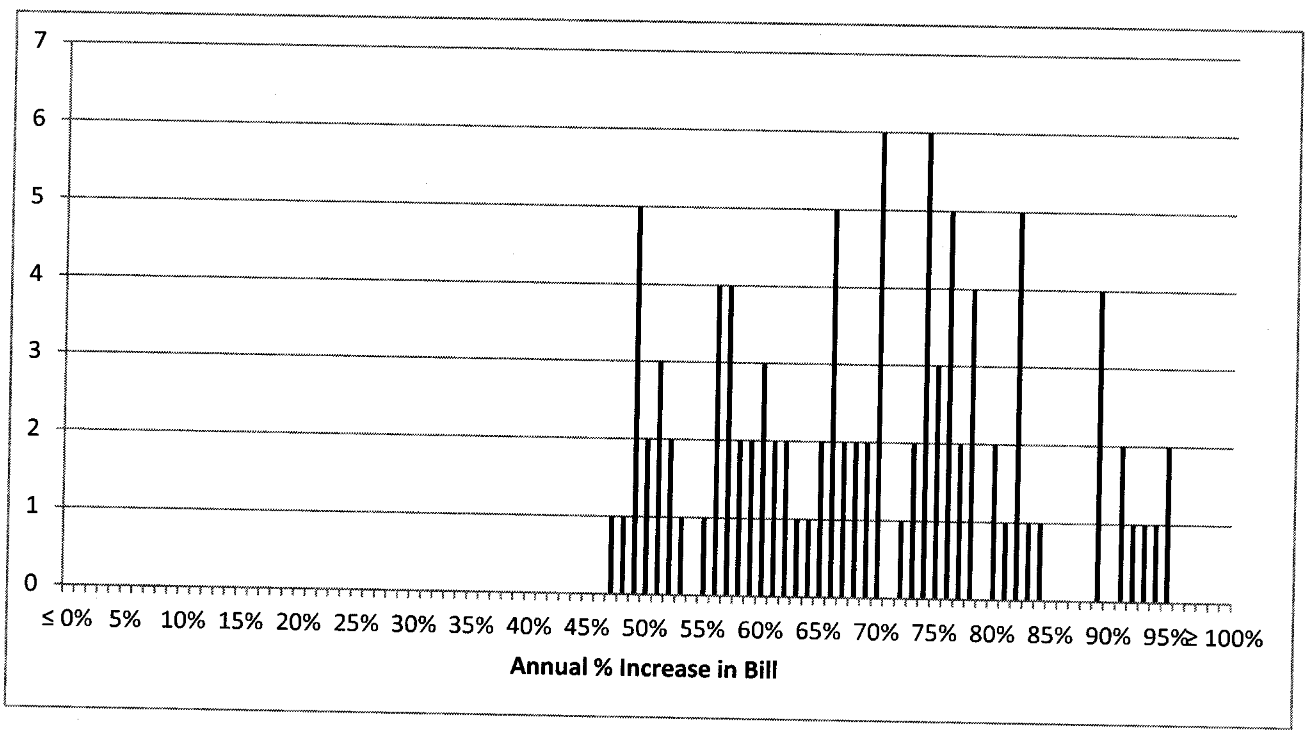


Slope	0.607	N	100			
Intercept	15.805	Avg. Diff.	36%	Tot. Rev.	$	39,934
R-square	0.797	% > Cost	3	Tot. Cost	$	63,175

Sample of 100 Residential Customers
Comparison of Cost of Service and UNS Originally Proposed Distribution Bill



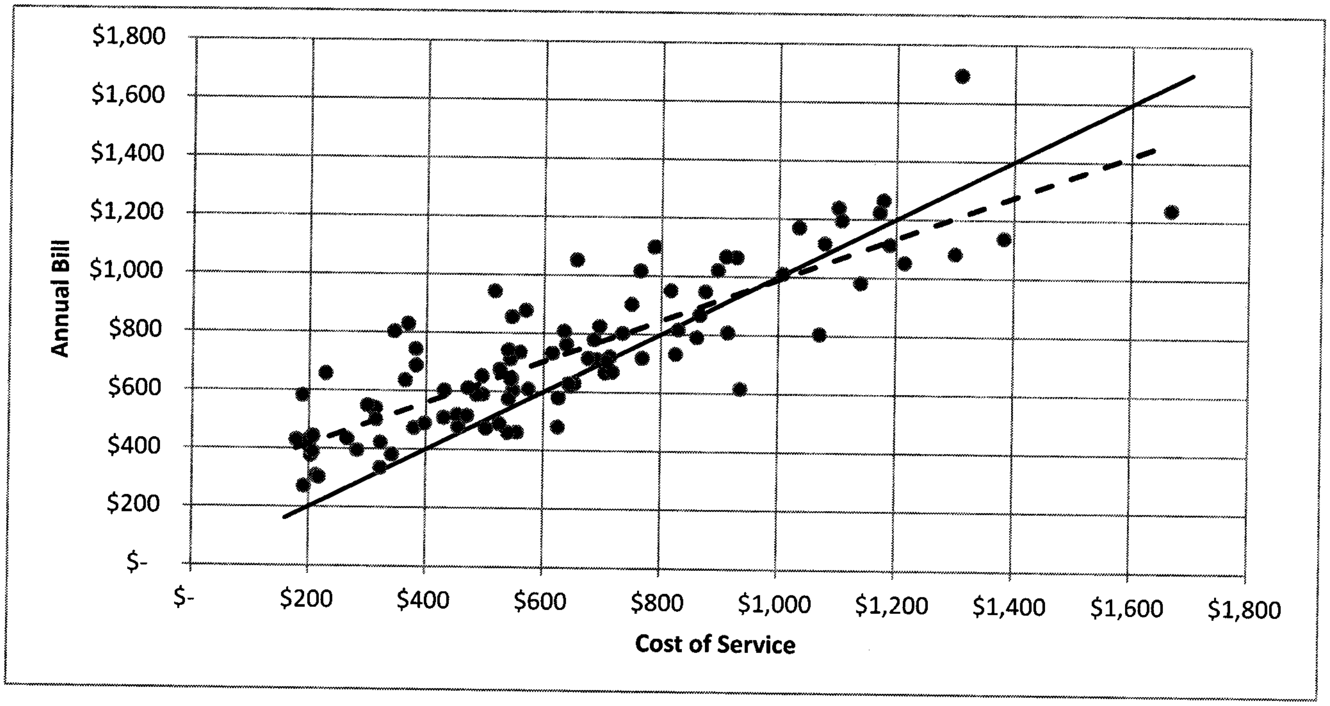
Slope	0.846	N	100	Range		47% to 95%
Intercept	114.490	Avg. Diff.	22%	Tot. Rev.	$	64,904
R-square	0.797	% > Cost	54	Tot. Cost	$	63,175



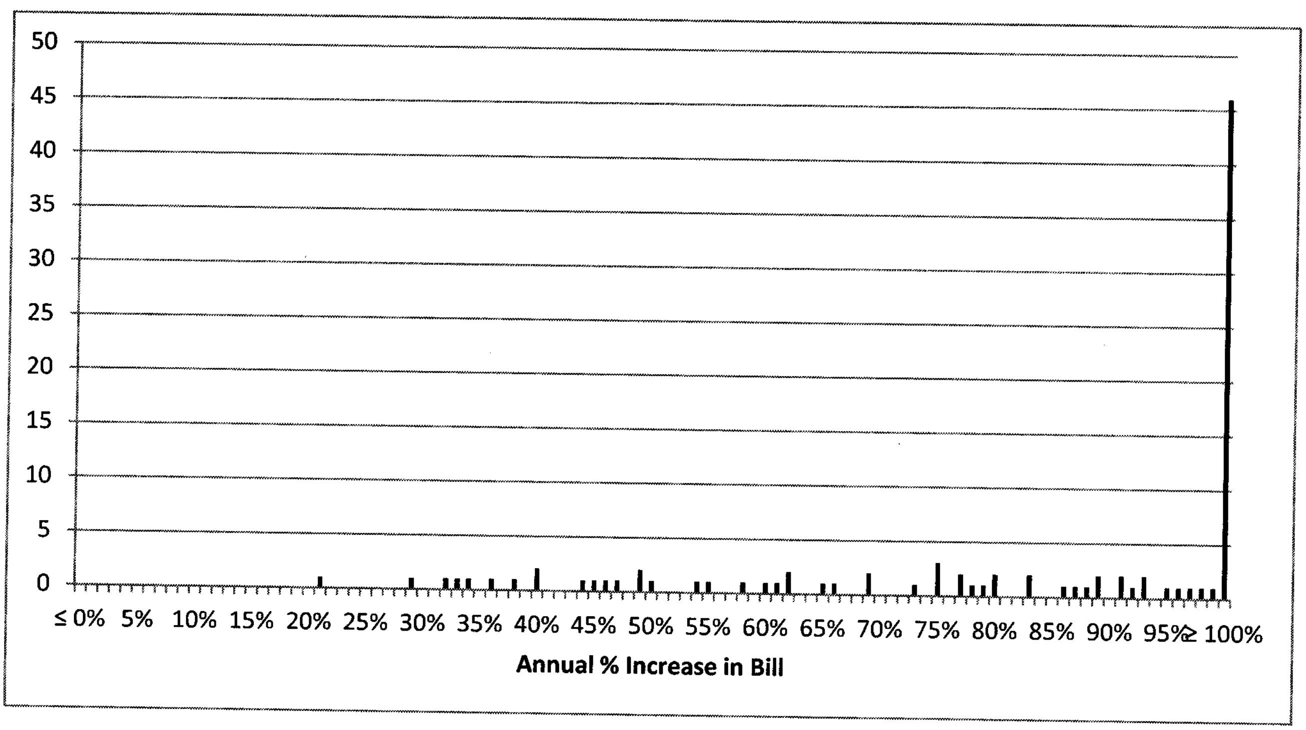
UNS Electric Inc.
Arizona Corp. Comm'n Docket No. E-04204A-15-0142

Exhibit SJR-5

Sample of 100 Residential Customers
Comparison of Cost of Service and UNS Originally Proposed Demand Distribution Bill



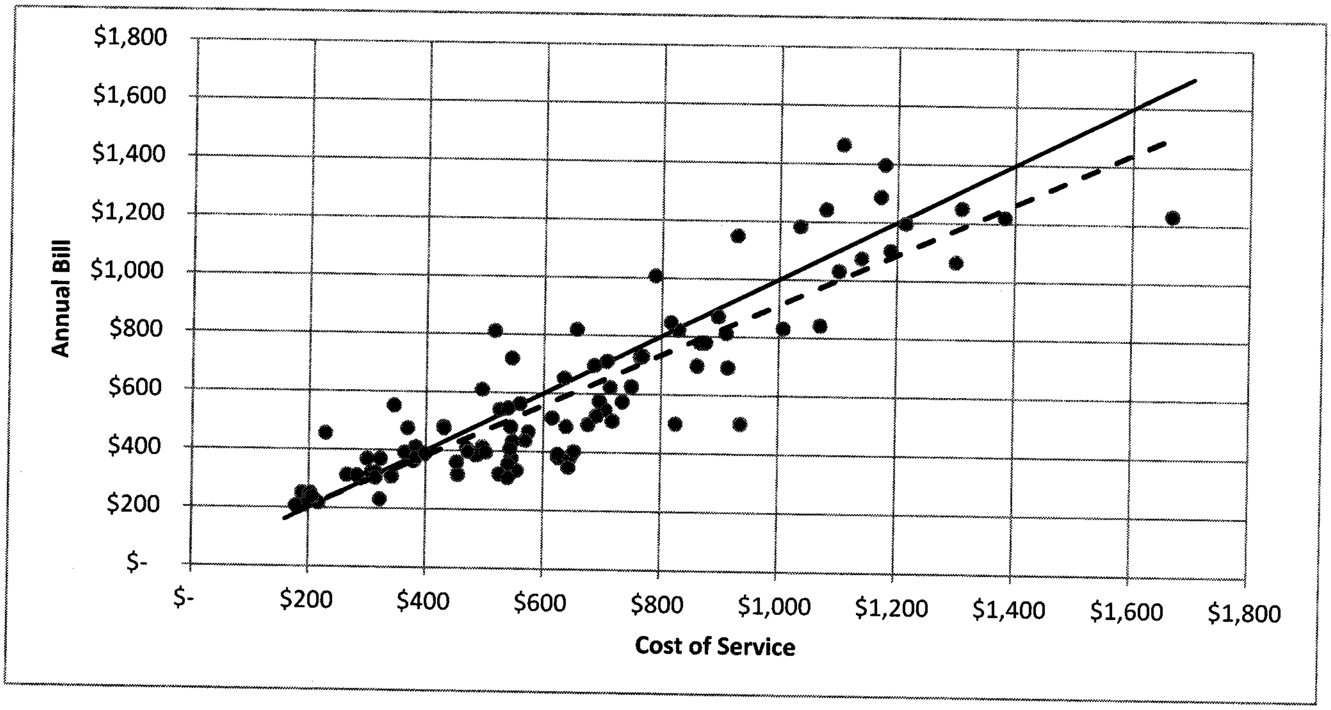
Slope	0.717	N	100	Range		21% to 257%
Intercept	273.979	Avg. Diff.	35%	Tot. Rev.	$	72,685
R-square	0.725	% > Cost	75	Tot. Cost	$	63,175



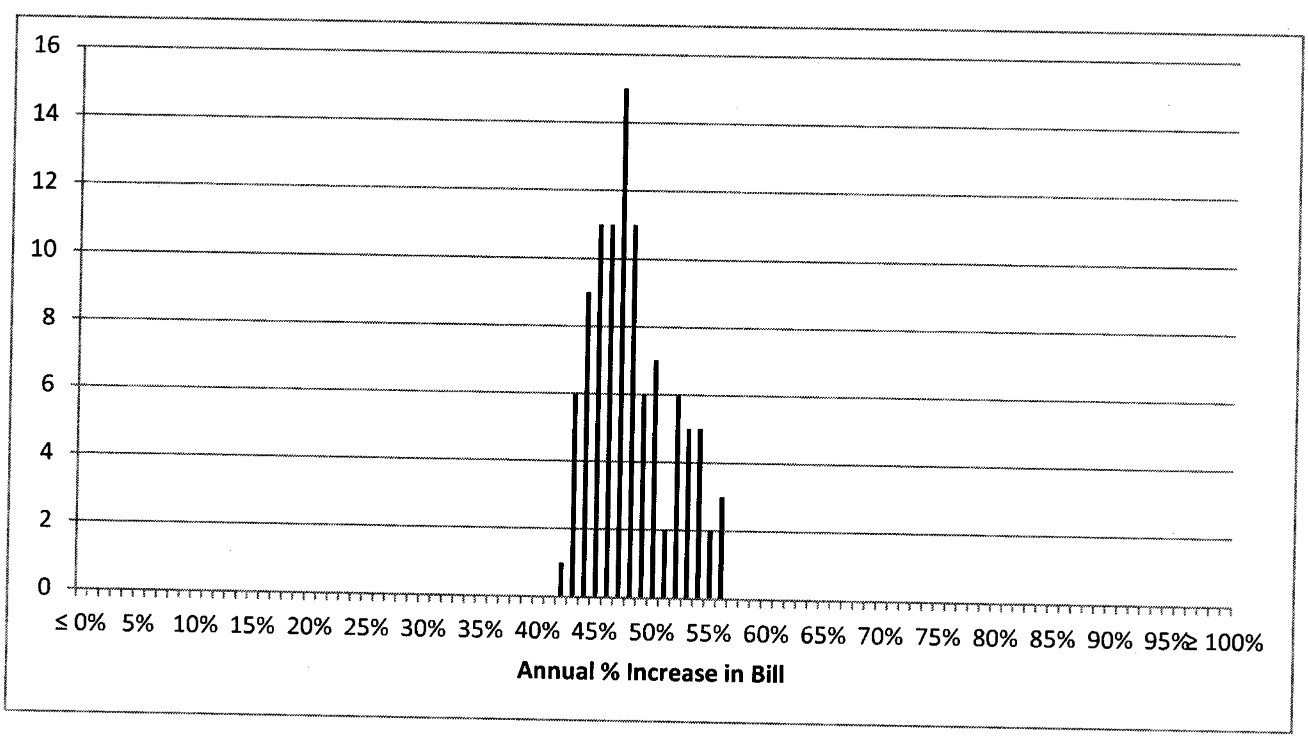
UNS Electric Inc.
Arizona Corp. Comm'n Docket No. E-04204A-15-0142

Exhibit SJR-6

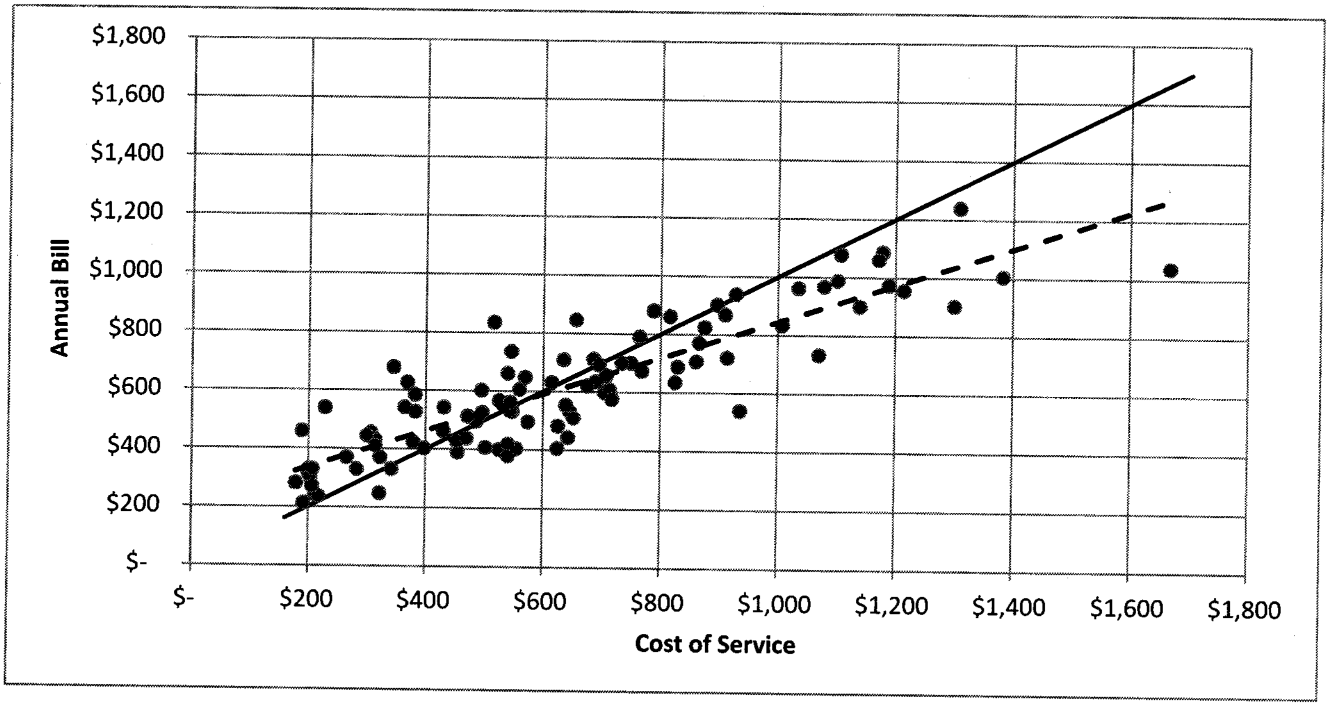
Sample of 100 Residential Customers
Comparison of Cost of Service and UNS Rebuttal Proposed Transition Distribution Bill



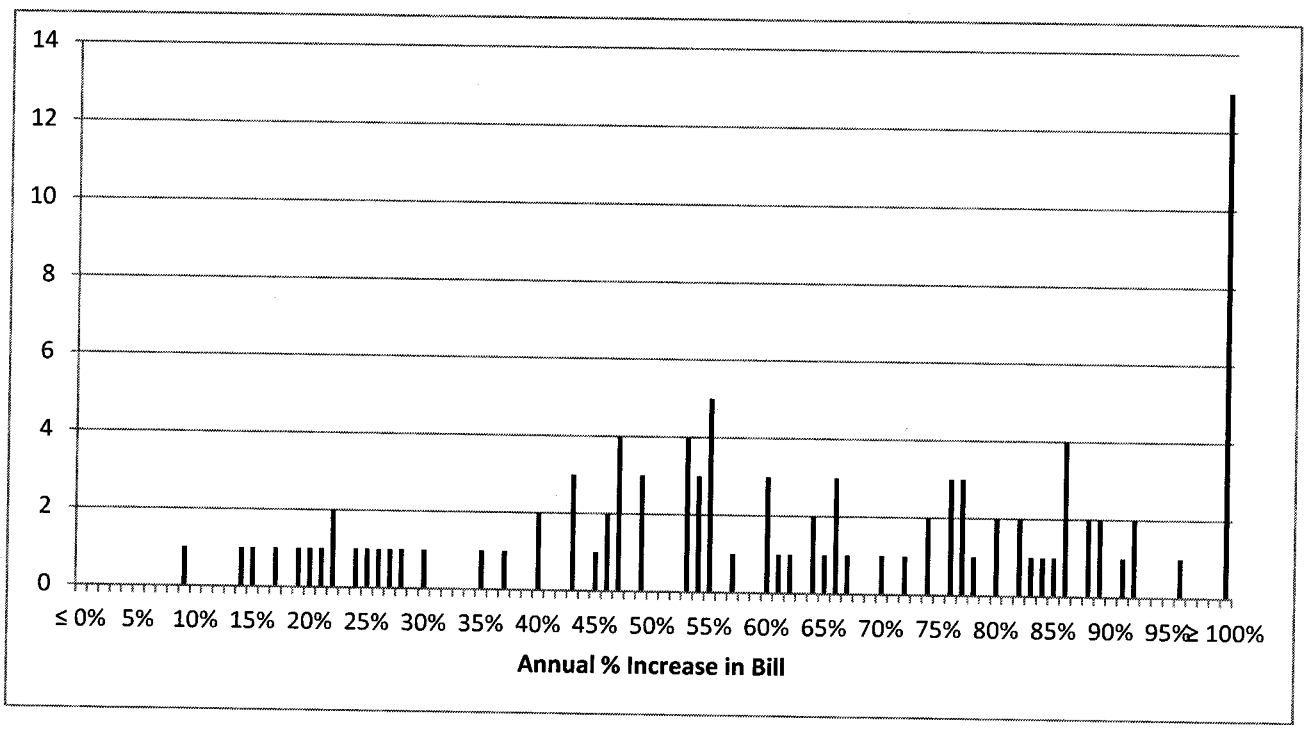
Slope	0.881	N	100	Range		42% to 56%
Intercept	30.202	Avg. Diff.	19%	Tot. Rev.	$	58,692
R-square	0.797	% > Cost	41	Tot. Cost	$	63,175



Sample of 100 Residential Customers
Comparison of Cost of Service and UNS Rebuttal Proposed Demand Distribution Bill (No Limiter)



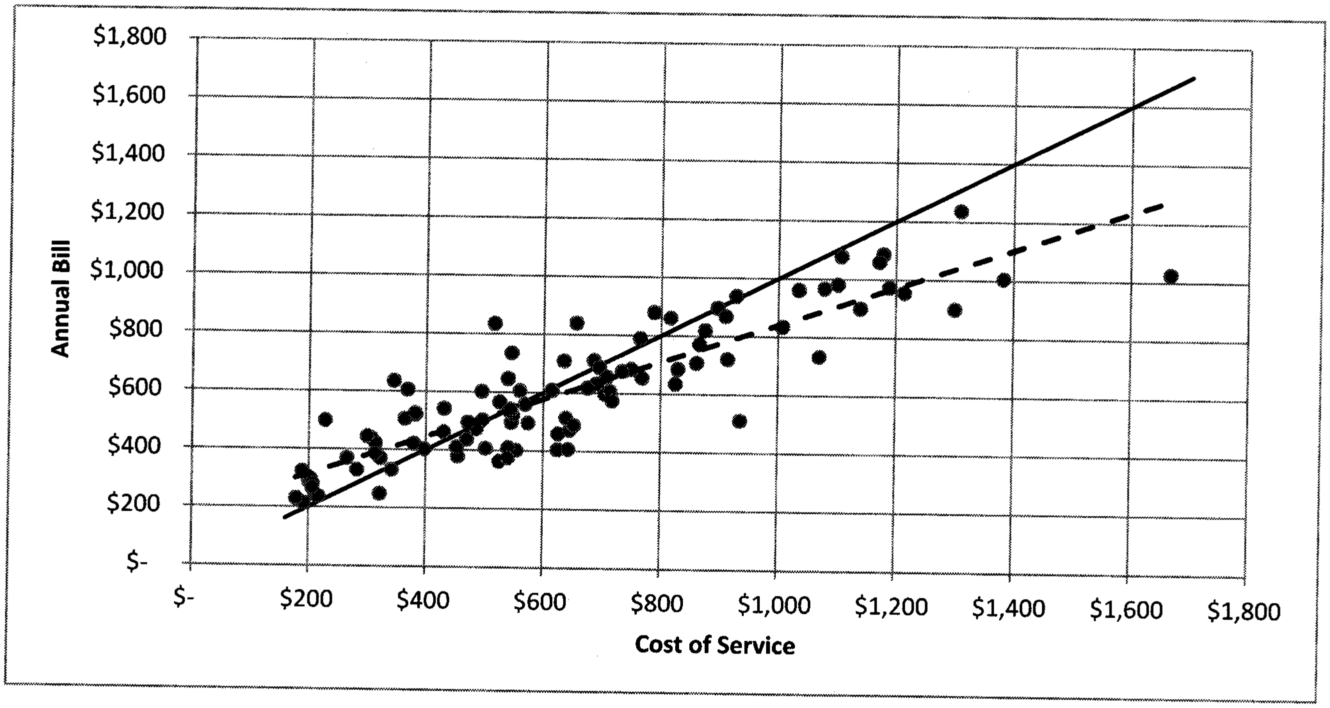
Slope	0.636	N	100	Range		9% to 182%
Intercept	208.738	Avg. Diff.	23%	Tot. Rev.	$	61,078
R-square	0.773	% > Cost	49	Tot. Cost	$	63,175



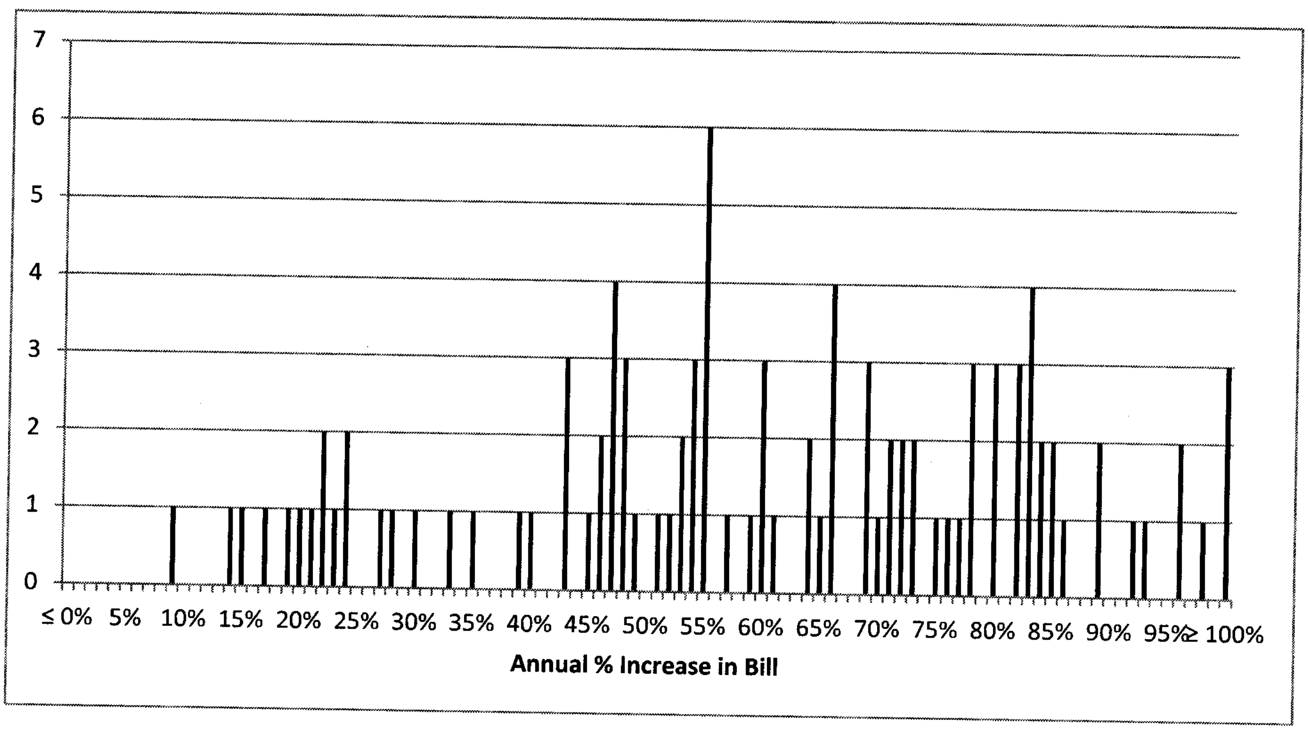
UNS Electric Inc.
Arizona Corp. Comm'n Docket No. E-04204A-15-0142

Exhibit SJR-8

Sample of 100 Residential Customers
Comparison of Cost of Service and UNS Rebuttal Proposed Demand Distribution Bill (15% L.F. Limit)



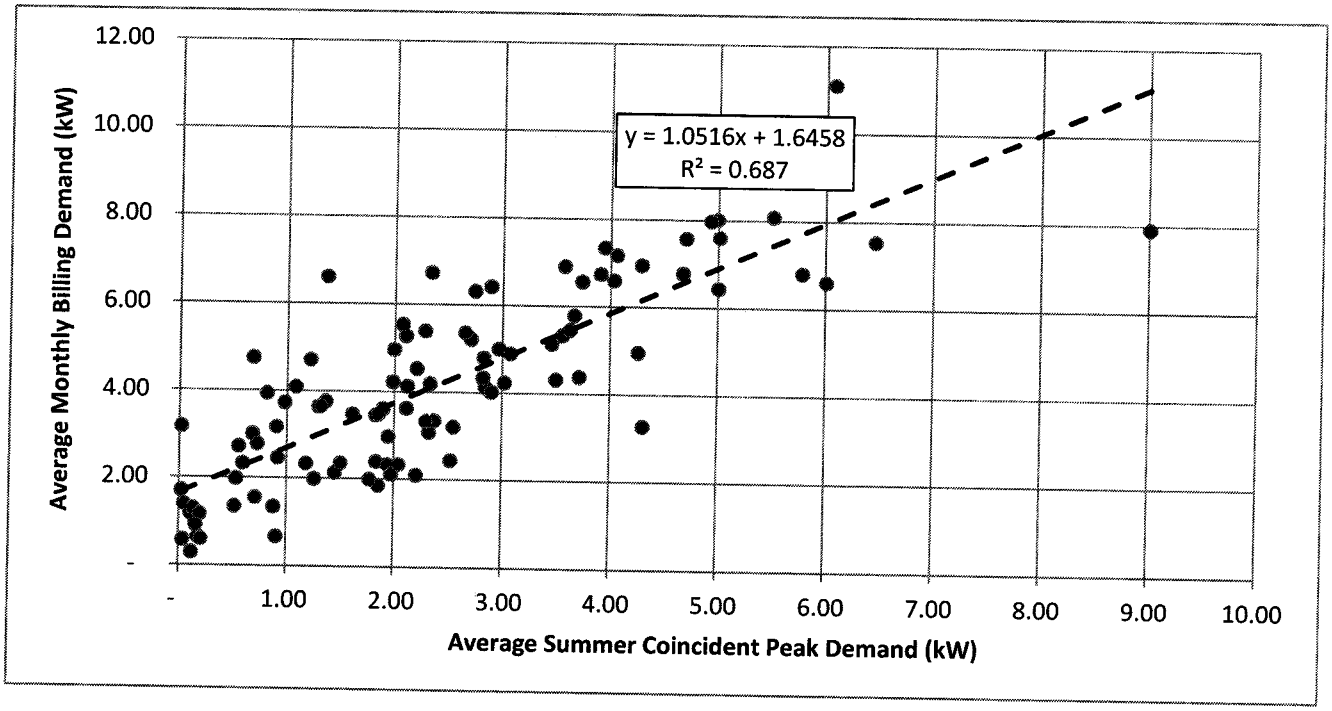
Slope	0.657	N	100	Range		9% to 113%
Intercept	183.234	Avg. Diff.	21%	Tot. Rev.	$	59,847
R-square	0.785	% > Cost	44	Tot. Cost	$	63,175



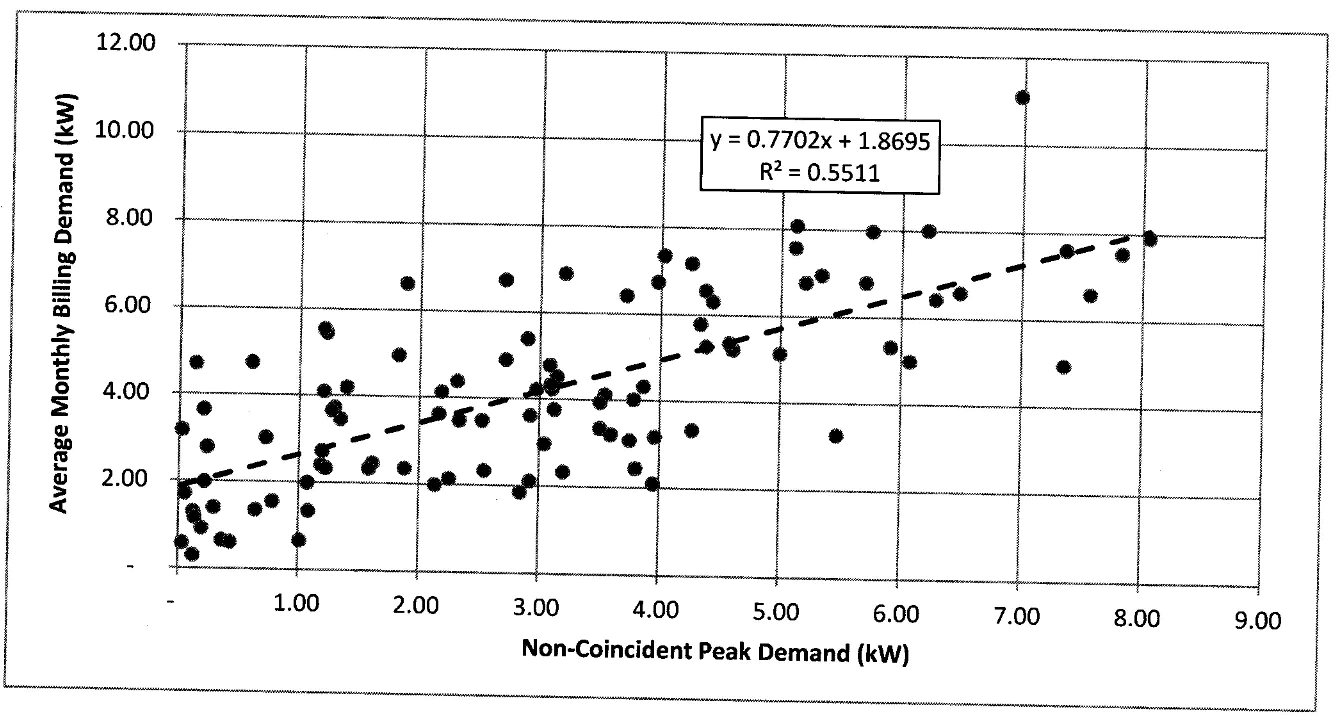
UNS Electric Inc.
Arizona Corp. Comm'n Docket No. E-04204A-15-0142

Exhibit SJR-9

Sample of 100 Residential Customers
Comparison of Summer Coincident Peak Demand and Monthly Billing Demand (With 15% L.F. Limit)

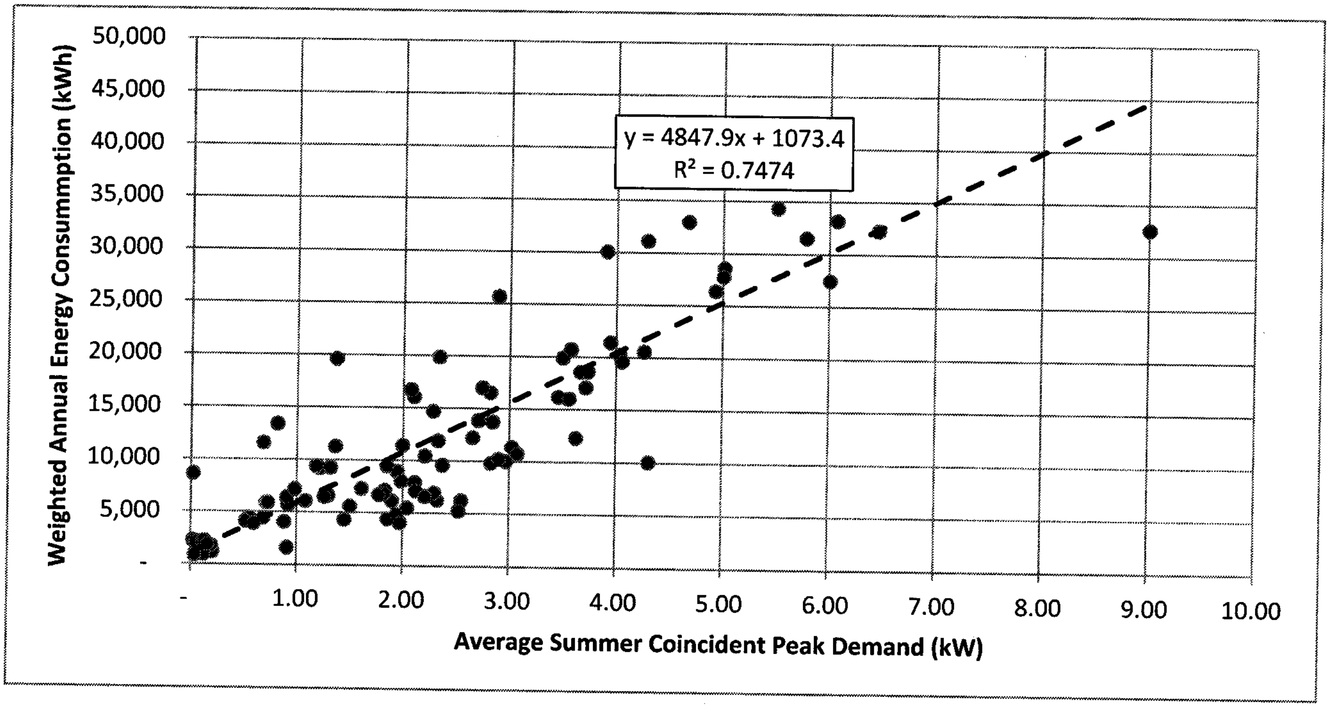


Comparison of Non-Coincident Peak Demand and Monthly Billing Demand (With 15% L.F. Limit)



Sample of 100 Residential Customers

Comparison of Summer Coincident Peak Demand and Annual Energy Consumption (Weighted)



Comparison of Non-Coincident Peak Demand and Annual Energy Consumption (Weighted)

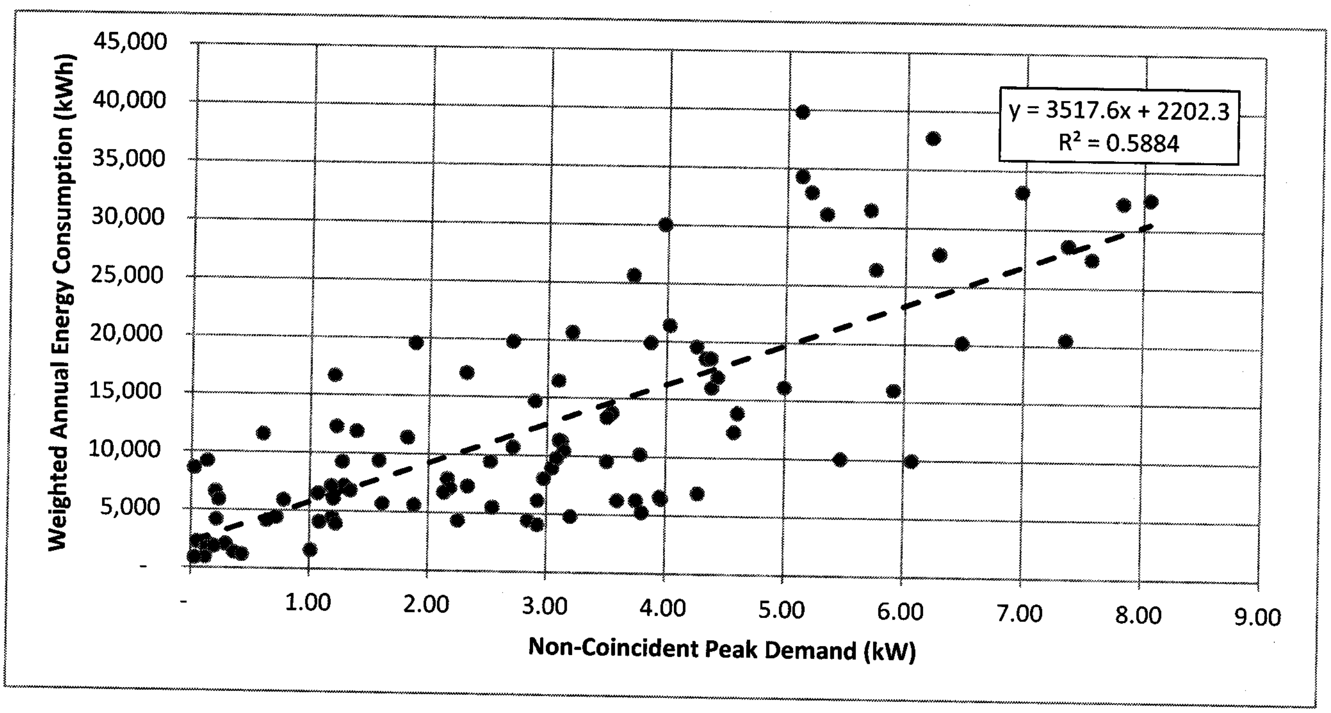


EXHIBIT AURA-7 admitted

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

RATE DESIGN TESTIMONY
OF
THOMAS ALSTON
ON BEHALF OF
ARIZONA UTILITY RATEPAYER ALLIANCE
DECEMBER 9, 2015

I INTRODUCTION

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND TELEPHONE NUMBER.

A. My name is Thomas Alston. My business address is 5521 E Cholla St. Scottsdale, AZ 85254, and my phone number is 602-524-9978.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS MATTER?

A. I am testifying on behalf of the Arizona Utility Ratepayer Alliance ("AURA").

Q. PLEASE SUMMARIZE YOUR EDUCATION AND WORK EXPERIENCE.

A. I hold a BA from the University of Arizona and an MBA from the Thunderbird School of Global Management. Most recently, I was the energy policy advisor for the Mayor of Tucson. Before that, I was a congressional legislative assistant focusing on energy issues for Southern Arizona's Congresswoman Gabriele Giffords and Congressman Ron Barber.

I have also served as the vice-president of the Arizona Solar Industries Association (AriSEIA) and the Arizona state lead for the Solar Alliance.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. No. However, I have participated in many open dockets before the Arizona Corporation Commission.

II PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS MATTER?

A. As discussed by Mr. Quinn in his testimony, AURA has serious concerns about several aspects of the 2015 UNS Electric Inc. ("UNSE") rate-case Application.

III RATE DESIGN TESTIMONY

Q. WHAT ASPECTS OF THE UNS ELECTRIC APPLICATION WILL YOU DISCUSS?

A. I will address the issues, other than those associated with EDR and EE, identified in Mr. Quinn's testimony.

Q. WHY IS FURTHER STUDY OF CROSS-SUBSIDIZATION WARRANTED?

A. In the UNS filing, DG customers are singled out as a significant source of under-recovery of fixed costs despite the statistic in the UNS filing indicating that 70% of their residential customers do not cover associated fixed charges. In 2015, UNS residential customers installed 229 DG systems for a total of 404 systems since 2012.[1] This represents under a half of one percent of the Company's 81,000 residential customers. Yet, two of the proposed rate design changes apply solely to DG customers. UNS disproportionately focuses on a very small customer class, while ignoring cross-subsidization of the remaining residential customers. UNS does not explain why it would discriminates against DG customers.

A comprehensive comparison of levels of cross-subsidization between different types of customers is necessary. For the Commission to make an informed decision, the financial burden of alleged subsidizations of DG customers must be compared against the burden imposed on other classes by the 70% of the residential customers that UNS identifies as subsidized. An investigation of the cross-subsidization within the residential class is also warranted

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[1] Page "2", Utilities Division Filing November 24, 2015 (E-05204A-15-0233) UNS ELECTRIC, INC. – APPLICATION FOR 2016 REST Plan.

Such subsidized residential groups might include rural customers with subsidized line extensions, owners of vacant properties, summer home owners, and homes owned by seasonal "snowbirds." With the emphasis on volumetric rates, customers such as these are not covering their own share of fixed costs, which means they are being subsidized by other customers. UNS must provide and maintain generation, transmission lines, and distribution lines year-round, but actual energy usage is low. In many such cases, it is likely that these types of customers use fewer kWh per billing period than those utilizing DG, without any off-setting economic and societal benefits.

Because the UNSE proposal for curbing adoption of Distributed Generation relies on the assertion that, "other customer classes are supporting DG customers," any analysis of cost shifts should include all subsidized customer groups, and be conducted in a non-discriminatory, holistic, manner. For each group, the Commission should weigh the costs and benefits of the associated subsidy.

Q. WHY SHOULD THE COMMISSION BE CONCERNED WITH CUSTOMER SUBSIDIES?

A. In its filing, UNSE states:

> First, the Company is experiencing declining usage per customer. This trend, which is the result of many factors, results in significant under-recovery of fixed costs due the current rate structure that is heavily dependent on volumetric rates to recover fixed costs. Second, a significant proportion of UNS Electric's residential and small general service customers have little to no volumetric usage. These customers include everything from seasonal homeowners, vacant structures and net metered rooftop PV systems, all of which seem more prevalent given the characteristics of the UNS Electric service area.[2]

[2] Page 7 Line "14" E-O4204A-15-0142 UNS ELECTRIC, INC. APPLICATION TESTIMONY AND EXHIBITS VOLUME 1 of4

Cross-subsidization of customer classes is systemic throughout UNSE's rate design. Further, UNSE believes that "all customers should pay their fair share of the Company's service costs."[3] Therefore, any claimed DG-related subsidies should not be evaluated in a vacuum, but instead as part of an evaluation of all cross-subsidized customers. Any other approach would be discriminatory.

Q. WHY SHOULD THE BENEFITS OF DG TO THE GRID BE TAKEN INTO ACCOUNT?

A. In the UNSE Filing there is little discussion of the benefits of DG which have been well proven and extensively studied.[4] At the very least, the economic impact of DG should be considered in light of proactive UNS decisions to "play a bigger role in attracting and promoting the growth of businesses in its service territories."[5] Other groups, such as The Alliance for Solar Choice, have made well-reasoned cases for the value of DG. AURA supports a thorough investigation of DG costs and benefits, as part of a larger investigation into the costs and benefits of all customer subsidies.

Q. WHAT WILL HAPPEN TO DISTRIBUTED GENERATION ADOPTION RATES IF UNSE's PROPOSED RATE-DESIGN CHANGES ARE IMPLEMENTED?

A. As stated above, UNSE chooses to ignore the vast majority of its residential customer subsidies, while exclusively focusing on alleged DG subsidies. UNSE's proposed rate-design changes for the DG customer class are so severe and focused that they have the potential to eliminate the economic benefits of installing residential solar systems. The

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[3] Page 13 Line "10" "E-O4204A-15-0142 UNS ELECTRIC, INC. APPLICATION TESTIMONY AND EXHIBITS VOLUME 1 of 4.

[4] Synapse Energy Economics, Inc, "Net Metering in Mississippi: Costs, Benefits and Policy Considerations." Prepared for the Public Service Commission of Mississippi, September 19,2014.

[5] Page "30" Line "1" "E-O4204A-15-0142 UNS ELECTRIC, INC. APPLICATION TESTIMONY AND EXHIBITS VOLUME 1 of 4.

discriminatory combination of new demand charges, higher fixed rates, and the reduction of distributed generation benefits (low net metering rate, monthly credit vs. annual) suggest anti-competitive practices.

Q. TURNING TO ANOTHER SUBJECT, HOW WOULD HIGHER FIXED CHARGES AFFECT LOW-INCOME CUSTOMERS?

A. Higher fixed charges would punish low-income customers who, on an average, use less electricity on a monthly basis. Accordingly, any increases in fixed costs would have a disproportionate effect on low-income customers. Bills would be unpredictable and difficult to understand.

Q. ARE THERE ISSUES WITH SUBJECTING RESIDENTIAL CUSTOMERS TO DEMAND CHARGES?

A. Yes, there are several issues. It is unclear why demand charges are only being applied to DG customers who represent such a small percentage of the total customers. Additionally, more information is needed about how UNSE plans to help residential customers, subject to proposed demand charges, understand and predict their bills. The following questions need to be addressed.

- During what hours, and for how long of a period will peak billing occur?
- Can current UNSE meters provide customers with the information to determine when the peak billing period occurs for each individual customer?

Without this information, managing costs associated with peak billing could be very difficult.

As the American Council for an Energy Efficient Economy points out, adoption of residential demand charges will require utilities to provide customers with "extensive education" and even then, "consumers generally will not understand" how their rates will be calculated.

Q. WHAT IS THE PREFERRED ALTERATIVE TO INCREASING DEMAND CHARGES?

A. Time-of-use pricing structures are far more appropriate mechanisms for residential customers. They are easier to understand and do not negate the benefits of energy-efficiency improvements.

Q. COULD YOU PROVIDE ANY EXAMPLES OF HOW DEMAND CHARGES COULD MAKE RESIDENTIAL BILLS UNPREDICTABLE AND DIFFICULT TO UNDERSTAND?

A. Yes. Demand charges have the potential to make residential bills much less predictable. One can imagine a small business owner outside of Kingman working out of his home. If this business owner has a small solar system and participates in distributed generation, simply doing 15 minutes of welding for a client could skyrocket his demand peak and, coupled with a new 30 dollar a month fixed fee, could cause his bill to soar.

Another scenario is a vacation home owner who has a solar system installed. A large portion of the bill could be based on the two days a month the owner uses the home regardless of how much energy was consumed over the course of a billing cycle.

Q. WOULD TIME-OF-USE RATES BE EASIER TO UNDERSTAND?

A. Yes. These rates send proper price signals to customers, providing incentives to reduce peak consumption. Utilities also benefit by reduced usage during high demand times when the utility must bring less efficient/more expensive generation on line.

In our example of the Kingman resident with a welding business in his home, the customer would know not to use his welding equipment during times when peak time-of-day rates were effective. The vacation homeowner could see the benefit of installing increased storage to offset usage during on-peak times when the house is occupied.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

EXHIBIT AURA-3 admitted

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

SURREBUTTAL TESTIMONY
OF
THOMAS ALSTON
ON BEHALF OF
ARIZONA UTILITY RATEPAYER ALLIANCE
FEBRUARY 23, 2016

I INTRODUCTION

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND TELEPHONE NUMBER.

A. My name is Thomas D. Alston My business address is 5521 E. Cholla St., Scottsdale, AZ 85254, and my phone number is 602-524-9978.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS MATTER?

A. I am testifying on behalf of the Arizona Utility Ratepayer Alliance ("AURA").

Q. ARE YOU THE SAME THOMAS ALSTON WHO PREVIOUSLY SUBMITTED TESTIMONY IN THIS DOCKET?

A. Yes.

Q. ARE DEMAND CHARGES OVERLY CONFUSING?

A. Yes. Demand charges are more difficult to understand than time-of-use charges. Large companies often hire sophisticated consultants to help them effectively manage demand charges. Residential customers do not have access to these resources. Residential demand charges have traditionally favored upper-income home owners with the time, resources, and education to understand complex rate designs and bills. As I discuss later in my testimony, low-income customers may have more difficulty adjusting to a demand-based rate design.

Below, is a typical APS residential bill that includes demand charges. To fully understand this bill, and accordingly how to adjust behavior to minimize charges, a customer would need to know the following:

1. On peak vs off peak per-kWh charges and when peak times occur;
2. What a per-kW demand charge actually is;

3. When the demand charge occurred and what was going on in the house to cause usage to spike;
4. Whether or not peak demand only occurs during on-peak hours;
5. What percentage of the bill can be attributed to per kWh charges vs demand charges (there are several demand charges on this bill that would have to be added together);
6. How to control demand by limiting total usage, for instance, it is intuitive to make sure that lights in a house are turned off when not in use but less intuitive to make sure an AC unit does not kick on while doing laundry; and
7. It is up to the Commission to decide if the answer to these questions can be reasonably derived from bills, such as the one below, by the average residential customer.

Your electricity bill [redacted]
August 12, 2015

Your account number [redacted]

Your service plan: Combined Advantage 7pm - Noon

Meter number: [redacted]
Meter reading cycle: 08

Charges for electricity services

Cost of electricity you used

Customer account charge	$6.90
Delivery service charge	$52.49
Demand charge on-peak - delivery	$50.40
Environmental benefits surcharge	$11.34
Federal environmental improvement surcharge	$0.41
System benefits charge	$11.13
Power supply adjustment*	$3.33
Metering*	$5.39
Meter reading*	$1.80
Billing*	$2.03
Generation of electricity on-peak*	$43.69
Generation of electricity off-peak*	$68.02
Demand charge on-peak - generation*	$100.80
Federal transmission and ancillary services*	$19.49
Federal transmission cost adjustment*	$24.61
Four-Corners adjustment*	$7.35
LFCR adjustor	$5.97
Cost of electricity you used	$415.15

Taxes and fees

Regulatory assessment	$0.97
State sales tax	$23.77
County sales tax	$2.97
City sales tax	$11.46
Franchise fee	$8.32
Cost of electricity with taxes and fees	$462.64

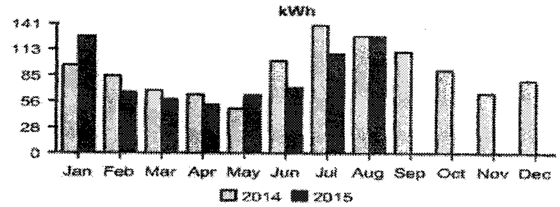
Total charges for electricity services **$462.64**

** These services are currently provided by APS but may be provided by a competitive supplier.*

Amount of electricity you used

Meter reading on Aug 12	43071
Meter reading on Jul 14	39322
Total electricity you used, in kWh	**3749**
On-peak meter reading on Aug 12	6875
On-peak meter reading on Jul 14	6218
On-peak electricity you used, in kWh (Noon to 7 pm Monday to Friday)	**657**
Off-peak electricity you used, in kWh (7 pm to noon weekdays, all day Saturday and Sunday and certain holidays)	**3092**
On-peak demand meter reading	11.2
Your billed on-peak demand in kW	**11.2**

Average daily electricity use per month



Comparing your monthly use

	This month	Last month	This month last year
Billing days	29	32	30
Average outdoor temperature	92°	93°	91°
Your total use in kWh	3749	3513	3884
Percentage of on-peak use	18%	14%	20%
Your billed demand in kW	11.2	7.8	11.7
Your average daily cost	$15.95	$12.15	$15.93

Q. ARE RESIDENTIAL DEMAND CHARGES CONSISTENT WITH BEST PRACTICES FOR HOW SYSTEM CAPACITY COSTS SHOULD BE REFLECTED IN RATES?

A. No, residential customers have a great deal of diversity in their usage, which seldom coincides with the system peak. Below, is a table that shows how three-part vs. two-part rates align with best practices for reflecting capacity costs in rates as outlined in a recent article by Jim Lazar.[1]

Exhibit 3. Garfield and Lovejoy Criteria and Alternative Rate Forms

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

Q. COULD DEMAND CHARGES AFFECT PROPERTY VALUES?

A. Yes. Vacation homes in use one or two days a month could receive dramatically higher bills as a large portion of each bill would be based on the few days a month the property was in use. This could increase electricity costs for a property by hundreds or even

1 Lazar, Jim. "Use Great Caution in Design of Residential Demand Charges." Natural Gas & Electrify, Regulatory Assistance Project February, 2016 P.15 Exhibit 3

thousands of additional dollars per year, putting a damper on the purchase of vacation homes and the associated tourism that comes with it.

Q. WOULD DEMAND CHARGES DISPORPOTIONATELY AFFECT LOW-INCOME CUSTOMERS?

A. Yes, low-income customers are often time-deprived, and as a result do not have the luxury of spreading out usage load so as to avoid raising peak demand. In other words, if one is pressed for time, sometimes the laundry needs to get done at the same time the air conditioning is running. Low-income customers are also less likely to have access to load-limiters, monitoring devices, and energy efficiency improvements that can help wealthier customers limit their demand. AURA shares the concerns on this matter expressed in the testimony submitted on behalf of the Arizona Community Action Association.

Q. ARE MANDATORY RESIDENTIAL DEMAND CHARGES USED BY OTHER UTILITIES?

A. To AURA's knowledge no other utility in the country has implemented mandatory residential demand charges. There is no compelling reason for the Commission to lead the nation into uncharted rate-design testimony. If the Commission were to approve a three-part rate, it would be forcing all residential customers to adopt a rate design that has not been tested in a real-world setting.

AURA has offered compelling reasons why it would be premature to implement mandatory residential demand charges. And the law of unintended consequences ensures that there would likely be other negative consequences that no party can presently foresee.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

EXHIBIT
AURA-4
admitted

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

RATE DESIGN TESTIMONY
OF
PATRICK J. QUINN
ON BEHALF OF
ARIZONA UTILITY RATEPAYER ALLIANCE
DECEMBER 9, 2015

I **INTRODUCTION**

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND TELEPHONE NUMBER.

A. My name is Patrick J. Quinn. My business address is 5521 E. Cholla St., Scottsdale, AZ 85254, and my phone number is (602) 579-1934.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS MATTER?

A. I am testifying on behalf of the Arizona Utility Ratepayer Alliance ("AURA").

Q. PLEASE SUMMARIZE YOUR EDUCATION AND WORK EXPERIENCE.

A. I have a BS in Mathematics and a MBA from the University of South Dakota. Additionally, I have 30-plus years' experience in the Telecommunications Industry and the Consulting business dealing with utility regulation. Most recently, I served as Director of the Residential Utility Consumer Office from January 2013 until February 2015.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. Yes. Overall, I have testified over 50 times before state and federal regulatory commissions on issues including finance, economics, pricing, policy, rate design, and other related areas.

Q. WHAT IS THE ARIZONA UTITLIY RATEPAYER ALLIANCE?

A. The Arizona Utility Ratepayer Alliance was founded in 2015 to advise and represent utility ratepayers on vital issues affecting their pocketbooks. AURA is a nonpolitical, non-partisan organization advocating on behalf of everyday Arizonans to ensure that utilities act responsibly with affordable rates, subject to transparent regulation, while providing sustainable utility services. Independent from the Governor's Office, Legislature, or any other government entity, AURA is unique in its commitment to all Arizona ratepayers, advocating effective and efficient utility oversight. AURA does not advocate any particular alternative energy production or efficiency measures; rather it believes that all such prudent measures should be part of Arizona's energy portfolio, with rates set accordingly but without undue ratepayer subsidies.

II PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS MATTER?

A. AURA has serious concerns about several aspects of the 2015 Unisource Electric, Inc. ("UNSE") rate-case application, which are expressed in this testimony.

III RATE-DESIGN TESTIMONY

Q. WHAT IS RATE DESIGN?

A. Generally speaking, there exist two basic parts of a rate case, revenue-requirement determination and rate design. Methodologies and polices for setting the revenue requirement are well-established and are being addressed by other parties in the docket.

Accordingly, AURA'S concerns lie primarily with aspects of the proposed rate design, which has historically been based on Commission polices. Rate design has traditionally been used by rate regulators to implement their preferences for cross-class subsidization, which is prevalent throughout the various customer classes. Commission general policy is typically to keep rates affordable for residential customers. Rate design usually starts with the determination of what price the residential customer should pay, how much revenue that will generate, and the remaining revenue requirement is then generated by the non-residential customers. There is some variation between residential rates. Again, rate design has historically been based on Commission policies to minimize residential rate increases through subsidies from other rate classes.

Q. WHAT ASPECTS OF THE UNS ELECTRIC APPLICATION PRIMARILY CONCERN AURA?

A. AURA raises the following issues:

- Before the issue of cross subsidies and fixed cost coverage can be appropriately addressed by the Commission, a comprehensive cost study of revenues generated by types of customers is necessary. This will allow the Commission to make informed decisions on new polices about proposed rate design changes for any customer class.
- UNS proposes significant and burdensome increases in base charges for residential and small business customers and the introduction of demand charges for Distributed Generation ("DG") customers.
- A valuation of the benefits of DG should be included in any assessment of the costs of DG.
- The changes in rate design for the DG customer class are overly punitive and anti-competition. Modifications include an increase in the basic charge, a new demand charge, a reduction in net-metering payments and a change in credit distribution from annually to monthly.
- Increased fixed costs for residential customers punish low-income customers.
- Demand charges are likely to be extremely confusing for many customers, especially elderly residential customers.
- The proposed Economic Development Rate ("EDR") is directly counter to UNS' stated goal of setting rates based on the cost of providing service to each customer group. A decrease in revenues from one class of customers has the same effect on

other customers as a cost shift. Other customers have to cover the loss and it is unclear who covers these decreased revenues.

- Robust funding for energy-efficiency programs should be achieved through a more stable cost recovery in base rates.

Q. WHAT ISSUES OF CONCERN WILL YOU DISCUSS?

A. I will discuss the proposed EDR and Energy Efficiency funding. AURA witness Tom Alston will address the remaining issues.

Q. WHAT CONCERNS DOES AURA HAVE ABOUT UNS' PROPOSED ECONOMIC DEVELOPMENT RATE?

A. At the same time that UNSE proposes significant rate increases for DG customers, UNSE's proposes an EDR with lower prices for large businesses users meeting certain requirements. To be fair, UNSE should not base the EDR cost shift on alleged economic development benefits, while taking the opposite view concerning DG despite the proven and well-studied economic development benefits associated with adoption of DG.

The lower revenue received from these EDR customers has the same effect as the cost shifts caused by certain other customers. Less of the total revenue requirement will be covered by EDR customers than if they paid the normal rate. This means non-EDR customers will have to make up additional lost revenue. It is unclear which customers will be subject to increased prices to produce this missing revenue. Will those customers see price decreases as the EDR rates phase out?

While on the surface EDR seems like a good idea there remain too many unanswered questions, particularly when it proposes to increase costs to DG customers.

There are many lessons to be learned from the Arizona Public Service Trial AG1 rate about implementation, cost recovery and termination. Because of the cap on megawatts that qualify for both AG1 and EDR programs, some qualified customers will be left out once the cap is reached. APS had a lottery and only 8 of 13 qualified companies received the AG1 rate. How will UNS handle this issue. APS absorbed lost revenues from their original trial but wants full recovery if the trial is extended beyond original termination date. It was extended and so, like EDR, which customers are going to cover the lost revenues? Unlike APS, the EDR rates increase to full rates over time. Will the customers covering the lost revenues see rate reductions as the EDR rates increase over time? These are some of the major issues that arose in the APS AG1 trial and should be addressed.

These questions need to be resolved before the EDR is approved.

Q. WHAT IS AURA'S POSITION ON ENERGY EFFICIENCY?

A. AURA agrees with most of what the Southwest Energy Efficiency Project ("SWEEP") stated in their filing to this docket. We support Energy Efficiency ("EE") as a low-cost energy resource and recognize the need for both an increase in funding and a more streamlined method of approving the Integrated Resource Plan. To ensure continued funding of EE programs a more stable cost-recovery mechanism than is currently utilized must be approved. AURA believes that SWEEP's proposal to fund EE in base rates is a viable alternative.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

EXHIBIT
AURA-5
admitted

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

SURREBUTTAL TESTIMONY
OF
PATRICK J. QUINN
ON BEHALF OF
ARIZONA UTILITY RATEPAYER ALLIANCE
FEBRUARY 23, 2016

I INTRODUCTION

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND TELEPHONE NUMBER.

A. My name is Patrick J. Quinn. My business address is 5521 E. Cholla St., Scottsdale, AZ 85254, and my phone number is (602) 579-1934.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS MATTER?

A. I am testifying on behalf of the Arizona Utility Ratepayer Alliance ("AURA").

Q. ARE YOU THE SAME PATRICK J. QUINN WHO PREVIOUSLY SUBMITTED TESTIMONY IN THIS DOCKET?

A. Yes

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. AURA proposes modifications to the rate design proposals from Unisource Electric, Inc. ("UNSE") and the Arizona Corporation Commission's Utility Division Staff's ("Staff").

Specifically, the Commission should approve UNSE's rebuttal two-part rate (termed the "transition" rate) as the permanent residential rate design, not UNSE's rebuttal three-part rate. However, the residential customer charge should be lowered from $15.00 to RUCO's proposed $12.26, with any reduction in revenues spread over the usage charges once a revenue requirement is approved. Additionally, as Staff suggests, there should be no changes to net metering until the generic docket on the cost and value of solar is completed.

Q. WHY DOES AURA SUPPORT THE UNSE REBUTTAL TWO-PART RATE?

The rebuttal two-part rate:

- Avoids the numerous problems associated with a mandatory demand charge;

- Is fairer to customers and consistent with best-practice rate design principles that include understandability, ease of administration, nondiscrimination, revenue stability, and gradualism; and
- Is superior to a three-part rate in aligning costs of service with cost recovery.

Q. WHY DOES AURA OPPOSE THE UNSE REBUTTAL THREE-PART RATE?

First, and most importantly, the testimony of nationally-recognized rate design expert Scott Rubin demonstrates that facts do not support UNSE's assertion that its proposed three-part rate design recovers costs more equitably, promotes fairness, and reduces intra-class subsidization. In fact, precisely the opposite is true. Compared to UNSE's rebuttal two-part rate design proposal, its proposed rebuttal three-part rate design is less equitable, unfair to lower-cost customers, and increases intra-class subsidization.

Q. ARE THERE OTHER REASONS WHY THE UNSE REBUTTAL THREE-PART RATE SHOULD NOT BE APPROVED?

Yes. A significant reason that UNSE's three-part rate design does not work is that over 80 percent of UNSE residential demand costs are based on summer peaks and the relationship between billing demand and summer peak demand is relatively weak. This is a common issue with residential demand charges. As a recent article by Jim Lazar published in *Natural Gas and Electricity* points out, "Residential consumers have much more diversity in their usage, with individual customer maximum demands seldom coinciding with the system peak."[1]

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[1] Lazar, Jim. "Use Great Caution in Design of Residential Demand Charges." *Natural Gas & Electrify, Regulatory Assistance Project* February, 2016 P.15.

Q. ARE THERE ANY OTHER REASONS WHY THE UNSE REBUTTAL THREE-PART RATE SHOULD NOT BE APPROVED?

Yes. Tom Alston discusses issues inherent to mandatory demand charges as they have currently been proposed. Other downsides of these charges are that they:

- May be overly confusing and limit residential customers' ability to control their bills;
- May negatively affect property values;
- May overly burden low and fixed income customers;
- Are untested in other service territories; and
- Are inconsistent with accepted best practices.

Q. DOES AURA OPPOSE VOLUNTARY DEMAND CHARGES?

A. No, AURA supports customer choice and would not oppose properly designed voluntary demand charges.

Q. WOULD ADOPTING UNSE'S AND STAFF'S RECOMMENDED RATE DESIGNS SUPPORT ECONOMIC DEVELOPMENT?

A. No. UNSE has expressed a desire to "play a bigger role in attracting and promoting the growth of businesses in its service territories," and has proposed an Economic Development Rate ("EDR") to help promote economic development. A proven and well-studied[2] way to support this development is to promote Distributed Generation ("DG"). Unfortunately, demand charges have the effect of greatly reducing the economic benefits

[2] Solar Jobs Census, *Energy Foundation Arizona* 2014
http://www.thesolarfoundation.org/wp-content/uploads/2015/02/Arizona-Solar-Jobs-Census-2014.pdf

Distributed Generation Standard Contracts and Renewable Energy Fund Jobs, Economic and Environmental Impact Study, *Brattle Group* April 30, 2014
http://www.energy.ri.gov/documents/DG/RI%20Brattle%20DG-REF%20Study.pdf

The Value of Distributed Solar Electric Generation to New Jersey and Pennsylvania *MSEIA* November, 2012
http://mseia.net/site/wp-content/uploads/2012/05/MSEIA-Final-Benefits-of-Solar-Report-2012-11-01.pdf

of Distributed DG systems. Under the proposed three-part rate, a DG system, such as roof-top solar, would not typically be producing energy concurrently with the demand assessment time period (although it may coincide with the system peak) and thus reduce demand charges only slightly if at all. If economic development is truly a concern then DG should be supported through the adoption of the UNS rebuttal two-part rate.

The Alliance for Solar Choice has made a well-reasoned case for the value of DG. AURA supports a thorough investigation of DG costs and benefits, as part of a larger investigation into the costs and benefits of all customer subsidies.

Q. SHOULD ANY RATE DESIGN CHANGES THAT INCLUDE DEMAND CHARGES BE POSTPONED UNTIL THE NEXT RATE CASE?

A. Yes, Mr. Rubin demonstrates that UNSE's three-part rate design would actually further shift costs to low-usage customers, so for that reason alone this proposal should be rejected in this case. Further, because of the radical nature of the rate-designs proposed, the short time for full consideration, and the lack of full participation from the communities most affected (due to a short comment period), any significant rate-design changes should be postponed until UNSE's next rate case.

Q. IF THE COMMISSION APROVES A THREE PART RATE, SHOULD IMPLEMENTATION BE DELAYED FOR STUDY?

A. Should the Commission authorize a three-part rate instead of the rebuttal two-part rate, UNSE should only make the new rate available to customers on a voluntary basis to allow for education and data collection.

The included testimony of Scott Rubin conclusively demonstrates that the three-part rate, as currently proposed, is ineffective in recovering demand-related costs and any revision should be based on data from customers participating in a pilot study.

Q. WHAT IS AURA'S POSITION ON ENERGY EFFICIENCY?

AURA agrees with most of what the Southwest Energy Efficiency Project ("SWEEP") states in its testimony. We support Energy Efficiency as a low-cost energy resource and recognize a need for an increase in funding and a more streamlined method of approving the Integrated Resource Plan. To insure continued funding of EE programs a more stable cost recovery mechanism than is currently utilized must be approved. SWEEP's proposal to fund EE in base rates is a viable alternative.

Q. SHOULD ANY PROPOSED RATE BE BASED ON ACTUAL CUSTOMER DATA?

A. Yes. Actual customer data must be analyzed to evaluate the impact of different rate design options. Rate impacts have the potential to surprise in some analyses, for example, essentially no improvement in cost relationships were achieved after a move to rates based on billing demand. The goal is to Remember One Thing: Customers. UNS must obtain real data from customers and analyze the actual bill impacts (and relationship to cost) of different rates design options. Data and experience from other jurisdictions should also be evaluated.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

UNS ELECTRIC INC.'S RESPONSE TO TASC'S SIXTH SET OF DATA REQUESTS
REGARDING THE 2015 UNS ELECTRIC RATE CASE
DOCKET NO. E-04204A-15-0142
February 12, 2016

TASC 6.1

Concerning monthly bills issued to residential customers in calendar year 2015:

a. How many monthly bills did UNSE issue to residential customers and how many residential customers did UNSE have on January 1, 2015 and on December 31, 2015?

b. What was the amount of the average monthly bill issued to residential customers?

c. How many residential customers' monthly bills fit into the following categories for 2015:

1. monthly average from $0.00 to $20.00 per month
2. monthly average from $20.01 to $40.00 per month
3. monthly average from $40.01 to $60.00 per month
4. monthly average from $60.01 to $80.00 per month
5. monthly average from $80.01 to $100.00 per month
6. monthly average from $100.01 to $120.00 per month
7. monthly average from $120.01 to $140.00 per month
8. monthly average from $140.01 to $160.00 per month
9. monthly average from $160.01 to $180.00 per month
10. monthly average from 180.01 to $200.00 per month
11. monthly average from $200.01 to $220.00 per month
12. monthly average in excess of$220.00 per month

d. How many monthly bills did UNSE issue to residential customers that also utilize net metering and how many customers did UNSE have fitting this description on January 1, 2015 and on December 31, 2015?

e. What was the average monthly bill for residential customers that also utilize net metering?

f. Perform the same analysis requested in question (C), above, analyzing only residential customers that also utilize net metering.

g. Of the monthly bills to residential solar customers identified in response to (D), how many of those bills were for an amount greater than or equal to UNSE's alleged cost to serve its residential class of customers?

h. Of the monthly bills to all residential customers identified in response to (A), how many of those were for an amount greater than or equal to UNSE's alleged cost to serve its residential class of customers?

i. How many kWhs of left over year end net metering credits did UNSE acquire from its residential customers and what was the per kWh price paid for those credits?

j. What was the average retail rate charged for all kWh of electricity sold to the residential class in 2015?

RESPONSE:

The Company had initially objected to this data request for several reasons including the request to use 2015 which is outside of the 2014 test year. TASC subsequently asked if we could answer the data request for 2014. Accordingly, this response is based on test year data (calendar year 2014) for residential rate RES-01.

a. In January 2014, there were 78,350 bills and 74,035 customers in RES-01. In December 2014, there were 75,682 bills and 74,665 customers in RES-01. Data for monthly bills and customers during the test year is available in the RES-01 tab of the filed workpaper 2015 UNSE Revenue Proof - Public Version.xlsx provided in response to UDR 1.001.

b. During the test year, the average kWh per bill in RES-01 was 830 kWh. As shown in Schedule H-4, this calculates to a billed amount of approximately $33, excluding fuel, taxes and assessments.

c. The Company objects on the basis that it is not obligated to create new documents. However, without waiver of objection, the bill count by kWh range for the test year is provided in Schedule H-5, and detailed kWh data for all RES-01 bills are included in the filed workpaper UNSE BF Data RES.xlsx provided in response to UDR 1.001. The requested information can be obtained using this data and the tariff rates posted on the Company's website.

d. In January 2014, there were 1,074 net metering bills and 1,042 net metering customers in RES-01. In December 2014, there were 1,609 net metering bills and 1,328 net metering customers in RES-01. Monthly bill count data for RES-01 net metering customers was also provided in response to TASC 1.23 via UDR 2.10.

e. The average kWh per bill for RES-01 net metering customers during the test year was 330 kWh. Using the same method as the calculations in Schedule H-4, this calculates to a billed amount of approximately $17, excluding fuel, taxes and assessments.

f. The Company objects on the basis that it is not obligated to create new documents. However, without waiver of objection, for bill count by kWh range, please refer to the file UNSE 2014 Bill Freq with NEM Breakouts v2.xlsx submitted with the Company's Rebuttal Testimony workpapers in UDR 3.1. Detailed kWh data for all RES-01 bills (including net metering customers) are included in the filed workpaper UNSE BF Data RES.xlsx provided in UDR 1.001. The requested information can be obtained using this data and the tariff rates posted on the Company's website.

g. The cost to serve the residential class was calculated in the last rate case to be $45. To recover this amount from the current Basic Service Charge and energy delivery charges, the billed usage under RES-01 must be at least 1,174 kWh without the Transmission Cost Adjustor ("TCA"), and at least 1,140 kWh with the initial TCA. In January 2014, there were 126 net metering RES-01 bills over 1,000 kWh, or approximately 12% of the net metering bills. In December 2014, there were 256 net metering RES-01 bills over 1,000 kWh, or approximately 16% of the net metering bills. Detailed kWh data for all RES-01 bills are included in the filed workpaper UNSE BF Data RES.xlsx provided in UDR 1.001, and monthly bill count data has also been provided in the response to TASC 1.23 via UDR 2.10.

h. The cost to serve the residential class was calculated in the last rate case to be $45. To recover this amount from the current Basic Service Charge and energy delivery charges, the billed usage under RES-01 must be at least 1,174 kWh without the Transmission Cost Adjustor ("TCA"), and at least 1,140 kWh with the initial TCA. In January 2014, there were 25,862 RES-01 bills over 1,000 kWh, or approximately 33% of all bills. Of these bills, 99.5% (25,736) were from full requirements customers. In December 2014, there were 18,621 RES-01 bills over 1,000 kWh, or approximately 25% of all bills. Of these bills, 98.6% (18,365) were from full requirements customers. Detailed kWh data for all RES-01 bills are included in the filed workpaper UNSE BF Data RES.xlsx provided in UDR 1.001, and monthly bill count data has also been provided in the response to TASC 1.23 via UDR 2.10.

i. The UNS Electric MCCCG rate is approved and effective June of each year. The rate for the period January through May was $0.036653 and thereafter $0.036970. The residential monthly detail of excess kWh and revenue credits are shown in the table below.

Month	Monthly Credits	kWh Excess Amoun
January	$4.03	110
February	$190.92	5,209
March	$73.75	2,012
April	$325.44	8,879
May	$415.29	11,330
June	$37.98	1,032
July	$175.05	4,735
August	$134.42	3,636
September	$216.61	5,859
October	$52,808.13	1,428,406
November	$7.84	212
December	$16.68	451
Grand Total	**$54,406.14**	**1,471,871**

j. Excluding the Basic Service Charge, the average retail rate per kWh charged during the test year was approximately $0.09/kWh for RES-01. This amount is calculated as the total revenue excluding the Basic Service Charge divided by the total kWh, as reported in the test year revenue proof (2015 UNSE Revenue Proof-Public-R.xlsx provided in UDR 3.1).

RESPONDENT:

Brenda Pries / Greg Strang / Anne Trostle

WITNESS:

Craig Jones

UNS ELECTRIC INC.'S RESPONSE TO TASC'S FIFTH SET OF DATA REQUESTS
REGARDING THE 2015 UNS ELECTRIC RATE CASE
DOCKET NO. E-04204A-15-0142
December 28, 2015

TASC 5.1

Provide the number of residential customer currently interconnected to UNS's system that utilize net metering.

RESPONSE:

As of December 16, 2015, there were 1,716 residential net metering customers in UNS Electric's system.

RESPONDENT:

Nikole White

WITNESS:

Carmine Tilghman

EXHIBIT
VoteSolar-2
ADMITTED

Center for American Progress

Solar Power to the People: The Rise of Rooftop Solar Among the Middle Class

By Mari Hernandez October 21, 2013

Homeowners across the United States have begun a rooftop solar revolution. Since 2000, more than 1,460 megawatts of residential solar installations have been installed across the country, and more than 80 percent of that capacity was added in the past four years.[1] In 2012 alone, rooftop solar installations reached 488 megawatts, a 62 percent increase over 2011 installations and nearly double the installed capacity added in 2010.[2]

Residential solar photovoltaic, or PV, systems—also referred to as "distributed" or "rooftop solar" in this report—consist of an array of solar panels that are roof or ground mounted to produce electricity that is either fed back into the electric grid—grid connected—or solely used onsite by the residential building—off grid.

The question is: Who is buying up all of those solar power systems? Through our analysis of solar installation data from Arizona, California, and New Jersey, we found that these installations are overwhelmingly occurring in middle-class neighborhoods that have median incomes ranging from $40,000 to $90,000. The areas that experienced the most growth from 2011 to 2012 had median incomes ranging from $40,000 to $50,000 in both Arizona and California and $30,000 to $40,000 in New Jersey. Additionally, the distribution of solar installations in these states aligns closely with the population distribution across income levels.

But many within the electric utility industry have claimed that distributed solar is mainly being adopted by wealthy customers. Concerned by the threat that rooftop solar's rapid growth poses to traditional utility business models, some utility executives have used this claim to support a rising desire within the industry to alter existing solar programs and policies. The idea is that through solar policies such as net metering, middle- and low-income customers who cannot afford to go solar are subsidizing the wealthy customers who can.

In this issue brief, we show that rooftop solar is not just being adopted by the wealthy; it is, in fact, mostly being deployed in neighborhoods where median income ranges from $40,000 to $90,000. In the first section, we present the overall findings from our income analysis of solar installation data from Arizona, California, and New Jersey. We then discuss the implications of those results in the context of the current growth of rooftop solar and the ongoing discussion of solar policies that will affect its future growth.

California, Arizona, and New Jersey are currently leading the nation in solar deployment and therefore offer insights into the way that rooftop solar is being adopted across the country. Although these states are home to varying solar programs and incentives, similarities exist in the way that residential solar installations occur across income levels, with our research showing that the majority of solar power systems are being installed in middle-class neighborhoods.

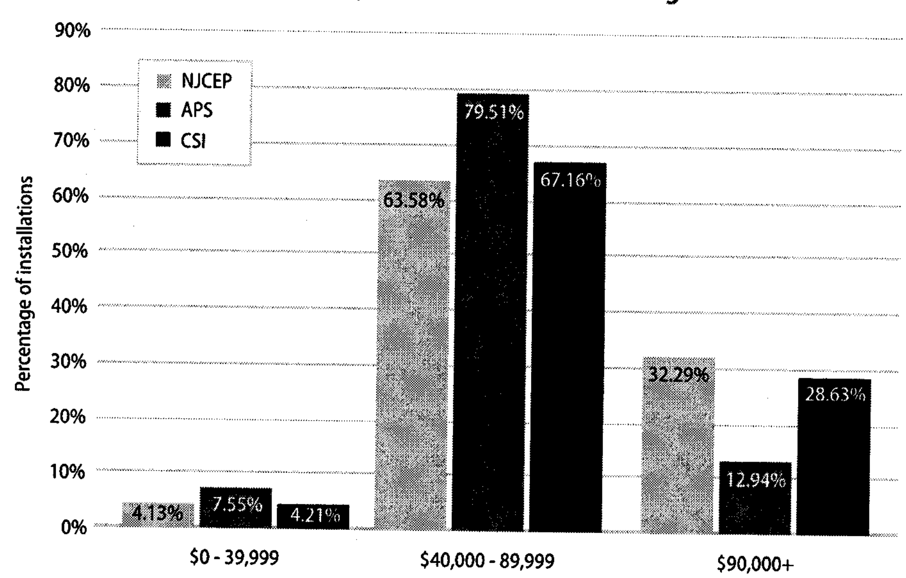
We collected solar installation data contained in the Arizona Public Service, or APS; the California Solar Initiative, or CSI; and New Jersey's Clean Energy Program, or NJCEP, databases to examine the adoption of rooftop solar by income level. These databases contain information on individual installations for which residential and nonresidential customers have applied for solar incentives, such as rebates or renewable energy certificates.

The APS database contains data on installations made under the solar rebate program offered by Arizona Public Service, which is the largest utility in Arizona and provides electric service to most of the state. The CSI database tracks installations made under the California Solar Initiative program, which offers rebates to customers of three investor-owned utilities: Pacific Gas and Electric, Southern California Edison, and San Diego Gas & Electric. The NJCEP database contains data on installations made under any of the following incentive programs offered in New Jersey: Solar Renewable Energy Certificates, the Renewable Energy Incentive Program, and the Customer On-site Renewable Energy Program.

By analyzing the median household income that corresponds with installations from each ZIP code in the three datasets, we found three key similarities. First, they all exhibit a similar installation distribution pattern, in that at least 60 percent of homeowners are installing solar panels in ZIP codes with median incomes ranging from $40,000 to $90,000. In fact, 80 percent of APS installations were for customers in that income range. To demonstrate this, Figure 1 shows the percentage of rooftop solar installations by dataset and income range.

FIGURE 1

Percentage of installations by dataset and income range



Sources: Arizona Goes Solar, "Arizona Public Service (APS): Installations," available at http://arizonagoessolar.org/UtilityIncentives/ArizonaPublicService.aspx (last accessed August 2013); Go Solar California, "Download Current CSI Data," available at http://www.californiasolarstatistics.ca.gov/current_data_files/ (last accessed August 2013); New Jersey's Clean Energy Program, "New Jersey Solar Installation Update," available at http://www.njcleanenergy.com/renewable-energy/project-activity-reports/installation-summary-by-technology/solar-installation-projects (last accessed September 2013); U.S. Census Bureau, "American FactFinder: Advanced Search," available at http://factfinder2.census.gov/faces/nav/jsf/pages/searchresults.xhtml?refresh=t (last accessed September 2013).

Another characteristic the datasets share is that the distributions of solar installations across income levels are similar to the population distributions within each region. Figure 2 displays the installation and population distributions across income levels for each dataset.

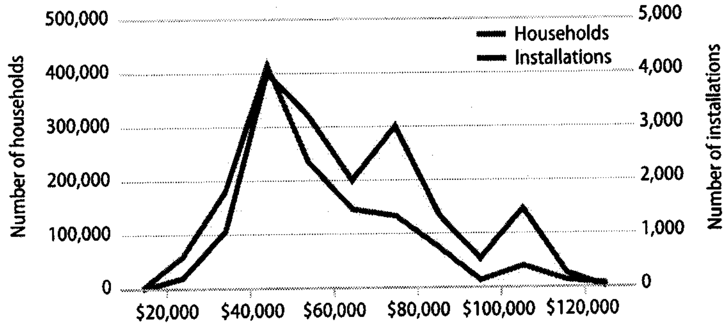
As you can see in Figure 2, the APS and CSI graphs show that installations and populations are more closely aligned in the lower income brackets of less than $60,000, while the NJCEP graph shows nearly perfect alignment in the higher income brackets of $90,000 and above. This alignment between solar installations and household distribution indicates that installations are being spread somewhat evenly over the population, especially in the lower income ranges in Arizona and California and in the higher income ranges in New Jersey. Out of all of the datasets, the distribution of CSI installations is the most skewed toward the upper income brackets.

The third similarity between the datasets is the growth of solar installations occurring in neighborhoods with median incomes ranging from $40,000 to $90,000 over the past several years. Figure 3 shows the share of installations by income range for each dataset from 2009 to the present.

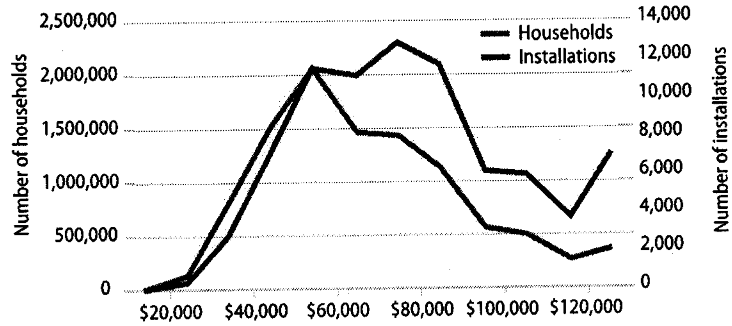
All three graphs in Figure 3 show a positive growth trend for the $40,000 to $90,000 income range, and so far, 2013 has continued that trend. Notably, the share of installations occurring in ZIP codes with median incomes of less than $40,000 increased in both the CSI and NJCEP datasets from 2011 to 2012.

FIGURE 2

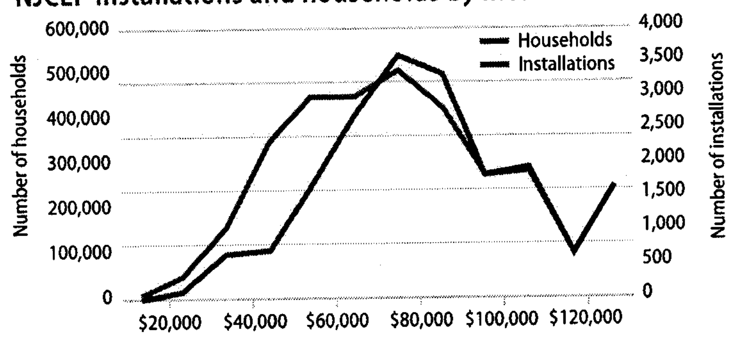
APS installations and households by income level



CSI installations and households by income level



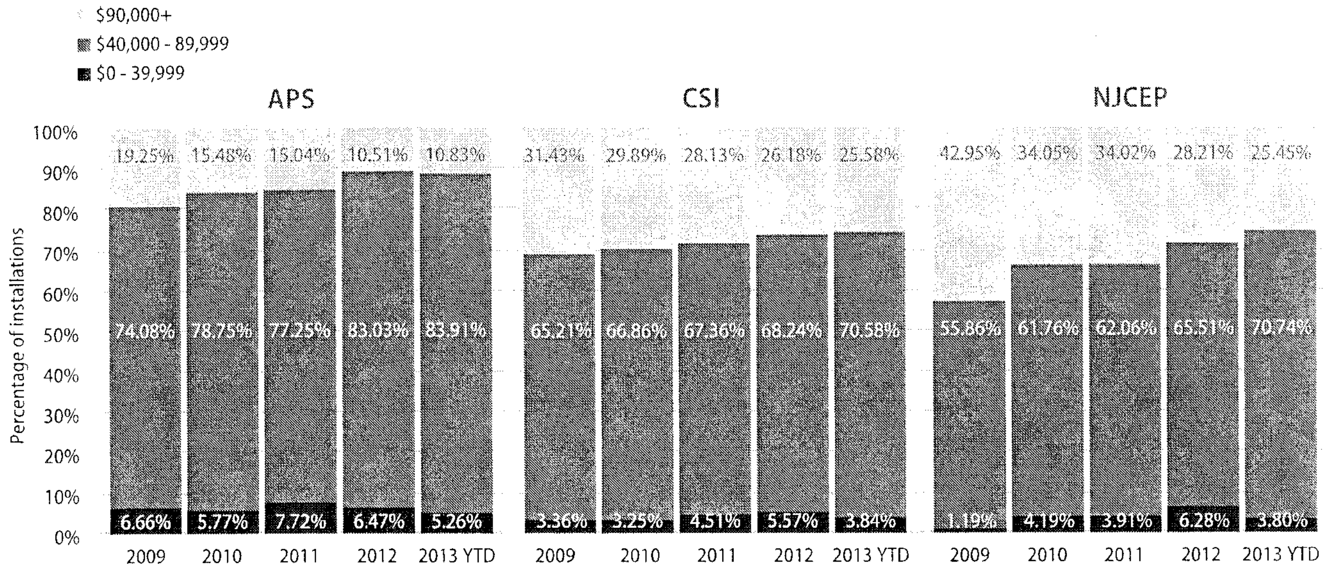
NJCEP installations and households by income level



Sources: Arizona Goes Solar, "Arizona Public Service (APS): Installations," available at http://arizonagoessolar.org/UtilityIncentives/ArizonaPublicService.aspx (last accessed August 2013); Go Solar California, "Download Current CSI Data," available at http://www.californiasolarstatistics.ca.gov/current_data_files/ (last accessed August 2013); New Jersey's Clean Energy Program, "New Jersey Solar Installation Update," available at http://www.njcleanenergy.com/renewable-energy/project-activity-reports/installation-summary-by-technology/solar-installation-projects (last accessed September 2013); U.S. Census Bureau, "American FactFinder: Advanced Search," available at http://factfinder2.census.gov/faces/nav/jsf/pages/searchresults.xhtml?refresh=t (last accessed September 2013).

FIGURE 3

APS, CSI, and NJCEP percentage of installations by income level and year



Sources: Arizona Goes Solar, "Arizona Public Service (APS): Installations," available at http://arizonagoessolar.org/UtilityIncentives/ArizonaPublicService.aspx (last accessed August 2013); Go Solar California, "Download Current CSI Data," available at http://www.californiasolarstatistics.ca.gov/current_data_files/ (last accessed August 2013); New Jersey's Clean Energy Program, "New Jersey Solar Installation Update," available at http://www.njcleanenergy.com/renewable-energy/project-activity-reports/installation-summary-by-technology/solar-installation-projects (last accessed September 2013); U.S. Census Bureau, "American FactFinder: Advanced Search," available at http://factfinder2.census.gov/faces/nav/jsf/pages/searchresults.xhtml?refresh=t (last accessed September 2013); "American FactFinder: Advanced Search," available at http://factfinder2.census.gov/faces/nav/jsf/pages/searchresults.xhtml?refresh=t (last accessed September 2013).

Other key findings

Our analysis also provided other interesting results in the areas that have seen the highest number of cumulative installations and the fastest year-over-year growth from 2011 to 2012. In Arizona, the highest number of installations occurred in ZIP codes with median incomes ranging from $40,000 to $50,000. In California and New Jersey, homeowners who live in ZIP codes with median incomes ranging from $70,000 to $80,000 have installed the most solar power systems. The areas that experienced the most growth from 2011 to 2012 had median incomes ranging from $40,000 to $50,000 in both Arizona and California and $30,000 to $40,000 in New Jersey.

Context and implications

Although rooftop solar currently makes up less than one-quarter of 1 percent of the electricity produced in the United States, utilities are beginning to see how solar could eventually affect their business models as it is rapidly adopted in their service territories. As homeowners install solar panels on their roofs, they reduce the amount of electricity they have to buy from their utility. Utilities, which generally include a portion of fixed costs in their energy-use charges, will then need to raise their electricity rates in order to maintain the electric grid and infrastructure, leading to what is known as the "utility death spiral." As rates increase, more utility customers will choose to go solar, and rates will continue to go up.

The death-spiral threat has caused many in the utility industry to examine their solar-related policies, and some utilities are now attempting to revise solar incentives and rate structures such as net metering.[3] Net metering, which allows solar customers to get credit for any excess energy they supply to the electric grid, is one of the most contentious topics right now in the utility industry; solar advocates are following it closely because of its importance to the growth of rooftop solar.

Many utility executives, in explaining their desire to alter existing solar policies, have said they are concerned that only wealthy customers are adopting rooftop solar, meaning that customers who cannot afford to go solar are subsidizing the rich through the utility's solar policies. At an annual meeting earlier this year, Southern Company CEO Thomas Fanning told shareholders that if solar customers are not paying the utility for the use of the electric grid, then "... you in effect have a de facto subsidy of rich people putting solar panels on their roof and having lower-income families subsidize them."[4] In recent comments filed with the Massachusetts Department of Energy Resources in response to the proposal for an expanded solar carve-out program, Ronald Gerwatowski, senior vice president of National Grid, wrote that, "Net metering operates much like a regressive tax, where the customers who cannot afford to install solar generation pay more to subsidize those customers who are able to afford an investment in solar."[5]

But solar technology, which has become more accessible in the past few years due to falling costs, as well as incentives and solar programs, is now being installed across different income levels, and it is especially popular among homeowners who live in ZIP codes with median incomes ranging from $40,000 to $90,000. While it is true that the wealthy are generally the first adopters of new technologies, our research suggests that solar technology has moved beyond the early adopter phenomenon and onto more widespread installation by the middle class.

The oft-repeated utility-industry narrative is not only being used as a vehicle for solar policy scrutiny—it also serves as a distraction from the fact that solar technology provides the same benefits to the grid regardless of the homeowner's income level. These benefits include avoided fuel costs, reduced transmission and distribution costs, emissions-free energy production, and generation capacity that can offset use during peak energy-consumption times during the day in certain regions. Some utilities have quantified those benefits and found that the value that solar technology brings to the grid in their service territory is actually higher than the retail electricity rate. Through a value-of-solar rate structure, for example, Austin, Texas-based municipal utility Austin Energy pays its solar customers 12.8 cents for every kilowatt hour[6] their systems generate, which is higher than the current retail rates, which range from 3.3 cents to 11.4 cents per kilowatt hour—depending on each customer's overall energy use[7]—and are based on a value-of-solar study done by Clean Power Research that is updated annually.[8]

Net metering and other solar policies encourage rooftop solar deployment and have made solar power generation a good deal for more than just the wealthy. It is important that these policies continue to be offered to accelerate the growth of rooftop solar in neighborhoods across the country.

The transition to a cleaner, lower-carbon electricity system is critical to our ability to meaningfully address climate change now and in the coming years. This transition will require the deployment of vast amounts of solar power systems, and the opportunity to put those systems on homes in every city is too great to pass up. As net metering and other solar policies are debated in different parts of the country, regulators and policymakers should consider the impacts that any changes will have on the affordability of solar technology for middle-class homeowners and how they will impact the future growth of rooftop solar.

Conclusion

Middle-class homeowners are leading the rooftop solar revolution. This finding will have far-reaching implications as utilities across the country consider revising their solar programs and rate structures, which benefit lower- and middle-class people—who are increasingly installing solar—and not just wealthier people.

Our research shows that most solar installations are occurring in middle-class neighborhoods, and that the fastest-growing areas for rooftop solar have median incomes ranging from $40,000 to $50,000 in Arizona and California and from $30,000 to $40,000 in New Jersey. Regulators and policymakers should consider how net metering and other solar policies support the growth of rooftop solar among middle-class homeowners and how they can continue to expand the use of a clean, renewable energy resource.

Data collection and methodology

To determine the income distribution of rooftop solar customers, we collected data from the APS, CSI, and NJCEP databases. APS is the largest electric utility in Arizona. It provides electric service to almost all of the state, excluding half of the Phoenix metropolitan area, the Tucson metropolitan area, and Mohave County in Northwestern Arizona. The APS database contains solar installation data for residential and non-residential customers who applied for solar incentives within the APS territory from January 2002 to the present.[9] The APS data were downloaded on August 8, 2013, and filtered for completed residential solar photovoltaics, or PV, system installations.

CSI is the solar rebate program offered to customers of three investor-owned utilities: Pacific Gas and Electric, Southern California Edison, and San Diego Gas & Electric. The CSI database contains solar installation data for residential and nonresidential customers who have applied for rebates under the CSI program from January 2007 to the present.[10] The CSI data were filtered for completed residential solar PV system installations. Our analysis was based on the August 7, 2013, version of the CSI database.

NJCEP promotes energy efficiency and the use of renewable energy sources in New Jersey. The NJCEP database contains solar installation data for residential and nonresidential customers who have registered for Solar Renewable Energy Certificates or received solar rebates through the Renewable Energy Incentive Program—which closed to new solar rebate applications in 2010—and the Customer On-site Renewable Energy Program, which closed to new applicants in 2008.[11] The NJCEP data were downloaded on September 5, 2013, and filtered for completed residential solar PV system installations.

Using information from the U.S. Census Bureau's 2011 American Community Survey, which gauged five-year estimates, we found the median household income for each ZIP code in which there was a residential solar installation accounted for in the APS, CSI, and NJCEP databases.[12] We analyzed 17,162 installations and 187 ZIP codes in Arizona, 80,440 installations and 1,275 ZIP codes in California, and 17,987 installations and 562 ZIP codes in New Jersey.

Data limitations

We analyzed median income data at the ZIP-code level from the U.S. Census Bureau because actual income data for each installation are not publicly available. There is an inherent amount of uncertainty in using median income data as proxies for real income data, as actual incomes associated with each installation could be higher or lower than the median income.

It should also be noted that the number of installations in the three datasets analyzed in this study does not reflect all residential solar installations within each state. As of the end of 2012, the NJCEP dataset we analyzed captured 98 percent of cumulative installed residential capacity in megawatts in New Jersey, the APS dataset covered 64 percent of cumulative installed residential capacity in Arizona, and the CSI dataset accounted for 55 percent of cumulative installed residential capacity in California.[13]

Additionally, the CSI program rebates have been declining as installed capacity reaches specific milestones. Initial rebates began at $2.50 per watt in 2007, and because the program has been so successful, the rebates are now just $0.20 per watt, as each utility participating in the program has nearly met its final capacity goals.[14] Because of these lower rebate payments, it is likely that fewer new customers are accounted for in the CSI database, which could be especially true for wealthier customers, who may have decided to forgo the CSI application process. Therefore, some of the increase in the share of installations that have occurred in areas with lower median incomes over the past couple years could be due to the lower rebate payments.

Mari Hernandez is a Research Associate on the Energy team at the Center for American Progress.

Utility Dive

OPINION

Black & Veatch: Why fixed charges are a solution to the solar conundrum

By Dr. H. Edwin Overcast | March 10, 2015

Editor's Note: The following article is a guest post by H. Edwin Overcast, Ph.D. Overcast is a director in Black & Veatch's management consulting business specializing in the practice areas of regulatory policy and economics, energy pricing and rate design and economic analysis. He is the author of Black & Veatch's *Smart Rates for Smart Utilities* (http://bv.com/event-landing-pages/smart-rates-for-smart-utilities-download) white paper.

There is an ongoing debate in the media (http://www.utilitydive.com/news/tong-and-wellinghoff-why-fixed-charges-are-a-false-fix-to-the-utility-indu/364428/) and before regulatory commissions on the use of fixed charges in electric utility rates to properly recover the costs of serving customers who have installed distributed generation (DG) resources, such as solar.

While most of the media debate appears to reflect partisan supporters staking out positions that directly benefit their financial interests, the concepts underlying the use of fixed charges, and even the definition of fixed charges, have not yet been adequately discussed.

The purpose of this post is to define the parameters of the debate about the use of fixed charges and to demonstrate that both economic efficiency and achieving the least cost alternative for a safe and reliable utility grid dictate that modern rate designs include the recovery of a utility's fixed costs through fixed charges. This is not just a single customer charge as is traditionally designed, but also includes multiple demand charges for the pricing of different services.

To begin, it is useful to understand the significant change in the structure of the electric industry as the result of DG options such as solar now being readily available to a utility's smallest customers.

Why many utility rate designs have not changed since the 19th century

Historically, electric utilities served full requirements customers whose load patterns varied with the end uses served by electricity. The electric utility competed with gas, oil and propane for loads such as heating and water heating. If they lost those loads to a competitive energy source, the customers' requirements for plant investment were simply reduced as a result of their lower maximum load requirements. Alternatively, the capacity resources were reallocated to serve the growth in electric load from other customers.

Rates were designed to recover costs for the residential class based on differing load profiles using a declining block rate structure that recognized the higher unit costs of smaller kWh use customers. Even in that era, it is likely that larger customers within a rate class subsidized smaller customers in the class. Those subsidies are exacerbated with flat or inclining block rates today.

In contrast, partial requirements customers do not change their demand profile for distribution and may not change their requirements for production and transmission. However, they do change the amount of electricity they use (resulting in reduced kWh) and thus limit the ability of the utility's consumption-based rates to fully recover its fixed costs to serve such customers.

With the advent of DG and particularly PV solar, the nature of the utility model and the services it provides has fundamentally changed. The new industry structure is now a mixed monopoly and competition model. DG customers are a class of partial requirements customers because they still require a variety of services from the utility while also providing energy or kWh competition for the generation portion of the electric system. So long as these customers remain connected to the utility, they continue to take other services from the utility. The ancillary services they require typically include *starting capacity* to meet the in-rush current requirements for starting motor loads such as air conditioning compressors, *supplemental services* when solar is not available at night, and *frequency services* to maintain power quality.

For most electric utilities, current rate designs have not changed since the 19th century. Those rates were developed to recover costs from full requirements customers whose electric use was homogeneous. Partial requirements customers no longer look like or use electric services the same way as full requirements customers. In a mixed monopoly and competitive market model, the solution for efficient cost recovery is to unbundle utility rates and charge customers directly for only the services they actually use. This means changing from the 19th century block rate structure to a more efficient rate design. An efficient rate design requires recovering fixed costs in the utility's fixed charges to ensure customers are incentivized to make economically rational energy decisions.

Why fixed charges may not be what you think they are

The concept of a fixed charge within a utility's rate structure is much more than its traditional monthly customer charge. To be clear, the definition of a fixed charge as used herein does not equate to the concept of a customer charge. Rather, it also includes a variety of demand charges to recognize the different utility services provided to partial requirements customers. Attempting to recover fixed costs for all of the utility services used by partial requirements customers through a single fixed charge is not feasible, and could never produce a reasonable result. Moreover, a single fixed charge cannot provide efficient price signals for customers whether they are partial *or* full requirements customers.

With the advent of the mixed monopoly and competitive model, the "one size fits all" prescription for rate design must be discarded because the impact of competitive entry is to drive out subsidies where those subsidies are otherwise recoverable in charges for the service that is competitive. In this case, such charges consist of the utility's usage-based kWh charge.

The often cited California rates where solar has achieved significant penetration provide a perfect example of the cross subsidy in usage-based utility rates. The current fixed charge (http://www.pge.com/nots/rates/tariffs/electric.shtml#RESELEC) for Pacific Gas & Electric Company (PG&E) is about $4.50 per month. This charge will typically not compensate the utility for more than the meter and service line. As such, there is no rate revenue remaining to recover the costs of customer services and the fixed investment in facilities at the customer's location (e.g., the smallest size of transformer). All of the other costs are collected through the utility's inclining block rates that have a charge in excess of $0.33 per kWh in the highest rate block. In fact, the cost for this rate block is over 60% higher than the average unit rate. There is no question that the charges for the higher rate blocks subsidize the lower tiers and the subsidy provides added incentives to customers for the further adoption of the competitive market alternative.

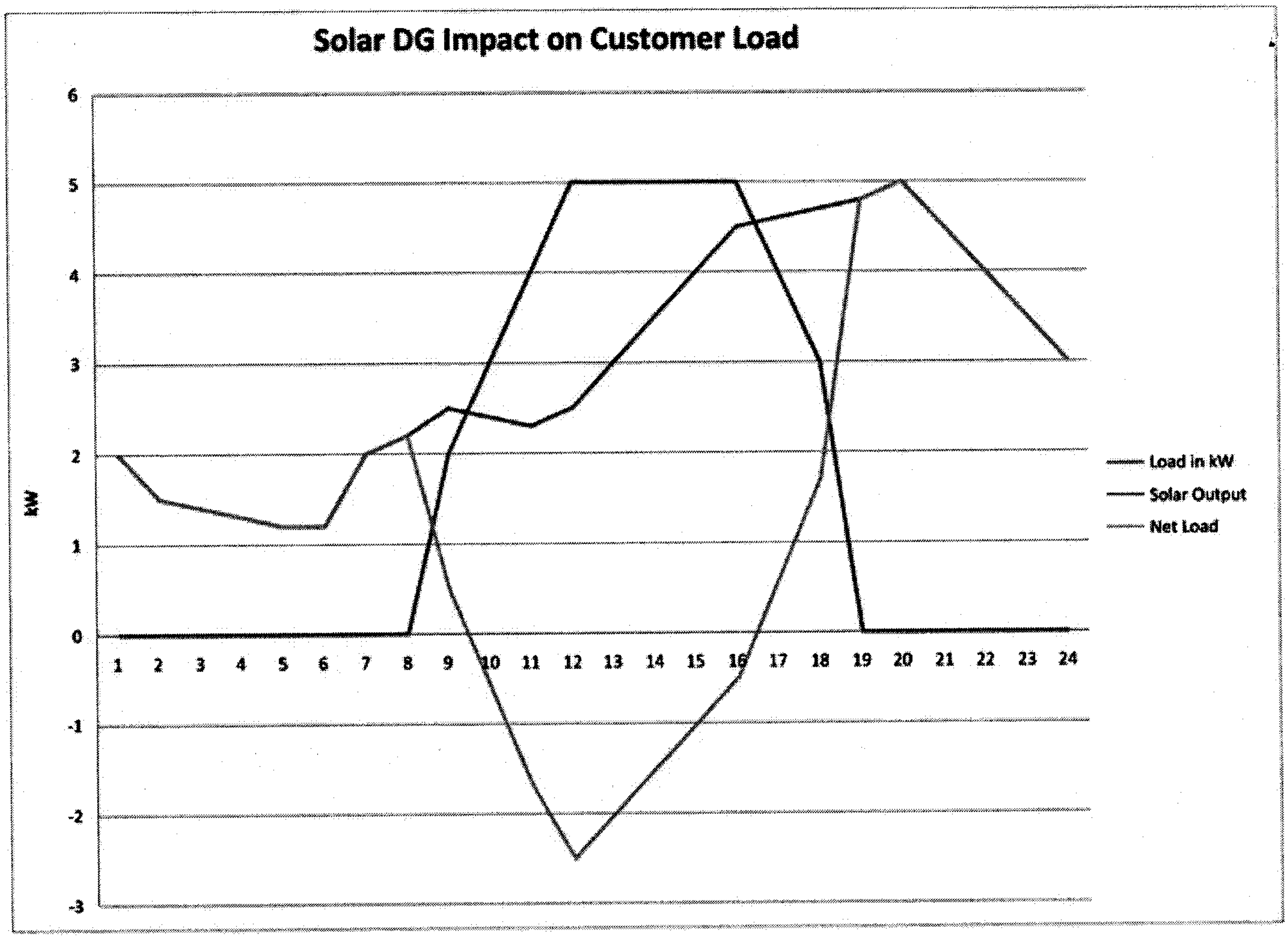
To the extent the utility's net energy metering tariff allows the customer to use zero net kWhs each month, the resulting bill would be equal to about $4.50 per month for all of the services used by the DG customer. Absent investment in storage for excess generation and excess capacity in the DG investment sufficient to be able to start motor loads (somewhere between 2 and 8 times the rated load of the motor), the customer will require use of the utility's generation, transmission and distribution system to serve its load when solar is not available and to allow the solar generation to serve motor loads when it is available. Essentially, the solar customers will have the same fixed distribution costs that they had before installing solar, and potentially they may cause the utility to incur incremental costs after installing DG to provide the types of ancillary services described earlier.

Why fixed charges send the right message

The utility must have a ratemaking mechanism to recover the fixed costs that it incurs to provide delivery service to its partial requirement customers. These costs are fixed costs based on the maximum demand of the customer whenever that occurs (i.e., the maximum non-coincident demand). These costs cannot be recovered through usage charges simply because the revenue generated from these charges could be zero if the customer achieves net-zero energy consumption during the month through its DG resource. Moreover, these fixed costs cannot be recovered through a fixed customer charge because such costs will differ from one DG customer to the next due to their unique load characteristics.

The rational and efficient method to recover distribution system costs is through a fixed charge based on the maximum kW demand whenever it occurs subject to a 100% ratchet based on that demand level. (A ratchet is a billing option that allows for a demand charge to be based on the higher of the current month's demand or the demand that occurred during the ratchet period in a previous month.)

Since the utility's service obligation is to have available the delivery capacity to meet the customer's maximum demand, this fixed charge results in a proper matching of the costs incurred to serve the customer and the revenues the customer generates for the separate or unbundled distribution service. The use of unbundled rates results in price signals to use the utility system more efficiently. This same conclusion relates to separate fixed charges for generation capacity and for transmission capacity. The chart below is illustrative of this issue.



The chart depicts that the utility must still have adequate system capacity to satisfy the required maximum demand of the customer's net load when the solar DG is not operating
Credit: Dr. Overcast

An unbundled rate design also needs to reflect time varying energy charges so that customers who use DG are incentivized to maximize their energy output at the times when energy costs are highest, or to use storage to minimize their total energy costs. Contrary to the claims of some solar advocates (http://www.utilitydive.com/news/tong-and-wellinghoff-why-fixed-charges-are-a-false-fix-to-the-utility-indu/364428/) , fixed charges will not cause customers to, "lack clear signals to act more efficiently, adopt appropriate technologies, or utilize DER to improve the grid for others."

Instead, a utility's fixed charges will create the proper price signals to incent customers to make more efficient and cost-effective energy investment decisions. The resulting decisions will be made in light of the costs of the actual monopoly utility services that the customer requires relative to the customer's own competitive energy and production capacity costs. If the customer's DG resource also reduces other costs such as the utility's transmission or distribution costs, those savings will also accrue to the DG customer as reduced fixed charges, but they can never be zero as long as the DG customer requires the grid for partial requirements service.

The use of fixed charges to recover the fixed costs of unbundled utility services in the new mixed monopoly and competition model produces the best possible economic outcome for all customers — both now and in the future. Smart rates that include fixed cost recovery through fixed charges for the pricing of a utility's monopoly services assure that safe, reliable and high quality grid services continue to be available at the most reasonable cost for consumers. Markets work so long as price signals are efficient — and the fixed charge concept is fully supportive of that important outcome.

Top Image Credit: Flickr; Walmart (https://www.flickr.com/photos/walmartcorporate/5250473518/)

Filed Under:

Solar & Renewables Distributed Energy Regulation & Policy

UNS ELECTRIC INC.'S RESPONSE TO VOTE SOLAR'S FIRST SET OF DATA REQUESTS REGARDING THE 2015 UNS ELECTRIC RA[illegible]
DOCKET NO. E-04204A-15-0142
September 8, 2015

VS 1.06

Page 14 of Mr. Dukes' direct testimony discusses an 8% decline in UN[illegible] since 2007, and on lines 14–17 Mr. Dukes testifies: "There are several factors contributing to lower consumption, including: adoption of energy efficiency measures; more energy efficient building codes and appliance standards; increased use of distributed generation; challenging economic conditions; and other conservation efforts by UNS Electric's customers." Please indicate what proportion of the 8% decline since 2007 can be attributed to each of the following:

a. Adoption of energy efficiency measures

b. Adoption of more energy efficient building codes and appliance standards

c. Increased use of distributed generation

d. Economic conditions

e. Other conservation efforts by UNS Electric's customers.

RESPONSE:

The Company has not performed analysis to quantify each of these components and to do so would be overly burdensome. The list of causes was not intended to be exhaustive, but simply illustrative of some of the major causes of sales decline.

RESPONDENT:

Greg Strang

WITNESS:

Dallas Dukes

EXHIBIT
Vote Solar-6
admitted

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 AND EXHIBITS OF BRIANA KOBOR

ON BEHALF OF VOTE SOLAR

DECEMBER 9, 2015

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List of Tables and Figures

List of Exhibits

1 Introduction

Q. Please state your name and business address.

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

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

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

Q. What is Vote Solar?

A. Vote Solar is a non-profit grassroots organization working to foster economic opportunity, promote energy independence, and fight climate change by making solar a mainstream energy resource across the United States. Since 2002, Vote Solar has engaged in state, local, and federal advocacy campaigns to remove regulatory barriers and implement key policies needed to bring solar to scale. Vote Solar has approximately 60,000 members nationally and 3,500 in Arizona.

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

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

Q. Please describe your education and experience.

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

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

A. No. I have not.

Q. Have you previously testified before other regulatory commissions?

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

2 Purpose of Testimony and Summary of Recommendations

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

A. My testimony addresses certain rate design proposals put forth by UNS Electric, Inc. ("UNS" or the "Company") in its general rate case application. Among the rate design proposals in the UNS application, the Company has requested significant changes to rate design for net energy metering ("NEM") customers and modifications to the rate structure for residential and small commercial customers. The specific proposals I address in my testimony include: (1) the proposed modification of the NEM export rate from the retail rate to a Renewable Credit Rate; (2) the proposal to make a three-part tariff mandatory for NEM customers; (3) proposed changes to the Lost Fixed Cost Recovery Mechanism ("LFCR"); (4) the request to increase fixed charges for residential and small commercial customers; and (5) the request to remove the third tier in the standard residential rate. There are a number of additional proposals in UNS's application that are not addressed in my testimony, but that does not imply that I agree with those proposals. I reserve the opportunity to discuss any additional proposals not addressed in my direct testimony through surrebuttal testimony.

Q. Please describe how your testimony is organized.

A. The remainder of my testimony consists of seven major sections. In the first section I summarize the rationale UNS has provided to support the rate design proposals listed above. In the second section I examine whether that rationale supports the NEM-specific proposals put forth by UNS. In the third section I examine UNS's specific NEM proposals, including (1) UNS's request to reduce the credit NEM customers receive for excess energy exports; and (2) UNS's proposal to implement a mandatory three-part rate structure for NEM customers. I also examine the relationship between UNS's proposed rate design changes and the LFCR, and assess UNS's proposed changes to the LFCR. In the fourth section I address UNS's assessment of the impacts of its proposed NEM rate design changes. I also look at the potential implications of these proposals and examine the applicability of the Commission's NEM Rules to these proposals. In the fifth section I evaluate UNS's proposals to increase the fixed charges for all residential and small commercial customers, and to remove the third residential rate tier. In the sixth section I describe how UNS and the Commission should plan for distributed energy resources ("DERs") and the modern grid. Finally, the seventh section provides a summary of my recommendations.

Q. Please summarize your findings and recommendations.

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

UNS's two primary methods to address the problems allegedly caused by DG are both significantly flawed and should be rejected. First, UNS proposes to modify the existing NEM tariff to substantially reduce the credit NEM customers receive for excess generation. I find that UNS has not provided sufficient basis for its recommendation that exports be valued at the Renewable Credit Rate. Without a full benefit/cost analysis there is no way to determine the current relationship between the retail rate and the value of NEM exports, and thus no way to determine the reasonableness of the Renewable Credit Rate. Moreover, I find significant flaws in the calculation of the Renewable Credit Rate. As a result, I recommend that the Commission reject UNS's proposal to lower the compensation rate it pays for NEM customers' excess generation and that exports continue to be valued at the retail rate until an independent benefit/cost analysis has been completed.

Second, UNS proposes to implement a mandatory three-part rate structure with a demand charge for NEM customers. I show that the proposed demand charges would not fully reflect costs associated with the system peak, and that demand charges for residential and small commercial customers would not provide an actionable price signal to help customers make informed decisions regarding their energy usage. Because most customers lack the tools to effectively respond to the price signals in demand charges, these charges would act like an additional fixed charge for residential and small commercial customers. I find that a mandatory demand charge for NEM customers would be discriminatory, and such charges are not appropriate for any residential or small commercial customers. I recommend that demand charges be offered only through optional rate tariffs for all residential and small commercial customers, including NEM customers.

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

My testimony also shows that UNS has not adequately assessed how its NEM-specific proposals would impact customers. UNS's reliance on vague and hypothetical data fails to meet its burden of justifying changes to NEM rates under the Commission's rules. In addition, UNS's proposals would likely cause a significant decline in DG adoption rates in its service territory, but the Company did not asses how this would impact regulatory compliance, overall energy costs, and local employment.

I also address two aspects of UNS's proposals that would apply to all residential and small commercial customers, rather than just NEM customers. I find that a revised study of embedded and marginal costs based on a more reasonable allocation method demonstrates that current fixed charges for residential and small commercial customers are reasonable and I recommend that the

Commission reject UNS's proposal to increase fixed charges for these classes. I also recommend that the Commission reject UNS's proposal to eliminate the third residential rate tier. The Commission approved the current inclining block rate structure for the express purpose of incenting conservation, and the alleged fixed cost recovery differential between high and low-use customers under the current rate structure is reasonable.

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

3 UNS's Rationale for Its Rate Design Proposals

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

A. In a section of UNS's application labeled "Need for Updated Rate Design," the Company describes the rationale for its rate design proposals.[1] UNS indicates that an updated rate design is needed due to a decrease in retail sales of nearly 8% below the June 30, 2012 test year used in the last rate case.[2] UNS indicates that as a result of the lower level of sales, the Company must recover its fixed costs over a small number of kilowatt-hours ("kWh"), which can contribute to an under-recovery of fixed costs over time.[3] UNS claims that its current rate design, which recovers a portion of fixed costs through a volumetric per-kWh rate, "may have been appropriate in times of increasing customer usage and sales growth."[4] But, according to the Company, because of the decline in retail sales "this approach

[1] Application at 3:21.
[2] *Id.* at 3:22–23.
[3] *Id.* at 4:4–8.
[4] *Id.* at 4:10–11.

has created both difficulties for UNS Electric in recovering its authorized revenue requirement and inequities in recovering fixed costs from customers."[5]

Q. Does UNS describe what is behind the 8% reduction in retail sales?

A. Yes. UNS stated: "The significant decline in sales is due to several factors, including: (i) the shutdown or curtailment of operations by certain large customers; (ii) the effects of increased energy efficiency ("EE") and distributed generation ("DG"); and (iii) the slow pace of economic recovery. Sales reductions resulting from successful EE measures and DG systems were exacerbated by business closures, including the 2014 bankruptcy of UNS Electric's largest customer."[6]

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

A. Yes. UNS describes three phenomena that drive the need for its rate design proposals.

1. UNS claims that the Company is experiencing declining usage per customer.[7]

2. The Company reports that "a significant proportion of UNS Electric's residential and small general service customers have little to no volumetric usage."[8] UNS says that "[t]hese customers include everything from seasonal homeowners, vacant structures and net metered rooftop PV systems."[9] The Company claims that under the current rate design, these customers do not pay "an equitable share of the fixed costs to operate and maintain the UNS Electric

[5] *Id.* at 4:11–13.
[6] *Id.* at 3:25–4:3.
[7] *Id.* at 4:14–16.
[8] *Id.* at 4:17–18.
[9] *Id.* at 4:18–19.

grid to which they are connected and on which they are dependent to continue to receive safe and reliable electric service when needed."[10]

3. UNS claims it "is also suffering lost revenues because the LFCR is not designed to capture all of the lost fixed cost revenues associated with meeting the Commission's Renewable Energy Standard and Energy Efficiency Rules."[11]

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

A. UNS describes three "primary objectives" of the proposed rate design changes.[12] First, UNS claims that rate structures need to be updated to more closely match the price customers pay for the service they receive.[13] Second, UNS seeks to reduce the level of cross-subsidies between customers.[14] Third, UNS would like to give itself an "appropriate" opportunity to recover its fixed costs.[15]

4 UNS has not provided sufficient evidence to justify a change to its rate structure for NEM customers

Q. Does UNS's rationale described above support the NEM-related rate design proposals the Company is advocating for?

A. No. As I explain in detail below, my examination of the data reveals that DG is not a significant driver of the reduction in retail sales that UNS has experienced since the last rate case. In fact, 98% of the residential customers that UNS alleges

[10] *Id.* at 4:23–25.
[11] *Id.* at 4:27–5:2.
[12] David G. Hutchens Direct Testimony ("Hutchens Direct Test.") at 6:14–7:9 (May 5, 2015).
[13] *Id.* at 6:16–18.
[14] *Id.* at 7:1.
[15] *Id.* at 7:4.

are causing a cost shift are not NEM customers.[16] In addition, UNS has not established the existence of significant grid impacts related to DG.

4.1 Distributed Generation is not a significant driver of the reduction in UNS's retail sales

Q. UNS has indicated that retail sales decreased nearly 8% since the last rate case test year. What were the drivers of this reduction?

A. UNS attributes this reduction in retail sales to three factors: (1) loss of load from industrial and mining customers, (2) effects of increased EE and DG, and (3) the slow pace of economic recovery.[17]

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

A. Yes. I examined the decline in retail sales between the test year for UNS's last rate case (the 12 months ending June 30, 2012) and the current test year (calendar year 2014). This allowed me to gather information on the relative impact of each of the three drivers identified by UNS. Table 1 below summarizes the loss of load by customer class in Megawatt-hours ("MWh") between the last rate case test year and the current test year. The data in Table 1 confirms UNS's claim that there was an 8% reduction in retail sales between test years. Retail sales in the current rate case test year were roughly 141,000 MWh less than retail sales in the prior test year.

[16] Dukes workpaper "Graph P 13.xlsx" (Ex. BK-2 at 52); UNS Resp. to UDR 2.10 (Ex. BK-2 at 43).
[17] Hutchens Direct Test. at 5:20–23.

Table 1: Comparison of Retail Sales – Last Rate Case and Current Rate Case (MWh)[18]

	Last Rate Case	Current Rate Case	Change in Sales	Contribution to Total Reduction
Residential	850,000	816,000	-34,000	24%
Commercial	704,000	703,000	-1,000	1%
Industrial	130,000	93,000	-37,000	26%
Mining	133,000	64,000	-69,000	49%
Other	2,000	2,000	0	0%
Total	1,819,000	1,678,000	-141,000	100%

As shown in Table 1, approximately 75% of the 141,000 MWh reduction in retail sales that UNS claims is driving the need for its rate design proposals can be attributed to the first factor identified by UNS: reduced sales in the mining and industrial classes. This means that the other factors— non-industrial EE, DG impacts, and the slow pace of economic recovery—were collectively responsible for the remaining 25% of the 141,000 MWh decline in UNS's overall retail sales.

Q. **Have you examined the relative impacts of the other factors?**

A. Yes. I obtained data on the impact of DG on an annual basis, but not a monthly basis. This prevented me from calculating the level of DG consumed onsite by NEM customers during the prior test year, as I could not isolate data for the 12 months ending June 30, 2012. In order to approximate the impacts of DG between test years, I instead examined the difference in DG impacts between calendar year 2011 and calendar year 2014. Because the prior test year did not include the first half of 2011, these estimates are likely to inflate the values shown for DG. However, the values serve as a reasonable approximation to enable an analysis of the relative impact of DG compared to other factors.

[18] UNS Resp. to Staff 9.2 (Ex. BK-2 at 34). Numbers may not add due to rounding.

Q. What does your analysis show?

An examination of the data on the total reduction in retail sales attributed to DG between calendar year 2011 and calendar year 2014 shows that DG reduced residential load by only 8,000 MWh over that period.[19] <u>This implies that DG contributed no more than 6% to the 141,000 MWh decline in system-wide retail sales</u>.

Non-industrial EE and "the slow pace of economic recovery"[20] are responsible for the remaining 19% of the 141,000 MWh decline in retail sales not associated with reductions in the industrial and mining classes.

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

Figure 1: Impact of Industrial and Mining Reductions, DG, and EE/Other Factors on Decline in Retail Sales Between Rate Cases[21]

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

[19] UNS Resp. to Staff 2.017 (Ex. BK-2 at 25).
[20] *See* Hutchens Direct Test. at 5:20–23.
[21] Due to data limitations, the value shown for DG impact represents residential retail sales reductions due to DG between calendar years 2011 and 2014, rather than between the two test years and is therefore likely an overestimate of the DG impact between test years.

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

A. Yes. To support its rate design proposals, UNS points to the fact that residential usage per customer has declined 4% between 2012 and 2014.[22] Examination of the data indicates that residential usage per customer did in fact decline by roughly 4%, amounting to 398 kWh per year.[23] Additional reductions from DG, however, were minimal, amounting to an additional decline of only 13 kWh per year for the average residential customer between 2012 and 2014.[24] This indicates that 97% of the decline in residential usage per customer was driven by factors other than growth of DG.

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

A. Yes. In Dallas Dukes' Direct Testimony, UNS attributes this problem to the fact that nearly one in every four residential bills issued by UNS during the test year reflected usage of 300 kWh or less.[25] UNS says that "[b]ecause even a studio apartment with basic appliances and moderate usage would likely consume at least 400 kWh per month, these bills probably were generated by vacant homes, seasonal customers and DG customers."[26]

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[22] Application at 3:24.
[23] UNS Resp. to Staff 9.2 (Ex. BK-2 at 34).
[24] UNS Resp. to Staff 2.017 (Ex. BK-2 at 25).
[25] Dallas J. Dukes Direct Testimony ("Dukes Direct Test.") at 12:9–10 (May 5, 2015).
[26] *Id.* at 12:11–13.

Q. Have you been able to assess the proportion of bills amounting to 300 kWh or less that could be attributed to vacant homes, seasonal customers, and NEM customers?

A. Yes. In discovery UNS indicated that it does not track seasonal or vacant accounts.[27] However, the Company did provide data on the number of NEM customer bills that fell below the 300 kWh threshold.[28] <u>UNS reports that over 95% of the 205,129 low-usage bills were from customers who were not NEM customers.</u>[29]

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

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

1. DG contributed less than 6% to the overall decline in retail sales—more than 94% of the decline can be attributed to other causes.

2. DG reduced average residential usage per customer by 13 kWh between 2012 and 2014, indicating that 97% of the decline in residential usage per customer was due to factors other than DG.

3. More than 95% of residential customer bills for usage under 300 kWh were from customers who were <u>not</u> NEM customers.

The data shows that the problems UNS claims warrant their rate design proposals are not DG problems. In fact, drivers such as sales declines in the industrial and mining sector and reductions due to EE and other factors, had a much larger

[27] UNS Resp. to VS 1.05(b), (c) (Ex. BK-2 at 2).
[28] UNS Resp. to VS 1.05(d) (Ex. BK-2 at 2).
[29] *Id.*

impact on UNS's sales. Therefore, the Company should not single out NEM customers for rate reform based on the mistaken rationale that DG has caused a significant decrease in retail sales.

4.2 Ninety-Eight Percent of the Residential Customers UNS Alleges are Causing a Cost Shift are not NEM Customers

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

A. UNS alleges that under the current rate design, lower-usage customers shift fixed costs to higher-usage customers.[30] To illustrate this problem, UNS points to three examples of low-usage customers: (1) seasonal customers; (2) vacant homes or businesses; and (3) NEM customers.[31] In addition, UNS provides a chart that claims to show that roughly two-thirds of the bills issued in the last four years to residential customers did not provide fixed cost recovery equivalent to the class average established in the most recent rate decision.[32] In the data underlying the chart, UNS shows that the usage level at which they define customers as achieving fixed cost recovery is roughly 1,000 kWh per month.[33]

Q. Does UNS discuss cost shifts that are specific to NEM customers?

A. UNS claims that "under the Company's current rates, which feature a tiered rate design that relies heavily on volumetric sales to recover fixed costs, solar DG users are not asked to pay for their fair share of the electric system. Instead, those costs are shifted to other customers."[34] The Company also points to a Commission decision regarding NEM rate design in Arizona Public Service Company's ("APS") territory as evidence that a cost shift exists in its own territory.[35]

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[30] Dukes Direct Test. at 3:6–9.
[31] *Id.* at 11:5–12:6.
[32] *Id.* at 13:6–27.
[33] Dukes workpaper "Graph P 13.xlsx." (Ex. BK-2 at 52).
[34] Hutchens Direct Test. at 13:20–23.
[35] *Id.* at 14:10–12.

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

A. Yes. Very few of these low-usage customers are NEM customers. As described above, UNS points to problems associated with customers that use less than 300 kWh monthly. The Company suggests that these bills are related to seasonal customers, vacant homes, and NEM customers. The analysis described above reveals that NEM customers are in fact <u>less than 5% of this low-consumption cohort</u>.[36]

UNS further alleges that two thirds of residential customers (those with consumption under roughly 1,000 kWh monthly) do not pay their fair share of fixed costs. However, an examination of the level of NEM customers in that cohort reveals that NEM customer bills accounted for only <u>2% of all customer bills below 1,000 kWh</u> in 2014.[37]

Q. What do these findings show?

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

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[36] UNS Resp. to VS 1.05(d) (Ex. BK-2 at 2).
[37] UNS Resp. to UDR 2.10 (Ex. BK-2 at 43).

4.3 UNS has not shown that DG causes significant grid impacts

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

A. Yes. Carmine Tilghman's Direct Testimony describes several grid operation considerations associated with integrating DG, and in particular distributed solar generation.[38]

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

A. UNS breaks the discussion of DG integration issues into three categories: (1) intermittency of generation; (2) the utility's inability to monitor and control systems; and (3) excess generation flowing back to the grid.[39]

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

Underlying UNS's discussion of each of these categories is the Company's assumption that the typical NEM customer will size their system to offset 100% of annual usage. As I discuss in a later section of this testimony, despite repeated questioning from multiple intervenors, UNS has not provided any data to support this assumption.[40] The lack of data to support this most basic premise is indicative of the imprecise nature of UNS's assertions regarding the impacts of DG on its grid. Furthermore, even if the Company were able to provide data to support this foundational assumption, UNS has failed to conduct any detailed analysis of issues related to DG on its system at either current or anticipated levels of penetration. UNS instead relies on broad national and regional studies, which may

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[38] Carmine Tilghman Direct Testimony ("Tilghman Direct Test.") at 4:12–6:23 (May 5, 2015).
[39] *Id.* at 4:14–16.
[40] *See infra* at section 6.1.

or may not apply to UNS's grid and service territory. As a result, the entire discussion of grid impacts is speculative.

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

A. UNS claims that renewable generation "requires the continued services of the centralized grid to supply the necessary back-up energy and ancillary services to support solar and other intermittent renewable resources."[41] The Company also claims that "[t]his problem is exacerbated through policies such as net metering, which encourages customers to oversize their solar systems beyond their average load in order to 'bank' as many credits as possible for use later."[42] UNS reports that higher levels of intermittent generation will create greater load imbalance and fluctuations in voltage and frequency, requiring additional ancillary services.[43] UNS says that "updated rate design and large scale energy storage facilities on a system-wide basis will likely be needed to manage this issue."[44]

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

A. In my opinion, UNS's testimony overstates the issue. First of all, UNS's assessment is based on the premise that the typical NEM customer will size its system to offset 100% of load,[45] but as shown below, there is no data to support this assumption. In addition, UNS has not provided data on any additional ancillary services that have been required on its system as a result of current DG levels in UNS's service territory. UNS has also not provided an estimate of what level of ancillary services may be required with future DG penetration.[46]

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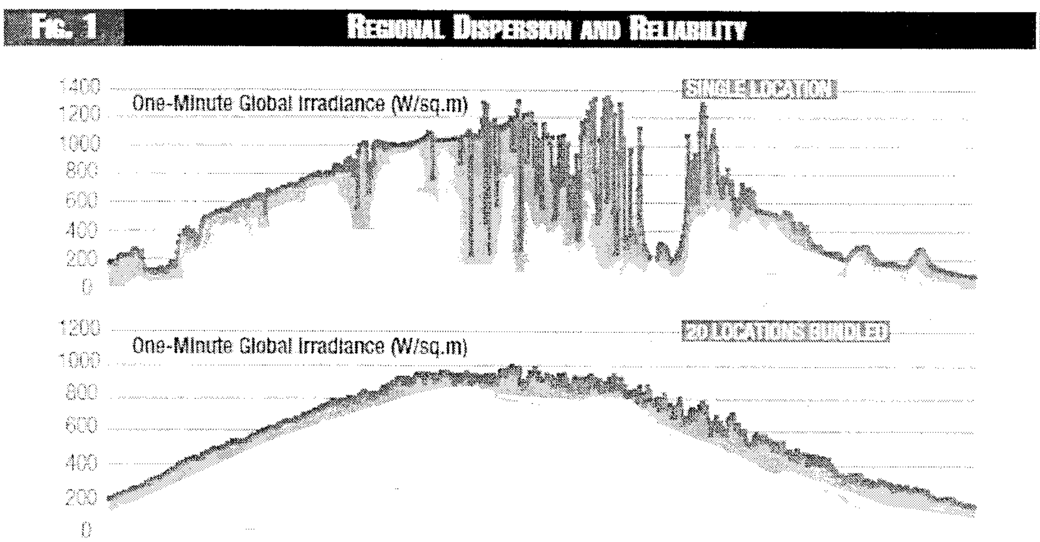
[41] Tilghman Direct Test. at 4:21–23.
[42] *Id.* at 4:24–26.
[43] *Id.* at 5:10–12.
[44] *Id.* at 5:12–13.
[45] UNS Resp. to VS 2.15 (Ex. BK-2 at 6).
[46] UNS Resp. to VS 2.17 (Ex. BK-2 at 7).

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

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

Figure 2: Effects of Geographic Diversity on PV System Intermittency[47]



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

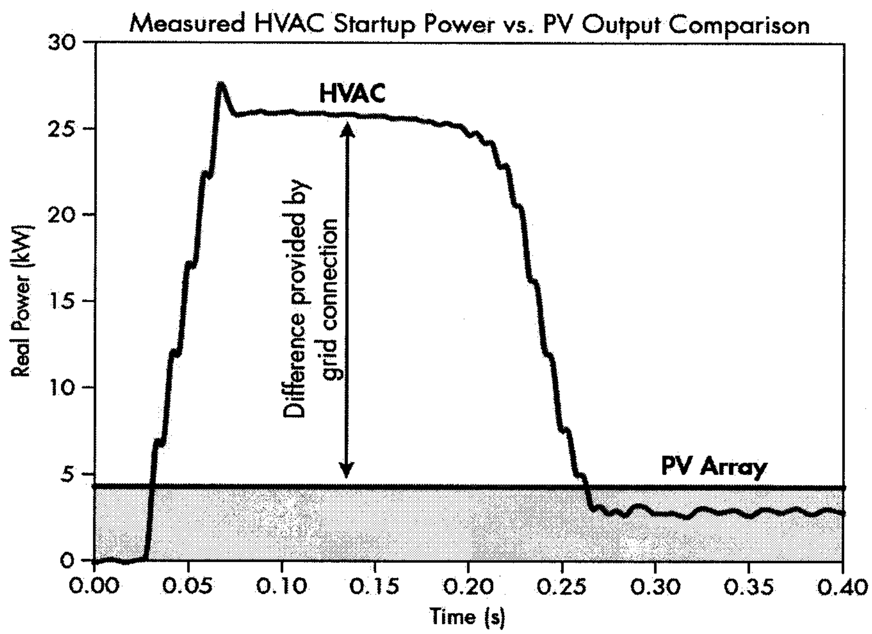
Because distributed PV systems are not uniformly intermittent, having a group of PV systems decreases variability and creates a more predictable pattern.

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

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

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

Figure 3: Air Conditioning Startup Power[48]



Roughly one third of UNS customers have central AC in their homes.[49] As shown in Figure 3, if a group of air conditioners of this type started at the same time there would be significant swings in demand that may require support from additional ancillary services.

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

[49] UNS Resp. to VS 3.34 (Ex. BK-2 at 23).

In addition, as adoption of electric vehicles increases in Arizona, UNS will have to accommodate large swings in residential demand as consumers plug in their electric vehicles at home charging stations. The Nissan Leaf, for example, has a 6.6 kW charger option,[50] and could result in demand swings larger than the average residential PV system size of 5 kW.[51]

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

A. UNS says that because DG is not connected to the utility's energy management system, the utility has no ability to see the output or control the inverter.[52] UNS claims that this creates a situation where the utility is "driving blind" and that with larger amounts of DG this situation can result in significant load to generation imbalances.[53]

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

A. UNS possesses sophisticated technologies that they employ to produce forecasts of PV generation on a daily and hourly basis.[54] In addition, UNS requires that DG sources install a meter to collect generation production data.[55] Interconnected PV systems above 300kW-ac are also required to install advanced metering equipment at the customer's expense that transmits real-time production data to the utility.[56] UNS uses the data obtained from these larger systems to approximate production of the smaller customer-owned DG systems.[57] Additionally, while UNS does not possess the ability to monitor all DG systems in real time, they

[50] Nissan, 2016 Nissan Leaf Specs, http://www.nissanusa.com/electric-cars/leaf/versions-specs/version.sv.html (last visited Dec. 8, 2015).
[51] Solar Energy Indus. Ass'n, Solar Photovoltaic Technology, http://www.seia.org/research-resources/solar-photovoltaic-technology (last visited Dec. 8, 2015).
[52] Tilghman Direct Test. at 5:16–18.
[53] *Id.* at 5:18–23.
[54] UNS Resp. to Staff 2.031 (Ex. BK-2 at 28).
[55] UNS Resp. to Staff 2.033 (Ex. BK-2 at 30).
[56] *Id.*
[57] *Id.*

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

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

A. UNS claims that excess energy that is exported from NEM customer generators to the grid creates "issues on the distribution system."[58] The issues listed include the potential to exceed capacity ratings on individual transformers or feeders; significantly higher energy flows that increase operations and maintenance costs and equipment wear and tear; exported energy flowing back up through the distribution system; and potential for reverse power flow and overload conditions.[59]

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

A. UNS has revealed through discovery that the Company has not conducted any studies concerning increased operations and maintenance costs or equipment wear and tear resulting from DG.[60] The Company also has not conducted any studies on the impact of energy flowing back up through the generation system from DG.[61] UNS acknowledges that its statements were based on broad national and regional studies, rather than any analysis unique to the UNS territory and level of DG penetration.[62] In addition, UNS explicitly states that its claims regarding issues with excess generation are based on the assumption that the typical NEM

[58] Tilghman Direct Test. at 5:25–26.
[59] *Id.* at 5:25–6:23.
[60] UNS Resp. to TASC 3.2(a) (Ex. BK-2 at 48).
[61] UNS Resp. to TASC 3.2(b) (Ex. BK-2 at 48).
[62] UNS Resp. to TASC 3.2(c) (Ex. BK-2 at 48).

customer will size their system to offset 100% of load.[63] But as noted above, there is no data to support this assumption.

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

No. In discovery, UNS stated that "[a] number of circuits within both UNS Electric and TEP's systems have shown to have reverse current flow on at least one phase due to distributed generation."[64] However, when further information was requested, UNS declined to quantify the number of circuits that have experienced reverse power flow, making it difficult to assess the prevalence of this issue.[65] When UNS receives a generation interconnection request, the Company may model PV generation on the distribution system using SynerGEE Electric powerflow software.[66] Through this modeling, UNS has only identified three instances where the existing distribution facilities could not support the proposed generation source.[67] In two of those instances, upgrading the existing overhead feeder conductor was identified as a possible solution.[68] And in the third instance, power factor correction at the generation facility was found to mitigate the problem.[69] Again, the data do not indicate that this is a common issue on the UNS system.

Q. Has UNS adequately supported its claim that excess DG generation requires additional investments related to frequency control and power factor correction?

No. Craig Jones' Direct Testimony states that a "DG customer may require additional investments in the distribution system to provide frequency control and

[63] Tilghman Direct Test. at 6:5–6.
[64] UNS Resp. to VS 2.24 (Ex. BK-2 at 10).
[65] UNS Resp. to VS 3.21 (Ex. BK-2 at 21).
[66] UNS Resp. to VS 3.24(b) & Staff 2.035 (Ex. BK-2 at 22, 31).
[67] UNS Resp. to VS 3.24(d) (Ex. BK-2 at 22).
[68] UNS Resp. to VS 4.4(c) (Ex. BK-2 at 24).
[69] *Id.*

power factor correction."[70] However, when asked in discovery to identify any expenditures related to investments in the distribution system due to NEM customers, UNS replied that it "has not attempted to track and assign all of the additional costs associated with the above impacts caused by the addition of these partial requirements customers, but is certain none of these services can be provided without additional costs."[71] This assumption is not necessarily true. Rather than requiring additional investments such as UNS describes, DERs, including demand response and distributed storage, can provide frequency control. Smart inverters can also provide power factor correction, as well as voltage and frequency control. As I discuss below, proactive planning for efficient DER deployment can avoid the need for capital investments and reduce overall costs for all customers.[72]

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

A. No. It is clear from the information provided by the Company that UNS's claims regarding the impacts of excess generation on the grid are not based on an analysis of the utility's own system. The limited impacts that UNS has been able to identify on its own system do not point to a large-scale problem due to these issues.

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

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

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

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[70] Craig A. Jones Direct Testimony ("Jones Direct Test.") at 15, n.4 (May 5, 2015).
[71] UNS Resp. to VS 3.03(c) (Ex. BK-2 at 13).
[72] *See infra* at section 8.

5.1 The Commission should not approve UNS's proposed amendments to the NEM tariff

Q. What is net metering?

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

> "'Net Metering' means service to an Electric Utility Customer under which electric energy generated by or on behalf of that Electric Utility Customer from a Net Metering Facility and delivered to the Utility's local distribution facilities may be used to offset electric energy provided by the Electric Utility to the Electric Utility Customer during the applicable billing period."[73]

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

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

A. UNS has proposed to decrease the credit NEM customers receive for their excess generation. Specifically, UNS has proposed to implement a new NEM tariff for customers submitting an application for interconnection after June 1, 2015, which would eliminate the compensation of NEM customers' excess generation at the retail rate. Instead, UNS would compensate NEM customers for their exports at the "Renewable Credit Rate."[74] UNS is additionally requesting a partial waiver of Rule R14-2-2306 to "eliminate the 'roll over' of excess generation to offset future usage."[75] In place of the excess generation roll over, UNS proposes that NEM

[73] A.A.C. R14-2-2302(11).
[74] Tilghman Direct Test. at 7:3–5, 8:18–21.
[75] *Id.* at 7:6–7.

customers taking service under the new rider be able to "carry over unused bill credits to future months if they exceed the amount of their current bill."[76]

Q. What is the Renewable Credit Rate?

A. UNS's proposed Renewable Credit Rate is based on the most recent utility-scale renewable energy purchased power agreement ("PPA") connected to UNS or sister company Tucson Electric Power's ("TEP's") distribution system.[77] UNS proposes that the Renewable Credit Rate be updated annually with the Company's REST filing and that it would be based on the most recent comparable utility-scale PPA.[78] The Renewable Credit Rate proposed in this application is based on a PPA signed December 17, 2014, for a 21.5 MW ground mounted PV system.[79] The initial Renewable Credit Rate based on this PPA would be set at 5.84¢/kWh.[80]

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

A. UNS witness Dukes claims that adoption of the Renewable Credit Rate "is a further step to send more accurate price signals to net metered customers about their true energy costs."[81] He additionally testifies that the rate will "partially alleviate the bypass of fixed cost recovery that occurs when customers self-generate a portion of their energy requirements,"[82] and that it "will reduce but not eliminate the subsidy" to NEM customers.[83]

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[76] Dukes Direct Test. at 20:1–2.
[77] Tilghman Direct Test. at 7:14–17.
[78] *Id.* at 8:4–9.
[79] UNS Resp. to VS 3.01(b)–(d) (Ex. BK-2 at 11).
[80] Tilghman Direct Test. at 7:14–15.
[81] Dukes Direct Test. at 4:20–21.
[82] *Id.* at 20:18–20.
[83] *Id.* at 22:27.

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

A. As demonstrated in earlier sections of this testimony, when compared to the impact of declining sales to industrial and mining customers and EE/other reductions, DG is an insignificant cause of the reduced retail sales that the Company claims are driving the need for its rate design proposals. In addition, as shown above, NEM customers account for less than 2% of the residential customers that UNS claims do not pay their fair share of the fixed costs of UNS's system. Because UNS's justifications for reducing DG levels are unsupported by the evidence, the Commission should reject its attempt to reduce DG adoption by decreasing the retail rate credit NEM customers receive for excess generation. In addition, to the extent that UNS claims compensation for DG exports shifts costs to other customers on the UNS system—a contention I also dispute—focusing on the cost shift UNS attributes to NEM customers would be unduly discriminatory because NEM customers would represent just 2% of such customers.

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

A. UNS has not provided any evidence in this proceeding to establish whether or not the current NEM tariff design, including compensation for NEM exports at the full retail rate, results in any cost shift either to or from NEM customers. The question of whether a cost shift exists depends on the relationship between the retail rate credit and the value of exported solar generation. UNS has provided <u>no evidence</u> on which to analyze the relationship between the Company's retail rate and the value of exported solar generation. Before the reasonableness of the proposed Renewable Credit Rate can be assessed, the Commission must establish the value of the exported DG for which the Renewable Credit Rate is intended to compensate. Because there has been no assessment of the value of distributed solar on the UNS system, there is no basis on which to conclude whether retail rate compensation is too high or too low, or if a cost shift exists (and in which direction).

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

A. In order to determine the relationship between the value of distributed solar and the retail rate, a full benefit/cost analysis would need to be completed. To produce a reliable and reasonable result, it is vital that an unbiased party completes the benefit/cost analysis and that the analysis is comprehensive in scope. Different approaches to value of solar studies can produce large variations in the result, as evidenced by studies completed of the APS system. In 2013, competing studies sponsored by APS and the solar industry concluded that the value of solar was 3.56¢/kWh and 21–24¢/kWh, respectively.[84] The Commission must guide the development of the benefit/cost analysis for UNS's service territory to ensure that any future analysis produces a reliable result.

Q. Are there any guidelines for how a benefit/cost analysis should be conducted?

A. Yes, the Interstate Renewable Energy Council has developed a useful guidebook on the calculation of the costs and benefits of distributed solar generation that can inform the Commission's process.[85] The guidebook builds on experiences throughout the country to propose a standardized and reliable approach to the analysis. The guidebook recommends that policy makers consider the following categories of benefits and costs, and provides guidance on their calculation:

- Avoided Energy Benefits
- System Losses
- Generation Capacity

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[84] Interstate Renewable Energy Council, Inc., *A Regulator's Guidebook: Calculating the Benefits and Costs of Distributed Solar Generation* 5 (Oct. 2013), *available at* http://votesolar.org/wp-content/uploads/2013/09/IREC_Rabago_Regulators-Guidebook-to-Assessing-Benefits-and-Costs-of-DSG1.pdf.
[85] *Id.*

- Transmission and Distribution Capacity
- Grid support services
- Financial services
- Security services
- Environmental services
- Social services
- Customer costs
- Utility costs, and
- Decline in value for incremental solar additions at high market penetration.[86]

Before the Commission adopts an alternative export credit such as the Renewable Credit Rate, it should assess the relationship between the retail rate and the value of distributed solar by analyzing each of these categories of costs and benefits.[87]

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

A. No, in fact, evidence from other states suggests that the value of solar may exceed the retail rate. And in some cases, the value of distributed solar exceeds the retail rate by a significant amount. As discussed above, the results of distributed solar benefit/cost analyses can differ greatly depending on the assumptions and perspective of the entity sponsoring the study. As a result, it is important to look at studies sponsored or performed by an independent party, such as a state agency. A number of notable studies have been sponsored by independent state entities concluding that the benefits that distributed solar generation provides to the utility exceed the costs. Table 2 below summarizes the results of recent studies performed by or for state governments.

[86] *E.g.*, *id.* at 36, 42.
[87] The Commission is currently seeking to address these issues in Docket No. E-00000J-14-0023, and Vote Solar has intervened in that proceeding.

Table 2: Recent Benefit/Cost Studies

State	Date	Sponsor	Resulting Value
ME	1-Mar-2015	Legislature	33.7¢/kWh levelized[88]
MS	19-Sep-2014	PSC	17.0¢/kWh levelized[89]
NV	Jul-2014	PUC	18.5¢/kWh levelized[90]
MN	31-Jan-2014	Dep't of Commerce	14.5¢/kWh levelized[91]
VT	1-Oct-2014	Legislature	23.7¢/kWh levelized[92]

This experience in other states shows that the existence of a cost shift should not be assumed in this proceeding. As the studies in Table 2 demonstrate, state sponsored studies have found that the benefits of solar can be as high as 25-30¢/kWh in some jurisdictions. Without evidence on the benefits and costs of solar in the UNS territory, the Commission has no means to determine the need for an alternate export rate, nor a basis on which to evaluate the appropriateness of UNS's proposed Renewable Credit Rate.

Q. If the Commission elects to consider an alternate export rate, do you have any comments on the specific aspects of the Renewable Credit Rate proposal?

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

[88] Me. Pub. Utils. Comm'n, *Maine Distributed Solar Valuation Study* 6 (Apr. 2015), *available at* http://www.maine.gov/mpuc/electricity/elect_generation/documents/MainePUCVOS-FullRevisedReport_4_15_15.pdf.
[89] Elizabeth A. Stanton et al., Synapse Energy Econ., Inc., *Net Metering in Mississippi: Costs, Benefits, and Policy Considerations* 43 (Sept. 2014), *available at* http://www.synapse-energy.com/sites/default/files/Net%20Metering%20in%20Mississippi.pdf.
[90] Energy & Envtl. Econ., *Nevada Net Energy Metering Impacts Evaluation* 93 (July 2014), *available at* http://puc.nv.gov/uploadedFiles/pucnvgov/Content/About/Media_Outreach/Announcements/Announcements/E3%20PUCN%20NEM%20Report%202014.pdf?pdf=Net-Metering-Study.
[91] Peter Fairley, *Minnesota Finds Net Metering Undervalues Rooftop Solar*, IEEE Spectrum (Mar. 24, 2014), *available at* http://spectrum.ieee.org/energywise/green-tech/solar/minnesota-finds-net-metering-undervalues-rooftop-solar.
[92] Vt. Pub. Serv. Dep't, *Evaluation of Net Metering in Vermont Conducted Pursuant to Act 99 of 2014*, at 17 (Nov. 2014), *available at* http://psb.vermont.gov/sites/psb/files/Act%2099%20NM%20Study%20Revised%20v1.pdf.

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

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

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

A. UNS rationalizes linking the Renewable Credit Rate to the most recent renewable PPA connected to the generation system based on the assertion that "as long as the Company has a renewable energy requirement and would otherwise be procuring renewable energy, it [is] reasonable to pay the prevailing wholesale market price for renewable energy on our distribution grid."[93] But crediting DG exports at utility-scale renewable rates ignores many key benefits provided by DG that are not provided by utility-scale renewables. Distributed solar's unique benefits compared to utility-scale solar generation include higher generation capacity value due to the geographic diversity of DG systems, potentially greater avoided distribution costs and grid services from DG, and greater local employment benefits accruing from DG.

UNS attempts to treat DG and utility-scale solar as interchangeable renewable energy sources, but Arizona and other states have recognized that this is not the case. For example, the Arizona Renewable Energy Standard ("RES") sets a 15% renewables requirements by 2025, and 30% of that requirement must be met with DG.[94] The Commission thus recognizes that DG and utility-scale solar are not fungible resources. Moreover, several other states' renewable energy standards contain similar DG carve outs acknowledging that DG and utility-scale solar are

[93] UNS Resp. to TASC 1.13(d) (Ex. BK-2 at 46).
[94] A.A.C. R14-2-1804, R14-2-1805.

not equivalent.[95] UNS's attempt to equate the value of DG and utility-scale solar without a proper assessment of DG's costs and benefits should be rejected.

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

A. UNS has proposed to base the Renewable Credit Rate on the single most recent contract and to update the rate annually. Utility supply contracts are complex agreements with pricing and terms established through a closed-door negotiation process, often with price escalators and performance-oriented terms. In fact, UNS has indicated that even the Company itself cannot predict future Renewable Credit Rates.[96] By setting the Renewable Credit Rate based on a single PPA, UNS has made the rate subject to large annual fluctuations. This can be seen through examination of utility-scale solar prices from recent TEP PPAs. The PPA used as the basis for UNS's proposal has a rate of 5.84¢/kWh, while another contract signed by TEP has a rate as high as 10.875¢/kWh.[97] A Renewable Credit Rate that could fluctuate so widely from year to year would subject NEM customers to significant uncertainty and volatility, potentially making financing of projects more difficult and expensive.

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

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[95] *See, e.g.*, Colo. Rev. Stat. § 40-2-124(1)(c)(I)(E), (1)(c)(II)(A) (3% DG carve out by 2020, with half of that requirement from retail DG); 20 Ill. Comp. Stat. 3855/1-56(b) (1% DG carve out, with half of that requirement from systems smaller than 25 kW); Minn. Stat. § 216B.1691 subdiv. 2f(a) (1.5% solar carve out, with 10% of that requirement from DG systems smaller than 20 kW); N.M. Code R. § 17.9.572.7(G) (3% DG carve out).

[96] UNS Resp. to TASC 1.13(d) (Ex. BK-2 at 46).

[97] UNS Resp. to VS 3.01(f) (Ex. BK-2 at 11).

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

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

> "If the kWh supplied by the Electric Utility exceed the kWh that are generated by the Net Metering Facility and delivered back to the Electric Utility during the billing period, the Customer shall be billed for the net kWh supplied by the Electric Utility in accordance with the rates and charges under the Customer's standard rate schedule."[98]

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

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

A. Yes, UNS has requested a partial waiver of Rule R14-2-2306 to "eliminate the 'roll over' of excess generation to offset future usage."[99] However, the Company has not addressed the fact that its proposal also violates the NEM rules by proposing to take the "net" out of net energy metering. The Commission has previously stated that compensation for exports at the retail rate is a fundamental part of the NEM rules. In Appendix B to Decision 69127 adopting the Renewable Energy Standard and Tariff Rules, the Commission explicitly addressed the question of customer compensation for generation supplied to the grid.[100] Faced

[98] A.A.C. R14-2-2306(C).
[99] Tilghman Direct Test. at 7:6–7.
[100] Decision No. 69127 at App. B 1:19–6:20 (Nov. 14, 2006).

with proposals, including a proposal from APS, to delete the requirement crediting exports at the full retail rate, the Commission concluded that "Net Metering is an important piece of the regulatory infrastructure for distributed generation" and did not approve APS's proposed change.[101] UNS's proposal would violate Commission rules, and the "partial waiver" it has requested would not cover the deviations from the NEM rules that the Company proposes.

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

A. Commission rules dictate that UNS must compensate NEM customers' exported DG at the retail rate. Absent any evidence to reliably determine whether the current retail rate is above or below the value of DG on the UNS system, there is no basis on which to support a departure from the current NEM compensation structure. In addition, the proposed Renewable Credit Rate has several significant flaws. Therefore, even if the Commission decides to consider an alternate export rate, the proposed Renewable Credit Rate should be rejected.

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

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

A. The Company has proposed to implement optional tariff schedules for residential and small commercial customers that include a demand charge, in addition to the basic service charge and volumetric energy charge. This type of rate design is referred to as a "three-part" rate structure. UNS has proposed that a three-part rate structure be mandatory only for NEM customers.[102] While the Company has not

[101] *Id.* at 2:2–5, 6:8–9.
[102] Dukes Direct Test. at 4:1–2, 5:2–3.

proposed mandatory three-part rates for all residential and small commercial customers at this time, it hopes to "make such a move possible in the future."[103]

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

A. UNS claims:

> "Three-part rates more fairly allocate costs to the customers within a class that 'cause' them and provide proper price signals that help customers make informed decisions regarding their energy and electrical system usage. Three-part rates also reward customers for better load factors and reductions in peak usage – attributes that lead to lower system costs, which benefits all customers."[104]

In addition, UNS points to eight other utilities that offer residential rates that include demand charges.[105]

Q. Do you agree that the demand charge proposed by UNS better reflects utility costs than the current rates that include only a basic service charge and volumetric energy charges?

A. No. UNS has proposed to charge customers based on the hour of maximum measured demand in the billing month, regardless of the time of day in which that demand occurs.[106] Many of the costs that UNS allocates to the demand charge are associated with the system peak, rather than individual customer peaks. Data on the annual UNS system peak for the last five years shows that the system peak can be expected to occur in the mid-afternoon during the summer months.[107] A residential customer, on the other hand, may set her peak demand in the early morning while making coffee, and using the clothes dryer and hair dryer. Therefore, it is not clear that a demand charge based on the individual customer peak, which can occur at any time day or night, would result in fair allocation of costs among customers within the residential and small commercial classes.

[103] *Id.* at 18:6–13.
[104] *Id.* at 17:11–15.
[105] *Id.* at 16:22–17:6.
[106] Jones Direct Test. Ex. CAJ-3 (Proposed RES-01 Demand tariff).
[107] UNS Resp. to WRA 1.06 (Ex. BK-2 at 50).

Q. Do you agree that demand charges would send price signals that help customers make informed decisions regarding their energy and electrical system usage?

A. I do not. In order for a rate structure to send a price signal to help customers make informed decisions, the customers must be able to understand how to respond to that price signal. In the case of demand charges, residential and small commercial customers would first need to know when their peak demands occur. Because the demand charge would be assessed based on the highest hour of consumption in a given billing period, there would be an average of 730 hours in which each individual customer's peak demand may occur. Moreover, the day of the week and hour of the day in which that peak occurs may vary from month to month. In addition, to gain an understanding of when their peak demand may occur in any given month, the customer would also need to understand how common behaviors such as staying home sick from work, having friends over for a poker night, or hosting an annual family holiday may impact the level and timing of their peak demand. Even if the typical residential customer were to have this level of understanding of their peak demand, it is not clear how that customer would be able act to reduce their peak demand.

Making an informed decision to respond to the price signal of peak demand can happen in one of two ways: through behavioral changes or through adoption of enabling technologies. As described above, it is unlikely that the average residential customer who spends only a few minutes a month focused on their electric bill will possess the information necessary to modify behavior in response to demand charges without enabling technologies. In fact, it is most likely that a mandatory demand charge would function as an additional fixed charge for residential and small commercial customers. While enabling technologies may in fact allow residential and small commercial customers to manage peak demand over time, these technologies are uncommon, costly to implement, and have not achieved widespread adoption. This fact supports demand charge rates as an optional tariff, but shows that they are not appropriate for mandatory implementation.

Q. Why do you say that a mandatory demand charge would likely function as an additional fixed charge for residential and small commercial customers?

A. A mandatory demand charge would 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. This is confirmed by survey evidence from California, which found that customers compared a demand charge to a fixed customer charge because they failed to comprehend the basic mechanics of the demand charge.[108] A survey of customers in Ontario who are familiar with time-of-use ("TOU") rates had similar results:

> "The concept of maximum use during peak times is difficult for people to understand and raised concern among a few. There is no template for measuring maximum use that people are used to in the way they understand TOU. It was not obvious how this would be calculated.
>
> Without precise details of this there was concern expressed by some that small lapses in their conservation efforts will mean they will have to pay a high price for that (even if they conserve diligently on the vast majority of days during peak times). So there will be questions of fairness if they have conserved on the vast majority of days during peak demand times and essentially helped to reduce peak consumption."[109]

Q. How do you interpret these customer survey results?

A. The customers in Ontario are calling out the "gotcha" element of demand charges. Residential customers who elect to purchase only energy efficient appliances, invest in home weatherization, and turn off lights in rooms when not in use could be penalized with a high demand charge that occurs during a single hour of the month—for example, when they prepare to host their child's birthday party and

[108] Hiner & Partners, Inc., *RROIR Customer Survey Key Findings* 12, 22 (Apr. 16, 2013), *available at* http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M065/K932/65932012.PDF (App. A.1).

[109] Gandalf Grp., *Ontario Energy Board: Distribution Charge Focus Groups* 9 (Oct. 2013), *available at* http://www.ontarioenergyboard.ca/oeb/_Documents/EB-2012-0410/Appendix%20B%20-%20Gandalf%20Distribution%20Focus%20Groups.pdf.

happen to be running the air conditioning, baking a cake in the oven, and running the clothes dryer at the same time. This concept is not just a hypothetical. The experience of Arizona public schools has shown similar results.

For example, the Mingus Union High School District ("Mingus") in Cottonwood implemented $1.1 million in energy savings measures during the 2013-2014 fiscal year.[110] These measures included lighting replacements, HVAC replacements, installation of an energy management system, and behavioral conservation efforts resulting in a decrease in electric consumption of nearly 30%.[111] However, when APS added a demand charge to their rate schedule, Mingus saw their savings from these investments evaporate.[112] Even for a school district that has much greater resources to manage energy consumption than the average residential or small commercial customer, demand charges can be difficult to respond to.

Q. UNS states that at least eight other utilities offer residential rates that include demand charges. Are these demand charges mandatory?

A. Generally not. While UNS claims that at least eight utilities in nine states offer residential rates that include a demand charge, they do not mention the fact that in all but one of these cases, the demand charge rate is optional. The only instance of a mandatory demand charge is in Salt River Project ("SRP") territory, where a demand charge was implemented earlier this year for customers with DG. While there has been much rhetoric in the UNS application about the need to "modernize" the rate structure, movement towards mandatory demand charges for all residential customers is in no way reflective of modern trends in ratemaking. Importantly, no regulatory commission in the nation has approved mandatory demand charges for residential customers.

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[110] Dr. Paul Tighe, Superintendent, Mingus Union High Sch. Dist., *Why Rates Matter: Case Studies of the Effect of Energy Rates on Users*, at slide 5 (Nov. 7, 2015), *available at* http://www.ariseia.org/download/AEATC/Why_Rates_Matter_Panel.pdf.
[111] *Id.*
[112] *Id.*

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

A. UNS specifically mentions that APS has an optional demand charge residential rate, which has been in effect since the 1980s and currently has 10% enrollment.[113] In a case study of its optional residential demand rate, APS explains that it "helps customers select the best rate at time of new service through [its] website rate comparison tool."[114] Not surprisingly, an examination of the relative size of residential customers that have self-selected onto the demand rate reveals that they have an average monthly consumption that is nearly three times the average monthly consumption of customers on the default rate.[115] Because the optional demand rate also includes a much lower volumetric rate, it is likely that the vast majority of APS customers who have chosen to take service on the demand rate have done so because it would lower their bills without any modification in consumption patterns. Current enrollment in APS's optional demand rate does not imply that customers in APS's territory have the ability to respond to the price signal set by demand charges. To the contrary, the fact that APS has marketed its optional demand charge rates for upwards of three decades with only 10% current enrollment demonstrates that 90% of APS's customers have either not gained an understanding of how the demand charge rate would impact them, or they have decided that the demand charge rate is not the best option for them.

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

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

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[113] Dukes Direct Test. at 17:7–8.
[114] Meghan Grabel, APS, *Residential Demand Rates: APS Case Study* 3 (June 25, 2015), *available at* http://www.ksg.harvard.edu/hepg/Papers/2015/June%202015/Grabel%20Panel%201.pdf.
[115] *Id.* at 7.

fell by 95%.[116] Both the SRP experience and the evidence from APS's optional demand charge make clear that the majority of residential customers do not fare well under demand charges.

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

A. UNS makes two claims to support mandatory demand charges for NEM customers. First, UNS claims that "two-part rates are designed to recover costs based on average consumption levels for full-requirements customers."[117] According to UNS, because NEM customers offset some of their energy requirements through onsite generation, the current rates that do not include a demand charge "are ill-equipped in accounting for how these customers use UNS Electric's system."[118] Second, UNS claims that requiring NEM customers to take service on a rate with a demand charge will help to mitigate the cost shift they allege is occurring.[119]

Q. Is there any evidence to support these claims?

A. In order to address these claims it is important to think about what makes NEM customers different from other customers. The difference is twofold: (1) NEM customers typically use DG to supply some proportion of their energy requirements and consume the balance of energy from the grid, and (2) NEM customers may export excess generation from their DG system to the grid.

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[116] Bobby Magill, *New Fees May Weaken Demand for Rooftop Solar,* Climate Central, Nov. 11, 2015, *available at* http://www.scientificamerican.com/article/new-fees-may-weaken-demand-for-rooftop-solar/.
[117] Dukes Direct Test. at 5:1–2.
[118] *Id.*at 4:26–5:1.
[119] *Id.* at 5:3–4.

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

A. UNS has not provided any evidence as to whether the load factors and energy requirements from NEM customers differ significantly from the load factors and energy requirements of non-NEM customers. In the Company's own words: "The Company has no actual data on whether monthly peak loads of residential customers with DG on the UNS Electric system differ from those of residential customers without DG."[120]

Even if UNS were to provide data on whether and how NEM customers' consumption patterns differed from non-NEM customers' consumption patterns, it would not automatically justify differential rate treatment for NEM customers. The residential and small commercial rate classes each inevitably contain customers with widely-varying consumption patterns, yet these diverse customers are subject to the same rate design. For example, cooling technology can drive significant differences in customer load factors, and urban customers with higher population density can have a lower per-customer cost to serve than rural customers who may require lengthy line extensions.

Any difference between the consumption patterns of NEM and non-NEM customers would have to be significantly greater than the inevitable diversity within the residential and small commercial classes in order to warrant a rate design singling-out NEM customers. Discriminatory rate treatment of NEM customers due to differing consumption patterns would be a slippery slope toward segregation of other portions of the residential and small commercial classes (e.g., by cooling equipment or urban vs. rural customers). Piecemeal subdivision of the residential and small commercial classes in this manner would add significant complexity and may harm low- and fixed-income ratepayers.

[120] UNS Resp. to WRA 1.15 (Ex. BK-2 at 51).

In addition, UNS has claimed that "two-part rates are designed to recover costs based on average consumption levels for full-requirements customers."[121] This claim, however, is false. UNS neglected to isolate NEM customers as a sub-class in their cost of service study, electing instead to group NEM customers with the rest of the residential and small commercial classes.[122] As a result, the two-part rates proposed by UNS were designed to recover costs based on average consumption for the entire residential and small commercial classes, including NEM customers.

Q. Would a mandatory demand charge for NEM customers reduce the alleged cost shift between NEM and non-NEM customers?

A. No, UNS's claim that a mandatory demand charge would help mitigate a cost shift is also unsupported by the evidence. To the extent that UNS contends NEM customers cause a cost shift by offsetting a portion of their energy requirements with DG, the data analyzed in an earlier section of this testimony shows that DG has not been a significant driver in the reduction of retail sales. In addition, NEM customers do not represent a meaningful proportion of the customers UNS alleges are causing a cost shift due to low level of usage. In fact, NEM customers represent just 2% of the customers who do not pay their fair share of fixed costs according to UNS's rationale. There is also no evidence that compensating NEM customers for DG exports at the retail rate overvalues their excess generation and creates a cost shift.

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

A. NEM customers are similarly situated to other residential and small commercial customers regarding the ability to understand and respond to demand charges. DG systems are effective at reducing the customer's consumption of energy supplied by the utility, but they can have little impact on individual customer peak demand.

[121] Dukes Direct Test. at 5:1–2.
[122] UNS Resp. to VS 1.04 & Staff 2.079 (Ex. BK-2 at 1, 32).

This is because the timing of the customer's peak may occur outside the hours in which the DG system is operating. This is illustrated by UNS's own assumptions in its assessment of a hypothetical NEM customer who sizes their DG system to offset 100% of load. UNS's analysis assumes that the NEM customers' peak demand will be equivalent to the non-NEM customer's peak in all but 4 months of the year. In those 4 months, the peak demand will be reduced by 6% or less.[123] UNS has stated that it "has no actual data on whether monthly peak loads of residential customers with DG on the UNS Electric system differ from those of residential customers without DG."[124]

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

A. UNS's proposal to require demand charges for NEM customers would effectively function as an additional fixed charge, because most NEM customers lack the ability to effectively respond to the price signal in demand charges. Imposing additional fixed charges solely on NEM customers would be unduly discriminatory because UNS has not provided evidence that NEM customers shift costs to other customers, nor that NEM customers constitute a meaningful proportion of the residential customers that allegedly do not pay their fair share of fixed costs.

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

A. I recommend that UNS's proposed demand rates for residential and small commercial customers be approved only as optional rate schedules for customers with and without DG.

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[123] Dukes workpaper "RES Demand-DG_04-29-15_FINAL_v1.xlsx" (Ex. BK-2 at 54).
[124] UNS Resp. to WRA 1.15 (Ex. BK-2 at 51).

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

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

A. Yes, 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.

Q. What is the LFCR?

A. The LFCR is a partial decoupling mechanism that supports EE and DG "at any level or pace set by this Commission."[125] The LFCR was agreed upon through settlement negotiations during UNS's last general rate case and reflects a compromise between UNS, Commission Staff, and the Residential Utility Consumer Office ("RUCO"). The LFCR "is intended to recover a portion of distribution and transmission costs associated with residential, commercial and industrial customers when sales levels are reduced by EE and DG, but is not intended to recover lost fixed costs attributable to generation and other potential factors, such as weather or general economic conditions."[126] In this manner, the LFCR appropriately balances UNS's desire to recover fixed costs with Commission policy that promotes certain levels of EE and DG adoption.

[125] Decision No. 74235 at 24:12 (Dec. 31, 2013).
[126] *Id.* at 11:21–24.

Q. How is the LFCR applied to customer rates?

A. The LFCR is applied to rates as percentage-based charge on total Delivery Service and Power Supply Charges. The current LFCR is 0.6985% for EE and 0.1693% for DG.[127] This means that EE-related charges are more than four-times the level of DG-related charges, but both charges are small. UNS estimates that the average residential customer pays only 61¢/month for the EE-related LFCR and 15¢/month for the DG-related LFCR.[128]

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

A. UNS claims that its proposed NEM rate design changes are needed to ensure greater recovery of fixed costs.[129] However, a transparent and targeted rate mechanism designed specifically to compensate UNS for lost fixed costs due to EE and DG already exists: the LFCR. In discovery, UNS states that while the LFCR was designed to recover a portion of the costs not paid by partial requirements customers, "[i]mproving cost recovery through rate design is a much better option."[130] In my opinion, addressing fixed cost recovery through the LFCR is a more transparent and efficient method than the proposed rate design. The current LFCR, unlike UNS's other proposals, does not create a disincentive for EE and DG.

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

A. Rate decoupling mechanisms, such as the LFCR, are useful tools that enable policy makers to separate utility revenue streams from the volume of sales. The Commission has recognized the value of sales reduction measures, including EE

[127] UNS Electric Statement of Charges (Jan. 1, 2014), *available at* https://www.uesaz.com/doc/customer/rates/electric/UES-801.pdf.
[128] UniSource Energy Servs., Lost Fixed Cost Recovery Mechanism, https://www.uesaz.com/news/updates/LFCR/ (last visited Dec. 8, 2015).
[129] *E.g.*, Dukes Direct Test. at 20:18–20.
[130] UNS Resp. to VS 3.08(e) (Ex. BK-2 at 14).

and DG, and has promoted certain levels of these activities through targeted policies. Under the current utility business model (i.e., return on rate base regulation), a reduction in sales can be problematic, not just because it results in fewer units of energy over which to spread fixed costs, but also because a reduction in sales can delay or eliminate the need for future infrastructure investments that the utility could add to its rate base thus boosting earnings.

UNS's preferred approach is to recover fixed costs through unavoidable fixed charges.[131] But this approach would undermine the Commission's efforts to increase EE and DG by making these measures less cost-effective, as lower per kWh volumetric rates decrease the value of each kWh saved by EE and DG. Indeed, UNS has stated that "an over-dependence on fixed cost recovery through volumetric energy charges creates an economic disincentive for the utility to promote conservation, EE, and DG."[132] The LFCR has been designed precisely to address that disincentive and to compensate the utility accordingly.

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

Q. Has UNS proposed to maintain the LFCR that was approved in the last Settlement?

A. No. UNS has proposed a number of changes to the LFCR. Among the proposed changes, UNS has requested the addition of generation related costs in the LFCR.[133] UNS has additionally proposed a number of other changes to the LFCR that are not addressed by my opening testimony. I reserve the opportunity to address these additional proposals in surrebuttal if necessary.

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[131] Jones Direct Test. at 38:5–8.
[132] *Id.* at 36:20–21.
[133] *Id.* at 74:25–75.3.

Q. Do you agree that generation related costs should be included in the LFCR?

A. I do not. UNS states that while it agreed to the exclusion of generation costs in the settlement, the Company did not agree with excluding generation costs in theory and it is now asking that these costs be added to the LFCR.[134] UNS claims its generation assets are necessary to meet current and anticipated load, and that it incurred these asset costs to serve all customers, including those who have reduced consumption due to EE and DG.[135] However, according to its most recent Integrated Resource Plan ("IRP"), UNS-owned generating assets, including the newly acquired interest in Gila River, account for just over 60% of the utility's capacity obligations.[136] UNS must acquire nearly 40% of its capacity obligations on the market or through future commitments. UNS thus has the ability to take projected levels of EE and DG into account as it procures capacity needed to meet its remaining resource adequacy obligations. As a result, UNS is able to avoid fixed generation costs associated with EE and DG, and these costs should therefore be excluded from the LFCR.

Q. Please summarize your recommendations regarding the LFCR.

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

In addition, the Company maintains sufficient flexibility in generation capacity procurement to reasonably account for EE and DG sales reductions while avoiding stranded costs. Therefore, generation related costs are not appropriately

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[134] *Id.* at 74:26–75.3.
[135] *Id.* at 75:7–11.
[136] UNS Electric, Inc., *2014 Integrated Resource Plan* 55 (Apr. 2014), *available at* https://www.uesaz.com/doc/planning/2014-UES-IRP.pdf.

classified as "lost fixed costs." The Commission should reject UNS's proposal to add generation related charges to the LFCR.

6 UNS has not adequately evaluated the impacts of its proposals

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

A. No. UNS has not adequately evaluated the impacts of its rate design proposals. As I discuss in detail below, UNS has failed to sufficiently analyze (1) how its proposed rate design changes will impact NEM customers; (2) the costs of service and benefit/cost analyses related to its DG proposals, as required by Commission Rule 14-2-2305; (3) the regulatory compliance risks resulting from its proposals; and (4) the solar jobs created by DG in Arizona that the proposals may put at risk.

6.1 UNS did not reliably assess the impacts of its proposals on NEM customers

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

A. Witness Dukes claims that he shows "how DG customers still save on their total electric bill" as a result of UNS's proposals.[137] However, the analyses put forth in his testimony are not based on actual NEM customer data.

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

A. In the Direct Testimony of witness Dukes, UNS presents two tables that purport to show the average monthly electric bills for residential customers with electric usage levels of 500 kWh, 900 kWh, 1,200 kWh, and 1,500 kWh.[138] The data in

[137] Dukes Direct Test. at 5:4–5.
[138] *Id.* at 20–21, 28–29.

both of these tables were derived based on average full requirements customer load shapes with an engineering-based assessment of solar generation based on the assumption that customers will size their PV systems to offset 100% of annual energy requirements.[139] These tables were not based on actual NEM customer data.

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

A. UNS has not provided sufficient information to answer that question. UNS was asked in discovery, "How many of the residential solar PV systems in UNS's territory are sized to yield zero excess kWh?"[140] UNS replied that "[t]he Company does not track that information."[141] Vote Solar further asked UNS for any data, analyses, or other documentation to support the statement in Mr. Tilghman's testimony that net metering encourages NEM customers to oversize their DG system.[142] UNS never provided any data, analyses, or other documentation to support these claims.[143]

Vote Solar also requested data, analyses, and other documentation in support of Mr. Tilghman's claim that "[m]ost customers attempt to generate between 90%-100% [of their connected load annually].[144] UNS replied that "[c]ustomer applications received by the Company validate the fact that most applications and system sizes are designed to provide a near net-zero home based on the customer's annual consumption."[145] The Company, however, declined to provide any actual data.

After repeated questioning from various parties, UNS has been unable to provide any evidence to support its assumption that the "typical" solar facility is sized to

[139] Dukes workpaper "RES Demand-DG_04-29-15_FINAL_v1.xlsx" (Ex. BK-2 at 54).
[140] UNS Resp. to TASC 1.34(a) (internal quotation marks omitted) (Ex. BK-2 at 47).
[141] *Id.*
[142] UNS Resp. to VS 2.15 & VS 3.18 (Ex. BK-2 at 6, 20).
[143] *Id.*
[144] UNS Resp. to VS 2.21 (Ex. BK-2 at 9).
[145] *Id.*

offset 100% of customer load. In addition, UNS has not provided actual data on the average bills of customers before and after going solar,[146] and the Company has not supplied a bill frequency analysis for NEM customers despite requests to do so.[147]

Q. What does this imply about UNS's assessment of the impact of its proposals on NEM customers?

A. Because I cannot verify UNS's claims that the "typical" NEM customer will offset 100% of load, there is no basis on which to evaluate the reasonableness of UNS's purported NEM customer impacts from the Company's rate design proposals. Even if this claim could be verified, it is likely that at least some level of diversity exists among the NEM customers. This diversity would also need to be understood to provide a reliable assessment of the impact of the proposals on NEM customers.

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

A. To ensure that a rate change is just and reasonable, utilities often develop an assessment of representative load data for customers impacted by a rate proposal in order to provide evidence that a new rate will not unfairly impact the utility's customers. UNS acknowledges this with the following statement: "To best determine the true impact on the customer and the Company revenues, we went to great lengths to determine the appropriate levels of billing determinants. It was essential that we had a complete understanding of the billing determinants as we modified provisions within the tariffs."[148] In addition, UNS states that "in developing these proposed modifications, a thorough analysis must be performed to best ensure that the impacts on the customer are understood and the proposals

[146] UNS Resp. to TASC 1.10 (Ex. BK-2 at 45).
[147] UNS Resp. to VS 1.04 (Ex. BK-2 at 1).
[148] Jones Direct Test. at 33:6–9.

are fair and equitable."[149] However, despite UNS's own assertions that it is essential to have a complete understanding of the billing determinants and that a thorough analysis must be performed to ensure proposals are fair, UNS's cost of service study does not separately analyze NEM customer billing determinants.

6.2 UNS did not provide the costs of service and benefit/cost analyses required by Commission Rule 14-2-2305

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

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

> "Net Metering charges shall be assessed on a nondiscriminatory basis. Any proposed charge that would increase a Net Metering Customer's costs beyond those of other customers with similar load characteristics or customers in the same rate class that the Net Metering Customer would qualify for if not participating in Net Metering shall be filed by the Electric Utility with the Commission for consideration and approval. <u>The charges shall be fully supported with cost of service studies and benefit/cost analyses. The Electric Utility shall have the burden of proof on any proposed charge</u>."[150]

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

A. No. While UNS attempts to single out NEM customers for differential treatment compared to non-NEM customers, the Company's cost of service study does not analyze NEM customers as a separate group of customers from the residential and small commercial classes. As a result, the cost of service study does not adequately support any new or additional charges for NEM customers.

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149 *Id.* at 33:20–22.
150 A.A.C. R14-2-2305 (emphasis added).

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

A. No. UNS has not provided any assessment of the costs or benefits of its proposal. UNS has not even analyzed the billing impact of its proposals on NEM customers, not to mention the impact its proposals may have on DG adoption rates.[151] Furthermore, as discussed above, UNS has failed to conduct a benefit/cost analysis to support its proposal to modify the NEM tariff.

6.3 <u>UNS did not evaluate how its proposals could create regulatory compliance risks</u>

Q. What are the potential implications of UNS's proposals regarding DG rate design changes?

A. UNS has proposed far-reaching changes in DG rate design that have the potential to severely undermine the solar market in its territory. The recent experience with SRP clearly demonstrates that rate design changes can significantly impact solar adoption rates. If the Commission were to approve UNS's proposals to compensate customers for their DG exports at the Renewable Credit Rate and to impose a mandatory demand charge rate on NEM customers, growth of DG on the UNS system would most certainly be reduced. Indeed, it is possible that UNS's proposals may even put the utility's regulatory compliance at risk and result in significant additional costs for ratepayers.

Q. Why would UNS's regulatory compliance be at risk?

A. The RES regulations require that UNS generate a minimum of 15% of its energy from renewable resources by 2025, with an interim target of 6% in 2016.[152] The regulations additionally contain a distributed renewable energy requirement that requires UNS to meet 30% of its RES requirement with distributed renewable

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[151] UNS Resp. to VS 2.09(a) (Ex. BK-2 at 4).
[152] A.A.C. R14-2-1804.

energy resources.[153] While it is clear that this proposal may have a significant impact on the rate of DG growth in UNS's territory, UNS has not analyzed how large that impact may be.[154] It has, however, forecasted the expected level of DG adoption without its proposed changes and has predicted that under the current NEM tariff structure, DG adoption would be expected to continue at the pace required to meet the RES targets.[155] This indicates that if the proposed NEM tariff changes were to impact DG adoption in UNS's territory, it may have difficulty meeting the RES targets. Of additional concern is the fact that in its most recent RES Implementation Plan filed on July 1, 2015, UNS indicated that it will be unable to meet the 2016 small commercial DG requirement under the RES and requested a waiver from the Commission.[156]

If UNS has difficulty meeting the DG requirement under the RES, it may have significant consequences for UNS ratepayers. In UNS's most recent IRP, the utility examined a scenario in which UNS achieves only about 50% of the EE and DG targets directed by the Commission.[157] In that scenario, UNS found that if EE and DG were to be significantly reduced, it would need to install additional combustion turbines in 2019 and 2024 to meet the additional load growth.[158] There would be a significant cost to ratepayers if UNS must pay for additional power plants because its customers install less DG as a result of the Company's proposals. The decision to allow these substantial changes to the current DG rate structure should not be taken lightly.

Q. **Would other aspects of UNS's proposals create regulatory compliance risks?**

A. Yes. As I discuss in detail below, UNS has proposed to significantly increase the fixed charges for residential and small commercial customers. These higher fixed

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[153] A.A.C. R14-2-1805.
[154] UNS Resp. to VS 2.09 (Ex. BK-2 at 4).
[155] *See id.*
[156] UNS Electric, Inc., *2016 Renewable Energy Standard Implementation Plan* 6 (July 2015), *available at* http://images.edocket.azcc.gov/docketpdf/0000162403.pdf.
[157] *See* UNS IRP, *supra* note 136, at 221.
[158] *Id.*

charges can have far reaching environmental compliance impacts. For example, the Clean Power Plan ("CPP") will require reductions in carbon dioxide emissions from the electric power sector, and the cost of CPP compliance can be significantly impacted by rate design. In a recent paper from the Regulatory Assistance Project, the authors found that rate designs that increase fixed customer charges have the potential to significantly increase customer consumption levels.[159] Because utilities dispatch electric generating units based in part on variable operating costs, marginal generating units that would respond to increases in consumption are generally less efficient than the units that have already been dispatched. As a result, the authors point out that small changes in customer usage can produce larger-than-average changes in total emissions.[160] This implies that "a utility with a progressive rate design that moves to a high-fixed-charge rate design may experience a significant increase in generation and emissions, making compliance with the CPP more difficult."[161] UNS's proposal to reduce the number of residential tiers would likely have a similar impact.

6.4 UNS should consider solar jobs along with the Economic Development Rider

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

A. UNS has proposed to offer a discounted rate to business customers with a projected peak demand of 1,000 kW or more, and a load factor of 75% or higher.[162] The rate discount would decline over a five year period beginning with a 20% discount in Year 1 and declining to 2.5% discount in Year 5.[163] The Economic Development Rider would be available for 5 years and enrollment

[159] Jim Lazar & Ken Colburn, Regulatory Assistance Project, *Rate Design as a Compliance Strategy for the EPA's Clean Power Plan* 2–3 (Nov. 2015), *available at* http://www.raponline.org/document/download/id/7842.
[160] *Id.* at 1.
[161] *Id.* at 3.
[162] Duke Direct Test. at 31:25–27.
[163] *Id.* at 32:23–24.

would be capped at 50 MW.[164] To qualify for the Economic Development Rider, a customer must qualify for at least one of two existing Arizona state tax programs.[165]

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

A. UNS points out that its service territory has been slow to recover from the recession and has lost several large customers in the past few years.[166] UNS claims that the Economic Development Rider would put UNS's service territory in a better competitive position to attract and expand business load, which would be beneficial to the entire customer base and the State of Arizona.[167]

Q. Will the Economic Development Rider generate new jobs?

A. That is unclear. UNS has not performed any estimation of the number of jobs (if any) that the Economic Development Rider would be expected to generate.[168]

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

A. Yes. As of November 2014, there were 9,170 solar workers employed in Arizona and with the vast potential for additional solar deployment it is expected that at least 3,000 new solar jobs could be created.[169]

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

A. As the Commission considers the merits of an Economic Development Rider that would reduce fixed cost recovery from participating customers,[170] it should also

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[164] *Id.* at 32:2–4.
[165] *Id.* at 32:7–10.
[166] *Id.* at 30:17–19.
[167] *Id.* at 31:16–20.
[168] UNS Resp. to VS 2.03(b) (Ex. BK-2 at 3).
[169] Solar Found., *Arizona Solar Jobs Census 2014*, at 4–5 (Feb. 2015), *available at* http://www.thesolarfoundation.org/wp-content/uploads/2015/02/Arizona-Solar-Jobs-Census-2014.pdf.

consider the very real economic benefits provided by the Arizona solar industry. UNS's proposed changes to the NEM tariff have the potential to destroy the solar market in UNS's service territory, putting real solar jobs at risk.

7 UNS Claims It Needs To Modernize Its Rate Design, But Its Proposals Are Regressive

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

A. UNS's application characterizes its proposals as necessary to "modernize" rate design.[171] The Company claims that "[i]n this proceeding, UNS Electric seeks approval for 21st century rates."[172]

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

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

7.1 UNS's request to increase fixed charges for residential and small commercial customers should be rejected

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

A. UNS proposes to increase all monthly basic service charges "in a manner consistent with the results of the [Customer Cost of Service Study] and equitable fixed cost recovery."[173] UNS proposes to increase the residential fixed charge

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[170] UNS Resp. to VS 2.03(a) (Ex. BK-2 at 3).
[171] Application at 8:5.
[172] Hutchens Direct Test. at 3:16.
[173] Jones Direct Test. at 34:12–13.

from $10/month to $20/month[174] and the small commercial fixed charge from $14.50-$16.50/month to $30/month.[175] Current and proposed fixed charges for residential and small commercial customers are summarized in Table 3.

Table 3: Current and Proposed Fixed Charges – Residential and Small Commercial[176]

Cost Study	Residential	Small Commercial
Current Fixed Charge	$10.00	$14.50-$16.50
Proposed Fixed Charge	$20.00	$30.00

Q. What support does UNS give for its proposal?

A. UNS has completed a customer cost of service study ("CCOSS"), which includes an embedded cost study and a marginal cost study. UNS says "[t]he goal of the CCOSS is to determine fair cost allocation and rate design among the customer classes based on the principle of cost causation"[177] In developing the CCOSS, UNS classified utility costs into three basic categories: customer, demand, and energy.[178] UNS's approach to the CCOSS was similar to the approach used in the last general rate case, with one notable exception in the methodology for allocating distribution-related costs.

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

A. UNS has proposed a significant change to the methodology for classifying distribution-related costs, which has inflated its estimates of customer-related costs. In the last rate case, UNS used the Basic Customer Method, basing customer costs on "metering, services, meter reading, customer service and

174 *Id.* at 40:26–41.1.
175 *Id.* at 43:14–16.
176 *Id.* at 40:26–41.1, 43:14–16.
177 *Id.* at 3:17–19.
178 *Id.* at 17:21–22.

billing."[179] In its application, UNS has proposed to re-classify a significant amount of additional costs as customer-related through the Minimum System Method.

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

A. The Minimum System Method is an approach to utility cost classification that looks at the theoretical minimum demand of a customer and estimates the smallest size of infrastructure necessary to serve the theoretical minimum customer, including poles, cable, transformers, etc. Under the Minimum System Method, investments in the theoretical minimum sized infrastructure are allocated to the customer cost function. The Minimum System Method is not a new approach to utility cost classification. In fact, Professor Bonbright addressed this method in his seminal text, "Principles of Public Utility Rates" in 1961. Bonbright did not agree with the Minimum System Method for customer cost allocation, stating that "the inclusion of the costs of a minimum-sized distribution system among the customer-related costs seems to me clearly indefensible."[180]

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

"In this case, the only directive the Commission will give regarding future cost-of-service studies is to repeat its rejection of the inclusion of the costs of a minimum-sized distribution system among customer-related costs. As the Commission stated in previous orders, the minimum system method is likely to lead to the double allocation of costs to residential customers and over-allocation of costs to low-use customers. Costs such as meter reading, billing, the cost of meters and service drops, are properly attributable to the marginal cost of serving

[179] Craig Jones Direct Testimony in UNS 2013 General Rate Case, Docket No. E-04204A-12-0504, at 16:26–27 (Dec. 31, 2012), *available at* http://images.edocket.azcc.gov/docketpdf/0000141155.pdf.
[180] James C. Bonbright, *Principles of Public Utility Rates* 348 (1961), *available at* http://media.terry.uga.edu/documents/exec_ed/bonbright/principles_of_public_utility_rates.pdf.

a single customer. The cost of a minimum-sized system is not. The parties should not use the minimum system approach in future studies."[181]

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

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

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

Table 4: CCOSS Customer Cost Results using Minimum System Method[182]

Cost Study	Residential	Small Commercial
Marginal Customer Cost	$51.82	$102.03
Embedded Customer Cost	$14.00	$28.18

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

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

"The embedded cost of service study guides the allocation of revenues among the classes of service .... In order to fully evaluate the appropriate level of basic service charge, a marginal cost of service is required in order to support and reflect a valid price signal related to connecting customers.... Together, the embedded and marginal cost studies provide the Commission with the full picture as to how total revenues should be allocated across classes; and in turn, how

[181] *Wash. Utils. & Transp. Comm'n v. Puget Sound Power & Light Co.*, 3d Supplemental Order, Docket Nos. U-89-2688-T & U-89-2955-T, at 71 (WUTC Jan. 17, 1990), *available at* http://www.utc.wa.gov/_layouts/CasesPublicWebsite/GetDocument.ashx?docID=89&year=1989&docketNumber=892688.
[182] Jones Direct Test. at 30:5–7.

customer costs and the cost of connecting a customer should be set to send correct price signals to customers and to encourage economic use of the system."[183]

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

A. It appears that UNS ultimately used the results of the embedded cost study for both customer-related costs and demand-related costs as the foundation of its customer charge proposal. This is evidenced by the Company's assertion that its $20 residential basic service charge proposal represents 37% of the $54.46 in combined customer and demand related charges identified for the residential customer.[184]

Q. How was the $54.46 in combined customer and demand related charges derived, and what is UNS's rationale for its importance?

A. UNS states:

"Historically, basic charges are limited to metering, meter-reading, service (service drop) to the specific customer, and customer service and billing. While these costs should be included in the basic service charge and may be used as the guide to what the basic service charge should be for classes with Demand Charges, they are not sufficient for classes without a Demand Charge."[185]

In support of this notion, UNS estimated the combined customer and demand related costs by adding together the $14.00 customer costs and $40.46 in demand costs from the embedded cost study to arrive at an estimate of $54.46 for residential customers.[186]

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[183] *Id.* at 30:24–31:8.
[184] *Id.* at 41:1–4.
[185] *Id.* at 37:5–9.
[186] While the $54.46 in total customer and demand costs identified by the UNS embedded cost study is similar to the marginal cost study result of $51.82, this similarity appears to be a coincidence.

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

A. It does not. Despite an over-allocation of costs to the customer-related category, the Minimum System Method identified only $14.00 in embedded customer costs for residential customers. In support of its proposal, UNS also looks at the $40.46 its own methodology classified as unrelated to the customer function. UNS claims "it must collect approximately $54 per month from residential customers to recover all of the fixed costs associated with providing them with electric service."[187]

This approach is wholly inappropriate. UNS is seeking to over-allocate costs to the customer charge by mischaracterizing demand-related costs as fixed costs. Demand-related costs identified by the CCOSS should not be considered in the assessment of an appropriate basic service charge, regardless of whether the customer class in question is subject to a demand charge. UNS's own assessment of cost causation in the CCOSS allocates demand-related costs based on various measures of customer usage. Therefore, these costs are variable and not fixed. Basic service charges should be limited to customer-related costs identified using the Basic Customer Method.

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

A. I have. To derive my estimate, I used the following methodology and calculations. In support of using the Minimum System Method, UNS developed an estimate of the proportion of distribution costs in FERC Accounts 364-368 that should be classified as customer-related.[188] UNS additionally assumed that a proportionate amount of operations and maintenance ("O&M") costs associated with these accounts should be customer-related, as well as a certain level of general plant

[187] Hutchens Direct Test. at 12:5–7.
[188] Jones Direct Test. at 22:1–4.

and administrative and general costs.[189] FERC Accounts 364-368 are associated with distribution system investments and are summarized in Table 5 below. Table 5 also shows the percent of costs by account that were allocated to customer costs in the current application and in the last approved rate case.

Table 5: Distribution Cost Allocation[190]

FERC Account	Description	Application Customer %	Last Rate Case Customer %
364	Poles Towers & Fixtures	60%	0%
365	Overhead Conductors & Devices	35%	0%
366	Underground Conduit	100%	0%
367	Underground Conductor	35%	0%
368	Line Transformers	60%	0%

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

A. I modified UNS's CCOSS to include the methodology the Company used in its last rate case for allocating FERC Accounts 364 through 368 and associated O&M, general plant, and administrative and general costs.[191] This allowed me to develop an estimate of the embedded and marginal customer costs under the Basic Customer Method that is consistent with the methodology employed in the last rate case. My results are summarized in Table 6 below.

Table 6: CCOSS Customer Cost Results using Basic Customer Method

Cost Study	Residential	Small Commercial
Marginal Customer Cost	$9.96	$12.48
Embedded Customer Cost	$7.50	$11.74

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189 *Id.* at 22:21–23:2.

190 2015 UNSE Schedule G – COSS.xlsx, tab Cust%; UNS Resp. to VS 3.14(b) (Ex. BK-2 at 16).

191 I also discovered a spreadsheet error in UNS's original CCOSS related to meter cost allocation. UNS has acknowledged the error and the results shown in my testimony have corrected for this error.

As shown in Table 6, using the Basic Customer Method instead of the Minimum System Method results in a significantly lower estimate of customer-related costs. When the Basic Customer Method is employed, the marginal cost for residential and small commercial customers is estimated at $9.96 and $12.48, respectively. The embedded cost is estimated at $7.50 for residential customers and $11.74 for small commercial customers. These results demonstrate that the Minimum System Method significantly over-allocates costs to the customer function.

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

A. They do not. In fact, an examination of the results of the CCOSS using the Basic Customer Method show that UNS's current basic service charges for residential and small commercial customers are reasonable and should therefore not be modified.

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

A. Yes. In addition to the very clear results of the CCOSS using the Basic Customer Method, the Commission should consider the policy implications of increasing fixed customer charges. In UNS's application, the Company states that "[m]odifying the rates to include a higher proportion of fixed costs in the monthly basic service charges will send customers the right price signals and provide additional support for the Company's efforts to promote EE and DG."[192] However, increasing fixed costs would be expected to decrease deployment of EE and DG due to the lower volumetric rate. What UNS appears to mean by this statement is that an increase to fixed charges would diminish the unrecovered fixed costs from EE and DG. As discussed above under the section on the LFCR, however, this argument is flawed. Any need for fixed cost recovery resulting from EE and DG growth is better addressed through the LFCR decoupling mechanism than through rate design.

[192] Jones Direct Test. at 37:21–24.

Increasing fixed charges as UNS proposes would have an impact beyond EE and DG. As discussed below, the Commission should take an active role in directing utilities to plan for the modern grid. This includes proactive planning on rate design structures that will enable efficient and cost-effective deployment of all distributed resources, not just EE and DG. Because higher fixed charges dampen the usage-based price signal, they interfere with price signals embedded in rates that motivate customers and DER providers to take action to reduce energy usage. A high fixed charge is not the "modern" rate design characterized by UNS, but rather a regressive blunt force instrument that is out of step with evolving technologies and the modern grid.

7.2 UNS's request to eliminate the third residential tier should be rejected

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

A. UNS has proposed elimination of the third tier in the standard residential rate.[193] UNS claims the third tier "adds no cost-based value to the rate class other than exacerbating the issues of fixed cost being inequitably recovered from the higher usage customers."[194] Interestingly, UNS has not proposed elimination of the third tier for standard small commercial rates despite the fact that it would seem to be subject to the same rationale.

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

A. An inclining block rate structure was first put into rates in 2008 with Decision No. 70628, which included the following Finding of Fact: "The inclining block rate structure, TOU rates and other rate design changes as set forth in the 2008 Settlement Agreement will promote energy conservation and beneficial load

[193] Dukes Direct Test. at 18:26–27.
[194] Jones Direct Test. at 42:5–6.

shifting."[195] Inclining block rates were never intended to be based on cost causation, but rather, were approved by the Commission for the express purpose of incenting conservation.

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

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

8 The Commission should consider UNS's proposals in the context of the modern grid

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

A. With increasing availability of new technologies, the fundamental operation of the distribution grid is changing. In the evolution to the modern grid, the consumer is becoming a much more active participant in the production and consumption of their electricity through various DERs.[196] The modern grid will empower customers of all sizes to manage their energy usage and production in coordination with the utility for the benefit of both the consumer and the grid. Small customers may participate through third party aggregators, while larger and more sophisticated customers may participate directly. Transition to the modern grid is being driven by technology development. This is already happening and will continue to accelerate as prices for photovoltaic generators, distributed energy storage, electric vehicles, and other technologies continue to decrease.

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[195] Decision No. 70628 at 46:22–23 (Dec. 1, 2008).

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

It is crucial that the Commission recognizes this evolution in order to ensure that DERs can be deployed in a way that provides maximum grid support and improves reliability, while lowering overall costs and maximizing consumer benefits. In a recent report from Lawrence Berkeley National Laboratory ("LBNL"), economists found that "DERs will not only improve customers' energy costs, resilience and power quality, they can help utilities avoid risky capital expenditures and operate their systems more efficiently. By facilitating DERs, utilities can both lower their costs and increase the benefits they can offer customers who deploy DERs . . . ."[197]

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

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

[197] *Id.*

According to the LBNL study:

> "DERs—with appropriate levels of coordination or virtual integration—can augment the capabilities of the distribution system and even reduce the amount of capital the utility must invest in it. Further, to the extent DER owners and hosts can realize additional value from DER ownership by, for example, providing frequency regulation or voltage support to the wholesale markets and the local distribution system, this leveraging of utility investment can be further enhanced. In effect, by substituting for utility investment, customer DERs can help keep utility revenue requirements within the bounds that increasingly price-sensitive customers will pay for."[198]

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

A. To date, UNS's grid evolution policies and planning have been limited. While the Company is planning to install meters capable of providing interval data for all customers and has implemented various EE programs, UNS does not have any policies or plans for how to integrate demand response, energy storage, or electric vehicles to maximize benefits for the grid and consumers.[199] As described above, while customers with electric vehicles can have large swings in energy requirements, UNS has no information on the current or forecast number of electric vehicles in its service territory.[200] The Company has also not performed any studies to determine the ability of its existing transformers to absorb increased load due to continued growth in popularity of electric vehicles.[201]

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

A. UNS has recommended far-reaching changes to rates paid by customers who elect to install DG. The changes seek to make DG less cost effective for customers and will very likely slow down or stall the pace of DG deployment in UNS's service territory. DG is just one of many forms of DER that will be deployed by

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[198] *Id.* at 18 (footnotes omitted).
[199] UNS Resp. to VS 2.13 (Ex. BK-2 at 5).
[200] UNS Resp. to Staff 12.3 (Ex. BK-2 at 41).
[201] UNS Resp. to Staff 12.6 (Ex. BK-2 at 42).

customers or third parties on the UNS system. However, UNS has not considered the potentially game-changing impacts of technologies like electric vehicles, demand response, and energy storage. Instead, UNS has focused on rate measures to slow down the pace of consumer-driven DG deployment. By neglecting to plan for DERs and penalizing early technologies, UNS is ensuring that the inevitable evolution of the grid will be less efficient, will come at a higher cost, and will limit customer choice.

9 Conclusions and Recommendations

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

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

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

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

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

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

Q. What are your recommendations for the Commission?

A. I recommend the following:

- The Commission should reject UNS's proposal to modify the existing NEM tariff and should not grant any waiver of the Commission's NEM rules.
- The Commission should reject UNS's proposal to create a mandatory demand charge for NEM customers.
- The Commission should reject UNS's proposal to include generation-related costs in the LFCR.
- The Commission should analyze how UNS's proposals will impact solar jobs when it considers the proposed Economic Development Rider.
- The Commission should require UNS to use the Basic Customer Method in its embedded and marginal costs studies in place of the Minimum System Method.
- The Commission should reject UNS's proposal to increase basic service charges for residential and small commercial customers.
- The Commission should reject UNS's proposal to modify the existing inclining block structure of residential rates.
- The Commission should begin a formal proceeding to address distributed resource planning.

Q. Does this conclude your testimony?

A. Yes, it does.

Exhibit BK-1

Statement of Qualifications

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

PROFESSIONAL EMPLOYMENT

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

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

Senior Associate, MRW & Associates
April 2007-August 2015

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

EDUCATION

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

PREPARED TESTIMONY

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

SELECTED PUBLICATIONS AND PRESENTATIONS

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

Exhibit BK-2

Discovery Responses Referenced in Testimony

UNS ELECTRIC INC.'S RESPONSE TO VOTE SOLAR'S FIRST SET OF DATA REQUESTS REGARDING THE 2015 UNS ELECTRIC RATE CASE
DOCKET NO. E-04204A-15-0142
September 8, 2015

VS 1.04

Please provide a bill frequency analysis for net metered customers based on the same strata and time frame as the response to VS Request 1-3 above.

RESPONSE:

Currently, the sales from net metering customers are booked in the total of their applicable standard offer tariff and not treated separately therefore all rate schedule bill frequencies as described in response to VS 1.03 also include net metering customers.

RESPONDENT:

Brenda Pries

WITNESS:

Craig Jones

UNS ELECTRIC INC.'S RESPONSE TO VOTE SOLAR'S FIRST SET OF DATA REQUESTS REGARDING THE 2015 UNS ELECTRIC RATE CASE
DOCKET NO. E-04204A-15-0142
September 8, 2015

VS 1.05

Please provide the information requested below regarding the following statement by Mr. Dukes at page 12, lines 9–13 of his direct testimony: "Nearly one out of every four residential (Residential RES-01) bills issued by UNS Electric during the test year – 205,129 to be precise – reflected usage of 300 kWh or less. Because even a studio apartment with basic appliances and moderate usage would likely consume at least 400 kWh per month, these bills probably were generated by vacant homes, seasonal customers and DG customers."

a. Please indicate the basis for Mr. Dukes' statement.

b. Please indicate what proportion of these bills is attributed to vacant homes.

c. Please indicate what proportion of these bills is attributed to seasonal customers.

d. Please indicate what proportion of these bills is attributed to DG customers.

RESPONSE:

a. The basis of the claim that 205,129 residential test year bills reflected usage of 300 kWh or less can be found in the 2015 UNSE Schedule H-5 Unadjusted. The claim refers to the standard tariff residential customers (RES-01).

The 400 kWh portion of the statement is a rough estimate based on industry experience.

b.,c. The Company does not track whether the home that belongs to a bill is vacant or for what reason a home might be vacant.

d. Just under 5% of the 205,129 bills are attributed to residential DG customers.

RESPONDENT:

Greg Strang

WITNESS:

Dallas Dukes

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

VS 2.03

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

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

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

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

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

RESPONSE: September 28, 2015

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

b. The Company has not performed this estimation.

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

RESPONDENT:

Rick Bachmeier

WITNESS:

Dallas Dukes

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

VS 2.09

Please provide forecasted distributed generation capacity (kW-AC) under each of the following scenarios for each year from 2015-2025:

a. The Commission approves UNS Electric's proposed modifications to the net metering tariff.

b. The Commission disapproves UNS Electric's proposed modifications to the net metering tariff and leaves the current tariff in place.

RESPONSE: September 28, 2015

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

RESPONDENT:

Carmine Tilghman

WITNESS:

Carmine Tilghman

SUPPLEMENTAL RESPONSE: September 29, 2015

a. The Company does not have access to distributed industry business plans or business models and is not able to make a reasonable forecast of DG capacity.

b. For the distributed generation forecast without proposed changes to the net metering tariff, please refer to page 182 of the Company's most recent integrated resource plan found at https://www.uesaz.com/doc/planning/2014-UES-IRP.pdf

RESPONDENT:

Carmine Tilghman

WITNESS:

Carmine Tilghman

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

VS 2.13

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

RESPONSE: **September 28, 2015**

UNS Electric is implementing different technologies that are generally considered grid modernization activities. These include the use of two way communications to distribution capacitor bank controllers and line reclosers. The plan is to implement these type of capabilities for all new or replacement activities involving this type of equipment. There are no policies or incentive associated with this plan.

UNS Electric does not have any policies, plans or incentives associated with electric vehicles.

UNS Electric does not have any policies, plans or incentives associated with demand response.

UNS Electric does have plans and incentives associated with energy efficiency. UNS Electric proposes an energy efficiency plan annually to the Commission for approval. UNS Electric implements the energy efficiency plan as approved by the Commission.

UNS Electric does not have any policies, plans or incentives associated with energy storage.

UNS Electric does not have any policies or incentives associated with advanced metering. UNS Electrics' plan is to install meters that provide interval data for all customers. The interval data will be stored in a meter data management system. The meter data management system is able to aggregate the intervals into billing determinants for any type of billing rate. The customer information system can use the billing determinants to create and issue the corresponding customer bill.

RESPONDENT:

Jim Taylor

WITNESS:

Jim Taylor

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

VS 2.15

On page 4, lines 25-26 of his direct testimony, Mr. Tilghman states that net metering "encourages customers to oversize their solar systems beyond their average load in order to 'bank' as many credits as possible for use later." Please provide data, analyses, and any other documentation to support that statement that are specific to the Company's service territory and that contemplate distributed generation at current penetration levels and at penetration levels projected in response to data requests VS 2-9(b) and VS 2-11(b). If applicable, please provide responses in executable electronic format with formulas and links intact.

RESPONSE: September 28, 2015

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

RESPONDENT:

Carmine Tilghman

WITNESS:

Carmine Tilghman

SUPPLEMENTAL RESPONSE: September 29, 2015

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

In its service area, the Company's experience is fact is that a typical solar facility is designed to be as close to "net zero" as possible, which also appears to be typical in other utility service areas. As such, with all solar generation being produced only during daylight hours and with a capacity factor of only (approximately) 25%, the maximum peak generation from the solar facility from a typical near net-zero facility is anywhere from 25-50% higher than the customer's average summer load; and significantly higher than the customer's average load during most of the year.

RESPONDENT:

Carmine Tilghman

WITNESS:

Carmine Tilghman

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

VS 2.17

Please provide the information requested below regarding the following statement by Mr. Tilghman on page 5, lines 10-12 of his direct testimony: "Increased intermittent generation creates greater load imbalance and fluctuations in voltage and frequency requiring additional ancillary services."

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

b. Please quantify the level of additional ancillary services required on the Company's system due to current levels of distributed solar generation. Please answer separately for each of the following services: (1) load balancing, (2) frequency support, (3) voltage support, (4) spinning reserves, and (5) non-spinning reserves.

c. Please indicate the total annual capital cost expenditures incurred by the Company over the last five years related to provision of ancillary services that were incurred as a direct result of distributed generation at current penetration levels. Please answer separately for each of the following services: (1) load balancing, (2) frequency support, (3) voltage support, (4) spinning reserves, and (5) non-spinning reserves.

d. Please indicate the total levels of each type of ancillary service in the Company's territory. Please answer separately for each of the following services: (1) load balancing, (2) frequency support, (3) voltage support, (4) spinning reserves, and (5) non-spinning reserves.

e. Please indicate the total capital cost expenditures incurred by the Company over the last five years related to each type of ancillary service in the Company's territory. Please answer separately for each of the following services: (1) load balancing, (2) frequency support, (3) voltage support, (4) spinning reserves, and (5) non-spinning reserves.

RESPONSE: **September 28, 2015**

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

RESPONDENT:

Carmine Tilghman

WITNESS:

Carmine Tilghman

SUPPLEMENTAL RESPONSE: **September 29, 2015**

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

a. As noted in UNS Electric's response to VS 2.14, the Company relies on information provided by respected entities such as NERC, WECC, and others to provide supporting data for these statements.

b. Due to the fact that the entire service territory is controlled as one balancing authority (under TEP), it is impractical and overly burdensome to isolate and identify specific quantities of individual ancillary services or associated costs.

c. See UNS Electric's response to 2.17(b).

d. See UNS Electric's response to 2.17(b).

e. See UNS Electric's response to 2.17(b).

RESPONDENT:

Carmine Tilghman

WITNESS:

Carmine Tilghman

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

VS 2.21

Please provide the information requested below regarding the following statement by Mr. Tilghman on page 6, lines 5-6 of his direct testimony: "Most [net metering] customers attempt to generate between 90%-100% [of their connected load annually]."

a. Please provide data, analyses, and any other documentation to support this statement that are specific to the Company's service territory. If applicable, please provide responses in executable electronic format with formulas and links intact.

b. Please define "connected load" and the relationship between connected load and peak load for a customer.

RESPONSE: September 28, 2015

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

RESPONDENT:

Carmine Tilghman

WITNESS:

Carmine Tilghman

SUPPLEMENTAL RESPONSE: September 29, 2015

a. Customer applications received by the Company validate the fact that most applications and system sizes are designed to provide a near net-zero home based on the customer's annual consumption.

b. Connected load used in this context is the customer's annual consumption. The relationship between a customer's connected load and peak load varies by customer and cannot be "defined". A customer's peak load can be daily, seasonal, or annual and represents their instantaneous peak consumption.

RESPONDENT:

Carmine Tilghman

WITNESS:

Carmine Tilghman

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

VS 2.24

On page 6, lines 16-19 of his direct testimony, Mr. Tilghman states: "Excess energy does not always 'flow to the next door neighbor' as is often quoted. During times of high export and low customer load, neighbors of exporting customers often have low usage as well, resulting in the energy flowing back up through the distribution system." Please provide data, analyses, and any other documentation to support any negative impacts resulting from "energy flowing back up through the distribution system" that are specific to the Company's service territory and that contemplate distributed generation at current penetration levels and at penetration levels projected in response to data requests VS 2-9(b) and VS 2-11(b). If applicable, please provide responses in executable electronic format with formulas and links intact.

RESPONSE: September 28, 2015

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

RESPONDENT:

Carmine Tilghman

WITNESS:

Carmine Tilghman

SUPPLEMENTAL RESPONSE: September 29, 2015

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

A number of circuits within both UNS Electric and TEP's systems have shown to have reverse current flow on at least one phase due to distributed generation. This is a result of random installations of customer sited distributed generation systems, resulting in unbalanced current flows on phases. This phenomenon is a relatively new issue that has been identified as a result of individual DG systems being connected single phase to a distribution system that was originally designed for one way power flow from the three phase system with equal loading among the phases. Unbalanced distributed generation between phases creates reverse power flows, which the system may see as a fault condition.

RESPONDENT:

Carmine Tilghman

WITNESS:

Carmine Tilghman

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

VS 3.01

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

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

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

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

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

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

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

RESPONSE:

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

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

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

c. The agreement is dated December 17, 2014.

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

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

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

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

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

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

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

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

RESPONDENT:

Carmine Tilghman

WITNESS:

Carmine Tilghman

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

VS 3.03

Please provide the information requested below regarding the following statement by Mr. Jones at page 15, lines 15–17 of his direct testimony: "For distribution services, the cost of serving these partial requirements customers is typically the same or higher than it was when the customer was a full requirements customer."

a. How does Company define the term "typically" as used in this sentence?

b. Please provide an estimate of the average increase in distribution services costs when a customer elects to install distributed generation.

c. Footnote 4 states distributed generation customers "may require additional investments in the distribution system." Please indicate whether UNS has completed any additional investments in the distribution system due to partial requirements customers on its system. If the answer is yes, please provide the annual expenditures on such investments in each of the last 5 years.

RESPONSE:

a. In this instance, "typically" means...the cost of serving these partial requirements customers "normally" is the same or higher than it was when the customer was a full requirements customer.

b. The Company has not performed a specific study to determine what the additional distribution system cost increases are caused by connecting a partial requirements customer to the distribution system is precisely, but is certain that the added equipment, personnel time, training and energy needs will typically generate additional costs and burdens on the existing distribution system when compared to the costs associated with serving a full requirements customers. Items contributing to this additional costs include, but are not limited to: equipment and services necessary to provide ability to bi-directionally meter these generators and the related system controls needed to allow this type of usage, special disconnect equipment, voltage and power quality issues created by inverters, intermittency mitigation resources and necessary reserves, additional safety considerations and training, longer outage times due to back-feed onto the system from these distributed generation sources, dedicated customer service representatives and related training, additional requirements to modify weather and other load profile evaluations to address the intermittent loads, evaluation and accommodation of the impacts on the utility's system based on where the generator is located on the system, etc.

c. The Company has not attempted to track and assign all of the additional costs associated with the above impacts caused by the addition of these partial requirements customers, but is certain none of these services can be provided without additional costs.

RESPONDENT:

Rick Bachmeier / Craig Jones

WITNESS:

Craig Jones

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

VS 3.08

Please provide the information requested below regarding the following statement by Mr. Jones at page 37, lines 21–24 of his direct testimony: "Modifying the rates to include a higher proportion of fixed costs in the monthly basic service charges will send customers the right price signals and provide additional support for the Company's efforts to promote EE and DG."

a. Please explain how increasing the monthly fixed charge will provide additional support for the Company's efforts to promote EE and DG.

b. Please describe the Company's current policies, plans, and incentives to promote EE and DG.

c. Please describe any future policies, plans, and incentives the Company plans to implement to promote EE and DG.

d. Has the Company evaluated how its proposed rate structure would impact customer demand for EE and DG?

e. Has the Company evaluated decoupling as a method of promoting both Company and consumer investments in EE and DG? If so, please describe how decoupling was considered and provide any supporting documentation.

RESPONSE:

a. More fixed costs being recovered through a fixed charge reduces the amount of fixed cost recovery lost due to the promotion of EE and DG.

b. Please refer to the Company's recent EE and REST implementation plans that have been docketed with an approved by the Commission.

c. Please refer to the Company's recent EE and REST implementation plans that have been docketed with and approved by the Commission.

d. The Company is not aware of any specific studies performed by the Company that would be responsive to this request. However, creating a three part rate will promote the use of equipment and systems that will reduce a customer's capacity needs instead of just offsetting volumetric needs. Offsetting volumetric needs only contributes to the reduction in fuel and purchased power, it does not reduce capacity needs. By creating a rate structure that promotes a reduction in capacity needs, the rate structure will provide a better end result to the promotion or EE and DG. By creating a rate structure that allows those customers who can modify their habits in a manner that truly helps the system, both the system (i.e. other customers) and the participating customer will benefit.

e. Yes. The LFCR was approved by the Commission in Company's last rate case. A portion of the costs not paid by the partial requirements customers is recovered through the LFCR by passing it on to the other customers, but not all of the lost fixed cost revenue is recovered through the LFCR. Improving cost recovery through rate design is a much better option.

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

RESPONDENT:

Craig Jones

WITNESS:

Craig Jones

VS 3.14

Please provide the following information regarding the tab entitled "Function Allocators" in 2015 UNSE Schedule G – COSS.xlsx:

a. Please indicate the source and underlying calculations and/or documentation to support the values presented in the following cells of the spreadsheet: I40, I41, J43, I44, I137, N137, I145, N145, I155, N155.

b. Please provide the equivalent functional allocators that were approved in the Company's last rate case in Docket E-04204A-12-0504.

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

RESPONSE:

a. The percentages included in the cells referenced above represent the results of the Marginal Cost Study approach used in this case as described in Craig Jones's direct testimony on pages 25 through 31.

b. Please see VS 3.14b.xlsx, which provides the function allocators used in the last Cost of Service Study and approved in the last rate case. The Excel file is <u>not</u> identified by Bates numbers.

c. The minimum system method used in this case was not developed or presented in the last approved case. Although it would have been preferred, the Company did not complete such a study in the last rate case. See response to STF 2.068 for a narrative and excel file discussing the allocations in COSS.

RESPONDENT:

Brenda Pries

WITNESS:

Craig Jones

VS 3.14b.xlsx

UNS ELECTRIC, INC.
ALLOCATION OF FUNCTIONS
INTERNAL WORKPAPER

FERC ACCT.		TOTAL COMPANY	DIRECT ASSIGNMENT	DEMAND: PRODUCTION	DEMAND: Blank	DEMAND: TRANSMISSION EXPENSE	DEMAND: Blank	DEMAND: DISTRIBUTION PRIMARY	DEMAND: DISTRIBUTION SECONDARY	ENERGY: FUEL	ENERGY: Cust	ENERGY: Blank	CUSTOMER: Customer Delivery	CUSTOMER: METER	CUSTOMER: BILLING & COLLECTIONS	CUSTOMER: METER READING	ALLOCATION
	DEVELOPMENT OF RATE BASE FUNCTION ALLOCATORS																
FERC	**Plant in Service**																
301-303	**Total Intangible Plant**	100.00%	0.00%	21.31%	0.00%	0.00%	0.00%	60.90%	12.93%	0.00%	0.00%	0.00%	3.08%	1.78%	0.00%	0.00%	PISXGENL
	Total Intangible Plant Excluding Direct Assignment	100.00%		21.31%	0.00%	0.00%	0.00%	60.90%	12.93%	0.00%	0.00%	0.00%	3.08%	1.78%	0.00%	0.00%	
	Total Steam Production																
310	Land & Land Rights	100.00%		100.00%													DPROD/DPRODMR
311	Structures & Improvements	100.00%		100.00%													DPROD/DPRODMR
312	Boiler Plant Equipment	100.00%		100.00%													DPROD/DPRODMR
313	Engines & Engine-Driven Generators	100.00%		100.00%													DPROD/DPRODMR
314	Turbogenerator Units	100.00%		100.00%													DPROD/DPRODMR/DPRC
315	Accessory Electric Equipment	100.00%		100.00%													DPROD/DPRODMR
316	Miscellaneous Power Plant Equipment	100.00%		100.00%													DPROD/DPRODMR
114	San Juan & Irvington Acquistion Adjustment	100.00%		100.00%													DPROD/DPRODMR
102	Electric Plant Purchased or Sold	100.00%		100.00%													DPROD/DPRODMR
	Other Production Plant																
340	Land & Land Rights	100.00%		100.00%													DPROD/DPRODMR
341	Structures & Improvements	100.00%		100.00%													DPROD/DPRODMR
342	Fuel Holders, Producers, & Accessories	100.00%		100.00%													DPROD/DPRODMR
343	Prime Movers	100.00%		100.00%													DPROD/DPRODMR
344	Generators	100.00%		100.00%													DPROD/DPRODMR
345	Accessory Electric Equipment	100.00%		100.00%													DPROD/DPRODMR
346	Miscellaneous Power Plant Equipment	100.00%		100.00%													DPROD/DPRODMR
	Transmission Non-EHV (138 KV & below) AD	100.00%				100.00%											DTNEHV
	Transmission EHV (345 KV & above) AD	100.00%				100.00%											DTEHV
	Distribution Plant																
360	Land & Rights	100.00%						100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%			DPIS
361	Structures & Improvements	100.00%						100.00%	0.00%				0.00%	0.00%			DPIS
362	Station Equipment	100.00%						100.00%	0.00%				0.00%	0.00%			DDISPSUB
364	Poles, Towers, & Fixtures	100.00%						100.00%	0.00%				0.00%	0.00%			DDISTPOL
365	Overhead Conductors & Devices	100.00%						100.00%	0.00%				0.00%	0.00%			DDISTPOL
366	Underground Conduit	100.00%							100.00%				0.00%	0.00%			DDISTSUL
367	Underground Conductors & Devices	100.00%							100.00%				0.00%	0.00%			DDISTSUL
368	Line Transformers	100.00%						100.00%	0.00%				0.00%	0.00%			DDISTSOT
369	Services	100.00%											100.00%				CUST
370	Meters	100.00%												100.00%			CMETERS
373	Street Lighting & Signal Systems	100.00%	0.00%						100.00%								DDISTLTG
374	Asset Retirement Obligation	100.00%							100.00%	0.00%	0.00%	0.00%	0.00%	0.00%			DPIS
389-398	**General Plant**	100.00%	0.00%	21.31%	0.00%	0.00%	0.00%	60.90%	12.93%	0.00%	0.00%	0.00%	3.08%	1.78%	0.00%	0.00%	PISXGENL
	General Plant Excluding Direct Assign	100.00%		21.31%	0.00%	0.00%	0.00%	60.90%	12.93%	0.00%	0.00%	0.00%	3.08%	1.78%	0.00%	0.00%	
	Less: Accumulated Depreciation																
	Intangible Plant AD	100.00%	0.00%	21.31%	0.00%	0.00%	0.00%	60.90%	12.93%	0.00%	0.00%	0.00%	3.08%	1.78%	0.00%	0.00%	PISXGENL
	Production Plant	100.00%		100.00%	0.00%	0.00%	0.00%	0.00%									DPRODPIS
	Other Production Plant	100.00%		100.00%	0.00%	0.00%	0.00%	0.00%									DPRODPIS
	Transmission Non-EHV (138 KV & below) AD	100.00%				100.00%											DTNEHV
	Transmission EHV (345 KV & above) AD	100.00%				100.00%											DTEHV
	Distribution Plant AD																
360	Land & Rights	100.00%						100.00%	0.00%				0.00%	0.00%			PLT360
361	Structures & Improvements	100.00%						100.00%	0.00%				0.00%	0.00%			PLT361
362	Station Equipment	100.00%						100.00%	0.00%				0.00%	0.00%			PLT362
364	Poles, Towers, & Fixtures	100.00%						100.00%	0.00%				0.00%	0.00%			PLT364
365	Overhead Conductors & Devices	100.00%						100.00%	0.00%				0.00%	0.00%			PLT365
366	Underground Conduit	100.00%						0.00%	100.00%				0.00%	0.00%			PLT366
367	Underground Conductors & Devices	100.00%						0.00%	100.00%				0.00%	0.00%			PLT367
368	Line Transformers	100.00%						100.00%	0.00%				0.00%	0.00%			PLT368
369	Services	100.00%						0.00%	0.00%				100.00%	0.00%			PLT369
370	Meters	100.00%						0.00%	0.00%				0.00%	100.00%			PLT370
373	Street Lighting & Signal Systems	100.00%	0.00%					0.00%	100.00%				0.00%	0.00%			PLT373
374	Asset Retirement Obligation	100.00%						0.00%	100.00%				0.00%	0.00%			DDISPSUB
	General Plant Accumulated Depreciation	100.00%	0.00%	21.31%	0.00%	0.00%	0.00%	60.90%	12.93%	0.00%	0.00%	0.00%	3.08%	1.78%	0.00%	0.00%	PISXGENL
	Working Capital																
n/a	Cash Working Capital	100.00%	0.00%	21.31%	0.00%	0.00%	0.00%	60.90%	12.93%	0.00%	0.00%	0.00%	3.08%	1.78%	0.00%	0.00%	OM
	Cash Working Capital Excluding Direct Assign	100.00%		21.31%	0.00%	0.00%	0.00%	60.90%	12.93%	0.00%	0.00%	0.00%	3.08%	1.78%	0.00%	0.00%	
151, 152	Fuel Inventory	100.00%		100.00%						0.00%							EPROD
154, 163	Materials & Supplies	100.00%	0.00%	21.31%	0.00%	0.00%	0.00%	60.90%	12.93%	0.00%	0.00%	0.00%	3.08%	1.78%	0.00%	0.00%	TOTPIS
165	Prepayments	100.00%	0.00%	21.31%	0.00%	0.00%	0.00%	60.90%	12.93%	0.00%	0.00%	0.00%	3.08%	1.78%	0.00%	0.00%	OM
	Less: Customer Contributions																
252	Customer Advances for Construction	100.00%	0.00%						100.00%								DCUSTADV
235	Customer Deposits	100.00%	0.00%						100.00%								DCUTDEP
230&253	Deferred Credits - Asset Retirement	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	77.39%	16.44%	0.00%	0.00%	0.00%	3.92%	2.26%	0.00%	0.00%	DISTPIS
	Other Rate Base																
105.0	Plant Held for Future Use - Transmission Plant (Non-EHV)						100.00%										DTNEHV
182.3	Regulatory Assets								100.00%								DISTPIS
254	Regulatory Liabilities								100.00%								DISTPIS
	Less: Accumulated Deferred Taxes (ADIT)																
190	ADIT	100.00%	0.00%	21.31%	0.00%	0.00%	0.00%	60.90%	12.93%	0.00%	0.00%	0.00%	3.08%	1.78%	0.00%	0.00%	TOTPIS
282	ADIT - Other Property	100.00%	0.00%	21.31%	0.00%	0.00%	0.00%	60.90%	12.93%	0.00%	0.00%	0.00%	3.08%	1.78%	0.00%	0.00%	TOTPIS
283	ADIT - Other	100.00%	0.00%	21.31%	0.00%	0.00%	0.00%	60.90%	12.93%	0.00%	0.00%	0.00%	3.08%	1.78%	0.00%	0.00%	TOTPIS
	DEVELOPMENT OF OPERATION & MAINTENANCE EXPENSE FUNCTION ALLOCATORS																
	Steam Power Generation Expense																
500	Operation Supervision & Engineering	100.00%		100.00%	0.00%	0.00%	0.00%	0.00%									DPROD
501	501-FUEL PPFAC ELIGIBLE	100.00%					Function Allocators			100.00%							EFUEL
502	Steam Expenses	100.00%		100.00%	0.00%	0.00%	0.00%	0.00%									DPROD

Ex. BK-2 017

UNS ELECTRIC, INC.
ALLOCATION OF FUNCTIONS
INTERNAL WORKPAPER

FERC		TOTAL	DIRECT	DEMAND						ENERGY			CUSTOMER				
ACCT.		COMPANY	ASSIGNMENT	PRODUCTION	Blank	TRANSMISSION EXPENSE	Blank	DISTRIBUTION PRIMARY	DISTRIBUTION SECONDARY	FUEL	Cust	Blank	Customer Delivery	METER	BILLING & COLLECTIONS	METER READING	ALLOCATION
505	Electric Expenses	100.00%		100.00%	0.00%	0.00%	0.00%	0.00%									DPROD
506	Miscellaneous Steam Power Expenses	100.00%		100.00%	0.00%	0.00%	0.00%	0.00%									DPROD
507	Rents	100.00%		100.00%	0.00%	0.00%	0.00%	0.00%									DPROD
510	Maintenance Supervision & Engineering	100.00%		100.00%	0.00%	0.00%	0.00%	0.00%									DPROD
511	Maintenance of Structures	100.00%		100.00%	0.00%	0.00%	0.00%	0.00%									DPROD
512	Maintenance of Boiler Plant	100.00%		100.00%	0.00%	0.00%	0.00%	0.00%									DPROD
513	Maintenance of Electric Plant	100.00%		100.00%	0.00%	0.00%	0.00%	0.00%									DPROD
514	Maintenance Miscellaneous Steam Plant	100.00%		100.00%	0.00%	0.00%	0.00%	0.00%									DPROD
411	FAS 143 Accretion Expense	100.00%		100.00%													DPROD
412	Gain on Sales of Emission Allowances	100.00%		100.00%													DPROD
	OTHER POWER GENERATION																
546	SUPERVISION & ENGINEERING	100.00%		100.00%	0.00%	0.00%	0.00%	0.00%									DPROD
547	FUEL	100.00%								100.00%							EFUEL
551	SUPERVISION & ENGINEERING	100.00%		100.00%	0.00%	0.00%	0.00%	0.00%									DPROD
552	MAINTENANCE OF STRUCTURES	100.00%		100.00%	0.00%	0.00%	0.00%	0.00%									DPROD
553	GENERATING & ELECT PLT	100.00%		100.00%	0.00%	0.00%	0.00%	0.00%									DPROD
554	MISC OTH POWER GEN PLT	100.00%		100.00%	0.00%	0.00%	0.00%	0.00%									DPROD
557	OTHER EXPENSES	100.00%		100.00%	0.00%	0.00%	0.00%	0.00%									DPROD
	Other Power Supply Expense																
555	PURCHASED POWER																
	DEMAND CHARGES	100.00%		100.00%						0.00%							EPROD
	ENERGY CHARGES	100.00%								100.00%							EFUEL
	TOTAL PURCHASED POWER	0.00%															
556	SYS CONTRL & LOAD DISP	100.00%					100.00%										DPROD
557	OTHER EXPENSES	100.00%		100.00%													DPROD
560-573	PPFAC Transmission of Elec By Others	100.00%					0%			100%							DTNEHV
560-573	Transmission EXPENSE	100.00%				100%				0%							DTEHV
	Distribution Expense																
580	Operation Supervision & Engineering	100.00%						29.81%	43.33%				0.00%	26.86%			DISTPIS
581	Load Dispatching	100.00%						40.75%	59.25%				0.00%	0.00%			DISTPIS
582	Station Expenses	100.00%						100.00%	0.00%				0.00%	0.00%			DISTPIS
583	Overhead Line Expenses	100.00%						100.00%	0.00%				0.00%	0.00%			OHDIST
584	Underground Line Expenses	100.00%						0.00%	100.00%				0.00%	0.00%			UGDIST
585	Street Lighting & Signal System Expenses	100.00%	0%					0.00%	100.00%				0.00%	0.00%			DDISTLTG
586	Meter Expenses	100.00%						0.00%	0.00%				0%	100%			CMETERS
587	Customer Installations Expense	100.00%						0.00%	0.00%				0%	100%			CMETERS
588	Miscellaneous Distribution Expenses	100.00%						0.00%	100.00%				0.00%	0.00%			DISTPIS
589	Rents	100.00%						100.00%	0.00%				0.00%	0.00%			DISTPIS
590	Maintenance Supervision & Engineering	100.00%						96.00%	4.00%				0.00%	0.00%			DISTPIS
591	Maintenance of Structures	100.00%						100.00%	0.00%				0.00%	0.00%			DISTPIS
592	Maintenance of Station Equipment	100.00%						100.00%	0.00%				0.00%	0.00%			DISTPIS
593	Maintenance of Overhead Lines	100.00%						100.00%	0.00%				0.00%	0.00%			OHDIST
594	Maintenance of Underground Lines	100.00%						0.00%	100.00%				0.00%	0.00%			UGDIST
595	Maintenance of Line Transformers	100.00%						100.00%	0.00%				0.00%	0.00%			PLT368
596	Maintenance of Street Lighting & Signal Systems	100.00%	0%					0%	100%				0%	0%			DDISTLTG
597	Maintenance of Meters	100.00%						0%	0%				0%	100%			CMETERS
598	Maintenance of Miscellaneous Distribution Plant	100.00%						100.00%	0.00%				0.00%	0.00%			DISTPIS
407	Regulatory Asset Amortization	100.00%						0.00%	100.00%				0.00%	0.00%			DISTPIS
	Customer Account Expense																
901	Supervision	100.00%							0%	0%	0%	0%	0%	0%	73%	27%	CACCT
902	Meter Reading Expenses	100.00%														100%	CREAD
903	Customer Records & Collection Expenses	100.00%													100%		CBILLCOL
904	Uncollectible Accounts	100.00%							100%			0%					dUNCOL
905	Miscellaneous Customer Accounts Expenses	100.00%							0%	0%	0%	0%	0%	0%	73%	27%	ECUSINFO
907	Supervision	100.00%							0%	0%	0%	0%	0%	0%	73%	27%	ECUSINFO
908	Customer Assistance Expenses	100.00%							0%	0%	0%	0%	0%	0%	73%	27%	ECUSINFO
909	Informational and Instructional Advertising Expenses	100.00%							0%	0%	0%	0%	0%	0%	73%	27%	ECUSINFO
910	Miscellaneous Customer Service & Informational Expe	100.00%							0%	0%	0%	0%	0%	0%	73%	27%	DISTPIS
	Administrative and General Expense	100.00%	0.00%	11.14%	0.00%		0.00%	24.48%	19.65%				0.00%	8.56%	26.39%	9.78%	OMXF
	Depreciation and Amortization																
301-303	Total Intangible Plant Depreciation Expense	100.00%	0.00%	21.31%	0.00%	0.00%	0.00%	60.90%	12.93%	0.00%	0.00%	0.00%	3.08%	1.78%	0.00%	0.00%	PISXGENL
	Production	100.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	DPRODP
	PPFAC Transmission of Elec By Others	0.00%					0.00%										DTNEHVP
	Transmission EXPENSE	100.00%				100.00%											DTEHVP
	Distribution Plant Depreciation Expense																
360	Land & Rights	100.00%						100.00%	0.00%				0.00%	0.00%			PLT360
361	Structures & Improvements	100.00%						100.00%	0.00%				0.00%	0.00%			PLT361
362	Station Equipment	100.00%						100.00%	0.00%				0.00%	0.00%			PLT362
364	Poles, Towers, & Fixtures	100.00%						100.00%	0.00%				0.00%	0.00%			PLT364
365	Overhead Conductors & Devices	100.00%						100.00%	0.00%				0.00%	0.00%			PLT365
366	Underground Conduit	100.00%						0.00%	100.00%				0.00%	0.00%			PLT366
367	Underground Conductors & Devices	100.00%						0.00%	100.00%				0.00%	0.00%			PLT367
368	Line Transformers	100.00%						100.00%	0.00%				0.00%	0.00%			PLT368
369	Services	100.00%						0.00%	0.00%				100.00%	0.00%			PLT369
370	Meters	100.00%						0.00%	0.00%				0.00%	100.00%			PLT370
373	Street Lighting & Signal Systems	100.00%	0.00%					0.00%	100.00%				0.00%	0.00%			PLT373
374	Asset Retirement Obligation	100.00%						0.00%	100.00%				0.00%	0.00%			PLT374
389-398	**General Plant Depreciation Expense**	100.00%	0.00%	21.31%	0.00%	0.00%	0.00%	60.90%	12.93%				3.08%	1.78%			PISXGENL
	Taxes Other Than Income Taxes																
408	Property Tax - Production	100.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	DPROD
408	Property Tax - Transmission (Non-EHV)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	DTEHV
408	Property Tax - Transmission (EHV)	100.00%	0.00%	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	DTNEHV
408	Property Tax - Distribution	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	77.39%	16.44%	0.00%	0.00%	0.00%	3.92%	2.26%	0.00%	0.00%	DISTPIS
408	Property Tax - General	100.00%	0.00%	21.31%	0.00%	0.00%	0.00%	60.90%	12.93%	0.00%	0.00%	0.00%	3.08%	1.78%	0.00%	0.00%	GENLPIS
408	Business Activity Tax - Generation	100.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	DPROD
408	Business Activity Tax - Transmission	100.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	DTNEHV
408	Other (Including Payroll Taxes)	100.00%	0.00%	21.31%	0.00%	0.00%	0.00%	60.90%	12.93%	0.00%	0.00%	0.00%	3.08%	1.78%	0.00%	0.00%	TOTPIS
431	Customer Deposit Interest Expense	100.00%	0%						100%	0.00%	0.00%						CUSTDEP

Function Allocators

Ex. BK-2 018

UNS ELECTRIC, INC.
ALLOCATION OF FUNCTIONS
INTERNAL WORKPAPER

FERC ACCT.		TOTAL COMPANY	DIRECT ASSIGNMENT	DEMAND PRODUCTION	Blank	TRANSMISSION EXPENSE	Blank	DISTRIBUTION PRIMARY	DISTRIBUTION SECONDARY	ENERGY FUEL	Cust	Blank	CUSTOMER Customer Delivery	METER	BILLING & COLLECTIONS	METER READING	ALLOCATION
	Income Taxes																
409	Current Income Tax - State & Federal	100.00%	0.00%	21.31%	0.00%	0.00%	0.00%	60.90%	12.93%	0.00%	0.00%	0.00%	3.08%	1.78%	0.00%	0.00%	PLANT
410	Deferred IT - Federal & State (debits)	100.00%	0.00%	21.31%	0.00%	0.00%	0.00%	60.90%	12.93%	0.00%	0.00%	0.00%	3.08%	1.78%	0.00%	0.00%	PLANT
411	Deferred IT - Federal & State (credits)	100.00%	0.00%	21.31%	0.00%	0.00%	0.00%	60.90%	12.93%	0.00%	0.00%	0.00%	3.08%	1.78%	0.00%	0.00%	PLANT

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

VS 3.18

In response to VS 2.15, the Company stated: "In its service area, the Company's experience . . . is that a typical solar facility is designed to be as close to 'net zero' as possible, which also appears to be typical in other utility service areas." Please provide any available data, analyses, or other documentation to support this assertion. If possible, please provide data from the Company's Customer Care and Billing system.

RESPONSE:

The Company reviews all contracts as they are received, and as part of the review process, verifies that the system size is appropriate based on the customer's usage. As such, the Company typically sees solar system size designed to approximate the customer's annual consumption. The Company is also well aware that promotional materials and sales presentations by solar leasing companies are presented promoting net (or near) zero consumption in order to "eliminate you electric bill".

Providing all customers' data to show this premise would be unduly burdensome and would require not only the download of all NEM customers' data, but the calculation of total customer load versus production. This data is not readily available from the Company's CC&B system and would require manual calculation of each customer's data. As such, the Company objects to providing this data.

RESPONDENT:

Carmine Tilghman

WITNESS:

Carmine Tilghman

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

VS 3.21

Please provide the information requested below regarding the Company's response to VS 2.24:

a. Please provide the number of circuits in each of UNS's and TEP's systems that have shown to have reverse power flow.

b. For each circuit identified, please indicate the date that circuit was identified as having reverse power flow.

c. For each circuit identified, please indicate the circuit capacity rating and the total capacity of installed distributed generation on that circuit (kW-AC).

RESPONSE:

UNS Electric objects to this request because the Company does not possess the information requested in the form it is requested and producing it in that form would be unduly burdensome and time consuming.

There are thousands of individual circuits from shared transformers to distribution feeders to substations that would require specific monitoring equipment to provide this information. The Company has found, that during either routine or specific testing, times when energy flow has been reversed. The Company does not; however, have equipment installed on all circuits that monitor and store this information.

RESPONDENT:

Carmine Tilghman

WITNESS:

Carmine Tilghman

VS 3.24

Please provide the information requested below regarding the Company's Response to Staff 2.035:

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

b. Please indicate why these circuits were selected.

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

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

e. Please define "impact to operations" as used in this response.

f. Please describe, and to the extent possible quantify, any impact on operations identified in response to VS 3.25(d).

RESPONSE:

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

b. Generation Interconnection requests, system reinforcement projects, capacitor placement studies, customer voltage complaints.

c. See (a) above

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

e. Impact to operations in this context refers to any contribution from the proposed generation source that negatively affects operations. Power flow studies associated with distributed generation interconnection requests include analysis of steady-state voltage, voltage flicker, and fault current with and without the proposed generation source.

f. There is no section (d) to question VS 3.25.

RESPONDENT:

Chris Lindsey

WITNESS:

Carmine Tilghman

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

VS 3.34

Please provide information on the number of residential customers in the Company's service area with evaporative cooling and the number with refrigerated AC. If available, please provide average load profiles for these two customer types.

RESPONSE:

A 2010 study by Navigant Consultant provided the following breakdown of air conditioning system types for UNS Electric:

Central AC: 33%

Central Heat Pumps: 37%

Evaporative (Swamp) Cooler: 26%

Room A/C: 2%

Other: 2%

Source: Navigant Consulting, May 2011, "Demand-side Management (DSM) 2010 Targeted Baseline Study for Tucson Electric Power, Unisource Electric and Unisource Gas."

The Company does not have more recent data nor load profiles for these customer types.

RESPONDENT:

Sandra Holland

WITNESS:

Craig Jones

UNS ELECTRIC INC.'S RESPONSE TO VOTE SOLAR'S FORTH SET OF DATA REQUESTS REGARDING THE 2015 UNS ELECTRIC RATE CASE
DOCKET NO. E-04204A-15-0142
November 18, 2015

VS 4.4

Please provide the information requested below regarding the Company's response to VS 3.24:

a. In response to VS 3.24(a), the Company stated that "SynerGEE Powerflow software is used to model all Company circuits when required." Please indicate the number of circuits that have required modeling with SynerGEE Powerflow software.

b. In response to VS 3.24(d), the Company stated: "Three PV generation interconnection studies done with SynerGEE power flow software indicated existing distribution facilities could not support the proposed generation source, and would therefore have an impact on operations." How many PV interconnection studies have been done overall with SynerGEE power flow software?

c. The sub question number referenced in VS 3.24(f) was incorrect. Please describe, and to the extent possible quantify, any impact on operations identified in response to VS 3.24(d).

RESPONSE:

a. SynerGEE Powerflow software is the current tool used by the Company to model power flow on the distribution system. 18 circuits in Santa Cruz County and 12 circuits in Mohave County have been modeled using SynerGEE Powerflow software.

b. SynerGEE Powerflow software is used for both UNS Electric and Tucson Electric Power. Seven (7) PV interconnection studies have been completed with SynerGEE Powerflow software; two (2) for UNS Electric and five (5) for Tucson Electric Power.

c. Two (2) interconnection studies identified that the addition of generation would overload existing Company feeder conductors. For these two instances, upgrading the existing overhead feeder conductor was identified as a possible solution for supporting the proposed generation facilities.

   One (1) interconnection study identified that the addition of generation would create high-voltage and therefore violate the operating voltage criteria. Power factor correction at the generation facility was found to mitigate the problem.

RESPONDENT:

Christopher Lindsey

WITNESS:

Carmine Tilghman

STF 2.017

Retail Sales: Please provide in an Excel worksheet a summary of the impact (by month) of DG (by type) in UNS Electric's service area since January 2006 to the present. Provide the number of installations, total annual kWh (generated, used on-site and/or sold to the Company) and the peak load reductions from DG installations. Also please provide each of the Company's various forecasts for DG over that same period.

RESPONSE:

UNS Electric has data from the beginning of 2008 for DG systems. The Company does not track peak load reductions from DG installations, or conduct forecasts for DG installs.

Please see **STF 2.017.xlsx** for summary data. The Excel file is not identified by Bates numbers.

RESPONDENT:

Carmine Tilghman

WITNESS:

Carmine Tilghman

Number of Installations by Month

		Residential			Non-Residential	
Year	Month	Total PV Installations	Total Wind Installations		Total PV Installations	Total Wind Installations
2008	January	0	0		0	0
	February	0	0		0	0
	March	0	0		0	0
	April	0	0		0	0
	May	0	0		0	0
	June	0	0		0	0
	July	2	0		0	0
	August	3	6		1	0
	September	2	2		0	0
	October	2	6		0	0
	November	2	1		0	0
	December	2	6		0	0
		13	**21**		**1**	**0**
2009	January	9	3		0	2
	February	9	3		0	0
	March	6	2		0	0
	April	13	4		0	1
	May	6	7		0	1
	June	12	17		0	0
	July	3	2		0	0
	August	11	6		2	0
	September	5	0		0	0
	October	26	12		0	0
	November	16	4		0	0
	December	16	7		3	0
		132	**67**		**3**	**4**
2010	January	0	24		0	0
	February	0	0		0	0
	March	18	0		1	0
	April	23	2		0	0
	May	25	0		1	0
	June	22	0		5	0
	July	25	0		1	0
	August	20	0		6	0
	September	13	1		0	0
	October	11	0		4	0
	November	13	2		0	0
	December	11	0		0	0
		181	**29**		**18**	**0**
2011	January	16	1		15	0
	February	9	1		4	0
	March	20	1		0	0
	April	22	0		0	0
	May	17	0		3	0
	June	9	0		2	0
	July	9	0		1	0
	August	19	1		4	0
	September	11	0		1	0
	October	25	0		2	0
	November	25	1		3	0
	December	21	0		7	0
		203	**5**		**42**	**0**
2012	January	20	0		2	0
	February	28	0		5	0
	March	39	0		2	0
	April	19	0		0	0
	May	26	0		3	0
	June	34	0		4	0
	July	20	0		2	0

Annual Production (kWH)

Residential	2008	2009	2010	2011	2012	2013	2014
PV	497,104	1,083,000	2,968,853	5,750,367	9,793,168	12,502,033	14,843,105
Wind	10,476	113,302	273,614	232,437	206,264	192,032	168,621
Non-Residential							
PV	24,856	96,904	329,366	1,356,949	6,344,477	10,157,204	9,752,817
Wind	1,405	8,915	8,354	9,626	6,216	8,124	6,112

Annual Overproduction Delivered Back to Company (Kilowatt Buyback Hours or KBH)

	2008	2009	2010	2011	2012	2013	2014
Residential	*	503,257	1,771,653	3,211,545	5,363,777	7,019,888	9,224,548
Non-Residential	*	17,722	163,303	679,300	1,708,087	3,105,456	4,252,135

*No Data Available for 2008 and prior.

	August	16	0		1	0
	September	40	0		2	0
	October	24	0		6	0
	November	3	0		3	0
	December	2	0		4	0
		271	0		34	0
2013	January	1	0		1	0
	February	0	0		3	0
	March	14	0		1	0
	April	13	0		0	0
	May	7	0		0	0
	June	12	0		0	0
	July	6	0		2	0
	August	19	0		2	0
	September	6	0		1	0
	October	10	0		1	0
	November	9	0		2	0
	December	11	0		2	0
		108	0		15	0
2014	January	35	0		1	0
	February	19	0		0	0
	March	25	0		0	0
	April	21	0		2	0
	May	16	0		0	0
	June	32	0		1	0
	July	25	0		0	0
	August	22	0		0	0
	September	19	0		0	0
	October	29	0		0	0
	November	35	0		1	0
	December	50	0		5	0
		328	0		10	0
2015	January	47	0		0	0
	February	24	0		1	0
	March	37	0		2	0
	April	17	0		0	0
	May	27	0		0	0
	June	47	0		0	0
	July	29	0		2	0
		228	0		5	0

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 2.031

Renewable Resources: Please provide a narrative discussing how the Company forecasts short term (daily and hourly) PV generation. [Tilghman 4:18]

RESPONSE:

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

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

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

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

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

RESPONDENT:

Carmine Tilghman

WITNESS:

Carmine Tilghman

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 2.033

Renewable Resources: Please provide a narrative discussing how the Company has either implemented and/or researched the use of metering at individual PV connections (upstream of the utility meter) to monitor PV generation at the source. [Tilghman 5:15]

RESPONSE:

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

RESPONDENT:

Carmine Tilghman

WITNESS:

Carmine Tilghman

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 2.035

Renewable Resources: Please provide a narrative discussing how the Company models PV generation at the feeder level. [Tilghman 2:15]

RESPONSE:

The Company utilizes SynerGEE Electric powerflow software to model PV generation on the distribution system. The SynerGEE software has inverter-based generation models that can be added to a selected distribution circuit for analysis. Powerflow simulations are then run for peak feeder loading and minimum daytime feeder loading with and without the generation source to determine if the PV generation will have impact to operations

RESPONDENT:

Carmine Tilghman

WITNESS:

Carmine Tilghman

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 2.079

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

RESPONSE:

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

The Company has looked at revenue recovery from a full requirement customer vs. a DG/net metering customer with 100% PV offset on an annual basis. See UNS Electric's supplemental response to UDR 1.001 dated July 30, 2015, specifically files RES Demand-DG_04-29-15_FINAL_v1.xlsx and SGS Demand-DG_04-29-15_FINAL_v1.xlsx. (The referenced files can be accessed in UNS Electric's electronic data room under Data Requests\Uniform Data Requests\Attachments - 1st Set\UDR 1.001\Workpapers – Testimony\Dallas Dukes.)

RESPONDENT:

Brenda Pries

WITNESS:

Craig Jones

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 2.119

LFCR: Please provide a recalculation of the LFCR for the previous year demonstrating the impact of customer charges at the levels proposed by the Company and at 50% of the increase proposed by the Company. [Jones 41:7]

RESPONSE:

Please refer to **STF 2.119 LFCR Calculations.xlsx**. If the Company's proposed basic service charges were in place, the Company estimates that the LFCR would decrease by approximately $509,000 with respect to the Company's 2015 LFCR filing. This is because an increase to the basic service charge would result in a decrease to the volumetric energy delivery charges, if everything else is held constant. Using 50% of the proposed changes to the basic service charges, the Company estimates that the LFCR would decrease by approximately $255,000.

RESPONDENT:

Annie Trostle

WITNESS:

Craig Jones

STF 9.2

Please provide UNSE's customer count, usage per customer, and total mWh sales historical data by customer class for at least the past 10 years preferably both graphed and tabular.

RESPONSE:

Please see **STF 9.2.xlsx** for the requested information. The Excel file is not identified by Bates numbers.

RESPONDENT:

Brenda Pries

WITNESS:

Craig Jones

Date	Total Residential	Total Commercial	Total Industrial	Total Mining	Total Other	Total
9/1/03	77,087,194	54,358,426	6,483,458	0	190,615	138,119,693
10/1/03	56,555,756	49,390,907	7,734,186	0	226,194	113,907,043
11/1/03	41,535,252	46,178,020	8,314,663	0	227,612	96,255,547
12/1/03	50,061,412	47,241,510	8,858,683	0	265,010	106,426,615
1/1/04	55,782,100	45,528,992	8,252,485	0	263,630	109,827,207
2/1/04	49,285,081	44,592,643	8,733,509	0	253,450	102,864,683
3/1/04	47,720,293	47,241,196	9,200,447	0	259,786	104,421,722
4/1/04	40,839,608	48,202,637	9,049,712	0	237,957	98,329,914
5/1/04	52,270,017	57,088,170	9,612,903	0	258,328	119,229,418
6/1/04	45,765,827	76,235,309	17,160,008	0	402,852	139,563,996
7/1/04	90,530,360	64,950,690	7,015,260	0	227,292	162,723,602
8/1/04	89,824,899	58,310,515	16,418,957	0	214,400	164,768,771
9/1/04	65,338,318	52,876,904	12,323,018	0	212,888	130,751,128
10/1/04	45,772,089	48,846,894	12,347,010	0	276,556	107,242,549
11/1/04	43,392,275	46,284,243	12,851,830	0	278,583	102,806,931
12/1/04	62,036,089	54,791,203	20,404,600	0	276,296	137,508,188
1/1/05	59,630,892	43,042,248	12,282,479	0	275,951	115,231,570
2/1/05	43,265,953	44,941,232	11,238,889	0	222,472	99,668,546
3/1/05	48,801,170	40,603,434	11,981,462	0	284,859	101,670,925
4/1/05	44,285,182	44,453,695	12,004,687	0	230,789	100,974,353
5/1/05	48,959,906	58,131,068	13,040,362	0	268,833	120,400,169
6/1/05	76,278,177	60,822,663	12,930,520	0	211,194	150,242,554
7/1/05	106,269,231	66,889,302	12,783,972	0	208,349	186,150,854
8/1/05	93,875,769	58,813,039	13,202,321	0	241,236	166,132,365
9/1/05	73,385,812	57,569,676	13,035,856	0	247,481	144,238,825
10/1/05	49,118,342	52,576,483	13,597,266	0	251,667	115,543,758
11/1/05	39,457,479	45,745,626	12,879,745	0	290,134	98,372,984
12/1/05	61,841,359	47,687,780	13,496,905	0	262,568	123,288,612
1/1/06	59,831,417	44,480,774	13,640,565	0	244,739	118,197,495
2/1/06	46,909,913	45,059,925	11,347,764	0	257,655	103,575,257
3/1/06	56,014,171	48,050,555	12,789,756	0	280,809	117,135,291
4/1/06	43,041,331	46,983,834	12,500,254	0	247,706	102,773,125
5/1/06	61,539,045	61,049,199	13,893,786	0	237,751	136,719,781
6/1/06	88,846,341	64,644,094	13,706,280	0	186,218	167,382,933
7/1/06	114,212,065	67,304,427	12,948,790	0	219,828	194,685,111
8/1/06	102,517,838	66,147,232	13,796,104	0	232,414	182,693,589
9/1/06	76,869,836	55,165,323	12,652,405	0	215,512	144,903,076
10/1/06	50,372,478	55,026,020	12,732,004	0	266,598	118,397,100
11/1/06	40,301,597	48,121,960	11,656,828	0	275,084	100,355,469
12/1/06	63,524,339	48,623,599	11,218,646	0	269,941	123,636,525
1/1/07	77,796,226	45,812,761	11,779,385	0	231,711	135,620,083
2/1/07	53,080,354	45,216,837	11,795,040	0	260,771	110,353,002
3/1/07	50,629,291	50,008,001	13,059,071	0	257,280	113,953,643
4/1/07	46,367,132	50,604,610	11,890,839	0	123,251	108,985,831
5/1/07	63,090,150	62,488,054	12,571,549	0	177,315	138,327,068
6/1/07	88,507,604	62,061,581	12,214,354	0	138,705	162,922,244
7/1/07	113,515,194	71,428,115	12,603,260	0	212,327	197,758,896
8/1/07	106,893,771	70,409,003	13,190,581	0	159,169	190,652,524
9/1/07	93,500,773	60,658,421	12,803,421	0	42,147	167,004,762
10/1/07	42,144,261	54,898,783	13,387,125	0	359,769	110,789,939
11/1/07	48,974,718	51,720,683	11,848,860	0	186,994	112,731,255
12/1/07	69,611,607	50,956,174	12,058,340	0	97,952	132,724,073
1/1/08	71,943,454	49,181,400	12,837,262	0	327,447	134,289,563

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2/1/08	60,074,202	48,016,165	12,103,177	0	206,297	120,399,841
3/1/08	51,295,916	49,315,595	13,378,634	0	74,104	114,064,249
4/1/08	44,888,529	57,016,009	13,165,074	0	315,702	115,385,314
5/1/08	57,889,155	57,922,263	13,468,090	0	119,357	129,398,865
6/1/08	80,899,635	65,948,499	14,002,131	0	136,094	160,986,359
7/1/08	110,013,739	66,972,525	14,310,507	0	135,542	191,432,313
8/1/08	105,086,031	67,432,655	14,586,337	0	174,176	187,279,199
9/1/08	84,667,076	64,712,521	13,604,081	0	182,480	163,166,158
10/1/08	49,228,643	50,371,620	13,853,523	0	181,120	113,634,906
11/1/08	46,536,367	52,183,571	10,062,326	0	145,687	108,927,951
12/1/08	59,966,877	51,361,356	12,778,378	0	238,624	124,345,235
1/1/09	67,799,701	48,014,198	8,257,789	10,647,000	224,800	134,943,488
2/1/09	52,859,325	45,708,472	8,771,707	9,805,000	190,179	117,334,683
3/1/09	45,910,966	51,413,441	9,841,225	13,475,000	196,933	120,837,565
4/1/09	46,428,581	51,728,158	10,377,664	15,117,000	170,223	123,821,626
5/1/09	68,415,877	62,789,328	11,090,287	11,772,000	153,185	154,220,677
6/1/09	69,281,884	63,021,940	10,055,048	12,791,000	152,145	155,302,017
7/1/09	108,562,443	72,658,046	10,433,005	15,082,000	164,991	206,900,485
8/1/09	110,229,160	70,842,306	11,136,232	14,530,000	164,282	206,901,980
9/1/09	82,089,071	65,794,937	10,967,177	13,424,000	169,458	172,444,643
10/1/09	48,595,836	56,760,669	10,452,114	15,720,000	195,669	131,724,288
11/1/09	46,390,753	54,279,880	10,234,062	15,068,000	212,453	126,185,148
12/1/09	67,231,810	52,828,890	9,774,388	16,043,000	225,539	146,103,627
1/1/10	70,507,462	50,258,740	10,170,314	15,798,000	136,207	146,870,723
2/1/10	55,403,070	46,939,644	9,782,157	13,544,000	174,566	125,843,437
3/1/10	49,434,244	55,988,396	10,002,813	17,510,000	255,101	133,190,554
4/1/10	47,392,792	54,024,349	9,286,742	16,770,000	155,498	127,629,381
5/1/10	51,037,989	62,253,316	6,792,792	17,343,000	145,077	137,572,174
6/1/10	77,490,590	65,020,664	11,446,422	17,174,000	173,654	171,305,330
7/1/10	111,981,254	75,122,666	11,812,629	16,986,750	125,513	216,028,812
8/1/10	107,466,032	71,878,536	11,250,821	17,837,250	189,843	208,622,482
9/1/10	81,743,639	62,609,514	10,690,694	16,290,750	164,760	171,499,357
10/1/10	55,162,299	55,579,334	11,125,333	20,013,400	163,895	142,044,261
11/1/10	50,193,354	53,897,294	10,272,975	19,702,150	231,728	134,297,501
12/1/10	62,539,376	50,738,544	8,538,080	20,337,950	102,200	142,256,150
1/1/11	70,506,656	51,548,525	10,706,604	20,470,700	170,578	153,403,063
2/1/11	60,030,533	49,621,419	8,611,454	17,423,500	142,877	135,829,783
3/1/11	49,628,559	51,992,180	10,332,488	20,836,000	161,801	132,951,028
4/1/11	47,823,523	53,466,994	8,413,962	20,814,350	131,813	130,650,642
5/1/11	51,894,987	58,433,967	11,290,098	21,723,650	131,655	143,474,357
6/1/11	73,546,688	70,338,145	10,989,314	21,404,250	108,842	176,387,239
7/1/11	104,511,913	63,794,077	12,019,732	22,047,100	89,958	202,462,780
8/1/11	109,513,738	74,838,882	12,150,316	15,979,578	126,985	212,609,499
9/1/11	84,538,093	60,868,752	10,760,243	11,774,283	118,493	168,059,864
10/1/11	54,786,847	55,873,331	11,824,379	9,581,081	150,516	132,216,154
11/1/11	48,955,203	52,949,010	10,509,184	9,028,943	190,839	121,633,179
12/1/11	72,057,767	51,970,594	9,497,474	9,535,637	164,793	143,226,266
1/1/12	65,733,165	48,332,238	11,304,874	9,296,075	138,805	134,805,157
2/1/12	52,628,602	50,420,781	9,511,705	8,606,150	165,230	121,332,468
3/1/12	52,336,185	53,893,544	10,839,982	9,699,569	126,525	126,895,805
4/1/12	50,771,687	57,101,370	10,492,374	9,155,570	164,153	127,685,154
5/1/12	67,442,397	65,188,433	10,965,395	8,913,775	135,398	152,645,399
6/1/12	86,314,033	68,622,862	10,297,415	9,514,288	78,369	174,826,967
7/1/12	99,263,873	65,680,284	11,245,233	9,303,329	133,335	185,626,054
8/1/12	108,297,273	68,242,272	11,317,386	5,554,548	139,370	193,550,850
9/1/12	82,747,097	63,152,839	10,389,546	5,023,532	117,607	161,430,621
10/1/12	59,183,162	54,479,976	11,564,864	4,176,173	157,478	129,561,653

Total Sales

11/1/12	47,134,941	54,575,296	7,103,466	5,484,683	158,614	114,457,001
12/1/12	63,931,510	56,497,349	6,188,944	5,960,862	145,610	132,724,275
1/1/13	82,378,659	48,995,832	7,298,527	6,652,245	174,226	145,499,489
2/1/13	57,694,033	49,939,974	6,811,316	2,985,131	313,901	117,744,355
3/1/13	50,139,201	48,797,240	8,131,497	3,562,498	67,188	110,697,624
4/1/13	47,382,208	58,374,296	7,895,451	4,239,368	133,757	118,025,080
5/1/13	63,942,437	63,509,191	8,282,653	6,555,723	151,069	142,441,073
6/1/13	89,844,432	72,038,931	8,426,706	5,237,070	86,931	175,634,070
7/1/13	112,480,385	69,538,054	8,389,880	6,230,855	125,035	196,764,209
8/1/13	100,693,447	67,695,659	8,613,094	5,439,107	150,226	182,591,533
9/1/13	73,695,238	59,138,317	7,663,531	4,600,028	152,019	145,249,133
10/1/13	49,603,561	54,501,348	8,387,625	4,162,262	173,912	116,828,709
11/1/13	46,200,759	53,691,561	7,934,926	4,930,318	186,514	112,944,079
12/1/13	69,562,377	52,272,367	6,775,799	6,084,295	192,897	134,887,735
1/1/14	64,506,394	48,110,287	7,837,873	4,399,912	176,536	125,031,002
2/1/14	47,415,456	49,628,463	7,091,435	4,671,596	139,803	108,946,753
3/1/14	47,088,366	54,433,231	8,069,547	5,344,566	171,541	115,107,250
4/1/14	50,931,843	56,072,424	7,670,084	5,343,467	161,235	120,179,053
5/1/14	61,199,342	64,729,278	8,592,013	5,288,519	134,979	139,944,132
6/1/14	87,688,812	68,920,615	7,655,492	6,023,080	114,809	170,402,808
7/1/14	108,428,290	69,636,660	8,165,177	6,537,041	120,867	192,888,036
8/1/14	94,710,131	65,726,993	7,965,069	4,998,313	141,573	173,542,079
9/1/14	83,523,066	62,974,695	8,158,526	5,243,299	155,478	160,055,065
10/1/14	58,151,344	56,526,048	8,144,703	5,935,339	151,906	128,909,340
11/1/14	46,759,813	54,135,898	7,118,771	5,637,485	178,121	113,830,089
12/1/14	65,536,151	51,757,597	6,296,583	4,791,449	228,026	128,609,807
1/1/15	67,995,824	48,383,539	6,503,887	3,397,070	159,235	126,439,556
2/1/15	45,164,464	47,731,885	6,308,359	1,528,899	151,914	100,885,521
3/1/15	52,296,470	52,169,493	7,162,280	1,295,658	186,183	113,110,085
4/1/15	49,648,281	51,361,769	7,585,942	1,244,973	143,772	109,984,737
5/1/15	54,011,292	57,971,263	7,905,474	1,222,627	137,220	121,247,877
6/1/15	90,973,546	69,337,166	8,137,601	1,187,174	136,230	169,771,718
7/1/15	100,983,695	62,155,217	7,915,981	1,144,371	103,484	172,302,748
8/1/15						
9/1/15						
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Total Sales

Ex. BK-2 037

Date	Total Residential	Total Commercial	Total Industrial	Total Mining	Total Other	Total
9/1/03	67,081	8,925	4	0	72	76,082
10/1/03	67,433	8,947	4	0	252	76,637
11/1/03	67,185	8,939	4	0	249	76,377
12/1/03	67,592	9,032	6	0	605	77,235
1/1/04	68,054	9,061	4	0	249	77,368
2/1/04	68,235	9,064	8	0	250	77,557
3/1/04	68,688	9,192	4	0	247	78,131
4/1/04	69,063	9,228	4	0	248	78,543
5/1/04	69,041	9,128	4	0	247	78,420
6/1/04	69,624	9,143	4	0	250	79,021
7/1/04	69,909	9,199	4	0	250	79,362
8/1/04	70,129	9,242	4	0	250	79,625
9/1/04	70,339	9,279	4	0	250	79,872
10/1/04	70,588	9,305	4	0	252	80,149
11/1/04	71,026	9,376	4	0	250	80,656
12/1/04	71,181	9,583	4	0	251	81,019
1/1/05	71,438	9,468	4	0	253	81,163
2/1/05	70,965	9,434	4	0	250	80,653
3/1/05	72,250	9,502	4	0	250	82,006
4/1/05	72,486	9,498	4	0	251	82,239
5/1/05	72,667	9,566	4	0	251	82,487
6/1/05	73,144	9,567	4	0	251	82,965
7/1/05	73,251	9,546	4	0	251	83,051
8/1/05	73,861	9,577	4	0	249	83,692
9/1/05	73,931	9,637	4	0	253	83,825
10/1/05	74,137	9,649	4	0	251	84,041
11/1/05	74,433	9,673	4	0	251	84,360
12/1/05	74,589	9,694	4	0	250	84,537
1/1/06	74,978	9,711	6	0	249	84,944
2/1/06	75,499	9,747	7	0	248	85,501
3/1/06	75,835	9,774	7	0	248	85,864
4/1/06	76,147	9,826	7	0	248	86,228
5/1/06	76,426	9,862	7	0	248	86,543
6/1/06	76,633	9,883	7	0	248	86,771
7/1/06	76,897	9,908	7	0	248	87,060
8/1/06	77,159	9,938	7	0	248	87,352
9/1/06	77,384	10,011	7	0	248	87,650
10/1/06	77,786	10,028	13	0	248	88,075
11/1/06	77,786	10,028	13	0	248	88,075
12/1/06	78,204	10,080	12	0	248	88,544
1/1/07	78,444	10,085	13	0	251	88,793
2/1/07	78,725	10,098	13	0	251	89,087
3/1/07	78,872	10,112	7	0	251	89,242
4/1/07	78,858	10,108	7	0	251	89,224
5/1/07	79,096	10,122	7	0	252	89,477
6/1/07	79,142	10,140	7	0	252	89,541
7/1/07	79,059	10,152	7	0	252	89,470
8/1/07	79,054	10,167	7	0	252	89,480
9/1/07	79,274	10,214	7	0	252	89,747
10/1/07	79,236	10,252	7	0	253	89,748
11/1/07	79,336	10,265	7	0	253	89,861

12/1/07	79,433	10,297	7	0	254	89,991
1/1/08	79,471	10,298	8	0	257	90,034
2/1/08	79,507	10,309	8	0	255	90,079
3/1/08	79,454	10,342	8	0	255	90,059
4/1/08	79,492	10,336	8	0	255	90,091
5/1/08	79,449	10,335	8	0	256	90,048
6/1/08	79,437	10,349	8	0	257	90,051
7/1/08	79,463	10,363	8	0	257	90,091
8/1/08	79,534	10,370	8	0	257	90,169
9/1/08	79,267	10,338	8	0	258	89,871
10/1/08	79,084	10,356	8	0	258	89,706
11/1/08	79,228	10,369	9	0	258	89,864
12/1/08	79,149	10,358	9	0	259	89,775
1/1/09	79,177	10,347	7	1	260	89,792
2/1/09	79,557	10,364	7	1	260	90,189
3/1/09	79,490	10,355	7	1	262	90,115
4/1/09	79,509	10,363	7	1	262	90,142
5/1/09	79,614	10,365	7	1	264	90,251
6/1/09	79,366	10,338	7	1	264	89,976
7/1/09	79,477	10,326	7	1	264	90,075
8/1/09	79,505	10,317	7	1	265	90,095
9/1/09	79,445	10,328	7	1	266	90,047
10/1/09	79,474	10,339	7	1	266	90,087
11/1/09	79,544	10,343	7	1	266	90,161
12/1/09	79,641	10,352	7	1	266	90,267
1/1/10	79,837	10,352	7	1	266	90,463
2/1/10	80,101	10,361	7	1	266	90,736
3/1/10	80,131	10,347	7	1	266	90,752
4/1/10	80,168	10,361	7	1	266	90,803
5/1/10	80,217	10,361	7	1	266	90,852
6/1/10	80,242	10,387	8	2	266	90,905
7/1/10	80,286	10,386	7	2	266	90,947
8/1/10	80,171	10,356	6	2	266	90,801
9/1/10	80,189	10,357	5	2	266	90,819
10/1/10	80,222	10,363	5	2	261	90,853
11/1/10	80,192	10,355	5	2	258	90,812
12/1/10	80,257	10,363	5	2	254	90,881
1/1/11	80,425	10,372	5	2	249	91,053
2/1/11	80,542	10,390	5	2	249	91,188
3/1/11	80,673	10,393	5	2	249	91,322
4/1/11	80,586	10,395	5	2	249	91,237
5/1/11	80,552	10,399	5	2	249	91,207
6/1/11	80,527	10,409	5	2	249	91,192
7/1/11	80,598	10,414	5	2	249	91,268
8/1/11	80,622	10,406	5	2	249	91,284
9/1/11	80,601	10,406	5	2	248	91,262
10/1/11	80,506	10,411	5	2	248	91,172
11/1/11	80,612	10,427	5	2	363	91,409
12/1/11	80,671	10,429	5	2	363	91,470
1/1/12	80,702	10,432	4	2	360	91,500
2/1/12	80,761	10,427	5	2	473	91,668
3/1/12	80,904	10,440	5	2	474	91,825
4/1/12	80,815	10,453	5	2	475	91,750
5/1/12	80,754	10,471	5	2	475	91,707
6/1/12	80,815	10,469	5	2	475	91,766

7/1/12	80,798	10,492	5	2	473	91,770
8/1/12	80,894	10,485	5	2	473	91,859
9/1/12	80,887	10,495	5	2	473	91,862
10/1/12	80,939	10,505	4	2	477	91,927
11/1/12	80,996	10,517	4	2	528	92,047
12/1/12	81,111	10,513	4	2	531	92,161
1/1/13	81,277	10,521	4	2	531	92,335
2/1/13	81,336	10,536	4	2	531	92,409
3/1/13	81,406	10,584	4	2	533	92,529
4/1/13	81,273	10,577	4	2	533	92,389
5/1/13	81,330	10,579	4	2	533	92,448
6/1/13	81,412	10,573	4	2	533	92,524
7/1/13	81,382	10,585	4	2	534	92,507
8/1/13	81,387	10,572	4	2	573	92,538
9/1/13	81,359	10,594	4	2	576	92,535
10/1/13	81,412	10,621	4	2	582	92,621
11/1/13	81,542	10,666	4	2	580	92,794
12/1/13	81,677	10,676	4	2	583	92,942
1/1/14	81,800	10,665	4	2	583	93,054
2/1/14	81,940	10,683	4	2	583	93,212
3/1/14	81,928	10,686	4	2	584	93,204
4/1/14	81,935	10,694	4	2	584	93,219
5/1/14	81,993	10,694	4	2	585	93,278
6/1/14	82,098	10,712	4	2	585	93,401
7/1/14	82,108	10,722	4	2	585	93,421
8/1/14	82,210	10,722	4	2	585	93,523
9/1/14	82,179	10,744	4	2	585	93,514
10/1/14	82,258	10,749	4	2	586	93,599
11/1/14	82,396	10,751	4	2	587	93,740
12/1/14	82,438	10,737	4	2	588	93,769
1/1/15	82,522	10,741	4	1	588	93,856
2/1/15	82,654	10,747	4	1	588	93,994
3/1/15	82,645	10,759	4	1	588	93,997
4/1/15	82,625	10,782	4	1	588	94,000
5/1/15	82,676	10,784	4	1	588	94,053
6/1/15	82,698	10,785	4	1	589	94,077
7/1/15	82,894	10,798	4	1	589	94,286
8/1/15						
9/1/15						
10/1/15						
11/1/15						
12/1/15						
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1/1/17						

UNS ELECTRIC INC.'S RESPONSE TO STAFF'S TWELFTH SET OF DATA REQUESTS REGARDING THE 2015 UNS ELECTRIC RATE CASE DOCKET NO. E-04204A-15-0142 SEPTEMBER 24, 2015

STF 12.3

What is UNSE's current estimate of the number of electric vehicles (EVs) in its service territory?

RESPONSE:

The Company has no information currently available that is responsive to this request.

RESPONDENT:

Todd Stocksdale/Craig Jones

WITNESS:

Craig Jones

UNS ELECTRIC INC.'S RESPONSE TO STAFF'S TWELFTH SET OF DATA REQUESTS REGARDING THE 2015 UNS ELECTRIC RATE CASE
DOCKET NO. E-04204A-15-0142
SEPTEMBER 24, 2015

STF 12.6

Has UNSE performed studies to determine the ability of its existing transformers to absorb increased load due to EVs?

RESPONSE:

No.

RESPONDENT:

Todd Stocksdale/Craig Jones

WITNESS:

Craig Jones

UNS ELECTRIC, INC.'S RESPONSE TO THE SECOND SET OF UNIFORM DATA REQUESTS - 2015 UNS ELECTRIC RATE CASE
DOCKET NO. E-04204A-15-0067
July 30, 2015

UDR 2.10

For each month since July 1, 2012 through December 31, 2014, please provide:

i. Total number of residential bills;

ii. Number of bills with usage less than 300 kWh;

iii. Number of bills with usage between 300 and 1000 kWh; and

iv. Number of bills with usage over 1000 kWh.

RESPONSE:

Please see UDR 2.10 Bill Frequency.xlsx for monthly data from July 1, 2012 through December 31, 2014. The Excel file is <u>not</u> identified by Bates numbers.

RESPONDENT:

Anne Trostle (a) / Greg Strang (a-d)

WITNESS:

Dallas Dukes

UNS Electric Bill Frequency Data

Total Residential RES-01

MONTH	BILL_COUNT_0_TO_300	BILL_COUNT_301_TO_1000	BILL_COUNT_ABOVE_1000	TOTAL_BILL_COUNT
201207	11974	23223	38784	73981
201208	12329	24915	43416	80660
201209	10920	22045	34062	67027
201210	18053	36251	26441	80745
201211	19692	37852	12721	70265
201212	16989	34237	16313	67539
201301	14574	31997	30231	76802
201302	15292	34440	21234	70966
201303	17860	40134	16268	74262
201304	21936	43919	11420	77275
201305	20532	39631	17364	77527
201306	14001	26754	29962	70717
201307	11429	22079	44065	77573
201308	11843	24264	41329	77436
201309	12247	25579	33282	71108
201310	21209	40755	18478	80442
201311	20848	37947	9692	68487
201312	16615	34205	20567	71387
201401	15832	36656	25862	78350
201402	17267	39418	15003	71688
201403	20894	44315	10148	75357
201404	22310	45222	11433	78965
201405	20739	39305	15541	75585
201406	15306	29618	30815	75739
201407	12210	24551	42284	79045
201408	11888	24530	39446	75864
201409	12711	26312	36811	75834
201410	19032	38703	24443	82178
201411	18732	35485	11654	65871
201412	18208	38853	18621	75682

Residential RES-01 Net Metering

MONTH	BILL_COUNT_0_TO_300	BILL_COUNT_301_TO_1000	BILL_COUNT_ABOVE_1000	TOTAL_BILL_COUNT
201207	511	139	177	827
201208	451	190	285	926
201209	366	180	228	774
201210	602	254	117	973
201211	643	150	49	842
201212	522	178	77	777
201301	525	259	206	990
201302	493	216	101	810
201303	718	134	55	907
201304	878	99	30	1007
201305	835	108	34	977
201306	685	105	102	892
201307	610	139	244	993
201308	556	195	267	1018
201309	464	230	222	916
201310	828	169	62	1059
201311	746	125	35	906
201312	634	225	96	955
201401	686	262	126	1074
201402	743	193	63	999
201403	914	120	36	1070
201404	1005	108	34	1147
201405	977	92	39	1108
201406	878	147	110	1135
201407	803	182	235	1220
201408	665	222	297	1184
201409	633	318	251	1202
201410	863	322	125	1310
201411	854	180	55	1089
201412	926	427	256	1609

Ex. BK-2 044

UNS ELECTRIC INC.'S RESPONSE TO TASC'S FIRST SET OF DATA REQUESTS REGARDING THE 2015 UNS ELECTRIC RATE CASE DOCKET NO. E-04204A-15-0142 July 30, 2015

TASC 1.10

Re: page 4, lines 24-25: "policies such as net metering [] encourages customers to oversize their solar systems beyond their average load."

a. What is the average utility bill for solar customers before going solar?

b. What is the average utility bill for solar customers after going solar?

RESPONSE:

a.-b. Please see UNS Electric's supplemental response to UDR 1.001 dated July 30, 2015, specifically files RES Demand-DG_04-29-15_FINAL_v1.xlsx and SGS Demand-DG_04-29-15_FINAL_v1.xlsx.

RESPONDENT:

Rick Bachmeier

WITNESS:

Carmine Tilghman

UNS ELECTRIC INC.'S RESPONSE TO TASC'S FIRST SET OF DATA REQUESTS REGARDING THE 2015 UNS ELECTRIC RATE CASE DOCKET NO. E-04204A-15-0142 July 30, 2015

TASC 1.13

Re: page 7, lines 14-17. "The Renewable Credit Rate - currently proposed to be 5.84 cents per kWh - is equivalent to the most recent utility scale renewable energy purchased power agreement connected to the distribution system of UNS Electric' s affiliate, TEP."

a. Please provide all documentation, assumptions, and workpapers used in determining the 5.84 cents per kWh Renewable Credit Rate.

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

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

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

RESPONSE:

a. The 5.84 cents is simply the price paid by TEP for its most recent utility scale renewable energy purchase power agreement.

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

c. The Company cannot predict the future renewable credit rates.

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

RESPONDENT:

Carmine Tilghman

WITNESS:

Carmine Tilghman

UNS ELECTRIC INC.'S RESPONSE TO TASC'S FIRST SET OF DATA REQUESTS REGARDING THE 2015 UNS ELECTRIC RATE CASE DOCKET NO. E-04204A-15-0142 July 30, 2015

TASC 1.34

Re: page 21, lines 3-5.

a. How many of the residential solar PV systems in UNS's territory are sized to "yield zero excess kWh."

b. Please provide all workpapers supporting the table on page 21.

c. What rates are assumed in this table? I.e., Current, or the proposed 3-part?

d. If "current," please replicate the table with UNS's proposed 3-part rate.

RESPONSE:

a. The Company does not track this information..

b. Please see UNS Electric's supplemental response to UDR 1.001 dated July 30, 2015, specifically file RES Demand-DG_04-29-15_FINAL_v1.xlsx.

c. All comparisons in the table referenced in part "c" assumes the proposed 3-part rates.

d. The requested information is provided in the table on page 29 of Mr. Dukes' Direct Testimony and in the Excel file identified in the response to TASC 1.34(b).

RESPONDENT:

Carmine Tilghman (a) / Rick Bachmeier (b-d)

WITNESS:

Dallas Dukes / Carmine Tilghman

UNS ELECTRIC INC.'S RESPONSE TO TASC'S THIRD SET OF DATA REQUESTS REGARDING THE 2015 UNS ELECTRIC RATE CASE DOCKET NO. E-04204A-15-0142 October 19, 2015

TASC 3.2

Tilghman p. 6, lines 14-23

Please provide all studies, conducted by or for UNS concerning:

a. Increased operations and maintenance costs, equipment wear and tear, resulting from distributed solar generation.

b. Energy flowing back up through the distribution system resulting from distributed solar generation.

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

RESPONSE:

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

b. The Company has not completed any studies on back flow. However, the Company sees reverse flow at its Sacramento Substation, and its sister company, TEP, routinely has back flow on its circuits and has recently discovered reverse flow on individual phases on at least one of its circuits.

c. Listed below are examples of reports highlighting additional costs and O&M associated with variable generation.

1. Western Electricity Coordinating Council's Variable Generation Subcommittee Marketing Workgroup whitepaper – "Electricity Markets and Variable Generation Integration". Read entire report pages 1-56.
2. Western Electricity Coordinating Council's – "WECC Variable Generation Planning Reference Book: A Guidebook for Including Variable Generation in the Planning Process". Read report pages 1-161.
3. MIT Study on the Future of Solar Energy, specifically Chapter 7 – Integration of Distributed Photovoltaic Generators. https://mitei.mit.edu/futureofsolar
4. North American Electric Reliability Corporation (NERC) Special Report: Accommodating High Levels of Variable Generation, April 2009. http://www.nerc.com/files/IVGTF_Report_041609.pdf Read all pages.
5. Western Wind and Solar Integration Study – "Analysis of Cycling Costs in Western Wind and Solar Integration Study". http://www.nrel.gov/docs/fy12osti/54864.pdf. Read entire report, pages 1 through 19.
6. NREL – "Fundamental Drivers of the Cost and Price of Operating Reserves". http://www.nrel.gov/docs/fy13osti/58491.pdf Read entire report pages 1-57.
7. Intertek APTECH report prepared for NREL and WECC – "Power Plant Cycling

Costs" – All pages with specific references to the report Preface and Executive Summary.

This list is sample of documents presented by various research and institutional entities that support and validate Mr. Tilghman's statements.

RESPONDENT:

Carmine Tilghman

WITNESS:

Carmine Tilghman

WRA 1.06

Does solar DG production shift the time of day that peak load occurs on the UNSE system? Please provide data that supports your answer. If this data is not available, please explain why.

RESPONSE:

Solar production peaks at noon and its production significantly reduced by summer peak demand hours (between 4-5 pm). As such, its low ELCC value has not yet had the effect of moving or shifting the time of day that peak load occurs. The Company's annual system peak has occurred on the following dates and times over the last 5 years (since the significant introduction of distribute resources):

2015: August 16, HE 1700

2014: July 24, HE 1600

2013: Jun 28, HE 1700

2012: Aug 8, HE 1600

2011: June 27, HE 1600

RESPONDENT:

Carmine Tilghman

WITNESS:

Carmine Tilghman

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

WRA 1.15

On average, do peak monthly loads for residential customers with DG on the UNSE system differ from peak monthly loads for residential customers without DG? Please provide any data, studies, reports, or documents the Company relies upon for its conclusion.

RESPONSE:

The Company has no actual data on whether monthly peak loads of residential customers with DG on the UNS Electric system differ from those of residential customers without DG. The Company does not possess metered monthly peak load data for all residential customers on the system, much less data on peak load differences between residential customers with and without DG.

RESPONDENT:

Rick Bachmeier / Carmine Tilghman

WITNESS:

Carmine Tilghman

	Year	c		Average_kWh	Average_TD	Sum_kWh	Sum_TD	Max_kWh	Max_TD	Min_kWh	Min_TD		
0	5	2010	43127	6.437452176	10.12424283	277628	436628.2204	30	10.579	0	10	0-5	0.0%
5	10	2010	43129	69.42303323	11.33986454	2994146	489077.0178	110	12.123	30	10.579	5-10	0.4%
10	15	2010	43128	148.903172	12.87383122	6421896	555222.5928	189	13.6477	110	12.123	10-15	0.9%
15	20	2010	43128	226.3757884	14.36905272	9763135	619708.5055	264	15.0952	189	13.6477	15-20	1.3%
20	25	2010	43129	300.1681699	15.79324568	12945953	681146.8929	335	16.4655	264	15.0952	20-25	1.8%
25	30	2010	43128	369.3401966	17.12851426	15928904	738718.5628	402	17.7887	335	16.4655	25-30	2.2%
30	35	2010	43128	436.2975329	18.96682026	18816640	818001.024	470	20.1245	402	17.7887	30-35	2.6%
35	40	2010	43128	503.3520219	21.27014195	21708566	917338.6821	538	22.4603	470	20.1245	35-40	3.0%
40	45	2010	43129	571.5094252	23.61134876	24648630	1018333.861	607	24.83045	538	22.4603	40-45	3.4%
45	50	2010	43128	642.7685031	26.05909808	27721320	1123876.782	680	27.338	607	24.83045	45-50	3.8%
50	55	2010	43128	718.7175849	28.66794904	30996852	1236391.306	760	30.086	680	27.338	50-55	4.2%
55	60	2010	43129	800.9988871	31.49431177	34546281	1358318.172	845	33.00575	760	30.086	55-60	4.7%
60	65	2010	43128	891.4297672	34.6006125	38445583	1492255.216	940	36.269	845	33.00575	60-65	5.2%
65	70	2010	43128	993.7218744	38.15886665	42857237	1645715.601	1050	40.25495	940	36.269	65-70	5.8%
70	75	2010	43129	1111.775928	42.63326145	47949784	1838729.933	1178	45.182822	1050	40.25495	70-75	6.5%
75	80	2010	43128	1250.850955	47.98751093	53946700	2069605.371	1330	51.03467	1178	45.182822	75-80	7.3%
80	85	2010	43128	1422.355198	54.59025279	61343335	2354368.422	1523	58.464977	1330	51.03467	80-85	8.4%
85	90	2010	43128	1648.71049	63.30470514	71105586	2730205.323	1791	68.782709	1523	58.464977	85-90	9.7%
90	95	2010	43129	1993.632707	76.58386557	85983385	3302985.538	2248	86.376752	1791	68.782709	90-95	11.7%
95	100	2010	43128	2922.00262	112.3251789	126020129	4844360.314	13520	520.33748	2248	86.376752	95-100	17.2%
0	5	2011	43209	6.362979935	10.12280551	274938	437396.3034	30	10.579	0	10	0-5	0.0%
5	10	2011	43210	70.60404999	11.36265816	3050801	490980.4593	110	12.123	30	10.579	5-10	0.4%
10	15	2011	43210	149.4233742	12.88387112	6456584	556712.0712	190	13.667	110	12.123	10-15	0.9%
15	20	2011	43210	227.2586207	14.38609138	9819845	621623.0085	265	15.1145	190	13.667	15-20	1.3%
20	25	2011	43210	301.0049063	15.80939469	13006422	683123.9446	336	16.4848	265	15.1145	20-25	1.8%
25	30	2011	43210	369.7740106	17.13731132	15977935	740503.2221	403	17.82305	336	16.4848	25-30	2.2%
30	35	2011	43210	436.956399	18.98945231	18880886	820534.2341	470	20.1245	403	17.82305	30-35	2.6%
35	40	2011	43210	503.1585744	21.26349703	21741482	918795.7067	537	22.42595	470	20.1245	35-40	3.0%
40	45	2011	43210	571.2083314	23.60100618	24681912	1019799.477	606	24.7961	537	22.42595	40-45	3.4%
45	50	2011	43210	641.934205	26.03043994	27737977	1124775.31	680	27.338	606	24.7961	45-50	3.8%
50	55	2011	43209	717.3937374	28.62247488	30997866	1236748.517	758	30.0173	680	27.338	50-55	4.2%
55	60	2011	43210	799.8078685	31.45340028	34559698	1359101.426	842	32.9027	758	30.0173	55-60	4.7%
60	65	2011	43210	890.1932192	34.55813708	38465249	1493257.103	940	36.269	842	32.9027	60-65	5.2%
65	70	2011	43210	992.349433	38.10856311	42879419	1646671.012	1049	40.216451	940	36.269	65-70	5.8%
70	75	2011	43210	1108.95906	42.52481487	47918121	1837497.25	1174	45.028826	1049	40.216451	70-75	6.5%
75	80	2011	43210	1247.170956	47.84583463	53890257	2067418.514	1325	50.842175	1174	45.028826	75-80	7.3%
80	85	2011	43210	1417.316848	54.39628133	61242261	2350463.316	1519	58.310981	1325	50.842175	80-85	8.3%
85	90	2011	43210	1643.793937	63.11542276	71028336	2727217.418	1789	68.705711	1519	58.310981	85-90	9.7%
90	95	2011	43210	1987.62025	76.352392	85885071	3299186.858	2240	86.06876	1789	68.705711	90-95	11.7%
95	100	2011	43210	2919.919371	112.2449758	126169716	4850105.406	13480	518.79752	2240	86.06876	95-100	17.2%
0	5	2012	44591	6.816151241	10.13155172	303939	451776.0227	30	10.579	0	10	0-5	0.0%
5	10	2012	44592	72.78321224	11.404716	3245549	508559.0957	113	12.1809	30	10.579	5-10	0.4%
10	15	2012	44592	153.3514083	12.95968218	6838246	577898.1478	193	13.7249	113	12.1809	10-15	0.9%
15	20	2012	44592	233.1898547	14.5005642	10398402	646609.1586	271	15.2303	193	13.7249	15-20	1.4%
20	25	2012	44592	308.1335217	15.94697697	13740290	711107.597	343	16.6199	271	15.2303	20-25	1.8%
25	30	2012	44592	378.1860423	17.31586449	16864072	772149.0294	412	18.1322	343	16.6199	25-30	2.2%
30	35	2012	44592	445.9745694	19.29922646	19886898	860591.1063	480	20.468	412	18.1322	30-35	2.6%
35	40	2012	44592	512.9122713	21.59853652	22871784	963121.9404	547	22.76945	480	20.468	35-40	3.0%
40	45	2012	44592	581.5569609	23.95648161	25932788	1068267.428	617	25.17395	547	22.76945	40-45	3.4%
45	50	2012	44592	653.3407113	26.42225343	29133769	1178221.125	690	27.6815	617	25.17395	45-50	3.8%
50	55	2012	44591	729.9775291	29.05472812	32550428	1295579.382	770	30.4295	690	27.6815	50-55	4.2%
55	60	2012	44592	813.1612845	31.91209012	36260488	1423023.923	858	33.4523	770	30.4295	55-60	4.7%
60	65	2012	44592	904.7478698	35.05808933	40344517.01	1563310.319	954	36.7499	858	33.4523	60-65	5.3%
65	70	2012	44592	1007.330396	38.65438165	44918877	1723676.187	1063	40.755437	954	36.7499	65-70	5.9%
70	75	2012	44592	1124.759508	43.13311632	50155276	1923391.923	1190	45.64481	1063	40.755437	70-75	6.5%
75	80	2012	44592	1262.86529	48.45005079	56313689	2160484.665	1340	51.41966	1190	45.64481	75-80	7.3%
80	85	2012	44592	1432.609011	54.9850143	63882901	2451891.758	1532	58.811468	1340	51.41966	80-85	8.3%
85	90	2012	44592	1657.554853	63.64520428	73913686	2838066.949	1800	69.1292	1532	58.811468	85-90	9.6%
90	95	2012	44592	1996.63776	76.69955713	89034071	3420186.651	2242	86.145758	1800	69.1292	90-95	11.6%
95	100	2012	44592	2911.142671	111.9070817	129813674	4990160.587	14320	551.13668	2242	86.145758	95-100	16.9%
0	5	2013	44828	6.712255733	10.12954654	300897	454087.3121	30	10.579	0	10	0-5	0.0%
5	10	2013	44829	72.20736577	11.39360216	3236984	510763.7912	111	12.1423	30	10.579	5-10	0.4%
10	15	2013	44830	151.6322329	12.92650209	6797673	579495.0889	191	13.6863	111	12.1423	10-15	0.9%
15	20	2013	44829	230.533204	14.44929084	10334573	647747.2589	269	15.1917	191	13.6863	15-20	1.3%
20	25	2013	44829	304.644672	15.87964217	13656916	711868.4788	340	16.562	269	15.1917	20-25	1.8%
25	30	2013	44829	374.2492137	17.23054506	16777218	772428.1046	409	18.02915	340	16.562	25-30	2.2%
30	35	2013	44829	441.535167	19.14673299	19793580	858328.893	475	20.29625	409	18.02915	30-35	2.6%
35	40	2013	44830	508.3235336	21.44091338	22788144.01	961196.1467	542	22.5977	475	20.29625	35-40	2.9%
40	45	2013	44829	577.4027973	23.81378609	25884390	1067548.217	613	25.03655	542	22.5977	40-45	3.3%
45	50	2013	44829	650.1250753	26.31179634	29144457	1179531.518	689	27.64715	613	25.03655	45-50	3.8%
50	55	2013	44829	727.9499877	28.98508208	32633270	1299372.244	770	30.4295	689	27.64715	50-55	4.2%
55	60	2013	44829	812.5389145	31.89071171	36425307	1429628.715	858	33.4523	770	30.4295	55-60	4.7%
60	65	2013	44830	905.515503	35.08445753	40594260	1572836.231	956	36.8186	858	33.4523	60-65	5.2%
65	70	2013	44829	1010.151331	38.75933202	45284074	1737542.095	1068	40.947932	956	36.8186	65-70	5.9%
70	75	2013	44829	1130.314997	43.34699707	50670891	1943202.532	1197	45.914303	1068	40.947932	70-75	6.6%
75	80	2013	44829	1271.436012	48.78001504	56997205	2186759.294	1350	51.80465	1197	45.914303	75-80	7.4%
80	85	2013	44829	1443.781035	55.41512605	64723260	2484204.686	1545	59.311955	1350	51.80465	80-85	8.4%
85	90	2013	44830	1671.598104	64.1858554	74937743	2877451.898	1815	69.706685	1545	59.311955	85-90	9.7%
90	95	2013	44829	2016.089273	77.4484209	90379266	3471935.261	2269	87.185231	1815	69.706685	90-95	11.7%
95	100	2013	44829	2946.51924	113.2690442	132089511	5077737.983	14720	566.53628	2269	87.185231	95-100	17.1%
0	5	2014	45657	6.583995444	10.12707111	300605.48	462371.6858	30	10.579	0	10	0-5	0.0%
5	10	2014	45657	71.86401319	11.38697545	3281095.25	519895.1383	111	12.1423	30	10.579	5-10	0.4%
10	15	2014	45658	150.8643388	12.91168174	6888163.98	589521.5648	190	13.667	111	12.1423	10-15	0.9%
15	20	2014	45657	228.0274442	14.40092967	10411049.02	657503.2461	265	15.1145	190	13.667	15-20	1.4%
20	25	2014	45658	299.4907609	15.78017168	13674149.16	720491.0788	333	16.4269	265	15.1145	20-25	1.8%
25	30	2014	45658	366.3302429	17.07017369	16725906.23	779389.9902	399	17.7007	333	16.4269	25-30	2.2%
30	35	2014	45657	430.8512285	18.7797809	19671374.54	857428.4567	463	19.88405	399	17.7007	30-35	2.6%
35	40	2014	45658	495.1811345	20.98947197	22608980.24	958337.3112	528	22.1168	463	19.88405	35-40	3.0%
40	45	2014	45657	561.0945229	23.25359686	25617892.63	1061689.472	595	24.41825	528	22.1168	40-45	3.4%
45	50	2014	45658	630.0086366	25.62079667	28764934.33	1169794.334	666	26.8571	595	24.41825	45-50	3.8%
50	55	2014	45658	703.148049	28.13313548	32104333.62	1284502.7	741	29.43335	666	26.8571	50-55	4.2%
55	60	2014	45657	782.5855921	30.86181509	35730510.38	1409057.892	825	32.31875	741	29.43335	55-60	4.7%
60	65	2014	45658	870.7142247	33.88903362	39755070.07	1547305.497	919	35.54765	825	32.31875	60-65	5.2%
65	70	2014	45657	969.7071814	37.29964206	44273920.78	1702989.758	1023	39.215477	919	35.54765	65-70	5.8%
70	75	2014	45658	1083.033594	41.52671035	49449147.85	1896026.541	1146	43.950854	1023	39.215477	70-75	6.5%
75	80	2014	45658	1216.880456	46.67968066	55560327.84	2131300.86	1292	49.571708	1146	43.950854	75-80	7.3%
80	85	2014	45657	1381.432614	53.01477419	63072068.84	2420495.545	1479	56.771021	1292	49.571708	80-85	8.3%
85	90	2014	45658	1598.116397	61.35688318	72966798.47	2801432.572	1736	66.665264	1479	56.771021	85-90	9.6%
90	95	2014	45657	1925.820059	73.97314645	87927166.43	3377391.947	2164	83.142836	1736	66.665264	90-95	11.6%
95	100	2014	45658	2822.086885	108.478523	128850843	4952912.402	12507	481.337993	2164	83.142836	95-100	17.0%

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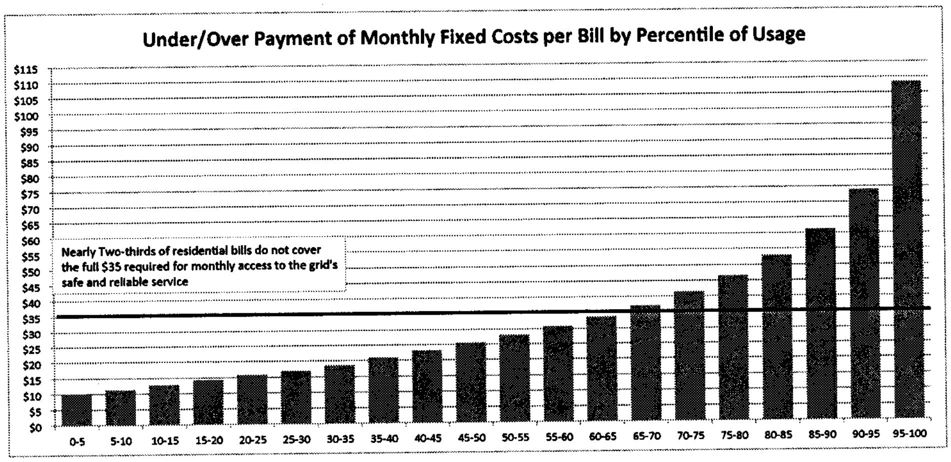
			2010	2011	2012	2013	2014	5 Year Average	
1.4%	10.12	0-5	$10	$10	$10	$10	$10	$10	35.048043
1.6%	11.34	5-10	$11	$11	$11	$11	$11	$11	35.048043
1.8%	12.87	10-15	$13	$13	$13	$13	$13	$13	
2.0%	14.37	15-20	$14	$14	$15	$14	$14	$14	
2.3%	15.79	20-25	$16	$16	$16	$16	$16	$16	
2.4%	17.13	25-30	$17	$17	$17	$17	$17	$17	
2.7%	18.97	30-35	$19	$19	$19	$19	$19	$19	
3.0%	21.27	35-40	$21	$21	$22	$21	$21	$21	
3.4%	23.61	40-45	$24	$24	$24	$24	$23	$24	
3.7%	26.06	45-50	$26	$26	$26	$26	$26	$26	
4.1%	28.67	50-55	$29	$29	$29	$29	$28	$29	
4.5%	31.49	55-60	$31	$31	$32	$32	$31	$32	
4.9%	34.60	60-65	$35	$35	$35	$35	$34	$35	
5.4%	38.16	65-70	$38	$38	$39	$39	$37	$38	
6.1%	42.63	70-75	$43	$43	$43	$43	$42	$43	
6.8%	47.99	75-80	$48	$48	$48	$49	$47	$48	
7.8%	54.59	80-85	$55	$54	$55	$55	$53	$54	
9.0%	63.30	85-90	$63	$63	$64	$64	$61	$63	
10.9%	76.58	90-95	$77	$76	$77	$77	$74	$76	
16.0%	112.33	95-100	$112	$112	$112	$113	$108	$112	
1.4%	10.12								
1.6%	11.36								
1.8%	12.88								
2.1%	14.39								
2.3%	15.81								
2.4%	17.14								
2.7%	18.99								
3.0%	21.26								
3.4%	23.60								
3.7%	26.03								
4.1%	28.62								
4.5%	31.45								
4.9%	34.56								
5.4%	38.11								
6.1%	42.52								
6.8%	47.85								
7.8%	54.40								
9.0%	63.12								
10.9%	76.35								
16.0%	112.24								
1.4%	10.13								
1.6%	11.40								
1.8%	12.96								
2.1%	14.50								
2.3%	15.95								
2.4%	17.32								
2.7%	19.30								
3.1%	21.60								
3.4%	23.96								
3.7%	26.42								
4.1%	29.05								
4.5%	31.91								
5.0%	35.06								
5.5%	38.65								
6.1%	43.13								
6.9%	48.45								
7.8%	54.99								
9.0%	63.65								
10.8%	76.70								
15.8%	111.91								
1.4%	10.13								
1.6%	11.39								
1.8%	12.93								
2.0%	14.45								
2.2%	15.88								
2.4%	17.23								
2.7%	19.15								
3.0%	21.44								
3.4%	23.81								
3.7%	26.31								
4.1%	28.99								
4.5%	31.89								
4.9%	35.08								
5.5%	38.76								
6.1%	43.35								
6.9%	48.78								
7.8%	55.42								
9.0%	64.19								
10.9%	77.45								
16.0%	113.27								
1.5%	10.13								
1.7%	11.39								
1.9%	12.91								
2.1%	14.40								
2.3%	15.78								
2.5%	17.07								
2.7%	18.78								
3.1%	20.99								
3.4%	23.25								
3.7%	25.62								
4.1%	28.13								
4.5%	30.86								
4.9%	33.89								
5.4%	37.30								
6.1%	41.53								
6.8%	46.68								
7.7%	53.01								
9.0%	61.36								
10.8%	73.97								
15.8%	108.48								



Load/PV System Summary:

Small Customer Monthly kWh	500	
Annual Customer Energy (kWh)	6,000	
Annual PV Production-South (kWh)	6,000	Note: Input for annual production in "Rate_PV Input" tab.
Annual PV Production-West (kWh)	5,074	
System Size	3.33	kW-DC
Initial System Cost	$ 5,833.22	

	Day Count	365	31	28	31	30	31	30	31	31	30	31	30
			1	2	3	4	5	6	7	8	9	10	11
1	**Description**	**Annual**	**January**	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**
2	Energy Use (kWh)	6,001	451	368	362	372	460	667	794	679	590	393	384
3	Total Peak Demand (kW)	4.16	3.40	3.26	3.14	3.27	3.65	3.86	4.16	3.91	3.80	3.26	3.15
4	Ratchet Minimum-Total (kW)	-	-	-	-	-	-	-	-	-	-	-	-
5	Net Demand at Peak (kW)	4.00	3.40	3.26	3.14	3.27	3.47	3.71	4.00	3.84	3.80	3.26	3.15
6	Ratchet Minimum-Net (kW)	-	-	-	-	-	-	-	-	-	-	-	-
7	Load Factor (Total Peak)	16.5%	17.8%	16.8%	15.5%	15.8%	16.9%	24.0%	25.7%	23.3%	21.6%	16.2%	16.9%
8													
9	Net Hourly Energy Delivered (kWh)	3,447	309	242	229	205	231	333	418	357	318	229	254
10	Net Hourly Energy Received (kBh)	3,448	225	259	355	418	419	274	222	256	259	307	253
11													
12	Total PV Output (kWh)	6,000	374	401	519	585	623	593	595	564	520	475	397
13	PV Output (max kW)	2.9	2.4	2.9	2.8	2.8	2.9	2.8	2.8	2.7	2.8	2.7	2.4
14	Capacity Factor	23.5%	21.3%	20.7%	24.7%	29.3%	28.7%	29.7%	28.8%	28.2%	25.9%	23.8%	22.9%
15													
16	Net-Metering Rollover		-	-	33	190	403	565	491	292	177	107	189
17	Billing kWh		77	-	-	-	-	-	-	-	-	-	-
18													
19													

	1	Loads without DG: 2	3	4	5	6	PV kWh/kBh Data: 7	8	9	10	11	12
		2014 Solar Billing Dets - 50th percentile			Scaled to:	6,000	SAM PV scaled	Solar House	Solar House	Solar House	SAM PV scaled	Scaled
		kWh	kW	Load Factor	kWh	kW	w/Annual Use	total PV out	Net kWh in	kBh	w/Bill Dets.	Net kWh in
31 January	1	595	4.49	17.8%	451	3.40	445	324	245	200	374	309
28 February	2	485	4.30	16.8%	368	3.26	409	348	192	231	401	242
31 March	3	478	4.14	15.5%	362	3.14	543	450	181	316	519	229
30 April	4	491	4.31	15.8%	372	3.27	580	507	162	372	585	205
31 May	5	607	4.82	16.9%	460	3.65	577	540	183	373	623	231
30 June	6	880	5.10	24.0%	667	3.86	533	514	264	244	593	333
31 July	7	1,048	5.49	25.7%	794	4.16	515	516	331	198	595	418
31 August	8	896	5.16	23.3%	679	3.91	528	489	283	228	564	357
30 September	9	778	5.01	21.6%	590	3.80	496	451	252	231	520	318
31 October	10	518	4.30	16.2%	393	3.26	492	412	181	273	475	229
30 November	11	507	4.16	16.9%	384	3.15	455	344	201	225	397	254
31 December	12	635	4.64	18.4%	481	3.52	429	309	255	179	356	322
365		7,918	5.49	16.5%	6,000	4.16	6,000	5,204	2,730	3,070	6,000	3,447
30.4	Monthly Avg.	660	4.66	19.4%		3.53			88.9%	2,900		100.0%
		Annual kWh as % of South orientation			84.6%				50th pctl			

Ex. BK-2 054

31
12
December
481
3.52
-
3.52
-
18.4%
322
201
356
2.3
20.5%
201
-

	Peak kW Scaling and Adjustments:						Peak Shifting Analysis:					For Scaling 8760:		Check:	
13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28
												2014 Res Avg Hrly Profile			
Scaled kBh	Scaled net kW	Max net kW Hour Position	Max net kW Hour	Count	PV output at Peak	net kW adj for DG	Max kW Hour Position	Max kW Hour	Count	DG output at Peak	Max kW less PV	Raw kWh	Raw kW	Scaled kWh	Scaled kW
225	3.40	116	1/5 19:00	1	-	3.40	116	1/5 19:00	1	-	3.40	410	0.88	451	3.40
259	3.26	813	2/3 20:00	1	-	3.26	813	2/3 20:00	1	-	3.26	337	0.85	368	3.26
355	3.14	1988	3/24 19:00	1	-	3.14	1988	3/24 19:00	1	-	3.14	337	0.72	362	3.14
418	3.27	2661	4/21 20:00	1	-	3.27	2661	4/21 20:00	1	-	3.27	332	0.84	372	3.27
419	3.47	3523	5/27 18:00	1	0.1813	3.47	3523	5/27 18:00	1	0.1679	3.48	436	1.49	460	3.65
274	3.56	4339	6/30 18:00	1	0.1510	3.71	4338	6/30 17:00	1	0.6304	3.23	707	2.20	667	3.86
222	3.44	4363	7/1 18:00	1	0.1556	4.00	4913	7/24 16:00	1	1.2842	2.88	880	2.51	794	4.16
256	3.42	5491	8/17 18:00	1	0.0731	3.84	5490	8/17 17:00	1	0.5600	3.35	754	2.22	679	3.91
259	3.41	5851	9/1 18:00	1	-	3.80	5849	9/1 16:00	2	1.2288	2.57	659	2.07	590	3.80
307	3.11	6666	10/5 17:00	1	-	3.26	6665	10/5 16:00	1	1.1715	2.09	399	1.08	393	3.26
253	3.15	7868	11/24 19:00	1	-	3.15	7868	11/24 19:00	1	-	3.15	352	0.80	384	3.15
201	3.52	8755	12/31 18:00	1	-	3.52	8755	12/31 18:00	1	-	3.52	451	1.27	481	3.52
3,447	3.56					4.00				1.28		6,055	2.51	6,000	4.16
3,447	3.35														
57.4%															

Ex. BK-2 055

Load/PV System Summary:

Medium Customer Monthly kWh	900	
Annual Customer Energy (kWh)	10,800	
Annual PV Production-South (kWh)	10,800	Note: Input for annual production in "Rate_PV Input" tab.
Annual PV Production-West (kWh)	9,133	
System Size	6.00	kW-DC
Initial System Cost	$ 10,499.79	

	Day Count	365	31	28	31	30	31	30	31	31	30	31	30	31
			1	2	3	4	5	6	7	8	9	10	11	12
1	Description	Annual	January	February	March	April	May	June	July	August	September	October	November	December
2	Energy Use (kWh)	10,800	805	627	640	640	845	1,236	1,428	1,251	1,102	738	639	849
3	Total Peak Demand (kW)	6.30	5.49	5.15	4.80	5.08	5.66	5.97	6.30	6.01	5.75	5.07	5.01	5.60
4	Ratchet Minimum-Total (kW)	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Net Demand at Peak (kW)	6.02	5.49	5.15	4.80	5.08	5.33	5.70	6.02	5.88	5.75	5.07	5.01	5.60
6	Ratchet Minimum-Net (kW)	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Load Factor (Total Peak)	19.6%	19.7%	18.1%	17.9%	17.5%	20.1%	28.8%	30.4%	28.0%	26.6%	19.5%	17.7%	20.4%
8														
9	Net Hourly Energy Delivered (kWh)	5,918	519	388	353	336	419	610	724	639	563	395	421	551
10	Net Hourly Energy Received (kBh)	5,918	413	459	620	704	677	455	382	426	427	525	455	375
11														
12	PV Output (kWh)	10,800	672	722	935	1,052	1,121	1,067	1,071	1,015	936	854	713	641
13	PV Output (max kW)	5.2	4.2	5.2	5.1	5.0	5.2	5.0	5.0	4.8	5.0	4.8	4.3	4.2
14	Capacity Factor	23.5%	21.3%	20.7%	24.7%	29.3%	28.7%	29.7%	28.8%	28.2%	25.9%	23.8%	22.9%	20.5%
15														
16	Net-Metering Rollover		-	-	95	390	802	1,078	910	553	316	151	267	341
17	Billing kWh		133	-	-	-	-	-	-	-	-	-	-	-
18														
19														

		Loads without DG:					PV kWh/kBh Data						
	1	2	3	4	5	6	7	8	9	10	11	12	13
		2014 Solar Billing Dets - 75th percentile			Scaled to:	10,800	SAM PV scaled	Solar House	Solar House	Solar House	SAM PV scaled	Scaled	Scaled
		kWh	kW	Load Factor	kWh	kW	w/Annual Use	total PV out	Net kWh In	kBh	w/Bill Dets.	Net kWh In	kBh
31 January	1	969	6.60	19.7%	805	5.49	800	539	427	348	672	519	413
28 February	2	754	6.20	18.1%	627	5.15	736	579	319	387	722	388	459
31 March	3	770	5.78	17.9%	640	4.80	978	750	290	522	935	353	620
30 April	4	770	6.12	17.5%	640	5.08	1,043	844	276	593	1,052	336	704
31 May	5	1,017	6.81	20.1%	845	5.66	1,038	899	344	570	1,121	419	677
30 June	6	1,487	7.18	28.8%	1,236	5.97	959	856	501	383	1,067	610	455
31 July	7	1,718	7.59	30.4%	1,428	6.30	927	859	595	322	1,071	724	382
31 August	8	1,505	7.23	28.0%	1,251	6.01	950	814	525	359	1,015	639	426
30 September	9	1,326	6.92	26.6%	1,102	5.75	894	751	463	360	936	563	427
31 October	10	888	6.11	19.6%	738	5.07	885	685	325	442	854	395	525
30 November	11	769	6.03	17.7%	639	5.01	818	572	346	383	713	421	455
31 December	12	1,021	6.74	20.4%	849	5.60	772	514	453	316	641	551	375
365		12,994	7.59	19.6%	10,800	6.30	10,800	8,662	4,864	4,985	10,800	5,918	5,918
30.4	Monthly Avg.	1,083	6.61	22.4%		5.49			97.6%	4,925		100.0%	5,918

Ex. BK-2 056

Peak kW Scaling and Adjustments:						Peak Shifting Analysis:					For Scaling 8760:		Check:	
14	15	16	17	18	19	20	21	22	23	24	25	26	27	28
											2014 Res Avg Hrly Profile			
Scaled net kW	Max net kW Hour Position	Max net kW Hour	Count	PV output at Peak	net kW adj for DG	Max kW Hour Position	Max kW Hour	Count	DG output at Peak	Max kW less PV	Raw kWh	Raw kW	Scaled kWh	Scaled kW
5.49	128	1/6 7:00	1	-	5.49	128	1/6 7:00	1	-	5.49	887	1.92	805	5.49
5.15	824	2/4 7:00	1	-	5.15	824	2/4 7:00	1	-	5.15	701	1.94	627	5.15
4.80	1988	3/24 19:00	1	-	4.80	1988	3/24 19:00	1	-	4.80	690	1.37	640	4.80
4.84	2659	4/21 18:00	1	-	5.08	2658	4/21 17:00	1	0.8304	4.25	722	2.07	640	5.08
5.00	3523	5/27 18:00	1	0.3263	5.33	3522	5/27 17:00	1	1.1015	4.56	989	3.25	845	5.66
5.55	4339	6/30 18:00	1	0.2719	5.70	4338	6/30 17:00	1	1.1348	4.83	1,481	4.09	1,236	5.97
5.35	4363	7/1 18:00	1	0.2801	6.02	4913	7/24 16:00	1	2.3115	3.99	1,793	4.52	1,428	6.30
5.30	5491	8/17 18:00	1	0.1315	5.88	5488	8/17 15:00	1	3.0425	2.97	1,548	4.09	1,251	6.01
5.16	5851	9/1 18:00	1	-	5.75	5848	9/1 15:00	2	3.0935	2.65	1,365	3.82	1,102	5.75
4.77	6666	10/5 17:00	1	-	5.07	6665	10/5 16:00	1	2.1087	2.97	876	2.51	738	5.07
5.01	7869	11/24 20:00	1	-	5.01	7869	11/24 20:00	1	-	5.01	747	1.65	639	5.01
5.60	8755	12/31 18:00	1	-	5.60	8755	12/31 18:00	1	-	5.60	1,010	2.73	849	5.60
5.60					6.02				3.09		12,809	4.52	10,800	6.30
5.17														

Ex. BK-2 057

Load/PV System Summary:

Large Customer Monthly kWh	1,200	
Annual Customer Energy (kWh)	14,400	
Annual PV Production-South (kWh)	14,400	Note: Input for annual production in "Rate_PV Input" tab.
Annual PV Production-West (kWh)	12,178	
System Size	8.00	kW-DC
Initial System Cost	$ 13,999.72	

	Day Count	365	31	28	31	30	31	30	31	31	30	31	30	31
			1	2	3	4	5	6	7	8	9	10	11	12
1	**Description**	**Annual**	**January**	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**
2	Energy Use (kWh)	14,401	1,050	846	831	880	1,143	1,572	1,899	1,650	1,467	991	893	1,179
3	Total Peak Demand (kW)	7.55	6.69	6.29	5.78	6.22	6.73	7.14	7.55	6.95	6.84	5.96	5.87	6.87
4	Ratchet Minimum-Total (kW)	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Net Demand at Peak (kW)	7.13	6.69	6.29	5.78	6.22	6.29	6.77	7.13	6.78	6.84	5.96	5.80	6.87
6	Ratchet Minimum-Net (kW)	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Load Factor (Total Peak)	21.8%	21.1%	20.0%	19.3%	19.7%	22.8%	30.6%	33.8%	31.9%	29.8%	22.3%	21.1%	23.1%
8														
9	Net Hourly Energy Delivered (kWh)	7,702	700	505	464	422	534	781	948	822	745	523	509	749
10	Net Hourly Energy Received (kBh)	7,702	549	622	847	927	850	588	511	537	522	657	602	490
11														
12	PV Output (kWh)	14,400	897	963	1,246	1,403	1,495	1,423	1,428	1,353	1,248	1,139	951	855
13	PV Output (max kW)	7.0	5.7	6.9	6.8	6.6	7.0	6.7	6.7	6.4	6.7	6.4	5.8	5.6
14	Capacity Factor	23.5%	21.3%	20.7%	24.7%	29.3%	28.7%	29.7%	28.8%	28.2%	25.9%	23.8%	22.9%	20.5%
15														
16	Net-Metering Rollover		-	-	117	532	1,055	1,406	1,258	786	490	271	419	476
17	Billing kWh		153	-	-	-	-	-	-	-	-	-	-	-
18														
19														

		Loads without DG:					PV kWh/kBh Data						
	1	2	3	4	5	6	7	8	9	10	11	12	13
		2014 Solar Billing Dets - 90th percentile			Scaled to:	14,400	SAM PV scaled	Solar House	Solar House	Solar House	SAM PV scaled	Scaled	Scaled
		kWh	kW	Load Factor	kWh	kW	w/Annual Use	total PV out	Net kWh in	kBh	w/Bill Dets.	Net kWh in	kBh
31 January	1	1,361	8.67	21.1%	**1,050**	**6.69**	1,067	792	690	525	897	700	549
28 February	2	1,097	8.15	20.0%	**846**	**6.29**	982	850	498	595	963	505	622
31 March	3	1,077	7.49	19.3%	**831**	**5.78**	1,304	1,100	458	810	1,246	464	847
30 April	4	1,140	8.06	19.6%	**880**	**6.22**	1,391	1,238	416	886	1,403	422	927
31 May	5	1,481	8.72	22.8%	**1,143**	**6.73**	1,384	1,320	527	813	1,495	534	850
30 June	6	2,037	9.25	30.6%	**1,572**	**7.14**	1,279	1,257	770	562	1,423	781	588
31 July	7	2,461	9.78	33.8%	**1,899**	**7.55**	1,235	1,260	934	489	1,428	948	511
31 August	8	2,138	9.01	31.9%	**1,650**	**6.95**	1,267	1,195	811	513	1,353	822	537
30 September	9	1,902	8.87	29.8%	**1,467**	**6.84**	1,192	1,102	735	499	1,248	745	522
31 October	10	1,284	7.73	22.3%	**991**	**5.96**	1,180	1,006	516	629	1,139	523	657
30 November	11	1,158	7.61	21.1%	**893**	**5.87**	1,091	839	502	576	951	509	602
31 December	12	1,528	8.91	23.1%	**1,179**	**6.87**	1,029	755	739	468	855	749	490
365		18,664	9.78	21.8%	14,400	7.55	14,400	12,714	7,596	7,365	14,400	7,703	7,703
30.4	Monthly Avg.	1,555	8.52	25.0%		6.57			103.1%	7,480		100.0%	7,703

Peak kW Scaling and Adjustments:						Peak Shifting Analysis:					For Scaling 8760:		Check:	
14	15	16	17	18	19	20	21	22	23	24	25	26	27	28
											2014 Res Avg Hrly Profile			
Scaled net kW	Max net kW Hour Position	Max net kW Hour	Count	PV output at Peak	net kW adj for DG	Max kW Hour Position	Max kW Hour	Count	DG output at Peak	Max kW less PV	Raw kWh	Raw kW	Scaled kWh	Scaled kW
6.69	224	1/10 7:00	1	-	**6.69**	224	1/10 7:00	1	-	6.69	1,661	3.48	1,050	6.69
6.29	824	2/4 7:00	1	-	**6.29**	824	2/4 7:00	1	-	6.29	1,337	3.53	846	6.29
5.78	1460	3/2 19:00	1	-	**5.78**	1460	3/2 19:00	1	-	5.78	1,332	2.52	831	5.78
6.04	2659	4/21 18:00	1	-	**6.22**	2658	*4/21 17:00*	1	*1.1072*	*5.11*	1,374	3.56	880	6.22
5.83	3523	5/27 18:00	1	0.4352	**6.29**	3496	*5/26 15:00*	1	*4.1520*	*2.58*	1,738	4.96	1,143	6.73
6.67	4339	6/30 18:00	1	0.3626	**6.77**	4314	*6/29 17:00*	1	*1.5920*	*5.54*	2,344	5.64	1,572	7.14
6.42	4891	7/23 18:00	1	0.4186	**7.13**	4912	*7/24 15:00*	1	*4.1063*	*3.44*	2,772	6.19	1,899	7.55
6.34	5491	8/17 18:00	1	0.1754	**6.78**	5488	*8/17 15:00*	1	*4.0567*	*2.89*	2,428	5.84	1,650	6.95
6.37	5851	9/1 18:00	1	-	**6.84**	5850	*9/1 17:00*	1	*1.4952*	*5.35*	2,174	5.46	1,467	6.84
5.64	6666	10/5 17:00	1	-	**5.96**	6664	*10/5 15:00*	1	*4.2308*	*1.73*	1,555	4.01	991	5.96
5.80	7856	11/24 7:00	1	0.0667	**5.80**	7856	11/24 7:00	1	*0.0765*	*5.79*	1,425	3.10	893	5.87
6.70	8755	12/31 18:00	1	-	**6.87**	8754	*12/31 17:00*	1	*0.2213*	*6.65*	1,853	4.67	1,179	6.87
6.70					**7.13**				4.23		21,991	6.19	14,400	7.55
6.21														

Ex. BK-2 059

Load/PV System Summary:

Large Customer Monthly kWh	1,500	
Annual Customer Energy (kWh)	18,000	
Annual PV Production-South (kWh)	18,000	Note: Input for annual production in "Rate_PV Input" tab.
Annual PV Production-West (kWh)	15,222	
System Size	10.00	kW-DC
Initial System Cost	$ 17,499.65	

	Day Count	365	31	28	31	30	31	30	31	31	30	31	30	31
			1	2	3	4	5	6	7	8	9	10	11	12
1	Description	Annual	January	February	March	April	May	June	July	August	September	October	November	December
2	Energy Use (kWh)	17,998	1,359	1,055	1,029	1,085	1,440	1,968	2,364	2,094	1,846	1,258	1,109	1,391
3	Total Peak Demand (kW)	8.56	7.77	7.34	6.66	7.06	7.80	8.29	8.56	8.15	8.03	6.88	7.02	7.93
4	Ratchet Minimum-Total (kW)	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Net Demand at Peak (kW)	8.42	7.77	7.34	6.66	7.06	7.60	7.83	8.42	7.94	7.95	6.88	7.02	7.93
6	Ratchet Minimum-Net (kW)	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Load Factor (Total Peak)	24.0%	23.5%	21.4%	20.8%	21.3%	24.8%	33.0%	37.1%	34.5%	31.9%	24.6%	21.9%	23.6%
8														
9	Net Hourly Energy Delivered (kWh)	9,648	868	652	566	518	656	937	1,168	1,057	937	663	665	961
10	Net Hourly Energy Received (kBh)	9,650	691	770	1,036	1,103	1,048	784	652	686	709	826	731	614
11														
12	PV Output (kWh)	18,000	1,121	1,204	1,558	1,753	1,868	1,779	1,784	1,692	1,560	1,424	1,188	1,069
13	PV Output (max kW)	8.7	7.1	8.6	8.5	8.3	8.7	8.3	8.3	8.1	8.4	8.0	7.2	7.0
14	Capacity Factor	23.5%	21.3%	20.7%	24.7%	29.3%	28.7%	29.7%	28.8%	28.2%	25.9%	23.8%	22.9%	20.5%
15														
16	Net-Metering Rollover		-	-	149	677	1,346	1,774	1,585	1,006	603	317	483	563
17	Billing kWh		238	-	-	-	-	-	-	-	-	-	-	-
18														
19														

		Loads without DG:					PV kWh/kBh Data						
	1	2	3	4	5	6	7	8	9	10	11	12	13
		2014 Solar Billing Dets - 95th percentile			Scaled to:	18,000	SAM PV scaled	Solar House	Solar House	Solar House	SAM PV scaled	Scaled	Scaled
		kWh	kW	Load Factor	kWh	kW	w/Annual Use	total PV out	Net kWh In	kBh	w/Bill Dets.	Net kWh In	kBh
31 January	1	1,751	10.01	23.5%	**1,359**	**7.77**	1,334	1,334	1,204	913	1,121	868	691
28 February	2	1,359	9.45	21.4%	**1,055**	**7.34**	1,227	1,433	904	1,018	1,204	652	770
31 March	3	1,326	8.58	20.8%	**1,029**	**6.66**	1,630	1,854	785	1,369	1,558	566	1,036
30 April	4	1,398	9.10	21.3%	**1,085**	**7.06**	1,739	2,087	717	1,458	1,753	518	1,103
31 May	5	1,855	10.05	24.8%	**1,440**	**7.80**	1,730	2,224	909	1,385	1,868	656	1,048
30 June	6	2,535	10.68	33.0%	**1,968**	**8.29**	1,599	2,118	1,299	1,036	1,779	937	784
31 July	7	3,046	11.03	37.1%	**2,364**	**8.56**	1,544	2,124	1,619	861	1,784	1,168	652
31 August	8	2,698	10.51	34.5%	**2,094**	**8.15**	1,583	2,014	1,465	906	1,692	1,057	686
30 September	9	2,378	10.34	31.9%	**1,846**	**8.03**	1,489	1,857	1,299	938	1,560	937	709
31 October	10	1,621	8.86	24.6%	**1,258**	**6.88**	1,475	1,695	918	1,092	1,424	663	826
30 November	11	1,429	9.04	22.0%	**1,109**	**7.02**	1,364	1,415	922	966	1,188	665	731
31 December	12	1,792	10.22	23.6%	**1,391**	**7.93**	1,286	1,272	1,332	811	1,069	961	614
365		23,188	11.03	24.0%	**18,000**	**8.56**	18,000	21,429	13,374	12,754	18,000	9,649	9,649
30.4	Monthly Avg.	1,932	9.82	27.0%		**7.62**			104.9%	13,064		100.0%	9,649

Peak kW Scaling and Adjustments:						Peak Shifting Analysis:					For Scaling 8760:		Check:	
14	15	16	17	18	19	20	21	22	23	24	25	26	27	28
											2014 Res Avg Hrly Profile			
Scaled net kW	Max net kW Hour Position	Max net kW Hour	Count	PV output at Peak	net kW adj for DG	Max kW Hour Position	Max kW Hour	Count	DG output at Peak	Max kW less PV	Raw kWh	Raw kW	Scaled kWh	Scaled kW
7.77	127	1/6 6:00	1	-	7.77	127	1/6 6:00	1	-	7.77	2,305	4.75	1,359	7.77
7.34	824	2/4 7:00	1	-	7.34	824	2/4 7:00	1	-	7.34	1,874	4.83	1,055	7.34
6.56	1964	3/23 19:00	1	-	6.66	1451	3/2 10:00	1	5.5939	1.06	1,868	3.43	1,029	6.66
6.88	2635	4/20 18:00	1	-	7.06	2658	4/21 17:00	1	1.3840	5.68	1,913	4.74	1,085	7.06
6.85	3524	5/27 19:00	1	0.2024	7.60	3520	5/27 15:00	1	5.1873	2.61	2,336	6.17	1,440	7.80
7.53	4339	6/30 18:00	1	0.4532	7.83	4313	6/29 16:00	1	3.6763	4.61	2,992	6.88	1,968	8.29
7.45	5060	7/30 19:00	1	0.1456	8.42	4912	7/24 15:00	1	5.1329	3.43	3,516	7.39	2,364	8.56
7.38	5491	8/17 18:00	1	0.2192	7.94	5487	8/17 14:00	1	6.2326	1.92	3,102	7.09	2,094	8.15
7.41	5971	9/6 18:00	1	0.0802	7.95	6161	9/14 16:00	1	3.7114	4.32	2,800	6.69	1,846	8.03
6.38	6642	10/4 17:00	1	-	6.88	6664	10/5 15:00	1	5.2886	1.59	2,095	5.25	1,258	6.88
7.00	7855	11/24 6:00	1	-	7.02	7935	11/27 14:00	1	6.4984	0.52	1,953	4.00	1,109	7.02
7.63	8755	12/31 18:00	1	-	7.93	8748	12/31 11:00	1	0.9211	7.01	2,523	6.10	1,391	7.93
7.77					8.42				6.50		29,276	7.39	18,000	8.56
7.18														

Vote Solar-7

BEFORE THE ARIZONA CORPORATION COMMISSION

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

SURREBUTTAL TESTIMONY AND EXHIBITS OF BRIANA KOBOR

ON BEHALF OF VOTE SOLAR

FEBRUARY 23, 2016

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1 Introduction

Q. Please state your name and business address.

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

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

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

Q. Did you submit direct testimony in this proceeding?

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

2 Purpose of Testimony and Summary of Recommendations

Q. Please describe how your testimony is organized.

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

Q. Please briefly summarize your findings and recommendations.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

[1] Broderick Direct Test. at 6:9–13.

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

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

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

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

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

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

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

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

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

Q. Please describe RUCO's alternative NEM proposal.

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

3.2 UNSE rebuttal

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

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

3.2.1 Rebuttal Testimony of Mr. Dukes

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

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

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

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

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

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

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

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

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

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

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

[11] *In re the investigation of the costs and benefits of PacifiCorp's net metering program*, Order, Docket No. 14-035-114, at 11, (Utah PSC Nov. 10, 2015) ("Utah PSC Order"), *available at* http://www.psc.utah.gov/utilities/electric/elecindx/2014/documents/27044914035114o.pdf.

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

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

3.2.2 Rebuttal Testimony of Dr. Overcast

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

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

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

[12] Dukes Rebuttal Test. at 18.3–4.

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

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

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

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

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

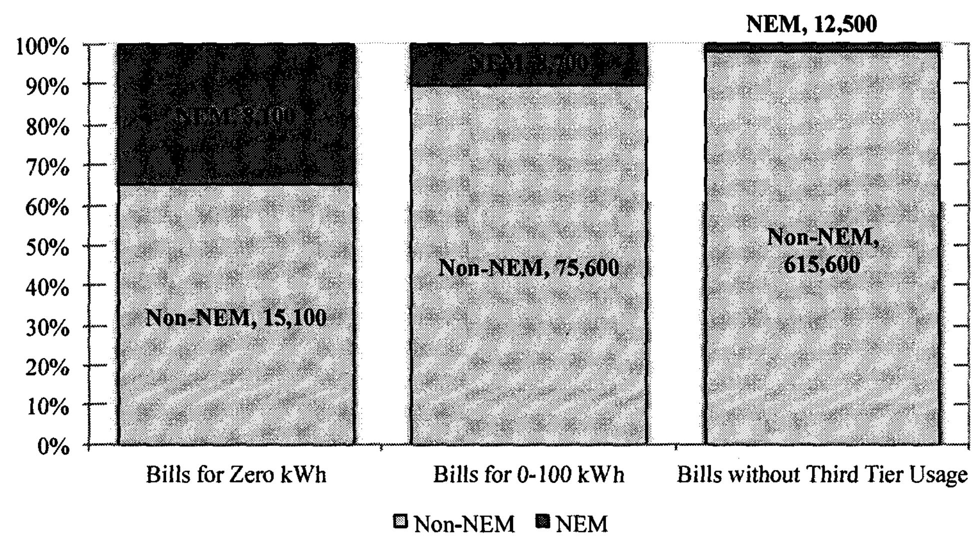
A. No. In fact, examination of the bill frequency data for NEM and non-NEM customers reveals just the opposite: NEM customer bills are not outliers, but rather are consistent with the variation seen in the residential class. While a larger proportion of NEM bills reflect zero kWh of usage, there were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

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

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

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

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



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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

[27] Overcast Rebuttal Test. at Ex. HEO-2.

[28] Overcast Rebuttal Test. at 13:9–14.

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

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

Category	Average Annual Marginal Cost
Deliveries	$24.72
Exports	$27.56

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

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

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

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

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

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

[29] *Id.* at 19:13–14.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Q. What do these findings imply?

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

3.2.3 Rebuttal Testimony of Mr. Tilghman

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

4.1 Other Parties' positions

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

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

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

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

4.2 UNSE Rebuttal

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

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

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

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

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

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

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

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

4.3 RUCO's NEM tariff proposal should be denied

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

5 Mandatory demand charges should be rejected

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

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

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

[68] RUCO Resp. to VS 1.4.
[69] *In re UNSE for approval of its 2016 Renewable Energy Standard Implementation Plan*, Ex. 2., Docket No. 15-0233 (July 1, 2015).
[70] Dukes Direct Test. at 4:1–2, 5:2–3.
[71] Jones Direct Test. at Ex. CAJ-3 (Proposed RES-01 Demand tariff).

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

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

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

Table 3: Summary of Proposed Residential Demand Charges

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

5.1 <u>NEM customers and Non-NEM customers are similarly situated regarding demand charges</u>

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Q. What are the implications of this uncertainty?

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

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

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

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

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

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

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

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

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

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

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

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

Q. Please discuss the proposed temporary minimum load factor.

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

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

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

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

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

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

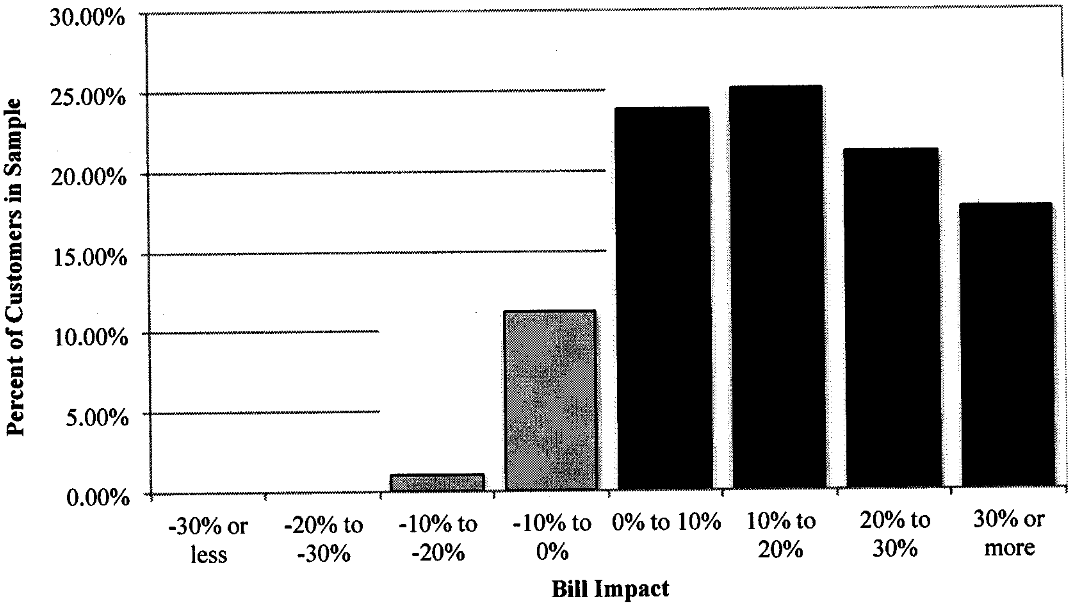
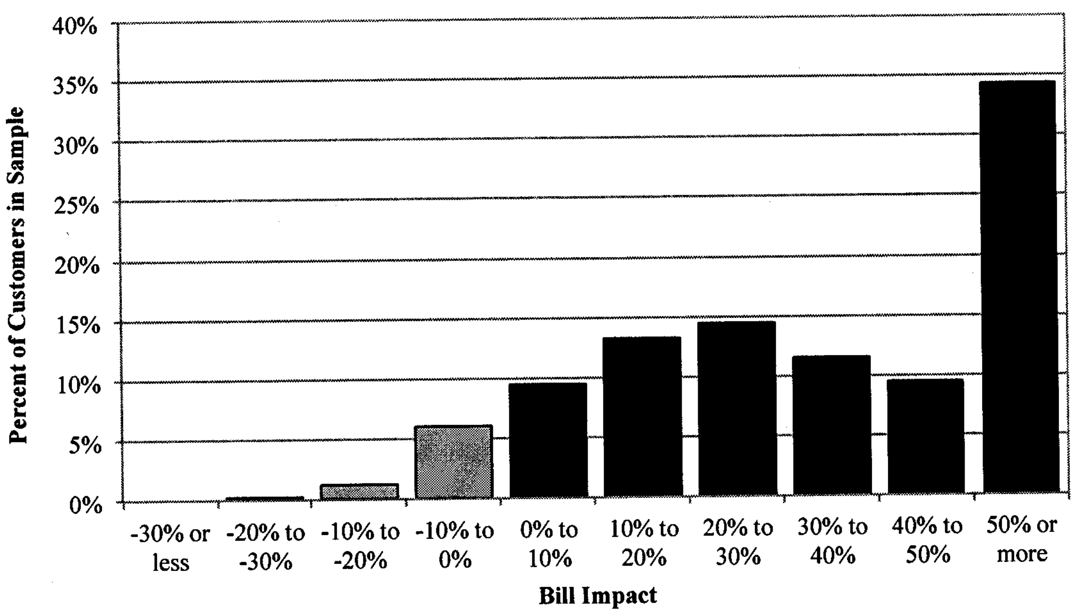


Figure 3: Distribution of Small Commercial bill impacts under UNSE proposal[113]



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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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[138] *Id.* at 8:24–25.

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

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

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

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

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

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

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

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

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

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[141] UNSE Resp. to WRA 1.16 (Ex. BK-SR-1 at 22).
[142] City of Santa Clara, Silicon Valley Power, Appliance Energy Use Chart, *available at* http://www.siliconvalleypower.com/for-residents/save-energy/appliance-energy-use-chart.
[143] Duke Energy, Electric Appliance Operating Cost List, *available at* http://www.duke-energy.com/pdfs/appliance_opcost_list_duke_v8.06.pdf.

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

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

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

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

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

5.6 <u>The Commission should exercise caution in its consideration of mandatory demand charges</u>

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

[158] *Id.*

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

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

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

Table 4: Garfield and Lovejoy Criteria[160]

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

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

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

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

[160] Lazar article at 15.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

7 Fixed charges should not be increased

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

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

[170] Kobor Direct Test. at 55–63.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

8 The Commission should not modify the existing NEM program

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

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

[179] Kobor Direct Test. at 60.

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

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

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

Q. How do you respond to these criticisms?

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

10 Conclusions and Recommendations

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

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

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

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

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

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

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

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

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

Q. What are your recommendations for the Commission?

A. I recommend the following:

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

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

Q. Does this conclude your testimony?

A. Yes.

Exhibit BK-SR-1

Discovery Responses Referenced in Testimony

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

VS 2.14

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

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

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

RESPONSE: September 28, 2015

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

RESPONDENT:

Carmine Tilghman

WITNESS:

Carmine Tilghman

SUPPLEMENTAL RESPONSE: September 29, 2015

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

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

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

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

RESPONDENT:

Carmine Tilghman

WITNESS:

Carmine Tilghman

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

VS 2.16

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

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

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

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

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

RESPONSE: **September 28, 2015**

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

RESPONDENT:

Carmine Tilghman

WITNESS:

Carmine Tilghman

SUPPLEMENTAL RESPONSE: **September 29, 2015**

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

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

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

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

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

RESPONDENT:

Carmine Tilghman

WITNESS:

Carmine Tilghman

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

VS 3.22

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

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

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

c. How was the random sample generated?

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

RESPONSE:

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

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

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

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

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

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

RESPONDENT:

Greg Strang

WITNESS:

Craig Jones

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

VS 5.05

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

RESPONSE:

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

RESPONDENT:

H. Edwin Overcast

WITNESS:

H. Edwin Overcast

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

VS 5.10

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

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

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

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

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

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

RESPONSE:

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

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

c. The test period for this rate case.

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

RESPONDENT:

H. Edwin Overcast

WITNESS:

H. Edwin Overcast

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

VS 5.38

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

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

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

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

RESPONSE:

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

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

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

RESPONDENT:

H. Edwin Overcast

WITNESS:

H. Edwin Overcast

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

VS 5.42

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

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

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

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

RESPONSE:

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

RESPONDENT:

H. Edwin Overcast

WITNESS:

H. Edwin Overcast

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

VS 5.48

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

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

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

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

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

RESPONSE:

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

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

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

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

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

UNSE Res Dem_Data_01-11-16_r0.xlsx

UNSE SGS Dem_Data_01-12-16_r0.xlsx

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

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

Residential Winter Bills (n=2,309)

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

Residential Summer Bills (n=2,309)

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

SGS Winter Bills (n=2,239)

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

SGS Summer Bills (n=2,239)

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

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

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

RESPONDENT:

Greg Strang/Rick Bachmeier

WITNESS:

Craig Jones

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

Regarding the rebuttal testimony of Mr. Tilghman:

VS 5.53

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

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

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

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

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

RESPONSE:

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

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

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

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

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

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

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

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

RESPONDENT:

Carmine Tilghman

WITNESS:

Carmine Tilghman

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

VS 5.54

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

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

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

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

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

RESPONSE:

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

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

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

RESPONDENT:

Carmine Tilghman

WITNESS:

Carmine Tilghman

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

VS 6.5

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

a. At least 12 months of demand data.

b. At least 3 months of demand data.

RESPONSE:

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

RESPONDENT:

Rick Bachmeier

WITNESS:

Dallas Dukes

Residential Utility Consumer Office's

Responses to Data Requests by Vote Solar

UNS Electric, Inc. Rate Case

Docket No. E-04204A-15-0142

VS 1.3

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

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

VS 1.4

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

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

VS 3.4 On page 11, lines 1-3 of his direct testimony, Mr. Solganick states: "In the long-term, customers might receive cost 'warning' using a simple red/yellow/green indication in their home or business and, for example, their demand controllers could access detailed price information online." Is Mr. Solganick aware of any such technologies on the market today? If so, please provide information on these technologies, including the cost of the technologies and any available information regarding customer adoption.

RESPONSE: **Mr. Solganick observed the red/yellow/green technology in use in Missouri in 2007, but is not aware if it has been commercialized. Whirlpool indicates that its "Smart" washer and dryer can "Auto-delay laundry cycles during energy rush hours" working with the Nest thermostat. Mr. Solganick has not investigated the cost or adoption rate.**

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

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

VS 3.11

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

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

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

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

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

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

RESPONSE:

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

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

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

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

e) When a customer is satisfied.

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

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

TASC 1.1: Regarding the Testimony of Mr. Faruqui:

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

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

Response:

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

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

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

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

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

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

Witness: Dr. Ahmad Faruqui

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

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

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

RESPONSE:

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

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

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

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

WRA 1.16

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

RESPONSE:

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

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

RESPONDENT:

Carmine Tilghman

WITNESS:

Carmine Tilghman

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

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

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

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

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

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

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

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

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

Witness: Charles Miessner

Response to RUCO 1.2 (continued):

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

c. The summary information is provided in APS15766.

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

e. As shown in the attachment, the top 20% (most successful) savers reduced their bills by 10% to 20% or more under the demand rate.

f. As provided in the attachment, the average demand reduction for the sample was 3% to 4% while the top 20% reduced their monthly demand by roughly 24% on average.

Witness: Charles Miessner

ARIZONA PUBLIC SERVICE COMPANY
Residential Demand Rate Analysis

Background:
Analysis performed in 2015
The purpose of the study was to assess the impact of a three-part demand rate on demand, energy, and monthly bills for residential customers.
The study isolated the demand chage impact by comparing the same customer before and after switching to a three-part rate.
Since the three-part rate was a time-of-use rate, APS compared customers moving from a two-part TOU rate with similar on-peak hours.
The study specifically compared the two-part Rate ET-2 with the three-part Rate ECT-2, both having on-peak hours of 12 noon to 7 pm weekdays.

Sampling Frame:
Phoenix Metro customers
Switched from ET-2 to ECT-2 in 2013
Had 12 months billing data in 2012 and 2014
Resided in same home for the three year period
Total sample size = 977 customers

Adjustments:
Load data was normalized for temperature and humidity for summer months.
Winter months were not adjusted because correlation factors between load and weather were very low.

APS15766_Demand Rate Analysis.xlsx
Background

ARIZONA PUBLIC SERVICE COMPANY

Residential Demand Rate Analysis

stratified by % kW change during summer months

The change in kW, kWh, and monthly bill resulting from switching from a two-part rate to a three-part rate

Summer Load Change (Weather Normalized - temp, humidity)									Summer Bill[1]	
% Customers	Total kWh	On-Pk kWh	Off-Pk kWh	On-Pk kW	% Total kWh	% On-Pk kWh	% Off-Pk kWh	% On-Pk kW	$ Change	% Change
5%	(617)	(234)	(383)	(3.0)	-27%	-40%	-22%	-39%	$ (93.94)	-35%
10%	(444)	(134)	(310)	(1.8)	-19%	-24%	-17%	-24%	$ (66.07)	-25%
15%	(386)	(139)	(247)	(1.6)	-15%	-21%	-13%	-19%	$ (64.35)	-22%
20%	(364)	(117)	(246)	(1.3)	-14%	-17%	-13%	-16%	$ (62.67)	-21%
25%	(358)	(89)	(269)	(1.1)	-14%	-14%	-14%	-13%	$ (58.15)	-20%
30%	(196)	(76)	(120)	(0.9)	-8%	-11%	-7%	-11%	$ (45.61)	-16%
35%	(99)	(48)	(51)	(0.7)	-4%	-8%	-3%	-9%	$ (37.68)	-14%
40%	(162)	(66)	(96)	(0.7)	-6%	-9%	-5%	-8%	$ (45.06)	-14%
45%	(40)	(29)	(11)	(0.5)	-2%	-5%	-1%	-6%	$ (29.43)	-11%
50%	(78)	(41)	(38)	(0.4)	-3%	-6%	-2%	-4%	$ (30.38)	-10%
55%	(31)	(25)	(6)	(0.2)	-1%	-4%	0%	-2%	$ (29.28)	-10%
60%	7	(12)	19	(0.1)	0%	-2%	1%	-1%	$ (22.88)	-9%
65%	2	(4)	6	0.1	0%	-1%	0%	1%	$ (17.45)	-6%
70%	68	8	60	0.2	3%	1%	4%	3%	$ (14.64)	-5%
75%	3	7	(4)	0.3	0%	1%	0%	4%	$ (17.65)	-6%
80%	181	25	156	0.5	8%	4%	9%	6%	$ (7.49)	-3%
85%	200	45	155	0.7	8%	7%	8%	9%	$ (1.01)	0%
90%	144	52	92	0.9	6%	9%	5%	12%	$ (3.11)	-1%
95%	256	63	193	1.2	11%	10%	11%	16%	$ 7.82	3%
100%	519	166	353	2.1	25%	34%	22%	33%	$ 41.43	18%
Average	(70)	(32)	(37)	(0.31)	-2.9%	-5.2%	-2.1%	-3.9%	$ (29.88)	-11%

APS15766_Demand Rate Analysis.xlsx
Load & Bill Impacts

ARIZONA PUBLIC SERVICE COMPANY

Residential Demand Rate Analysis

stratified by % kW change during summer months

Winter Load Change (No Weather Normalization)									Winter Bill[1]	
% Customers	Total kWh	On-Pk kWh	Off-Pk kWh	On-Pk kW	% Total kWh	% On-Pk kWh	% Off-Pk kWh	% On-Pk kW	$ Change	% Change
5%	(242)	(61)	(182)	(1.2)	-21%	-29%	-19%	-26%	$ (27.63)	-23%
10%	(159)	(45)	(115)	(0.9)	-12%	-18%	-11%	-18%	$ (25.31)	-19%
15%	(88)	(23)	(66)	(0.3)	-7%	-10%	-6%	-7%	$ (13.58)	-11%
20%	(140)	(32)	(108)	(0.5)	-10%	-13%	-10%	-10%	$ (18.44)	-14%
25%	(147)	(22)	(125)	(0.4)	-12%	-9%	-12%	-9%	$ (16.23)	-13%
30%	(52)	(5)	(46)	(0.3)	-4%	-2%	-5%	-6%	$ (10.51)	-8%
35%	(94)	(3)	(92)	(0.1)	-8%	-1%	-9%	-3%	$ (10.56)	-9%
40%	(63)	(9)	(54)	(0.3)	-4%	-3%	-5%	-5%	$ (13.28)	-9%
45%	(5)	1	(6)	(0.3)	0%	0%	-1%	-5%	$ (6.04)	-5%
50%	(22)	3	(24)	0.1	-2%	1%	-2%	2%	$ (7.40)	-6%
55%	(1)	11	(12)	(0.1)	0%	5%	-1%	-1%	$ (5.18)	-4%
60%	(18)	(0)	(17)	(0.2)	-2%	0%	-2%	-4%	$ (7.61)	-7%
65%	12	17	(5)	0.0	1%	8%	-1%	0%	$ (3.20)	-3%
70%	45	20	25	0.1	4%	10%	3%	2%	$ 0.77	1%
75%	23	16	7	0.1	2%	8%	1%	3%	$ (4.20)	-4%
80%	137	33	104	0.2	12%	16%	11%	4%	$ 5.20	4%
85%	53	26	27	0.2	4%	10%	2%	4%	$ (1.60)	-1%
90%	58	29	30	0.3	5%	14%	3%	6%	$ (0.26)	0%
95%	151	53	98	0.6	13%	26%	10%	13%	$ 9.10	8%
100%	231	68	163	0.8	19%	32%	17%	17%	$ 13.41	11%
Average	(16)	4	(20)	(0.11)	-1.3%	1.7%	-2.0%	-2.2%	$ (7.13)	-6%

APS15766_Demand Rate Analysis.xlsx
Load & Bill Impacts

ARIZONA PUBLIC SERVICE COMPANY

Residential Demand Rate Analysis

stratified by % kW change during summer months

Annual Load Change									Annual Bill [1]	
% Customers	Total kWh	On-Pk kWh	Off-Pk kWh	On-Pk kW	% Total kWh	% On-Pk kWh	% Off-Pk kWh	% On-Pk kW	$ Change	% Change
5%	(430)	(147)	(282)	(2.1)	-25%	-37%	-21%	-34%	$ (60.78)	-32%
10%	(302)	(89)	(213)	(1.3)	-16%	-22%	-15%	-21%	$ (45.69)	-23%
15%	(237)	(81)	(156)	(1.0)	-12%	-18%	-11%	-14%	$ (38.96)	-18%
20%	(252)	(75)	(177)	(0.9)	-13%	-16%	-12%	-13%	$ (40.56)	-18%
25%	(252)	(55)	(197)	(0.8)	-13%	-12%	-14%	-11%	$ (37.19)	-18%
30%	(124)	(41)	(83)	(0.6)	-7%	-9%	-6%	-9%	$ (28.06)	-14%
35%	(97)	(26)	(71)	(0.4)	-5%	-6%	-5%	-7%	$ (24.12)	-12%
40%	(113)	(37)	(75)	(0.5)	-5%	-8%	-5%	-6%	$ (29.17)	-13%
45%	(23)	(14)	(8)	(0.4)	-1%	-3%	-1%	-6%	$ (17.73)	-9%
50%	(50)	(19)	(31)	(0.1)	-3%	-4%	-2%	-2%	$ (18.89)	-9%
55%	(16)	(7)	(9)	(0.1)	-1%	-2%	-1%	-2%	$ (17.23)	-8%
60%	(5)	(6)	1	(0.1)	0%	-2%	0%	-2%	$ (15.25)	-8%
65%	7	7	0	0.1	0%	2%	0%	1%	$ (10.33)	-5%
70%	56	14	43	0.1	3%	3%	3%	2%	$ (6.93)	-4%
75%	13	12	1	0.2	1%	3%	0%	4%	$ (10.92)	-6%
80%	159	29	130	0.3	9%	7%	10%	5%	$ (1.15)	-1%
85%	127	36	91	0.5	7%	8%	6%	7%	$ (1.30)	-1%
90%	101	40	61	0.6	6%	10%	4%	10%	$ (1.68)	-1%
95%	204	58	146	0.9	12%	14%	11%	15%	$ 8.46	4%
100%	375	117	258	1.5	23%	33%	20%	26%	$ 27.42	16%
Average	(43)	(14)	(29)	(0.21)	-2.4%	-3.4%	-2.0%	-3.3%	$ (18.50)	-9%

Notes:

1. Excluding adjustors and taxes.

ARIZONA PUBLIC SERVICE COMPANY

Residential Demand Rate Analysis

stratified by % kW change during summer months

Three-part Demand Rate (Time-of-use)

ECT-2 Load (calendar year 2014)

	Summer Monthly Avg (May-Oct)				Winter Monthly Avg (Nov-April)				Annual				Avg Monthly Load Factor		
% Customers	Total kWh	On-Pk kWh	Off-Pk kWh	On-Pk kW	Total kWh	On-Pk kWh	Off-Pk kWh	On-Pk kW	Total kWh	On-Pk kWh	Off-Pk kWh	On-Pk kW	Summer	Winter	Annual
5%	1,700	345	1,355	4.7	937	149	788	3.5	1,319	247	1,071	4.1	49%	37%	43%
10%	1,898	432	1,465	5.8	1,162	199	963	4.1	1,530	316	1,214	4.9	45%	39%	42%
15%	2,156	526	1,630	7.0	1,209	206	1,003	4.7	1,683	366	1,316	5.9	42%	35%	38%
20%	2,272	566	1,705	7.3	1,222	221	1,001	4.9	1,747	394	1,353	6.1	42%	34%	38%
25%	2,195	572	1,623	7.2	1,098	217	881	4.7	1,647	394	1,252	6.0	41%	32%	37%
30%	2,252	587	1,665	7.4	1,173	234	939	4.9	1,713	410	1,302	6.1	41%	33%	37%
35%	2,254	581	1,673	7.1	1,137	215	921	4.8	1,695	398	1,297	6.0	43%	33%	38%
40%	2,563	637	1,926	8.1	1,379	254	1,124	5.4	1,971	446	1,525	6.7	43%	35%	39%
45%	2,329	602	1,727	7.5	1,211	217	994	4.8	1,770	410	1,360	6.2	42%	35%	38%
50%	2,454	638	1,816	8.3	1,304	255	1,049	5.4	1,879	447	1,433	6.9	40%	33%	37%
55%	2,421	620	1,801	7.7	1,248	233	1,015	5.0	1,834	426	1,408	6.4	42%	34%	38%
60%	2,240	571	1,668	7.1	1,081	196	885	4.2	1,660	384	1,277	5.7	43%	36%	39%
65%	2,410	624	1,786	8.2	1,234	236	998	5.0	1,822	430	1,392	6.6	40%	34%	37%
70%	2,388	631	1,757	8.0	1,182	224	958	5.0	1,785	428	1,357	6.5	40%	33%	37%
75%	2,428	616	1,812	8.0	1,201	231	970	4.8	1,815	424	1,391	6.4	41%	35%	38%
80%	2,540	646	1,894	8.1	1,301	240	1,061	5.1	1,920	443	1,478	6.6	42%	35%	39%
85%	2,685	693	1,992	8.9	1,419	274	1,145	5.7	2,052	484	1,568	7.3	41%	34%	38%
90%	2,515	649	1,866	8.3	1,228	235	993	4.9	1,871	442	1,430	6.6	41%	35%	38%
95%	2,569	671	1,897	8.7	1,312	260	1,052	5.4	1,940	466	1,475	7.1	40%	33%	37%
100%	2,606	654	1,952	8.5	1,424	282	1,142	5.7	2,015	468	1,547	7.1	42%	35%	38%
Average	2,344	593	1,751	7.6	1,223	229	994	4.9	1,783	411	1,372	6.3	42%	35%	38%

APS15766_Demand Rate Analysis.xlsx
Load Data

ARIZONA PUBLIC SERVICE COMPANY

Residential Demand Rate Analysis

stratified by % kW change during summer months

Two-part Energy Rate (Time-of-use)

ET-2 Load (calendar year 2012)

	Summer Monthly Avg (May-Oct)				Winter Monthly Avg (Nov-April)				Annual				Load Factor		
% Customers	Total kWh	On-Pk kWh	Off-Pk kWh	On-Pk kW	Total kWh	On-Pk kWh	Off-Pk kWh	On-Pk kW	Total kWh	On-Pk kWh	Off-Pk kWh	On-Pk kW	Summer	Winter	Annual
5%	2,317	579	1,738	7.7	1,179	210	969	4.7	1,748	394	1,354	6.2	41%	35%	38%
10%	2,342	566	1,776	7.6	1,321	244	1,078	5.0	1,832	405	1,427	6.3	42%	37%	39%
15%	2,542	665	1,877	8.6	1,297	229	1,068	5.1	1,920	447	1,473	6.8	40%	35%	38%
20%	2,635	683	1,952	8.6	1,362	254	1,108	5.5	1,999	469	1,530	7.1	41%	34%	38%
25%	2,553	661	1,892	8.3	1,245	238	1,007	5.2	1,899	450	1,449	6.7	42%	33%	38%
30%	2,448	663	1,785	8.4	1,225	239	986	5.2	1,837	451	1,385	6.8	40%	33%	36%
35%	2,353	630	1,724	7.9	1,231	218	1,013	4.9	1,792	424	1,368	6.4	41%	35%	38%
40%	2,725	703	2,023	8.7	1,442	263	1,179	5.7	2,084	483	1,601	7.2	42%	35%	39%
45%	2,369	632	1,737	8.0	1,217	217	1,000	5.1	1,793	424	1,369	6.5	40%	33%	37%
50%	2,533	679	1,854	8.7	1,326	252	1,074	5.3	1,929	466	1,464	7.0	40%	34%	37%
55%	2,452	645	1,808	7.9	1,249	222	1,026	5.1	1,851	434	1,417	6.5	42%	34%	38%
60%	2,232	583	1,650	7.2	1,099	196	902	4.3	1,666	390	1,276	5.8	42%	35%	39%
65%	2,409	629	1,780	8.1	1,221	218	1,003	5.0	1,815	423	1,392	6.6	40%	34%	37%
70%	2,320	623	1,697	7.8	1,137	204	933	4.9	1,729	414	1,315	6.3	40%	32%	36%
75%	2,426	609	1,816	7.7	1,178	215	963	4.6	1,802	412	1,390	6.2	43%	35%	39%
80%	2,359	621	1,738	7.7	1,164	207	957	4.9	1,761	414	1,348	6.3	42%	33%	37%
85%	2,485	648	1,837	8.2	1,366	248	1,118	5.5	1,925	448	1,477	6.9	41%	34%	38%
90%	2,371	597	1,774	7.4	1,170	206	964	4.6	1,770	402	1,369	6.0	44%	35%	39%
95%	2,312	608	1,704	7.5	1,161	207	954	4.8	1,736	408	1,329	6.1	42%	34%	38%
100%	2,087	488	1,600	6.4	1,193	214	979	4.9	1,640	351	1,290	5.6	45%	34%	39%
Average	2,414	626	1,788	7.9	1,239	225	1,014	5.0	1,826	425	1,401	6.5	41%	34%	38%

ARIZONA PUBLIC SERVICE COMPANY

Residential Demand Rate Analysis

stratified by % kW change during summer months

Three-part Demand Rate (Time-of-use)

ECT-2 Average Monthly Bill [1]

% Customers	Summer	Winter	Annual
5%	$ 171.15	$ 90.08	$ 130.61
10%	$ 198.22	$ 105.72	$ 151.97
15%	$ 230.36	$ 113.95	$ 172.16
20%	$ 241.06	$ 116.50	$ 178.78
25%	$ 236.56	$ 109.36	$ 172.96
30%	$ 242.96	$ 114.00	$ 178.48
35%	$ 238.98	$ 111.42	$ 175.20
40%	$ 267.80	$ 127.85	$ 197.82
45%	$ 248.55	$ 114.87	$ 181.71
50%	$ 266.28	$ 125.11	$ 195.69
55%	$ 256.19	$ 118.49	$ 187.34
60%	$ 237.77	$ 103.32	$ 170.54
65%	$ 262.34	$ 118.24	$ 190.29
70%	$ 258.80	$ 115.16	$ 186.98
75%	$ 259.67	$ 114.06	$ 186.86
80%	$ 267.91	$ 121.54	$ 194.72
85%	$ 287.12	$ 132.75	$ 209.93
90%	$ 268.61	$ 116.33	$ 192.47
95%	$ 277.96	$ 125.27	$ 201.62
100%	$ 275.72	$ 132.57	$ 204.14
Average	$ 249.70	$ 116.33	$ 183.01

Two-part Energy Rate (Time-of-use)

ET-2 Average Monthly Bill [1]

% Customers	Summer	Winter	Annual
5%	$ 265.09	$ 117.71	$ 191.40
10%	$ 264.30	$ 131.03	$ 197.66
15%	$ 294.71	$ 127.53	$ 211.12
20%	$ 303.73	$ 134.94	$ 219.34
25%	$ 294.71	$ 125.59	$ 210.15
30%	$ 288.58	$ 124.51	$ 206.54
35%	$ 276.66	$ 121.98	$ 199.32
40%	$ 312.86	$ 141.13	$ 226.99
45%	$ 277.98	$ 120.91	$ 199.44
50%	$ 296.66	$ 132.50	$ 214.58
55%	$ 285.47	$ 123.67	$ 204.57
60%	$ 260.65	$ 110.93	$ 185.79
65%	$ 279.79	$ 121.45	$ 200.62
70%	$ 273.44	$ 114.39	$ 193.91
75%	$ 277.31	$ 118.26	$ 197.79
80%	$ 275.40	$ 116.34	$ 195.87
85%	$ 288.13	$ 134.35	$ 211.24
90%	$ 271.72	$ 116.58	$ 194.15
95%	$ 270.15	$ 116.17	$ 193.16
100%	$ 234.29	$ 119.17	$ 176.73
Average	$ 279.58	$ 123.46	$ 201.52

Notes:

1. Excluding adjustors and taxes.

Exhibit BK-SR-2

ACC Decision No. 51472 (Oct. 21, 1980)

BEFORE THE ARIZONA CORPORATION COMMISSION

JIM WEEKS
Chairman
BUD TIMS
Commissioner
JOHN AHEARN
Commissioner

IN THE MATTER OF THE COMMISSION, ON ITS OWN MOTION, CONDUCTING A HEARING PURSUANT TO A.R.S. SECTION 40-252 TO CONSIDER AMENDING DECISION NO. 49060	DOCKET NO. U-1345-80-98 DECISION NO. 51472 OPINION AND ORDER

DATE OF HEARING: September 4, 1980

PLACE OF HEARING: Phoenix, Arizona

PRESIDING OFFICERS: William R. Giese, Hearing Officer
Jim Weeks, Chairman
Bud Tims, Commissioner
John Ahearn, Commissioner

APPEARANCES: Robert K. Corbin, The Attorney General, by Thomas P. Prose, Assistant Attorney General, on behalf of the Arizona Corporation Commission

Snell & Wilmer, by Steven M. Wheeler, on behalf of Arizona Public Service Company

Carmichael, McClue & Powell, by Donald W. Powell, on behalf of the Homebuilders Association of Central Arizona

John Michael Morris, on his own behalf

Godfrey J. Danielson, on his own behalf

William Eden, on his own behalf

The purpose of the above proceeding was to consider the advisability of adopting a non-timed energy-capacity rate, known as the EC-1 Rate, for certain types of residential service. APS initially filed a proposed EC-1 rate on August 29, 1977 in Phase II of its 1977 rate case. By Decision No. 49060, dated June 9, 1978, the Commission deferred implementation of the EC-1 rate in order that further consideration might be given data obtained from certain load research activities being conducted by APS. By the aforesaid decision the Commission also created an "Advisory Committee on APS Time of Use Rate Design" and among other things referred the EC-1 rate to the committee for further study. Subsequently, the Advisory Committee proposed that the Commission approve the EC-1 rate structure. By notice of hearing in the above docket, Decision No. 51239, dated August 5, 1980, the Commission decided to reopen its consideration of the appropriateness of the EC-1 rate pursuant to A.R.S. § 40-252. Accordingly, a hearing was held on this proceeding on September 4, 1980, before the above named hearing officer and the full Commission. At the hearing the Company presented two witnesses and considerable evidence regarding design, implementation and effect of the EC-1 rate concept. The record in this hearing also consists of eighteen exhibits and official notice was taken of that part of the APS 1978 rate case which dealt with EC-1 rate. No evidence in opposition to the implementation of the EC-1 rate was introduced. However, the Home Builders Association of Central Arizona has indicated its opposition to mandatory load control devices on new construction.

FINDINGS OF FACT

1. The APS residential electric rate structure has historically been based primarily on the consumption of each customer. Such a rate structure ignores the fact that the cost of providing electric service is increasingly a function the demand for electricity places on the system rather than total power consumed. Commercial and industrial rates charged by APS have long recognized this fact and it is now appropriate that residential rate design should similarly reflect the primary components of cost of service. The

energy capacity rate (EC-1) as proposed by APS divides residential rates into three cost of service components: (1) a basic service charge, (2) a capacity charge based on the average KW rate supplied during the 60 minutes of maximum use during the month, and (3) an energy charge associated with the total number of kilowatt hours consumed during the month.

2. As proposed by APS, the EC-1 rate would be required for all new residential customers with central refrigerated air conditioning and optional for existing residential customers with central refrigerated air conditioning. APS further proposes that the special demand meter which is necessary for implementation of the EC-1 rate be installed and owned by the utility. The present cost of such a meter is approximately $100. Approximately 60% to 65% of the existing APS customers and 85% of the new customers are equipped with central air conditioning.

3. The three part EC-1 energy-demand rate concept provides an incentive to customers to manage their electric load in a manner that can result in lower electric bills for the individual customers and, equally important a reduction in APS peak demand which can have the effect of reducing the need for expensive additional generating facilities.

4. Without considering the demand modifications which the customers may make as a result of the load management incentive of the EC-1 rate, a composite study of the all electric and dual energy groups indicated a 50% division of increased and decreased electric bills. (Exhibit A-16) However, the installation of load management devices will increase the savings in electric bills to individual APS customers with all electric or dual energy systems.

Testimony indicated that such load control devices are presently available in varying degrees of sophistication. Exhibit A-11 indicates that the customer load control options vary in price with multiple circuit controllers, the most expensive ranging from $300 to $470, depending on the manufacturer. This price includes costs of installation presently estimated to be $150. Single circuit devices as indicated by Exhibit II can be purchased for nominal sums. As the market for such devices increases, it is anticipated that the cost will decrease.

5. The savings to an APS all electric customer could approximate as much as $200 per year with the addition of the multiple circuit controller on his residential electric service which presently would involve approximately $400 investment. Savings for other electric customers and the pay back periods for load control devices installed will vary depending on the type of load control device and the individual customer's load pattern. Thomas D. Morron of APS testified that the demand reduction of a dual energy customer with a load control device is going to approximate one-third of that of an all electric customer. APS proposed that the cost of the load management devices should be assumed by the individual residential customer. APS presently is studying financing proposals for financing this proposed customer cost.

6. The load management concept is one method by which both APS and its customers can combat the rising cost of electricity through reductions in the massive seasonal peak system demands and through the improvement of system load factor. The implementation of the EC-1 rate will help achieve this goal by rewarding the consumer for his contribution to capacity reductions on the APS

system. The adoption of the EC-1 rate will assist in meeting the company's objective of achieving the most efficient use of existing plant facilities while reducing the future need for costly expansion programs. Some APS customers will benefit by having the opportunity to reduce their electric bills by taking advantage of a rate design which rewards load management action.

7. To properly implement, promote and market the EC-1 rate, sufficient lead time must be available to APS, equipment manufacturers, home builders and customers. APS stated that for the EC-1 rate to be implemented by June 1, 1981, a Commission Order approving the EC-1 rate concept must be approved prior to November 1, 1980 and the actual EC-1 rate should be determined by March 1, 1981.

CONCLUSIONS OF LAW

1. Pursuant to A.R.S. § 40-252 the Commission has authority to alter or amend any order or decision made by it.

2. The EC-1 rate concept as approved herein is just, reasonable and otherwise in the public interest.

ORDER

WHEREFORE IT IS ORDERED: That the non-timed energy/demand rate concept described herein as EC-1 and required for all new homes with central electric refrigeration is hereby approved.

IT IS FURTHER ORDERED: That Arizona Public Service Company shall install non-timed energy/demand meters on new homes with central electric refrigeration on and after April 1, 1981.

IT IS FURTHER ORDERED: That the company shall give similar accounting treatment to those meters necessary to the implementation of the EC-1 rate as that utilized for current residential meters.

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IT IS FURTHER ORDERED: That load control devices located on the customers side of the meter shall not be the responsibility of the company.

IT IS FURTHER ORDERED: That Arizona Public Service Company shall file appropriate tariff sheets with the Commission implementing the EC-1 rate, effective for usage on and after May 1, 1981, or as soon thereafter as the Commission may order, at such rate levels as shall be determined by the Commission in Phase II of the Company's present rate case.

IT IS FURTHER ORDERED: That Decision No. 49060 is hereby amended in accordance with this Order.

BY ORDER OF THE ARIZONA CORPORATION COMMISSION

Chairman | Commissioner | Commissioner

IN WITNESS WHEREOF, I, G.C. ANDERSON, JR., Executive Secretary, of the Arizona Corporation Commission, have hereunto set my hand and caused the official seal of this Commission to be affixed at the Capitol, in the City of Phoenix, this 21st day of October, 1980.

G. C. ANDERSON, JR.
Executive Secretary

Exhibit BK-SR-3

ACC Decision No. 53615 (June 27, 1983)

wrg/jg

BEFORE THE ARIZONA CORPORATION COMMISSION

DIANE B. McCARTHY
Chairman
BUD TIMS
Commissioner
RICHARD KIMBALL
Commissioner

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATE MAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, AND THEREAFTER, TO DEVELOP SUCH RETURN, AND, IN CONNECTION THEREWITH, TO DETERMINE WHETHER THE INTERIM RATE INCREASE EFFECTIVE ON FEBRUARY 4, 1981 PURSUANT TO COMMISSION ORDER 51753 SHOULD BE MADE PERMANENT. (PHASE II - 1981)	DOCKET NO. U-1345-81-150 DECISION NO. 53615 OPINION AND ORDER

DATE OF HEARING: October 25, 1982 to October 29, 1982 incl.

PLACE OF HEARING: Phoenix, Arizona

IN ATTENDANCE: Bud Tims, Chairman
Jim Weeks, Commissioner
Diane McCarthy, Commissioner

PRESIDING OFFICER: Wm. R. Giese

APPEARANCES:

Snell & Wilmer, by Steven M. Wheeler, and Robert A. Schwartz, Arizona Public Service Company Legal Department, on behalf of Arizona Public Service Company

Robert K. Corbin, The Attorney General, by Lynwood J. Evans and James M. Flenner, Assistant Attorneys General, on behalf of Arizona Corporation Commission Staff

Martinez & Curtis, by Michael A. Curtis and William P. Sullivan, on behalf of Arizona Cotton Growers' Association

Campana & Horne, P.C., by Thomas C. Horne and Martha Kaplan, on behalf of Arizona Energy Users Association, Arizona Association of Industries, Arizona Hotel and Motel Association and Arizona Hospital Association

John C. Hall, in propria persona

John Michael Morris, in propria persona

Ralph W. Vaughn, in propria persona

Peter Q. Nyce, Jr., Regulatory Law Office, and Capt. Maurice A. Bergeron, on behalf of U. S. Department of Defense

Andy Baumert, City Attorney, by Ben P. Marshall, Assistant City Attorney, on behalf of the City of Phoenix

John F. Mills, Attorney at Law, on behalf of Magma Copper Company

Charles D. Wahl, Attorney at Law, on behalf of Sun City Taxpayers' Association, Inc.

Fennemore, Craig, von Ammon, Udall & Powers, by Scot Butler, III, on behalf of Arizona Multihousing Association and Arizona Chamber of Commerce

Gust, Rosenfeld, Divelbess & Henderson, by James M. Koontz, on behalf of Arizona Retailers Association

Grace Frei, in propria persona

INTRODUCTION

The instant proceeding concerned Phase II of the 1981 rate case of Arizona Public Service Company (APS). Phase I established a fair value rate base, a fair rate of return, and the appropriate revenue levels for APS pursuant to Commission Decision No. 52558, issued October 29, 1981. In Decision No. 52558, the Commission approved a $78.9 million settlement of APS's May 1, 1981, request for an increase in both electric and natural gas rates. The approved 10.4% electric rate increase and 6.9% overall gas increase became effective November 1, 1981. The Commission also made permanent a $79.5 million, 14% interim electric rate increase granted in Decision No. 51753, February 4, 1981.

The purpose of this Phase II proceeding is to: (1) allocate the authorized revenue levels among the various customer classes; (2) design and implement appropriate rate schedules by customer class which will permit APS to earn its authorized revenues; (3) consider certain additional, non-rate design issues. Pursuant to Commission Decision No. 52666, entered December 14, 1981, the issue of gas rate design was not re-litigated in this current Phase II proceeding.

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ALLOCATION OF REVENUE REQUIREMENTS

In the instant proceeding, the issue which has created the greatest disagreement among the parties, is the allocation of the total revenue increase, as provided in Decision No. 52593, among the various customer classes. The differences concerning the correct allocation of revenue requirements among customer classes primarily concern the weight to be given cost of service studies and the manner in which they should be conducted. APS submitted three cost of service studies, two of which were based on embedded cost and the third study based upon marginal cost. EBASCO, the staff consultants, presented evidence examining the APS cost of service studies and its own cost of service study which was also based upon embedded cost, using the 4 CP method. With the exception of staff and the intervenor, Arizona Cotton Growers Association, all parties chose to rely upon the APS cost of service study.

All of the allocation of revenue recommendations of APS are based solely upon its embedded cost study set forth in schedules GE-1 & 3 which allocates cost on the basis of the four months coincident peak (4 CP) demand allocation methodology. The APS proposed class revenue allocation is fully set forth in Exhibit A-11. The indicated revenue allocation increases the revenue requirement for residential class by 2.03% and the irrigation class by 1.47%, while decreasing the revenue requirement for the general service class (commercial/industrial) by 1.85%, compared to current rates.

The APS class revenue allocation was developed by a comprehensive process involving consideration of the APS embedded cost and marginal cost of service studies, with due consideration being given to the well accepted Bonbright principles of rate making (See, Bonbright, James C., Principles of Public Utility Rates. New York: Columbia University Press, 1961). While APS regards cost of service as the most important factor to be taken into account on rate design, it also properly considered additional factors of a non-cost nature such as continuity, equity, comprehensibility and revenue stability. (Tr. Vol. II, p. 161-165, 183-186, 223-226) The process for revenue allocation used by APS in this proceeding is consistent and in harmony with this Commission's adoption of the PURPA cost of service standard, in Decision No. 52593. That Decision provided that cost of service was not to be the sole consideration of rate design and that other relevant factors could also be considered. (Id. p. 5 & 6) For the Commission to allow the allocation of revenue requirements and ultimately rate design, upon strict cost of service would deprive it of its authority and discretion to use all available methods in the development of just and reasonable rates.

The historical indices of return for the various customer classes of APS indicate a trend in the direction of a more uniform return for each customer class. As this movement has historically taken place in a gradual manner, the adoption of the APS proposals will continue that historical movement within a reasonable range or "band of tolerance." This "band of tolerance" takes into consideration the inexactitudes of cost of service studies and allows for due consideration of such non-cost factors as continuity, equity, comprehensibility, rate and revenue stability. The combination of the total APS rate design package including increased residential revenue requirement responsibility, greater seasonal residential differential and the continuation of the demand price signal, results in a continuing movement towards a reasonable range of revenue indices.

RATE DESIGN

RESIDENTIAL RATES

The major residential rate of APS has been and continues to be, its E-10 rate schedule. During the 1981 test year, 99.79% of APS's residential customers and energy sales were billed under that rate schedule. The balance of APS's sales in the residential class were under three frozen rates, one experimental, and less than one hundred customers on APS's EC-1 rate for the last two months of the test year. (Exh. A-8, p. 20)

As the present basic combination of the E-10, EC-1, ECT-1 and ET-1 rates provide a wide practical range of choices to accommodate various customer consumption characteristics, APS proposes continuation of these basic rate choices. However, APS proposes a major modification to the E-10 rate and only minor changes to the EC-1, ECT-1 and ET-1 rates. Additionally, APS, Arizona Multihousing Association and Staff have proposed a new optional rate schedule, called the ECL-1 rate, for low volume residential users with central air conditioning. All of these changes and additions to the existing basic rate choices are more fully discussed hereinafter.

E-10 RATE

The APS proposed E-10 rate is set forth on Exhibit A-23. It consists of a basic service charge, unchanged from the last rate case, for all 12 months of $10.56, plus a commodity rate which varies depending upon the season and level of usage. The major modification of this rate involves changing the block rate structure for both the winter and summer rates. The present winter rate has a declining block which commences at the 1500 kWh level. APS would eliminate this block and bill all consumption during the winter on the E-10 rate at a flat rate per kWh. The revenue reduction resulting from this change has been transferred to the summer period for recovery. This seasonal revenue transfer will better reflect the very significant seasonal cost differences between those two periods (Exh. A-8, p. 22).

For the summer portion of the E-10 rate, APS proposes to leave unchanged the inverted block rate structure. The rate for the first consumption block (first 400 kWh) also remains unchanged. However, APS has proposed to invert the second rate block, which is the next 400 kWh. Under the present rate the 401st kWh costs $3.66 which results from all consumption being billed at 6.306¢/kWh when use is over 400 kWh. By inverting the second rate block the abrupt bill change occurring under the present rate design at 401 kWh would be avoided. (Exh. A-8, p. 22) APS has further proposed to increase the rate for the third and final block. The overall impact on summer bills would therefore be zero for all consumption up to 400 kWh, a decrease for bills between 400 kWh and 578 kWh, and increases for all consumption above that level. This will result in bill increases for high-volume, residential customers of approximately 8.08%. However, the overall annual increase for all E-10 customers is approximately 2% (Exh. A-8, p.23 & 24, Sch. HE-2, p. 1).

The resulting revenue shifts from winter to summer and from lower to higher consumption customers is justified by cost of service studies conducted by APS. These studies have shown that consumers who never exceeded 600 to 700 kWh in any month during the summer period had lower average costs than those whose use exceeded that amount. The reduction in the winter rate reduces the overall burden on the lower-user group since that group uses relatively greater amounts during the winter. (Exh. A-8, p. 23 & 24)

EC-1 RATE

The EC-1 rate is an energy-capacity rate having a separate price for the three major cost components of customer, demand and energy. The application of the EC-1 rate is limited to service locations with electric central air conditioning and which were first connected to the APS system after May 1, 1981. This rate approximates a time of day rate but with much lower metering and administrative costs. At the time of the instant hearing, there were approximately 8,000 customers on that rate making it the second largest residential rate as to the number of customers and sales. (Exh. A-8, p. 25) The EC-1 rate is designed to track the E-10 rate for each season (not monthly) for central air conditioning customers with average usage characteristics. Therefore, a change was required to reflect changes in the E-10 rate. The rate was also modified to reflect the actual experience of APS with the rate during the winter period from November 1981 through April 1982. This second modification has caused APS to propose an absolute limit to bills under the winter EC-1 rate of not more than 3.256¢/kWh. Imposing this limit recognizes that individual loads at low load factors tend to have a lower coincident demand, thus creating proportionately less demand on the system than those with normal and higher load factors. Such a ceiling, which is also applicable to the summer EC-1 rate also insures that there is a reasonable limit to the potential increases, as compared to E-10, that are experienced by the customers. (Exh. A-8, p. 27 to 30)

The summer rate portion of the EC-1 rate continues to track the E-10 rate. Modifications have been made to the rate level, but not to the rate form, because available data for the 1981 summer indicates that the EC-1 rate did track the E-10 rate quite well in terms of revenue equivalency. (Exh. A-8, p. 30)

. . .

ECT-1 AND ET-1 RATE

Both the ECT-1 and ET-1 rate are optional for residential customers of APS and each are limited to 1,000 customers. At the time of the instant hearing, ECT-1 had approximately 60 customers and the ET-1 approximately 120. The ECT-1 rate charges for demand (or capacity) and for energy by daytime and nighttime use. It is a seasonal time of day rate that has a separate charge for the three major cost components of customer, demand and energy. This rate should be generally favorable to customers who can control their day-time demand and take overt action to use energy at night. The lack of a demand charge for nighttime use (except when night demands exceed day demands) makes this rate attractive to EC-1 customers whose life style requires major appliances to be used at night rather than during the day. The ET-1 rate also charges separately for energy during the day and night period. It does not have a charge for measured killowatts of demand. Since these rates have only been effective since January 1, 1982, both should be continued pending further definitive results.

ECL-1

During the instant hearing an agreement was reached by APS, Ariz. Multihousing Association and the staff with regard to the development of a new rate for small use residential customers who have central air conditioning. This rate is in response to complaints that the mandatory nature of the EC-1 rate produced unfair results for low volume users. The rate design will alleviate the necessity for investment by low consumption customers in load control devices to mitigate what would otherwise be significant rate impacts under the EC-1 rate. (Tr. IV & V, p. 710, 735 & 736) The ECL-1 rate is described fully in Exhibit A-23 and is consistent with the agreement reached by the parties as outlined in Exhibit S-22(a). This rate schedule would be available to new residential electric customers with central refrigerated air conditioning, and to any reconnections where the immediately previous service was billed under the E-10 or E-207 rate. The winter portion of this rate is identical to the E-10 rate proposed by APS. The summer ECL-1 rate is also equal to the E-10 proposed rate by APS for the first two blocks, i. e., up to the first 800 kWh.

The rate in excess of 800 kWh is higher than the E-10 rate and is designed to track revenue generated from the summer EC-1 rate for similar consumption levels above 800 kWh. This will result in an equal set of energy and demand rates for air conditioning customers. The adoption of the ECL-1 rate will not affect the allocation of revenue requirements among the various customer classes.

RESIDENTIAL RATE SUMMARY

The Commission adopts the modifications to the E-10 and EC-1 rates and the creation of the ECL-1 rate as proposed by APS as described in Exhibit A-23. Upon adoption of this Order the following rates shall be available to the customers of APS:

Type of Customer	Available Rates
Existing residential customer as of May 1, 1981, with central air conditioning	E-10, EC-1, ECL-1, ECT-1, or ET-1
New residential customer after 1981 with central air conditioning	EC-1, ECL-1, ECT-1, or ET-1
Reconnection of existing residences with central air conditioning (previously on E-10 or E-207 rate)	EC-1, ECL-1, ECT-1, or ET-1
New or existing residential customers without central air conditioning	E-10

LARGE AND EXTRA LARGE GENERAL SERVICE RATES - E-32 & E-34

The Commission adopts the proposal of APS for the creation of new two primary rates for the general service class E-32 and E-34 and the cancellation of existing rate schedules E-32-1, E-32-2, E-33, E-46, and its contract ("Magma") rate. The new E-32 rate contains several significant changes from previous general rate schedules, all of which are designed to more accurately track cost incurrence and to send appropriate price signals to APS customers. The E-34 rate divides the large general service class into two sections for rate making purposes. It distinguishes between those customers whose maximum demand was 3,000 kW or greater and those with less than 3,000 kW but with at least 1,000 kW demand. The proposed E-34 rate schedule is a straight forward three part, customer, demand and energy rate with a five month seasonal 80% rachet. (Exh. A-8, p. 12) The individual components of the rate are based on the APS cost of service schedule and its revenue index limit. Approximately one-third of the demand costs are recovered in the energy component of the rate in order to recognize the coincidence and load factor characteristics of the customers.

The average decrease projected for the general service class as the result of these proposed rates is approximately 1.9%. However, individual bills may be increased or decreased depending upon size and load factor. Extra large customers (E-34 rate) will have annual bill changes ranging from an 8% increase to an 8% decrease. The frozen service rates of APS (E-120, E-126, E-220, E-251, E-49 and E-57) will be initially increased approximately 10% and will have annual automatic 10% increases until such time as they no longer serve any customers.

TIME OF DAY RATE FOR EXTRA LARGE GENERAL SERVICE CLASS

APS designed but did not recommend, a mandatory time of day rate for those customers qualifying for the E-34 rate schedule. This time of day rate is referred to as ECT-2 and is fully set forth in Exhibit A-18. APS presented the ECT-2 rate as an alternative to the E-34 rate and not optional as proposed by staff. APS originally based its objections to an optional ECT-2 rate on the basis that the Company would be exposed to the definite possibility of revenue erosion and earnings instability. These objections can be overcome by the adoption of an adjustment clause similar to the present fuel adjustment clause of APS. In the long term, an optional industrial time of day rate would allow APS to more efficiently utilize its generating facilities. This will be accomplished by encouraging existing industrial customers to shift demand during the peak period to the off peak period. Furthermore, new customers would be encouraged to design their production facilities so as not to impose a demand at the time of the summer system peak. The Commission is of the opinion that revenue erosion resulting from the adoption of an optional ECT-2 rate can also be minimized by initially limiting its availability to three customers as recommended by staff. (S-13, p. 28 & 29) With the above conditions, the Commission approves the optional ECT-2 rate as provided in Exh. A-18.

. . .

IRRIGATION RATES

The evidence supports adoption of the irrigation rate design E-38 & E-143 presented by APS. Exhibit A-21 indicates that adoption of the APS rate design proposal for irrigation class results in an average increase of approximately 1.5%. However, individual customers may experience different increases, or decreases, depending on their size, load factor, and seasonal use pattern. APS has recommended seasonal rates for the irrigation class based on the summer season of June through October. As a result, a higher energy charge will be effective for the summer months over that charged during the winter months. For consistency and other reasons more fully set forth in the record, the irrigation rates should be priced on a seasonal basis identical to the residential class. Consequently, a summer season of May through October should be utilized. (S-13, p. 36) Due to the similarity of the E-38 and E-143 rates both should be consolidated into one rate.

MISCELLANEOUS RATE CLASSES

APS has made only minor modifications to its street lighting and other public authority rates. (Exh. A-8, p. 34 & 35) These changes were not contested by the other parties and their adoption appears to be just and reasonable.

APS in making its determination of the revenue requirement of the lighting class used an "addendum approach." The use of this approach consists of determining the revenue requirement of the lighting as if it were a separate investment from the rest of APS. (Exh. S-13, p.39) The treatment of the lighting class in this manner ignores the fact that the lighting system is electrically intregated with the distribution system. As a result, in determining the revenue requirement for the lighting class, APS failed to include the recovery of any administrative and general expenses (other than employee benefits) as well as the cost of general plant which is normally allocated to a customer class. The Commission directs that in future Phase II proceedings, APS as a revenue requirement, alternative, use the same methodology as other classes, with such adjustments considered necessary because of the off peak use by the lighting class. It is further recommended that APS in the future submit lighting rates not based upon a uniform percent increase but based upon a methodology that reflects the unit investment for each lamp. (Exh. S-13, p.42)

APS PURCHASED POWER AND FUEL ADJUSTMENT CLAUSE

In Decision No. 52593, which was the result of the last APS Phase II hearing, the Commission deferred a general ruling regarding modification of the purchased power fuel adjustment clause, as it relates to non-jurisdictional layoff sales of power. In this proceeding, APS has again proposed to reduce the fuel expenses appearing in the purchased power and fuel adjustment clause for sales to non-jurisdictional customers made from specific generating units or plants. Previously, APS was authorized by Decision No. 52593 to use this particular treatment with respect to a specific layoff sale it made to Utah Power & Light Company from the Cholla Unit No. 4 plant. The Commission is of the opinion that this treatment should now be extended to all non-jurisdictional layoff sales of power by APS, and it is hereby approved.

Under the present application of the fuel adjustment clause, APS either over or under recovers its fuel costs whenever it makes sales at rates that are tied to specific plants or generating units. The adoption of this change in the PPF adjustment clause will allow APS to recover all of the allowable fuel expenses. Without this change, the resulting under or over collection of total fuel expenses, operates to defeat the purpose of the PPF adjustment clause. (Exh. S-13, p.42 to 45 & A-8, p.35 to 40)

The recommendation of staff to roll the current fuel adjustment into the current base rates is also approved. The result will be the avoidance of the cost of an additional hearing for the sole purpose of increasing the amount of base fuel collected in the fuel adjustment clause and is consistent with Decision No. 53256 which rolled fuel costs into base rates for APS as of December 1982.

The foregoing statements constitute the Findings of Fact and Conclusions of Law of this Commission.

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ACCORDINGLY, IT IS ORDERED:

1. On or before July 1, 1983, Arizona Public Service Company shall file with this Commission additions, cancellations and/or amendments to its existing tariffs including the revised EC-1 and the ECL-1 rates, which are consistent with the Findings, Conclusions and directives set forth herein.

2. With respect to any revenue shift to the residential class the proposed APS rate design shall be modified to allocate the revenue deficiency across all residential rates consistent with the other rate designs as initially proposed by APS.

3. The rates, charges and tariff provisions established herein shall become effective on November 1, 1983, except as otherwise provided below.

4. The ECL-1 residential rates shall be available, as of July 1, 1983 usage, on an optional basis as an alternative to E-10 or EC-1 for new residential customers, residential reconnects and existing residential customers, with central air conditioning. As of November 1, 1983, the ECL-1 rate shall become mandatory (except as to alternative EC-1) for new residential customers and residential customer reconnects, with central air conditioning.

5. All other rates and charges as proposed by APS, not specifically otherwise addressed in this Order, are hereby approved.

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6. APS shall file with the Utilities Division within thirty (30) days after the date of this Order detailed information on its proposed program to inform its customers of the new rate designs approved herein prior to their mandatory effective date.

7. This Order shall become effective immediately.

BY ORDER OF THE ARIZONA CORPORATION COMMISSION.

CHAIRMAN COMMISSIONER COMMISSIONER

IN WITNESS WHEREOF, I, THOMAS MUMAW, Acting Executive Secretary of the Arizona Corporation Commission, have hereunto set my hand and caused the official seal of this Commission to be affixed at the Capitol, in the City of Phoenix, this 27th day of June, 1983.

Thomas Mumaw
THOMAS MUMAW
Acting Executive Secretary

Exhibit BK-SR-4

ACC Decision No. 52593 (Nov. 9, 1981)

BEFORE THE ARIZONA CORPORATION COMMISSION

BUD TIMS
Chairman
JIM WEEKS
Commissioner
DIANE McCARTHY
Commissioner

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATE-MAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, AND THEREAFTER TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN. (PHASE II)

DOCKET NO. U-1345

DECISION NO. 52593

DATES OF HEARING: January 12-23, 1981

PLACE OF HEARING: Phoenix, Arizona

HEARING OFFICER: Andrew W. Bettwy

APPEARANCES:

SNELL & WILMER, by JARON B. NORBERG and STEVEN M. WHEELER, Attorneys for Arizona Public Service Company;

ROBERT K. CORBIN, The Attorney General, by CHARLES S. PIERSON, Assistant Attorney General, on behalf of the Arizona Corporation Commission Staff;

BILBY, SHOENHAIR, WARNOCK & DOLPH, by DWIGHT M. WHITLEY, JR., Attorneys for ASARCO, Inc.;

PAUL W. PHILLIPS and LAWRENCE A. GOLLOMP, Assistant General Counsel, Attorneys for the Department of Energy;

BRUCE E. MEYERSON, Arizona Center for Law in the Public Interest, Attorney for Arizona Community Action Association (ACAA), and Danny Valenzuela;

PETER Q. NYCE, JR., General Attorney, Regulatory Law Office, U.S. Army Legal Services Agency, Attorney for the Department of Defense;

MILLER, PITT & FELDMAN, by HENRY M. HUFFORD, Attorneys for Arizona Retailers Association;

NEISSER, CAMPANA & HORNE, by THOMAS C. HORNE, Attorneys for Arizona Association of Industries and Arizona Energy Users Association;

CARMICHAEL, McCLUE & POWELL by DONALD W. POWELL, Attorneys for Homebuilders Association of Central Arizona;

TWITTY, SIEVWRIGHT & MILLS, by JOHN F. MILLS, Attorneys for Magma Copper Company;

MARTINEZ, CURTIS, GOODWIN & KARASEK, by MICHAEL A. CURTIS, Attorneys for the Arizona Cotton Growers Association;

JENNINGS, STROUSS & SALMON, by THOMAS J. TRIMBLE, Attorneys for Turf Paradise, Inc.;

J. MICHAEL MORRIS, on his own behalf;

RALPH W. VAUGHN, on his own behalf;

GODFREY J. DANIELSON, on his own behalf;

RAYMOND RUGGE, on his own behalf;

ROLAND JAMES, on his own behalf.

Addressed during Phase II have been issues related to (1) consideration of the six rate design standards embodied in the Public Utility Regulatory Policies Act of 1978 (PURPA), (2) allocation of responsibility for Arizona Public Service Company's revenue requirements among the various classes of APS' customers and (3) design of rate schedules.

PURPA STANDARDS

PURPA, which became effective in November of 1978, mandates consideration by this Commission of six rate design standards and, further, a determination by this Commission of whether or not adoption of any or all of the standards is appropriate for the APS System to further the requirements of Arizona's law and the following goals of PURPA:

. . . . .

1. Conservation of energy supplied by electric utilities;

2. The optimization of the efficiency of use of facilites and resources by electric utilities; and

3. Equitable rates to electric consumers.
16 U.S.C. § 2611.

PURPA § 111 (i.e., 16 U.S.C. § 2621(d)) sets forth the six rate design standards as follows:

> (1) <u>Cost of service</u>.--Rates charged by any electric utility for providing electric service to each class of electric consumers shall be designed, to the maximum extent practicable, to reflect the costs of providing electric service to such class, as determined under section 2625 (a) of this title.
>
> (2) <u>Declining block rates</u>.--The energy component of a rate, or the amount attributable to the energy component in a rate, charged by any electric utility for providing electric service during any period to any class of electric consumers may not decrease as kilowatt-hour consumption by such class increases during such period except to the extent that such utility demonstrates that the costs to such utility of providing electric service to such class, which costs are attributable to such energy component, decrease as such consumption increases during such period.
>
> (3) <u>Time-of-day rates</u>.--The rates charged by any electric utility for providing electric service to each class of electric consumers shall be on a time-of-day basis which reflects the costs of providing electric service to such class of electric consumers at different times of the day unless such rates are not cost-effective with respect to such class, as determined under section 2625(b) of this title.
>
> (4) <u>Seasonal rates</u>.--The rates charged by an electric utility for providing electric service to each class of electric consumers shall be on a seasonal basis which reflects the costs of providing service to such class of consumers at different seasons of the year to the extent that such costs vary seasonally for such utility.

(5) Interruptible rates.--Each electric utility shall offer each industrial and commercial electric consumer an interruptible rate which reflects the cost of providing interruptible service to the class of which such consumer is a member.

(6) Load management techniques.--Each electric utility shall offer to its electric consumers such load management techniques as the State regulatory authority (or the nonregulated electric utility) has determined will--

(A) be practicable and cost-effective, as determined under section 2625(c) of this title,

(B) be reliable, and

(C) provide useful energy or capacity management advantages to the electric utility.

Our stated responsibility in this proceeding is established as follows in PURPA § 111(a):

(a) Consideration and determination.--Each State regulatory authority (with respect to each electric utility for which it has ratemaking authority) and each nonregulated electric utility shall consider each standard established by subsection (d) of this section and made a determination concerning whether or not it is appropriate to implement such standard to carry out the purposes of this chapter. For purposes of such consideration and determination in accordance with subsections (b) and (c) of this section, and for purposes of any review of such consideration and determination in any court in accordance with section 2633 of this title, the purposes of this chapter supplement otherwise applicable State law. Nothing in this subsection prohibits any State regulatory authority or nonregulated electric utility from making any determination that it is not appropriate to implement any such standard, pursuant to its authority under otherwise applicable State law.

16 U.S.C. § 261(a) (emphasis added).

. . . . .

We are confident that the six rate design standards enunciated in PURPA have been addressed exhaustively by the parties to this proceeding and, accordingly, we are satisfied that this Commission has been furnished with data, testimony and argument sufficient to make informed determinations regarding the appropriateness of adopting any or all of the six rate design standards for the APS system.

Subject to the qualifications expressed hereinafter, we hereby find and determine that, with respect to each of the six rate design standards promulgated by The Congress, its adoption for the APS system would promote one or more of the PURPA-stated goals and, accordingly, we conclude that adoption and implementation of all of the six rate design standards for the APS system would be appropriate.

Our adoption and implementation of the PURPA standards shall not in any manner supersede state law, restrict the lawful discretion of this Commission or prevent us from considering such other relevant factors such as but not limited to continuity, equity, comprehensibility and revenue stability as we may deem appropriate in the establishment of just and reasonable rates.

COST OF SERVICE

Our adoption of the Cost of Service standard is qualified by our declaration that neither the adoption nor implementation of such standard requires a design of rates for the APS system which is based solely on the cost of furnishing electricity. Among other well-established principles of rate-making, we intend to continue to be sensitive to the desirability of rate stability and the potential impacts of abrupt changes in rate design which may affect adversely APS existing customers.

Further, we do not intend by our adoption of the Cost of Service standard to endorse any particular costing methodology; in that regard, we intend to maintain for all affected interests and this Commission the continued freedom to employ a marginal cost of service study or an embedded cost of service study or any other methodology or combination thereof. Consistent with that objective, and to assure meaningful assessments in future rate proceedings of available costing methodologies, APS is hereby directed to include both a marginal cost of service study and an embedded cost of service study in its rate design filings in future rate proceedings.

In connection with our decision to adopt the Cost of Service standard, we are mindful and supportive of our Staff's recommendation that implementation be a cautious and gradual process.

DECLINING BLOCK RATES

We hereby express our intention to effect the eventual elimination of declining block rates for the APS system, except to the extent APS demonstrates to the satisfaction of this Commission in any particular instance that the energy-related costs to APS of providing electricity decreases as consumption increases. Our rate of progress in achieving that objective will be dependent upon reasonable application of principles of stability and continuity of rates.

.....

.....

TIME-OF-DAY RATES

As a general proposition, time-of-day rates trigger an accurate price signal to the consumer of electricity. Moreover, applied specifically to the APS system, we are persuaded that properly established time-of-day rates would encourage optimization of the efficiency and utilization of APS' facilities and resources. Accordingly, we hereby express our intention to authorize and encourage the implementation of time-of-day rates which are cost-effective (i.e., whenever the long-run benefits of such rate to APS and its affected consumers are likely to exceed the metering costs and other costs associated with the employment of such rates).

SEASONAL RATES

Since rates in APS' territory have reflected seasonality for several years, and since the evidence submitted by parties to this proceeding suggests that costs do vary substantially by season, we conclude that adoption of the seasonal rates standard is appropriate for the APS system. By our adoption of the seasonal rates standard, we do not endorse specifically any particular seasonal rate or rate design among those proposed by the parties to this proceeding; however, we do intend to assure that the existence of cost differentials by season generally be reflected in rate design, as historically has been the case with respect to APS' rates.

INTERRUPTIBLE RATES

In an effort to minimize peaking problems on the APS system and to appropriately recognize those commercial and industrial users which are willing to tolerate interruption during peak periods, we conclude that adoption of the interruptible rates standard is appropriate for the APS system. The record discloses that APS has had limited success in its effort to make available interruptible rates to commercial and industrial customers on a voluntary basis. With the objective of improving that success record, APS is hereby directed to survey its industrial and commercial customers and to report to this Commission within 18 months after the effective date of this Decision regarding the viability of a voluntary interruptible rates program. The written report shall detail the costs of providing such service, the categories of customers which would benefit by such rates, the proposed timing and duration of interruptions, potential problems associated with participation by various categories of customers and any other information which would assist this Commission in its evaluation of the practicability of an effective voluntary interruptible rates program.

LOAD MANAGEMENT TECHNIQUES

It would be curious indeed if one were to not readily applaud management techniques which are directed to the reduction of peak demand, assuming the long-run cost savings of such reduction are likely to exceed the long-run costs associated with implementation of such techniques. Our adoption herein of the load management techniques standard reflects our commitment to encourage the implementation by APS of such techniques.

Within 18 months after the effective date of this

Decision, APS shall furnish a written report to this Commission detailing (1) load management options which are available to APS, (2) analyses of the cost effectiveness of the various options and (3) a plan for load management.

NON-PURPA ISSUES

For the reasons detailed hereinafter, we hereby approve (1) APS' proposed ECT-1 rate schedule, which provides optional time-of-day rates for those residential customers who believe their consumption characteristics would warrant being billed on that basis, (2) Staff's proposed ET-1 rate schedule, which provides on alternate time-differentiated rate schedule and (3) to a limited extent, APS' proposed modification to its Purchased Power and Fuel Adjustment Clause to exclude from the calculation of the system average the fuel and related costs for generation units devoted to producing power for layoff sales.

1. Optional Time-of-Day Rates for Residential Customers.

Since the rates included in APS' proposed ECT-1 rate schedule do not include a revenue erosion adjustment and since the expected impacts of time-of-day rates on the APS system for residential customers continues somewhat in the experimental stage, we are in agreement with our staff and APS' suggestion that the rate be limited at this time to 1,000 customers.

Staff has proposed a tariff provision with respect to meters for the ECT-1 rate schedule which we think is appropriate and, accordingly, we adopt staff's proposed provision, which is:

> The cost of metering facilities in excess of the cost of metering for the EC-1 rate

shall be charged to the customer at a rate of $4.50 per month.

As an alternative to APS' proposed ECT-1 rate schedule, we are approving Staff's proposed ET-1 rate schedule. Both rates, of course, are being made available on an optional basis; and each at the present time is being limited to 1,000 customers at the urging of both APS and our Staff. With respect to the meters for the ET-1 rate, APS shall include the following provision in the applicable tariff:

> The cost of metering facilities in excess of the cost of metering for the EC-1 rate shall be charged to the customer at a rate of $2.40 per month.

2. <u>Modification to APS' Purchased Power and Fuel Adjustment Clause</u>.

We are not prepared at this time to decide whether or not it is appropriate, with respect to all non-jurisdictional layoff sales of power, to exclude the associated fuel and related costs from calculation of the system average when utilizing the Purchase Power and Fuel Adjustment Clause.

However, we are satisfied at the present time that such treatment of the layoff sales to Utah Power & Light from the Cholla 4 Plant is justified and appropriate on the basis of the record in this proceeding. Accordingly, we hereby approve such treatment of those sales. However, our treatment herein of such sales is subject to further examination; specifically, we intend to scrutinize such treatment when modification of the adjustment clause is considered next by the Commission.

Insofar as APS' requested modification relates to other layoff sales, a decision on that requested modification is deferred until the next general rate proceeding.

Mandatory Time-of-Day Rates for Extra Large General Service Customers.

The record discloses that the affected extra large customers already have the metering in place to commence implementation of mandatory time-of-day rates. Consistent with our stated commitment hereinabove to encourage the implementation of time-of-use rates that are cost-effective, we are anxious to move forward immediately with implementation of either APS' proposed ECT-2 rate schedule or some acceptable variation thereof; however, we are concerned after our examination of the record that we may not be informed sufficiently regarding the intra class dislocations that could be expected to result and, most particularly, how such dislocations likely may affect adversely any individual customer.

In an effort to avoid any unnecessary delay in the implementation of appropriate, mandatory time-of-day rates for APS' Extra Large General Service Customers, and in an effort to be assured that any action we take in that regard is based on reliable and complete information, APS and the parties representing the customers which would be affected by such rates are requested to submit to this Commission no later than December 1, 1981 specific information regarding expected impacts on individual customers within the Extra Large General Service class. Further, such parties may submit to this Commission on or before December 1, 1981 any additional information or comments pertaining in any manner whatsoever to the proposed implementation of mandatory time-of-day rates.

With respect to the remaining issues, which are related to allocation of APS' revenue requirements among APS' customers and the consequent design of specific rate schedules, we think all affected interests would be served best by a deferral of our treatment of such issues until the upcoming Phase II of the on-going APS general rate proceeding.

Most importantly, to attempt a wholesale realignment of rates at this time, with full knowledge that another comprehensive restructuring of rates reasonably can be expected within the next 6 to 12 months in connection with the most current APS general rate proceeding, would be to cause an unnecessary and unwarranted disruption among all of APS' electric customers.

Considerations of rate stability mandate that we be careful not to impose any more confusion and uncertainty regarding expected rates and charges than is required for our regulatory purposes. Further, and of particular significance, is the fact that our reexamination of APS' rate structure in connection with the most current APS general rate proceeding will be based on more current and more complete information.

The foregoing statements constitute the Findings of Fact and Conclusions of Law of this Commission.

ACCORDINGLY, IT IS ORDERED:

1. No later than December 10, 1981, Arizona Public Service Company shall file with this Commission additions and/or amendments to its existing tariffs which are consistent with the findings, conclusions and directives set forth herein.

2. The gas rate schedules and the associated terms

and conditions which are included in the record as ATTACHMENT C to APS' initial brief, filed June 5, 1981, are hereby adopted.

3. The rates, charges and tariff provisions established herein shall become effective on January 1, 1982.

4. Within the time frames stated, Arizona Public Service Company shall submit to this Commission the reports contemplated hereinabove in connection with our discussions of the PURPA standards pertaining to interruptible rates and load management techniques.

5. Arizona Public Service Company shall take immediate steps which are reasonably calculated to lead to the provision of electric service to residential customers under the new optional time-of-day rate schedules.

BY ORDER OF THE ARIZONA CORPORATION COMMISSION

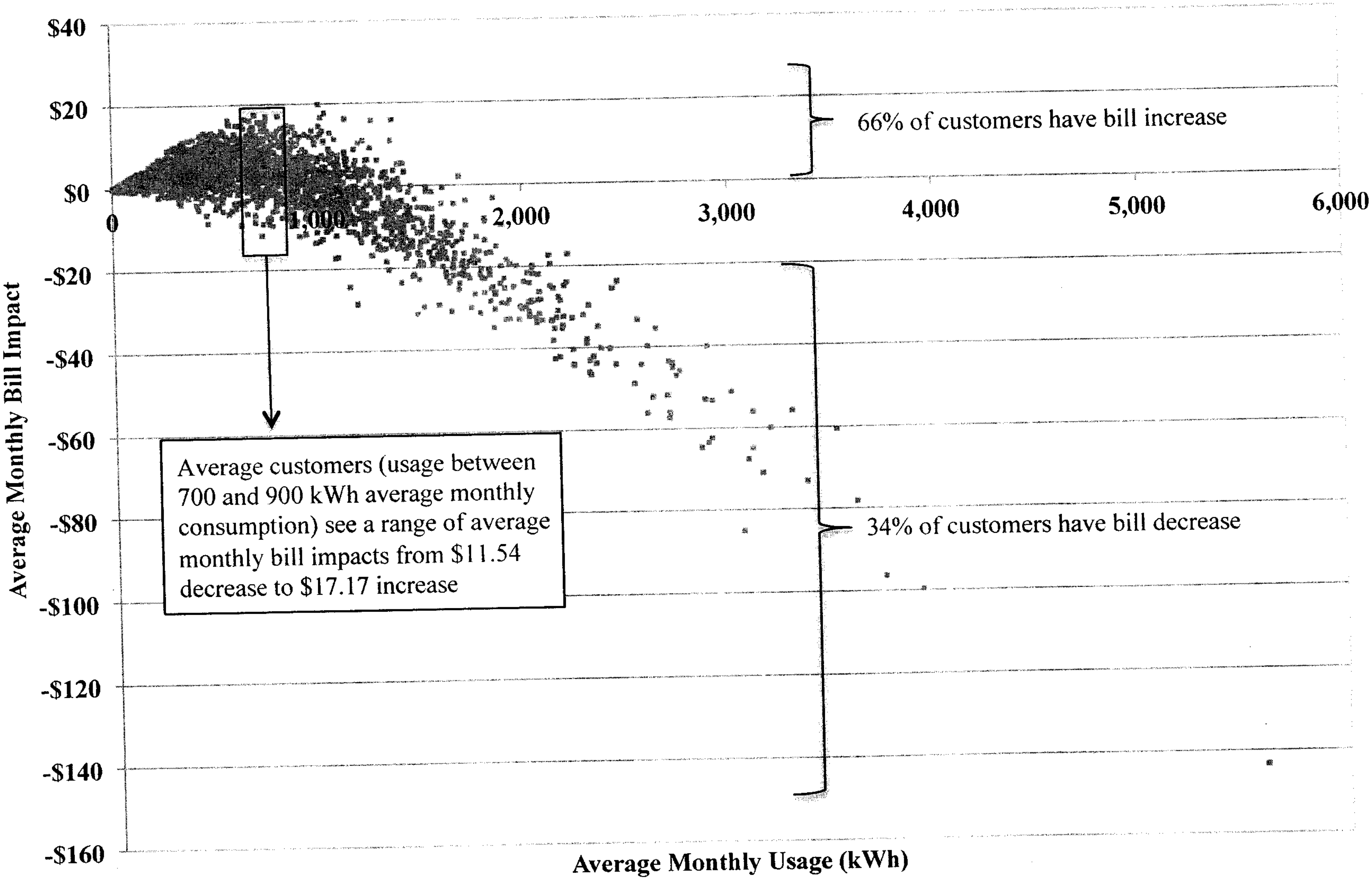
Bud Tims — CHAIRMAN | Diane B. McCarthy — COMMISSIONER | Jim Weeks — COMMISSIONER

IN WITNESS WHEREOF, I, TIMOTHY A. BARROW, JR., Executive Secretary of the Arizona Corporation Commission, have hereunto set my hand and caused the official seal of the Commission to be affixed at the Capitol in the City of Phoenix, this 9th day of November, 1981.

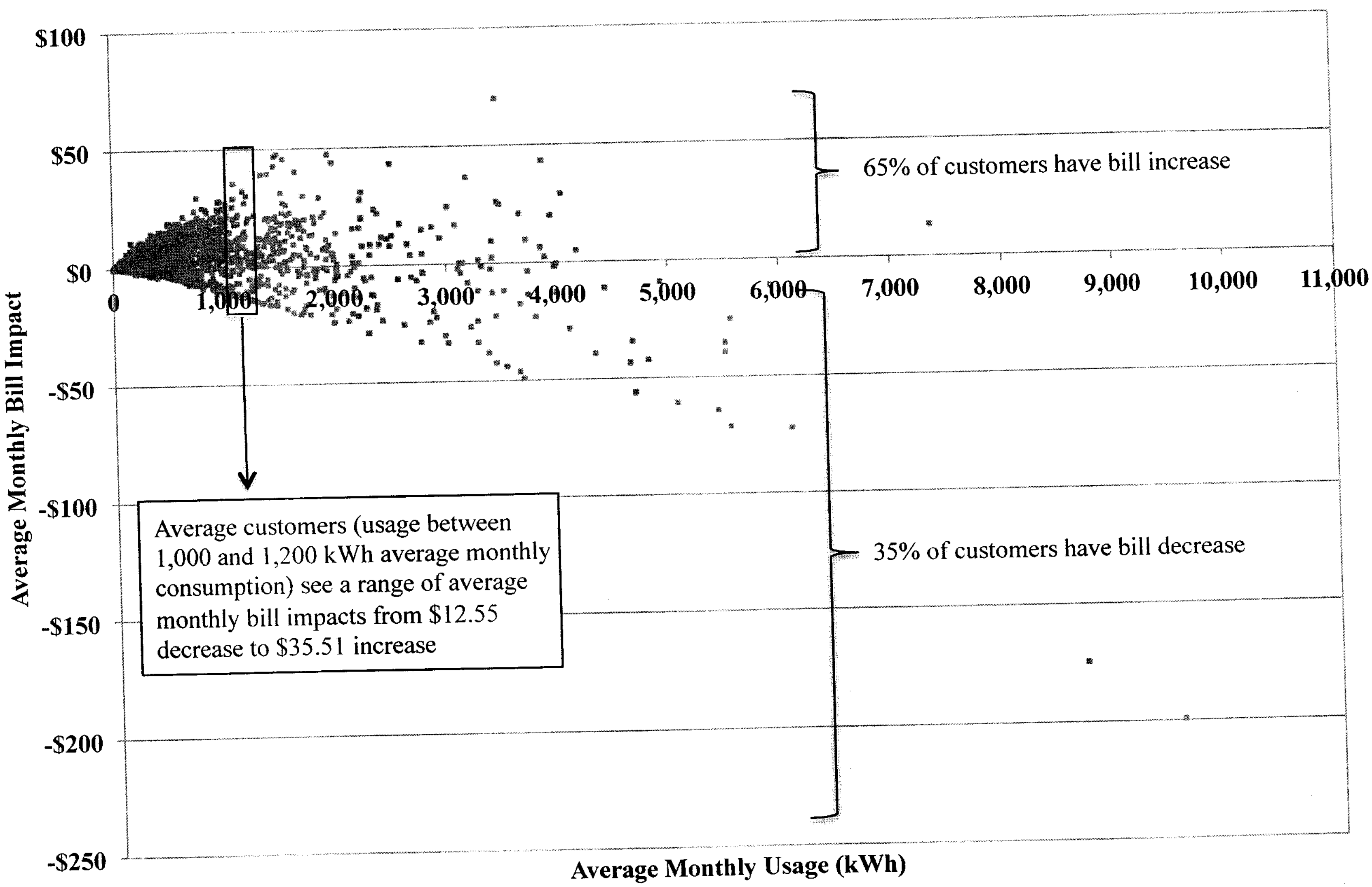
Timothy A. Barrow
TIMOTHY A. BARROW
Executive Secretary

Vote Solar Exh

Distribution of Residential Bill Impacts - Transition Rate to Proposed 3-Part Rate



Distribution of Small Commercial Bill Impacts - Transition Rate to Proposed 3-Part Rate



UNS ELECTRIC, INC.

DOCKET NO. E-04204A-15-0142

RUCO-1

RUCO-1 ADMITTED

DIRECT TESTIMONY

OF

JEFFREY M. MICHLIK

ON BEHALF OF THE

RESIDENTIAL UTILITY CONSUMER OFFICE

NOVEMBER 6, 2015

TABLE OF CONTENTS

ATTACHMENTS

EXECUTIVE SUMMARY

UNS Electric, Inc. ("UNS or Company") is an Arizona "C" Corporation. UNS is a for profit, certificated Arizona public service corporation that provides electric utility service to various communities in Santa Cruz County and Mohave County, Arizona. On May 5, 2015, UNS filed an application with the Arizona Corporation Commission ("Commission") for a permanent rate increase. The UNS corporate business office is located at 88 East Broadway Blvd., Tucson, AZ 85702.

UNS Energy is a subsidiary of Fortis Inc., the largest investor-owned electric and gas distribution utility in Canada. UNS Energy is based in Tucson, Arizona and is the parent company of both Tucson Electric Power (TEP) and UniSource Energy Services (UES). TEP serves more than 414,000 customers in and around Tucson, while UES provides natural gas and electric service to about 243,000 customers in northern and southern Arizona. Electric service is provided through a UES subsidiary called UNS Electric, Inc., while natural gas service is provided through a subsidiary called UNS Gas, Inc.

The Company utilized a test year ended December 31, 2014.

Rate Application denoted in thousands of dollars:

The Company-proposed rates, as filed, produce total operating revenue of $171.557 million, an increase of $22.621 million or 15.19 percent, over adjusted test year revenue of $148.936 million. The Company-proposed revenue will provide operating income of $22.108 million and a 6.22 percent rate of return on its proposed $355.720 million fair value rate base ("FVRB").

The Residential Utility Consumer Office ("RUCO") recommends rates that produce total operating revenue of $164.298 million an increase of $12.271 million or 8.07 percent, from the RUCO-adjusted test year revenue of $152.027 million. RUCO's recommended revenue will provide operating income of $18.147 million and a 5.26 percent return on the $345.131 million RUCO-adjusted FVRB.

RUCO recommends that the Company update its lead-lag study in the next rate case.

RUCO recommends that in the future it is incumbent on the Company to provide all of the expense categories to support its membership expenses. Further, the Commission should send a strong message to the Company

that ***all*** EEI membership may be disallowed in the future if this information is not provided.

Other Items:

RUCO recommends denial of the Company's proposed deferral of property taxes.

RUCO recommends a 50/50 sharing between shareholders and ratepayers in its appeal of the Arizona Department of Revenues ("ADOR") assessment of its Gila River Power Plant. RUCO also recommends a reasonable cap be placed on legal expenses; once this level is exceeded, the Company shareholders should bear any extra costs.

RUCO recommends that the deferred savings accrued as a result of the Deferred Accounting Order related to the acquisition of Gila River Plant be credited back to ratepayers over a three year period through the PPFAC.

RUCO recommends that the current PPFAC not be modified.

I. INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is Jeffrey M. Michlik. I am a Public Utilities Analyst V employed by the Arizona Residential Utility Consumer Office ("RUCO"). My business address is 1110 West Washington Street, Suite 220, Phoenix, Arizona 85007.

Q. Briefly describe your responsibilities as a Public Utilities Analyst V.

A. In my capacity as a Public Utilities Analyst V, I analyze and examine accounting, financial, statistical and other information and prepare reports based on my analyses that present RUCO's recommendations to the Arizona Corporation Commission ("Commission") on utility revenue requirements, rate design and other matters. I also provide expert testimony on these same issues.

Q. Please describe your educational background and professional experience.

A. In 2000, I graduated from Idaho State University, receiving a Bachelor of Business Administration Degree in Accounting and Finance, and I am a Certified Public Accountant with the Arizona State Board of Accountancy. I have attended the National Association of Regulatory Utility Commissioners' ("NARUC") Utility Rate School, which presents for study and review general regulatory and business issues. I have also attended various other NARUC sponsored events.

I joined RUCO as a Public Utilities Analyst V in September of 2013. Prior to my employment with RUCO, I worked for the Arizona Corporation Commission in the Utilities Division as a Public Utilities Analyst for a little over seven years. Prior to employment with the Commission, I worked one year in public accounting as a Senior Auditor, and four years for the Arizona Office of the Auditor General as a Staff Auditor.

Q. What is the scope of your testimony in this case?

A. I am presenting RUCO's analysis and recommendations on UNS's proposed revenue requirement for UNS' application for a permanent rate increase. I am also presenting testimony and schedules addressing rate base, operating revenues and expenses. In addition, Mr. Robert Mease will be addressing Cost of Capital, and Mr. Lon Huber will be addressing rate design.

Q. What is the basis of your testimony in this case?

A. I performed a regulatory audit of the Company's application and records. The regulatory audit consisted of examining and testing financial information, accounting records, and other supporting documentation and verifying that the accounting principles applied were in accordance with the Commission-adopted FERC Uniform System of Accounts ("USOA").

Q. How is your testimony organized?

A. My testimony is presented in six sections. Section I is this introduction. Section II provides a background of the Company. Section III is a summary of the Company's filing and RUCO's rate base and operating income adjustments. Section IV presents RUCO's rate base recommendations. Section V presents RUCO's operating income recommendations. Section VI presents RUCO's recommendations on other issues identified during our review.

II. BACKGROUND

Q. Please review the background of this application.

A. UNS Electric, Inc. ("UNS or Company") is an Arizona "C" Corporation. UNS is a for profit, certificated Arizona public service corporation that provides electric utility service to various communities in Santa Cruz County and Mohave County, Arizona. On May 5, 2015, UNS filed an application with the Arizona Corporation Commission ("Commission") for a permanent rate increase. The UNS corporate business office is located at 88 East Broadway Blvd., Tucson, AZ 85702.

Q. Can you provide additional background on UNS' corporate structure?

A. Yes. UNS Energy is a subsidiary of Fortis Inc., the largest investor-owned electric and gas distribution utility in Canada. UNS Energy is based in Tucson, Arizona and is the parent company of both Tucson Electric Power (TEP) and UniSource Energy Services (UES). TEP serves more than 414,000 customers in and around Tucson, while UES provides natural gas and electric service to about 243,000 customers in northern and southern Arizona. Electric service is provided through a UES subsidiary called UNS Electric, Inc., while natural gas service is provided through a subsidiary called UNS Gas, Inc.

III. SUMMARY OF FILING, RECOMMENDATIONS, AND ADJUSTMENTS.

Q. Please summarize the Company's proposals in this filing.

A. Based on the Company's schedules filed on May 5, 2015, the Company has proposed the following rounded to the nearest $1,000:

The Company-proposed rates, as filed, produce total operating revenue of $171.557 million, an increase of $22.621 million or 15.19 percent, over adjusted test year revenue of $148.936 million. The Company-proposed revenue will provide operating income of $22.108 million and a 6.22 percent rate of return on its proposed $355.720 million fair value rate base ("FVRB").

The Residential Utility Consumer Office ("RUCO") recommends rates that produce total operating revenue of $164.298 million an increase of $12.271 million or 8.07 percent, from the RUCO-adjusted test year revenue of $152.027 million. RUCO's recommended revenue will provide operating income of $18.147 million and a 5.26 percent return on the $345.131 million RUCO-adjusted FVRB (see RUCO schedule JMM-1).

Q. For the purposes of this rate case, has RUCO accepted the Company's gross revenue conversion factor of 1.6084?

A. Yes, see RUCO schedule JMM-2.

Q. Please summarize RUCO's rate base adjustments.

A. The two rate base adjustment(s) are presented below:

Rate Base Adjustment No. 1 - Net Operating Loss Carryforward ("NOLC") Accumulated Deferred Income Tax ("ADIT") Offset – This adjustment reverses the Company's pro-forma adjustment in the amount of $7,467,062, as this methodology was recently rejected by the Commission.

Rate Base Adjustment No. 2 - Allowance for Cash Working Capital - This adjustment applies to the cash working capital and the prepaid insurance component of the Company's working capital allowance, and increases cash working capital by $5,429.

Q. Please summarize RUCO's operating revenue and expense adjustments.

A. The eleven operating income adjustment(s) are presented below:

Operating Income Adjustment No. 1 - Current Charges Authorized by the Commission not applied to Test Year Billing Determinants – This adjustment uses the Commission authorized tariff rates and applies them to the Company's adjusted test year billing determinants. This adjustment increases adjusted test year electric retail sales by $3,090,705.

Operating Income Adjustment No. 2 – Not Used

Operating Income Adjustment No. 3 – Medical and Dental Expense Normalization - This adjustment normalizes medical and dental expenses that fluctuate year to year, and reduces adjusted test year medical and dental expenses by $305,848.

Operating Income Adjustment No. 4 – Officers and Directors Insurance ("D&O") Expense – This adjustment recognizes that this expense benefits both ratepayers and shareholders and therefore RUCO recommends a 50/50 sharing of this cost. This reduces adjusted test year D&O expense by $70,077.

Operating Income Adjustment No. 5 – Wellness Incentive Program, Employee Recognition, and Spot Awards Expense - These adjustments reduces expenses that are not necessary to the provision of electric service and have been eliminated. These adjustments reduce adjusted test year expenses by $46,551.

Operating Income Adjustment No. 6 – UNS Short-Term Incentive Program Expense - This adjustment recognizes that this expense benefits both ratepayers and shareholders and therefore RUCO recommends a 50/50 sharing of this cost. This adjustment reduces adjusted test year short-term incentive program expense by $169,700.

Operating Income Adjustment No. 7 – Injuries and Damages Expense – This adjustment removes items that RUCO believes should not be included in injuries and damages expense. This adjustment reduces injuries and damages expense by $343,815.

Operating Income Adjustment No. 8 – Edison Electric Institute ("EEI") Dues – This adjustment removes expense items that do not benefit ratepayers, and reduces adjusted test year EEI dues by $15,517.

<u>Operating Income Adjustment No. 9 – Rate Case Expense</u> – This adjustment reduces estimated rate case expense by $16,667 to account for what RUCO has determined to be just and reasonable.

<u>Operating Income Adjustment No. 10 – Interest Synchronization Expense</u> – This adjustment resynchronizes interest expense based on RUCO's recommended rate bases and increases adjusted test year income taxes by $58,805.

<u>Operating Income Adjustment No. 11 – Income Tax Expense</u> – This adjustment increases income tax by $1,526,666 to account for RUCO's adjustments to operating expenses.

IV. RATE BASE

Fair Value Rate Base ("FVRB")

Q. Did the Company prepare a schedule showing the elements of a Reconstruction Cost New Depreciated ("RCND") Rate Base?

A. Yes. The Company derived its FVRB by taking the average of the Original Cost Rate Base ("OCRB") and RCND. This methodology has been accepted by the Commission in prior decisions.

Q. Has RUCO presented its schedules to reflect OCRB, RCND and FVRB?

A. Yes. For purposes of this presentation, I have used the Company's OCRB information as the starting point for RUCO's determination of the Company's FVRB.

Rate Base Summary

Q. Please summarize RUCO's adjustments to the Company's OCRB base denoted in thousands.

A. RUCO's adjustments to the Company's rate base resulted in a net decrease of $7.462 million, from $272.013 million to $264.551 million the decrease was primarily due to RUCO's adjustments: (1) to the NOLC ADIT offset and (2) to cash working capital, as shown on RUCO schedules 4, and 5.

Rate Base Adjustment No. 1 – Net Operating Loss Carryforward ("NOLC") Accumulated Deferred Income Tax ("ADIT") Offset

Q. Has the Company proposed an adjustment to reduce its ADIT balance by its NOLC ADIT offset?

A. Yes.

Q. What is the rationale behind this adjustment?

A. The Company relies on three Internal Revenue Service ("IRS") private letters to support its position.

Q. What is an IRS private letter ruling?

A. From the IRS website "A private letter ruling, or PLR, is a written statement issued to a taxpayer that interprets and applies tax laws to the taxpayer's represented set of facts. A PLR is issued in response to a written request submitted by a taxpayer. A PLR may not be relied on as precedent by other taxpayers or by IRS personnel."

Q. Has the Company asked for a private letter ruling from the IRS in this case?

A. No.

Q. Has the Company excluded a private letter ruling that did not support its position in this case?

A. Yes. On May 2, 2014, the IRS issued PLR 201418024 regarding the treatment of deferred tax assets (DTAs) for NOL carryforwards under the deferred tax normalization requirements of Treas. Reg. § 1.167(1)-1(h)(1)(iii). The PLR held that not including the NOL carryforward DTA in rate base, the methodology advocated by the applicable public utility commission, complied with the normalization requirements in a specific circumstance.

Q. Has the Commission adhered to or followed the IRS code and GAAP (which is covered in Accounting Standards Codification ("ASC") 740 Income Taxes) in the past?

A. No. In fact, in the case of Limited Liability Corporations ("LLC's") and Subchapter S Corporations ("Sub S") the Commission has created its own tax methodology for ratemaking purposes.

Q. Please elaborate?

A. Under the Commission's Income Tax Policy (see attachment A, followed by RUCO's comments) the ratepayers now have to pay the utility owners personal tax liability under pass through corporate organization (Chapter S and Limited Liability Corporation), The Commission's tax policy provides for what in RUCO's opinion is a **"phantom tax"**. Thus, the Commission can create its own tax policy any time it wants and is not bound by GAAP.

Q. More importantly how has the Commission treated this issue?

A. Recently the Commission in Decision No. 75268 (dated September 8, 2015), stated on page, 34, line 15. "A fundamental tenet of ratemaking is that a utility should earn a return only on used and useful assets financed by investors. Since ADIT is a source of non-investor capital, matching of plant with ADIT in the calculation of rate base is appropriate. In this case, RUCO's ADIT recommendations provide the best matching. We also believe that ratepayers should not be deprived of rate base recognition of ADIT arising from income tax timing differences when bonus depreciation results in an NOL. The circumstances that result in an NOL are subject to decisions by utility management, not ratepayers, and since an NOL can be carried forward to future years, it represents an asset that a utility can use to provide a tax benefit in future years. Accordingly, we will adopt RUCO's proposed ADIT adjustments."

Needless to say RUCO agrees with the Commission's Decision, and there is no reason ratepayers should not benefit now.

Q. What is RUCO's recommendation?

A. RUCO recommends increasing the ADIT balance by $7,467,062 from $35,161,108 to $42,628,170, as shown in RUCO schedule JMM-6.

Rate Base Adjustment No. 2 – Allowance for Working Capital

Q. What is cash working capital?

A. Working capital measures the amount of investors' funds that must be used to sustain the day to day operations of the Company, in this case on average over a test year. In general the components of cash working capital are fuel inventory; materials and supplies inventories; prepayments; and cash working capital.

Q. Has RUCO made adjustments to any of these components?

A. Yes. RUCO has adjusted the Company's prepayments in regards to Directors and Officers ("D&O") Insurance. RUCO has removed the D&O insurance which will be discussed in greater detail in RUCO's Operating Adjustment No. 4, that D&O insurance be shared equally between ratepayers and shareholders. In this case RUCO recommends a sharing of the D&O prepaid insurance of $40,055, after applying the ACC jurisdiction ratio, RUCO has reduced the prepaid insurance by $19,092.

RUCO has also adjusted the Company's cash working component, usually an area of disagreement. RUCO notes that the Company's lead-lag study dates back to 2005. RUCO recommends that the Company update its lead-lag study in the next rate case. RUCO has adjusted its expenses to flow through the Company's lead-lag summary, and reduces the working capital allowance by $5,429 from $7,174,709 to $7,169,280, as shown in RUCO schedule JMM-7.

V. OPERATING INCOME

Operating Income Summary

Q. What are the results of RUCO's analysis of test year revenues, expenses, and operating income?

A. RUCO's analysis resulted in adjusted test year operating revenues of $152.027 million, operating expenses of $141.509 million and operating income of $10.517 million, as shown on RUCO schedules 8 and 9. RUCO made eleven adjustments to operating expenses, as presented below.

Operating Income Adjustment No. 1 – Current Charges authorized by the Commission not applied to adjusted test year billing determinants.

Q. Please describe the Companies process of adjusting its billing determinants?

A. The Company starts with the unadjusted billing determinants, and then adjusts the billing determinants for customer annualization, and weather normalization. For example, the ***unadjusted test*** year billing determinants from the 2015 UNSE Revenue Proof were as follows:[1]

[1] To simplify the example, I have excluded the TCA, Base Power, and PPFAC.

Table I. Unadjusted Test Year Revenues

[A] Rate Schedule	[B] Current Rates	[C] Test Year Billing Determinants	[D] Test Year Billed Revenues
5703 RESIDENTIAL SERVICE			
Basic Service Charge	$10.00	910,158	$9,101,580
Energy Charge 1st 400 kWh	$0.019300	306,169,110	5,909,064
Energy Charges 401 - 1,000 kWh	$0.034350	265,903,606	9,133,789
Energy Charge, all additional kWh	$0.038499	182,932,901	7,042,734
Total			$31,187,166

Table II. Adjusted Test Year Revenues

[A] Rate Schedule	[B] Current Rates	[C] Test Year Billing Determinants	[D] Test Year Billed Revenues
5703 RESIDENTIAL SERVICE			
Basic Service Charge	$10.00	912,420	$9,124,200
Energy Charge 1st 400 kWh	$0.019300	305,205,763	5,890,471
Energy Charges 401 - 1,000 kWh	$0.034350	265,302,752	9,113,150
Energy Charge, all additional kWh	$0.038499	190,706,885	7,342,024
Total			$31,469,845

Table III. Proposed Revenues

[A] Rate Schedule	[B] Proposed Rates	[C] Test Year Billing Determinants	[D] Test Year Billed Revenues
5703 RESIDENTIAL SERVICE			
Basic Service Charge	$20.00	912,420	$18,248,400
Energy Charge 1st 400 kWh	$0.030810	305,205,763	9,403,390
Energy Charges 401 - 1,000 kWh	$0.050810	265,302,752	13,480,033
Energy Charge, all additional kWh	$0.050810	190,706,885	9,689,817
Total			$50,821,639

As can be seen, in Table II Column [C] the Company has adjusted its billing determinants for each of the above categories (e.g. Basic Service Charge from $910,158 to $912,420) for the effects of customer annualization and weather normalization from Table I Column [C]. It is important to note that both Column B from Table I and Table II is the ***Commission Authorized***

Current Rate, as shown in the Company's H-3 schedule and its authorized tariff. The Company in Table III Column [C] utilizes the adjusted test year billing determinants from Table II Column [C] and applies its proposed rates ***which have not been authorized by the Commission*** to generate its proposed revenue.

Q. Did RUCO tie out both the Companies test year and proposed revenues?

A. Yes, for each customer class (e.g. residential, small commercial, large general service, etc.) and for each component (e.g. basic service charge, energy charge 1st 400 kWh, etc.).

Q. Did you encounter any discrepancies along the way?

A. Yes, a minor one and a large one.

Q. Please explain the minor discrepancy first?

A. The Company's Residential Bright Community Solar Class's adjusted H-5 utilized 959 customer billing determinants should tie to the Company's adjusted test year billing determinants, but it did not. The Company in response to RUCO data request 4.03, provided a revised H-5 schedules that utilized 944 customers billing determinants (15 less). The Company claims that some customers were billed twice in the same month.

Q. Please explain the second discrepancy?

A. The second discrepancy involves the Company applying its proposed rates to its adjusted test year billing determinants to derive its adjusted test-year revenue.

Q. Was this widespread or limited to a certain class of customer class?

A. The error seems to be isolated to customer rate classes that the Company has moved into new rate classes.

Q. Please explain and show the billing migration from the former customer classes to the new customer classes?

A. Based on the Public Version – Revenue Proof, the Company is proposing the following changes:

Customer Rate Class	Billing Determinants		Customer Rate Class	Billing Determinants	Migrating Billing Determinants
Large General Service	16,092	moved to	New Medium Service	15,972	120
Large Power Service 3<69 KV	84	moved to	New Large General Service	84 Plus 120 = 204	0
Large General Service TOU	96	moved to	New Medium General Service TOU	96	0
Large Power Service 3 TOU<69KV	24	moved to	New Large Service TOU	24	0

Q. Please provide an example.

A. Provided is an example that accounts for most of the total discrepancy. For the total RUCO adjustment please see RUCO schedule JMM-10.

Customer Class		Current Rates	Test Year Billing Determinents		Adjusted Test Year Revenues
5713 LARGE GENERAL SERVICE					
Basic Service Charge	$	50.000000	16,092	$	804,600
Demand Charge, per kW	$	12.810000	1,394,255	$	17,860,410
Energy Charge, per kWh	$	0.005470	445,782,493	$	2,438,430
TCA, per kW	$	0.432900	0	$	-
Margin Total					
Base Power	$	0.056603	445,782,493	$	25,232,626
PPFAC Revenue		Varies by Month			
Total Fuel Revenue					
Total Large General Service				$	46,336,067

The highlighted Base Power Charge indicates the current charge $ 0.056603 authorized by the Commission that ties to the Company's H-3 tariff (see Attachment B for a copy of the Company's current tariffs that are in question). The test year revenues based on the adjusted billing determinants and current authorized Commission charge produce test year revenues of $46,336,067.

The Company reduced the proposed Base Power Charge to $0.048440 and used this rate which has not been authorized by the Commission to produce its test year revenues of $42,697,144. A difference of $3,638,922, (i.e. $46,336,067 - $42,697,144) as shown below:

Customer Class	Current Rates	Test Year Billing Determinents	Adjusted Test Year Revenues
5713 LARGE GENERAL SERVICE			
Basic Service Charge	$ 50.000000	16,092	$ 804,600
Demand Charge, per kW	$ 12.810000	1,394,255	$ 17,860,410
Energy Charge, per kWh	$ 0.005470	445,782,493	$ 2,438,430
TCA, per kW	$ 0.432900	0	$ -
Margin Total			
Base Power	$ 0.048440	445,782,493	$ 21,593,704
PPFAC Revenue	Varies by Month		
Total Fuel Revenue			
Total Large General Service			$ 42,697,144

Q. Please state the total difference between the Company's test year revenues and RUCO's tie-out of the Company's test year revenues?

A. The Company's test year revenues for all classes totaled $147,178,138. RUCO's test year revenues for all classes total $150,268,843. The difference of $3,090,705, and the differences between the other three customer classes is shown in RUCO schedule JMM-10.

Q. Did you ask the Company to explain these discrepancies and why they used the proposed unauthorized Commission rates to calculate their test year revenues?

A. Yes. In response to RUCO data request 4.12, the Company stated they were rebalancing their fuel costs. However, you still cannot use proposed rates to calculate your current adjusted test year revenues. The Company is free to rebalance its fuel costs and propose any changes and charges in its proposed rates.

Q. What other unintended consequences does this present?

A. The Company's H-4's schedules for these customers' classes are misstated.

Q. Please state the total difference between the Company's proposed revenues and RUCO's tie-out of the Company's proposed revenues?

A. The difference between RUCO's and the Company is $9,681.

Q. Can you reconcile the difference?

A. Yes. The difference is related to Residential Service Bright Arizona Community Solar – Base Power Supply Charge, all kWhs. The Company carried over the current rate of 0.08451 instead of its proposed rate of 0.069260 resulting in the difference of $9,681 (i.e. 53,651 – 43,970).

Operating Income Adjustment No. 2 – Weather Normalization

Q. Has the Company proposed an adjustment for Weather Normalization?

A. Yes, the Company proposed a weather normalization adjustment.

Q. Is RUCO making an adjustment at this time?

A. No. RUCO is in the process of issuing more data requests. RUCO reserves the right to update its recommendation in its surrebuttal testimony after it becomes aware of all the facts.

Q. Did the Company use a new weather normalization model?

A. Yes. In response to RUCO data request 1.16, the utilization of the new weather normalization model costs is an approximate $2,015,578 loss for ratepayers versus the old method.

Q. Is RUCO aware of any Company proposing a weather normalization adjustment that benefits or adds-on to test year revenues?

A. No. RUCO likens this to a rigged game at the county fair, the ratepayer always loses, and in this case it just depends on how much which RUCO intends to find out.

Operating Income Adjustment No. 3 – Medical and Dental Expense Normalization

Q. Did the Company provide its medical and dental expenses for the test year and prior two years?

A. Yes, along with its retirement expenses, vision expense, administrative expenses, and other insurance expenses, the Company in its response to data request # 1.029, explained all variances over/under 10 percent. The Company stated that the discount rate for the pension expense, had increased and decreased. RUCO looked at a three year average and determined the test year amount was not materially different from the three year average amount (i.e. $246,498 test year, $246,756 three year average). However, in regards to medical and dental expenses the Company stated "Due to the nature of self-funded plans, expenditures fluctuate with usage, and are significantly impacted by the number of serious medical conditions of participants." RUCO agrees with the

Company's statement and has normalized both medical and dental expenses over a three year period to reflect a more realistic and reasonable amount.

Q. What is RUCO's recommendation?

A. RUCO recommends decreasing medical expenses by $316,694, and increasing dental expenses by $10,846, as shown in RUCO schedule JMM-12.

Operating Income Adjustment No. 4 – Director and Officers' ("D&O") Liability Insurance

Q. What is D&O Liability Insurance?

A. D&O liability Insurance is liability insurance that covers directors and officers for claims made against them by shareholders or others for decisions they may make.

Q. Has the Company requested that ratepayers bear the full burden of this cost?

A. Yes.

Q. What is the total amount of D&O Liability Insurance included in adjusted test year expenses?

A. $140,155 ($145,954 x ACC Raito of 96.0266 percent).

Q. What is RUCO's recommendation?

A. RUCO recommends a 50/50 sharing between ratepayers and shareholders, since D&O Liability Insurance not only benefits ratepayers, but also shareholders. Shareholders benefit from insurance coverage in litigation cases brought against the Company's Director and Officers. Shareholders would also benefit from payments under this policy which may not be recoverable from ratepayers. Similarly, it can be argued that ratepayers benefit, since the Company can attract and retain directors and officers, and provides them with some degree of freedom from personal liability. Therefore, it is reasonable for shareholders to bear a portion of the cost for the D&O liability insurance. RUCO recommends reducing D&O liability insurance by $70,077 from $140,154 to $70,077, as shown in RUCO schedule JMM-13.

Operating Income Adjustment No. 5 – Wellness Incentive Program, Employee Recognition, and Spot Awards

Q. Has the Company asked ratepayers to pay for the costs of the Wellness Incentive Program, Employee Recognition, and Spot Awards?

A. Yes.

Q. What are the amounts of these programs?

A. In response to RUCO data requests 2.03 and 2.04 the Company stated the following amounts were expended:

Wellness Incentive Program - $15,738

Employee Recognition - $10,740

Spot Awards - $22,000

Q. Does RUCO believe these costs are necessary for the provision of electrical services?

A. No, and these costs should be absorbed by the shareholders.

Q. What is RUCO's recommendation?

A. RUCO recommends reducing administrative and general expense by $48,478 (i.e. 15,738+10,740+22,000), and on an ACC jurisdictional basis $46,551, as shown in RUCO schedule JMM-14.

Operating Income Adjustment No. 6 – UNS's Short-Term Incentive Program ("PEP")

Q. Has the Company asked for ratepayers to fund 100 percent of its incentive compensation program?

A. Yes, and 100 percent of the pro-forma adjustment.

Q. Briefly describe the PEP?

A. According to Company data request Uniform Data Request ("UDR") 1.034, "The PEP performance targets and weighting are based on factors that are essential for the long-term success of the Company and are identical to the performance objectives used in its performance plan for other non-union employees. In 2014, the objectives were (i) net income; (ii) O&M cost containment; and (iii) excellent operations and safe work environment, which include both quantitative and qualitative measures. The Compensation Committee selected the goals and individual weightings for the 2014 PEP to ensure an appropriate focus on profitable growth and expense control, as well as operational and customer service excellence, and process improvements. According to the Company, this balanced scorecard approach encourages all employees to work toward common goals that are in the interests of UNS Energy's various stakeholders. The outcomes of which all benefit our customers in the long run.

The financial and other metrics for the Company's 2014 Short-Term Incentive Compensation program were:

• Financial – 50% • Net Income – 40%

• O&M Cost Containment – 10%

• Excellent Operations and Safe Work Environment – 50%"

Q. What are the amounts of the PEP test year expense and Pro-forma amount?

A. The Company stated in its response to RUCO data request # 2.05 that it is seeking recovery of $674,000 in PEP in this rate case. However, in the Company's pro-forma Income-Incentive Compensation excel spreadsheet, after adjustments, the Company is requesting a total of $326,753 consisting of the test year amount of $151,471 and the pro-forma amount of $175,282, as shown in RUCO schedule JMM-15.

Q. Does RUCO agree with the calculation of the Pro-forma amount?

A. No. The Company has projected pay increases of 2 percent, and taxes for future years 2016 and 2017, which are not known and measureable.

Q. Has RUCO recalculated this amount?

A. RUCO's recalculation of the Company's pro-forma adjustment amount results in a decrease of $12,112 from $175,282 to $163,170.

Q. Does PEP benefit both ratepayers and shareholders?

A. Yes. As the Company stated above.

Q. What is RUCO's recommendation?

A. RUCO again recommends a 50/50 sharing between shareholders and ratepayers. RUCO recommends that incentive compensation expense be reduced by $169,700 after application of the ACC jurisdictional ratio, as shown in RUCO schedule JMM-15.

Operating Income Adjustment No. 7 – Injuries and Damages

Q. Has the Company taken a three year average of injuries and damages to try to normalize fluctuations to these expenses?

A. Yes.

Q. Does RUCO agree with the normalization of these expenses?

A. No. The Company requested an increase of $355,543 that is primarily driven by an insurance deductible amount of $1 million that relates to a pedestrian truck accident that occurred in 2013.

Q. Did the Company request to include this adjustment in the last rate case?

A. Yes. Staff's witness Mr. Ralph Smith, addressed this problem in the last rate case. RUCO has the same concerns as in the last rate case, which are as follows:

- That being the accident occurred in 2013 expense and is tantamount to retro-active ratemaking.
- Nonrecurring and unusual.
- The Company has not demonstrated that it is normal for a $1 million expense to occur, or for it to occur approximately every three years.

Q. Historically what has been the costs in account 78100 injury and damages?

A. The historical the costs are as follows:

2010 $0

2011 $0

2012 $10,000

2013 $1,071,000

2014 $0

Q. Did RUCO question the $1,071,000 in injury and damages?

A. Yes, in response to RUCO data request 6.01, the Company stated the $1,071,000 was comprised of the following:

1. $1 Million claim reserve for a lawsuit in which the owner and tenant of a warehouse in Nogales allege a fire at their warehouse on 05-15-2013 was caused by an improperly installed dusk to dawn light that allegedly sparked causing the fire. On 07-24-2015 a jury returned a verdict in favor of UNS Electric with zero negligence and zero damages due. In July, 2015 the claim reserve was reversed.

2. $30,000 claim reserve for a pending lawsuit in which the plaintiff alleges UNS Electric was negligent for an auto accident on 05-15-2012 in Kingman, AZ resulting in injuries to the plaintiff.

3. $41,000 claim payment to the US Forest Service for firefighting expenses from a 2008 fire in Santa Cruz County allegedly caused by a downed power line.

Q. Does RUCO believe any of these amounts should be included in the test year?

A. No. The largest driver of the injury and expenses - the $1 million claim has been settled in the Company's favor. However, the Company still wants to recovery this amount from ratepayers. A claim reserve is not relevant because it is not known and measureable. The only claim that could be relevant is the $41,000 claim payment to the US Forest Service. However RUCO does not see a pattern of the Company paying the US Forest Service $41,000 every year, as this is a non-reoccurring and unusual expense.

Q. What is RUCO's recommendation?

A. RUCO recommends that that the $1,071,000 be removed, and a three year average be applied. RUCO's adjustment reduces other operations and maintenance expense by $343,815, as shown on schedule JMM-16.

Operating Income Adjustment No. 8 – Edison Electric Institute ("EEI") Dues

Q. Did the Company remove any EEI Utility Air Regulation Group ("UARG") membership dues?

A. No.

Q. Whose interest does UARG represents?

A. UARG represents the interest of electric generators such as UNS and TEP in Environmental Protection Agency ("EPA") rulemaking procedures and litigation procedures against the EPA. Membership in UARG is voluntary. These issues are purely-political and are not necessary for the provision of utility services. Further, without a listing of activities that UARG allocates by function or category (e.g. advertising) it is impossible to determine which expense costs may be allowable or disallowable therefore the entire amount should be removed.

Q. What is RUCO's recommendation regarding EEI – UARG Membership Dues?

A. RUCO recommends removing $14,523 (i.e. $15,123 x .9603 ACC jurisdiction ratio) of EEI – UARG Membership Dues.

Q. Has the Company already reduced the $3,500 it paid in EEI – Regular Membership Dues?

A. Yes. Based on a letter from EEI, the Company stated its actual lobbying expenses were 6.20 percent for 2014 and estimates lobbying expense for 2015 to be 7.00 percent. Therefore, the Company reduced this expense by 208 (i.e. $3,500 x 6.20 percent x .9603 ACC jurisdiction ratio).

Q. What has the Commission recommended in prior Decisions?

A. The Commission recommended a reduction in EEI dues of 49.93 percent in Decision No. 71914 and 70860.

Q. How was this percentage determined?

A. The percentage was determined using the following NARUC Operating Expense Categories:[2]

NARUC Operating Expense Categories	Percentage of Dues
Legislative Advocacy	20.38%
Regulatory Advocacy	16.49%
Advertising	1.67%
Marketing	3.68%
Public Relations	7.71%
Total Expenses	49.93%

For other expense items see Attachment C.

[2] Based on the Edison Electric Institute Schedule of Expenses by NARUC Category For Core Dues Activities for the Year Ended December 31, 2005.

Q. Has RUCO updated this information from EEI?

A. Unfortunately RUCO cannot. After 2006, the EEI stopped providing this information. RUCO believes after a series of regulatory partial disallowances of EEI dues by Commissions across the nation, EEI decided not to provide this information to NARUC, which it had previously done for at least a decade.

Q. So in other words, the letter the Company received from EEI only addresses one expense category- Legislative Advocacy?

A. Yes. The letter provides no information on the other eight categories or 93.80 percent of EEI's other budgeted expenses.

Q. Please comment further.

A. Since it is apparent that the percentage of Legislative Advocacy expense has dropped from 20.38 percent to 6.20 percent, it only makes sense that most of these costs have been shifted elsewhere, but RUCO does not know because EEI does not supply an expense report anymore that has these details.

Q. What is RUCO's recommendation?

A. RUCO recommends a disallowance percentage of 35.75 percent based on *the best information available*, as follows:

NARUC Operating Expense Categories	Percentage of Dues
Legislative Advocacy	6.20%
Regulatory Advocacy	16.49%
Advertising	1.67%
Marketing	3.68%
Public Relations	7.71%
Total Expenses	35.75%

This results in an additional disallowance of EEI membership dues of 29.55 percent (i.e. 35.75 – 6.20) or $994 (i.e. $3,500 x 29.55 percent x .9603 ACC jurisdiction ratio).

RUCO, recommends that in the future it is incumbent on the Company to provide all of the expense categories to support its membership expenses. Further, the Commission should send a strong message to the Company that ***all*** EEI membership may be disallowed in the future if this information is not provided.

In summary, RUCO recommends a total disallowance of EEI dues in the amount of $15,517 (i.e. 14,523 + 994), as shown in RUCO schedule JMM-17.

Operating Income Adjustment No. 9 – Rate Case Expense

Q. What has the Company requested as an estimate of rate case expense to be authorized in this case?

A. The Company in its initial filing had requested an estimated $400,000 in rate case expense to be amortized over 3 years. Subsequently, the Company in response to Staff data request # 4.01 has revised its estimate upwards to $770,000. Almost double the original estimate.

Q. What was the amount of Rate Case Expense requested and authorized by the Commission in prior cases?

A. In Decision No. 70360 (dated May 27, 2008), the Company requested $600,000 in estimated rate case expense and was authorized $300,000. In Decision No. 71914 (dated September 30, 2010), the Company requested $500,000 in estimated rate case expense and was authorized $300,000. In Decision No. 74235 (dated December 31, 2013), the Company requested $500,00 in estimated rate case expense, the parties settled in that case, for $300,000.

Q. When asked, did the Company explain the difference between this case and the prior case that would necessitate an increase in rate case expense?

A. Yes. The Company in response to Staff data request 4.02 stated that "In this case, the Company is seeking recovery for outside labor resulting from a Marginal Cost Study and rate design, which it did not seek in the last three rate cases. The Company is requesting recovery of those costs in this filing. In the last UNS Electric rate case (Decision No. 74235, dated December

31, 2013) the Company did not perform a depreciation study and therefore did not incur any incremental costs."

Q. What does RUCO recommend as a reasonable allowance for rate case expense in this proceeding?

A. RUCO recommends $350,000 in rate case expense to be normalized over three years, as shown is RUCO Schedule JMM-18.

Operating Income Adjustment No. 10 – Interest Synchronization

Q. Please explain interest synchronization?

A. An interest synchronization adjustment is done to insure that the revenue requirement reflects the tax savings generated by the interest component of the revenue requirement. The interest synchronization expense is calculated by multiplying the rate base by the weighted average cost of debt. The combined state and federal income tax rates are then applied to the resulting interest deduction difference to determine the income tax expense adjustment.

Q. Has RUCO made an adjustment for interest synchronization?

A. Yes. Since the Company's rate base differs from RUCO's recommended rate base, an adjustment was required. RUCO's adjustment increases interest synchronization by $58,805, as shown is RUCO Schedule JMM-19.

Operating Income Adjustment No. 11 – Income Tax Expense

Q. Has RUCO adjusted income taxes as a result of its adjustments, mentioned above?

A. Yes. RUCO applied the statutory state and federal income tax rates to RUCO's taxable income. As a result, RUCO has increased Income tax expenses for the adjusted test year by $1,526,666, as shown in RUCO schedule JMM-20.

VI. OTHER ISSUES

Arizona Property Tax Deferral

Q. Is the Company also asking for a property tax deferral in this case?

A. Yes. The Company is asking for a two part property tax deferral. 1) To account for 100% of the Arizona property taxes above or below the test year level caused by changes in the composite property tax rate. 2) To account for changes in the Gila River property tax values, and defer all costs associated with appealing Gila River property values. In order to separate the issues RUCO will first address the Arizona property tax deferral first, and then the Arizona property tax deferral related to the Gila River property tax values and related legal costs involved with appealing the Department of Revenue Decision. Each of which deserves separate consideration.

Q. What is the Company's basis for the first part of its request?

A. The Company claims the overall property values on which property taxes are assessed have gone down in Mohave and Santa Cruz counties. At the same time, the property tax rates have also increased in Mohave and Santa Cruz Counties. The Company then states there is a correlation between the two, as the overall property value declines, property taxes must increase. The Company also cites Decision No. 73183 (dated May 24, 2012) to support its decision.

Q. Please comment?

A. I agree that the decline in property values may be one factor for the increase in the property tax rate. However, I do not believe it is the only one. Property taxes are generally used to fund the county's general fund. For example, employee positions, reductions in expenses, and sales tax revenues that are also considered when developing a County budget. I have included the FY 2015 Budget Review of Arizona Counties issued by the Arizona Tax Research Association (see Attachment D), which shows all facts related to county budgets and property taxes not just the selected information provided by the Company. In fact on page 5 of this budget review the Net Assessed Values did drop by 2.9 percent. However, the tax rate stayed the same for Mohave County (see page 33 of this budget review). This disproves the Company's property tax theory.

Q. Please address the Company's assertion that Arizona Public Service Company ("APS") had property tax deferral approved by the Commission in Decision No. 73183 (May 24, 2012), and the same logic should apply to the Company?

A. Decision No. 73183 was the result of a settlement agreement.

Q. What is a settlement agreement?

A. It is a negotiation between the parties, in which there is give and take on the respective parties' positions.

Q. Please elaborate.

A. In the APS case as a result of a settlement between the parties, APS reduced its return on equity by 100 basis points. In addition, APS agreed to a stay out for four years.

As Staff stated in its opening brief in which they cited APS witness Guldner, "APS is concerned that its property tax rate and related expenses could increase significantly during the course of the proposed 4 year stay-out, as it has over the past few years."[3]

Q. Is the property tax deferral approved by the Commission in Decision No. 73183 the same as what the Company is proposing here?

A. No. The only similarity is they are both requests for property tax deferrals. As was stated in Decision No. 73183, referring to Section XII. Cost Deferral Related to Changes in Arizona Property Tax Rate – "This Section allows APS to defer without interest for future recovery: 25 percent of the prorated property tax rate increase in 2012, 50 percent in 2013, and 75 percent each year thereafter, and 100 percent of all property tax rate decreases; recovery will begin after the next general rate case with recovery of a positive balance

[3] See Staff Opening Brief in Docket No. E-01345A-11-0224 (dated February 29, 2012).

spread over 10 years and a negative balance over three years; and the signatories may review the deferrals for reasonableness and prudence."[4]

Clearly, the provisions in the APS property tax deferral were more palatable to ratepayers, then what the Company has proposed in this case.

Q. Has the Company stated that it is willing to reduce its Cost of Equity by 100 basis points or has it agreed to a four year stay-out provision?

A. No.

Q. What is RUCO's recommendation?

A. Property tax is just one type of expense that may go up or down between rate cases. The risk that the Company faces is that expenses may increase or decrease between rate cases is reflected in the Company's cost of capital, as it has always been done through traditional ratemaking. There is nothing extra ordinary about the Company's request for a deferral of property taxes in this case, other than APS received one. Further to allow such treatment would be tantamount to single issue ratemaking. RUCO recommends denial of the Company's proposed deferral of property taxes.

<u>Gila River Property Tax Deferral</u>

Q. Please respond to the Company's second component of its proposed tax deferral.

A. The Company states that it disagrees with the Arizona Department of Revenues ("ADOR") assessment of its Gila River Power Plant full cash

[4] See page 15, line 20 of Decision No. 73183.

value estimate of $50 million, while the Company estimates the value to be approximately $29 million.

Q. Would this save ratepayers money in the longer term on property taxes if the appeal is successful?

A. Yes. However, this would also save the Company's shareholders money in the long term. In exchange, the Company wants to transfer the risk from the shareholders to ratepayers. If the Company loses the appeal, ratepayers are responsible for the legal bill.

Q. What does RUCO recommend?

A. RUCO recommends a 50/50 sharing between shareholders and ratepayers in its appeal of the Arizona Department of Revenues ("ADOR") assessment of its Gila River Power Plant. RUCO also recommends a reasonable cap be placed on legal expenses. Once this level is exceeded, the Company shareholders should bear any extra costs. If the Company wins, it is my understanding, although I am not an attorney, that ADOR would have to pay the Company's legal expenses and if the Company prevails, in which case the Company would need to refund half of this money to ratepayers.

Gila River One Time Purchased Power Fuel Adjustment Clause ("PPFAC") Credit

Q. Please explain the Company's proposed one time PPFAC credit?

A. Based on page 6 of Company's witness Dallas Dukes testimony he states "UNS Electric is proposing a one-year credit to the purchased power and fuel adjustment clause ("PPFAC") to collect the deferred savings accrued as a result of' the Deferred Accounting Order related to the acquisition of Gila River (estimated at $9.3 million). As a result of these factors, UNS Electric's request would decrease revenue by approximately $5.8 million, or 3.6%, in the first year after new rates take effect. In year two, after the deferred savings are fully credited, the Company's revenue would rise to a level that represents an increase of approximately $3.5 million, or 2.1%, over test year adjusted retail revenue."

Q. Does RUCO agree with the Company's proposal?

A. RUCO agrees that the Company should credit back deferred savings to ratepayers, but would recommend the deferred savings be credited back to ratepayers over a three year period.

Q. Why does RUCO believe the deferred savings should be credited back to ratepayers over a three year period?

A. RUCO believes a normalized approach over three years is preferable to one year. This sends the proper price signal to ratepayers, so that ratepayers are not confused when they get a decrease in the first year and then an increase in the second year. RUCO recommends the deferred savings accrued as a result of' the Deferred Accounting Order related to the acquisition of Gila River be credited back to ratepayers over a three year period through the PPFAC.

<u>Other Changes to the PPFAC</u>

Q. Has the Company asked to have its PPFAC modified?

A. Yes. On page 7 of Company witness Craig A. Jones states the following:

"Regarding the PPFAC, the Company proposes a single percentage-based adjustment applicable to all rate classes and based on the monthly change in total annual fuel cost compared to the annual fuel cost approved in this proceeding - while also changing the rate band to 1% and adding a Base Rate Annual Adjustment."

Q. Does RUCO agree with the Company's proposed adjustments?

A. No. RUCO has concerns that under the single percentage-based approach, this may shift costs from one rate class to another. The current 0.83 percent band reduces the impact of the PPFAC to ratepayers. The Base Rate Annual Adjustment also exposes the ratepayers to more risk. RUCO recommends that the current PPFAC not be modified.

<u>Lost Fixed Cost Recovery ("LFCR") Mechanism</u>

Q. Has the Company asked to have its LFCR mechanism modified?

A. Yes. On page 7 of Company's witness Craig A. Jones testimony he states, "For the LFCR, the Company proposes to allow recovery of lost fixed costs attributable to generation and the full recovery of lost demand revenues."

Q. What has been RUCO's position in the past regarding the LFCR, in this case and in other cases?

A. RUCO has agreed in the past not to oppose the LFCR as long as the LFCR provided an opt-out provision for ratepayers. RUCO has never said the LFCR qualifies as a legal adjustor mechanism. RUCO did not oppose the LFCR as part of the previous settlements because the opt-out provision provided ratepayers with an undisputed legal option to address the Company's fixed-cost concerns.

Q. With the advent of the recent Court of Appeals decision regarding the System Improvement Benefit ("SIB") Mechanism, has RUCO changed its position on the LFCR?

A. No. RUCO is reviewing the legality of the LFCR in light of the Court's opinion.

Q. Does your silence on any issue in this rate filing preclude you from addressing these issues in future testimony?

A. No, it does not.

Q. Does this conclude your direct testimony?

A. Yes.

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Schedule JMM-1

REVENUE REQUIREMENT
ACC JURISDICTIONAL
(Thousands of Dollars)

LINE NO.	DESCRIPTION	(A) COMPANY ORIGINAL COST	(B) COMPANY RCND	(C) COMPANY FAIR VALUE	(D) RUCO ORIGINAL COST	(E) RUCO RCND	(F) RUCO FAIR VALUE
1	Adjusted Rate Base	$ 272,013	$ 439,427	$ 355,720	$ 264,551	$ 425,710	$ 345,131
2							
3	Adjusted Operating Income (Loss)	8,044	8,044	8,044	10,517	10,517	10,517
4							
5	Current Rate Of Return (Line 3 / Line 1)	2.96%	1.83%	2.26%	3.98%	2.47%	3.05%
6							
7	Required Operating Income (Line 13 X Line 1)	$ 22,108	$ 22,108	$ 22,108	$ 18,147	$ 18,147	$ 18,147
8							
9	Weighted Average Cost of Capital	7.67%	7.67%	7.67%	6.61%	6.61%	6.61%
10							
11	Fair Value Adjustment	0.46%	-2.96%	-1.45%	0.25%	-2.35%	-1.35%
12							
13	Required Rate of Return	8.13%	5.03%	6.22%	6.86%	4.26%	5.26%
14							
15	Operating Income Deficiency (Line 7 - Line 3)	$ 14,064	$ 14,064	$ 14,064	7,629	7,629	7,629
16							
17	Gross Revenue Conversion Factor (Schedule JMM-2)	1.6084	1.6084	1.6084	1.6084	1.6084	1.6084
18							
19	Increase In Gross Revenue Requirement (Line 15 X Line 17)	$ 22,621	$ 22,621	$ 22,621	$ 12,271	$ 12,271	$ 12,271
20							
21	Adjusted Test Year Revenue	$ 148,936	$ 148,936	$ 148,936	$ 152,027	$ 152,027	$ 152,027
22							
23	Proposed Annual Revenue Requirement (Line 19 + Line 21)	$ 171,557	$ 171,557	$ 171,557	$ 164,298	$ 164,298	$ 164,298
24							
25	Required Percentage Increase In Revenue (Line 19 / Line 21)	15.19%	15.19%	15.19%	8.07%	8.07%	8.07%
26							
27	Rate Of Return On Common Equity	10.35%	10.35%	10.35%	8.16%	8.16%	8.16%

References:
Columns (A) Thru (C): Company Schedule A-1, C-1 and D-1
Column (D): Schedules JMM-3, JMM-8, and JMM-20
Column (E): Schedule JMM-2, Column (B)
Column (F): Average of Column (D) + Column (E) / 2

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Schedule JMM-2

GROSS REVENUE CONVERSION FACTOR, INCOME TAX CALCULATION

LINE NO.	DESCRIPTION	[A] Company Proposed	[B] RUCO Recommended
1	Gross Revenue	100.00%	100.00%
2	Less: Uncollectibel Revenue	0.34%	0.34%
3	Taxable Income as a Percent	99.66%	99.66%
4	Less: Federal and State Income Taxes	37.48%	37.48%
5	Changes in Net Operating Income	62.17%	62.17%
6	Gross Revenue Conversion Factor	1.6084	1.6084

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Schedule JMM-3

RATE BASE (OCRB, RCND and FVRB)
ACC JURISDICTIONAL
(Thousands of Dollars)

LINE NO.	DESCRIPTION	(A) COMPANY OCRB	(B) COMPANY RCND	(C) COMPANY FVRB	(D) OCRB/RCND % DIFF.	(E) RUCO OCRB	(F) RUCO RCND	(G) RUCO FVRB
1	Gross Utility Plant In Service	$ 664,701	$ 1,169,067	$ 916,884	175.88%	$ 664,701	1,169,067	$ 916,884
2	Accumulated Depreciation	(296,962)	(561,910)	(429,436)	189.22%	(296,962)	(561,910)	(429,436)
3	Net Utility Plant In Service	367,739	607,156	487,448		367,739	607,156	487,448
4								
5	Citizens Acquisition Discount	(95,155)	(170,848)	(133,002)	179.55%	(95,155)	(170,848)	(133,002)
6	Less: Accu Amort Citizens Acq Discount	36,098	69,678	52,888	193.02%	36,098	69,678	52,888
7	Net Citizens Acquisition Discount	(59,057)	(101,170)	(80,113)		(59,057)	(101,170)	(80,113)
8								
9	Total Net Utility Plant	308,682	505,987	407,334	163.92%	308,682	505,987	407,334
10								
11	Deductions:							
12	Cust. Advances For Const.	(3,833)	(4,268)	(4,051)	111.35%	(3,833)	(4,268)	(4,051)
13	Customer Deposits	(4,428)	(4,428)	(4,428)	100.00%	(4,428)	(4,428)	(4,428)
14	Other (ITC)	(422)	(422)	(422)	100.00%	(422)	(422)	(422)
15	Acc. Deferred Income Taxes	(35,161)	(64,617)	(49,889)	183.77%	(42,628)	(78,339)	(60,484)
16	Total Deductions	(43,844)	(73,735)	(58,789)		(51,311)	(87,457)	(69,384)
17								
18	Allowance - Working Capital	7,175	7,175	7,175	100.00%	7,180	7,180	7,180
19								
20	Regulatory Assets	-	-	-	100.00%	-	-	-
21								
22	Regulatory Liability	-	-	-	100.00%	-	-	-
23								
24								
25	TOTAL TEST YEAR RATE BASE	$ 272,013	$ 439,427	$ 355,720		$ 264,551	$ 425,710	$ 345,131

References:
Columns (A) (B) (C): Company Schedule B-1
Column (D): Column (B) / Column (A)
Column (E): Schedule JMM-4, Column (C)
Column (F): Column (D) X Column (E)
Column (G): Average Of Column (E) + Column (F) / 2

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Schedule JMM-4

ORIGINAL COST RATE BASE - ACC JURISDICTIONAL (Shown in Thousands)

LINE NO.	DESCRIPTION	(A) COMPANY FILED AS OCRB	(B) RUCO ADJUSTMENTS	(C) RUCO ADJUSTED AS OCRB
1	Gross Utility Plant In Service	$ 664,701	-	$ 664,701
2	Accumulated Depreciation	(296,962)	-	(296,962)
3	Net Utility Plant In Service	367,739	-	367,739
4				
5	Citizens Acquisition Discount	(95,155)	-	(95,155)
6	Less: Accu Amort Citizens Acq Discount	36,098	-	36,098
7	Net Citizens Acquisition Discount	(59,057)	-	(59,057)
8				
9	Total Net Utility Plant	308,682	-	308,682
10				
11	Deductions:			
12	Cust. Advances For Const.	$ (3,833)	-	$ (3,833)
13	Customer Deposits	(4,428)	-	(4,428)
14	Other - Investment Tax Credits ("ITC")	(422)	-	(422)
15	Accumulated Deferred Income Taxes ("ADIT")	(35,161)	(7,467)	(42,628)
16	Total Deductions	(43,844)	(7,467)	(51,311)
17				
18	Allowance - Working Capital	7,175	5	7,180
19				
20	Regulatory Assets	-	-	-
21				
22	Regulatory Liability	-	-	-
23				
24				
25	TOTAL OCRB	$ 272,013	$ (7,462)	$ 264,551

Reconciliation to RCN (Thousands of Dollars)

	OCRB	RCN Ratio for ADIT	RCN
Company RCN as Filed			$ 439,427
RUCO ADIT Adjustment #1	$ (7,467)	1.8377	(13,723)
Cash Working Capital	5,429	1.0000	5,429
	$ (7,462)		$ 425,710

References:
Column [A]: Company as Filed
Column [B]: RUCO Schedule 5
Column (C): Column (A) + Column (B)

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SUMMARY OF ORIGINAL COST RATE BASE ADJUSTMENTS
(Thousands of Dollars)

Line No.	DESCRIPTION	ACC Jurisdiction (A) Company Adjusted OCRB As Filed	[B] Rate Base Adjustment No. 1 Reverse Net Operating Loss Carry forward Accumulated Deferred Income Tax Offset	(C) Rate Base Adjustment No. 2 Working Capital	(D) RUCO Adjusted OCRB Recommended Balances
1	Gross Utility Plant in Service	664,701	$ -	$ -	$ 664,701
2					
3	Accumulated Depreciation	(296,962)	-	-	$ (296,962)
4	Net Utility Plant in Service	$ 367,739	$ -	$ -	$ 367,739
5					
6	Citizens Acquisition Discount	$ (95,155)	$ -	$ -	$ (95,155)
7	Accumulated Amortization - Citizens Acquisition Discount	36,098	-	-	$ 36,098
8	Net Citizens Acquisition Discount	$ (59,057)	$ -	$ -	$ (59,057)
9					
10	Total Net Utility Plant	$ 308,682	$ -	$ -	$ 308,682
11					
12	Customer Advances for Construction	$ (3,833)	$ -	$ -	$ (3,833)
13					
14	Customer Deposits	(4,428)			(4,428)
15					
16	Other - Investment Tax Credits ("ITC")	(422)			(422)
17					
18	Accumulated Deferred Income Taxes ("ADIT")	(35,161)	(7,467)		(42,628)
19	Total Deductions	$ (43,844)	$ (7,467)	$ -	$ (51,311)
20					
21					
22	Allowance for Working Capital	$ 7,175	$ -	$ 5	$ 7,180
23					
24	Regulatory Assets	-	-	-	-
25					
26	Regulatory Liabilities	-	-	-	-
27					
28	Total Original Cost Rate Base	$ 272,013	$ (7,467)	$ 5	$ 264,551

REFERENCES:
Column (A) Company Schedule B-1
Column (B) See RBM-4
Column (D) See RBM-5
Column (E) See Column (B) through (D)

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Schedule JMM-6

RATE BASE ADJUSTMENT NO. 1
Reverse Net Operating Loss Carryforward
Accumulated Deferred Income Tax Offset

Line No.	DESCRIPTION	(A) Company Proposed	(B) RUCO Adjustment	(C) RUCO As Adjusted
1	Accumulated Deferred Taxes	$ (35,161,108)	$ (7,467,062)	$ (42,628,170)
	ADIT NOLC Offset	$ (7,819,101)		
	ACC Jurisdictional Factor	0.9550		
		$ (7,467,062)		

References:
Column (A) Per Company Filing
Column (B) Testimony JMM
Column (C) = Column (A) + Column (B)

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Schedule JMM-7

ALLOWANCE FOR WORKING CAPITAL
LEAD/LAG DAY SUMMARY

LINE NO.	DESCRIPTION	(A) COMPANY ADUSTED TEST YEAR AS FILED	(B) RUCO Adj	(C) RUCO Adjusted Results	(D) Revenue Lag Days	(E) Exp Lag Days	(F) Net Lag Days	(G) Lead Lag Factor	(H) Cash Working Capital Requiredments
1	OPERATING EXPENSES								
2	Non-Cash Expenses:								
3	Bad Debts Expense	$ 506	-	$ 506	-		-		-
4	Depreciation	11,406	-	11,406			-		-
5	Amortization	(3,629)	(17)	(3,646)			-		-
6	Deferred Income Taxes	4,627	-	4,627			-		-
7	Total Non-Cash Expenses	$ 12,909	(17)	12,892					-
8									
9	Other Operating Expenses:								
10	Salaries & Wages	$ 4,616	-	$ 4,616	35.59	23.33	12.26	0.0336	155
11	Incentive Pay	329	(216)	113	35.59	267.00	(231.41)	(0.6340)	(72)
12	Purchased Power	62,965	-	62,965	35.59	33.79	1.80	0.0049	309
13	Transmission Other	9,014	-	9,014	35.59	40.67	(5.08)	(0.0139)	(125)
14	Meter Reading	574	-	574	35.59	33.67	1.92	0.0053	3
15	Customer Records & Coll Exp	1,169	-	1,169	35.59	34.94	0.65	0.0018	2
16	Office Supplies and Expenses	1,005	(16)	989	35.59	50.89	(15.30)	(0.0419)	(41)
17	Injuries and Damages	750	(414)	336	35.59	70.52	(34.93)	(0.0957)	(32)
18	Pensions and Benefits	1,960	(306)	1,654	35.59	51.37	(15.78)	(0.0432)	(71)
19	Support Services	6,059	-	6,059	35.59	44.77	(9.18)	(0.0252)	(153)
20	Property Taxes	6,733	-	6,733	35.59	212.00	(176.41)	(0.4820)	(3,245)
21	Payroll Taxes	376	-	376	35.59	12.00	23.59	0.0646	24
22	Current Income Taxes	-	-	-	35.59	-	35.59	0.0975	-
23	Interest on Customer Deposits	7	-	7	35.59	182.50	(146.91)	(0.4025)	(3)
24	Other O&M Expenses	25,050	-	35,762	35.59	41.21	(5.62)	(0.0154)	(551)
25	Total Other Operating Exp.	$ 120,607	(952)	$ 130,367					
26									
27	Total Operating Expenses	$ 133,516	$ (968)	$ 143,259					$ (3,801)
28									
29	Other Cash Working Capital Elements:								
30	Interest on Long-Term Debt	7,859	-	7,859	35.59	89.5	$ (53.91)	$ (0.1477)	(1,161)
31	Rev. Taxes and Assessments	11,717	-	11,717	35.59	49.43	$ (13.84)	$ (0.0379)	(444)
32									
33		$ 19,576	$ -	$ 19,576					$ (1,605)
34									
35	TOTAL CASH WORKING CAPITAL	$ 166,001		$ 175,728					
36									
37									
38	Pro Fc Pro Forma Operating Expenses - Excluding Income Taxes	$ 128,889		$ 138,633					
39	Less: ! Less: Other O&M	103,839		102,871					
40		$ 25,050		$ 35,762					Shown in Thousands
41									
42					Total RUCO				$ (5,405,605)
43									
44					Total Company				$ (5,431,223)
45									
46					Cash Working Capital Adjustment				$ 24,521
47					With ACC Jurisdictioanl Ratio .95717				
48									
49					Pre-paid D&O Insurance Adjustment				$ (19,092)
50					With ACC Jurisdictioanl Ratio .95328				
51									
52					Total Adjustment				$ 5,429

53 References:
54 Column (A): - Company Schedule B-5
55 Column (B): RUCO Operating Income Adjustments
56 Column (C): Column (A) + (B)
57 Column (D): Company Schedule B-5
58 Column (E): Company Schedule B-5
59 Column (F): Column (D) - Column (E)
60 Column (G): Column (E)/365

UNS Electric, Inc.
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Schedule JMM-8

SUMMARY OF OPERATING INCOME STATEMENT - ACC JURISDICTIONAL - ADJUSTED TEST YEAR AND RUCO
(Thousands of Dollars)

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED	(B) RUCO TEST YEAR ADJM'TS	(C) RUCO TEST YEAR AS ADJ'D
1	Operating Revenues:			
2	Electric Retail Revenues	$ 147,107	$ 3,091	$ 150,197
3	Sales for Resale	-	-	-
4	Other Operating Revenue	1,829	-	1,829
5				-
6	TOTAL OPERATING REVENUES	148,936	3,091	152,027
7				
8	Operating Expenses:			
9	Fuel, Purchased Power and Trans	77,522	-	77,522
10	Other Operations and Maintenance Exp	42,870	(968)	41,901
11	Depreciation and Amortization	13,060	-	13,060
12	Taxes Other than Income Taxes	6,149	-	6,149
13	Income Taxes	1,291	1,585	2,877
14	Rounding Differences	-	-	-
15	TOTAL OPERATING EXPENSES	140,892	617	141,509
16				
17	OPERATING INCOME (LOSS)	$ 8,044	$ 2,473	$ 10,517

References:
Column (A): Company Schedule C-1
Column (B): RUCO Schedule 9
Column (C): Column (A) + Column (B)

OPERATING INCOME STATEMENT - ACC JURISDICTIONAL - ADJUSTED TEST YEAR AND RUCO RECOMMENDED ADJUSTMENTS

(Thousands of Dollars)

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED	(B) Adj. 1 Current Charges Authorized by the Commission not applied JMM-10	(C) Adj. 2 Not Used JMM-11	(D) Adj. 3 Normalize Medical nd Dental Expense JMM-12	(E) Adj. 4 Directors & Officers Ins. JMM-13	(F) Adj. 5 Vellness, Employee, Spot Award JMM-14
1	Operating Revenues:						
2	Electric Retail Revenues	$ 147,107	$ 3,091	$ -	$ -	$ -	$ -
3	Sales for Resale	-	-	-	-	-	-
4	Other Operating Revenue	1,829	-	-	-	-	-
5				-			
6	TOTAL OPERATING REVENUE	148,936	3,091	-	-	-	-
7							
8	Operating Expenses:						
9	Fuel, Purchased Power and Tr	77,522	-	-	-	-	-
10	Other Operations and Mainten:	42,870	-	-	(306)	(70)	(47)
11	Depreciation and Amortization	13,060	-	-	-	-	-
12	Taxes Other than Income Taxe	6,149	-	-	-	-	-
13	Income Taxes	1,291	-	-	-	-	-
14	Rounding Differences	-	-	-	-	-	-
15	TOTAL OPERATING EXPENSE	140,892	-	-	(306)	(70)	(47)
16							
17	OPERATING INCOME (LOSS)	$ 8,044	$ 3,091 $ -	$ -	$ 306	$ 70	$ 47

OPERATING INCOME STATEMENT - ACC JURISDICTIONAL - ADJUSTED TEST YEAR AND RUCO RECOMMENDED ADJUSTMENTS

(Thousands of Dollars)

	(G) Adj. 6 PEP Expense JMM-15	(H) Adj. 7 Injuries and Damages JMM-16	(I) Adj. 8 EEI Dues JMM-17	(J) Adj. 9 Rate Case Expense JMM-18	(k) Adj. 10 Interest Synchronization JMM-19	(L) Adj. 11 Income Tax JMM-20	(M) RUCO as Recommended
	$ -	$ -	$ -	$ -	$ -	$ -	$ 150,197
	-	-	-	-	-	-	-
	-	-	-	-	-	-	1,829
	-	-	-	-	-	-	152,027
	-	-	-	-	-	-	$ 77,522
	(170)	(344)	(16)	(17)		-	41,901
	-	-	-	-	-	-	13,060
	-	-	-	-	-	-	6,149
	-	-	-	-	59	1,527	2,877
	-	-	-	-	-	-	-
	(170)	(344)	(16)	(17)	59	1,527	141,509
	$ 170	$ 344	$ 16	$ 17	$ (59)	$ (1,527)	$ 10,517

UNS Electric, Inc.
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OPERATING INCOME ADJUSTMENT NO. 1
CURRENT CHARGES AUTHORIZED BY THE COMMISSION NOT APPLIED TO TEST YEAR BILLING DETERMINANTS

Line No.	DESCRIPTION	(A) COMPANY PROPOSED	(B) RUCO ADJUSTMENT	(C) RUCO AS ADJUSTED
1	Electric Retail Revenues	$ 147,106,730	$ 3,090,705	$ 150,197,434
2				
3				
4	RUCO's Calculation			
5				
6				

Line No.	Customer Class	RUCO's Calculation: Current Rates	RUCO's Calculation: Test Year Billing Determinents	RUCO's Calculation: Adjusted Test Year Revenues	Company's Calculation: Current Rates	Company's Calculation: Test Year Billing Determinents	Company's Calculation: Adjusted Test Year Revenues	Difference
7								
8								
9								
10	5713 LARGE GENERAL SERVICE							
11	Basic Service Charge	$ 50.000000			$ 50.000000			
12	Demand Charge, per kW	$ 12.810000	16,092	$ 804,600	$ 12.810000	16,092	$ 804,600	
13	Energy Charge, per kWh	$ 0.005470	1,394,255	$ 17,860,410	$ 0.005470	1,394,255	$ 17,860,410	
14	TCA, per kW	$ 0.432900	445,782,493	$ 2,438,430	$ 0.432900	445,782,493	$ 2,438,430	
15	Margin Total		0	$ -		0	$ -	
16								
17	Base Power	$ 0.056603			$ 0.048440			
18	PPFAC Revenue	Varies by Month	445,782,493	$ 25,232,626	Varies by Month	445,782,493	$ 21,593,704	
19	Total Fuel Revenue							
20								
21	Total Large General Service							
22				$ 46,336,067			$ 42,697,144	$ 3,638,922
23								
24	5771 LARGE GENERAL SERVICE TIME OF USE							
25	Basic Service Charge	$ 52.000000			$ 52.0000			
26	Demand Charge, per kW	$ 12.810000	96	$ 4,992	$ 12.8100	96	$ 4,992	
27	Energy Charge, per kWh	$ 0.005470	16,192	$ 207,417	$ 0.0055	16,192	$ 207,417	
28	TCA, per kW	$ 0.432900	7,718,956	$ 42,223	$ 0.4329	7,718,956	$ 42,223	
29	Margin Total		0	$ -		0	$ -	
30								
31	Base Power							
32	Summer On-peak	$ 0.114886			$ 0.1099			
33	Summer Off-peak	$ 0.039886	728,854	$ 83,735	$ 0.0335	728,854	$ 80,101	
34	Winter On-peak	$ 0.114886	2,959,583	$ 118,046	$ 0.0899	2,959,583	$ 99,146	
35	Winter Off-peak	$ 0.026168	907,877	$ 104,302	$ 0.0316	907,877	$ 81,618	
36	PPFAC Revenue	Varies by Month	3,122,643	$ 81,713	Varies by Month	3,122,643	$ 98,676	
37	Total Fuel Revenue							
38								
39	Total Large General Service TOU			$ 642,429			$ 614,173	$ 28,256

40								
41								
42	5709 LARGE POWER SERVICE 3<69 kV							
43	Basic Service Charge	$ 1,200.000000	84	$ 100,800	$ 1,200.000000	84	$ 100,800	
44	Demand Charge, per kW	$ 22.000000	125,432	$ 2,759,504	$ 22.000000	125,432	$ 2,759,504	
45	Power Factor Adjustment			$ 94,842			$ 94,842	
46	Energy Charge, per kWh	$ 0.000462	58,092,107	$ 26,839	$ 0.000462	58,092,107	$ 26,839	
47	Primary Discount			$ (20,808)			$ (20,808)	
48	TCA, per kW	$ 0.432900	0	$ -	$ 0.432900	0	$ -	
49	Margin Total							
50								
51	Base Power	$ 0.041880	58,092,107	$ 2,432,897	$ 0.046400	58,092,107	$ 2,811,658	
52	PPFAC Revenue	Varies by Month			Varies by Month			
53	Total Fuel Revenue							
54								
55	Total Large Power Service-Distribution							
56				$ 5,394,074			$ 5,772,835	$ (378,761)
57	LARGE POWER SERVICE 3 TOU <69 kV							
58	Basic Service Charge	$ 1,200.000000	24	$ 28,800	$ 1,200.000000	24	$ 28,800	
59	Demand Charge, per kW	$ 22.000000	33,511	$ 737,242	$ 22.000000	33,511	$ 737,242	
60	Power Factor Adjustment			79,046			79,046	
61	Energy Charge, per kWh	$ 0.000462	15,418,264	$ 7,123	$ 0.000462	15,418,264	$ 7,123	
62	TCA, per kW	$ 0.432900	0	$ -	$ 0.432900	0	$ -	
63	Margin Total							
64								
65	Base Power							
66	Summer On-peak	$ 0.123580	1,259,777	$ 155,683	$ 0.145510	1,259,777	$ 183,310	
67	Summer Off-peak	$ 0.024716	6,623,822	$ 163,714	$ 0.034510	6,623,822	$ 228,588	
68	Winter On-peak	$ 0.093880	1,200,529	$ 112,706	$ 0.124510	1,200,529	$ 149,478	
69	Winter Off-peak	$ 0.022105	6,334,135	$ 140,016	$ 0.032910	6,334,135	$ 208,456	
70	PPFAC Revenue	Varies by Month			Varies by Month			
71	Total Fuel Revenue							
72								
73	Total Large Power Service Distribution TOU							
74				$ 1,424,331			$ 1,622,044	$ (197,713)
75	RUCO Adjustment							$ 3,090,705

References:
Column (A) Per Company Filing
Column (B) Testimony JMM
Column (C) = Column (A) + Column (B)

UNS Electric, Inc.
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Test Year Ended December 31, 2014

Schedule JMM-11

OPERATING INCOME ADJUSTMENT NO. 2
NOT USED

Line No.	DESCRIPTION	(A) COMPANY PROPOSED	(B) RUCO ADJUSTMENT	(C) RUCO AS ADJUSTED
1		$ -	$ -	$ -

References:
Column (A) Per Company Filing
Column (B) Testimony JMM
Column (C) = Column (A) + Column (B)

UNS Electric, Inc.
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Test Year Ended December 31, 2014

Schedule JMM-12

OPERATING INCOME ADJUSTMENT NO. 3
MEDICAL AND DENTAL EXPENSE NORMALIZATION

Line No.	DESCRIPTION	(A) COMPANY PROPOSED	(B) RUCO ADJUSTMENT	(D) RUCO AS ADJUSTED	(E) ACC Juridictional Factor	(F) ACC Juridictional RUCO ADJUSTMENT
1	Medical Expense	$ 2,205,353	$ (329,800)	$ 1,875,553	0.9603	$ (316,694)
2	Dental Expense	82,709	11,295	94,004	0.9603	$ 10,846
3	Total	$ 2,288,062	$ (318,505)	$ 1,969,557	0.9603	$ (305,848)
4						
5	RUCO's Calculation:					
6	Year	Medical Expense Amount				
7	2014	$ 2,205,353				
8	2013	1,863,496				
9	2012	1,557,810				
10	Three Year Average	$ 1,875,553				
11						
12	RUCO's Calculation:					
13	Year	Dental Expense Amount				
14	2014	$ 82,709				
15	2013	92,243				
16	2012	107,060				
17	Three Year Average	$ 94,004				

References:
Column (A) Per Company Filing
Column (B) Testimony JMM
Column (C) = Column (A) + Column (B)

UNS Electric, Inc.
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Schedule JMM-13

OPERATING INCOME ADJUSTMENT NO. 4
OFFICERS AND DIRECTORS INSURANCE

Line No.	DESCRIPTION	(A) COMPANY PROPOSED	(B) RUCO ADJUSTMENT	(D) RUCO AS ADJUSTED	(E) ACC Juridictional Factor	(F) ACC Juridictional RUCO ADJUSTMENT
1	Officers and Directors Liability Insurance	$ 145,954	$ (72,977)	$ 72,977	0.9603	$ (70,077)
2						
3	RUCO's Calculation:					
4	Company Proposed	$ 145,954				
5	Split between Ratepayers and Shareholder	50%				
6	RUCO Adjustment - Total Company	$ 72,977				

References:
Column (A) Per Company Filing
Column (B) Testimony JMM
Column (C) = Column (A) + Column (B)

UNS Electric, Inc.
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Schedule JMM-14

OPERATING INCOME ADJUSTMENT NO. 5
WELLNESS INCENTIVE PROGRAM, EMPLOYEE RECOGNITION, AND SPOT AWARD

Line No.	DESCRIPTION	(A) COMPANY PROPOSED	(B) RUCO ADJUSTMENT	(C) RUCO AS ADJUSTED	(E) ACC Juridictional Factor	(F) RUCO AS ADJUSTED
1	Wellnes Incentive Program	$ 15,738	$ (15,738)	$ -	0.9603	$ (15,113)
2	Employee Recognition	10,740	(10,740)	-	0.9603	(10,313)
3	Spot Awards	22,000	(22,000)	-	0.9603	(21,126)
4	Total	$ 48,478	$ (48,478)	$ -	0.9603	(46,551)

References:
Column (A) Per Company Filing
Column (B) Testimony JMM
Column (C) = Column (A) + Column (B)

UNS Electric, Inc.
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Test Year Ended December 31, 2014

Schedule JMM-15

OPERATING INCOME ADJUSTMENT NO. 6
UNS SHORT-TERM INCENTIVE PROGRAM

Line No.	DESCRIPTION	(A) 2014 Company Total	(B) Company Pro Forma Adjusment	(C) Total COMPANY PROPOSED	(D) RUCO ADJUSTMENT	(E) ACC Juridictional Factor	(F) RUCO AS ADJUSTED
1	FERC						
2	0581	$ 5,914	$ 2,199	$ 8,113	$ (4,057)	1.0000	$ (4,057)
3	0583	-	4,412	4,412	(2,206)	1.0000	(2,206)
4	0592	-	4,247	4,247	(2,123)	1.0000	(2,123)
5	0593	3,661	5,642	9,302	(4,651)	1.0000	(4,651)
6	0901	13,287	9,402	22,689	(11,344)	1.0000	(11,344)
7	0908	5,962	800	6,763	(3,381)	1.0000	(3,381)
8	0920	116,594	140,893	257,487	(128,743)	0.9603	(123,628)
10	O&M Expense	$ 145,417	$ 167,595	$ 313,012	$ (156,506)		$ (151,391)
11	0408 FICA Tax	6,054	7,687	13,741	(6,871)	0.9601	(6,597)
12	Total	$ 151,471	$ 175,282	$ 326,753	$ (163,377)		$ (157,988)

Less: RUCO removal of Company projected costs 12,122 x acc jurisdicition ratio of .9661	$ (11,712)
Total RUCO adjustment	$ (169,700)

References:
Column (A) Per Company Filing
Column (B) Testimony JMM
Column (C) = Column (A) + Column (B)

UNS Electric, Inc.
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Test Year Ended December 31, 2014

Schedule JMM-16

OPERATING INCOME ADJUSTMENT NO. 7
INJURIES AND DAMAGES

Line No.	UNSE Adjustment to Injuries & Damages	(A)	(B)	(C)	(D)
1	Account Description	2012	2013	2014	Average for 3 Years
2	Workers' Compensation	$ 55,586	$ 44,482	$ 37,493	$ 45,854
3	Workers' Compensation	(32,917)	18,204	(9,696)	(8,136)
4	Injuries & Damages	10,000	1,071,000	-	360,333
5					
6	Total for Three Year Period	$ 32,670	$ 1,133,687	$ 27,797	$ 398,051
7					
8					
9	Company Average for 3 years	$ 398,051	Column (D) Ln 6		
10					
11	Expenses for Test Year	$ 27,797	Column (C) Ln 6		
12					
13	Company Adjustment Using 3 Year Average	$ 370,254	Column (A) Ln 9 - Ln 11		
14					
15	ACC Jurisdictional	96.027%			
16					
17	ACC Jurisdictional Adjustment	$ 355,543	PER COMPANY'S Calculation		
18					
19					
20	RUCO's Adjustment to Injuries & Damages				
21					
22	Account Description	2012	2013	2014	Average for 3 Years
23	Workers' Compensation	$ 55,586	$ 44,482	$ 37,493	$ 45,854
24	Workers' Compensation	(32,917)	18,204	(9,696)	(8,136)
25	Injuries & Damages	10,000	1,071,000	-	360,333
26	RUCO Reduction in Injuries and Damages	-	(1,071,000)	-	(357,000)
27					
28	Total for Three Year Period	$ 32,670	$ 62,687	$ 27,797	$ 41,051
29					
30					
31					
32	RUCO does not believe that the Injuries and damages expense for $1,071,000 incurred at year ending 2013 should be included in the				
33	calculation for the the three year period. The expense is extraordinary in nature and should be excluded.				
34					
35	RUCO'S Average for 3 years	$ 41,051	Column (D) Ln 28		
36					
37	Expenses for Test Year	$ 27,797	Column (C) Ln 28		
38					
39	Company Adjustment Using 3 Year Average	$ 13,254	Column (A) Ln 35 + Ln 37		
40					
41	ACC Jurisdictional	96.027%			
42					
43	ACC Jurisdictional Adjustment	$ 11,728	PER RUCO's Calculation		
44					
45					
46	TOTAL RUCO ADJUSTMENT	$ (343,815)	Line Column (A) Ln 18 + Column (A) Ln 44		

References:
Columns (A) through (D) Lines 3 through 18 provided by Company in UDR 1.01 Workpaper Schedules.

Columns (A) through (D) Lines 21 through 47 RUCO calculations

UNS Electric, Inc.
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Schedule JMM-17

OPERATING INCOME ADJUSTMENT NO. 8
EEI DUES

Line No.	DESCRIPTION	(A) TEST YEAR AMOUNT	(B) COMPANY ADJUSTMENT	(C) COMPANY PROPOSED	(D) RUCO ADJUSTMENT	(E) RUCO ACC JURISDICTIONAL ADJUSTMENT
1	EEI Membership - USWAG	$ 3,500	$ (217)	$ 3,283	$ (1,035)	$ (994)
2	UARG - Membership Dues	15,123	-	15,123	$ (15,123)	$ (14,523)
3	Total Dues Expense	$ 18,623	$ (217)	$ 18,406	$ (16,158)	$ (15,517)

RUCO's Calculation:	
EEI - Membership	$ 3,500
RUCO's Disallowance	0.3575
Amount Disallowed	$ 1,251
ACC Jurisdictional Ratio	0.9603
ACC Jurisdictional Amount	$ 1,202
Reconciliation	
$217 x .9603 Already removed by Company	$ 208
$1,035 (1,251 - 217) x .9603	994
	$ 1,202
UARG Dues $15,123 x .9603	$ 14,523

References:
Column (A) Per Company Filing
Column (B) Testimony JMM
Column (C) = Column (A) + Column (B)

UNS Electric, Inc.
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Schedule JMM-18

OPERATING INCOME ADJUSTMENT NO. 9
RATE CASE EXPENSE

Line No.	DESCRIPTION	(A) COMPANY PROPOSED	(B) RUCO RECOMMENDED	(C) RUCO ADJUSTMENT
1	Rate Case Expense	$ 400,000	$ 350,000	
2	Normalization Years	3	3	
3	Rate Case Expense	$ 133,333	$ 116,667	$ (16,667)

References:
Column (A) Per Company Filing
Column (B) Testimony JMM
Column (C) = Column (A) + Column (B)

UNS Electric, Inc.
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Schedule JMM-19

Operating Adjustment No. 10
Interest Synchronization

Line No.	Description	Tax Rate	[A] Company Proposed	[B] RUCO Recommended
1	Adjusted Rate Base		$ 272,013,129	$ 264,551,496
2	Weighted Cost of Debt		2.20%	2.20%
3	Synchronized Interest Deduction		$ 5,979,180	$ 5,815,165
4	Increase (Decrease) in Deductible Interest			$ (164,016)
5	State Income Taxes	5.48%		$ 8,980
6	Federal Taxable Income			$ (155,036)
7	Federal Income Taxes	32.14%		$ 49,825
8	Increase (Decrease) to Income Tax Expense			$ 58,805

References:
Column (A) Per Company Filing
Column (B) Testimony JMM
Column (C) = Column (A) + Column (B)

UNS Electric, Inc.
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Schedule JMM-20

OPERATING INCOME ADJUSTMENT NO. 11
INCOME TAX EXPENSE

Line No.	RUCO Income Tax Calculation on RUCO Adjustments (Thousands of Dollars)		
1	Operating Revenues:		
2	Electric Retail Revenues	$	3,090,705
3	Sales for Resale		-
4	Other Operating Revenue		-
5	Total Operting Revenue	$	3,090,705
6			
7	Operating Expenses:		
8	Fuel, Purchased Power and Trans	$	-
9	Other Operations and Maintenance Exp	$	(968,174)
10	Depreciation and Amortization	$	-
11	Taxes Other than Income Taxes	$	-
12	Pre -Tax Operating Expenses	$	(968,174)
13	Pre -Tax Operating Income	$	4,058,879
14	Income Taxes	$	1,526,666
	Combined Effective Tax Rate from Company's C-3		37.6130%

References:
Column (A) Per Company Filing
Column (B) Testimony JMM
Column (C) = Column (A) + Column (B)

UNS Electric, Inc. Schedule JMM-21
Docket No. E-04204A-15-0142
Test Year Ended December 31, 2014

COST OF CAPITAL - ORIGINAL COST RATE BASE
Thousands of Dollars

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED	(B) RUCO ADJUSTMENTS	(C) RUCO AS ADJUSTED	(D) PERCENT	(E) COST RATE	(F) WEIGHTED COST RATE
1	Long-term Debt	169,590	-	169,590	47.17%	4.82%	2.27%
2							
3	Common Equity	189,932	-	189,932	52.83%	10.35%	5.47%
4							
5	TOTAL CAPITAL	$ 359,522	$ -	$ 359,522	100.00%		
6							
7	WEIGHTED COST OF CAPITAL (Sum Lines 1 Thru 5)						7.74%
8							
9							

COST OF CAPITAL - FAIR VAUE RATE BASE

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED	(B) RUCO ADJUSTMENTS	(C) RUCO AS ADJUSTED	(D) PERCENT	(E) COST RATE	(F) WEIGHTED COST RATE
10							
11							
16							
17	Long-term Debt	169,590	$ -	$ 169,590	47.17%	4.66%	2.20%
18							
19	Common Equity	189,932	-	189,932	52.83%	8.35%	4.41%
20							
21	TOTAL CAPITAL	$ 359,522	$ -	$ 359,522	100.00%		
22							
23	WEIGHTED COST OF CAPITAL (Sum Lines 1 Thru 5)						6.61%
24							
25							
26					Fair Value Incement		0.25%

References:
- Column (A): Company Schedule D-1
- Column (B): Testimony, RBM
- Column (C): Column (A) + Column (B)
- Column (D): Column (C), Line Item / Total Capital
- Column (E): Testimony, RBM
- Column (F): Column (D) X Column (E)

ATTACHMENT A

I

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

BOB STUMP - Chairman
GARY PIERCE
BRENDA BURNS
BOB BURNS
SUSAN BITTER SMITH

Arizona Corporation Commission
DOCKETED
FEB 2 2 2013
DOCKETED BY nR

IN THE MATTER OF THE COMMISSION'S GENERIC EVALUATION OF THE REGULATORY IMPACTS FROM THE USE OF NON-TRADITIONAL FINANCING ARRANGEMENTS BY WATER UTILITIES AND THEIR AFFILIATES.

Docket No. W-00000C-06-0149

DECISION NO. 73739

Open Meeting
February 12, 2013
Phoenix, Arizona

BY THE COMMISSION:

FINDINGS OF FACT

1. On June 15, 2012, a draft policy statement ("Policy Statement") regarding the treatment of income tax expense for tax-pass through entities was filed in this docket for the Commission's consideration.

2. Comments were filed by various interested parties. The Commission's Utilities Division Staff ("Staff") docketed a Staff Report on June 27, 2012 providing Staff's analysis and recommendations for Commission consideration.

3. A revised draft policy statement ("Revised Policy Statement") was docketed on February 11, 2013 and is attached as Attachment 1.

4. During the Commission Open Meeting held on February 12, 2013, the Commission considered the Revised Policy Statement, the Staff Report, and the filed and oral comments provided by interested parties. After deliberation, the Commission voted to adopt the Revised Policy Statement.

. . .

CONCLUSIONS OF LAW

1. The Arizona Corporation Commission is a constitutionally created agency with authority to promulgate orders, rules, and regulations regarding the methodology of establishing the rates charged by public service corporations pursuant to Article XV of the Arizona Constitution and A.R.S. Title 40.

2. It is in the public interest to adopt the attached Revised Policy Statement to guide the ratemaking treatment of income taxes for tax pass-through public service corporations.

ORDER

IT IS THEREFORE ORDERED that the revised policy statement regarding the ratemaking treatment of income tax expense for tax pass-through entities is hereby adopted.

IT IS FURTHER ORDERED that this decision shall become effective immediately.

BY ORDER OF THE ARIZONA CORPORATION COMMISSION

CHAIRMAN COMMISSIONER

COMMISSIONER COMMISSIONER COMMISSIONER

IN WITNESS WHEREOF, I, JODI JERICH, Executive Director of the Arizona Corporation Commission, have hereunto, set my hand and caused the official seal of this Commission to be affixed at the Capital, in the City of Phoenix, this 21st day of February 2013.

JODI JERICH
Executive Director

DISSENT: Brenda Burns

DISSENT: ______________

SERVICE LIST FOR: DOCKET NO. W-00000C-06-0149

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ATTACHMENT 1

Policy Statement on Income Tax Expense for Tax Pass-Through Entities

Revised 2/8/13

In several recent rate cases,[1] the Arizona Corporation Commission ("Commission") has been asked to impute income tax expense in the cost of service of so-called tax pass-through entities such as limited liability companies, Subchapter S corporations and partnerships. In each of these proceedings, the applicants presented testimony and evidence to the Commission supporting their request for including income tax expense. On the basis of this testimony and evidence, some commissioners expressed interest in reconsidering the income tax issue. In a Staff Meeting held January 12, 2011, the commissioners directed Utilities Division Staff to examine the merits of allowing income tax expense for tax pass-through entities in the generic docket captioned In the Matter of the Commission's Generic Evaluation of the Regulatory Impacts from the Use of Non-traditional Financing Arrangements by Water Utilities and their Affiliates.[2] A workshop was subsequently publicly noticed by Utilities Division Staff and held on March 25, 2011. Various participants in the generic docket made presentations, which were filed with Docket Control, addressing the arguments for and against including income tax expense in the cost of service of tax pass-through entities.

Because some commissioners were interested in reconsidering the question of imputed income tax expense, in early 2011 the Commission began to include an ordering paragraph in its rate case decisions for tax pass-through entities which recognized the possibility that the Commission might change its practice on the issue, and which specified a process for an affected utility to obtain a prospective increase in its revenue requirement through the filing of a petition under A.R.S. § 40-252 in the event the Commission did change its policy on imputed income tax expense. For example, the Commission included the following language in Decision 72177 (February 11, 2011) from the last Sahuarita Water Company rate case:

> IT IS FURTHER ORDERED that in the event the Commission alters its policy to allow S-corporation and LLC entities to impute a hypothetical income tax expense for ratemaking purposes, Sahuarita Water Company, LLC may file a motion to amend this Order prospectively, and Sahuarita Water Company, LLC's authorized revenue requirement hereunder, pursuant to A.R.S. § 40-252, to reflect the change in Commission policy.[3]

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[1] Sunrise Water Co. (Docket No. W-02069A-08-0406), Farmers Water Co. (Docket No. W-01654A-08-0502), Johnson Utilities, LLC (Docket No. WS-02987A-08-0180), Sahuarita Water Company, LLC (Docket No. W-03718A-09-0359), and Pima Utility Company (Docket Nos. W-02199A-11-0329 and W-02199A-11-0330).

[2] Docket W-00000C-06-0149.

[3] Decision 72177 at 45-46.

There are a number of states which allow income tax expense in the cost of service for tax pass-through entities. For example, in Suburban Utility Corporation v. Public Utility Commission of Texas, 652 S.W.2d 358 (1983), the Supreme Court of Texas held that recognition of income tax expense for tax pass-through entities is necessary:

> "The income taxes required to be paid by shareholders of a Subchapter S corporation on a utility's income are inescapable business outlays and are directly comparable with similar corporate taxes which would have been imposed if the utility operations had been carried on by a corporation. Their elimination from cost of service is no less capricious than the excising of salaries paid to a utility's employees would be. We therefore hold that Suburban [a Subchapter S corporation] is entitled to a reasonable cost of service allowance for federal income taxes actually paid by its shareholders on Suburban's taxable income or for taxes it would be required to pay as a conventional corporation, whichever is less."[4]

Based upon the evidence and testimony which has been presented in the recent rate cases before this Commission as well as the generic docket, we are persuaded that a tax pass-through entity should be allowed to recover income tax expense as a part of its cost of service and that its revenue requirement should be grossed up for the effect of income taxes. We are persuaded that the failure to include income tax expense needlessly discriminates against tax pass-through entities and creates an artificial impediment to investment in utility infrastructure. Neither of these outcomes serves the interests of rate payers. Thus, we hereby adopt a new policy which allows imputed income tax expense in the cost of service for limited liability companies, Subchapter S corporations and partnerships. While sole proprietorships are not technically tax pass-through entities, the arguments supporting the inclusion of income tax expense for tax pass-through entities are equally applicable in the case of sole proprietorships. Thus, the policy will apply to sole proprietorships as well as tax pass-through entities.

This new policy will be applied in pending and future rate cases. Also, companies that have been denied recognition of income tax expense in the past may make a filing under A.R.S. § 40-252 to modify the revenue requirement authorized in their most recent rate case order to include income tax expense prospectively from the date of an order of the Commission approving the A.R.S. § 40-252 filing.

We also desire at this time to provide guidance regarding how income tax expense for tax pass-through entities will be calculated in a fair and balanced way. We agree with the Supreme Court of Texas that the income tax expense for a tax pass-through entity should never be greater than it would be if the utility was a stand-alone C Corporation. Accordingly, tax expense will be determined as follows:

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[4] 652 S.W.2d at 364.

1. Identify all taxable persons or entities and all non-taxable entities[5] (if any) which are owners of the tax pass-through entity. If the tax pass-through entity has an owner which is itself a tax pass-through entity, identify all taxable persons or entities and all non-taxable entities (if any) of such tax pass-through owner. Income tax expense shall be permitted based only upon the effective income tax rates of owners which have actual or potential state and federal income tax liability. The owner or owners of a tax pass-through entity shall not be required to submit personal income tax returns to the Commission, but shall submit documentation showing all owners of the tax pass-through entity, the respective ownership percentages of each owner, and the tax status of each owner (i.e., whether the owner is a taxable entity or a non-taxable entity).

2. Identify the tax filing status (ie. Married filing jointly, married filing single, single, etc.) of the individuals and entities from step 1 above.

3. Compute the actual effective income tax rate for each owner of the tax pass-through entity based upon such owner's proportionate share of taxable income at the proposed revenue level using applicable statutory federal and state income tax rates.

4. Calculate a weighted average effective income tax rate for the combined ownership of the tax pass-through entity.

5. Use the weighted average effective income tax rate for calculating the income tax allowance.

6. Also, calculate the income tax allowance (federal and state) for the tax pass-through entity as though it were a stand-alone Subchapter C corporation.

7. The authorized income tax allowance for the tax pass-through entity shall be the lower of: (i) the income tax allowance using the weighted average effective tax rate for the combined ownership calculated using steps 1 through 5 above; and (ii) the income tax allowance assuming the tax pass-through entity is a stand-alone Subchapter C corporation calculated using step 6 above.

[5] Non-taxable entities are not-for-profit corporations, municipal corporations or other entities which do not have actual or potential state or federal income tax liability.

BRENDA BURNS
COMMISSIONER

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ARIZONA CORPORATION COMMISSION

February 21, 2013

Re: Policy Statement on Income Tax Expense for Tax Pass-Through Entities
Docket No. W-00000C-06-0149

Dissent by Commissioner Brenda Burns

I have not been persuaded that the Commission's constitutional duty to set "just and reasonable" rates should include the recovery of a utility shareholder's personal income taxes. "Just and reasonable" rates allow a utility to recover the expenses of a utility plus an opportunity to make a fair profit on its investment. Asking ratepayers to pay personal income taxes for shareholders of utilities organized as subchapter "S" corporations or limited liability corporations (LLCs) (aka "pass-through entities") is neither justifiable nor good public policy. Personal income taxes are not a utility expense.

It is my obligation to consider the interests of both the utility and ratepayers. I do not feel this decision strikes the right balance. There are many ways to ensure that utilities receive a fair amount of revenue to cover its prudently incurred expenses but requiring ratepayers to pay a shareholder's personal income taxes is not a proper solution. Therefore, I must dissent.

Currently, all C corporations are treated equally and all pass-through entities are treated equally. Utilities voluntarily organize as pass-through entities or C corporations for a variety of reasons. Evidence has been presented that shows many utilities have chosen to be pass-through entities because of the tax advantages, including avoidance of the 'double-taxation' faced by C corporations.

However, C corporations and pass-through entities are not treated on equal footing because they are fundamentally different from each other. Ratepayers do not reimburse a C corporation's shareholders for their personal income taxes. This policy change requires ratepayers to reimburse shareholders of pass-through entities for their personal income taxes even though no tax was paid by the company itself.

Indeed, there are necessary water industry reforms that the Commission should examine. I am concerned with how water companies can ably deal with issues such as increased expenses, arsenic remediation requirements, under-recovery of authorized revenues, aging infrastructure and needs for new wells. However, this Decision may result in higher rates for many ratepayers but it does little or nothing to address those issues and may even harm the debate on these potential water utility reforms.

While I do believe that utilities must be compensated for just and reasonable expenses I do not believe this Decision sets a policy that does so in a fair manner.

Brenda Burns
Brenda Burns
Commissioner

Decision No. 73739

ORIGINAL OPEN MEETING AGENDA ITEM

BEFORE THE ARIZONA CORPORATION COMMISSION

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Arizona Corporation Commission
DOCKETED
FEB 11 2013
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GARY PIERCE
COMMISSIONER
BRENDA BURNS
COMMISSIONER
BOB BURNS
COMMISSIONER
SUSAN BITTER SMITH
COMMISSIONER

IN THE MATTER OF A POLICY STATEMENT ON INCOME TAX EXPENSE FOR TAX PASS THROUGH ENTITIES.

Docket No. W-00000C-06-0149

RUCO'S COMMENTS

The Residential Utility Consumer Office ("RUCO") files these comments in response to the Commission's consideration of a Policy Statement that would change the current policy to allow tax recovery for pass-through entities.

I. INTRODUCTION

RUCO urges the Commission to not change its current policy which excludes the recovery of income taxes to pass-through entities (S Corporations and LLCs). Simply stated, a Commission policy which would allow pass-through entities to recover from ratepayers taxes that these utilities do not pay is bad public policy.

Commissioner Pierce submitted a draft policy statement ("draft policy") to stakeholders on June 15, 2012. The draft policy expressed numerous concerns with the current policy claiming that it "needlessly discriminates against tax pass-through entities and creates an artificial impediment to investment in utility infrastructure. Neither of these outcomes serves the interests of ratepayers." With all due respect each one of these concerns is empty, and changing the current policy would not serve the ratepayer's interests.

Among other things, a change in the current policy will unquestionably raise ratepayer's rates and result in unintended consequences. At a time when the Commission has its hands full dealing with the public perception of its energy efficiency and renewable energy polices, RUCO hopes that the Commission will give serious consideration to the public perception of a new policy that will result in higher rates because ratepayers will be required to pay a utilities taxes that the utility does not pay.

II. THE CURRENT POLICY DOES NOT DISCRIMINATE BECAUSE PASS-THROUGH CORPORATIONS ARE NOT THE SAME AS C CORPORATIONS.

The LLC/S Corporations and the C corporations are two different types of corporate entities for tax purposes and the Commission should not treat them as if they are the same. The LLC and S Corporation do not pay income tax and elect that form of organization to avoid double taxation. The C Corporation does pay income tax and elects that form of organization for other reasons such as avoiding the maximum shareholder requirement of the S corporation. Trying to treat these two different forms of corporate organization the same is as Commissioner Brenda Burns once said "trying to fit a square peg in a round hole".

Ironically, in the draft policy's quest for parity, the result of a policy change will be even more disparity – in both cases the investors would provide capital resulting in utility operating income, but only the C corporation will pay the income taxes on the operating income prior to distributing dividends to its investors who will then pay income taxes on those dividends.

If one were to believe that the current policy "needlessly discriminates"- surely the solution would not be to implement a policy that will "needlessly discriminate" against C corporation shareholders (i.e. C Corp. shareholders do not currently recover their personal income taxes from ratepayers) – two wrongs do not make a right. But more importantly, how is it that the current policy that does not reimburse the S Corporation for income taxes it does not pay by its own election, but does allow recovery to a C corporation for income taxes it does pay discriminate in any way, shape or form? Actually it is the draft policy that would discriminate. Hence, an unintended but very real consequence of the draft policy will be that the C Corporations will request that their shareholder's be reimbursed for the personal income taxes they pay. This will undoubtedly put the Commission in a very tight spot – for how can the Commission then distinguish the two situations?

Another reason why the two are not the same concerns Accumulated Deferred Income Tax ("ADIT"). When a C Corporation comes in for rate relief, there is an ADIT calculation associated with the corporate income tax. ADIT, which typically is booked as a liability, is also a deduction to ratebase. A deduction to ratebase benefits the ratepayers. With S corporations, an ADIT calculation is not necessary since there is no corporate income tax. The Commission's new policy will impute an income tax based on the shareholder's personal income tax which will ignore ADIT[1] as the calculation is made solely for the purpose of ascertaining the shareholder's recovery of personal income tax from ratepayers and not to ascertain corporate income tax liability. Ratepayer's will get the short end of the stick again.

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[1] The ADIT calculation in a newly filed rate case will apply prospectively since a Company will not have collected any income taxes in rates in the past as an S corporation or an LLC. Nonetheless, it still remains a valid concern.

III. THE CURRENT POLICY DOES NOT CREATE AN ARTIFICIAL IMPEDIMENT TO INVEST IN UTILITY INFRASTRUCTURE IN ARIZONA.

The draft policy purports to stimulate growth but there is no evidence that the current policy acts as an impediment to growth. To the contrary, since the 1980s when the Commission established its policy to deny recovery of personal income taxes of shareholders of pass-throughs, there has been an increase in the number of utilities switching to or organizing as pass-throughs. Particularly after the passage of Tax Reform Act of 1986, utilities have chosen to take advantage of the tax benefits afforded by S corporations and LLCs.

Arizona water/wastewater utilities have experienced phenomenal customer growth in the last few decades. The need for additional infrastructure has been a challenge. Additionally, water utilities have had to comply with the federal Safe Drinking Water Act, the Arizona Groundwater Code, and tougher EPA arsenic standards. Arizona's utilities have risen to the challenge and have done so without changing their corporate status. Some utilities, like Pima are built out, so it is difficult to appreciate the argument that allowance of recovery of personal income taxes will incent needed infrastructure when those utilities were able to meet the infrastructure demands when the challenge was the greatest without choosing to change their corporate status.

The Commission's policy will not spur investment in Arizona. The S corporation status allows utilities to avoid double taxation – paying corporate income taxes on revenues and also personal income taxes on the after-tax dividends. It allows start-ups to raise capital and lower their capital needs which even Pima's Senior Vice President and

Chief Financial Officer, Mr. Steven Soriano explained was a benefit in the Pima case.[2] These benefits are the attraction of organizing as an S corporation, not the Commission's policies.

1. THE CONCERN THAT PASS-THROUGHS WILL SWITCH TO C CORPORATIONS AND RATEPAYERS WILL PAY HIGHER TAXES IS ANOTHER EMPTY CONCERN.

Related to the investment argument is the concern that if utility customers do not cover the pass-through shareholders personal tax liability, then the pass-throughs will elect to reorganize as a C corporation. The maximum corporate income tax rate is higher than the maximum individual income tax rate. A C corporation is subject to corporate income tax. The concern is that since the maximum corporate income tax rate is higher than the individual income tax rate, the ratepayers would pay even higher rates if the rates included recovery for corporate income taxes rather the personal income taxes.

A. THE COMMISSION NEED NOT CHANGE ITS POLICY TO ATTRACT INVESTORS.

In the Pima case, former Commissioner Spitzer explained why on the FERC level there was a need to attract investors. Mr. Spitzer noted that the gas pipelines were desperately needed throughout the country, and the investment community had made it clear that they did not want to invest in the C corporations - they wanted to invest in the pass-through corporations. FERC's intent was to encourage investment in desperately needed gas pipelines.

In Arizona, there is a completely different set of circumstances. With many water utilities, such as Pima, the utility is built out so infrastructure investment is not a concern.

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[2] See Direct Testimony of William Rigsby at 6 in Docket No. W-02199A-11-0329.

Second, with FERC the question centered on desperately needed gas pipelines. In Arizona, the concern is water, not gas pipelines, and there is no air of desperation. Finally, there is no evidence that the Commission's current policy has pushed investors to C corporations. In fact, according to Mr. Spitzer, the evidence would indicate otherwise. Mr. Spitzer testified that most new entities are formed as pass-through LLCs. At the time Mr. Spitzer was an Arizona Commissioner, he testified that the ratio was approximately 100 to 1 and has probably gotten larger[3]. When asked if he was aware of any entities organized as a C corporation because of the Commission's policy he testified that he was not aware of any[4].

Mr. Spitzer's testimony is consistent with Staff's witness, Mr. Carlson who also testified that he had no knowledge of utilities converting to C corporations because of the Commission's long standing policy and could not even recall a single entity organized as an S corporation that converted to a C corporation[5]. The concern is unfounded because S Corporations provide the major benefit of avoiding double taxation which remains regardless of the Commission policy. Pima is a prime example of a pass-through utility that has not changed its corporate status since the mid-80s in spite of the Commission's policy because of the tax advantages implicit with its pass-through status.

IV. THE DRAFT POLICY WILL RAISE RATEPAYERS RATES SIGNIFICANTLY.

The effect on ratepayers of the draft policy will be to raise their rates significantly in most cases. At the Commission's Open Meeting held on July 19, 2012, RUCO discussed with the Commission the effect of such a policy. In response to then Commissioner

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[3] See Transcript of Hearing in the Pima case at 186, Docket No. W-02199A-11-0329.

Newman's comments about how such a policy would raise rates, RUCO explained that at that time there were at least three utilities, Johnson, Sahuarita, and Sunrise that were likely waiting to file 252 applications and one utility, Pima, which at that point had a pending rate application seeking pass-through recovery of income taxes[6]. Based on the filings of the four companies, RUCO had determined that a change in policy would have the combined effect on a total of 40,000 customers of over $2,000,000 in increased cost. Moreover, a change in policy will undoubtedly result in requests from other Arizona pass-through Company's for the recovery of income taxes including Saddle brook (4,800 customers), Sunrise, Tonto Creek, and Naco Water and on and on. The draft policy will result in a lot of ratepayers in Arizona seeing their rates increase to allow utilities to recover income taxes those utilities do not even pay.

V. THE DRAFT POLICY IS LIKELY TO HAVE UNINTENDED CONSEQUENCES.

1. INCREASING RATES TO COVER SHAREHOLDERS' PERSONAL INCOME TAX LIABILITY MAY RESULT IN AN UNJUST ENRICHMENT TO SHAREHOLDERS IF NO TAXES ARE ACTUALLY OWED.

As mentioned above, the shareholders of the C Corporation will undoubtedly complain that the new policy discriminates against them. Another unintended consequence concerns the tax imputation. Since shareholders may offset tax liability for income earned with losses from other S corporations or other investments as well as other deductions, credits and exemptions, it is quite possible that monies collected for the shareholders' tax liability will exceed the amount of tax actually owed. For example, a shareholder of a

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[4] See Transcript of Hearing in the Pima case at 186 - 187, Docket No. W-02199A-11-0329.
[5] See Transcript of Hearing in the Pima case at 308, Docket No. W-02199A-11-0329.
[6] Since the Open Meeting Pima's application has been decided and Pima has chosen to wait until the Commission decided its policy before moving forward on this issue – see Decision No. 73573.

profitable S corporation utility who also realized losses from ownership of a real estate development business can apply those losses to offset earnings derived from the utility. Additionally, a shareholder can apply numerous exemptions, deductions and tax credits that are available to the individual taxpayer but not to a corporation. Examples include exemptions for minor children, deductions for health savings accounts, moving expenses, student loan interest, child tax credit, dependent care tax credit, residential energy credits, and retirement savings credit.

The result would be essentially free money for the shareholders paid by the ratepayers who receive no benefit from these payments.

A. IF THE COMMISSION DECIDES TO CHANGE THE POLICY, THE COMMISSION SHOULD IMPUTE TAX RECOVERY BASED ON SHAREHOLDERS ACTUAL INCOME TAX LIABILITY.

There is no manner in which a system could be developed that would guarantee that ratepayers would pay the appropriate amount of income tax. The taxable income for a C corporation is based on the net income from the business. Taxable income for the individual is based on the transfer of income in any number of ways including salaries, interest, dividends, supplemental income, etc. The individual income tax rate will be the same for all of those income sources with no preferential tax treatment for any source in particular. There is no fair way to reconcile the shareholder's personal income tax with a corporate income tax rate that will guarantee that ratepayers will pay an appropriate and fair amount of income tax. As Staff recently acknowledged, about the best we can do is "damage" the ratepayer as little as possible[7].

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[7] See the testimony of Staff's witness, Daryl Carlson in the recent Pima Utilities case. Transcript at 326 – 327.

If the Commission changes the policy, RUCO recommends that the tax imputation be based on the actual taxes paid, and not a theoretical tax amount. The Commission itself argued before the Arizona Court of Appeals in the *Consolidated* case that "The issue of taxes that are actually paid dominates in states which have authorized inclusion of income taxes even for entities that do not directly incur income taxes."[8] The Commission made this argument to show that a theoretical tax allowance would be arbitrary and inappropriate. See attached excerpt of the Commission's Brief in the *Consolidated* case.

RUCO would not recommend that the Commission consider basing the imputation on federal and state statutory income tax rates. In reality, the vast majority of individuals pay an effective tax rate after deductions and adjustments. Their effective tax rate in most cases is always below the statutory rate.

If the Commission approves the draft policy, RUCO would recommend that the Commission adopt Staff's alternative methodology of imputation in Staff's Supplemental Staff Report dated June 27, 2012.

VI. THE CONSTITUTION'S DIRECTIVE TO SET JUST AND REASONABLE RATES PRECLUDES THE INCLUSION OF UTILTIY EXPENSES THAT DO NOT EXIST.

RUCO believes that the Commission is prohibited by the Arizona Constitution from setting rates that include shareholders' personal income tax liability. Neither the S Corporation nor the LLC pays income taxes. Setting rates based on an operating expense that does not exist will not result in just and reasonable rates. The Commission is required to set just and reasonable rates under the Arizona Constitution. Ariz. Const. Art. 15, § 3.

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[8] See Appellee Arizona Corporation Commission's Answering Brief at 29-33, *Consolidated Water Utilities, Ltd. v. Arizona Corp. Com'n*, 178 Ariz. 478, 875 P.2d 137 Ariz.App. Div. 1, 1993, (September 07, 1993), 1 CA-CC 92-0002. The relevant excerpt of the Answering Brief is attached hereto as Attachment 1.

A change in policy will violate Arizona's Constitutional requirement to set just and reasonable rates.

The Arizona Court of Appeals, at the Commission's request has upheld the current policy. *See Consolidated Water Utilities, Ltd. v. Arizona Corp. Com'n*, 178 Ariz. 478, 484, 875 P.2d 137, 143, Ariz.App. Div. 1, 1993 (September 07, 1993). The Arizona Court of Appeals rejected Consolidated's arguments to change the current policy made in the course of several Consolidated cases. *In the Matter of Consolidated Water Utilities*, Docket Nos. E-1009-86-216, E-1009-86-217, E-1009-86-332.) Decision No. 55839 (Docketed January 8, 1988). *In the Matter of Consolidated Water Utilities*, Docket Nos. E-1009-90-115, E-1009-90-116 (decision No. 57666 (docketed December 19, 1991).

It took more than five years, and many battles for the Commission to settle in on the current policy. The Court of Appeals decision made it clear that Arizona is not bound to follow FERC or any state for that matter on the issue. The Court held that the Commission set just and reasonable rates when it excluded recovery of personal tax expense. The Commission, consistent with its prior decisions as well as the Arizona Court of Appeals decision, should not change the current policy.

VII. CONCLUSION

For these and many other reasons, changing the current policy to allow pass-through entities recovery of income tax that these entities do not pay is bad public policy – period.

RESPECTFULLY SUBMITTED this 11th day of February, 2013.

Daniel Pozefsky
Chief Counsel

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Cheryl Fraulob

ATTACHMENT

COURT OF APPEALS

STATE OF ARIZONA

DIVISION ONE

CONSOLIDATED WATER UTILITIES, LTD., a limited partnership, Appellant,	)	1 CA-CC 92-0002
v.	)	CC Case No. E-1009-90-115, E-1009-90-116
ARIZONA CORPORATION COMMISSION, Appellee.	)	

APPELLEE'S ANSWERING BRIEF

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August 24, 1992

imposed what it recognized to be a hypothetical tax based on its understanding that an actual tax was paid, 412 P.2d at 850. The Suburban court notes that Moyston is the only decision of a court of last resort on the issue. After noting that the Public Utility Commission had recently approved the imputation of federal income tax liability for a Subchapter S utility, the Suburban court held "...that Suburban is entitled to a reasonable cost of service allowance for federal income taxes actually paid by its shareholders on Suburban's taxable income or for taxes it would be required to pay as a conventional corporation, whichever is less." 652 S.W.2d at 363, 364 (emphasis added).

The issue of taxes that are actually paid dominates in states which have authorized inclusion of income taxes even for entities that do not directly incur income taxes. While the Suburban case remains valid law in Texas, its effects have been somewhat mitigated. In Southern Union Gas Company v. Railroad Commission of Texas, 701 S.W.2d 277 (Tex.App. 3 Dist. 1985), the Texas Court of Appeals refined the Suburban doctrine somewhat, noting "...the Commission did not abuse its discretion in disallowing "theoretical" income tax liability for rate making purposes." 701 S.W.2d at 279. The Southern Union decision is cited approvingly by the Texas Supreme Court in Public Utility Commission of Texas v. Houston Lighting & Power Company, 748 S.W.2d 439 (Tex. 1987), in which theoretical income tax liability is also disapproved.

The most recent word on the topic of taxes actually paid is found in Kansas and it is particularly apposite in the current situation. In Greeley Gas Co. v. State Corporation Commission, 807

P.2d 167 (Kan.App. 1991), the Kansas Court of Appeals, while noting that Suburban appeared to still be good law in Texas, affirmed the Kansas Corporation Commission's disallowance of income taxes based on the utility's failure to produce the taxpayers income tax returns to demonstrate what income taxes were actually paid, if any, noting that the individual shareholders particular situation could cause the tax rate to vary across the various tax brackets that exist, 807 P.2d at 169, 170. In the current case, the issue of theoretical income taxes is squarely joined. Appellant asserts that their rebuttal evidence before the Commission provided evidence of an actual income tax obligation, Appellant's opening brief at page 39. Appellant also asserts that the witness upon whose testimony the income tax disallowance was based admitted that he would have allowed income taxes had Appellant been a corporation, Appellant's opening brief at page 33, citing TR. 446.

Appellant fails to do at least two things, however. First, appellant fails to provide clear and satisfactory evidence of income tax amounts actually paid. The testimony cited by appellant indicates a calculation of income tax attributable to the operation of the utility. Without evidence of the actual payments made by the partners, no clear and satisfactory showing of unreasonableness of the Commission's order has been made, see Greeley, *supra*. Secondly, in addition to failing to demonstrate the actual amounts paid, appellant has not addressed the theoretical nature of the calculation of income tax it offered. Appellant mentioned the testimony at page 446 of the transcript on the topic of whether the witness would have allowed income taxes if it had been a corporation. Appellant failed to address the

ATTACHMENT B

UniSourceEnergy SERVICES

UNS Electric, Inc.

Original Sheet No.: 204
Superseding:

Large General Service (LGS)

AVAILABILITY
Available throughout the Company's entire electric service area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
To all general power and lighting service on an optional basis when all energy is supplied at one point of delivery and through one metered service.

Not applicable to resale, breakdown, temporary, standby or auxiliary service.

Customers must stay on this rate for a minimum period of one (1) year.

CHARACTER OF SERVICE
The service shall be single-phase or three-phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery.

Primary metering shall be required for new installations with service requirements in excess of 2,500 kW.

RATE
A monthly bill at the following rate plus any adjustments incorporated herein:

BUNDLED STANDARD OFFER SERVICE - SUMMARY OF CUSTOMER AND ENERGY CHARGES

Customer Charge: $50.00 per month

Demand Charge: $12.81 per kW

Energy Charge (per kWh):

	Delivery Services-Energy[1]	Power Supply Charges[2]		Total[3]
		Base Power	PPFAC[2]	
All kWh	$0.005470	$0.056603	Varies	$0.062073

1. Delivery Services-Energy is a bundled charge that includes: Local Delivery, Generation Capacity and Transmission.
2. The Power Supply Charge shall be comprised of the Base Power Charge and the Purchased Power and Fuel Adjustment Clause (PPFAC), a per kWh adjustment in accordance with Rate Rider-1. The PPFAC reflects increases or decreases in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold. Please see Rider-1 for current rate.
3. Total is calculated above for illustrative purposes, and excludes PPFAC, because the PPFAC changes monthly pursuant to Rider-1 PPFAC. While only non-variable components are included in the illustration above, a Customer's actual bill in any given billing month will reflect the applicable PPFAC for that billing month.

BILLING DEMAND
The monthly billing demand shall be the greatest of the following:

1. The maximum 15 minute measured demand in the billing month;
2. 75% of the maximum demand used for billing purposes in the preceding 11 months; or
3. The contract demand amount, not to be less than 20 kW.

DIRECT ACCESS
A Customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this Tariff will be applied to the Customer's bill.

UNS ELECTRIC STATEMENT OF CHARGES
For all additional charges and assessments approved by the Arizona Corporation Commission see the UNS Electric Statement of Charges which is available on UNS Electric's website at www.uesaz.com.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added 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.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this Rate.

ADDITIONAL NOTES
Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

UniSourceEnergy SERVICES

UNS Electric, Inc.

Original Sheet No.: 204-2
Superseding:

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS

Customer Charge Components (Unbundled):

Description	Customer Charge
Meter Services	$ 7.28 per month
Meter Reading	$ 18.59 per month
Billing & Collection	$ 19.59 per month
Customer Delivery	$ 4.54 per month
Total	$50.00 per month

Demand Charges (per kW) (Unbundled):

Component	Rate
Demand Delivery	$ 7.64
Generation Capacity	$ 3.09
Transmission	$ 2.08

Energy Charge Components (per kWh) (Unbundled):

	Rate
Local Delivery	$0.002909
Generation	$0.002394
Transmission	$0.000167

Power Supply Charges (per kWh):

Component	Rate
Base Power Supply	$0.056603
PPFAC (see Rider-1 for current rate)	Varies

UniSourceEnergy SERVICES

Large Power Service Time-of-Use (LPS-TOU)

AVAILABILITY
Available throughout the Company's entire electric service area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
To all general power and lighting service on an optional basis when all energy is supplied at one point of delivery and through one metered service.

Not applicable to resale, breakdown, temporary, standby or auxiliary service.

CHARACTER OF SERVICE
The service shall be three-phase, 60 Hertz, and at the Company's standard transmission or distribution voltages that are available within the vicinity of the Customer's premises.

Primary metering shall be required for new installations with service requirements in excess of 2,500 kW.

RATE
A monthly bill at the following rate plus any adjustments incorporated herein:

BUNDLED STANDARD OFFER SERVICE - SUMMARY OF CUSTOMER AND ENERGY CHARGES

Customer Charge: $1,200.00 per month

Demand Charges:
Demand Charge (<69 kV Service) $22.00 per kW per month
Demand Charge (≥69 kV Service) $17.00 per kW per month

Energy Charges (per kWh):

Summer (May – October)	Delivery Services-Energy[1]	Power Supply Charges[2] Base Power	PPFAC[2]	Total[3]
On-Peak	$0.000462	$0.123580	Varies	$0.124042
Off-Peak	$0.000462	$0.024716	Varies	$0.025178

Winter (November – April)	Delivery Services-Energy[1]	Power Supply Charges[2] Base Power	PPFAC[2]	Total[3]
On-Peak	$0.000462	$0.093880	Varies	$0.094342
Off-Peak	$0.000462	$0.022105	Varies	$0.022567

1. Delivery Services-Energy is a bundled charge that includes: Local Delivery, Generation Capacity and Transmission.

2. The Power Supply Charge shall be comprised of the Base Power Charge and the Purchased Power and Fuel Adjustment Clause (PPFAC), a per kWh adjustment in accordance with Rate Rider-1. The PPFAC reflects increases or decreases in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold. Please see Rider-1 for current rate.
3. Total is calculated above for illustrative purposes, and excludes PPFAC, because the PPFAC changes monthly pursuant to Rider-1 PPFAC. While only non-variable components are included in the illustration above, a Customer's actual bill in any given billing month will reflect the applicable PPFAC for that billing month.

A credit of three percent (3%) will be applied to the demand charge if the Customer receives Distribution Service at primary voltage.

In the event a Customer achieves permanent, verifiable demand reduction through involvement in UNS Electric's Demand-Side Management (DSM) programs, such reductions will be applicable to adjusted demands billed during the eleven (11) month period prior to the installation of the DSM measures.

BILLING DEMAND

The monthly billing demand shall be the higher of:

1. the highest measured fifteen-minute integrated reading of the demand meter during the on-peak hours of the billing period;
2. one-half the highest measured fifteen minute integrated reading of the demand meter during the off-peak hours;
3. the higher of (1) or (2) above during the preceding eleven (11) months; or
4. the contract capacity or 500 kW, whichever is higher.

TIME-OF-USE TIME PERIODS

The Summer On-Peak period is 2:00 p.m. to 8:00 p.m., Monday through Friday (excluding Memorial Day, Independence Day, and Labor Day).

The Winter On-Peak periods are 6:00 a.m. - 12:00 p.m., Monday through Friday (excluding Thanksgiving Day, Christmas Day, and New Year's Day).

All other hours are Off-Peak. If a holiday falls on Saturday, the preceding Friday is designated Off-Peak; if a holiday falls on Sunday, the following Monday is designated Off-Peak.

POWER FACTOR ADJUSTMENT

(Maximum Demand / (.05 + PF)) - Maximum Demand) x Demand Charge Where Maximum Demand is the highest measured fifteen (15) minute demand in kilowatts during the billing period.

POWER FACTOR

1. The Company may require the Customer by written notice to either maintain a specified minimum lagging power factor or the Company may after thirty (30) days install power factor corrective equipment and bill the Customer for the total costs of this equipment and installation.

2. In the case of apparatus and devices having low power factor, now in service, which may hereafter be replaced, and all similar equipment hereafter installed or replaced, served under general commercial schedules, the Company may require the Customer to provide, at the Customer's own expense, power factor corrective equipment to increase the power factor of any such devices to not less than ninety (90) percent.
3. If the Customer installs and owns the capacitors needed to supply his reactive power requirements, then the Customer must equip them with suitable disconnecting switches, so installed that the capacitors will be disconnected from the Company's lines whenever the Customer's load is disconnected from the Company's facilities.
4. Gaseous tube installations totaling more than one thousand (1,000) volt-amperes must be equipped with capacitors of sufficient rating to maintain a minimum of ninety percent (90%) lagging power factor.
5. Company installation and removal of metering equipment to measure power factor will be at the discretion of the Company.

DIRECT ACCESS
A Customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this Tariff will be applied to the Customer's bill.

UNS ELECTRIC STATEMENT OF CHARGES
For all additional charges and assessments approved by the Arizona Corporation Commission see the UNS Electric Statement of Charges which is available on UNS Electric's website at www.uesaz.com.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added 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.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this Rate.

ADDITIONAL NOTES
Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the Customer or pursuant to the Customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

OTHER PROVISIONS
Service hereunder shall remain in full force and in effect until terminated by the Customer unless otherwise provided for in the Service Agreement. Termination of service requires twelve (12) months advance notice in writing to the Company.

Service hereunder may require the Customer to enter into a Service Agreement with the Company for a term of two (2) years or longer, with a minimum contract demand capacity at the Company's option in view of the anticipated demand of the Customer.

UniSourceEnergy SERVICES

UNS Electric, Inc.

Original Sheet No.: 302-3
Superseding:

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS

Customer Charge Components (Unbundled):

Description	Customer Charge
Meter Services	$ 184.69 per month
Meter Reading	$ 364.17 per month
Billing & Collection	$ 498.49 per month
Customer Delivery	$ 152.65 per month
Total	$1,200.00 per month

Demand Charge <69kV (Unbundled):

Component	Rate
Delivery Services- All kW	
Local Delivery	$ 17.50 per kW
Generation Capacity	$ 2.07 per kW
Transmission	$ 2.43 per kW

Demand Charge ≥69kV (Unbundled):

Component	Rate
Delivery Services- All kW	
Local Delivery	$ 12.73 per kW
Generation Capacity	$ 2.07 per kW
Transmission	$ 2.20 per kW

Energy Charge Components (per kWh) (Unbundled):

Summer (May – October)	On-Peak	Off-Peak
Local Delivery	$0.000343	$0.000343
Generation	$0.000100	$0.000100
Transmission	$0.000019	$0.000019

Power Supply Charge (per kWh):

Summer (May – October)	On-Peak	Off-Peak
Base Power Component	$0.123580	$0.024716
PPFAC	In accordance with Rider 1 - PPFAC	

Energy Charge Components (per kWh) (Unbundled):

Winter (November – April)	On-Peak	Off-Peak
Local Delivery Energy	$0.000343	$0.000343
Generation	$0.000100	$0.000100
Transmission	$0.000019	$0.000019

Power Supply Charge (per kWh):

Winter (November – April)	On-Peak	Off-Peak
Base Power Component	$0.093880	$0.022105
PPFAC	In accordance with Rider 1 - PPFAC	

Large General Service Time of Use (LGS TOU)

AVAILABILITY
Available throughout the Company's entire electric service area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
To all general power and lighting service on an optional basis when all energy is supplied at one point of delivery and through one metered service. Not applicable to resale, breakdown, temporary, standby or auxiliary service. Customers must stay on this rate for a minimum period of one (1) year.

CHARACTER OF SERVICE
The service shall be single-phase or three-phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery.

Primary metering shall be required for new installations with service requirements in excess of 2,500 kW.

RATE
A monthly bill at the following rate plus any adjustments incorporated herein:

BUNDLED STANDARD OFFER SERVICE - SUMMARY OF CUSTOMER AND ENERGY CHARGES

Customer Charge: $52.00 per month

Demand Charge: $12.81 per kW

Energy Charges (per kWh):

Summer (May – October)	Delivery Services-Energy[1]	Power Supply Charges[2] Base Power	PPFAC[2]	Total[3]
On-Peak	$0.005470	$0.114886	Varies	$0.120356
Off-Peak	$0.005470	$0.039886	Varies	$0.045356

Winter (November – April)	Delivery Services-Energy[1]	Power Supply Charges[2] Base Power	PPFAC[2]	Total[3]
On-Peak	$0.005470	$0.114886	Varies	$0.120356
Off-Peak	$0.005470	$0.026168	Varies	$0.031638

1. Delivery Services-Energy is a bundled charge that includes: Local Delivery, Generation Capacity and Transmission.
2. The Power Supply Charge shall be comprised of the Base Power Charge and the Purchased Power and Fuel Adjustment Clause (PPFAC), a per kWh adjustment in accordance with Rate Rider-1. The PPFAC reflects increases or decreases in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold. Please see Rider-1 for current rate.
3. Total is calculated above for illustrative purposes, and excludes PPFAC, because the PPFAC changes monthly pursuant to Rider-1 PPFAC. While only non-variable components are included in the illustration above, a Customer's actual bill in any given billing month will reflect the applicable PPFAC for that billing month.

BILLING DEMAND
The monthly billing demand shall be the greatest of the following:

1. The maximum 15 minute measured demand in the billing month;
2. 75% of the maximum demand used for billing purposes in the preceding 11 months; or
3. The contract demand amount, not to be less than 20 kW.

TIME-OF-USE TIME PERIODS
The Summer On-Peak period is 2:00 p.m. to 8:00 p.m., Monday through Friday (excluding Memorial Day, Independence Day, and Labor Day).

The Winter On-Peak periods are 5:00 a.m. - 9:00 a.m. and 5:00 p.m. - 9:00 p.m., Monday through Friday (excluding Thanksgiving Day, Christmas Day, and New Year's Day).

All other hours are Off-Peak. If a holiday falls on Saturday, the preceding Friday is designated Off-Peak; if a holiday falls on Sunday, the following Monday is designated Off-Peak.

DIRECT ACCESS
A Customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this Tariff will be applied to the Customer's bill.

UNS ELECTRIC STATEMENT OF CHARGES
For all additional charges and assessments approved by the Arizona Corporation Commission see the UNS Electric Statement of Charges which is available on UNS Electric's website at www.uesaz.com.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added 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.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this Rate.

ADDITIONAL NOTES
Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

UniSourceEnergy SERVICES

UNS Electric, Inc.

Original Sheet No.: 205-2
Superseding:

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS

Customer Charge Components (Unbundled):

Description	Customer Charge
Meter Services	$ 7.57 per month
Meter Reading	$ 19.33 per month
Billing & Collection	$ 20.38 per month
Customer Delivery	$ 4.72 per month
Total	$ 52.00 per month

Demand Charge (per kW) (Unbundled):

Component	Rate
Demand Delivery	$ 7.64
Generation Capacity	$ 3.09
Transmission	$ 2.08

Energy Charge Components (per kWh) (Unbundled):

	Rate
Local Delivery	$0.002909
Generation	$0.002394
Transmission	$0.000167

Power Supply Charges (per kWh):

Component	Rate
Base Power Supply Summer (May – October) On-Peak	$0.114886
Base Power Supply Summer (May – October) Off-Peak	$0.039886
Base Power Supply Winter (November – April) On-Peak	$0.114886
Base Power Supply Winter (November – April) Off-Peak	$0.026168
PPFAC (see Rider -1 for current rate)	Varies

Large Power Service (LPS)

AVAILABILITY
Available throughout the Company's entire electric service area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
To all general power and lighting service on an optional basis when all energy is supplied at one point of delivery and through one metered service.

Not applicable to resale, breakdown, temporary, standby or auxiliary service.

CHARACTER OF SERVICE
The service shall be three-phase, 60 Hertz, and at the Company's standard transmission or distribution voltages that are available within the vicinity of the Customer's premises.

Primary metering shall be required for new installations with service requirements in excess of 2,500 kW.

RATE
A monthly bill at the following rate plus any adjustments incorporated herein:

BUNDLED STANDARD OFFER SERVICE - SUMMARY OF CUSTOMER AND ENERGY CHARGES

Customer Charge: $1,200.00 per month

Demand Charges:
Demand Charge (<69 kV Service) $22.00 per kW per month
Demand Charge (≥69 kV Service) $17.00 per kW per month

Energy Charge (per kWh):

	Delivery Services-Energy[1]	Power Supply Charges[2]		Total[3]
		Base Power	PPFAC[2]	
All kWh	$0.000462	$0.041880	Varies	$0.042342

1. Delivery Services-Energy is a bundled charge that includes: Local Delivery, Generation Capacity and Transmission.
2. The Power Supply Charge shall be comprised of the Base Power Charge and the Purchased Power and Fuel Adjustment Clause (PPFAC), a per kWh adjustment in accordance with Rate Rider-1. The PPFAC reflects increases or decreases in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold. Please see Rider-1 for current rate.
3. Total is calculated above for illustrative purposes, and excludes PPFAC, because the PPFAC changes monthly pursuant to Rider-1 PPFAC. While only non-variable components are included in the illustration above, a Customer's actual bill in any given billing month will reflect the applicable PPFAC for that billing month.

A credit of three percent (3%) will be applied to the demand charge if the Customer receives Distribution Service at primary voltage.

In the event a Customer achieves permanent, verifiable demand reduction through involvement in UNS Electric's Demand-Side Management (DSM) programs, such reductions will be applicable to adjusted demands billed during the eleven (11) month period prior to the installation of the DSM measures.

BILLING DEMAND

The monthly billing demand shall be the higher of:

1. the highest measured fifteen-minute integrated reading of the demand meter during all hours of the billing period;
2. the highest demand metered during the preceding eleven (11) months; or
3. the contract capacity or 500 kW, whichever is higher.

POWER FACTOR ADJUSTMENT

(Maximum Demand / (.05 + PF)) - Maximum Demand) x Demand Charge Where Maximum Demand is the highest measured fifteen (15) minute demand in kilowatts during the billing period.

POWER FACTOR

1. The Company may require the Customer by written notice to either maintain a specified minimum lagging power factor or the Company may after thirty (30) days install power factor corrective equipment and bill the Customer for the total costs of this equipment and installation.
2. In the case of apparatus and devices having low power factor, now in service, which may hereafter be replaced, and all similar equipment hereafter installed or replaced, served under general commercial schedules, the Company may require the Customer to provide, at the Customer's own expense, power factor corrective equipment to increase the power factor of any such devices to not less than ninety (90) percent.
3. If the Customer installs and owns the capacitors needed to supply his reactive power requirements, then the Customer must equip them with suitable disconnecting switches, so installed that the capacitors will be disconnected from the Company's lines whenever the Customer's load is disconnected from the Company's facilities.
4. Gaseous tube installations totaling more than one thousand (1,000) volt-amperes must be equipped with capacitors of sufficient rating to maintain a minimum of ninety percent (90%) lagging power factor.
5. Company installation and removal of metering equipment to measure power factor will be at the discretion of the Company.

DIRECT ACCESS

A Customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this Tariff will be applied to the Customer's bill.

UNS ELECTRIC STATEMENT OF CHARGES

For all additional charges and assessments approved by the Arizona Corporation Commission see the UNS Electric Statement of Charges which is available on UNS Electric's website at www.uesaz.com.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added 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.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this Rate.

ADDITIONAL NOTES
Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the Customer or pursuant to the Customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

OTHER PROVISIONS
Service hereunder shall remain in full force and in effect until terminated by the Customer unless otherwise provided for in the Service Agreement. Termination of service requires twelve (12) months advance notice in writing to the Company.

Service hereunder may require the Customer to enter into a Service Agreement with the Company for a term of two (2) years or longer, with a minimum contract demand capacity at the Company's option in view of the anticipated demand of the Customer.

UniSourceEnergy SERVICES

UNS Electric, Inc.

Original Sheet No.: 301-3
Superseding:

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS

Customer Charge Components (Unbundled):

Description	Customer Charge
Meter Services	$ 184.69 per month
Meter Reading	$ 364.17 per month
Billing & Collection	$ 498.49 per month
Customer Delivery	$ 152.65 per month
Total	$ 1,200.00 per month

Demand Charge <69kW (Unbundled):

Component	Rate
Delivery Services- All kW	
Local Delivery	$ 17.50
Generation	$ 2.07
Transmission	$ 2.43

Demand Charge ≥69kW (Unbundled):

Component	Rate
Delivery Services- All kW	
Local Delivery	$ 12.73
Generation Capacity	$ 2.07
Transmission	$ 2.20

Energy Charge Components (per kWh) (Unbundled):

	Rate
Local Delivery	$0.000343
Generation	$0.000100
Transmission	$0.000019

Power Supply Charges (per kWh):

Component	Rate
Base Power Supply	$0.041880
PPFAC (see Rider-1 for current rate)	Varies

Filed By:	Kentton C. Grant	Rate:	LPS
Title:	Vice President	Effective:	January 1, 2014
District:	Entire Electric Service Area	Decision No:	74235

ATTACHMENT C

Edison Electric Institute
Schedule of Expenses by NARUC Category
For Core Dues Activities
For the Year Ended December 31, 2005

NARUC Operating Expense Category	% of Dues	Recommended Disallowance
Legislative Advocacy	20.38%	20.38%
Legislative Policy Research	6.02%	
Regulatory Advocacy	16.49%	16.49%
Regulatory Policy Research	13.99%	
Advertising	1.67%	1.67%
Marketing	3.68%	3.68%
Utility Operations and Engineering	11.31%	
Finance, Legal, Planning and Customer Service	18.75%	
Public Relations	7.71%	7.71%
Total Expenses	100.00%	49.93%

Comments:

* The above percentages represent expenses associated with EEI's core dues activities, based on the operating expense categories established by NARUC. Core expenses are those expenses paid for by shareholder-owned electric utilities' dues.

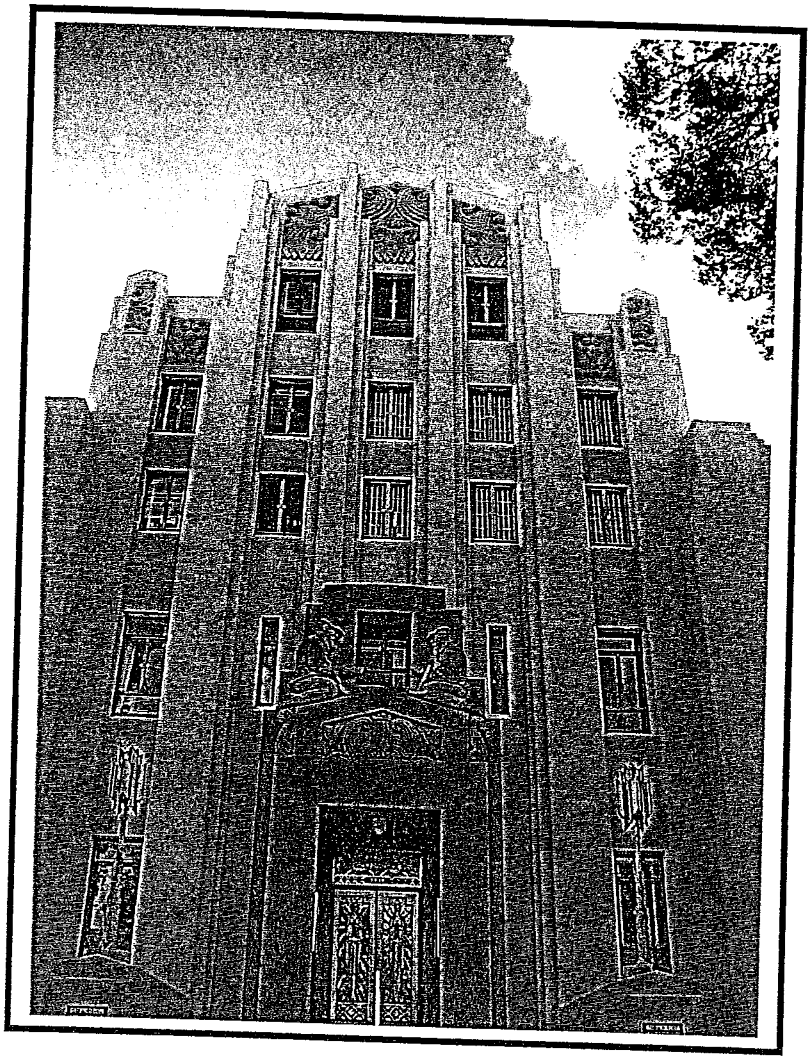
* The legislative advocacy percent will differ slightly for IRS reporting requirements. For 2005, the lobbying % for IRS reporting is 19.4%.

* Administrative expenses are included in the percentages listed above. Approximately 11% of EEI's core dues expenses are administrative.

ATTACHMENT D

FY 2015 BUDGET REVIEW

Arizona Counties



Cochise County, AZ

ARIZONA TAX RESEARCH ASSOCIATION

Jennifer Stielow
Vice President

Table of Contents

INTRODUCTION TO ARIZONA COUNTY BUDGETS

In an effort to emphasize the importance of the transparent use of taxpayer dollars, as well as compliance with budget and tax laws, ATRA staff annually reviews and meets with county officials of each county to discuss their budgets. The following report includes information compiled by ATRA staff during the FY 2015 budget year for Arizona's 15 counties.

This report includes a detailed analysis of the budgeted revenues and expenditures in the general fund and total funds of each county. The analysis reflects the change in primary and secondary net assessed values, primary rates and levies, as well as the change in the secondary tax rates and levies for overrides, debt service, and the levies of special districts and their associated expenditures.

Budgeted revenue projections are broken down by general fund and special revenue funds. A detailed summary of each county's budgeted expenditures is also provided, which includes the budgeted amounts for employee-related expenses, capital expenditures, debt service requirements, and specific information regarding plans to incur future debt, if applicable.

The summaries included in this document were provided to all counties for review and feedback prior to distribution of this publication. ATRA appreciates the cooperation of the counties and welcomes any additional feedback after the publication of this report.

Arizona County Budgets Rebound

County General Fund (GF) budgets rebounded in FY 2015 with an average increase of 4.3% (See Table 1). Despite the counties increased reliance on their cash balances over the past several years as a result of the recession, the cash position of the counties remains good. The healthy cash balances held by the counties coupled with the recent uptick in state-shared and local tax revenues allowed nearly all the counties to provide employee pay raises this year.

General Fund Budgets

County GF budgets are mainly funded with primary property taxes, state-shared and local sales tax revenues, and Auto in Lieu tax revenue. GF budgets provide a multitude of general government services, including public health, law enforcement, and other general government services. The GF budgets of all but three counties increased this year. The counties with the largest increases occurred in Greenlee (8.9%), Maricopa (7.8%), Navajo (6.4%), and Mohave (6.1%).

Table 1. General Fund Budgets

County	FY 2014	FY 2015	$ Change	% Change
Apache	$18,343,856	$18,404,897	$61,041	0.3%
Cochise	$80,459,345	$81,595,849	$1,136,504	1.4%
Coconino	$70,808,913	$72,591,508	$1,782,595	2.5%
Gila	$46,031,855	$44,230,262	($1,801,593)	-3.9%
Graham	$20,935,438	$21,270,214	$334,776	1.6%
Greenlee	$10,619,841	$11,562,861	$943,020	8.9%
La Paz	$16,318,525	$16,838,277	$519,752	3.2%
Maricopa	$942,780,433	$1,015,901,116	$73,120,683	7.8%
Mohave	$76,154,008	$80,781,059	$4,627,051	6.1%
Navajo	$39,984,750	$42,544,494	$2,559,744	6.4%
Pima	$503,524,831	$521,401,927	$17,877,096	3.6%
Pinal	$193,676,201	$184,084,963	($9,591,238)	-5.0%
Santa Cruz	$27,504,449	$28,661,791	$1,157,342	4.2%
Yavapai	$89,679,704	$94,937,304	$5,257,600	5.9%
Yuma	$77,258,446	$75,292,428	($1,966,018)	-2.5%
TOTALS	$2,214,080,595	$2,310,098,950	$96,018,355	4.3%

Counties rely heavily on state shared TPT (sales tax) revenues to support their GF budgets, which represent nearly 70% of the four major revenue sources listed in the table below (Table 2). State shared VLT (Auto in Lieu) account for nearly 19%, followed by local TPT (8%) and PILT revenues (4%).

Table 2. GF Revenues

County	State shared TPT	Local TPT	State Shared VLT* (Auto in Lieu)	PILT	TOTALS
Apache	$4,800,000	$1,200,000	$550,000	$1,109,854	$7,659,854
Cochise	$12,000,000	$7,000,000	$3,500,000	$1,816,386	$24,316,386
Coconino	$19,698,434	$12,697,600	$3,274,036	$1,666,210	$37,336,280
Gila	$4,956,150	$2,600,000	$1,556,944	$3,200,905	$12,313,999
Graham	$4,000,000	$2,000,000	$884,717	$2,778,581	$9,663,298
Greenlee	$4,350,000	$1,200,000	$325,000	$544,675	$6,419,675
La Paz	$2,252,000	$1,412,573	$572,581	$1,928,209	$6,165,363
Maricopa	$465,300,725	N/A	$132,858,100	$12,340,468	$610,499,293
Mohave	$20,519,000	$6,438,200	$6,208,900	$3,412,630	$36,578,730
Navajo**	$11,046,000	$6,816,000	$2,067,000	$1,519,256	$21,448,256
Pima	$106,640,000	N/A	$24,100,000	$2,035,000	$132,775,000
Pinal	$30,273,750	$14,352,000	$9,012,500	$1,215,622	$54,853,872
Santa Cruz	$4,500,000	$2,600,000	$1,400,000	$900,000	$9,400,000
Yavapai	$26,550,000	$15,150,875	$7,275,153	$2,428,943	$51,404,971
Yuma	$19,163,380	$11,794,780	$4,605,707	$3,244,942	$38,808,809
TOTAL	**$736,049,439**	**$85,262,028**	**$198,190,638**	**$40,141,681**	**$1,059,643,786**

*VLT revenues reported under Special Revenue Funds are not included in this table.

**Navajo County did not budget for PILT revenues in FY 2015. The amount reflected in the table is an estimate based on FY 2014 actual revenues.

The total budgets for counties dropped this year by 1.5% (Table 3), which is a smaller reduction relative to last year's 4.1% decrease. In addition to the GF, total funds (TF) include special revenue funds, capital project funds, debt service funds for voter-approved and non-voter approved bonds, and enterprise funds. Included in the special revenue funds are the countywide special taxing districts in which the county boards of supervisors (BOS) sit as the board of directors. The creation of special taxing districts have provided counties with a dedicated funding source separate from the GF to fund a variety of services, such as library services, flood control, public health services, as well as a television district specific only to Mohave County.

Table 3. Total Budgets

County	FY 2014	FY 2015	$ Change	% Change
Apache	$51,171,362	$52,839,970	$1,668,608	3.3%
Cochise	$160,363,511	$151,975,063	($8,388,448)	-5.2%
Coconino	$263,715,576	$235,165,312	($28,550,264)	-10.8%
Gila	$95,252,025	$94,444,905	($807,120)	-0.8%
Graham	$32,891,242	$33,523,198	$631,956	1.9%
Greenlee	$23,572,100	$25,130,309	$1,558,209	6.6%
La Paz	$33,036,650	$32,040,614	($996,036)	-3.0%
Maricopa	$3,065,393,528	$3,060,728,490	($4,665,038)	-0.2%
Mohave	$253,015,076	$252,282,568	($732,508)	-0.3%
Navajo	$118,533,913	$120,792,901	$2,258,988	1.9%
Pima	$1,569,147,951	$1,497,657,953	($71,489,998)	-4.6%
Pinal	$373,723,558	$378,079,096	$4,355,538	1.2%
Santa Cruz	$70,355,234	$74,308,956	$3,953,722	5.6%
Yavapai	$224,231,808	$231,642,537	$7,410,729	3.3%
Yuma	$249,718,511	$242,313,069	($7,405,442)	-3.0%
TOTALS	**$6,584,122,045**	**$6,482,924,941**	**($101,197,104)**	**-1.5%**

Note: Total budgeted amounts represent total financial resources for comparison purposes.

GF Cash Balances

The GF cash on hand reported by Arizona Counties in FY 2015 was $314 million (see Table 4). Total GF cash balances represent an average of 13.6% of total GF budgets, which range from a low of 6.2% in Pima County to a high of 37.6% in Coconino County. Total cash is down $135 million (30%) from last year, mostly as a result of the $116 million reduction in Maricopa County, otherwise the overall reduction would represent just $19 million. Nevertheless, the hefty cash balances that grew during the boom years provided a substantial cushion for the counties to weather the lean years.

The underreporting of cash balances by several counties continues to be a problem. Although state law clearly requires all cash, both restricted and unrestricted, be reported in the county GF balance, Arizona counties underreported their cash by $77 million (15%) based on the most recent financial audits. Although the beginning fund balance is an estimate, the amount budgeted compared to the audited amounts should be fairly close. That is clearly not the case for several counties that failed to report more than 50% of their actual cash balances, such as Apache (underreported by $4.7 million/54%), Greenlee ($5.5 million/59%), La Paz ($2.7 million/100%), and Mohave ($11.2 million/86%). With the exception of La Paz County, the underreporting of cash is the result of a legal interpretation by these counties that they are not required to show cash that they don't plan to spend. The Arizona Auditor General's office has supported ATRA's position that the law requires all cash to be included in the beginning fund balance.

Table 4. General Fund Cash Balances

County	FY 14 GF Budgeted Beg. Cash Balance	Audited (June 30, 2013) Cash Balance*	Diff. between Budgeted & Actual	FY 15 GF Budgeted Beg. Cash Balance	$ Change	% Change	% of FY 2015 GF budget
Apache	$4,000,000	$8,663,279	($4,663,279)	$5,000,000	$1,000,000	25.0%	27.2%
Cochise	$27,892,296	$30,510,247	($2,617,951)	$29,059,354	$1,167,058	4.2%	35.6%
Coconino	$30,237,664	$29,184,907	$1,052,757	$27,259,345	($2,978,319)	-9.8%	37.6%
Gila	$19,848,897	$25,204,358	($5,355,461)	$15,766,569	($4,082,328)	-20.6%	35.6%
Graham	$1,268,293	$2,155,713	($887,420)	$1,926,170	$657,877	51.9%	9.1%
Greenlee*	$3,802,990	$9,344,218	($5,541,228)	$3,532,504	($270,486)	-7.1%	30.6%
La Paz	$0	$2,729,106	($2,729,106)	$1,868,393	$1,868,393	100.0%	11.1%
Maricopa	$230,066,825	$258,686,425	($28,619,600)	$113,712,308	($116,354,517)	-50.6%	11.2%
Mohave*	$1,860,717	$13,026,776	($11,166,059)	$7,695,004	$5,834,287	313.6%	9.5%
Navajo	$4,000,000	$5,870,369	($1,870,369)	$4,300,000	$300,000	7.5%	10.1%
Pima	$44,056,613	$56,684,000	($12,627,387)	$32,474,480	($11,582,133)	-26.3%	6.2%
Pinal	$49,127,286	$47,326,000	$1,801,286	$40,392,961	($8,734,325)	-17.8%	21.9%
Santa Cruz	$10,949,691	$13,458,400	($2,508,709)	$10,336,084	($613,607)	-5.6%	36.1%
Yavapai	$5,268,001	$5,948,186	($680,185)	$6,523,933	$1,255,932	23.8%	6.9%
Yuma	$16,576,861	$17,337,497	($760,636)	$13,777,216	($2,799,645)	-16.9%	18.3%
TOTALS	$448,956,134	$526,129,481	($77,173,347)	$313,624,321	($135,331,813)	-30.1%	13.6%

*Apache and Gila County data is based on FY 2012 data, which is their most recent financial audit

Property Values & Levies

Statewide primary net assessed values (NAV) increased 2.7%; however, the growth was isolated to only a few counties. Greenlee County had the largest percentage growth of nearly 37%, followed by Graham County with 10%, Maricopa with 4.8%, and Pinal County with 0.8% growth. Secondary NAV grew at twice the rate of PNAV, with a 5.2% increase in FY 2015.

Table 5. Net Assessed Values

County	FY 2014 PNAV	FY 2015 PNAV	$ Change	% Change	FY 2014 SNAV	FY 2015 SNAV	$ change	% change
Apache	$ 525,723,278	$ 513,655,622	($12,067,656)	-2.3%	$ 531,638,110	$ 517,650,768	$ (13,987,342)	-2.6%
Cochise	1,006,475,403	955,783,522	($50,691,881)	-5.0%	1,011,138,917	959,542,199	$ (51,596,718)	-5.1%
Coconino	1,519,086,333	1,512,794,264	($6,292,069)	-0.4%	1,533,065,282	1,534,483,938	$ 1,418,656	0.1%
Gila	438,624,843	416,099,715	($22,525,128)	-5.1%	440,187,536	419,257,531	$ (20,930,005)	-4.8%
Graham	192,240,653	211,469,611	$19,228,958	10.0%	194,024,943	213,508,436	$ 19,483,493	10.0%
Greenlee	335,715,128	458,425,787	$122,710,659	36.6%	336,148,250	462,439,380	$ 126,291,130	37.6%
La Paz	216,835,366	205,814,389	($11,020,977)	-5.1%	224,552,041	210,720,562	$ (13,831,479)	-6.2%
Maricopa	31,996,204,979	33,519,795,354	$1,523,590,375	4.8%	32,229,006,810	35,079,646,593	$ 2,850,639,783	8.8%
Mohave	1,771,371,872	1,727,793,369	($43,578,503)	-2.5%	1,809,668,423	1,757,074,571	$ (52,593,852)	-2.9%
Navajo	903,351,854	845,018,236	($58,333,618)	-6.5%	904,776,433	846,247,083	$ (58,529,350)	-6.5%
Pima	7,559,129,097	7,518,481,988	($40,647,109)	-0.5%	7,623,691,280	7,579,898,868	$ (43,792,412)	-0.6%
Pinal	1,988,882,373	2,005,151,766	$16,269,393	0.8%	2,005,343,534	2,040,749,841	$ 35,406,307	1.8%
Santa Cru:	338,356,662	320,999,663	($17,356,999)	-5.1%	339,878,006	323,843,644	$ (16,034,362)	-4.7%
Yavapai	2,232,629,599	2,217,272,811	($15,356,788)	-0.7%	2,279,676,521	2,267,389,484	$ (12,287,037)	-0.5%
Yuma	1,112,115,440	1,112,447,688	$332,248	0.0%	1,131,581,406	1,139,598,176	$ 8,016,770	0.7%
Total	$ 52,136,742,880	$ 53,541,003,785	$1,404,260,905	2.7%	$ 52,594,377,492	$ 55,352,051,074	$ 2,757,673,582	5.2%

The average primary tax rates adopted by Arizona's counties increased over 7 cents, from $2.1046 to $2.1788 (See Table 6). Four counties left their tax rates the same while two reduced their rates. Overall, eight counties adopted tax rates within their truth in taxation (TNT) limits. Under the TNT laws, local governments are required to notify taxpayers of their intent to increase primary property taxes (exclusive of new construction) over the previous year. This year, seven counties exceeded their TNT limits, with the most significant increase in Pima County. Despite the extensive opposition from Pima County taxpayers and businesses, the Pima County BOS adopted a staggering 61-cent primary property tax rate increase. As a result, Pima County has regained the unfavorable distinction of levying the highest tax rate of all the counties with the adoption of its $4.2779 tax rate, which exceeds the average county primary tax rate by $2.0991.

Table 6. Primary Tax Rates

County	FY 2014	FY 2015	$ Change	% Change	Max Tax Rate	TNT	$ over TNT
Apache	$0.4593	$0.4810	$0.0217	4.7%	$0.4810	$0.4716	$0.0094
Cochise	$2.6276	$2.6276	$0.0000	0.0%	$3.3418	$2.8295	-$0.2019
Coconino	$0.5466	$0.5646	$0.0180	3.3%	$0.5646	$0.5535	$0.0111
Gila	$4.1900	$4.1900	$0.0000	0.0%	$6.7275	$4.5318	-$0.3418
Graham	$2.3711	$2.1794	($0.1917)	-8.1%	$2.3127	$2.1794	$0.0000
Greenlee	$0.7350	$0.5500	($0.1850)	-25.2%	$0.5559	$0.5390	$0.0110
La Paz	$1.9608	$2.2863	$0.3255	16.6%	$2.2863	$2.1145	$0.1718
Maricopa	$1.2807	$1.3209	$0.0402	3.1%	$1.8068	$1.2486	$0.0723
Mohave	$1.8196	$1.8196	$0.0000	0.0%	$2.2729	$1.8909	-$0.0713
Navajo	$0.6995	$0.8185	$0.1190	17.0%	$0.8185	$0.7561	$0.0624
Pima	$3.6665	$4.2779	$0.6114	16.7%	$4.9720	$3.7633	$0.5146
Pinal	$3.7999	$3.7999	$0.0000	0.0%	$5.9982	$3.8371	-$0.0372
Santa Cruz	$3.4215	$3.6471	$0.2256	6.6%	$4.1822	$3.6471	$0.0000
Yavapai	$1.9308	$1.9580	$0.0272	1.4%	$2.2599	$1.9732	-$0.0152
Yuma	$2.0606	$2.1608	$0.1002	4.9%	$2.4470	$2.1609	-$0.0001
Avg. Rates	**$2.1046**	**$2.1788**	**$0.0741**	3.5%	**$2.7352**	**$2.1664**	**$0.0123**

Overall, primary levies adopted by the counties increased more than $78 million (8.3%). Six counties that are at or near (within 10%) their constitutional levy limit include Apache, Coconino, Graham, Greenlee, La Paz, and Navajo County (Table 7).

Table 7. Primary Levies

County	FY 2014	FY 2015	$ Change	% Change	Max Levy
Apache	$2,414,647	$2,470,684	$56,037	2.3%	$2,470,684
Cochise	$26,446,148	$25,114,167	($1,331,981)	-5.0%	$31,940,374
Coconino	$8,303,326	$8,541,236	$237,910	2.9%	$8,541,236
Gila	$18,378,381	$17,434,578	($943,803)	-5.1%	$27,993,108
Graham	$4,558,218	$4,608,769	$50,551	1.1%	$4,890,658
Greenlee	$2,478,151	$2,521,341	$43,190	1.7%	$2,548,389
La Paz	$4,251,708	$4,705,534	$453,826	10.7%	$4,705,534
Maricopa	$409,775,397	$442,762,977	$32,987,580	8.1%	$605,635,662
Mohave	$32,231,883	$31,438,928	($792,955)	-2.5%	$39,271,015
Navajo	$6,318,553	$6,916,474	$597,921	9.5%	$6,916,474
Pima	$277,155,468	$321,633,141	$44,477,673	16.0%	$373,818,925
Pinal	$75,575,541	$76,193,762	$618,221	0.8%	$120,273,013
Santa Cruz	$11,576,873	$11,707,247	$130,374	1.1%	$13,424,848
Yavapai*	$43,108,560	$43,415,263	$306,703	0.7%	$50,108,148
Yuma	$22,916,250	$24,037,770	$1,121,520	4.9%	$27,221,595
TOTALS	$945,489,104	$1,023,501,871	$78,012,767	8.3%	$1,319,759,663

*The primary property tax levy for Yavapai County includes an additional levy of $306,703 for the Transwestern judgment.

Charges to Special Districts

Most of the 15 counties charge their special revenue funds, particularly their countywide special taxing districts, for the reimbursement of county services. The methodology used to determine the amount to charge the Districts vary between counties but should be representative of real costs associated with those Districts.

In addition, the state budget has included a provision over the last several years that has allowed the counties with population under 200,000 to transfer revenues from any special revenue source including countywide special taxing districts to their general funds to meet any financial obligation. Effective for FY 2014, the counties were required for the first time to report those transfers to the Joint Legislative Budget Committee. Of the ten counties that qualify for the transfers, only three reported using the flexibility language to transfer a total of $1.3 million from their special revenue funds to their GF. Apache County transferred $500,000 from three of its special taxing districts, Navajo $580,300 from the Public Health Services District, and Yuma transferred $28,868 from a few of its special taxing districts to their GF. The remaining qualifying counties that did not use the flexibility language included Cochise, Coconino, Gila, Graham, Greenlee, La Paz, and Santa Cruz Counties[1].

County Employee Compensation

In recent years, most counties opted to award employees with one-time distributions due to the uncertain economic times. However, now that county GF revenues are on the rise again, almost all of the counties made the decision to award employee pay raises. Many of the counties that previously awarded only one-time distributions moved to permanent pay raises this year, which included raises for cost-of-living (COLA), pay-for-performance (PFP), and market adjustments. Many counties have either conducted or are in the process of conducting a classification and compensation study conducted to make a determination on current and future employee pay increases (Table 8).

Table 8. Employee Compensation

County	FY 2014 Budget	Estimated Total Impact	FY 2015 Budget	Estimated Total Impact
Apache	5% COLA	$420,000	2%/3% COLA	$200,000
Cochise	one-time distribution	$1,482,000	One-time distribution + Market adjustments	$1.08 million
Coconino	1.5% market + 2.5% merit on anniversary	$2.75 million	2.5% Merit + $400k for compression adj.	$1.7 M (TF)
Gila	classification & compensation study	$2 million slated	Avg. 6.2% increase	$1.34 M (GF)
Graham	longevity raises	$53,000	longevity + 4% avg. market adj.	$346k (GF), $561k (TF)
Greenlee	3.5% increase + 1.5% add'l for sheriffs	$550,000	3% across the board	$160K (GF), $251K (TF)
La Paz	N/A	N/A	3% COLA	$250k (GF), $500k (TF)
Maricopa	PFP 5% avg. + equity adjs.	$67 million	2.5% PFP, Market adj., Ed Asst Program	$16.6 M (GF), $27.5 M (TF)
Mohave	2.5% COLA	$1.7 million	Conditional reclassifications	$180,100 (TF)
Navajo	2% adj.	$300,000	2% COLA, cond.2% one-time payment, Sheriff's mkt adj.	$784k (GF), $1.2 M (TF)
Pima	1% COLA + 2% + one-time adj	$12 million	$0.50 increase to all employees	$5.3 M (GF), $7.8M (TF)
Pinal	2.5% Merit	$2.4 million (annualized)	2.5% (conditional distribution in 4th QTR)	$2.2M (GF), $2.8 M (TF)
Santa Cruz	one-time distribution	$204,750	5% across the board	$359k (GF), $785k (TF)
Yavapai	Not budgeted	N/A	1% COLA, 0-3% adj.	$1.3 M (GF), $2.6 M (TF)
Yuma	Step increases	$1.69 million	Reclassifications	$27,114 (GF), $55,570 (TF)

*See county summaries for details on budgeted employee compensation.

Total GF salaries, including employee related expenses (EREs), increased 5.5% to approximately $1.3 billion in FY 2015. This year's increase was mainly driven by the 6.5% growth in EREs, which accounts for 30% of total employee compensation. EREs include the costs associated with retirement, health care, FICA, and Medicare. Employee salaries, which represent the majority of total compensation, grew 5.5%. The counties with the largest percentage increases in salaries were Greenlee (9.4%), Maricopa (8.5%), Navajo (7.4%), Coconino (5.1%), and Apache (5%). Employee compensation as a percentage of county GF budgets averaged approximately 55% in FY 2015, ranging from a low of 41% in Santa Cruz County to a high of nearly 63% in Yavapai County.

[1] JLBC Monthly Fiscal Highlights, November 2013.

Table 9. General Fund

County	FTE'S		Salaries		Employee Related Exp.		Total Comp		% Chg.	% of GF
	FY 2014	FY 2015	FY 2014	FY 2015	FY 2014	FY 2015	FY 2014	FY 2015		
Apache	154	165	$6,531,918	$6,858,429	$3,354,376	$3,175,628	$9,886,294	$10,034,057	1.5%	54.5%
Cochise	614	617	$28,146,530	$28,465,516	$11,174,045	$11,221,023	$39,320,575	$39,686,539	0.9%	48.6%
Coconino	487	497	$25,447,329	$26,738,366	$10,479,121	$10,999,580	$35,926,450	$37,737,946	5.0%	52.0%
Gila	413	404	$16,771,930	$16,335,391	$7,102,563	$7,014,193	$23,874,493	$23,349,584	-2.2%	52.8%
Graham	190	187	$8,494,295	$8,485,783	$2,726,287	$2,735,533	$11,220,582	$11,221,316	0.0%	52.8%
Greenlee	92	101	$4,286,247	$4,687,149	$1,820,229	$2,074,735	$6,106,476	$6,761,884	10.7%	58.5%
La Paz	131	130	$6,159,930	6,159,930	$2,660,706	2,667,535	$8,820,636	8,827,465	0.1%	52.4%
Maricopa*	7,339	7,620	$392,811,367	$426,022,150	$143,907,311	$159,184,541	$477,099,455	$519,517,084	8.9%	51.1%
Mohave	711	717	$32,140,407	$32,308,397	$14,051,947	$14,119,349	$46,192,354	$46,427,746	0.5%	57.5%
Navajo	376	394	$16,507,161	$17,722,468	$7,019,621	$7,733,837	$23,526,782	$25,456,305	8.2%	59.8%
Pima	4,739	4,755	$207,371,588	$217,362,979	$88,473,823	$92,192,216	$295,845,411	$309,555,195	4.6%	59.4%
Pinal	1,544	1,572	$81,358,979	$82,685,522	$29,671,584	$30,515,661	$111,030,563	$113,201,183	2.0%	61.5%
Santa Cruz	180	183	$8,161,289	$8,216,867	$3,534,033	$3,600,181	$11,695,322	$11,817,048	1.0%	41.2%
Yavapai	850	874	$40,565,156	$42,350,296	$16,097,460	$17,120,936	$56,662,616	$59,471,232	5.0%	62.6%
Yuma	666	659	$31,177,515	$30,910,513	$12,761,417	$13,665,260	$43,938,932	$44,575,773	1.4%	59.2%
TOTALS	18,486	18,875	$905,931,641	$955,309,756	$354,834,523	$378,020,208	$1,201,146,941	$1,267,640,357	5.5%	54.9%

*Total compensation in the Maricopa County FY 2014 GF budget nets out $59,619,223 in Personnel Allocation costs and $65,689,607 in FY 2015.

In FY 2015, full-time equivalents (FTEs) included in the county GF budgets represent 57% of total budgeted FTEs and varies between the fifteen counties (Table 9). The difference between counties can be due to the level of reliance on special taxing districts. For example, a low percentage of FTEs in the GF may be reflective of a county that has greater reliance on special taxing districts compared to a county that funds the same services from its GF without creating an additional taxing source. The percentage of GF budgeted FTEs as a percentage of total FTEs ranges from a low of 41% in Apache County, which relies the most on special taxing districts, to a high of 74% in Pinal County, which relies less on special taxing districts.

Total employee compensation, including EREs, in all funds increased 5.7% to over $2.2 billion in FY 2015 as a result of a 5.2% increase in EREs and a 5.9% increase in salaries. Total budgeted FTEs in FY 2015 are up 1.2% and amounted to 33,261 (Table 10).

Table 10. Total Funds

County	FTE'S		Salaries		Employee Related Exp.		Total Comp		% Chg.	% of TF
	FY 2014	FY 2015	FY 2014	FY 2015	FY 2014	FY 2015	FY 2014	FY 2015		
Apache	390	404	$14,413,425	$14,873,372	$7,155,563	$6,728,728	$21,568,988	$21,602,100	0.2%	40.9%
Cochise	908	898	$39,677,358	$40,246,293	$15,555,590	$15,651,738	$55,232,948	$55,898,031	1.2%	36.8%
Coconino	1,056	1,062	$50,638,768	$53,441,204	$21,146,941	$21,566,075	$71,785,709	$75,007,279	4.5%	31.9%
Gila	660	652	$25,882,666	$25,412,964	$10,908,052	$10,890,871	$36,790,718	$36,303,835	-1.3%	38.4%
Graham	264	260	$11,852,238	$11,617,613	$3,607,957	$3,767,184	$15,460,195	$15,384,796	-0.5%	45.9%
Greenlee	160	168	$6,525,373	$6,939,938	$2,855,093	$3,120,812	$9,380,466	$10,060,750	7.3%	40.0%
La Paz	278	289	$11,371,360	11,953,745	$5,130,317	5,344,543	$16,501,677	17,298,288	4.8%	54.0%
Maricopa	14,423	14,812	$711,507,690	$774,095,998	$268,841,994	$290,877,185	$980,349,684	$1,064,973,183	8.6%	34.8%
Mohave	1,272	1,275	$55,863,245	$55,347,435	$24,245,262	$24,163,337	$80,108,507	$79,510,772	-0.7%	31.5%
Navajo	679	692	$28,256,868	$29,320,344	$11,339,115	$12,639,255	$39,595,983	$41,959,599	6.0%	34.7%
Pima	7,328	7,255	$311,458,136	$330,630,578	$132,676,288	$134,022,351	$444,134,424	$464,652,929	4.6%	31.0%
Pinal	2,123	2,118	$108,398,857	$109,994,918	$38,321,770	$39,821,972	$146,720,627	$149,816,890	2.1%	39.6%
Santa Cruz	386	378	$16,553,523	$16,366,043	$7,033,273	$6,987,181	$23,586,796	$23,353,224	-1.0%	31.4%
Yavapai	1,504	1,555	$69,275,429	$72,779,035	$26,928,645	$28,844,580	$96,204,074	$101,623,615	5.6%	43.9%
Yuma	1,445	1,443	$64,910,376	$63,769,342	$26,429,124	$28,113,302	$91,339,500	$91,882,644	0.6%	37.9%
TOTALS	32,876	33,261	$1,526,585,312	$1,616,788,822	$601,492,196	$632,539,114	$2,128,077,508	$2,249,327,936	5.7%	34.7%

APACHE COUNTY

Overview

- Apache's GF budget for FY 2015 is $18,404,897. This represents an increase of $61,041 over last year's budget of $18,343,856.
- The County's GF balance is $5 million (27% of the GF budget). This amount is underreported by $3 million. The FY 2015 county budget presentation to the BOS shows the actual opening fund balance is nearly $8 million (43% of the GF budget), which County officials confirm is accurate.
- The total budget for FY 2015 is $52,839,970, which represents an increase of $1,668,608 (3.3%) over last year's budget of $51,171,362.

Property Values

- The primary NAV decreased 2.3% to $513,655,622. New construction amounted to $1,605,610 (0.31% of total NAV). The secondary NAV is down 2.6% to $517,650,768.

Property Tax Revenues

Primary Levy

- Apache County adopted its maximum tax rate of $0.4810. Since the adopted rate exceeded the TNT rate of $0.4716, the County was required to publish notice and hold a public hearing regarding the tax increase.
- The primary levy increased $56,037 (2.3%), from $2,414,647 to $2,470,684.

Flood Control District

- The District's NAV decreased $12,263,464 (5.5%), from $223,646,043 to $211,382,579.
- In FY 2014, there was enough in reserves to operate the District that the BOS did not need to levy a tax. In FY 2015 however, the County levied a tax rate of $0.0442, which resulted in a levy of $98,852.
- The FY 2015 District budget is down $182,708 (48%), from $382,000 to $199,292.
- The FY 2015 beginning fund balance in the District is approximately $200,000.

Library District

Operations

- The secondary tax rate for operations in the Library District is up $0.0714, from $0.2160 to $0.2874. As a result, the levy increased $339,390 (29.6%), from $1,148,338 to $1,487,728.
- The District's operating budget of $1,617,563 is $5,437 below last year's budget. The balance in the fund was approximately $785,000 in FY 2014, which dropped to nearly $150,000 in FY 2015.

GO Bonds

- At the November 2006 General Election, voters approved $7.19 million in General Obligation (GO) bonds to construct new libraries.
- The tax rate levied for bonds increased from $0.0813 to $0.0989. As a result, the levy increased $79,735 (18.4%), from $432,222 to $511,957.
- The FY 2015 debt service payment for the bonds is $915,000; however, the actual required payment is only $715,000. The fund balance in the District's GO debt fund was $500,000 in FY 2014. The FY 2015 beginning fund balance is $157,000.

Jail District

- The tax rate levied for the Jail District of $0.2000 is the maximum rate per statute. The FY 2015 levy is $1,035,302, a decrease of $27,974 (2.6%) below the FY 2014 levy.
- Apache County budgeted $686,350 in Federal inmate housing in FY 2015, $63,350 (8.5%) less than last year's budget (FY 2014 actual revenues were only $85,995). The County lost most of its Federal inmates and now currently has contracts with the Apache Reservation, Graham County, and is working on a contract

with the Navajo Nation. The adult facility can hold up to 178 beds. The jail was nearly 80% occupied on average in FY 2014 and is average occupancy is currently down to approximately 40%.

- The amount of budgeted FTEs in the District did not change as a result of the loss in Federal inmates. There are currently 39 FTEs in the District.
- The Jail District's budget decreased $812,115 (22.6%), from $3,591,333 to $2,779,218 (FY 2014 actual estimated expenditures amounted to $2,416,888).
- The maintenance of effort (MOE)[2] payment is $450,516 in FY 2015.
- In FY 2014, the budgeted medical expenses in the jail were flat at approximately $110,000 and dropped slightly to $105,000 in FY 2015. The District uses a contractor in Maricopa County to facilitate psychological medical care to inmates.
- The District's beginning fund balance in FY 2014 was $362,000 and dropped to approximately $200,000 in FY 2015.

Juvenile Jail District

- The Juvenile Jail District tax rate decreased from $0.0930 to $0.0916. The levy decreased $20,255 (4.1%), from $494,423 to $474,168.
- The juvenile facility holds 13 beds and the average occupancy is approximately 30%. The County does not rent beds to other entities but that option is currently being considered.
- The District budget decreased $50,695 (6%), from $844,343 to $793,648.
- The MOE payment is $316,033 in FY 2015.

Community College/Post Secondary Education

- Community College: Since there is no community college district in Apache County, the County levies a property tax to pay the cost of tuition for residents that attend other colleges. The tax rate levied for junior college tuition is down $0.0165, from $0.2982 to $0.2817. As a result, the levy decreased $127,123 (8%), from $1,585,345 to $1,458,222.
- The State General Fund budget partially offsets the costs incurred by Apache County. In FY 2015, tuition assistance from the state increased $233,300 (50%), from $466,000 to $699,300.
- The budget stayed the same at $2,600,650.
- Post Secondary Education: The tax rate levied for post secondary education to operate a local branch of Northland Pioneer College is staying the same at $0.1000. As a result, the levy decreased $13,987 (3%), from $531,638 to $517,651. The budget remains the same at $630,000.

Public Health Services District

- The District was created by a unanimous vote of the Board in April 2007 and FY 2008 was the first year the County levied a property tax for the District.
- The tax rate levied in FY 2015 decreased slightly from $0.1274 to $0.1260. This year's tax rate generated a levy of $652,240, $25,067 (3.7%) less than last year.
- The budget increased $107,436 (24%), from $447,058 to $554,494 (operations budget only).
- The MOE payment from the GF to the District is $105,688.
- The District's fund balance in FY 2014 was $398,000. The FY 2015 beginning fund balance is approximately $424,000.

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[2] A County that creates a Jail District and/or a Juvenile Jail District is required to maintain the same level of support of corrections facilities and programs by making a Maintenance of Effort (MOE) payment each year from the county GF to the District. The Auditor General determines the payment by using the amount expended by the County in the preceding fiscal year in which the District was initially created and adjusting that amount by the lesser of the annual change in the county primary property tax levy limit or the change in the GDP price deflator.

APACHE COUNTY	FY 2014 RATE	FY 2015 RATE	CHANGE	TNT	FY 2014 LEVY	FY 2015 LEVY	CHANGE	% CHANGE
Primary	0.4593	0.4810	0.0217	0.4716	$2,414,647	$2,470,684	$56,037	2%
Flood Control	0.0000	0.0442	0.0442		$0	$98,852	$98,852	100%
Library*	0.2973	0.3863	0.0890		$1,580,560	$1,999,685	$419,125	27%
Jail District	0.2000	0.2000	0.0000		$1,063,276	$1,035,302	-$27,974	-3%
Juvenile Jail	0.0930	0.0916	-0.0014		$494,423	$474,168	-$20,255	-4%
JR College	0.2982	0.2817	-0.0165		$1,585,345	$1,458,222	-$127,123	-8%
Post S.Ed	0.1000	0.1000	0.0000		$531,638	$517,651	-$13,987	-3%
Public Health Services	0.1274	0.1260	-0.0014		$677,307	$652,240	-$25,067	-4%
OVERALL RATE	1.5752	1.7108	0.1356		$8,347,196	$8,706,804	$359,608	4%

*Apache's Library District rate and levy is for operations and voter-approved GO bonds.

Other GF Revenues

- VLT is up $30,000 (5.8%), from $520,000 to $550,000.
- State shared sales tax revenues are up $200,000 (4.3%), from $4,600,000 to $4,800,000.
- The budgeted half-cent sales tax remains level at $1,200,000.
- PILT decreased $442,091 (28.5%), from $1,551,945 to $1,109,854.
- In FY 2015, the County received $550,038 in lottery revenue from the state.

Special Revenues

Road Fund

- HURF revenue is up $550,000 (10.6%), from $5,200,000 to $5,750,000.
- VLT revenue is down $100,000 (4.8%) to $2,000,000.
- In FY 2014, the fund balance in the Road Fund was approximately $1.4 million and increased to $2.5 million in FY 2015.
- The budget increased $1,600,251 (19.1%), from $8,381,782 to $9,982,033.

Charges to Special Districts - This section shows the charges for reimbursement of indirect services and/or per parcel charges to its special taxing districts and other special revenue funds.

- The amount transferred from the special taxing districts to the GF in FY 2014 amounted to $2,256,829 and $2,257,459 in FY 2015 (includes additional transfers of $500,000 in each fiscal year as authorized by the state budget provision to offset state cost shifts):
  - Flood Control District – FY 2014 = $112,361; FY 2015=$127,418
  - Library District – FY 2014 = $251,293; FY 2015 = $390,492
  - Jail District – FY 2014 = $400,000; FY 2015 = 0
  - Juvenile Jail District – FY 2014 = $213,496; FY 2015 = $218,477
  - Public Health Services District – FY 2014 = $351,997; FY 2015 = $566,229
  - Road Fund – FY 2014 = $927,682; FY 2015 = $954,843

Expenditures

- Employee compensation: In FY 2014, the County awarded employee's with a 5% COLA, effective the first pay period in July. The estimated total cost was $420,000 [$280,000 to the GF/$140,000 to other funds (OF)]. The FY 2015 budget includes a 3% COLA for employees making less than $50,000 and 2% for all other employees, amounting to a total impact of approximately $200,000.
- Budgeted payroll: In FY 2014, GF budgeted payroll, including EREs, were budgeted at $9,886,294. The payroll in TF was budgeted at $21,289,355. In FY 2015, the GF budgeted payroll increased to $10,034,057 and total budgeted payroll increased to $21,602,101.
- Health benefits: The County covers 98% of the health premium costs for employees and 76% (on average) for dependents. In FY 2014, health insurance costs increased 5% and was passed on to employees at a cost of $120/employee. There was a minimal increase in health insurance costs in FY 2015.
- Budgeted FTEs: In FY 2015, FTEs in the GF increased from 154 to 165. The FTEs in TF increased from 390 to 404.
- Employee vacancy & turnover rates: The employee turnover rate was 19% in 2013. The current employee vacancy rate is unknown.

Capital Projects/Debt

According to the Arizona Department of Revenue's FY 2014 Report of Bonded Indebtedness, the Library District had $4,245,000 in outstanding GO debt. As noted previously under the Library District summary, the FY 2015 debt service payment is $915,000. In addition, the County has a loan from the Greater Arizona Development Authority (GADA), which has an outstanding balance of $3,580,000. Currently, the County is paying interest-only on the GADA loan but is building up reserves in order to pay off the loan in FY 2017.

COCHISE COUNTY

Overview

- Cochise County's GF budget for FY 2015 is $81,595,849, a $1,136,500 (1.4%) increase above the FY 2014 budget of $80,459,345.
- The County has a beginning fund balance of $29,059,354, an increase of $1,167,058 (4.2%) above last year. The beginning fund balance represents 35.6% of the total GF budget.
- The total budget is $151,975,063, which is a decrease of $8,388,448 (5.2%) below last year's adopted budget of $160,363,511.

Property Values

- The primary NAV dropped 5.6% to $955,783,522. New construction amounted to $21,122,320 (2.21% of total NAV). The secondary NAV is down 5.1% to $959,542,199.

Property Tax Revenues

Primary Levy

- The primary tax rate remains the same at $2.6276 in FY 2015. Since the tax rate is lower than the TNT rate of $2.8295, the County was not required to hold a TNT hearing.
- The primary property tax levy dropped $1,331,981 (5%) to $25,114,167.

Flood Control District

- The District's NAV decreased $46,561,018 (5.4%), from $855,854,956 to $809,293,938.
- The secondary tax rate for the District remains the same at $0.2597. The levy decreased from $2,222,655 to $2,101,736, $120,919 (5%) less than last year.
- Budgeted expenditures for the District are $5,924,340, a decrease of $1,290,335 (17.9%). The estimated actual expenditures reported for last year amounted to $3,119,622, 43% of budgeted expenditures.
- In FY 2014, the beginning fund balance was $5,306,375. In FY 2015, the district's beginning fund balance is $4.1 million, which is estimated to drop to $2 million by the end of the fiscal year. Reserves have been built up to fund a variety of projects, which will be steadily drawn down over the next few years.

County Library

- The Library District levy is $1,392,296, $74,867 (5%) less than last year's levy. The rate remains the same at $0.1451.
- The District budget dropped $206,160 (9%), from $2,294,664 to $2,088,504. The County operates five branches and a bookmobile. The District also operates the information system that is used by the city libraries.
- The beginning fund balance in FY 2014 was $883,085 and increased slightly to $894,000 in FY 2015. The reserves in the District will be used to purchase a new library cataloging system in the future at an estiamted cost of $500,000.

COCHISE COUNTY	FY 2014 RATE	FY 2015 RATE	CHANGE	TNT	FY 2014 LEVY	FY 2015 LEVY	CHANGE	% CHANGE
Primary	2.6276	2.6276	0.0000	2.8295	$26,446,148	$25,114,167	-$1,331,981	-5%
Flood Control	0.2597	0.2597	0.0000		$2,222,655	$2,101,736	-$120,919	-5%
Library	0.1451	0.1451	0.0000		$1,467,163	$1,392,296	-$74,867	-5%
OVERALL RATE	3.0324	3.0324	0.0000		$30,135,966	$28,608,199	-$1,527,767	-5%

Other GF Revenues

- Budgeted Auto in Lieu revenues remain the same at $3,500,000.
- State shared sales tax is up $600,000 (5.3%), from $11,400,000 to $12,000,000.
- The County's half-cent sales tax in FY 2015 is budgeted at $7,000,000.
- PILT is budgeted to remain the same in FY 2015 at $1,816,386.
- The County budget includes $550,000 in State lottery fund revenues.

Special Revenues

HURF

- HURF revenues are up $792,279 (9.8%), from $8,100,000 to $8,892,279 (estimated actual revenues for FY 2014 are reported at $8,542,279).
- The HURF budget increased slightly to $15,134,349.

Charges to Special Districts

- Library District - In FY 2014, the County charged the District a $1.44 per parcel fee for the printing and mailing of tax bills, which amounted to a total charge of $181,872. The per parcel fee for FY 2015 is $181,900. The County also charged the District $256,431 for overhead costs.
- Flood Control District - In FY 2014, the $1.44 per parcel fee amounted to a total charge of $181,872 to the District. In FY 2015, the per parcel fee amounted to $181,900. An additional $64,197 was charged for overhead costs.
- Other taxing districts - In FY 2014, the County charged all of the other special taxing districts a total of $53,388 for indirect costs. The County charged the districts $53,328 in FY 2015.

Expenditures

- Employee compensation: In December 2013, the County provided employees with a one-time distribution that amounted to a total cost of $1.482 million ($1,000,000 impact to the GF). The distributions were based on employee performance and made in two separate payments in Decembers 2013 and May 2014. In addition, during FY 2014, the County provided market adjustments to Detention Officers due to high turnover. The County conducted an in-house study to determine the market adjustments, which was estimated to cost approximately $270,000 on an annual basis.
- For FY 2015, the County will be providing employees with one-time distributions once again at a maximum total cost of $880,000 ($600,000 to the GF and an estimated cost of $280,000 to OF). The distributions will be based on performance and are estimated to go into effect mid-fiscal year. The County also set aside an additional $200,000 in the GF for market adjustments that may be needed throughout the year and to assist in filling high turnover positions.
- Budgeted payroll: In FY 2015, the GF budgeted payroll, including EREs, increased from $39,320,575 to $39,686,539. Total budgeted payroll increased from $55,232,948 to $55,898,031.
- Health benefits: The 2.8% increase in health premium costs in FY 2013 was absorbed by the County. The impact to the GF was $103,826 and the impact to other funds was $57,703. The County subsidizes 100% of the employee's premiums and 44.5% of dependents (tiered system). There was no change in health care costs in FY 2014 and FY 2015.
- Budgeted FTEs: In FY 2015, the GF budgeted FTEs increased by 3 to 617 and TF FTEs dropped 10 to 898.
- Employee turnover & vacancy rates: In FY 2014, the employee vacancy rate was approximately 11% for all funds. The employee turnover rate was 22.4%.
- **Jail Facilities:**
  - **Juvenile**: The County has one juvenile facility with 20 detention cells that are double-bunked for a total of 40 beds. The average occupancy is estimated at 13. The County does not rent beds to other entities.
  - **Adult**: The adult facility is designed to hold 160 beds but actually accommodates 260 beds with double bunking, with an occupancy rate of approximately 77%. The County rents beds annually to the military, Customs, and Federal prisoners at a daily rate of $57.94. Federal prisoner reimbursements were budgeted at $9,000 in FY 2014. The Cochise County Jail operates a clinic in order to provide medical care to inmates and the Cochise County Health Department provides full-time medical professionals to the jail. Inmates are required to make a co-payment for medical services and medication. Medical costs for the jail were budgeted at $981,120 in FY 2014, which included $195,498 for mental health. The estimated medical costs for FY 2015 are budgeted at approximately $1 million.

Capital Projects
In FY 2015, the Capital Projects budget decreased from $29,117,440 to $22,220,813. The following is a list of some of the major capital projects:

- Jail Remodel ($2,500,000)
- Network upgrade ($600,000)
- Microwave improvements ($1,500,000)
- CCSO Regional Evidence Storage Facility ($130,000)
- IT Network backbone/infrastructure upgrade ($200,000)
- BDI Sweeper ($116,200)
- Joint Dispatch ($150,000)
- Mgt System Software ($104,153)
- Davis Road ($165,000)
- Communications Project ($771,601)

As noted in the above list, the County is currently considering a remodel of the existing jail facility at a maximum cost of $2.5 million. Although the jail population has been declining, partly due to a loss of Federal prisoners, the County must separate the prisoners with mental health issues and juveniles being tried as adults as well as the women prisoners, from the general prison population. Although the County has most if not all of the cash on hand to pay for the project, the County is currently near its Constitutional expenditure limit. County officials are considering all options, including the possibility of going to the voters to increase the base expenditure limit.

Debt
According to the Department of Revenue's FY 2014 Report of Bonded Indebtedness, the County held $3,165,000 in outstanding certificates of participation (COPs). The COPs funded the construction of the Melody Lane County Complex; however, County officials claim they have since paid the debt in full. The County also held $210,804 in outstanding lease purchase debt at the end of FY 2014.

COCONINO COUNTY

Overview

- Coconino County's GF budget for FY 2015 is $72,591,508. This is an increase of $1,782,595 (2.5%) over last year's budget of $70,808,913.
- The County's beginning fund balance decreased $2,978,319 (9.8%) in FY 2015 to $27,259,345. The fund balance is equivalent to 37.6% of the GF budget.
- Coconino County's total budget (financial resources) for FY 2015 is $235,165,312, a decrease of $28,550,264 (10.8%) below last year's budget of $263,715,576. The dramatic decrease in the total budget is largely the result of a $28 million reduction in unawarded grants. Of the total financial resources available, the County budgeted to spend $201,010,897.

Property Values

- In FY 2015, Coconino County's primary NAV fell just 0.41% to $1,512,794,264. New construction amounted to $12,653,745 (0.84% of total NAV). The Secondary NAV grew slightly to $1,534,483,938.

Property Tax Revenues

Primary Levy

- The County adopted its maximum tax rate of $0.5646, which exceeded the TNT rate of $0.5535 by $0.0111. As a result, the County was required to hold a TNT hearing and publish notice of the tax increase.
- The primary tax levy increased $237,910 (2.9%), from $8,303,326 to $8,541,236.

County Library

- The County kept the library district tax rate stayed the same at $0.2556. As a result, the levy increased $3,626 to $3,922,141.
- The budget decreased $4,925, from $3,834,594 to $3,829,669.
- In FY 2014, the estimated beginning fund balance was $254,789. The beginning fund balance in FY 2015 is 259,407.

Flood Control District

- The District's NAV dropped $11,299,482 (1.8%), from $617,332,542 to $606,033,060.
- Coconino County's Flood Control District tax is levied on all properties outside the cities of Flagstaff, Page, and Fredonia. The tax rate in FY 2015 remains the same at $0.4000.
- The levy increased $83,392 (3.4%), from $2,469,330 to $2,552,722.
- The District budget is down $710,608 (5.2%), from $13,736,681 to $13,026,073.
- In FY 2014, the beginning fund balance was estimated at $1,858,516. The beginning fund balance for FY 2015 is zero.

Public Health Services District

- The District was created in 2009 by a unanimous vote of the BOS. In FY 2011, the County levied a property tax for the first time and set the tax rate at the 25-cent maximum per state statute.
- In FY 2015, the levy increased $3,547 to $3,836,210.
- Other special revenue budgeted in the District in FY 2015 increased $57,136, from $5,802,075 to $5,859,211.
- In FY 2013, the MOE payment for the District was $3,739,233 and the County transferred an additional $299,155 from the GF to the District to augment the drop in property taxes (intended to be paid back in the future when the property taxes rebound). For FY 2014, the MOE increased to $3,851,420 and an additional $767,694 was transferred from the GF to the District to offset property taxes, as well as an additional $535,000 for Title 36 contracts (mental health services). The FY 2015 MOE increased to $3,928,438.
- The FY 2015 District budget (operating only) is up $89,403 (0.9%), from $10,292,465 to $10,381,868.

- The District's beginning fund balance in FY 2014 was estimated at $251,580 and increased to approximately $1.4 million in FY 2015.

COCONINO COUNTY	FY 2014 RATE	FY 2015 RATE	CHANGE	TNT	FY 2014 LEVY	FY 2015 LEVY	CHANGE	% CHANGE
Primary	0.5466	0.5646	0.0180	0.5535	$8,303,326	$8,541,236	$237,910	3%
Library	0.2556	0.2556	0.0000		$3,918,515	$3,922,141	$3,626	0%
Flood Control*	0.4000	0.4000	0.0000		$2,469,330	$2,552,722	$83,392	3%
Public Health Services	0.2500	0.2500	0.0000		$3,832,663	$3,836,210	$3,547	0%
OVERALL RATE	1.4522	1.4702	0.0180		$18,523,834	$18,852,309	$328,475	2%

*Applies to all property outside the cities of Flagstaff, Page, and Fredonia.

Other Revenues

GF Revenues

- Auto in Lieu revenues decreased $91,074 (2.7%), from $3,365,110 to $3,274,036.
- State shared sales tax is up $21,546, from $19,676,888 to $19,698,434.
- The half-cent sales tax is up $5,821, from $12,691,779 to $12,697,600.
- PILT revenue is up $593,210 (55.3%), from $1,073,000 to $1,666,210.
- Non-departmental revenue decreased $347,647 (10%), from $3,334,001 to $2,986,354. This line-item includes all of the indirect costs charged to County departments.
- The County continues to receive $550,038 in lottery revenue from the state.

Special Revenues

Jail District

- The County Jail District was initially approved by voters in 1997. In September 2006, the voters approved the County's request to increase the jail sales tax rate from a $^{3}/_{10}$-cent rate to a ½-cent, which went into effect on January 1, 2007. In addition, the Jail District sales tax was extended 15 years, which will now sunset in 2027.
- Total budgeted Jail District revenues in FY 2015 are up $5,821 to $14,310,140.
- The MOE payment increased $26,078, from $2,518,950 to $2,545,028.
- The operating budget increased $3,661,066 (25.9%), from $14,145,802 to $17,806,868.
- **Jail facilities**
  - **Juvenile**: The juvenile facility currently holds 34 beds. The County can potentially rent beds to the Federal Marshals at $265/day; however, revenue from renting beds was not collected or budgeted over the last four years. Last year, the average occupancy of the facility was 19.
  - **Adult Detention**: The Flagstaff Detention Facility holds 596 beds (the County attempts to maintain an average occupancy of approximately 80%) and the Page facility holds 48 beds. The County rents beds to the Bureau of Indian Affairs (BIA), the Federal Bureau of Prisons (BOP), and the Yavapai County Sheriff's office at $60/day. Revenues in FY 2014 were budgeted at $1,372,179 and dropped to approximately $1 million in FY 2015.
  - In FY 2014, the estimated medical expenses for the Flagstaff and Page facilities were estimated at $706,587.

Parks and Open Space

- At the 2002 General Election, voters approved a $^{1}/_{8}$-cent capital projects sales tax for the purpose of implementing the Coconino Parks and Open Space Program. The tax was scheduled to sunset once collections reached $33 million, which County officials expected would occur by September 2014. As a result, the tax rate was repealed effective October 1, 2014.
- The sales tax was budgeted at $3,217,556 in FY 2014.
- The FY 2015 budget increased $266,363 (2%), from $13,339,166 to $13,605,529.

Road Fund

- HURF (Public Works) budgeted revenues dropped $238,682 (2.2%), from $10,828,855 to $10,590,173.

- The HURF budget decreased $5,710,159 (24.4%), from $23,429,373 to $17,719,214.

Charges to Special Districts

- Public Health Services District- In FY 2014, the County charged the District $1,358,566 for indirect costs. In FY 2015, the County charged the District $1.3 million.
- Library District - The County does not charge the Library District for indirect costs.
- Jail District - The County charged the District $867,437 in FY 2014, which dropped to $786,036 in FY 2015.
- Flood Control District - The County charged the District $71,630 in FY 2014 and $179,352 in FY 2015.
- Road Fund - The County charged the Fund $907,145 in FY 2014 and $406,036 in FY 2015.

Expenditures

- Employee compensation: In FY 2014, the County awarded employees with a 1.5% market adjustment, effective July 1, 2013, and the total impact was $1.050 million ($500,000 to the GF/$550,000 to OF). In addition, the County provided employees with a 2.5% merit raise on their anniversary date for a total cost of $1.7 million ($800,000 to the GF/$900,000 to OF). In FY 2015, the County again awarded employees with a 2.5% merit increase effective on the employee's anniversary date at a total cost of $1.7 million ($800,000 to the GF/$900,000 to OF). The BOS set aside an additional $400,000 in the GF for possible compression mid-year raises for employees, which will be decided by the BOS following the November election (see discussion under *County Road Maintenance Sales Tax Initiative*).
- Budgeted payroll: Budgeted payroll, including EREs, in the GF increased from $35,926,450 to $37,737,946. The budgeted payroll in TF increased from $71,785,709 to $75,007,279.
- Health benefits: The County is the primary contributor to the Northern Arizona Public Employees Benefit Trust while employee contributions are minimal. The County has begun phasing in its wellness program, which offers a $20/month discount to employees who participate in preventive screenings and a healthy lifestyle. In FY 2014, the Health Insurance budget decreased 3.5% ($266,000). There is no increase budgeted for FY 2015.
- Budgeted FTEs: In FY 2015, the GF budgeted FTEs increased 10, from 487 to 497. Total FTEs rose 6, from 1,056 to 1,062.
- Employee vacancy and turnover rates: The turnover rate is approximately 12%. The vacancy rate is currently unknown.

County Road Maintenance Sales Tax Initiative (Prop 403)

Coconino County voters passed Prop 403 at the November 2014 ballot. The measure authorized a 3/10-cent County sales tax rate for maintaining and preserving the conditions of Coconino County roads. The tax will be in effect for 20 years beginning January 1, 2015. The County estimates that the sales tax will raise approximately $7 million a year to fund road maintenance costs, including costs related but not limited to snowplowing, dirt road grading, road surface chip sealing, road maintenance and other road-related expenses.

Capital Projects

The FY 2015 budget includes $2,050,278 in capital projects. Of the total, $757,961 is designated for repairs in the Jail District and the remainder is for various other capital improvement projects. The County is in the planning stages of demolishing the old jail that is not being utilized for its original purpose. The County is also planning to remodel the Page Justice building. The current jail facility is close to capacity; therefore, the County is planning to construct a new building on the existing parcel that will serve as transitional housing and is estimated to cost approximately $3 million.

Debt

According to the Department of Revenue's FY 2014 Report of Bonded Indebtedness, the County does not hold any debt.

GILA COUNTY

Overview

- Gila County's GF budget for FY 2015 is $44,230,262, a $1,801,593 (3.9%) decrease below last year's budget of $46,031,855. This year's decrease was accomplished with $1,342,343 in employee vacancy savings.
- The County's beginning fund balance for this year is $15,766,569, $4,082,328 (21%) less than last year. The fund balance represents 36% of the GF budget.
- The total budget for FY 2015 of $94,444,905 is a decrease of $807,120 (0.8%) below last year's adopted budget of $95,252,025.

Property Values

- The primary NAV decreased 5.14% to $416,099,715. New construction amounted to $10,558,743 (2.54% of total NAV). Secondary NAV is down 4.8% to $419,257,531.

Property Tax Revenues

Primary Levy

- Gila's primary property tax rate remains the same at $4.1900. This year's primary tax rate is $0.3418 below the TNT rate of $4.5318; therefore, the County was not required to hold a TNT hearing.
- The primary levy of $17,434,578 is $943,803 (5%) below last year's levy of $18,378,381.

County Library

- The Library District levy is $838,716, down $41,870 (4.8%) from last year. The tax rate stayed the same at $0.2000.
- The District budget decreased $200,485 (11.3%), from $1,779,558 to $1,579,073.
- The beginning fund balance for FY 2014 was $739,410, which dropped to $630,000 in FY 2015.

GILA COUNTY	FY 2014 RATE	FY 2015 RATE	CHANGE	TNT	FY 2014 LEVY	FY 2015 LEVY	CHANGE	% CHANGE
Primary	4.1900	4.1900	0.0000	4.5318	$18,378,381	$17,434,578	-$943,803	-5%
Library	0.2000	0.2000	0.0000		$880,586	$838,716	-$41,870	-5%
OVERALL RATE	4.3900	4.3900	0.0000		$19,258,967	$18,273,294	-$985,673	-5%

Other GF Revenues

- Auto in Lieu is up $56,944 (3.8%), from $1,500,000 to $1,556,944.
- State shared sales tax is up $56,150 (1.1%), from $4,900,000 to $4,956,150.
- The County's half-cent sales tax revenue stayed the same at $2,600,000.
- PILT revenue is up slightly to $3,200,905.
- Lottery revenues are budgeted at $550,000 in FY 2015.

Jail Facilities

Adult facility

- The adult facility holds 219 beds and is near max occupancy. The County currently rents beds to other counties at a rate of $54.63/day. Projected revenues in FY 2015 are budgeted at $136,500.

Juvenile facility

- The juvenile facility holds 26 beds. Gila County contracts with the US Marshals for renting beds at $131/day (until recently, the County rented beds to BIA; however, the tribe built their own facility so the County currently receives few if any BIA prisoners). Total revenues from renting beds remain the same at $80,000. The Juvenile Detention budget increased $9,936, from $1,312,349 to $1,322,285.
- In FY 2015, the Sheriff's budget decreased $51,755, from $10,708,918 to $10,657,163.

Special Revenues

Road Budget

- HURF revenues increased $215,152 (7%), from $3,066,000 to $3,281,152.
- VLT dropped slightly to $809,409.
- The County Transportation Sales Tax was scheduled to sunset on December 31, 2014; however, voters approved Prop 404 at the November 2014 ballot, which extended the sales tax another 20 years, effective January 2015. With its passage, the County plans to share the revenues with cities and towns. In FY 2015, the budgeted revenues are anticipated to drop $807,156 (26%) to $2,282,844.
- The total Road Fund budget is up $635,530 (5.4%), from $11,809,197 to $12,444,727.

Charges for Services

- Library District - Beginning in FY 2014, the County charged the District $94,990 for indirect costs. The charges dropped to $54,990 in FY 2015. The County does not charge a per parcel fee for printing and mailing of tax bills like some other counties.
- Road Fund - The County charged the Road Fund $798,767 for indirect costs in FY 2014. In FY 2015, the charges increased to $823,072.

Expenditures

- Employee compensation:
  - The County offers two opportunities each year for employees to receive financial recognition of a one-time payment in December based on the change in CPI or in June based on the employee's performance appraisal score.
  - The County had a classification and compensation study completed in the Spring of 2014, which became effective for FY 2015. As a result, employee salaries increased by an average 6.2% and the total impact to the GF amounted to $1.34 million.
- Budgeted payroll: In FY 2014, the GF budgeted payroll, including EREs, was budgeted at $23.9 million and $36.8 million in TF. In FY 2015, budgeted payroll in the GF decreased to $23.3 million and $36.3 million in TF.
- Health benefits: In FY 2014, the County's health insurance premium costs increased by approximately 2%, which was entirely absorbed by the County ($65,406 to the GF/$24,902 to OF). In FY 2015, health insurance premiums costs increased 2.8%, which was entirely absorbed by the County GF ($129,000 impact). The County currently pays 93% for employee coverage and 60% for dependents, depending on the level of benefits.
- Budgeted FTEs: In FY 2014, GF FTEs were down 5 to 413 and FTEs in TF were down 15 to 660. In FY 2015, GF FTEs dropped 9 to 404 and total fund FTEs dropped by 8 to 652.
- Employee vacancy & turnover rates: In FY 2015, the GF budget included a line item titled "vacancy savings" that amounted to $1,342,343 and represented 3.8% of the GF budgeted expenditures. The voluntary turnover rate remains at approximately 20%.
- Enterprise Funds: The budgeted expenditures increased from $3,405,826 in FY 2014 to $4,649,764 in FY 2015. Of that amount, $2,608,354 is dedicated for recycling and landfill management, $1,991,410 for the Russell Gulch expansion, and $50,000 for Buckhead Mesa expansion.

Capital Projects

In FY 2015, the capital projects budget increased from $2,720,100 to $3,216,162 (non-capitalized projects not included). Some of the major capital improvement projects are as follows: $648,612 for the Globe Courthouse remodel/repairs; $196,400 for the Globe Jail bldg repairs/parking lot repaving; $386,750 for the Payson Jail remodel/parking lot repaving; $500,000 to construct an Animal Control building in Globe (joint project with city); $111,080 for the Payson Chamber remodel; and $129,000 for the Payson Courthouse steps & landings. The budget also includes $408,400 in Court security projects and $483,946 in bond building projects.

Debt

According to the Department of Revenue's FY 2014 Report of Bonded Indebtedness, there is $6,575,000 outstanding in revenue bonds. During FY 2010, the County borrowed $8 million in revenue bonds over 20 years for the construction of the new Public Works facilities, expansion of its jail facilities, and a new evidence storage facility for the Sheriff's office. The budgeted debt service payment stayed the same for FY 2015 at $628,150. The County also held $33,970 in lease-purchase debt.

GRAHAM COUNTY

Overview

- Graham County's GF budget for FY 2015 is $21,270,214, an increase of $334,776 (1.6%) from $20,935,438 in FY 2014.
- The County's beginning fund balance is $1,926,170, up $657,877 (51.9%) over last year's fund balance. The fund balance represents 9.1% of the total GF budget.
- The County's total budget of $33,523,198 is an increase of $631,956 (1.9%) over last year's total budget of $32,891,242.

Property Values

- In FY 2015, the primary NAV increased 10% to $211,469,611. New construction amounted to $2,320,858 (1.1% of total NAV). Secondary NAV is up 10% to $213,508,436.

Property Tax Revenues

Primary Levy

- The primary tax rate decreased $0.1917, from $2.3711 to $2.1794, which is the County's TNT rate.
- The County's primary levy is $4,608,769, which is an increase of $50,551 (1.1%) over last year's levy of $4,558,218.

Flood Control District

- The District's NAV increased $12,254,579 (6.4%), from $191,000,605 to $203,255,184.
- The District rate stayed the same at $0.0953.
- The levy for the District increased $11,678 (6%), from $182,024 to $193,702.
- The budget increased $47,675 (11.7%), from $408,959 to $456,634 (actual expenditures for FY 2014 amounted to $106,738).
- The beginning fund balance in FY 2014 was $226,435. The FY 2015 beginning fund balance is up $36,000 to $262,332.

GRAHAM COUNTY	FY 2014 RATE	FY 2015 RATE	CHANGE	TNT	FY 2014 LEVY	FY 2015 LEVY	CHANGE	% CHANGE
Primary	2.3711	2.1794	-0.1917	2.1794	$4,558,218	$4,608,769	$50,551	1%
Flood Control	0.0953	0.0953	0.0000		$182,024	$193,702	$11,678	6%
OVERALL RATE	2.4664	2.2747	-0.1917		$4,740,242	$4,802,471	$62,229	1%

Other GF Revenues

- PILT increased $141,708 (5.4%), from $2,636,873 to $2,778,581.
- State shared sales tax stayed the same at $4,000,000.
- The half-cent sales tax revenues remain the same at $2,000,000.
- Auto in Lieu is up $59,717 (7.2%), from $825,000 to $884,717.
- The County continues to receive $550,000 in state Lottery revenues.
- The County received an additional legislative appropriation of $500,000 in FY 2015.

Jail facilities:

- Juvenile facility: The juvenile facility holds 48 beds. The County budgeted $750,000 for renting beds to other jurisdictions ($500,000 from BOP and $250,000 from USM). The County continues to charge Greenlee County $250,000 for utilizing up to three beds. The budget for regional juvenile detention increased from $1,461,125 to $1,470,456.
- Adult facility: The current adult facility holds a maximum of approximately 200 beds. The County rents beds to the state at $38/day and to cities at a rate of $50/day. Budgeted revenue from renting beds in FY 2015 is $67,000. The average occupancy was 82%.

- In situations of overcrowding, the County sends its female prisoners to Greenlee County at a cost of $50/day, which is budgeted at $30,000 in FY 2015.
- Budgeted medical costs in the jail facilities amounted to $481,757 in FY 2014 and increased to $531,117 in FY 2015 ($20,000 for the purchase of new medical records software). The medical care is provided by an in-house nurse (four nurses on rotation).
- The Sheriff's budget (GF only) increased $142,893 (2.4%), from $6,044,573 to $6,187,466.

Special Revenues

Road Fund

- HURF revenue increased $39,152 (1.3%), from $2,950,000 to $2,989,152.
- In FY 2015, forest fee revenues decreased $10,568 (1.8%), from $585,568 to $575,000.
- The Road Fund budget increased $210,622 (3.4%), from $6,212,465 to $6,423,087 (estimated actual expenditures for FY 2014 were $3,344,001).

Charges to Special Districts

- Flood Control District -The County charged the District $74,588 in FY 2014 and $78,977 in FY 2015.
- Road Fund - The County charged the Road Fund $372,556 in FY 2014 and $346,463 in FY 2015.

Expenditures

- Employee compensation: In FY 2014, the County budgeted only for longevity raises at a total cost of $53,000 ($38,000 to the GF/$15,000 to OF). Longevity raises of 4% are awarded to employees at one-year of employment, two years, five years, and every third year beyond that point. In FY 2015, longevity raises amounted to a total impact of $78,000 ($46,000 to the GF/$32,000 to OF). In addition, the County awarded employees with a 4% average market adjustment at a total cost of $483,000 ($300,000 to the GF/$183,000 to OF).
- Budgeted payroll: In FY 2015, the GF budgeted payroll, including EREs, increased from $11,220,582 to $11,221,316. Total payroll decreased from $15,460,195 to $15,384,797.
- Health benefits: The County is part of the six-county insurance pool and charges employees with single coverage of $100/month and employees with family coverage of $300/month. The County pays approximately 90% for single coverage and 78% for family coverage. The County has implemented a health risk analysis and encourages employees to fill out the assessment or pay a $10/pay period penalty for failure to do so. In FY 2015, health insurance costs increased approximately 2%, which was absorbed by the County ($29,000 to the GF/$12,000 to OF).
- Budgeted FTEs: The FY 2015 FTEs in the GF are budgeted at 187 and 260 total FTEs.
- Employee vacancy & turnover rates: The most recent calculation reflects that the employee vacancy rate is approximately 10% and the turnover rate is 23%, primarily in Detention.

Capital Projects/Debt

The capital projects budget remained the same in FY 2015 at just $75,000.
According to the Department of Revenue FY 2014 Report of Bonded Indebtedness, the County held $1,095,769 in lease-purchase debt.

Jail District Measure - November 2014 Ballot

Voters narrowly approved the creation of a Jail District in Graham County at the November 2014 ballot. As a result, the County will levy a half-cent sales tax effective July 1, 2015 for 25 years. The sales tax is expected to generate $2 million each year. County officials claim the creation of the District was necessary because existing facilities are dilapidated and are not sufficient to hold the current and anticipated inmate population (The current facility houses up to 125 inmates with the ability to hold up to 200 beds). The plan is to build a 250-bed jail with the ability to expand. The County expects the facility to cost approximately $25 million and would take up to four years to complete.

GREENLEE COUNTY

Overview

- Greenlee's GF budget for FY 2015 is $11,562,861, representing an increase of $943,020 (8.9%).
- The County GF budget reflects a cash balance of $3,532,504; however, the budgeted cash balance is understated by nearly $3 million. It is estimated that the actual cash balance is approximately $7.5 million (the County's FY 2013 financial audit showed the County held $9.4 million in its GF balance but the County budget only reflected $3.8 million at the time).
- The total budget (total financial resources) for FY 2015 is $25,130,309, an increase of $1,558,209 (6.6%) over the FY 2014 total budget of $23,572,100. The FY 2015 budgeted expenditures are $23,979,451.

Property Values

- The primary NAV increased 36.6% to $458,425,787. New construction amounted to $658,083 (0.14% of total NAV). The Secondary NAV increased 37.6% to $462,439,380.

Property Tax Revenues

Primary Levy

- Greenlee County adopted a primary tax rate of $0.5500, which is just below the County's maximum tax rate of $0.5559. This year's rate exceeded the TNT rate of $0.5390; therefore, the County was required to hold a TNT hearing and publish a notice of the tax increase.
- Although the County's primary tax rate dropped to $0.5500, the levy increased $43,190 (2%) as a result of the 36.6% increase in the PNAV.

Public Health Services District

- In June 2006, the County BOS created the District by unanimous vote of the Board. The tax rate increased $0.0219 this year, from $0.2081 to $0.2300 (the maximum tax rate allowed by statute is $0.2500). As a result of the tax rate increase combined with the 37% growth in secondary value, the levy increased $363,883 (52%) to $1,063,611.
- The County uses the Public Health Services District fund to pay for health department services, animal control, inmate medical expenses, and ambulance services. The expenses for inmate medical expenses include nurses' salaries.
- The District budget increased $85,244 (4.6%), from $1,869,196 to $1,954,440.
- The MOE payment for the District is $356,000.

Flood Control District

- The District's NAV increased $2,932,654 (5.5%), from $53,254,826 to $56,187,480.
- The District's tax rate increased $0.0253, from $0.1647 to $0.1900. The levy increased $19,076 (22%), from $87,672 to $106,748.
- The District budget is down $17,000 (9.8%), from $174,000 to $157,000.

GREENLEE COUNTY	FY 2014 RATE	FY 2015 RATE	CHANGE	TNT	FY 2014 LEVY	FY 2015 LEVY	CHANGE	% CHANGE
Primary	0.7350	0.5500	-0.1850	0.5390	$2,478,151	$2,521,341	$43,190	2%
Public Health Services	0.2081	0.2300	0.0219		$699,728	$1,063,611	$363,883	52%
Flood Control	0.1647	0.1900	0.0253		$87,672	$106,748	$19,076	22%
OVERALL RATE	1.1078	0.9700	-0.1378		$3,265,551	$3,691,700	$426,149	13%

Other GF Revenues

- Auto in Lieu remains the same at $325,000.
- The half-cent sales tax revenue stayed the same at $1,200,000 (actual FY 2014 revenues were $2,397,110).
- State shared sales tax revenue dropped $150,000 (3.3%), from $4,500,000 to $4,350,000 (FY 2014 actual revenues were $4,898,988. DOR estimates the County should receive $5,778,000 in state shared revenues in FY 2015).

- PILT is down $238,501 (30%), from $783,176 to $544,675 (FY 2014 actual revenues were $844,890).
- The County budgeted to receive $574,500 from the state for out-of-county tuition, which is up $191,700 (50%) from last year.
- The County continues to receive $550,000 in Lottery revenues from the state.

Special Revenue Funds

- Road fund revenue increased $130,000 (14.8%), from $880,000 to $1,010,000. The budget increased $330,000 (16.7%), from $1,980,000 to $2,310,000.
- National forest fee revenues stayed the same at $600,000. The County distributes $300,000 to both the schools and the Road Fund.

Charges to Special Districts

The County does not charge its special districts for reimbursement of services.

Expenditures

- In FY 2014, the County provided all employees with a 3.5% increase (increased pay scale by 1%, plus shifted all employees up one grade), effective September 1, 2013. Deputy Sheriff's received an additional 1.5% increase, effective July 1, 2013, at a total estimated annualized cost of $330,000 ($220,000 to the GF). In FY 2015, the County awarded employees with a 3% increase, effective September 1. The total estimated annualized cost, including EREs, is $280,000 ($180,000 to the GF).
- Budgeted payroll: In FY 2014, GF budgeted payroll, including employee related expenses (EREs), increased from $5,772,347 to $6,106,476. Total payroll increased from $8,863,964 to $9,380,466. In FY 2015, the GF budgeted payroll increased $655,408 (10.7%) to $6,761,884. Total budgeted payroll increased $680,294 (7.3%) to $10,060,750.
- Health benefits: In FY 2014, health premium costs increased 3% in FY 2014 and the County planned to share the cost with employees. The County currently covers 94% for employee coverage and 82% for dependents. In FY 2015, health premiums costs increased 2%, which will be entirely absorbed by the County at a total estimated cost of $107,142 ($96,428 to the GF).
- Budgeted FTEs: In FY 2014, the budgeted FTEs in the GF dropped from 101 to 92 and total FTEs decreased from 165 to 160. In FY 2015, GF FTEs increased back up to 101 and total fund FTEs increased to 168.
- Employee vacancy & turnover rates: The current employee vacancy rate is 2.5% and the turnover rate is 18%.
- Jail facilities: The County uses Gila Health Resources to control its inmate costs, which amounted to $87,410 in FY 2013. Also to control costs, the County has an ambulance service that it uses to avoid using a helicopter for emergencies. There are 55 beds in the adult facility and the facility is close to full capacity. The County does not have a facility to hold its juvenile inmates and instead transfers its juveniles to Graham County at an annual cost of approximately $250,000 by renting up to three beds.
- In FY 2015, the Sheriff's budgeted expenditures increased $481,458 (15.8%), from $3,056,666 to $3,538,124.

Debt

The Department of Revenue's FY 2014 Report of Bonded Indebtedness shows that the County held $2,286,459 in lease-purchase debt (the debt is for vehicles and equipment in the Road Department). The budgeted debt service payment in FY 2015 is $700,000.

Capital Projects

The capital projects budget increased $1,900,000 (127%), from $1,500,000 to $3,400,000.
The County budgeted for several projects, which include the following:

- New Duncan Annex building: total estimated cost of $1,900,000 (scheduled completion TBD).

- Greenlee County Airport: $335,000 to construct airport drainage/erosion control improvements (5-year project).
- Public Works: $259,000 (2-year project).
- Correctional Facility: The current correctional facility has been in use for 35 years and is in need of numerous repairs. A firm has provided the County with three options: 1) basic renovation ($1,056,000); 2) Fully renovate, replace deficient systems and building elements with new technology ($3,950,000); and 3) Replace facility ($5.5 million). Funding sources are currently being reviewed.

LA PAZ COUNTY

Overview

- La Paz's GF budget for FY 2015 is $16,838,277, an increase of $519,752 (3.2%) from the FY 2014 GF budget of $16,318,525.
- The County's FY 2015 GF beginning balance is $1,868,393.
- The FY 2015 total financial resources are $32,040,614, a decrease of $996,036 (3%) from last year's total budget of $33,036,650. Of the total financial resources, the County had budgeted $31,415,184 in total expenditures.

Property Values

- The primary NAV decreased 5.1% to $205,814,389. New construction amounted to $4,744,214 (2.31% of total NAV). The secondary NAV dropped 6.2% to $210,720,562.

Property Tax Revenues

Primary Levy

- La Paz County's primary tax rate increased $0.3255, from $1.9608 to $2.2863, which is the County's maximum tax rate. Since the County's adopted tax rate exceeded the TNT rate of $2.1145, the County was required to publish a notice and hold a public hearing regarding the tax increase.
- La Paz County's primary property tax levy is $4,705,534, which is $453,826 (10.7%) more than last year and is the maximum allowable constitutional levy.

LA PAZ COUNTY	FY 2014 RATE	FY 2015 RATE	CHANGE	TNT	FY 2014 LEVY	FY 2015 LEVY	CHANGE	% CHANGE
Primary	1.9608	2.2863	0.3255	2.1145	$4,251,708	$4,705,534	$453,826	11%

Other GF Revenues

- Auto in Lieu remains stable at $572,581. In FY 2015, the County began accounting for the Auto in Lieu revenues that were previously listed under the Road Fund under the GF. The amount budgeted in FY 2015 increased $26,128 (6%) to $456,987.
- State shared sales tax revenue dropped $148,000 (6.2%), from $2,400,000 to $2,252,000.
- Half-cent sales tax revenues increased $258,884 (22.4%), from $1,153,689 to $1,412,573.
- PILT is up $128,209 (7.1%) to $1,928,209.
- The County receives $550,000 in Lottery revenue from the state.
- Sanitation charges increased $1,320,000 (165%), from $800,000 to $2,120,000.
- Indirect cost revenues are budgeted at $500,000 in FY 2015.
- Other miscellaneous revenues remain the same at $100,000.

Special Revenues

Road Fund

- HURF revenue increased $163,547 (4.7%), from $3,480,632 to $3,644,179.
- The Public Works budget is down $416,005 (10.7%), from $3,885,750 to $3,469,745.

Enterprise Fund

- The revenues from the La Paz County Golf Course increased $101,777 (6.4%), from $1,583,183 to $1,684,940. The budget changed by the same amount.

Jail District

- The County levies a ½-cent sales tax to support its Jail District. Total revenues budgeted in the Jail District increased $138,700 (4.3%), from $3,200,000 to $3,338,700. The Jail District includes $1,350,000 in intergovernmental revenues from the housing of Federal and Coconino County inmates. The County rents beds to the US Marshals and ICE at a rate of $60/day (up from the previous $44/day charge) and currently house approximately 50 federal inmates on average. Beds are also rented to Lake Havasu, Kingman, and Mohave County at $65/day and to the Colorado River Indian Tribes and private entities at $65/day. The Jail District ½-cent excise tax is up $138,200 (12.2%), from $1,130,000 to $1,268,200.

- The District operations budget increased $155,392 (5%), from $3,134,608 to $3,290,000. The personnel costs in the District, including EREs, were budgeted at $2,092,525 in FY 2014. In FY 2015, total personnel costs in the Jail District increased to $2,209,989. There are currently 38 FTEs funded by the District.
- The County's MOE payment stayed the same in FY 2015 at $720,000.
- The adult facility holds 266 beds the average daily bed occupancy remains at approximately 135.
- The County does not currently have a juvenile facility, and instead, transfers its juveniles to Yuma County. Yuma County charges La Paz $80/day, which was budgeted at $50,000 in FY 2014.
- In FY 2015, the budget includes a lease purchase payment of $42,000.

<u>Yakima Judgment/Bonds</u>

With the passage of SB1178 in the 2011 legislative session, the County was authorized to issue TPT-funded bonds to pay its $14 million judgment to Yakima. The amount budgeted, not to exceed $19 million, includes the judgment, 2% underwriting fees, bond counsel fees, and charges for the bond issuance. The half-cent sales tax took effect on December 1, 2011. The tax is estimated to be in effect for twenty years.

- In FY 2015, the revenue generated from the sales tax for the judgment is down slightly to $2,179,576.
- The debt service payment for the bonds in FY 2015 is $1,500,000.

<u>Expenditures</u>

- <u>Employee compensation</u>: The County did not award pay raises in FY 2014. In FY 2015, the County awarded employees with a 3% COLA. The total impact amounted to approximately $500,000 ($250,000 impact to the GF).
- <u>Budgeted payroll</u>: The GF budgeted employee compensation in FY 2014 was $8,468,211 and budgeted employee compensation in TF was $14,291,688. In FY 2015, budgeted compensation in the GF increased to $8,827,465 and to $17,298,288 in TF (Includes $2,209,989 budgeted employee compensation in the Jail District).
- <u>Health benefits</u>: The County covers 100% of health benefit costs for employees and 50% for dependents.
- <u>Budgeted FTEs</u>: In FY 2014, the GF budgeted FTEs were 131 and TF FTEs were 278 (Includes an estimated 38 FTEs in the Jail District). In FY 2015, FTEs in the GF are budgeted at 130 and FTEs in TF are up to 289 (Includes 38 FTEs budgeted in the Jail District).
- <u>Employee vacancy & turnover rates</u>: The most recent data supplied by the County showed that the employee vacancy rate was 3.48% and the employee turnover rate was 13.2%.

<u>Debt</u>

According to the Department of Revenues FY 2014 Report of Bonded Indebtedness, the County held $18,760,000 in revenue bonds for the Yakima judgment. In addition, the County issued $2.022 million in COPs in 2007, financed over ten years, for the jail expansion. This debt was recently refinanced and the current outstanding debt is $1,585,000.

In addition, the Jail District held $1,585,000 in outstanding lease-purchase debt. The County held $93,699 in lease-purchase debt at the end of FY 2014.

MARICOPA COUNTY

Overview

- The GF budget increased $73,120,683 (7.8%), from $942,780,433 to $1,015,901,116.
- The GF balance decreased $116,354,517 (51%), from $230,066,825 to $113,712,308. The fund balance represents 11.2% of the GF budget.
- The County reports its total financial resources available at $3,060,728,490, which is down $4,665,038 (0.2%) from last year. Of the total financial resources, the County only budgeted to spend $2,309,530,514 in FY 2015 (75.7% of its total budgeted financial resources).

Property Values

- The County's primary NAV rose 4.8% to $33,519,795,354. New construction amounted to $701,381,830 (2.09% of total NAV). Secondary NAV increased 8.8% to $35,079,646,593.

Property Tax Revenues

Primary Levy

- The primary tax rate for Maricopa County increased $0.0402, from $1.2807 to $1.3209, which exceeded the $1.2486 TNT rate by $0.0723. As a result, the County was required to publish notice and hold a public hearing regarding the tax increase.
- The primary levy increased $32,987,580 (8.1%), from $409,775,397 to $442,762,977.

Library District

- The Library District's levy for FY 2015 is up $5,387,979 (38.2%), from $14,116,305 to $19,504,284. The secondary tax rate increased $0.0118, from $0.0438 to $0.0556.
- The Library District budget decreased $298,522 (1.2%), from $25,525,017 to $25,226,495.
- In FY 2014, the County's Library District beginning fund balance was $15,224,924. In FY 2015, the fund balance is $13,118,288.

Flood Control District

- The District's NAV increased $2,742,347,280 (9.6%), from $28,622,833,869 to $31,365,181,149.
- The FY 2015 levy is $43,660,332, a $3,817,347 (9.6%) increase above last year's levy. The tax rate remained the same at $0.1392.
- In the FY 2014 budget, the District began the year with a fund balance of $52,843,453. The district began FY 2015 with a $51,986,081 fund balance.
- The budget increased slightly, from $72,009,409 to $72,495,393. The FY 2015 District budget includes $40 million in capital projects, same as last year.

Stadium District

- Total revenue in the district increased from $10,334,868 to $10,458,111. Sales tax revenues remain the same at $4,997,042. License & permit revenues increased from $3,384,928 to $3,422,385. Other charges are up from $1,144,722 to $1,254,260.
- The FY 2015 Stadium District budget is $8,689,186, down $2,642,512 (23.3%) below last year's budget. Included in the budget is $2,985,808 for District operations, $3,700,378 for debt service, and $2,003,000 in reserves for long-term projects.
- In FY 2014, the District began the year with $27,316,604. The beginning fund balance in FY 2015 is $22,803,193.

MARICOPA COUNTY	FY 2014 RATE	FY 2015 RATE	CHANGE	TNT	FY 2014 LEVY	FY 2015 LEVY	CHANGE	% CHANGE
Primary	1.2807	1.3209	0.0402	1.2486	$409,775,397	$442,762,977	$32,987,580	8%
Library	0.0438	0.0556	0.0118		$14,116,305	$19,504,284	$5,387,979	38%
Flood Control	0.1392	0.1392	0.0000		$39,842,985	$43,660,332	$3,817,347	10%
OVERALL RATE	1.4637	1.5157	0.0520		$463,734,687	$505,927,593	$42,192,906	9%

Other GF Revenues

- State shared sales taxes increased $27,897,879 (6.4%), from $437,402,846 to $465,300,725.
- State shared vehicle license tax increased $13,109,877 (10.9%), from $119,748,223 to $132,858,100.
- PILT is up $368,401 (3.1%), from $11,972,067 to $12,340,468.

Special Revenues

Jail Sales Tax

- Jail Sales tax revenue increased $10,189,460 (7.8%), from $131,106,321 in FY 2014 to $141,295,781 in FY 2015. The MOE payment in FY 2015 is $176,801,288.
- The County charges cities & towns a booking fee of $266.41 and per diem of $81.85 for housing inmates in the County jail facilities. The FY 2015 booking and per diem revenues were budgeted at $31,016,456.
- In FY 2015, the total budget for the Sheriff's office increased $42,342,487 (14.2%), from $298,336,365 to $340,678,852.

Jail facilities

In October 2013, the U.S. District Court for Arizona issued a Judgment Order in the Melendres v. Arpaio case. The Judgment Order stated requirements which MCSO must follow in order to comply with the court ruling. In April 2014, the Judgment Order was amended to make the Court Monitor responsible for Community Outreach rather than MCSO. The total implementation costs budgeted for the judgment amounted to $7,687,376 in FY 2014. The FY 2015 MCSO GF budget includes $8,310,737 for operating costs and $4,200,000 for non-recurring costs for the purchase of vehicle mounted cameras. Non-Departmental budget includes $2,825,000 in operating costs for the Court Appointed Monitor and other judgment related charges. The budget for the MCSO operating costs and the monitor are $11 million for the year.

Additional funding was provided for General and Detention Non-Recurring costs: Airplane ($850,000); Helicopter ($5,000,000); Camera Security System ($247,978); Records Management System ($675,000);

- **Adult facilities**: The adult facilities hold up to 11,509 beds (includes triple-bunking, portable beds, and beds in "tent city"). According to the recently completed Jail Master Plan, functional capacity is 7,398. Average occupancy is approximately 8,100 inmates. Maricopa County does not rent beds to other jurisdictions.
- **Juvenile facilities**: The juvenile facilities hold up to 406 beds; however, the current staffing levels assume 187 beds. The most recently calculated average daily population is 169 as of October 2014.
- In FY 2015, the budget for correctional health services increased from $58,281,681 to $61,409,512.

Highway & Transportation Revenue

- Revenue in the Road Fund in FY 2015 is up $11,212,552 (11.8%), from $94,767,838 to $105,980,390.
- In FY 2015, the Transportation Operations budget is up from $140,961,689 to $145,000,754. Included in this year's budget is $61,737,434 for operations and $82,578,500 for capital projects.

Elderly Assistance Fund (EAF)

- The EAF is unique to only Maricopa County in which the revenues are derived from the 16% interest paid for the redemption on property tax liens. The revenues in the Fund are applied by the County Treasurer to property that qualifies under the Senior Valuation Freeze to offset school primary property taxes.
- The fund balance in the EAF as of 5/31/14 was $16,268,808.
- In FY 2013, assistance from the fund was applied to 10,659 parcels and 10,088 in FY 2014. The FY 2014 distributions totaled over $2.3 million.

Charges to Special Districts
The County charges the following amounts for the reimbursement of indirect costs to the GF:

- Library District - In FY 2014, the County transferred $1,085,301 from the Library District to the GF and $1,149,371 in FY 2015.
- Flood Control District - In FY 2014, the County charged the District $1,592,089, which increased to $1,730,641 in FY 2015.
- Stadium District - The County charged the Stadium District $49,326 in FY 2014 and $36,293 in FY 2015.
- Transportation Fund - Charges to the Transportation Fund in FY 2014 amounted to $2,395,364, which increased to 2,788,047 in FY 2015.

Expenditures

- Employee compensation:
  - In FY 2014, the County budgeted for an employee pay-for-performance (PFP) compensation plan, which was funded at approximately 5% on average (effective 7/8/13). The County also reviewed various positions for market equity and adjusted salaries accordingly (areas that have a lot of overtime, such as the attorney's office, IT, healthcare providers, etc.). The total impact of the County compensation plan was estimated at $67 million ($40 million to the GF/$19 million to the Detention Fund/$7.7 million to OF).
  - In FY 2015, the County budgeted for an average 2.5% salary increase for employees at a total cost of $20,650,600 ($10,841,809 to the GF/$4,908,790 to the Detention Fund/$4.9 million to OF). In addition, the County authorized market adjustments for select positions: MCSO deputies and sergeants ($2.5 million to the GF and DT); probation officers and supervisors ($2.2 million GF/$964,000 DT); mental health professionals ($35,000 GF/$160,000 DT); and epidemiologists ($41,000 GF). Also, the County budgeted $1 million for continuation of its Education Assistance Program.
- Budgeted payroll: In FY 2014, GF budgeted payroll, including EREs, was $477,099,455 and TF payroll was $980,349,684. In FY 2015, the GF budgeted payroll increased to $519,517,084 and TF budgeted payroll increased to $1,064,973,183.
- Health benefits: Maricopa County is self-insured for employee health benefits and charges each department a composite rate for each employee ($8,904/year).
- Budgeted FTEs: In FY 2014, budgeted FTEs in the GF were 7,339 and total budgeted FTEs were 14,423. In FY 2015, FTEs in the GF increased to 7,620 and TF FTEs increased to 14,812.
- Employee vacancy & turnover rates: The budgeted employee vacancy rate is approximately 5%. The voluntary turnover rate was projected at 8.4% in FY 2014.

Capital Projects
Maricopa County's Capital Improvement Program (CIP) is a modified "pay as you go" policy in which the County funds its projects with a combination of cash reserves and lease revenue bonds.

In the FY 2015 budget, the County is planning to spend $279 million on the following capital projects:

Transportation ($82,578,500): Bridge construction/preservation ($525,000); County arterials ($14,840,000); Dust mitigation ($3,160,000); Intelligent Trans. Syst. ITS ($2,175,000); MAG ALCP projects ($23,400,000); Partnership support ($1,577,500); Pavement const/preservation ($15,912,000); Right-of-way ($180,000); Safety projects ($3,155,000); Traffic improvements ($5,047,000); Transportation administration ($10,877,000); Transportation planning ($1,730,000).

Intergovernmental ($127,500): Maricopa Regional Trail System Vulture Mountain Study.

GF ($38,945,102): Chambers building ($1,373,091); Court tower ($1,247,290); East court improvements ($8,513,546); Maricopa Regional Trail System ($582,886); Security building ($2,065,187); Sheriff HQ project

($1,000,000); Southwest Justice Courts ($23,413,814); SWAT covered parking ($706,537); Vulture Mountain ($42,751).

Detention ($5,796,583): 4th Avenue Jail ($2,565,291); Lower Buckeye Jail ($3,231,292).

Technology ($145,754,406): BIX Room Byte Info Exchange ($4,299,455); Computer Aided Mass Appraisal ($4,795,000); County telephone system ($6,473,633); Enterprise data center ($18,738,694); Enterprise Resource Planning System ($16,060,899); Infrastructure refresh phase 1 ($5,000,000); Infrastructure refresh phase 2 ($37,604,275); Internal service delivery system ($350,000); Maximo maintenance management upgrade ($750,000); Public Safety radio system ($40,382,450); Sheriff HQ project IT infra. ($1,500,000); Treasurer Tech System upgrade ($572,448); and Project Reserves ($9,227,552).

Detention Tech. ($40,330,136): CHS electronic health records ($2,450,331); Jail MGMT Info. System ($1,795,563); Jail Security System Upgrade ($11,084,242); Project reserve ($25,000,000).

Debt
At the end of FY 2014, the County held $97,135,000 in revenue bonds, according to the Arizona Department of Revenue's Report of Bonded Indebtedness. The FY 2015 debt service payment is budgeted at $16.8 million.

On August 1, 2012, the Maricopa County Stadium District issued Revenue refunding bonds in the amount of $25,140,000, in which the net proceeds, along with $6,277,014 of Stadium District funds, were used to advance the Revenue refunding bonds series 2002, which mature on June 1, 2019. At the end of FY 2014, the Stadium District had $19,260,000 in total outstanding debt. The FY 2015 budgeted debt service payment is $3.7 million.

MOHAVE COUNTY

Overview

- Mohave County's GF budget increased $4,627,051 (6.1%), from $76,154,008 to $80,781,059.
- The County shows that the GF beginning balance increased $5,834,287 (314%), from $1,860,717 to $7,695,004; however, County officials claim that they actually have $13 million in their beginning fund balance. As in past years, the County continues to ignore the statutory requirement that they show all of their cash.
- The total budget for Mohave County is $252,282,568, which is a decrease of $732,508 (0.3%) below last year's total budget of $253,015,076.

Property Values

- The primary NAV decreased 2.5% to $1,727,793,369. New construction amounted to $23,178,631 (1.34% of total NAV). The secondary NAV dropped 2.9% to $1,757,074,571.

Property Tax Revenues

Primary Levy

- The County maintained its primary tax rate of $1.8196, which is below its TNT rate of $1.8909.
- By keeping the tax rate the same, the County's primary levy dropped $792,955 (2.5%), from $32,231,883 to 31,438,928 as a result of the reduction in property values.

Flood Control District

- The District's NAV decreased $45,384,733 (2.6%), from $1,751,482,173 to $1,706,097,440.
- The County continues to levy a tax rate of $0.5000, the same rate that the County has levied since 1998, which is also the maximum tax rate allowable by statute.
- In FY 2015, the District levy decreased $226,924 (2.6%), from $8,757,411 to $8,530,487.
- The budget decreased $11,250,089 (48.2%), from $23,356,666 to $13,585,755 (Actual FY 2014 expenditures were $13,549,200). The fund balance at the beginning of FY 2015 was $4.6 million.

Library District

- The Library District tax rate stayed the same at $0.3236, which will generate $170,194 (2.9%) less in revenue this year, from $5,856,087 to $5,685,893.
- The budget decreased $2,497,284 (22%), from $11,324,455 to $8,827,171 (Actual FY 2014 expenditures were $5,477,301).
- The FY 2015 fund balance was $5.9 million.

Television District

- Mohave County's TV District was originally created to provide and maintain communication equipment resources for residents. For the first time since 1998, the BOS reduced the tax rate levied for the TV District, from $0.0867 to $0.0700. As a result, the levy decreased $339,031 (21.6%), from $1,568,983 to $1,229,952.
- The District's budget increased $1,063,542 (29.2%), from $3,639,450 to $4,702,992 (Actual FY 2014 expenditures were only $600,723). The amount budgeted for the District is nearly eight times more than the actual amount necessary to fund the District.
- The FY 2015 beginning fund balance in the TV District was $3 million.

MOHAVE COUNTY	FY 2014 RATE	FY 2015 RATE	CHANGE	TNT	FY 2014 LEVY	FY 2015 LEVY	CHANGE	% CHANGE
Primary	1.8196	1.8196	0.0000	1.8909	$32,231,883	$31,438,928	-$792,955	-2%
Flood Control	0.5000	0.5000	0.0000		$8,757,411	$8,530,487	-$226,924	-3%
Library	0.3236	0.3236	0.0000		$5,856,087	$5,685,893	-$170,194	-3%
T.V.	0.0867	0.0700	-0.0167		$1,568,983	$1,229,952	-$339,031	-22%
OVERALL RATE	2.7299	2.7132	-0.0167		$48,414,364	$46,885,260	-$1,529,104	-3%

Other GF Revenues

- State shared sales tax is up $219,000 (1.1%), from $20,300,000 to $20,519,000.
- Auto in Lieu increased $154,105 (2.5%), from $6,054,795 to $6,208,900.
- PILT is up $267,598 (8.5%), from $3,145,032 to $3,412,630.
- The County levies a ¼ -cent sales tax that is used to fund capital projects. In FY 2015, the revenues increased $619,100 (10.6%), from $5,819,100 to $6,438,200.
- The County received $550,000 in lottery revenues in FY 2015 from the state.

Special Revenues

Road Fund

- Revenues in the Road Fund increased $644,447 (5.1%), from $12,650,537 to $13,294,984.
- In FY 2015, the HURF budget increased $1,446,244 (7.7%), from $18,699,893 to $20,146,137. Actual expenditures in FY 2014 were $12,810,332 (69% of the amount budgeted).
- The FY 2015 beginning fund balance in the Road Fund was $14.4 million.

Charges to Special Districts

- In FY 2014, the County transferred $1,177,878 from the special taxing districts to the GF for indirect costs and $1,101,786 in FY 2015, broken down as follows:
  - Flood Control District - FY 2014 = $392,626; FY 2015 = $367,262
  - Library District - FY 2014 = $392,626; FY 2015 = $367,262
  - TV District - FY 2014 = $392,626; FY 2015 = $367,262

Expenditures

- Employee compensation: In FY 2014, the County awarded employees with a 2.5% COLA. The total estimated cost of the COLA was $1.7 million ($1 million to the GF). In addition, certain positions in the County were reclassified. Employee pay raises were effective July 1, 2013. In FY 2015, the BOS approved the following salary increases on condition that GF revenues exceed the budget through the first five months of the fiscal year, with an effective date of January 1, 2015: Sheriff's Dispatchers' reclassification ($59,000); Public Defender new office clerk and attorney ($33,000); Legal Defender new secretary ($42,000); Probation Department Lead PO reclassification ($16,600); Procurement Department reclassification ($13,800); and reclassification of a Legal Advocate ($15,700).
- Budgeted payroll: The FY 2014 budgeted payroll, including EREs, in the GF was $46,192,354. The budgeted payroll for TF amounted to $80,108,507. In FY 2015, the GF budgeted payroll is $46,427,746. The TF budgeted payroll dropped slightly to $79,510,772.
- Budgeted FTEs: In FY 2014, the County budgeted for 711 FTEs in the GF and 1,272 in TF. In FY 2015, the GF FTEs increased to 717 and TF FTEs increased to 1,275.
- Jail facilities: The County built a new jail which opened in December 2010. The total cost of the project was $72 million, with the majority financed through a 15-year lease purchase agreement ($25.5 million was dedicated from the County's ¼-cent sales tax). The facility has 242,000 square feet and holds 688 beds, with the ability to expand up to 850 beds upon the completion of an unfinished pod, with maximum future expansion up to 1,400 beds. The FY 2015 budget for the jail amounted to $11,921,669, which includes 150 FTEs.

Capital Projects

The budget for capital projects in FY 2015 increased from $4,174,593 to $5,239,855.

Debt

Based on the Arizona Department of Revenue FY 2014 Report of Bonded Indebtedness, Mohave County held $25,390,000 in outstanding revenue bonds, which was used to construct the jail facilities. The County recently paid the $9 million previously held in COPs that funded construction of the County administration building.

NAVAJO COUNTY

Overview

- Navajo County's GF budget in FY 2015 increased $2,559,744 (6.4%), from $39,984,750 to $42,544,494.
- The GF beginning balance in FY 2015 is up $300,000 (7.5%), from $4 million to $4.3 million. The fund balance represents 10% of the total GF.
- The County's total budget is up $2,258,988 (1.9%), from $118,533,913 to $120,792,901.

Property Values

- The primary NAV in Navajo County dropped 6.5% to $845,018,236. New construction amounted to $9,347,135 (1.11% of total NAV). Secondary NAV dropped 6.5% to $846,247,083.

Property Tax Revenues

Primary Levy

- The County adopted the maximum tax rate of $0.8185, which is $0.1190 more than last year's tax rate and $0.0624 above the TNT rate of $0.7561. As a result, the County was required to hold a TNT hearing and publish a notice of the tax increase.
- The County levied the maximum tax of $6,916,474, which resulted in $597,921 (9.5%) in additional revenue for the County.

Flood Control District

- The District's NAV decreased $57,196,933 (9%), from $638,564,841 to $581,367,908.
- The tax rate remained the same at $0.3000 in FY 2015 and generated a levy of $1,744,104, $171,591 (9%) less than last year.
- The budget decreased $250,982 (3.1%), from $7,975,948 to $7,724,966.
- The District began FY 2015 with a $7 million fund balance. The County is building up the District fund balance for the repair of the Winslow levee, which is currently in the design phase. The County anticipates the cost to repair is approximately $60 million, in which 34% will be funded by the County and 66% by the Army Corps of Engineers. County officials do not expect construction to commence for another five to seven years.

Library District

- The County increased the Library District tax rate nearly 3 cents to $0.1000. The levy of $846,247 represents an increase of $209,792 (33%) over last year's levy.
- The Library District budget increased $227,545 (38%), from $598,644 to $826,189 (includes $23,000 in state grants and $60,000 from First Things First Early Childhood Literacy).
- The District began FY 2015 with a zero fund balance.

Public Health Services District

- The BOS established the District by unanimous vote of the Board in 2002. In FY 2015, the tax rate increased nearly 3 cents, from $0.2151 to $0.2430 (the statutory rate cap is 25 cents). The levy increased $110,746 (5.7%), from $1,945,634 to $2,056,380. The MOE payment is $211,175.
- The budget (operations only) increased slightly from $1,529,701 to $1,534,083.
- The District began FY 2014 with a $600,000 fund balance. In FY 2015, the beginning fund balance is $350,000.

NAVAJO COUNTY	FY 2014 RATE	FY 2015 RATE	CHANGE	TNT	FY 2014 LEVY	FY 2015 LEVY	CHANGE	% CHANGE
Primary	0.6995	0.8185	0.1190	0.7561	$6,318,553	$6,916,474	$597,921	9%
Flood Control	0.3000	0.3000	0.0000		$1,915,695	$1,744,104	-$171,591	-9%
Library	0.0704	0.1000	0.0296		$636,455	$846,247	$209,792	33%
Public Health Services	0.2151	0.2430	0.0279		$1,945,634	$2,056,380	$110,746	6%
OVERALL RATE	1.2850	1.4615	0.1765		$10,816,337	$11,563,205	$746,868	7%

Other GF Revenues

- Auto in Lieu increased $35,295 (1.7%), from $2,031,705 to $2,067,000.
- State shared sales tax is up $731,335 (7.1%), from $10,314,665 to $11,046,000.
- Half-cent sales tax increased $604,161 (9.7%), from $6,211,839 to $6,816,000.
- In FY 2014, the County budgeted $983,382 in PILT revenue; however PILT is not included in the FY 2015 budget (actual revenues in FY 2014 amounted to $1,519,256).
- The County continues to receive $550,000 in lottery revenues from the state (included in the "other governmental" budget).

Special Revenues

Road Fund

- HURF revenue increased $790,152 (11.6%), from $6,782,564 to $7,572,716.
- Auto in Lieu decreased $24,697 (1.2%), from $2,140,407 to $2,115,710.
- The Public Works/HURF budget increased $299,216 (1.8%), from $16,760,175 to $17,059,391.

Jail Facilities

Adult facilities: The County adult jail facilities hold approximately 500 beds between the Holbrook and Show Low complexes and the average daily inmate population is 220. During FY 2014, the County expanded its facilities by adding space for a kitchen, laundry facilities, and medical examinations.

- **Budgeted Revenues:** In FY 2013, the County began charging municipalities for bed rentals at half of the federal rate for three years. In FY 2015, the County budgeted to receive $547,000 in revenue as a result. The County recently lost its contract to house inmates with the U.S. Marshals. The County recently entered into a new five-year contract with BIA for up to $2 million/year to house up to 100 inmates at $55/inmate day. In FY 2015, the County anticipates receiving $264,556 in revenue for housing BIA prisoners.
- The FY 2015 total budgeted expenditures for jail operations amount to $6,272,376 (GF budget is $4,088,334). Total medical costs in the jail facilities in FY 2014 were budgeted at approximately $210,000 and increased to $247,000 in FY 2015.

Juvenile Detention: The Juvenile Detention facility houses up to 40 beds and the average occupancy is 12. The County contracts with BIA for housing juvenile inmates at $130/day. In FY 2015, the County budgeted to receive $113,000 in revenues from BIA.

- The Juvenile Detention Fund budget is up $23,033 (2%), from $1,146,685 to $1,169,718 (GF budget is $1,139,081).

Charges to Special Districts

- Flood Control District - In FY 2014, the County transferred $214,528 from the District to the County GF for reimbursement of indirect services. In FY 2015, the County transferred $326,567 to the GF.
- Library District - FY 2014, the County charged the District $245,564. In FY 2015, the County transferred $208,575 from the District to the GF.
- Public Health Services District - The County transferred $1,041,767 from the District to the GF, of which $461,467 was for reimbursement of indirect services and $580,300 was to offset state cost shifts (AHCCCS). In FY 2015, the County will transfer $408,222 for indirect services and $580,300 for state cost shifts (AHCCCS).
- HURF - The County transferred $726,763 from HURF to the County GF for reimbursement of indirect services. In FY 2015, the County charged $769,705 to HURF for reimbursement of services.
- State Budget Flex Language: The County is planning to transfer an additional $1.430 million from its special taxing districts at the end of FY 2015 if the PILT revenues are not realized. The transfers are planned as follows: Flood Control District ($650,000); Public Health Services District ($580,300); and Library ($200,000).

Expenditures

- Employee compensation: In FY 2014, the County gave employees a 2% salary adjustment, which was decided by the Board at its December 2013 meeting. The total impact was $250,000. In FY 2015, the County awarded all employees with a 2% COLA at a total cost of $454,173 ($244,757 to the GF/$209,416 to OF). An additional 2% one-time payment may be awarded at some point during FY 2015 if funds are available with the same total impact of $454,173 ($244,747 to GF/$209,416 to OF). In addition, the County awarded market adjustments to 52 of its Sheriffs, with increases ranging from 10% to 15%. The total impact is $316,053 ($294,576 to GF/$21,477 to OF).
- Budgeted payroll: The FY 2014 budgeted payroll in the GF, including EREs, decreased from $23,775,588 to $23,526,782. Total budgeted payroll dropped from $40,951,915 to $39,595,983. In FY 2015, the budgeted GF payroll increased $1,929,523 (8.2%) to $25,456,305. Total budgeted payroll increased $2,363,616 (6%) to $41,959,599.
- Budgeted FTEs: In FY 2014, budgeted FTEs in the GF increased from 346 to 376 (increase was the result of the GF absorbing Detention Officers due to the loss of the US Marshals contract). Total FTEs increased from 659 to 679. In FY 2015, GF FTEs increased 394 and total FTEs increased to 692.
- Health benefits: In FY 2014, the County's overall rates for health insurance were anticipated to increase by 6.5%; however, as a result of many employees converting to a high deductible health plan in lieu of their existing co-pay option, the cost to the County actually decreased by approximately $100,000. Depending on the Health Plan option, the employer/employee percentage contribution split for employee coverage can range between 90/10 to 95/5 and employee/family coverage can range between 80/20 to 85/15. In FY 2015, health insurance premium costs increased 9.7%, which was distributed proportionately between the County and employees. The total impact amounted to $236,825 ($147,891 to GF/$88,934 to OF.)
- Employee vacancy & turnover rates: In FY 2013, the County had an employee vacancy rate of approximately 10.6% and a turnover rate of approximately 20% for all funds.

Capital Projects

In FY 2015, the County's capital projects budget decreased from $10,060,926 to $6,500,000 and includes the following: Jail construction ($2 million); Regional Communications ($1.25 million); Public Works Complex-Holbrook ($3 million); and Health-Holbrook ($250,000).

Debt

According to the Department of Revenue's FY 2014 Report of Bonded Indebtedness, the County held $17,150,000 in revenue bonds. In FY 2014, the County issued $10,625,000 in new revenue bonds to refund $4.8 million of its existing revenue bonds, $1.2 million for Detention Facility improvements, and $4.5 million for a new Public Works complex. As a result, the total revenue bond debt service payments decreased from $7.5 million to $3 million.

PIMA COUNTY

Overview

- Pima County's GF budget for FY 2015 is $521,401,927, an increase of $17,877,096 (3.6%) over last year's GF budget of $503,524,831.
- The County's unreserved GF balance for the beginning of this fiscal year is $32,474,480, $11,582,133 (26.3%) less than last year's budgeted fund balance of $44,056,613.
- Total financial resources available decreased $71,489,998 (4.6%), from $1,569,147,951 to $1,497,657,953. Total budgeted expenditures decreased $78,435,365 (6.2%), from $1,266,899,617 to $1,188,464,252. The large decrease in this year's total budget was mainly the result of the county excluding $84 million in the Regional Wastewater Reclamation Capital Improvement Program from the total budgeted expenditures. The total budgeted expenditures represent 79% of the total budgeted financial resources.

Property Values

- Pima County's primary NAV dropped 0.5% to $7,518,481,988. New construction amounted to $153,837,905 (2.05% of total NAV). The secondary NAV decreased 0.6% to $7,579,898,868.

Property Tax Revenues

Primary Levy

- The County increased its primary tax rate over 61 cents, from $3.6665 to $4.2779. This year's tax rate exceeded the TNT rate of $3.7633 by $0.5146. As a result, the primary tax rate is just $0.6941 below the maximum tax rate of $4.9720.
- The primary levy increased $44,477,673 (16%), from $277,155,468 to $321,633,141.

Debt Service

- The County's debt service tax rate dropped $0.0800, from $0.7800 to $0.7000. The levy decreased $6,405,500 (10.8%), from $59,464,792 to $53,059,292.
- The debt service budget is down $9,089,649 (7.3%), from $124,043,471 to $114,953,822.

Flood Control District

- The District's NAV dropped $998,769, from $6,768,456,641 to $6,767,457,872.
- The levy is up $2,591,862 (14%), from $17,834,883 to $20,539,235. The tax rate increased $0.0400, from $0.2635 to $0.3035.
- The District's budget is up $3,436,583 (27.5%), from $12,484,183 to $15,920,766 (excluding grants).
- The FY 2015 beginning fund balance was 7,390,056.

Library District

- The Pima County Library District tax rate is up $0.0600, from $0.3753 to $0.4353. The levy increased $4,259,836 (15%), from $28,487,320 to $32,747,156.
- The Library District budget is up $2,202,853 (6.3%), from $35,000,000 to $37,202,853 (excluding grants). The County operates 27 branches, a Book Mobile, and main deposit locations at the Pima County Jail and the Juvenile Detention Center.
- The FY 2015 beginning fund balance was 4,526,990.

PIMA COUNTY	FY 2014 RATE	FY 2015 RATE	CHANGE	TNT	FY 2014 LEVY	FY 2015 LEVY	CHANGE	% CHANGE
Primary	3.6665	4.2779	0.6114	3.7633	$277,155,468	$321,633,141	$44,477,673	16%
Bonds	0.7800	0.7000	-0.0800		$59,464,792	$53,059,292	-$6,405,500	-11%
Flood Control	0.2635	0.3035	0.0400		$17,947,373	$20,539,235	$2,591,862	14%
Library	0.3753	0.4353	0.0600		$28,487,320	$32,747,156	$4,259,836	15%
OVERALL RATE	5.0853	5.7167	0.6314		$383,054,953	$427,978,824	$44,923,871	12%

Stadium District

- In FY 2015, the total budgeted revenue in the Stadium District is $2,656,135. The revenue in the Stadium District is generated from car and recreational vehicle space rental surcharges of $1,590,000, charges for services provided for special events of $1,045,000 (mostly from soccer events), and $21,135 from investment earnings.
- An additional $5,531,284 is transferred in from the County GF to the District as follows: $2,295,351 from the hotel/motel tax; $1,058,002 for maintenance of baseball practice fields; and $2,177,931 in additional GF support.
- The Stadium District budget increased from $5,039,746 to $5,253,097. There is a debt service payment of $2,855,700 included in the FY 2015 budget, which is the annual debt service for the COPs issued to pay for the construction of the stadium facilities. The COPs will be paid off in December 2017.

Other GF Revenues

- State shared sales tax revenues are budgeted to bring in $106,640,000, $7,340,000 (7.4%) more than last year.
- Auto in Lieu tax is up $768,000 (3.3%), from $23,332,000 to $24,100,000.
- Transient lodging tax is up $177,267 (3.2%), from $5,493,600 to $5,670,867.
- PILT is expected to generate $2,035,000 in FY 2015.

Other Special Revenues

Transportation

- Intergovernmental revenue (HURF) is budgeted to generate $49,323,707, $89,867 more than last year.
- The transportation budget decreased $1,095,454 (2.7%), from $40,277,267 to $39,181,813.

Sheriff

- The County charges $247.83 to jurisdictions for misdemeanor arrests for the first day and $80.10/day for the remaining time served. Total revenue budgeted for correctional housing is $7,626,700 in FY 2015. The adult facility can hold up to 2,377 beds and the estimated average occupancy is 88%.
- In FY 2015, budgeted expenditures in the Sheriff's office (GF and special revenue funds) increased $1,633,497 (1.1%), from $148,893,784 to $150,527,281.

Charges to Special Districts: In FY 2015, the County moved personnel costs that had been directly charged to departments into County administrative overhead, which was offset by corresponding reductions in personnel costs.

- Library District – The County charged the District $2,797,497 in FY 2014 for administrative overhead costs. In FY 2015, the County charged the district $4,032,733.
- Flood Control District – The County charges the Flood Control District for administrative overhead and a $1.60 per parcel fee for tax assessment and collections. In FY 2014, the County charged the District $1,296,362. In FY 2015, the County charged the district $1,612,597.
- Road Fund – In FY 2014, the charge to the Road Fund was $1,800,296. In FY 2015, the County charged the district $2,876,868.

Expenditures

- Employee compensation:
  - In FY 2014, all employees received a 1% COLA effective 7/1/13 and an additional 2% effective 1/1/14 at a total cost of $6,610,336 ($4,505,480 to the GF/$2,104,856 to OF). In addition, employees received a one-time lump sum compensation adjustment on July 19, 2013 based on length of time of service since the last compensation adjustment in FY 2008, which ranged from $200 to $1,000 per employee at an estimated total cost of $5,317,800 ($3,456,570 to the GF).

- In FY 2015, the County gave employees a $0.50/hour increase. The impact to the GF was estimated at $5,257,866 and $7,793,546 to TF (these costs were absorbed within the existing departmental budgets).

- Budgeted payroll: In FY 2014, the GF budgeted payroll, including EREs, was $295,845,411 and the amount budgeted for TF was $444,134,424. In FY 2015, the budgeted payroll in the GF is up $13,709,784 (4.6%) to $309,555,195 and TF are up $20,518,505 (4.6%) to $464,652,929.
- Health benefits: The County is self-funded and anticipates costs to increase approximately 5% in FY 2015.
- Budgeted FTEs: In FY 2014, GF FTEs increased from 4,731 to 4,739 and FTEs in TF increased from 7,314 to 7,328. In FY 2015, GF FTEs increased to 4,755 and TF FTEs dropped to 7,255.

Capital Projects

The total Capital Projects fund, which includes both bond and non-bond projects, is budgeted at $145,815,785 in FY 2015. The projects are broken down as follows:

- Transportation ($62,056,308): 49 projects.
- Facilities Management ($33,915,787): 18 projects including $30 million for the Downtown Court Complex project, $690,000 for the Roy Place Building Facade Restoration Completion, and $500,000 for the Legal Services Building Lighting Retrofit.
- Regional Flood Control ($15,138,247): 12 projects, including $4 million for the Santa Cruz River Flood Control Erosion Control & Linear Park, $2.4 million for the CDO Pathway, $2 million for the Urban Drainage project, $2 million for the El Corazon de los Tres Rios Del Norte project, $1.6 million for the TV Creek, and $1 million for the Floodprone Land Acquisition Program.
- Open Space ($10,404,623): $7.5 million for the Painted Hills property acquisition, $1.4 million for Town of Sahuarita priorities, $1.3 million for Tucson Mountain Park, and $100,000 for the Raytheon Buffer.
- Natural Resources, Parks and Recreation ($8,767,599): 11 projects including $4.1 million for the Northside Community Park, $1.2 million for the Pantano Path, $870,842 for the Southeast Community Park, $723,926 for the Santa Cruz River Park, $620,686 for the Catalina Community Park, and $579,000 for the Pantano Infill.
- Information Technology ($5,345,240): 8 projects, including $2 million for Data Center Storage Growth and $1.9 million for Public Works Permitting/Licensing Application.
- Sheriff ($4,561,707): $4.5 million for the Regional Public Safety Communications System.
- Community Development ($2,621,164): 5 projects, which includes a major project of $1.1 million for Housing Reinvestment 2004 Authorization.
- Finance ($1,000,000): AMS v.3.10 upgrade.
- Office of Sustainability and Conservation ($905,110): 7 projects total.
- Elections ($750,000): Election System upgrades.
- Environmental Quality ($350,000): Environmental Remediation/El Camino del Cerro Landfill.

Sources of Funding: Bond/COPs Proceeds ($78,681,000); Intergovernmental Revenue ($22,094,324); Operating Transfers ($41,312,487); Charges for Services/Impact Fees ($3,003,300); Investment & Miscellaneous Revenue ($724,674).

- Additional CIP projects for Telecommunications, Fleet Services, and Regional Wastewater Reclamation: $1.5 million for the VoIP Phone System; $6.8 million for Fleet Services ($5.2 million for the new Fleet Services Facility and $1.3 million for the Mission Road Complex Fuel Island); $84.3 million for 62 reclamation projects.

The County paid $8.75 million for the purchase of land to expand the soccer complex at the Kino Sports Complex (down payment of $1.75 million was paid from the GF and the remaining amount to be paid off over five years). Soccer fields will be constructed in a future fiscal year when funding becomes available. The cost to build the soccer fields are estimated to be between $25 million and $35 million. In addition, the County purchased land in the Painted Hills area for $7.5 million, $3.5 million of which came from the 2004 Open Space program. The remaining amount required from both projects will be included as part of the County's bond question on the FY 2015 ballot. If voters fail to approve the ballot measure, the GF will provide the necessary funding for the Kino Sports Complex debt and the Starr Pass Environmental Enhancement Fund for Painted Hills debt.

Prop 415

At the November 2014 election, voters approved $22 million in general obligation bonds to build a new Animal Control Center.

Debt

According to the Department of Revenue's FY 2014 Report of Bonded Indebtedness, Pima County held $138,900,000 in COPs, $407,275,000 in GO bonds, and $778,750,019 in Revenue bonds. In addition, the Stadium District held $10,375,000 in lease-purchase debt and the County held $639,400 in lease-purchase debt.

GO Bond debt: The budgeted payment in FY 2015 is $53,120,800.

Street and Highway Revenue Debt Service: The 1997 Transportation Bond authorization provides for the sale of Street and Highway Revenue bonds with the debt service being repaid from HURF revenues. The budgeted debt service in FY 2015 is $18,881,569.

Certificates of Participation (COPs): The 2008 and 2009 COPs were issued primarily to fund short-term cash flow requirements affecting the construction of transportation and sewer projects. The debt service is primarily funded with operating transfers from transportation impact fees and sewer revenue funds. In January, 2010, the County issued $20 million in COPs to fund the PimaCore project for the acquisition of a countywide resource management system. In FY 2013, the County issued $54.5 million in COPs, in which $30 million funded short-term cash flow requirements, $18.5 million for the construction of Fleet services facility improvements, and $6 million for the construction of Curtis Park. The total debt service payment in FY 2015 is $40,075,738.

Additional Debt Service: The debt service for the Stadium District is $2,855,700, $2,134,085 for the Regional Wastewater Reclamation Enterprise Fund, and $69,750,706 for Sewer Revenue Bonds.

In FY 2015, the Citizen's Bond Committee is reviewing possible projects for inclusion in a bond election that will not occur until 2014 or 2015.

PINAL COUNTY

Overview

- Pinal County's GF budget for FY 2015 is $184,084,963. This is a decrease of $9,566,238 (4.9%) below the FY 2014 budget of $193,676,201. The decrease in the GF was mainly the result of a reduction in the County reserves ("designation for financial stability" line item) by $14.6 million.
- The County shows an unreserved GF balance of $40,392,961, which is $8,734,325 (17.8%) less than last year. The fund balance represents 22% of the GF budget.
- The total budget increased $4,355,538 (1.2%), from $373,723,558 to $378,079,096.

Property Values

- Primary NAV increased 0.8% to $2,005,151,766. New construction amounted to $35,575,419 (1.77% of total NAV). Secondary NAV increased 1.8% to $2,040,749,841.

Property Tax Revenues

Primary Levy

- The primary tax rate remains the same at $3.7999, which is $0.0372 less than the TNT rate of $3.8371.
- The primary property tax levy for FY 2015 is $76,193,762, generating $618,221 (0.8%) more revenue than last year's levy of $75,575,541.

Flood Control District

- The District's NAV increased $71,471,257 (4.3%), from $1,669,430,618 to $1,740,901,875.
- The levy increased $121,501 (4.3%), from $2,838,032 to $2,959,533. The tax rate for the District remained the same at $0.1700.
- The budget is down $1,414,927 (9.1%), from $15,465,579 to $14,050,652.
- In FY 2014, the fund balance in the district was $13.3 million. The FY 2015 beginning fund balance is $10,958,065.

Library District

- The Library District levy is $34,344 (1.8%) higher than last year at $1,979,527. The rate remained the same this year at $0.0970.
- The total Library District budget decreased $562,784 (24%), from $2,345,879 to $1,783,095.
- The FY 2014 fund balance in the Library District was approximately $1.8 million. The FY 2015 fund balance is approximately $500,000.

Public Health Services District

- The County BOS created the District by unanimous vote of the Board, which became effective in October 2007, and is funded by a 0.10-cent sales tax rate.
- The sales tax revenue that supports the District budget increased $223,356 (9%), from $2,492,130 to $2,715,486.
- The budget is up $623,366 (10.2%), from $6,135,086 to $6,758,452.
- In FY 2014, the fund balance was approximately $2.4 million. The FY 2015 beginning fund balance is $2,605,441.
- The MOE payment was $1,207,075 in FY 2014 and increased to $1,407,075 in FY 2015 (environmental health services added to the budget in FY 2015).
- The FY 2014 budget included a transfer of $361,888 from the District to the County GF for the debt service payment on its revenue bonds.

PINAL COUNTY	FY 2014 RATE	FY 2015 RATE	CHANGE	TNT	FY 2014 LEVY	FY 2015 LEVY	CHANGE	% CHANGE
Primary	3.7999	3.7999	0.0000	3.8371	$75,575,541	$76,193,792	$618,251	1%
Flood Control	0.1700	0.1700	0.0000		$2,838,032	$2,959,533	$121,501	4%
Library	0.0970	0.0970	0.0000		$1,945,183	$1,979,527	$34,344	2%
OVERALL RATE	4.0669	4.0669	0.0000		$80,358,756	$81,132,852	$774,096	1%

Other GF Revenues

- The half-cent sales tax increased $1,311,000 (10%), from $13,041,000 to $14,352,000.
- State shared sales tax is up $1,473,750 (5.1%), from $28,800,000 to $30,273,750.
- Auto in Lieu is up $512,500 (6%), from $8,500,000 to $9,012,500.
- PILT increased $127,757 (11.7%), from $1,087,865 to $1,215,622.
- Building permit revenues increased $217,037 (15%), from $1,446,912 to $1,663,949.
- The County received $550,000 in lottery funds in FY 2015.

Special Revenue Funds

Roads

- HURF revenue is up $1,867,958 (8.5%), from $22,000,000 to $23,867,958.
- The HURF budget is up $7,135,371 (29%), from $24,372,710 to $31,508,081.

Jail Facilities

- **Adult Jail**: The adult facility has a maximum of 1,511 beds with an average daily occupancy of 1,135. The County has a contract with the US Marshals to rent up to 250 beds at $59.74/day, and up until recently, ICE to rent up to 625 beds at $59.64/day. Consequently, the County's ICE contract was terminated on July 25, 2014, which previously generated approximately $11 million in revenue. As a result, probationary employees were terminated and vacancies were held open for position eliminations. A consultant study is currently underway to determine the most efficient and effective way to operate and staff going forward. Budgeted revenue from renting beds in the adult facility was $15,402,300 in FY 2014. In FY 2015, estimated revenues dropped to $13,874,500. Now as a result of the terminated contract, an initial budget reduction of $5 million was approved by the Board, with further reductions to be determined once the study is final.
- **Juvenile**: The juvenile facility holds 96 beds, with an average occupancy of 23. Up to 22 beds are rented to the US Marshals at $175/day (average beds rented to the US Marshals is 4).

Charges to Special Districts

- Flood Control District - In FY 2014, the County charged the District $50,000 for reimbursement of services. The FY 2015 budgeted transfer is $47,413.
- Library District - In FY 2014 and FY 2015, the County charged the District $650,000.
- Public Health Services District - In FY 2014, the County charged the District $406,003. In FY 2015, the County is not charging the District due to the District taking over environmental Health Services and transportation program as a result of the loss in grant funding.
- Road Fund – The County charged the Fund $1,751,594 in FY 2014 and FY 2015 for indirect costs.

Expenditures

- Employee compensation: In FY 2014, the County awarded employees with a 2.5% merit increase (effective Spring 2014). The annualized cost was approximately $2.4 million. In FY 2015, an equivalent increase of 2.5% has been set aside in the budget that may be awarded to employees in the fourth quarter if approved by the Board. County officials state that the Board's approval depends on the financial status of the County at that time and the outcome of a classification and compensation study that is currently being conducted. If implemented, the annualized total impact will be $2.8 million ($2.2 million to the GF). The County currently has a 14-step system but there is no guarantee that employees will automatically receive a step increase and the Board will decide if that is something they want to authorize in the future. After the study, the County may move away from the 14-step system.

- Budgeted payroll: In FY 2015, GF budgeted payroll, including EREs, increased from $111 million to $113.2 million. Total payroll is up from $146.7 million to $149.8 million.
- Health benefits: In FY 2013, the County covered a flat amount toward employee benefits at $6,741/employee. The County absorbed 100% of the increase in insurance premiums, which was estimated to be 10%. The budgeted cost of the increase to the County was $503,909 to the GF and $686,801 to all funds. The County did no budget for any cost increases in FY 2014. In FY 2015, the flat rate benefit for contribution is $7,709/employee. Increases due to ACA were passed on to employees in the form of increasing their contributions and other actuary increases were absorbed by the County. The Impact to the County GF was approximately $1 million and $1.5 million to TF.
- Budgeted FTEs: In FY 2015, GF FTEs increased 28 to 1,572 and total FTEs decreased 5 to 2,118.
- Employee vacancy & turnover rates: The County has a vacancy rate factor of approximately 7%. The County does not currently calculate a turnover rate.

Capital Projects

The total capital projects budget in FY 2015 is $20,282,039:

- Countywide Computer Project ($2,860,000)
- Public Works/Kelvin Bridge ($5,931,000)
- Public Works/Gantzel Road ($8,759,987)
- Fairgrounds ($154,552)
- Capital projects miscellaneous ($2,574,500)

The BOS will consider approval of the four additional projects at its November meeting: Hunt Hwy ($20 m), Ironwood Dr. imps ($5 m), upgrade of radio systems for Sheriff's office ($19 m), and master plan for courts construction & security ($15 M).

Debt

According to the Department of Revenue's FY 2014 Report of Bonded Indebtedness, the County held $54,620,000 in MPC debt and $78,960,000 in revenue bonds. In addition, the County held $566,443 in lease-purchase debt.

In FY 2011, the County issued $30.4 million in new revenue bonds, of which $12 million was for construction of health clinics and renovations of human resources and administration office space. Over $18 million was for the refunding of the Series 2001 COPs.

At its November meeting, the BOS will consider the refinancing of approximately $41 million of the 2006 GADA loan and approximately $45 million of the 2004 COPS that was issued for the adult detention facility and other projects. The financing will be secured with excise tax revenue and may occur in the spring of 2015.

Debt Service Payments: Total debt service payments in FY 2015 amount to a total of $15,683,726 and include the following:

- Adult/juvenile detention expansion COP ($4,970,425); Series 2010 refunding bond ($2,500,900); capital leases ($89,019).
- GADA loan: Ironwood/Gantzel Road ($5,121,175); Animal Control expansion ($213,085); 2008 long-term care facility ($347,665); and various projects ($1,581,238).
- Series 2010 bonds/public health clinic and GF ($770,076).
- Lease & Long-Term Debt: Heavy equipment leases ($90,143).

SANTA CRUZ COUNTY

Overview

- Santa Cruz County's FY 2015 GF budget is $28,661,791, which is $1,157,342 (4.2%) higher than last year's budget of $27,504,449.
- The County started the year with an unreserved GF balance of $10,336,084. This is $613,607 (5.6%) below last year's balance of $10,949,691. The fund balance represents 35.6% of the total GF budget.
- This year's total budget of $74,308,956 is $3,953,722 (5.6%) more than last year's adopted budget of $70,355,234.

Property Values

- The primary NAV decreased 5.1% to $320,999,663. New construction amounted to $3,574,722 (1.11% of total NAV). The secondary NAV dropped 4.7% to $323,843,644.

Property Tax Revenues

Primary Levy

- The primary property tax rate of $3.6471 that was adopted by Santa Cruz County is the county's TNT rate, which is up $0.2256 from last year's adopted rate of $3.4215.
- The adopted primary property tax levy of $11,707,247 is $130,374 (1.1%) higher than last year's levy of $11,576,873.

Flood Control District

- The District's NAV decreased $17,202,133 (5.5%), from $311,805,366 to $294,603,233.
- The levy is up $15,152 this year, from $2,133,684 to $2,148,836. The rate increased $0.0451, from $0.6843 to $0.7294.
- The budget is down $539,326 (7.2%), from $7,454,383 to $6,915,057, of which $4,153,207 is dedicated as reserves.

SANTA CRUZ COUNTY	FY 2014 RATE	FY 2015 RATE	CHANGE	TNT	FY 2014 LEVY	FY 2015 LEVY	CHANGE	% CHANGE
Primary	3.4215	3.6471	0.2256	3.6471	$11,576,873	$11,707,247	$130,374	1%
Flood Control	0.6843	0.7294	0.0451		$2,133,684	$2,148,836	$15,152	1%
OVERALL RATE	4.1058	4.3765	0.2707		$13,710,557	$13,856,083	$145,526	1%

Other GF Revenues

- Auto in Lieu tax revenues are up $100,000 (7.7%), from $1,300,000 to $1,400,000.
- The half-cent sales tax is up $300,000 (13%), from $2,300,000 to $2,600,000.
- State shared sales tax is up $600,000 (15.4%), from $3,900,000 to $4,500,000.
- PILT stayed the same at $900,000.
- The County budget includes $550,000 in state Lottery revenues.

Special Revenue Funds

- Road fund revenue is up $231,000 (5.6%), from $4,119,000 to $4,350,000.
- Forest fees decreased $75,000 (13%), from $575,000 to $500,000.
- The Road Fund budget increased $300,804 (5%), from $5,966,584 to $6,267,388.

Jail District

- Voters approved the Jail District in November 2005, with the ability to levy a half-cent sales tax effective 7/1/06. In FY 2015, total revenues in the District decreased $1,497,891 (30%), from $5,000,000 to $3,502,109, which includes a combination of the ½-cent sales tax revenue and revenue from renting beds to other entities.

- **Adult facilities:** The adult jail facility holds 377 beds and the average occupancy is approximately 35%.
- The Jail District budget is down $2,087,510 (23%), from $9,081,023 to $6,993,513. The FTEs in the District dropped from 85 to 77. Total personnel compensation costs FTEs in the District, with total personnel compensation costs, including EREs, dropped from $4,043,644 to $2,617,876 (salaries from $2.8 million to $1.8 million). [Changes made to the personnel costs in the Jail District at final budget adoption are not reflected in Schedule G of the budget per County officials.]
- In FY 2015, medical expenses in the jail facilities are down from $900,000 to $400,000 as a result of the reduction in the jail population. The County now has three nurses (down from four) assigned to the jail facilities.
- In FY 2014, the District anticipated renting approximately 140 beds on average to other entities, such as the US Marshals, ICE, and Customs, at a charge of $65/day. The Feds are responsible for any additional medical and dental costs, as well as transportation costs. In FY 2014, approximately $2 million was estimated in revenue for the housing of inmates for other jurisdictions, which is down from the previous year's revenue estimate of $3 million. In FY 2015, the estimated revenue for renting beds to Federal prisoners plummeted to $700,000. Like other Arizona counties, Santa Cruz County is experiencing a dramatic decline in the housing of federal inmates.
- The MOE payment increased from $3,015,761 to $3,076,077.
- **Juvenile jail facility:** The juvenile facility was completed in 2010 and holds 32 beds. The current occupancy levels are low.

Charges to Special Districts:
- Flood Control District - The County charged the District $108,066 in FY 2014 and FY 2015.
- Road Fund - The amount charged to the Road Fund in FY 2014 and FY 2015 was $279,019.

Expenditures
- Employee compensation: In FY 2014, the County awarded employees with a one-time bonus of $1,000 for full-time employees and $500 for part-time permanent employees, effective December 2014. The total impact was $205,000 ($160,000 to the GF). In FY 2015, the County budgeted for a 5% across the Board raise for all permanent employees, which was awarded in October 2014. The estimated total impact was $785,000 ($359,000 to the GF).
- Budgeted payroll: In FY 2015, GF budgeted payroll, including EREs, increased from $11,695,322 to $11,817,048. Total budgeted payroll decreased from $23,586,796 to $23,353,224.
- Health benefits: Health premiums did not increase in FY 2013. The average subsidy for employee coverage is 89.3% and 75.3% for dependents. In FY 2014, the County absorbed the increase in health insurance costs at a total cost of approximately $106,000 ($48,000 to the GF and $58,000 to other funds). In FY 2015, health premiums increased 4.3%, which was entirely absorbed by the County. The net impact between the GF and other funds was $88,278.
- Budgeted FTEs: In FY 2015, budgeted GF FTEs increased from 180 to 183 and total FTEs decreased from 386 to 378.
- Employee vacancy & turnover rates: The County employee vacancy rate is less than 5% and the estimated employee turnover rate is less than 1%.

Debt

At the end of FY 2014, Santa Cruz County held $13,585,000 in outstanding revenue bonds, which was a GADA loan used for the new court facilities (the debt is scheduled to be paid off in 2032). The debt service payment in FY 2015 is budgeted at $1,094,515 (actual payment is $994,925). The County also held $9,351,453 in lease-purchase debt.

The Santa Cruz County Jail District had $36,665,000 outstanding in revenue bonds at the end of FY 2014 and the budgeted debt service payment in FY 2015 is $3,246,506. The debt in the Jail District is scheduled to be paid off in 2031.

Flood Control District-revenue debt

In January 2012, the BOS approved a $13 million, 20-year loan for the construction of the Chula Vista Bridge and Palo Parado Road. The $13 million obligation is the result of an IGA between the County BOS and the Flood Control District, in which the BOS is the Board of Directors. The annual debt service payment amounted to $688,172 in FY 2015.

Construction on the Palo Parado project was completed in March 2013. Construction on the Chula Vista Bridge will be completed during the Fall of 2014 and the County received the necessary funding from the federal government. Based on previous estimates, the total cost of the Chula Vista project was $56 million and the County impact amounted to approximately $2 million.

Capital Projects

The capital projects budget increased from $796,602 to $2,621,661, which includes the following projects: Apron Construction ($1,770,258); Phase I Apron design ($100,000); Environmental assessment ($203,000); Courthouse construction ($16,249); Jail District Construction ($92,179); Rio Rico Rd. improvement CDBG ($380,341); CDBG projects ($59,634).

YAVAPAI COUNTY

Overview

- The County GF budget for FY 2015 of $94,937,304 is a $5,257,600 (5.9%) increase over last year's adopted budget of $89,679,704.
- This year's beginning GF balance of $6,523,933 is $1,255,932 (23.8%) more than last year's balance of $5,268,001. The fund balance represents 6.9% of the total GF.
- The total financial resources in FY 2015 increased $7,410,729 (3.3%), from $224,231,808 to $231,642,537. The total budgeted expenditures in FY 2015 amount to $199,955,116 and represent 86% of total financial resources.

Property Values

- The primary NAV decreased 0.7% to $2,217,272,811. New construction amounted to $32,593,402 (1.47% of total NAV). The County's secondary NAV dropped 0.5% to $2,267,389,484.

Property Tax Revenues

Primary Levy

- This County's primary property tax levy of $43,415,263 is the same levy as last year plus an additional $306,703 for a property tax judgment.
- The primary rate increased $0.0272, from $1.9308 to $1.9580, which is below the County's TNT rate of $1.9732.

Flood Control District

- The District's NAV increased $41,128,020 (2.2%), from $1,893,026,850 to $1,934,154,870.
- The tax rate decreased from $0.2162 to $0.2116. The levy stayed the same at $4,092,000.
- The budget decreased $749,012 (8.9%), from $8,395,225 to $7,649,213.
- In FY 2014, the beginning fund balance was 4,103,225. In FY 2015, the beginning fund balance is $3,357,213.

Library District

- The Library District rate increased from $0.1491 to $0.1512. An additional $27,977 was levied for the property tax judgment, thereby increasing the levy from $3,400,000 to $3,427,977.
- The Library District budget decreased $482,896 (10%), from $4,827,414 to $4,344,518.
- In FY 2014, the beginning fund balance was $1,361,271. In FY 2015, the beginning fund balance is $878,375.
- County employees only staff libraries in unincorporated areas of the County. Otherwise, cities administer their municipal libraries and receive a direct contribution of cash for their operations. The County supports all libraries with the library network for inter-library book loans, databases, and capital improvements.

YAVAPAI COUNTY	FY 2014 RATE	FY 2015 RATE	CHANGE	TNT	FY 2014 LEVY	FY 2015 LEVY	CHANGE	% CHANGE
Primary	1.9308	1.9580	0.0272	1.9732	$43,108,560	$43,415,263	$306,703	1%
Flood Control	0.2162	0.2116	-0.0046		$4,092,000	$4,092,000	$0	0%
Library	0.1491	0.1512	0.0021		$3,400,000	$3,427,977	$27,977	1%
OVERALL RATE	2.2961	2.3208	0.0247		$50,600,560	$50,935,240	$334,680	1%

Other GF Revenues

- The County apportions the ½-cent sales tax as follows: 45% to the GF, regional roads 40%, and 15% for capital improvements. The total budgeted ½-cent sales tax for FY 2015 is $15,150,875, which is $904,704 (6.4%) more than last year's budgeted revenues of $14,246,171.
- VLT increased $462,357 (6.8%), from $6,812,796 to $7,275,153.
- State shared sales tax is up $1,808,962 (7.3%), from $24,741,824 to $26,550,786.
- PILT revenues decreased $214,027 (8.1%), from $2,642,970 to $2,428,943.

- The County received $550,038 in Lottery revenues.

Special Revenue Funds

Road Fund

- In FY 2015, total revenues in the Public Works funds are up $3,047,710 (20.7%), from $14,706,256 to $17,753,966. The available fund balance is $16,638,728.
- The Public Works budget increased $3,738,053 (15.5%), from $24,055,810 to $27,793,863.

Jail District

- Yavapai County voters approved the Jail District in November 1999 with the authority to levy a ¼-cent sales tax to fund the District. At the November 2014 ballot, the County asked voters to increase the ¼-cent sales tax to ½-cent for an additional 20 years; however, the measure failed to pass. According to County officials, the purpose of the increased sales tax was to fund a jail in Prescott to house up to 300 beds with the capability to expand since the existing jail, which is in Camp Verde, is at its maximum occupancy. The estimated cost to build the new jail was approximately $26 million.
- In FY 2015, the sales tax will generate $7,574,902, $452,650 (6%) more than last year.
- There are approximately 600 beds in the Verde Valley adult facility, with the ability to open an additional 44 beds (the Prescott facility held 135 beds). The average occupancy of the Verde Valley facility was 533 in FY 2014. In FY 2015, the County estimated total revenues from renting beds dropped from $1,770,000 to $1,200,000 due to the decrease in U.S. Marshals prisoners. The County also rents beds to the state Department of Corrections and the tribes.
- In FY 2015, the MOE payment increased $193,133 (2.8%), from $6,836,804 to $7,029,937.
- The Jail District budget increased $580,474 (3.6%), from $16,174,634 to $16,755,108. The fund balance in the District is $1,554,291.
- In FY 2015, medical costs in the jail are budgeted at $3,172,771, plus $312,499 in contingency. The County contracts with Wexford to deliver its medical services in the jails, including restoration-to-competency (RTC) services.
- The juvenile jail facility was built during FY 2013. The facility holds 80 beds and the average occupancy is approximately 50%.

Charges to Special Districts

- Flood Control District - In FY 2014, the County charged the District $550,000 for administrative costs. In FY 2015, the County charged the District $590,000.
- Library District - In FY 2014, the County charged the District $570,340 for administrative costs. In FY 2015, the County charged the District $650,340.

Expenditures

- Employee compensation: The County did not award pay raises to employees in FY 2014. In FY 2015, the County budgeted $2,550,411 in employee pay raises: a 1% COLA , with a total impact of $960,000 ($496,968 to the GF); up to 3% for "salary compression" raises to make up for the lack of pay raises over the last several years at a total impact of $1,590,411 ($837,679 to the GF).
- Budgeted payroll: In FY 2015, the GF budgeted payroll, including EREs, increased from $56,662,616 to $59,471,232. Total budgeted payroll increased from $96,204,074 to $101,623,615.
- Health benefits: In FY 2015, the 1.5% increase in health premium insurance costs were proportionally absorbed between the County and the employees. The total impact of the insurance premium increase was $605,907 ($282,281 estimated impact to the GF). The County continues to pay 100% of employee benefit costs and 25% for dependents.
- Budgeted FTEs: The budgeted GF FTEs in FY 2015 increased from 850 to 874. The total budgeted FTEs increased from 1,504 to 1,555.

- Employee vacancy & turnover rates: The turnover rate for calendar year 2013 was 15.3%. The County removed its hiring freeze and all unbudgeted positions as a result.

Capital Projects

In FY 2015, the County's capital projects include the following, which will be funded with cash:

- Public Works addition ($2,026,446)
- Phase III of Courthouse renovations ($2,420,000)
- Marina Street renovations ($2,000,000)
- Adult Probation building-Verde Valley complex ($2,000,000)
- Health Department Facility ($2,000,000)

Debt

According to DOR FY 2014 Report of Bonded Indebtedness, the County held $21,830,105 in lease-purchase debt. This debt is the result of a 20-year, $25 million agreement in 2008 that was used to fund the Superior Court building next to the Camp Verde Jail ($11 million) and the Juvenile Detention and Administration facility on the Prescott Lakes Parkway ($14 million). This debt agreement requires annual principal and interest payments of $2,111,865 through FY 2028.

YUMA COUNTY

Overview

- Yuma County's FY 2015 GF budget decreased $1,966,018 (2.5%), from $77,258,446 to $75,292,428, which was mainly the result of a $2 million reduction in County reserves.
- The County started FY 2015 with an unreserved GF balance of $13,777,216, which is $2,799,645 (16.9%) less than last year's fund balance of $16,576,861. The fund balance represents 18.3% of the GF Budget.
- The FY 2015 total budget decreased $7,405,442 (3%), from $249,718,511 to $242,313,069.

Property Values

- The primary NAV remained nearly flat this year at $1,112,447,688. New construction amounted to $51,929,659 (4.67% of total NAV). The secondary NAV increased 0.7% to $1,139,598,176.

Property Tax Revenues

Primary Levy

- The County adopted a primary levy of $24,037,770, which is an increase of $1,121,520 (4.9%) above last year's levy of $22,916,250.
- The primary tax rate of $2.1608 is $0.1002 over last year's primary tax rate but is just below the County's TNT rate of $2.1609.

Flood Control District

- The NAV in the District dropped $31,251,711 (3.3%), from $958,740,667 to $927,488,956.
- In FY 2015, the levy decreased $91,264 (3.4%), from $2,682,668 to $2,591,404.
- The secondary tax rate for the District remained the same at $0.2794.
- In FY 2015, the District began the year with a fund balance of approximately $16.6 million. The fund balance has been accumulated for several projects, including the Smucker Park Detention Basin, in which the total estimated cost of the project is approximately $8.7 million. Last year, the District completed the design-phase of the project and is expected to be completed during FY 2015 at the latest.
- In FY 2015, the budget decreased $806,397 (3.9%), from $20,929,161 to $20,122,764.

Library District

- In 2005, the voters of Yuma County authorized the Library District to sell $53 million in GO bonds to pay for three new libraries, expansion/renovation of three branches, and enhancements of two branches throughout the County.
- The Library District levy increased $25,556, from $9,566,146 to $9,591,702 (M&O from $6,226,171 to $6,248,177; bonds from $3,339,975 to $3,343,525).
- The tax rate decreased slightly from $0.8424 to $0.8417 (M&O rate stayed constant at $0.5483; bond rate decreased from $0.2941 to $0.2934).
- The budgeted amount for debt service in FY 2015 is $7,346,862 (budgeted payment is $3,343,525 and the remainder is contingency).
- The beginning fund balance for FY 2014 was $8,319,022 and dropped down to $7.1 million in FY 2015.
- The Library District budget decreased $1,248,734 (8.6%), from $14,558,700 to $13,309,966.

YUMA COUNTY	FY 2014 RATE	FY 2015 RATE	CHANGE	TNT	FY 2014 LEVY	FY 2015 LEVY	CHANGE	% CHANGE
Primary	2.0606	2.1608	0.1002	2.1609	$22,916,250	$24,037,770	$1,121,520	5%
Flood Control	0.2794	0.2794	0.0000		$2,682,668	$2,591,404	-$91,264	-3%
Library*	0.8424	0.8417	-0.0007		$9,566,146	$9,591,702	$25,556	0%
OVERALL RATE	3.1824	3.2819	0.0995		$35,165,064	$36,220,876	$1,055,812	3%

*Yuma's Library District rate includes a rate of $0.2941 for voter-approved GO bonds in tax year 2013 and $0.2934 in tax year 2014.

Other GF Revenue

- Auto in Lieu is up $59,922 (0.9%), from $6,445,785 to $6,505,707, and is distributed as follows: $4,605,707 (GF); $950,000 (HURF-Public Works); and $950,000 (HURF-Development Services).

- The budgeted half-cent County sales tax is down $355,798 (2.9%), from $12,150,578 to $11,794,780.
- State shared sales tax increased $728,959 (4%), from $18,434,421 to $19,163,380.
- PILT is up $85,865 (2.7%), from $3,159,077 to $3,244,942.
- The County continues to receive $550,038 in state lottery revenues.

Special Revenue Funds

HURF (Road) Fund

- The County's HURF revenues are up $621,123 (6.8%), from $9,153,000 to $9,774,123. In addition to the Auto in Lieu revenues noted above, the County distributed $3,396,807 of HURF revenues to Development Services and $6,377,316 to Public Works in FY 2015.
- The HURF fund budget increased $581,506 (2.1%), from $28,024,847 to $28,606,353 ($18,438,024 in the Development Services fund and $10,168,329 in Public Works).

Jail District

- In FY 2015, the Yuma County Jail District sales tax decreased $355,798 (2.9%), from $12,150,578 to $11,794,780. In May 2011, voters approved a 20-year extension for the Jail District sales tax. The tax, which was originally scheduled to expire at the end of 2015, will now expire in 2035.
- The adult facility holds 757 beds and the average occupancy is 550. The County rents beds at $78/day for total budgeted revenues of $553,500 from the Cocopah Tribe and other entities ($43,500), the US Marshals, and other federal law enforcement agencies ($510,000). Medical expenses were budgeted at $725,000 in FY 2014 and remain the same for FY 2015.
- The juvenile facility holds 79 beds, which are rented to La Paz County and the Cocopah Tribe at an estimated $45,000 in FY 2014 and increased to $84,885 in FY 2015.
- There are 273 FTEs in the adult facility (includes 37 vacant positions) and 62 in the juvenile facility (includes 4 vacant positions).
- The County jail holds up to 757 beds, of which approximately 550 are occupied on average.
- In FY 2014, the beginning fund balance was approximately $2.8 million. The beginning fund balance in FY 2015 dropped to $308,593.
- The Jail District budget decreased $2,072,732 (10%), from $20,477,864 to $18,405,132.
- The MOE payment in FY 2015 is $6,613,040.

Public Health Services District

- The County BOS created the District in April 2005, which is funded with a local sales tax. On June 17, 2013, the Board voted to increase the sales tax rate from 0.10% to 0.112%, effective October 1, 2013. The sales tax is estimated to produce $2,630,236 in FY 2015, down $18,590 (0.7%) from last year.
- The MOE payment for the District is $786,898.
- The beginning fund balance in FY 2014 was $258,368 and increased to $895,422 in FY 2015.
- The budget increased $628,545 (14.4%), from $4,376,394 to $5,004,939.

Charges to Special Districts

- Flood Control District - The County charges the District a $2.00 per parcel fee for reimbursement of services. In FY 2014, the County charged the district $316,000 and budgeted for a charge of $177,100 in FY 2015.
- Jail District - The District was charged $573,802 by the County for reimbursement of services in FY 2014 and has budgeted to charge the district $424,665 in FY 2015.
- Public Health Services District - The County charged the District $465,524 for reimbursement of services in FY 2014. In FY 2015, the charge increased to $687,545.
- Library District - The County charged the District $331,955 for reimbursement of services in FY 2014, which dropped down to $294,580 this year.

Expenditures

- Employee compensation: In FY 2014, the County provided employees that met certain standards a step increase based on the following: 2 years < 5 years of service-1/2-step (2.5%); 5+ years of service-1 step (5%). The step increases were effective 9/2013, with a total annualized impact of $2 million ($1.1 million to the GF). [This information is based on the County Regular Step Pay Plan. The information varies for the other pay plans.]. The FY 2015 budget does not include any adjustments to employee compensation. Reclassifications: The County budgeted for twelve reclassifications in the FY 2015 budget, effective for July 1, 2014. The impact to GF budget is $27,114 and $55,570 to TF.
- Budgeted payroll: The GF budgeted payroll in FY 2015 increased from $43,938,932 to $44,575,773. The total budgeted payroll increased from $91,339,500 to $91,882,644.
- Health benefits: In FY 2014, the County increased their $250 deductible plan to a $500 deductible PPO option and reduced three plan options to one PPO and a high deductible health savings account and the County pays a percentage of the monthly premium costs. In FY 2015, the Employee Benefit Trust Fund budget increased $813,469 (4.4%), from $18,484,061 to $19,297,530. The only change in the benefit structure pertains to dependent coverage, which was changed from a 90/10 split to 80/20 split.
- Budgeted FTEs: In FY 2014, the GF FTEs were budgeted at 666 and total budgeted FTEs amounted to 1,445. In FY 2015, GF FTEs decreased to 659 and total budgeted FTEs decreased to 1,443.
- Vacancy & turnover rates: The current employee vacancy rate is approximately 7% and the turnover rate is under 1%.
- Restoration to Competency (RTC): In an effort to decrease expenditures attributable to RTC costs, the County developed its own program in FY 2014, which is modeled after the Yavapai County model that uses private providers. There are currently between seven to eight individuals funded in the program, down from ten last year.

Capital Projects

- The Capital Projects budget decreased $3,081,408 (31.6%), from $9,745,590 to $6,664,182. Capital projects slated for FY 2015 include:
  - County administration: Includes the renovation of the vacant building at 197 Main St. containing approximately 50,000 square feet. Initially, the County plans to occupy approximately 20,000 square feet with the ability to expand to full capacity. The County pledged its sales taxes to pay the debt service on the lease-purchase. The amount budgeted for the project this year is $4,484,751.
  - The remaining capital projects are included for various improvement districts ($1,129,736); Library District ($205,678); Administration-Port of Entry ($153,000); Jail District ($40,000); and general capital improvement projects ($651,017).

Debt

In FY 2013, the County entered into a lease-purchase agreement to construct the East County facility. In FY 2014, the County refunded the outstanding revenue bonds and combined that debt with $5.3 million in new debt, and increased the payoff of the debt from 10 to 20 years. According to the DOR FY 2013-14 Report of Bonded Indebtedness, the total outstanding lease purchase debt was $7,216,000. The budgeted debt service in FY 2015 is $502,450.

Library District: As of June 30, 2014, the total GO debt for the Library District was $44,310,000. Although the debt service payment in FY 2015 is reported as $7,346,862, the actual debt service payment is $3,343,525. The debt is scheduled to be paid off in FY 2035.

Jail District: The outstanding debt as of June 30, 2014 in the District was reported at $6,020,000 and the budgeted debt service payment in FY 2015 was $1,038,752. The debt will be paid off in FY 2021.

ATTACHMENT E

UNS ELECTRIC INC.'S RESPONSE TO RUCO'S FIRST SET OF DATA REQUESTS
REGARDING THE 2015 UNS ELECTRIC RATE CASE
DOCKET NO. E-04204A-15-0142
August 7, 2015

RUCO 1.06

Gila River Fuel Cost and Revenue – On page 6 of the rate case Application, followed by a table on page 7, the Company states that rate payers would receive a reduction of $9.3 million or a decrease of 3.57 percent in year 1. Please provide the percentage increase per year if one were to average the $9.3 million over a three year period (i.e. $3.1 million per year). In addition, please provide the worksheet calculation.

RESPONSE:

THE FILE LISTED BELOW CONTAINS CONFIDENTIAL INFORMATION AND IS BEING PROVIDED PURSUANT TO THE TERMS OF THE PROTECTIVE AGREEMENT.

Attached files RUCO 1.06_9.3M over _3 Years CAJ-2.xlsx and RUCO 1.06_9.3M over_3 Years Bill Impact Summary CAJ-2.xlsx provide the results of averaging the $9.3 million in cost over a three year period.

The Excel file is not identified by Bates numbers.

RESPONDENT:

Brenda Pries

WITNESS:

Craig Jones

UNS ELECTRIC INC.'S RESPONSE TO RUCO'S FIRST SET OF DATA REQUESTS REGARDING THE 2015 UNS ELECTRIC RATE CASE DOCKET NO. E-04204A-15-0142 August 7, 2015

RUCO 1.08

Purchased Power and Fuel Adjustment Clause ("PPFAC") – On page 9, of the Company's Application the Company stated "Presently, the PPFAC rate is adjusted monthly and charged to customers on a per kWh basis. The modified PPFAC will still be adjusted monthly but the adjustment will be based on a percentage change calculation. This approach will better align the changes in fuel costs with each rate classes' base." Based on this statement and the example described on page 74 of Mr. Craig A. Jones testimony, is it fair to say the following:

a. Instead of assigning a partial percentage to each customer class based on a kilowatt per hour basis, the Company essentially wants the overall change in Kilowatt hours to be divided equally and allocated to each customer class. So there is no confusion hypothetically, if there are four customer classes with the following percentage decreases – Residential 30, Small General Services 30, Large General Service 20, and Large Light and Power 20. Under the Company's new proposal, each class of customer would be allocated a 25 decrease.

b. If the answer to subpart a. is correct, then please explain why this is not cross-subsidization?

c. Please explain why customer classes no longer have to pay their fair share?

RESPONSE:

a.-c. The hypothetical, as UNS Electric understands it, could not occur under either the current method or the proposed method. Under the current PPFAC method, in any given month the PPFAC kWh rate is the same for all rate classes. However, the Base Power kWh charge, as established in the Company's most recent rate case based on actual cost differences to serve each class.. That Base Power rate typically declines as the size of the class gets larger, reflecting the higher load factors and voltage differentials. Under current tariffs the Base Power rate for the Residential, Small General Service, Large General Service and Large Power Service rates are $0.064510, $0.058241, $0.056603 and $0.041880 per kWh, respectively. For purposes of this example, if one were to assume total system sales of 1.6 GWh, total fuel costs of $77 million and a change in fuel costs of $770,000, the current method would generally divide $770,000 by the sales of 1.6 GWh and calculate a PPFAC rate of approximately $0.000481 per kWh, and this would apply to all classes equally based on consumed kWh.

Using the above Base Power rates and PPFAC rate of $0.000481, the respective percentage change to each class' fuel cost would be: 0.75%, 0.83%, 0.85% and 1.15% ($0.000481 divided by the respective Base Power cost). Under the Company's proposed percentage based PPFAC method, the PPFAC rate would be 1.00% ($770,000 of fuel cost change divided by $77 million of Base Power cost). This percentage would be applied to each rate class equally. Thereby distributing the change in overall system purchased power and fuel cost equally based on the level of Base Power approved in the most recent rate case. In the Company's opinion this better aligns changes in fuel costs with each rate classes Commission approved Base Power costs.

UNS ELECTRIC INC.'S RESPONSE TO RUCO'S FIRST SET OF DATA REQUESTS
REGARDING THE 2015 UNS ELECTRIC RATE CASE
DOCKET NO. E-04204A-15-0142
August 7, 2015

RESPONDENT:

Craig Jones

WITNESS:

Craig Jones

UNS ELECTRIC INC.'S RESPONSE TO RUCO'S FIRST SET OF DATA REQUESTS
REGARDING THE 2015 UNS ELECTRIC RATE CASE
DOCKET NO. E-04204A-15-0142
August 7, 2015

RUCO 1.16

Weather Normalization – What are the results (i.e. revenue adjustment in dollar terms) if the Company used its old weather normalization model which it used in its last rate case. Please provide your calculations and Excel worksheets.

RESPONSE:

The Company's updated weather normalization model matches the improved weather normalization model that the Company has developed since the last rate case. The new model has proven to be more statistically robust, as well as better at providing weather variance guidance with more consistent results.

The benefits of the new model are as follows:

1. It utilizes more accurate and objective measures of temperature.

   The old model took the daily high and low temperature in each day of the month to produce two daily degree day values (cooling degree days and heating degree days), each of which were then summed to produce two monthly degree day variables. The degree day variables assume a comfort level as experienced by the customer, namely 65 degrees, and insists that this comfort level is the same year-round and for all customer classes.

   The new model averages the temperature from each hour in the month and averages the dew point from each hour in the month. This level of detail is easy to capture now that we have desktop computers and data storage is not as expensive as it was, say, 50 years ago. The new model makes no attempts to define a comfort level for the customer. It merely looks at historical average temperatures and average dew points and compares it to historical usage per customer values. As such, the data can speak for itself and customers comfort levels can adapt throughout the year as outdoor temperatures change.

2. The new model is simpler and does better statistically when compared to the old model.

   The relationship between customer usage and average monthly temperature is not linear. A downfall of using cooling degree days and heating degree days is that such models attempt to model the relationship between customer usage and temperature in a linear manner. To get around this, in the old rate case, the Company used a cooling degree day variable and a heating degree day variable for each month called a seasonal dummy model. So, a cooling degree day variable for January would have the appropriate cooling degree day value for each January in the data history and a value of 0 for every other month in the data history. This leads to 12 cooling degree day variables and 12 heating degree day variables in the initial model (this might be reduced if the model produces a coefficient of 0 for any of these variables). As opposed to the new model which has one average temperature variable and one average dew point variable. Since these measures of weather do not force a linear relationship, we don't need to inflate the number of variables that we have. Even when accounting for the economic trend variable, the moving average variable, and the autoregressive variable that the new model has, which are not in the old model, this is fewer variables. Fewer variables are desirable in a statistical model when the model comparison statistics between two models are similar. The new model is not only simpler, but it has better model comparison statistics, such as R^2 and MAPE, which make it the statistically better choice.

3. The new model attempts to isolate weather effects from economical trend effects and non-weather related seasonal effects.

In the old model, the only input variables were the monthly degree day variables. In the new model, the Company includes additional variables to better capture what variances are due to weather and what variances are due to other factors. An economic trend variable has been added. The forecasts for the economic trend variables are taken from IHS.

The adoption of the use of the ARIMAX model allows the Company to account for seasonal trends that are not weather related, such as the coming and going of snow birds or students. The ARIMAX model does this largely by introducing autoregressive terms and moving average terms. The terms look for seasonal patterns in the data and attempts to capture these. The inclusion of these terms, along with the economic trend term, allow us to better estimate how much of a month's variance are due to weather as opposed to another external factor.

For these reasons, the Company found it advantageous to switch to the new model for weather normalization. Given the sophistication of the new model, it is to be expected that the results will differ slightly from the old method. Since it seems counter-productive to continue using outdated and statistically weaker models, the Company used this new model in the current rate case. For these reasons, the Company did not produce a revenue model based on the old weather normalization method.

To answer this question, the Company ran the old model to obtain the needed coefficients to produce weather normalized sales adjustments. These coefficients have been run through the sales adjustments files to produce what the adjusted sales would be based on the old method. It is a time consuming process to run these numbers through the bill frequency process and through the revenue model process, and as such, the Company has estimated what the effect of the old weather normalization model would have been on sales.

The table below contains the adjusted sales for the residential and commercial rate classes, the adjusted revenue for the respective classes based on the revenue proof for the current weather normalization method, and an estimate of revenue based on the old weather normalization method. The industrial, mining, and other rate classes are not weather normalized and therefore were not included in the table.

Adjusted Sales	Current Model (A)	Old Model (B)	Difference (A-B)	Adjusted Revenue	Current Model (C)	Old Model Estimate (C/A*B)=D	Difference (C-D)
Residential	823,953,185	839,151,190	(15,198,005)	Residential	$88,446,210	$90,077,621	($1,631,411)
Commercial	607,753,087	611,522,502	(3,769,415)	Commercial	$61,940,344	$62,324,511	($384,167)
Residential + Commercial	1,431,706,272	1,450,673,692	(18,967,420)	Residential + Commercial	$150,386,554	$152,402,131	($2,015,578)

The total adjusted test year revenue was $164,220,093, and thus the result with the old weather normalization method would be estimated to be around $166,235,671. The adjusted revenue numbers come from the "TY Revenue Proof" tab in 2015 UNSE Revenue Proof - Public Version.xlsx. The revenue numbers in this tab do not contain any pro forma adjustments to fuel. (The referenced file can be accessed in UNS Electric's electronic data room under Data Requests\Uniform Data Requests\Attachments - 1st Set\UDR 1.001\Workpapers – Schedules\Schedule G and H Support.)

RESPONDENT:

Greg Strang

WITNESS:

Craig Jones

UNS ELECTRIC INC.'S RESPONSE TO RUCO'S SECOND SET OF DATA REQUESTS
REGARDING THE 2015 UNS ELECTRIC RATE CASE
DOCKET NO. E-04204A-15-0142
August 17, 2015

RUCO 2.03

Employee Benefits – Please provide the total costs spent on the Wellness Incentive program for the test year. In addition, is the Company seeking recovery of these costs in the current rate case?

RESPONSE:

Total costs spent on the Wellness Incentive program for the test year (2014) was $15,738.

Yes, the Company is seeking recovery of these costs in the current rate case.

RESPONDENT:

Steve Bracamonte

WITNESS:

David Lewis

UNS ELECTRIC INC.'S RESPONSE TO RUCO'S SECOND SET OF DATA REQUESTS
REGARDING THE 2015 UNS ELECTRIC RATE CASE
DOCKET NO. E-04204A-15-0142
August 17, 2015

RUCO 2.04

Employee Benefits – Is the Company seeking recovery of Employee Recognition costs (i.e. $32,653) in the current rate case?

RESPONSE:

Yes, the Company is seeking recovery of Employee Recognition costs of $10,740 in the current rate case.

RESPONDENT:

Steve Bracamonte

WITNESS:

David Lewis

UNS ELECTRIC INC.'S RESPONSE TO RUCO'S SECOND SET OF DATA REQUESTS
REGARDING THE 2015 UNS ELECTRIC RATE CASE
DOCKET NO. E-04204A-15-0142
August 17, 2015

RUCO 2.05

Short-Term Incentive Program ("PEP") – What was the amount PEP paid-out during the test year? In addition, is the Company seeking recovery of these costs in the current rate case?

RESPONSE:

Short-Term Incentive ("PEP") charged to UNS Electric during the 2014 test year was $674K and was included for recovery in the current rate case.

RESPONDENT:

Steve Sims

WITNESS:

David Lewis

UNS ELECTRIC INC.'S RESPONSE TO RUCO'S THIRD SET OF DATA REQUESTS
REGARDING THE 2015 UNS ELECTRIC RATE CASE
DOCKET NO. E-04204A-15-0142
September 2, 2015

RUCO 3.1

Residential Bright Solar Customers – In brief narrative please reconcile the difference between the Company's Adjusted H-5 bill count number of 959 and the 944 which was used to calculate the Company's test year revenue and proposed revenue. In addition please provide a new H-5 bill count that reconciles to the 944 customer billing. Where did the 15 residential bright solar customers migrate to?

RESPONSE:

On a booked basis the Company had an average customer count of 79 during the test year, which calculates to 944 annual bills based on customer counts; however the test-year bill count was actually 959 bills. Typically, this would occur when a "cycle billed" customer receives more than one bill in a month. The Company did not annualize this rate schedule based on bills and maintained the customer count status for both present and proposed rates in the revenue proof.

RESPONDENT:

Brenda Pries

WITNESS:

Craig Jones

UNS ELECTRIC INC.'S RESPONSE TO RUCO'S FOURTH SET OF DATA REQUESTS
REGARDING THE 2015 UNS ELECTRIC RATE CASE
DOCKET NO. E-04204A-15-0142
September 18, 2015

RUCO 4.01

Accumulated Deferred Income Tax ("ADIT") – On page 9, of Company Witness Jason Rademacher's testimony, he states that the Company has reduced its ADIT amount by its Net Operating Loss Carryforward ("NOLC"). Please provide the amount of the NOLC ADIT offset. In addition, please provide all other components that may be affected by the NOLC ADIT adjustment in this rate case (e.g. rate base and expenses), if not already provided.

RESPONSE:

Please refer to Rate Base – Accumulated Deferred Income Taxes.xlsm provided with response to UDR 1.001 for NOLC amounts. NOLC ADIT does not impact other components in this rate case. (The referenced file can be accessed in UNS Electric's electronic data room under Data Requests\Uniform Data Requests\Attachments - 1st Set\UDR 1.001\Workpapers – Schedules\Pro Forma Adjustments.)

RESPONDENT:

Jason Rademacher

WITNESS:

Jason Rademacher

UNS ELECTRIC INC.'S RESPONSE TO RUCO'S FOURTH SET OF DATA REQUESTS REGARDING THE 2015 UNS ELECTRIC RATE CASE
DOCKET NO. E-04204A-15-0142
September 18, 2015

RUCO 4.02

Private Letter Ruling – Has the Company asked for a Private Letter Ruling from the Internal Revenue Service ("IRS"), in relation to its NOLC ADIT offset? If yes, please provide a copy of the letter sent to the IRS and the current status of this ruling.

RESPONSE:

No.

RESPONDENT:

Jason Rademacher

WITNESS:

Jason Rademacher

UNS ELECTRIC INC.'S RESPONSE TO RUCO'S FOURTH SET OF DATA REQUESTS REGARDING THE 2015 UNS ELECTRIC RATE CASE DOCKET NO. E-04204A-15-0142 September 18, 2015

RUCO 4.03

Residential Bright Solar Customers – This is a follow-up question to RUCO Data Request 3.1 in which RUCO asked the following question:

In a brief narrative please reconcile the difference between the Company's Adjusted H-5 bill count number of 959 and the 944 which was used to calculate the Company's test year revenue and proposed revenue. In addition please provide a new H-5 bill count that reconciles to the 944 customer billing. Where did the 15 residential bright solar customers migrate to?

The Company responded as follows:

On a booked basis the Company had an average customer count of 79 during the test year, which calculates to 944 annual bills based on customer counts; however the test-year bill count was actually 959 bills. Typically, this would occur when a "cycle billed" customer receives more than one bill in a month. The Company did not annualize this rate schedule based on bills and maintained the customer count status for both present and proposed rates in the revenue proof.

Thank you for your response. However the response was not fully responsive to RUCO's data request.

Based on the Company's excel "2015 UNSE Schedule H-5 *Adjusted*" the following schedule has been reproduced below:

RESIDENTIAL SERVICE BRIGHT ARIZONA COMMUNITY SOLAR							
Usage Range - kWh		Number of Bills	kWh	Cumulative Bills		Cumulative kWh	
Lower	Upper			Number of Bills	Percent of Total	kWh	Percent of Total
0	0	0	0	0	0.00%	0	0.00%
1	100	3	160	3	0.31%	160	0.02%
101	200	93	14,315	96	10.01%	14,475	1.71%
201	300	103	28,951	199	20.75%	43,426	5.12%
301	400	38	13,473	237	24.71%	56,899	6.71%
401	500	61	27,378	298	31.07%	84,277	9.94%
501	600	78	44,951	376	39.21%	129,228	15.24%
601	700	46	30,085	422	44.00%	159,313	18.79%
701	800	112	84,317	534	55.68%	243,630	28.73%
801	900	82	71,579	616	64.23%	315,209	37.17%
901	1,000	27	25,647	643	67.05%	340,856	40.19%
1,001	1,500	179	212,011	822	85.71%	552,867	65.19%
1,501	2,000	78	133,770	900	93.85%	686,637	80.97%
2,001	2,500	33	73,697	933	97.29%	760,334	89.66%
2,501	3,000	13	34,693	946	98.64%	795,027	93.75%
3,001	4,000	8	26,992	954	99.48%	822,019	96.93%
4,001	5,000	1	4,076	955	99.58%	826,095	97.41%
5,001	6,000	4	21,968	959	100.00%	848,063	100.00%
	Total	959	Average Customers	79			
			Average kWh per Bill	884			
			Median kWh	750			

This bill count coincidently is the same as the Company's excel "2015 UNSE Schedule H-5 *Unadjusted*" 959 billings. This equates to an average customer billing of 79.9166 (i.e. 959/12) customers.

As part of the audit procedure RUCO ties the billing determents contained in the Company's H-5's to the Company's test year revenues and proposed revenues. Currently they do not tie.

As was previously requested, ***please provide a new H-5 bill count that reconciles to the 944 customer billings.*** Based on the above example, the Company should be able to provide a new H-5 schedule that has total billing determinants of 944, instead of 959 as is highlighted in the above schedule.

Further, as part of the response to RUCO data request 3.1 the Company states some customers were billed twice in one month. Please provide a listing of the month(s) customers were billed twice.

RESPONSE:

Please refer to **RUCO 4.03.xlsx** for a Schedule H-5 exhibit that reconciles to the 944 customer billings. The Excel file is not identified by Bates numbers. (2015 UNSE Schedule H-5 Adjusted.xlsx can be accessed in UNS Electric's electronic data room under Data Requests\Uniform Data Requests\Attachments - 1st Set\UDR 1.001\Workpapers – Schedules\Schedule G and H Support.)

During the test year period, the months of January, March, April, October, and November had instances where some Residential Service Bright Arizona Community Solar customers were billed twice during the month. Customers can be billed more or less than once during a given month for a variety of reasons, including bill cycle scheduling and starting or stopping service.

RESPONDENT:

Brenda Pries

WITNESS:

Craig Jones

UNS ELECTRIC INC.'S RESPONSE TO RUCO'S FOURTH SET OF DATA REQUESTS
REGARDING THE 2015 UNS ELECTRIC RATE CASE
DOCKET NO. E-04204A-15-0142
September 18, 2015

RUCO 4.12

Large General Service TOU – Please explain why the Company used the following charges $0.109900 Summer on Peak, $0.033500 Summer off Peak, $0.089900 Winter on Peak, and $0.031600 (H-4) instead of tariff rates of $0.114886 Summer on Peak, $0.039866 Summer off Peak, $0.114886 Winter on Peak, and $0.026168 (H-3). In addition, the Company's TY Revenue Proof does not tie to the Company's Final Revenue Proof tab in the Company's "2015 UNSE Revenue Proof- Public Version" excel sheet test year revenue because of this discrepancy.

RESPONSE:

Below is a snap shot of Schedule H-4, which the Company filed for current and proposed rates. As shown below, the Company used its tariff rates for current bill impacts and the $0.109900 number referenced was used in the proposed bill impacts – see highlight below. These same rates are presented in Schedule H-3. (2015 UNSE Revenue Proof- Public Version.XLSX and 2015 Schedule H-4.xlsx can be accessed in UNS Electric's electronic data room under Data Requests\Uniform Data Requests\Attachments - 1st Set\UDR 1.001\Workpapers – Schedules\Schedule G and H Support.)

UNS Electric, Inc. — Schedule H-4 (Revised 6/3/2015)
Typical Bill Comparison - Present and Proposed Rates — Page 13 of 22
Test Period Ending December 31, 2014

MEDIUM GENERAL SERVICE TIME OF USE

WINTER

BILL IMPACTS CURRENT RATES

	Load Factor	Total kWh	Demand (kW)	Delivery On-Peak (kWh)	Delivery Off-Peak (kWh)	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA	Base Fuel On-Peak	Base Fuel Off-Peak	PPFAC	Net Bill
		Winter		0.29		$52.00	$12.81	$0.005470	$0.43290	0.114886	0.026168	-$0.002139	
		Summer		0.20						0.114886	0.039886		
Xsm	0.46	27,974	83	8,112	19,862	$52.00	$1,067.14	$153.02	$36.06	$932.01	$519.74	-$59.85	$2,700.12
Small	0.46	28,067	84	8,139	19,928	$52.00	$1,070.69	$153.53	$36.18	$935.11	$521.46	-$60.04	$2,708.93
Medium	0.46	48,453	144	14,051	34,402	$52.00	$1,848.37	$265.04	$62.46	$1,614.31	$900.22	-$103.66	$4,638.74
Large	0.56	62,572	186	18,146	44,426	$52.00	$2,386.98	$342.27	$80.67	$2,084.71	$1,162.54	-$133.86	$5,975.31
XLg	0.66	193,470	576	56,106	137,364	$52.00	$7,380.44	$1,058.28	$249.41	$6,445.83	$3,594.53	-$413.90	$18,366.59
Ann Avg	0.58	69,713	208	20,217	49,496	$52.00	$2,659.39	$381.33	$89.87	$2,322.62	$1,295.22	-$149.14	$6,651.29
Avg Win	0.56	65,673	196	19,045	46,628	$52.00	$2,505.28	$359.23	$84.66	$2,188.02	$1,220.16	-$140.50	$6,268.85

BILL IMPACTS PROPOSED RATES

	Load Factor	Total kWh	Demand (kW)	Delivery On-Peak (kWh)	Delivery Off-Peak (kWh)	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA	Base Fuel On-Peak	Base Fuel Off-Peak	PPFAC	Net Bill	$ Change	% Change
		Winter				$100.00	$13.05	$0.005500	$0.00000	0.089900	0.031600	$0.000000			
		Summer								0.109900	0.033500				
Xsm	0.46	27,974	83	8,112	19,862	$100.00	$1,087.14	$153.86	$0.00	$729.31	$627.62	$0.00	$2,697.93	-$2.19	-0.1%
Small	0.46	28,067	84	8,139	19,928	$100.00	$1,090.75	$154.37	$0.00	$731.73	$629.71	$0.00	$2,706.56	-$2.37	-0.1%
Medium	0.46	48,453	144	14,051	34,402	$100.00	$1,883.00	$266.49	$0.00	$1,263.22	$1,087.09	$0.00	$4,599.80	-$38.94	-0.8%

There are four key steps in the Company filed revenue proof: 1) test year revenues; 2) adjusted revenues; 3) adjusted revenues with the rebalance of fuel cost (proposed fuel rates); and 4) final revenues (proposed rates with rebalance of fuel cost – new fuel rates). The tab "TY Revenue Proof" demonstrates step one and two, whereas the tab "Final Revenue Proof" completes steps three and four. Since the average cost of fuel is reset in the case, the Company felt it was important to show this third interim step between adjusted revenues and proposed rates which shows current rates with new fuel rates. This is why all fuel rates for step three and four are the same. The comparison of adjusted test-year revenues to proposed are simply between step two and four.

Both test-year and adjusted revenues and the bill impacts use current rates for calculating current revenues and current bill impacts

RESPONDENT:

Brenda Pries

WITNESS:

Craig Jones

UNS ELECTRIC INC.'S RESPONSE TO RUCO'S FIFTH SET OF DATA REQUESTS REGARDING THE 2015 UNS ELECTRIC RATE CASE DOCKET NO. E-04204A-15-0142 October 23, 2015

RUCO 5.04

Rate Case Expense – What was amount of rate case expense agreed to by the parties in settlement Decision No. 74235 (dated December 31, 2013).

RESPONSE:

The rate case amount agreed to in the referenced decision was $300,000, which was less than the $1,086,226 actually incurred for preparing the rate case.

RESPONDENT:

Anne Liu

WITNESS:

Craig Jones

UNS ELECTRIC INC.'S RESPONSE TO RUCO'S FIFTH SET OF DATA REQUESTS
REGARDING THE 2015 UNS ELECTRIC RATE CASE
DOCKET NO. E-04204A-15-0142
October 23, 2015

RUCO 5.05

Lost Fixed Cost Recovery ("LFCR") – Is the Company still willing to honor an opt-out provision of the LFCR in this case?

RESPONSE:

The Company agreed in settlement in the last case to establish a fixed price option for Residential customers to choose, if they desired. It is the Company's understanding that this fixed price option is what RUCO is referring to in their question. With that assumption, the Company is not proposing that option in this proceeding. Company witness Craig Jones indicated this in his direct testimony on page 77 at lines 15-18 that no customers have expressed an interest in this option to date; therefore, the Company believes it's unnecessary to retain the option.

RESPONDENT:

Craig Jones

WITNESS:

Craig Jones

UNS ELECTRIC INC.'S RESPONSE TO RUCO'S FIFTH SET OF DATA REQUESTS
REGARDING THE 2015 UNS ELECTRIC RATE CASE
DOCKET NO. E-04204A-15-0142
October 23, 2015

RUCO 5.06

Director and Officers' ("D&O") Liability Insurance – Please answer the following regarding D&O Liability Insurance:

a. What is the amount of D&O insurance that the Company is requesting to recover in this rate case?

b. Please provide a copy of the insurance policy.

c. Please provide the amounts of insurance that have been paid out if any for the last 5 years.

d. Is it the Company's intention to have ratepayers bear the full burden of this cost?

RESPONSE:

a. Please see UNS Electric's response to STF 16.05. The net amount of Officers & Directors Liability insurance premium included in the test year was $40,055.

b. The Company objects to the request to provide its D&O policy because it has negotiated favorable proprietary coverage it needs to keep confidential. Without waiver of objection, please see RUCO 5.06 10-19-15 UNS DO Insurance Summary 2014 to 2015.pdf, Bates Nos. UNSE\014691-014699, for a summary of the policy which provides the essential information regarding policy limits, deductible, coverages and policy exclusions in plain English rather than having to read 6 insurance policies.

c. No D&O claims have been paid by our insurers during the test period, nor have there been any claims paid for the previous five years. However, in 2015 a claim payment within the Company deductible was made to resolve the class action litigation objecting to the merger of UNS with Fortis. The UNS Electric expense portion of that settlement was $29,015 (9.39% of total based upon Massachusetts formula). In addition, the UNS Electric portion of an accrued expense reserve for notice of the settlement to shareholders is $4,695.

d. Yes, the Company is requesting a full recovery of D&O premium expense, because it is a standard business requirement in order to retain talented directors and officers, which is a benefit to the ratepayers. In addition, the majority of claims paid by D&O insurers for this type of coverage are on behalf of the insured entity, not individual directors and officers, which is a benefit to ratepayers, rather than being exposed to multi-million dollar claims.

RESPONDENT:

Karl Zimmel

WITNESS:

David Lewis

**UNS ELECTRIC INC.'S RESPONSE TO RUCO'S FIFTH SET OF DATA REQUESTS
REGARDING THE 2015 UNS ELECTRIC RATE CASE
DOCKET NO. E-04204A-15-0142
October 23, 2015**

RUCO 5.07

Short-Term Incentive Program ("PEP") – This a follow-up to RUCO data request 2.05 in which RUCO asked the following:

What was the amount PEP paid-out during the test year? In addition, is the Company seeking recovery of these costs in the current rate case?

The Company responded:

Short-Term Incentive ("PEP") charged to UNS Electric during the 2014 test year was $674K and was included for recovery in the current rate case.

Based on the Company Income – Incentive Compensation Excel worksheet, please answer the following:

a. Please clarify that the Company is seeking recover of $673,550.92 as shown on the tab entitled query in adjusted test year expenses.

b. If no to a. The tab entitled PEP Summary Pivot shows a reduction of $(265,055) from $673,550.92 to $408,495, is this the adjusted test year expense amount that the Company is seeking in this rate case?

c. Please confirm that the $169,377 on the Rev-Exp tab is the amount of the pro-forma adjustment that relates to the PEP, which includes projected costs in 2016 and 2017, as shown on tab 3 year average adjustment.

d. Is the $169,377 in addition to the $673,550.92 or is it included in this amount? Please break-out the test year expense amount and pro-forma expense amount. In addition please identify the payroll amount associated with the PEP.

RESPONSE:

a. The Company is seeking recovery of $315,745 in normalized incentive compensation expenses as determined below:

Incentive Compensation - Query tab	$673,551
J903 PEP Transfer - PEP Summary Pivot tab	(265,055)
	408,496
Less:	
920 Capitalized - Adjusted PEP Summary tab	(26,961)
920 Capitalized - Adjusted PEP Summary tab	(72,645)
	$308,890
Add:	
Normalized 3 Yr. Avg. Adjustment	4,122
Normalized Tax	13,741
Normalized 3 Yr. Avg. incl. 2% Projected Cost	$326,753
ACC Jurisdictional Factor	.96631
Normalized Incentive Compensation Expenses	$315,745

b. Refer to part "a" above.

c. Yes.

d. No, the Company is requesting a total of $315,745, consisting of $169,377 ($175,281*.96631) plus $146,368 ($151,472*.96631). The PEP associated with total payroll is approximately 9%.

RESPONDENT:

David Lewis

WITNESS:

David Lewis

UNS ELECTRIC INC.'S RESPONSE TO RUCO'S SIXTH SET OF DATA REQUESTS REGARDING THE 2015 UNS ELECTRIC RATE CASE DOCKET NO. E-04204A-15-0142 October 23, 2015

RUCO 6.1

Injuries and damages – Please answer the following regarding Injuries and damages?

a. The Company recorded injuries and damages of $1,071,000 in 2013, please break out the amounts between legal and medical expenses.

b. Please provide more detail of the incident, (i.e. time, day, persons involved).

c. Did the Company settle? If so why?

d. Why was the Company underinsured?

e. Is the Company currently underinsured?

f. Why did the Company not acquire supplemental insurance?

g. What is the deductible amount if any?

h. Please provide the 2011, and 2012 amounts for the following accounts

Account	Account Description	FERC	FERC Description
50250	Workers' Compensation	0925	Injuries & Damages
78040	Workers' Compensation	0925	Injuries & Damages
78100	Injuries & Damages	0925	Injuries & Damages

i. At what level does the Company's general liability insurance kick-in?

j. If self-insured, please provide in a brief narrative the coverage amounts, and threshold levels.

RESPONSE:

a. The $1,071,000 expense is for the claim reserve and/or liability claim payment for three claims.

b. 1. $1 Million claim reserve for a lawsuit in which the owner and tenant of a warehouse in Nogales allege a fire at their warehouse on 05-15-2013 was caused by an improperly installed dusk to dawn light that allegedly sparked causing the fire. On 07-24-2015 a jury returned a verdict in favor of UNS Electric with zero negligence and zero damages due. In July, 2015 the claim reserve was reversed.

2. $30,000 claim reserve for a pending lawsuit in which the plaintiff alleges UNS Electric was negligent for an auto accident on 05-15-2012 in Kingman, AZ resulting in injuries to the plaintiff.

3. $41,000 claim payment to the US Forest Service for firefighting expenses from a 2008 fire in Santa Cruz County allegedly caused by a downed power line.

c. The Company won the trial for the warehouse claim in Nogales. The auto accident in Kingman has not been settled and the litigation is still pending. The U.S. Forest Service claim was settled due to the documentation of a burned power line on the ground in the vicinity of the fire.

d. The Company was not underinsured for the three above mentioned claims. The expense for each claim is within the Company's self-insured retention, similar to having a deductible. Insurers charge significant additional premium above the actuarially expected loss amount for relatively low retention levels. Risk is better mitigated by utilizing insurance premium savings from self-insured retentions to procure higher insurance policy limits for protection from catastrophic losses. The Company regularly evaluates the most efficient level of self-insurance by taking into account the reduction in insurance premium for taking a higher retention of risk compared to the expected cost of self-insured claims from the higher retention. The Company self-insurance level is prudent based upon industry surveys and evaluation of its historical loss experience.

e. No, the Company is not currently underinsured. Continued evaluations of industry benchmarks and its own loss experience support the current amount of self-insurance and insurance policy limits above the self-insured retention.

f. The amount of losses incurred within the Company's self-insured retention is less than the premium it would pay for a lower retention.

g. The Company structures its Liability and Workers' Compensation policies with self-insured retentions rather than a deductible. While deductibles and self-insured retentions are a similar concept, insurance policies with self-insured retentions are less expensive than having deductibles. In addition, the Company insurer, which insures over 94% of investor owned utilities, only writes polices with self-insured retentions, not deductibles. The Company currently has a self-insured retention of $1 Million per occurrence for Auto Liability, $2 Million per occurrence for General Liability and $500,000 per occurrence for Workers' Compensation.

h. FERC 925 Injury and Damages for 2011 and 2012 are as follows:

Account	2011	2012
50250	$30,988.02	$55,586.04
78040	(23,305.42)	(32,916.52)
78100	-	10,000.00
Total	$7,682.60	$32,669.52

i. The Company transfers its risk to insurers via commercial insurance for losses above the self-insured retention levels stated in the response to question g.

RESPONDENT:

Rigo Ramirez (parts a, h) / Karl Zimmel (parts b, c, d, e, f, g, i, j)

WITNESS:

David Lewis

UNS ELECTRIC INC.'S RESPONSE TO RUCO'S SIXTH SET OF DATA REQUESTS REGARDING THE 2015 UNS ELECTRIC RATE CASE DOCKET NO. E-04204A-15-0142 October 23, 2015

RUCO 6.2

Membership Dues – Please answer the following regarding membership dues?

a. Does the company have a more recent Edison Electric Institute Schedule of Expenses by NARUC Category for Core Dues Activities that list all nine categories (e.g. Legislative Advocacy) other than the December 31, 2005 version? If so, please provide a copy.

b. To clarify on the Company excel sheet entitled "Income – Membership Dues, tab Inv 124829," of the $35,000 invoice is it correct to say $3,500 was allocated to UNS and the remainder to TEP. If correct how was the allocation factor determined?

c. Please provide an itemized expense category listing of core activities that EEI Utility Air Regulation Groups participates in.

RESPONSE:

a. The Company does not retain the information requested through its normal course of business and/or does not have immediate access to, or authority from EEI, to provide the information requested. Please see UDR 1.54 for the EEI percentage devoted to legislative.

b. $3,500 is equal to 10% allocated to UNS Electric, Inc. (not UNS). Ten percent is representative of the amount of work generally performed by TEP's Corporate Environmental Services for UNS Electric, Inc. that relates to USWAG issues.

c. The core activities or areas of regulation that the Utility Air Regulatory Group participates in are follows:

  Ambient Standards

  Atmospheric Modeling

  Climate Change

  Control Technologies

  Hazardous Air Pollutants

  Measurement Techniques

  Nonattainment

  Plant Repair, Enforcement, and Permitting

  Regional Air Quality Effects

RESPONDENT:

Erik Bakken (parts a, c) / Rigo Ramirez (part b)

WITNESS:

David Lewis

UNS ELECTRIC INC.'S RESPONSE TO RUCO'S SIXTH SET OF DATA REQUESTS
REGARDING THE 2015 UNS ELECTRIC RATE CASE
DOCKET NO. E-04204A-15-0142
October 23, 2015

RUCO 6.3

Director and Officers Insurance – Please provide the amount of D&O prepaid insurance by month included in the test year?

RESPONSE:

As requested, listed below is the D&O prepaid insurance by month:

Month	Expense
Jan-14	$ 5,592.81
Feb-14	5,592.81
Mar-14	5,592.81
Apr-14	5,592.81
May-14	5,592.81
Jun-14	5,592.83
Jul-14	5,647.75
Aug-14	-
Sep-14	-
Oct-14	(656.68)
Nov-14	650.76
Dec-14	856.58
Total	$40,055.29

RESPONDENT:

Rigo Ramirez

WITNESS:

David Lewis

UNS ELECTRIC INC.'S RESPONSE TO RUCO'S SIXTH SET OF DATA REQUESTS
REGARDING THE 2015 UNS ELECTRIC RATE CASE
DOCKET NO. E-04204A-15-0142
October 23, 2015

RUCO 6.4

Director and Officers Insurance - Has the Company included this amount in its calculation of working capital, or any other rate base line item? If so, please specify?

RESPONSE:

Yes, the Company has included $40,055.29 of Director and Officer Insurance in its calculation of working capital.

RESPONDENT:

Rigo Ramirez

WITNESS:

David Lewis

RUCO-2

UNS ELECTRIC, INC.

DOCKET NO. E-04204A-15-0142

SURREBUTTAL TESTIMONY

OF

JEFFREY MICHLIK

ON BEHALF OF THE

RESIDENTIAL UTILITY CONSUMER OFFICE

FEBRUARY 23, 2016

TABLE OF CONTENTS

ATTACHMENTS

EXECUTIVE SUMMARY - SURREBUTTAL

The Residential Utility Consumer Office ("RUCO") has reviewed the rebuttal testimony of UNS Electric, Inc. ("Company or UNS"), and the direct testimony of Commission Staff ("Staff") and the various interveners in this docket.

The following are the Company's and RUCO's proposed rate base and adjusted operating income positions as filed in its direct, rebuttal, and surrebuttal testimonies.

Rate Base in Thousands of Dollars

Company Direct	Company Rebuttal	RUCO Direct	RUCO Surrebuttal
$355,720	$353,891	$345,131	$353,755

Adjusted Operating Income in Thousands of Dollars

Company Direct	Company Rebuttal	RUCO Direct	RUCO Surrebuttal
$8,044	$8,434	$10,517	$8,673

The following tables present the required gross revenue increase as filed by the Company and RUCO in their direct, rebuttal, and surrebuttal testimonies.

Required Dollar Increase in Gross Revenues in Thousands of Dollars

Company Direct	Company Rebuttal	RUCO Direct	RUCO Surrebuttal
$22,621	$18,457	$12,271	$17,206

Required Percentage Increase in Gross Revenues

Company Direct	Company Rebuttal	RUCO Direct	RUCO Surrebuttal
15.9%	11.78%	8.07%	10.84%

Return on Equity

Company Direct	Company Rebuttal	RUCO Direct	RUCO Surrebuttal
10.35%	9.50%	8.16%	9.13%

I. INTRODUCTION

Q. Please state your name for the record.

A. My name is Jeffrey M. Michlik.

Q. Have you previously filed testimony regarding this docket?

A. Yes, I have. I filed direct testimony in this docket on November 6, 2015.

Q. What is the purpose of your surrebuttal testimony?

A. My surrebuttal testimony will address the Company rebuttal positions and Staff's positions on revenue requirement issues.

Q. How is your surrebuttal testimony organized?

A. My surrebuttal testimony is presented in four sections. Section I provides an introduction. Section II addresses surrebuttal rate base adjustments. Section III addresses surrebuttal operating adjustments, and Section IV addresses other issues.

Q. Did the Company in its rebuttal testimony provide updated rebuttal schedules?

A. No, the Company did not provide a completed set of updated rebuttal schedules, only G and H schedules.

Q. In the Company's rebuttal testimony did the Company state what they were requesting as an updated revenue requirement?

A. Yes, the Company stated that they are in agreement with Staff's revenue requirement of $18.5 million.[1]

Q. Did the Company also state that they were in agreement with most of Staff's revenue requirement adjustments?

A. Yes.[2]

Q. Did RUCO ask the Company to provide updated rebuttal schedules?

A. Yes, in RUCO data request 11.6.

Q. What was the Company's response?

A. The Company provided an excel version of its revenue requirement model. However, it is unclear whether the updated numbers were confidential or not.

Q. Did RUCO ask the Company if it could use the numbers from the excel sheet to update the Company's position?

A. Yes.

[1] See the Rebuttal Testimony of David J. Lewis, page 6, line 17.
[2] Ibid. page 1, line 18.

Q. Did RUCO update its schedules and in the executive summary to reflect the Company's rebuttal position?

A. Yes. In addition, RUCO removed several of its adjustments as they were the same or similar to Staff's adjustments as will be explained later.

Q. Are there any corrections you would like to make at this time?

A. Yes, as will be discussed later, RUCO is revising its operating adjustment number no. 1 Base Fuel Costs.

II. SURREBUTTAL RATE BASE ADJUSTMENTS

Q. Did the Company specifically state in its rebuttal testimony which Staff rate base adjustments it was willing to accept?

A. No. However, they did provide an Exhibit to the testimony of Company witness David J. Lewis. It should be noted that page two of this exhibit is missing from docket control. Please see attachment B for a full copy of Staff and the Company's agreement.

Q. Can you please identify the rate base adjustments along with the dollar amounts that both the Company and Staff have agreed on, and RUCO is willing to accept?

A. Yes.

<u>Gila River Adjustment</u>

The Company and Staff agree to reduce rate base by $2,000,000 related to depreciation expense as deferred by the accounting order for Gila River.

<u>Director and Officers (D&O) Prepaid Insurance</u>

The Company and Staff agree to reduce D&O prepaid Insurance by 50 percent ($16,778).

Q. Did you address RUCO's adjustment to Net Operating Loss Carryforwards in your direct testimony?

A. Yes. However, based on the Internal Revenue Service issuance of two additional Private Letter Rulings that support the Company's position, RUCO has withdrawn its adjustment.

Q. Has RUCO revised its schedules to reflect these adjustments?

A. Yes.

Q. Do you have any additional comments?

A. No.

III. SURREBUTTAL OPERATING INCOME ADJUSTMENTS

Q. Did the Company specifically state in its rebuttal testimony which Staff operating income adjustments it was willing to accept?

A. No. However, they did provide an Exhibit to the testimony of Company witness David J. Lewis. It should be noted that page two of this exhibit is missing from docket control. Please see attachment B for a full copy of Staff and the Company's agreement.

Q. Can you please identify the operating income adjustments along with the dollar amounts that both the Company and Staff have agreed on, and RUCO is willing to accept?

A. Yes.

Incentive Compensation

The Company and Staff have agreed to a 50/50 sharing of incentive compensation which results in an operating income adjustment of ($14,611).

Bad Debt Expense

The Company and Staff have agreed on Bad Debt Expense which results in an operating adjustment of $489,791. In addition, $450,000 of bad debt expense relating to the mine company filing for bankruptcy has been removed resulting in a decrease in the Gross Revenue Conversion Factor.

Injuries and Damages

The Company has removed the $1,000,000 insurance claim which results in an operating income adjustment of $40,376.

Directors and Officer ("D&O") Expenses

The Company and Staff have agreed to a 50/50 sharing of D&O expenses which results in an operating income adjustment of $20,028.

OATT

The Company and Staff have agreed to an OATT amount of $14,511,531 which results in an operating income adjustment of ($12,431).

BASE FUEL RATES

Q. Based on additional information gathered from the Company during the discovery process, has RUCO revised its operating adjustment to No. 1 base fuel costs?

A. Yes. Initially this was complicated by the Company's H-3 filings in which the present base fuel rates were the same as the Company's proposed base fuel rates. Frankly, RUCO was unclear on what the Company meant by rebalancing its fuel costs in a prior data request. In a follow-up data request RUCO 8.1 (see Attachment A), the Company stated that "UNS Electric proposed base cost of fuel of $.048427 per kWh. This results in total expenses of $77,522,386 based on test-year adjusted retail sales of 1,600,809,167 kWh. The $14,869,928 reduction to Fuel costs is necessary in order to reflect the average cost of fuel and purchase power at 4.8427 cent/kWh." Therefore, the base fuel rate was also reduced and allocated to the different customer classes.

Q. Has the Company revised its H-3 schedules in rebuttal testimony to reflect the Commission approved present rates?

A. Yes. See Exhibit CAJ-R-4 of Company witness Craig A. Jones.

Q. Does RUCO agree with the Company's updated proposed base cost of fuel of $.053288 per kWh, which is the same as Staff recommended in its direct testimony?

A. No. The Company relies on Staff's calculation which uses eight months of actual costs from January through August 2015, and the Company's forecasted costs for September through December 2015. The forecasted costs were not known and measureable at the time.

Q. Did RUCO ask the Company for an updated base fuel cost which is based on known and measureable costs?

A. Yes. The Company in response to RUCO data request 10.5 stated "UNS Electric's 2015 average fuel and purchase power rate was $0.053689 per kWh. This was based on 2015 actual fuel and purchase power costs of $87,301,407 and retail sales of 1,626,067,036 kWh."

Q. Has RUCO revised its adjustment to reflect this information?

A. Yes. RUCO has updated the forecasted costs for September through December 2015 with actual costs provided by the Company, see RUCO Surrebuttal Schedule JMM-6.

SHORT-TERM INCENTIVE COMPENSATION

Q. Did you address RUCO's adjustment to short-term incentive compensation in your direct testimony?

A. Yes.

Q. Do you have any additional comments?

A. Other than Decision No. 75268, cited on page 5, line 2 of Company witness Lewis' rebuttal testimony, historically the Commission has not allowed incentive compensation to be borne 100 percent by ratepayers.

Decision No. 68487 (dated February 23, 2006) - "In Decision No. 64172, the Commission adopted Staff's recommendation regarding MIP expenses based on Staffs claim that two of the five performance goals were tied to return on equity and thus primarily benefited shareholders. We believe that Staff's recommendation for an equal sharing of the costs associated with MIP compensation provides an appropriate balance between the benefits attained by both shareholders and ratepayers. Although achievement of the performance goals in the MIP, and the benefits attendant thereto, cannot be precisely quantified, there is little doubt that both shareholders and ratepayers derive some benefit from incentive goals. Therefore, the costs of the program should be borne by both groups and we find Staff's equal sharing recommendation to be a reasonable resolution."[3]

Decision No. 70011 (dated November 27, 2007) – "We believe that Staff's recommendation provides a reasonable balancing of the interests between ratepayers and shareholders by requiring each group to bear half the cost of the incentive program. As RUCO points out, the program is comprised of elements that relate to the parent company's financial performance and cost containment goals, matters that primarily benefit shareholders."[4]

Decision No. 70360 (dated May 27, 2008) – "Consistent with our finding in the UNS Gas rate case (Decision No. 7001 1. at 26-27), we believe that Staff's recommendation provides a reasonable balancing of the interests

[3] See page, 18 line 4 of Decision No. 68487.
[4] See page, 27 line 1 of Decision No. 70011.

between ratepayers and shareholders by requiring each group to bear half the cost of the incentive program."[5]

Decision No. 70665 (dated December 24, 2008) – "In the last Southwest Gas rate case, as well as several subsequent cases we disallowed 50 percent of management incentive compensation on the basis that such programs provide approximately equal benefits to shareholders and ratepayers because the performance goals relate to Financial performance and cost containment goals as well as customer service elements. (Decision Vo. 68487 at 18.) In that Decision, we stated: In Decision No. 64 172, the Commission adopted Staff's recommendation regarding MIP expenses based on Staff's claim that two of the five performance goals were tied to return on equity and thus primarily benefited shareholders. We believe that Staff's recommendation for an equal sharing of the costs associated with MIP compensation provides an appropriate balance between the benefits attained by both shareholders and ratepayers. Although achievement of the performance goals in the MIP, and the benefits attendant thereto, cannot be precisely quantified, there is little doubt that both shareholders and ratepayers derive some benefit from incentive goals. Therefore, the costs of the program should be borne by both groups and we find Staffs equal sharing recommendation to be a reasonable resolution. (Id.) We believe the same rationale exists in this case to adopt the position advocated by Staff and RUCO to disallow 50 percent of the Company's proposed MIP costs."[6]

[5] See page, 21 line 1 of Decision No. 70360.
[6] See page, 16 line 3 of Decision No. 70665.

Decision No. 71914 (dated September 30, 2010) – "We believe that the Staff and RUCO recommendations, to require a 50/50 sharing of incentive, compensation costs, provide a reasonable balancing of the interests between ratepayers and shareholders. The equal sharing of such costs recognizes that the program is comprised of elements that relate to the parent company's financial performance and cost-containment goals, matters that primarily benefit shareholders, while at the same time recognizing that a portion of the program's incentive compensation is based on meeting customer service goals. This offers the opportunity for the Company's customers to benefit from improved performance in that area."[7] Further, in some rate cases performance pay or bonus pay has been completely disallowed by the Commission.

Decision No. 71865 (dated August 31, 2010) – "We agree with Staff that the performance pay, or bonus pay, should not be included as part of expenses included in rates."[8]

Decision No. 74568 (dated June 20, 2014) – "We agree with Staff that the Company failed to quantify or justify its proposed recovery of incentive pay, and disagree with RUCO that half of the incentive pay request should be allowed."[9]

[7] See page, 28 line 19 of Decision No. 71914.
[8] See page, 27 line 8 of Decision No. 71865.
[9] See page, 25 line 14 of Decision No. 74568.

RATE CASE EXPENSE

Q. Did you address RUCO's adjustment to rate case expense in your direct testimony?

A. Yes.

Q. Do you have any additional comments?

A. Just a few.

Q. The Company states in surrebuttal testimony that outside consulting services are expected to increase. Further, these costs are the incremental real cost associated with filing this case and should be fully recoverable. Please respond?

A. First, the Company always has the discretion on who it contracts as outside witnesses. The Company has hired another consultant H. Edwin Overcast to reiterate what Company witnesses Dukes and Jones have already stated in both their direct and rebuttal testimonies regarding the Company's three part rate design.

Q. Are you saying the Company cannot hire additional witnesses or attorneys?

A. No. They can hire as many attorney's or expert witnesses as they want, but at some point the services become duplicative, and ratepayers should not bear the extra costs. In addition, allowing utility companies more in rate case expense will only encourage this type of behavior.

Q. Has RUCO revised its schedules to reflect these adjustments?

A. Yes.

IV. OTHER ISSUES

ARIZONA PROPERTY TAX DEFERRAL

Q. Did you address the Company's Arizona Property Tax Deferral in your direct testimony?

A. Yes.

Q. Do you have any additional comments?

A. No.

GILA RIVER PROPERTY TAX DEFERRAL

Q. Did you address the Company's Gila River Property Tax Deferral in your direct testimony?

A. Yes.

Q. Do you have any additional comments?

A. Yes.

Q. In your direct testimony you stated RUCO could support a 50/50 sharing of and deferral of legal costs up to a certain limit; costs that the *Company would not ordinarily be able to recover*, in order for the Company to litigate in Arizona Tax Court against the Arizona Department of Revenue?

A. Yes.

Q. Why is that?

A. The Gila River Power Plant was a good acquisition for ratepayers. The Company only asked for a deferral of 25 percent of its costs. In addition, the Company could not defer more cost than its deferred savings. The Company also only asked for a 5.00 percent carrying cost. These benefits are just a few of the benefits identified, so RUCO sees this as an extension of the acquisition.

Q. Is RUCO's recommended 50/50 sharing of legal costs only applicable to this case and to the Gila River Property Tax deferral?

A. Yes. Unfortunately, one can argue all types of legal fees incurred outside a rate case should be deferred and are extraordinary, which would set a bad precedent going-forward.

Q. How does this benefit the Company and Shareholders in the long-run?

A. The Company is able to reduce its expenses, recover 50 percent of legal fees it would ordinary not recover, and as a result of properly managing its expenses increases its credit ratings and as a result increases shareholders value in the Company.

Q. Has the Company provided any additional information in their rebuttal filing?

A. Yes. Company Witness Mr. Rademacher states on page 9. Line 11 of his testimony:

"Q. **What factors should the Commission be aware of that will mitigate costs?**

A. UNS Electric is not the first to litigate Gila River property tax values with the ADOR. Sun Devil Holdings, the owners of Gila River Block 1 & 2, are already in Tax Court litigating the same exact issue UNS Electric plans to litigate.

Q. How does the Sun Devil litigation mitigate UNS Electric's costs?

A. If Sun Devil wins its case, the Tax Court should not need to devote as much effort to hearing interpretations of statutes from UNS Electric and the ADOR. Precedent will have been set and UNS Electric's focus would be on proving that its facts are the same as Sun Devil's. If Sun Devil loses, UNS Electric has the opportunity to drop its case and avoid further litigation costs."

Q. **Has RUCO asked the Company in a Data Request, how much the Company has incurred in legal expenses to date regarding their tax case against the Arizona Department of Revenue?**

A. Yes. However, that information is subject to a confidentiality agreement. The Company did state that it has "filed its complaint with the Tax Court and is awaiting the answer from the Defendants, which we expect in February 2016. The Company is in the pre-discovery stage of the legal proceedings."

Q. Does your silence on any of the issues, matters or findings addressed in the testimony of any of the witnesses for the Company constitute your acceptance of their positions on such issues, matters or findings?

A. No. RUCO limited its discussion to the specific issues outlined above. RUCO's lack of response to any issue in this proceeding should not be construed as agreement with the Company's position in its rebuttal testimony; rather, where there is no response, RUCO relies on its original direct testimony.

Q. Does this conclude your rebuttal testimony?

A. Yes.

ATTACHMENT A

UNS ELECTRIC INC.'S RESPONSE TO RUCO'S EIGHTH SET OF DATA REQUESTS REGARDING THE 2015 UNS ELECTRIC RATE CASE DOCKET NO. E-04204A-15-0142 December 14, 2015

RUCO 8.1

Base Power Charges – This is a follow-up data request to RUCO 4.12 which asked the questions why the Company used its proposed rates to calculate its adjusted test year revenues in relation to base fuel rates:

The Company responded by stating:

There are four key steps in the Company filed revenue proof: 1) test year revenues; 2) adjusted revenues; 3) adjusted revenues with the rebalance of fuel cost (proposed fuel rates); and 4) final revenues (proposed rates with rebalance of fuel cost – new fuel rates). The tab "TY Revenue Proof" demonstrates step one and two, whereas the tab "Final Revenue Proof" completes steps three and four. Since the average cost of fuel is reset in the case, the Company felt it was important to show this third interim step between adjusted revenues and proposed rates which shows current rates with new fuel rates. This is why all fuel rates for step three and four are the same. The comparison of adjusted test-year revenues to proposed are simply between step two and four. Both test-year and adjusted revenues and the bill impacts use current rates for calculating current revenues and current bill impacts

Please answer the following questions:

a. Did the Company adjust the overall revenue related to base fuel to $77,522,386?

b. On the Company's Cost of Service Study, tab G-6 are the Function Expenses comprised of the following costs for energy?

547 PPFAC-Fuel	$ 5,543,690
555 PPFAC-Energy	$62,964,670
565 Transmission of Electricity	$ 9,014,026
Total	$77,522,386

c. Did the Company reduced the following expense accounts in the test year?

547 PPFAC-Fuel	$ 1,028,693
555 PPFAC-Energy	$12,168,583
565 Transmission of Electricity	$ 1,672,652
Total	$14,869,928

d. Does the $14,869,928 tie to the Company's 2015 UNSE Revenue Proof-Public Version, Summary tab, Cell M46?

e. Did the Company calculate the $14,869,928 adjustment as follows?

UNS ELECTRIC INC.'S RESPONSE TO RUCO'S EIGHTH SET OF DATA REQUESTS
REGARDING THE 2015 UNS ELECTRIC RATE CASE
DOCKET NO. E-04204A-15-0142
December 14, 2015

Test Year Adjusted Billing Determinants	1,600,809,167	(A)
Proposed PPFAC Rate	0.048427	(C)
Calculated New Fuel	77,522,385.53	
Test Year Proposed PPFAC Revenue	92,392,313	(B)
PPFAC Adjustment	(14,869,928)	

Source:
(A) 2015 UNSE Revenue Proof/Summary/Test Year Adjusted Sales (kWh)
(B) 2015 UNSE Revenue Proof/Summary/Test Year Adjusted Fuel Revenue
(C) M. Sheehan PPFAC Forecast - average June 2016 - May 2017

f. How is the proposed PPFAC rate known and measureable if the PPFAC is based on an average from June 2016 – May 2017?

g. Please provide a copy of Mr. Sheehan's forecast if not already provided, if already provided please provide a bates number or reference.

h. Based on the following table presented below, were the current rates authorized by the Commission in Column [A] changed by the Company in Column [D] to represent the Company's current rates after its quote "rebalancing of base fuel rates", based on Mr. Sheehan's forecast?

UNS ELECTRIC INC.'S RESPONSE TO RUCO'S EIGHTH SET OF DATA REQUESTS
REGARDING THE 2015 UNS ELECTRIC RATE CASE
DOCKET NO. E-04204A-15-0142
December 14, 2015

		[A]	[B]	[C] = [A] * [B]	[D]	[E]	[F] = [D] * [E]	[G]
LINE NO.	RATE SCHEDULE	COMMISSION AUTHORIZED CURRENT RATES	ADJUSTED BILLING DETERMINANTS	TEST YEAR ADJUSTED REVENUE	COMPANY CURRENT RATES	ADJUSTED BILLING DETERMINANTS	TEST YEAR ADJUSTED REVENUE	Company Adjustment to Test Year Revenue
1	**Residential Service**							
2	Base Power	$ 0.06451	761,215,400	$ 49,106,005	$ 0.04926	761,215,400	$ 37,497,471	$ 11,608,535
3								
4	**Cares Residential**							
5	Base Power	$ 0.06170	58,840,325	$ 3,630,448	$ 0.04926	58,840,325	$ 2,898,474	$ 731,974
6								
7	**Residential TOU**							
8	Summer On-peak	$ 0.1296	411,735	$ 53,363	$ 0.1011	411,735	$ 41,631	$ 11,732
9	Summer Off-peak	$ 0.0396	1,412,262	$ 55,933	$ 0.0339	1,412,262	$ 47,876	$ 8,057
10	Winter On-peak	$ 0.1296	299,937	$ 38,873	$ 0.0990	299,937	$ 29,682	$ 9,192
11	Winter Off-peak	$ 0.0314	928,930	$ 29,154	$ 0.0336	928,930	$ 31,193	$ (2,038)
12								
13	**Residential TOU - Super Peak**							
14	Summer On-peak	$ 0.1700	0	$ -	$ 0.1497	0	$ -	$ -
15	Summer Off-peak	$ 0.0397	0	$ -	$ 0.0383	0	$ -	$ -
16	Winter On-peak	$ 0.1500	78	$ 12	$ 0.1497	78	$ 12	$ 0
17	Winter Off-peak	$ 0.0387	186	$ 7	$ 0.0383	186	$ 7	$ 0
18								
19	**Residential Bright Community Solar**							
20	Total Fuel Revenue	$ 0.0845	634,848	$ 53,651	$ 0.0845	634,848	$ 53,651	$ -
21								
22	**Small General Service**	$ 0.0582	118,501,366	$ 6,901,638	$ 0.0486	118,501,366	$ 5,760,351	$ 1,141,287
23								
24	**Small General Service TOU**							
25	Summer On-peak	$ 0.1296	10,833	$ 1,404	$ 0.1265	10,833	$ 1,371	$ 34
26	Summer Off-peak	$ 0.0396	93,049	$ 3,685	$ 0.0330	93,049	$ 3,072	$ 614
27	Winter On-peak	$ 0.1296	15,595	$ 2,021	$ 0.1085	15,595	$ 1,692	$ 329
28	Winter Off-peak	$ 0.0314	62,953	$ 1,976	$ 0.0329	62,953	$ 2,072	$ (96)
29								
30	**Interuptible Power Service**							
31	Base Power	$ 0.0438	35,567,841	$ 1,556,449	$ 0.0498	35,567,841	$ 1,772,015	$ (215,567)
32								
33	**Medium General Service**							
34	Base Power	$ 0.0566	445,782,493	$ 25,232,626	$ 0.0484	445,782,493	$ 21,593,704	$ 3,638,922
35								
36	**Medium General Service TOU**							
37	Summer On-peak	$ 0.1149	728,854	$ 83,735	$ 0.1099	728,854	$ 80,101	$ 3,634
38	Summer Off-peak	$ 0.0399	2,959,583	$ 118,046	$ 0.0335	2,959,583	$ 99,146	$ 18,900
39	Winter On-peak	$ 0.1149	907,877	$ 104,302	$ 0.0899	907,877	$ 81,618	$ 22,684
40	Winter Off-peak	$ 0.0262	3,122,643	$ 81,713	$ 0.0316	3,122,643	$ 98,676	$ (16,962)
41								
42	**Large Power Service 3>69kV**							
43	Base Power	$ 0.0419	58,092,107	$ 2,432,897	$ 0.0484	58,092,107	$ 2,811,658	$ (378,761)
44								
45	**Large General Service TOU (Formally LPS 3 TOU<69KV**							
46	Summer On-peak	$ 0.1236	1,259,777	$ 155,683	$ 0.1455	1,259,777	$ 183,310	$ (27,627)
47	Summer Off-peak	$ 0.0247	6,623,822	$ 163,714	$ 0.0345	6,623,822	$ 228,588	$ (64,874)
48	Winter On-peak	$ 0.0939	1,200,529	$ 112,706	$ 0.1245	1,200,529	$ 149,478	$ (36,772)
49	Winter Off-peak	$ 0.0221	6,334,135	$ 140,016	$ 0.0329	6,334,135	$ 208,456	$ (68,440)
50								
51	**Large Power Service 3>69kV**							
52	Base Power	$ 0.04188	86,421,524	$ 3,619,333	$ 0.04841	86,421,524	$ 4,183,666	$ (564,333)
53								
54								
55	**Dusk To Dawn**							
56	Base Power	$ 0.0101	2,827,250	$ 28,592	$ 0.0131	2,827,250	$ 37,065	$ (8,473)
57								
58							$ 77,896,035	$ 15,811,950
59								
60					Less: Cares		$ (372,156)	
61					Plus: Residential			
62					Less: Medium/Large		$ (1,807,790)	
63					Service Migration			
64					Plus: Large Power		$ 1,806,298	
65					Customer migration			
66					Other Fuel Adjustments PPFAC			$ (30,681,878)
67							$ 77,522,386	$ (14,869,928)

i. Please provide a brief narrative on how the $14,869,928 adjustment was allocated to each customer class (i.e. residential, small generating, large power service, etc.)? In your response include any spreadsheet or calculations to support the Company's allocation.

j. Please provide a brief narrative on how each base fuel rate was adjusted (i.e. residential

.06451 to .04926)? In your response include any spreadsheet or work papers to support your calculation.

k. When did the Company first start using this methodology?

l. Please cite the Commission Decision that authorized this methodology, and provide a copy of the decision with the specific reference to the Commission's adoption of this methodology. In addition, please state whether the case was fully litigated or a result of a settlement agreement.

m. Why is Staff's recommended base fuel cost of $0.053288 per kWh, and total expense of $85,303,919, based on retail sales of 1,600,809,167 kWh unreasonable?

n. Please provide a random sample of five customer bills for the month of October 2015 for each customer class, with names and addresses redacted.

o. Please provide a random sample of five solar customer bills for the month of October, with names and addresses redacted. Please mark as solar customers.

RESPONSE:

a. Yes, UNS Electric proposed base cost of fuel of $.048427 per kWh. This results in a total expenses of $77,522,386 based on test-year adjusted retail sales of 1,600,809,167 kWh.

b. Yes.

c. Yes. The $14,869,928 reduction to Fuel costs is necessary in order to reflect the average cost of fuel and purchase power at 4.8427 cent/kWh.

d. Yes.

e. Yes.

f. Fuel, purchased power and purchased transmission cost are presently reconcilable through the Commission approved PPFAC process. Prior to Commission Decision No. 74235 (December 31, 2013), UNS Electric was forecasting these PPFAC expenses in advance of incurring them, billing the rates based off the estimate for a year and then truing up any over or under recovery the subsequent year. Therefore, fuel recovery rates were being established and approved by the Commission based upon estimates of sales and cost for the effective period of the PPFAC rates (this is presently still the practice at TEP).

In the present proceeding UNS Electric is establishing the base fuel rates that will be charged to customers in the second half of 2016 - then adjusted monthly based on actual cost (UNS Electric only recovers the actual cost incurred). As such, UNS Electric believes it is appropriate to establish the base fuel rates as closely as possible to expected levels; including the full operation of Gila River, to mitigate true-up or reconciling adjustments.

g. **THE FILE LISTED BELOW CONTAINS CONFIDENTIAL INFORMATION AND IS BEING PROVIDED PURSUANT TO THE TERMS OF THE PROTECTIVE AGREEMENT.**

Please see RUCO 8.1g UNSE April16-March17 Forecast-Confidential.xlsx.

h. No. The rates represented in your table as column D include the Company's proposed fuel rates. The revenue proof (public version) tab TY Revenue Proof columns C – E shows the test-year revenues based on current rates. The same tab, columns G – I show the test year adjustments for customer and weather normalization based on current rates. As shown in your table the Commission authorized current base power rate for the residential class is $0.064510. This same rate was used to calculate the test-year base fuel revenues and adjusted test-year base fuel revenues for residential (see column C, row 16 and column H, row 16 in the TY Revenue Proof tab). Below, please see the snapshot of Residential TY revenues and TY Adjusted Revenues calculated based on current Commission approved rates.

UNS ELECTRIC INC.
TEST PERIOD ENDING DECEMBER 31, 2014
REVENUE PROOF

Rate Schedule	Current Rates	Test Year Billing Determinants	Test Year Billed Revenues	Adjusted Billing Determinants	Current Rates	Adjusted TY Revenue
5703 RESIDENTIAL SERVICE						
Basic Service Charge	$10.00	910,158	$9,101,580	912,420	$10.00	$9,124,200
Energy Charge 1st 400 kWh	$0.019300	306,169,110	5,909,064	305,205,763	$0.019300	5,890,471
Energy Charges 401 - 1,000 kWh	$0.034350	265,903,606	9,133,789	265,302,752	$0.034350	9,113,150
Energy Charge, all additional kWh	$0.038499	182,932,901	7,042,734	190,706,885	$0.038499	7,342,024
TCA, per kWh	$0.001140	502,144,901	572,445	502,144,901	$0.001140	572,445
Margin Total			$31,759,612			$32,042,290
Base Power	$0.064510	755,005,617	$48,705,412	761,215,400	$0.064510	$49,106,005
PPFAC Revenue	Varies by Month		(1,705,692)		Varies by Month	(1,724,767)
Total Fuel Revenue			$46,999,721			$47,381,239
Total Residential Revenue			$78,759,332			$79,423,529

In the public revenue proof tab Final Revenue Proof the company is showing the proposed fuel rates in Column C (which was incorrectly labeled as Current Rates) and uses the proposed rates in column J. See the snapshot of residential information below.

UNS ELECTRIC INC.
TEST PERIOD ENDING DECEMBER 31, 2014
FINAL REVENUE PROOF

LINE NO.	RATE SCHEDULE	CURRENT RATES/Proposed Fuel Rates	ADJUSTED BILLING DETERMINANTS	TEST YEAR ADJUSTED REVENUE	NEW BILLING DETERMINANTS	PROPOSED RATES	PROPOSED REVENUES
	RESIDENTIAL SERVICE						
1	Basic Service Charge	$10.00	912,420	$9,124,200		$20.00	$18,248,400
2	0-400	$0.019300	305,205,763	5,890,471		$0.030810	9,403,390
2	401-1,000	$0.034350	265,302,752	9,113,150		$0.050810	13,480,033
3	Over 1,000	$0.038499	190,706,885	7,342,024		$0.050810	9,689,817
3	TCA, per kWh	$0.001140	0	0		$0.000000	0
4	**Margin Total**			$31,469,845			$50,821,639
5	Base Power	$0.049260	761,215,400	$37,497,471		$0.049260	$37,497,471
6	PPFAC Revenue	Varies by Month	0	0			0
7	**Total Fuel Revenue**			$37,497,471			$37,497,471
8	**Total Residential Revenue**			$68,967,316			$88,319,110

The interim step was to provide a test-year adjusted revenue proof that tied to the ACC Adjusted test-year retail revenue presented in Schedule C-1, page 1 of 1.

i. Adjustments to base power was done in conjunction with the adjustments to non-fuel rates. The adjustments were made with two primary goals in mind: 1) levelizing the base power cost between rate classes, and 2) bill impact. Overall, there is one average cost of purchased power and fuel for the system. Except for specific instances where cost differentials can be more easily justified, such as Time-of-use rates, interruptible rates, and transmission level services, large differentials in base power costs should be reduced in the Company's opinion. In this case the Company has moved the base power amounts closer to the average cost in most classes. Bill impact must also be considered; therefore, the combination of "re-alignment" of base power and non-fuel increases had to be considered as new rates were designed. The Company believes a fair and equitable set of proposed rates was the result of these efforts. There was no specific allocation of the $14.8 million between classes to arrive at the rates. Instead the rates were calculated using the described theory to create a more equitable base power cost between the classes and the distribution of total base power cost resulting from these recalculations generated the total base power cost reflected in the revenue proof, by class.

j. Please refer to the response to RUCO 8.01 (i) above.

k. There is no specific "methodology" being used other than the simple application of the theory of proposing rates reflective of equitable cost allocation. This is a primary goal of the Company in this case, while still considering overall bill impact.

l. As discussed above, this is not a specific "methodology". It is a goal being proposed in this proceeding and part of the Company's overall request for fair and equitable rates. Fair and equitable rates are the goal of all Commission Decisions. The rates being proposed by the Company in this proceeding are just another way of getting there.

m. The Company has not made a determination yet as to the reasonableness of Staff's proposed average base fuel rate.

n. Please see RUCO 8.1n.pdf, Bates Nos. UNSE\015041-015060, for the requested sample bills.

o. Please see RUCO 8.1o.pdf, Bates Nos. UNSE\015061-015065, for the requested sample bills.

RESPONDENT:

David Lewis (a, c, e) / Brenda Pries (b, d, h, n, o) / Dallas Dukes (f, m) / Michael Sheehan (g) /

Craig Jones (i, j, k, l)

WITNESS:

David Lewis (a, c, e) / Craig Jones (b, d, h, i, j, k, l, n, o) / Dallas Dukes (f, m) /

Michael Sheehan (g)

UNS ELECTRIC INC.'S RESPONSE TO RUCO'S TENTH SET OF DATA REQUESTS REGARDING THE 2015 UNS ELECTRIC RATE CASE DOCKET NO. E-04204A-15-0142 January 18, 2016

RUCO 10.5

UNSE Base Fuel Cost – In regards to UNSE base fuel costs, please answer the following question:

a. Please provide the base fuel costs in KWh from the period January through December 2015, in total and by month.

This should approximate Staff's calculated base fuel cost of $0.053288 per KWh which used actual costs from January through August 2015, and UNSE's forecasted costs for September through December 2015. To clarify please adjust Staff's calculation of base fuel costs to account for actual costs from September through December 2015.

RESPONSE:

Please see RUCO 10.5 - UNSE 2015 Fuel and Purchase Power Costs.xlsx. Using Staff's calculation methodology, UNS Electric's 2015 average fuel and purchase power rate was $0.053689 per kWh. This was based on 2015 actual fuel and purchase power costs of $87,301,407 and retail sales of 1,626,067,036 kWh. The Excel file is not identified by Bates numbers.

RESPONDENT:

Michael Sheehan

WITNESS:

Michael Sheehan

UNS ELECTRIC INC.'S RESPONSE TO RUCO'S ELEVENTH SET OF DATA REQUESTS REGARDING THE 2015 UNS ELECTRIC RATE CASE
DOCKET NO. E-04204A-15-0142
February 4, 2016

RUCO 11.6

Rebuttal Schedules – Please provide a copy in excel format with formula intact of any changes in the Company's Revenue Requirement Schedules (A-F), Cost of Capital, Cost of Service, Rate Design Schedules, Revenue Requirement Model, Proof of Revenue, Pro-forma adjustments, Exhibits, and any other excel worksheets used to develop the Company's rebuttal testimony.

RESPONSE:

Please see UDR 3.1 for the requested information, specifically the files listed in subfolders Revenue Requirement, Sch G&H Support, and Sch G&H Support Competitively-Sensitive Confidential for the requested files.

RESPONDENT:

David Lewis / Brenda Pries

WITNESS:

David Lewis / Craig Jones

ATTACHMENT B

Exhibit DJL-R-1

CONFIDENTIAL SETTLEMENT MATERIALS SUBJECT TO RULE 408

UNS Electric, Inc.
COMPARISON OF ADJUSTMENTS TO ACC JURISDICTIONAL REVENUE REQUIREMENT
Test Year Ended December 31, 2014

	As Filed UNSE 12/31/14	STAFF Revised Pos.	RUCO Revised Pos.	UNSE Revised Pos.	STAFF Summary of Position	RUCO Summary of Position
Original Cost Rate Base - Unadjusted	$272,560,320	$ 272,560,320	$272,560,320	$ 272,560,320		
Rate Base Adjustments						
Acquisition Discount Adjustment	4,371,344	4,371,344	4,371,344	$ 4,371,344	No Adjustment	No Adjustment
Accumulated Deferred ITC	4,272,926	4,272,926	4,272,926	$ 4,272,926	No Adjustment	No Adjustment
Accumulated Deferred Income Taxes	(1,773,667)	(1,773,667)	(9,240,729)	$ (1,773,667)	No Adjustment	to reduce rate base for the NOL associated bonus depreciation.
Fortis Rate Base Adjustment	(10,249)	(10,249)	(10,249)	$ (10,249)	No Adjustment	No Adjustment
Gila River Adjustment	(11,389)	(2,011,369)	(11,389)	$ (2,011,369)	To Reduce RB by $2M related to depreciation expense as deferred by the accounting order for Gila River.	
ARO	(1,101,971)	(1,101,971)	(1,101,971)	$ (1,101,971)	No Adjustment	
Working Capital	(6,294,187)	(6,123,207)	(8,288,758)	$ (6,123,207)	CWC adjustment- Increase $187,756, D&O prepaid reduction by 50% ($16,776), Staff adjustment for D&O insurance is at Total Company not ACC jurisdiction, Staff also used 50% reduction based on total expense not average balance.	CWC and D&O prepaid
Total Adjustments to Rate Base	(547,193)	(2,376,213)	(8,008,826)	(2,376,213)		
Rate Base	$ 272,013,127	$ 270,183,980	$ 264,551,496	$ 270,183,980		
Requested Rate of Return	7.67%	7.22%	6.61%	7.22%	Capital Structure: 47.17 % debt @ 4.66% , 52.83% Equity @ 9.5%, FVI .50%, ROR on OCRB 7.22%	Capital Structure: 47.17 % debt @ 4.66% , 52.83% Equity @ 8.35%, FVI .82%, ROR on OCRB 6.61%
Required Operating Income OCRB	$20,852,600	$19,500,907	$17,486,854	$19,500,907		
Fair Value Increment of Rate Base	$83,704,602	$83,707,020	$80,579,090	$83,707,020		
Fair Value Rate Base (FVRB)	$355,717,730	$353,891,000	$345,130,586	$ 353,891,000	Modified from original Position: To correct formula error FVROR changed from 5.50% to 5.63%	Reflects OCRB proposed changes
Proposed FVROR	1.50%	0.50%	0.82%	0.50%		
Required Operating Income on FVRB	1,255,569	$418,548	$660,139	$418,548		
Original Operating Income - Unadjusted	$22,042,438	$22,042,438	$22,042,438	$22,042,438		
Operating Revenue Adjustments						
LFCR	(1,377,647)	(1,377,647)	(1,377,647)	(1,377,647)	No Adjustment	
Non-Retail Rev, Fuel & Purchase Power	-	7,781,533	3,090,705	7,781,533	Staff recommended a Base Cost of fuel of $0.053288 vs $0.048427 requested by UNSE. Staff's rate consists of actual costs from January through August 2015 and forecasted costs for September through December 2015.	RUCO adjusted base fuel revenue to reflect $0.056603 average rate. No corresponding expense adjustment.
Customer and Weather Adjustment	(6,021,912)	(6,021,912)	(6,021,912)	($6,021,912)	No Adjustment for Weather. Staff requests that the company monitor revenues and file quarterly. Concerns are surrounding the larger customers entering back into the market.	N/A
REST & DSM	(1,537,369)	(1,537,369)	(1,537,369)	($1,537,369)	No Adjustment	
Service Fees	95,034	95,034	95,034	$95,034	No Adjustment	
Other Revenues	(45,506)	(45,506)	(45,506)	($45,506)	No Adjustment	
Total Adjustments to Operating Revenues	(8,887,400)	($1,105,867)	($5,796,695)	($1,105,867)		

UNS Electric, Inc.
COMPARISON OF ADJUSTMENTS TO ACC JURISDICTIONAL REVENUE REQUIREMENT
Test Year Ended December 31, 2014

	As Filed UNSE 12/31/14	STAFF Revised Pos.	RUCO Revised Pos.	UNSE Revised Pos.	STAFF Summary of Position	RUCO Summary of Position
Operating Expense Adjustments						
Payroll Expense	(172,011)	(172,011)	(172,011)	(172,011)	Staff removed the Incentive Comp amounts associated with payroll. The adjustment however does not include Incentive comp. Staff use Total Incentive Comp and did not exclude the portion that goes to Capital. After conversation with Staff witness the adjustment will be Withdrawn.	No Adjustment
Payroll Tax Expense	(13,397)	(13,397)	(13,397)	(13,397)	Staff removed the Incentive Comp amounts associated with payroll. The adjustment however does not include Incentive comp. Staff used Total Incentive Comp and did not exclude the portion that goes to Capital. After conversation with Staff witness the adjustment will be Withdrawn.	No Adjustment
Pension & Benefits	(123,376)	(123,376)	182,472	(123,376)	No Adjustment	RUCO used a 3 year average for Medical and Dental - did not account for the amount that is O&M only.
Retiree Medical	(37,384)	(37,384)	(37,384)	(37,384)	No Adjustment	No Adjustment
Rate Case Expense	(53,349)	(53,349)	(36,882)	(53,349)	No Adjustment	Allowed $350K over 3yrs
Bad Debt Expense	358,151	489,791	358,151	489,791	Staff excluded Mercator write off from their normalization ($450K). Staff used a Three Year retail revenues total divided by 3 year retail expense.	No Adjustment
Depr. & Amort. Expense	6,624,227	6,624,227	6,624,227	6,624,227	No Adjustment	No Adjustment
Property Tax	(873,950)	(873,950)	(873,950)	(873,950)	No Adjustment	No Adjustment
Incentive Compensation	(189,378)	(14,023)	46,873	(14,023)	Staff adjusts for a 2yr average. And 50-50 sharing between ratepayers and Stakeholders.	To reduce Operating income for Wellness programs and Spot awards. And to reflect 50/50 sharing of PEP
Injuries and Damages	(355,542)	(35,442)	(11,727)	(35,442)	To remove the $1M insurance deductible we booked in 2013 but reversed in July 2015 due to a favorable outcome.	Ruco removed all of the $1,071,000 then applied a 3yr average
Membership Dues	10,590	10,590	26,107	10,590	No Adjustment	Ruco excluded all of UARG and 25.55% of EEI, leaving only their estimate of legislative advocacy
Gila River Deferred Cost	(3,100,000)	(3,100,000)	(3,100,000)	(3,100,000)	No Adjustment	No Adjustment
Fortis Acquisition Costs	5,522,093	5,522,093	5,522,093	5,522,093	No Adjustment	No Adjustment
Gila O&M and Outages	(3,370,536)	(3,370,536)	(3,370,536)	(3,370,536)	No Adjustment	No Adjustment
Income Taxes	5,174,155	4,815,650	4,751,180	4,815,650	To adjust for STAFF changes (bad debt, Inj&dam,Payroll,Incentive Comp, D&O, Interest Sync, Purchased Power)	Ruco interest Sync
OATT	(14,531,456)	(14,511,531)	(14,531,456)	(14,511,531)	Staff is recommending the OATT Revenue Requirement amount that is currently used for the TCA rate in effect during the test year (2013 Plant data) should be used.	No Adjustment
D&O Insurance	-	20,028	70,077	20,028	Removal of 50% of the D&O related expense.	To reflect a 50-50 sharing
Purchased Power	-	(7,781,533)	(3,090,705)	(7,781,533)	Corresponding adjustment to revenue.	Corresponding adjustment to revenue.
Total Adjustments to Operating Expense	(5,111,163)	(12,504,153)	(7,656,658)	(12,504,153)		
Total Net Adjustments	(13,998,563)	(13,610,020)	(13,453,353)	(13,610,020)		
Adjusted Operating Income	$8,043,875	$8,434,000	$8,589,085	$8,434,000		
Operating Income Deficiency	$14,064,294	$11,485,455	$9,557,907	$11,485,456		
Gross Revenue Conversion Factor	1.6084	1.6070	1.6084	1.6070	This is due to the removal of $450,000 bad debt expense reserve for mining company bankruptcy filing.	No Adjustment
Increase in Gross Revenue Requirement	$22,621,010	$18,457,000	$15,372,938	$18,457,000		

ATTACHMENT C

UNS Electric, Inc.
Docket No. E-04204A-15-0142
Test Year Ended December 31, 2014

TABLE OF CONTENTS TO RUCO's SURREBUTTAL SCHEDULES

UNS Electric, Inc.
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Surrebuttal Schedule JMM-1

REVENUE REQUIREMENT
ACC JURISDICTIONAL
(Thousands of Dollars)

LINE NO.	DESCRIPTION	(A) COMPANY ORIGINAL COST REBUTTAL	(B) COMPANY RCND REBUTTAL	(C) COMPANY FAIR VALUE REBUTTAL	(D) RUCO ORIGINAL COST SURREBUTTAL	(E) RUCO RCND SURREBUTTAL	(F) RUCO FAIR VALUE SURREBUTTAL
1	Adjusted Rate Base	$ 270,184	$ 437,598	$ 353,891	$ 270,049	$ 437,462	$ 353,755
2							
3	Adjusted Operating Income (Loss)	8,434	8,434	8,434	8,673	8,673	8,673
4							
5	Current Rate Of Return (Line 3 / Line 1)	3.12%	1.93%	2.38%	3.21%	1.98%	2.45%
6							
7	Required Operating Income (Line 13 X Line 1)	$ 19,920	$ 19,920	19,920	19,380	$ 19,380	$ 19,380
8							
9	Weighted Average Cost of Capital	7.22%	7.22%	7.22%	7.02%	7.021%	7.02%
10							
11	Fair Value Adjustment	0.15%	-2.67%	-1.59%	0.15%	-2.59%	-1.54%
12							
13	Required Rate of Return	7.37%	4.55%	5.63%	7.18%	4.43%	5.48%
14							
15	Operating Income Deficiency (Line 7 - Line 3)	$ 11,486	$ 11,486	11,486	10,707	10,707	10,707
16							
17	Gross Revenue Conversion Factor (Schedule JMM-2)	1.6070	1.6070	1.6070	1.6070	1.6070	1.6070
18							
19	Increase In Gross Revenue Requirement (Line 15 X Line 17)	$ 18,457	$ 18,457	$ 18,457	$ 17,206	$ 17,206	$ 17,206
20							
21	Adjusted Test Year Revenue	$ 156,716	$ 156,716	$ 156,716	$ 158,714	$ 158,714	$ 158,714
22							
23	Proposed Annual Revenue Requirement (Line 19 + Line 21)	$ 175,173	$ 175,173	$ 175,173	$ 175,920	$ 175,920	$ 175,920
24							
25	Required Percentage Increase In Revenue (Line 19 / Line 21)	11.78%	11.78%	11.78%	10.84%	10.84%	10.84%
26							
27	Rate Of Return On Common Equity	9.50%	9.50%	9.50%	9.13%	9.13%	9.13%

References:
Columns (A) Thru (C): Company Schedule A-1, C-1 and D-1
Column (D): Schedules JMM-3, JMM-8, and JMM-20
Column (E): Schedule JMM-2, Column (B)
Column (F): Average of Column (D) + Column (E) / 2

UNS Electric, Inc.
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Surrebuttal Schedule JMM-2

GROSS REVENUE CONVERSION FACTOR, INCOME TAX CALCULATION

LINE NO.	DESCRIPTION	[A] Company Proposed	[B] RUCO Recommended
1	Gross Revenue	100.00%	100.00%
2	Less: Uncollectibel Revenue	0.29%	0.29%
3	Taxable Income as a Percent	99.71%	99.71%
4	Less: Federal and State Income Taxes	37.48%	37.48%
5	Changes in Net Operating Income	62.23%	62.23%
6	Gross Revenue Conversion Factor	1.6070	1.6070

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Surrebuttal Schedule JMM-3

RATE BASE (OCRB, RCND and FVRB)
ACC JURISDICTIONAL
(Thousands of Dollars)

LINE NO.	DESCRIPTION	(A) COMPANY OCRB	(B) COMPANY RCND	(C) COMPANY FVRB	(D) OCRB/RCND % DIFF.	(E) RUCO OCRB	(F) RUCO RCND	(G) RUCO FVRB
1	Gross Utility Plant In Service	$ 664,701	$ 1,169,067	$ 916,884	175.88%	$ 664,701	$ 1,169,067	$ 916,884
2	Accumulated Depreciation	(296,962)	$ (561,910)	(429,436)	189.22%	(296,962)	(561,910)	(429,436)
3	Net Utility Plant In Service	367,739	607,156	487,448		367,739	607,156	487,448
4								
5	Citizens Acquisition Discount	(97,155)	$ (172,852)	(135,004)	177.91%	(97,155)	(172,852)	(135,004)
6	Less: Accu Amort Citizens Acq Discount	36,098	$ 69,682	52,890	193.03%	36,098	69,682	52,890
7	Net Citizens Acquisition Discount	(61,057)	(103,170)	(82,114)		(61,057)	(103,170)	(82,114)
8								
9	Total Net Utility Plant	306,682	503,986	405,334	164.33%	306,682	503,986	405,334
10								
11	Deductions:							
12	Cust. Advances For Const.	(3,833)	(4,268.465)	(4,051)	111.35%	(3,833)	(4,268)	(4,051)
13	Customer Deposits	(4,428)	(4,427.886)	(4,428)	100.00%	(4,428)	(4,428)	(4,428)
14	Other (ITC)	(422)	(421.645)	(422)	100.00%	(422)	(422)	(422)
15	Acc. Deferred Income Taxes	(35,161)	(64,616.383)	(49,889)	183.77%	(35,161)	(64,616)	(49,889)
16	Total Deductions	(43,844)	(73,734)	(58,789)		(43,844)	(73,734)	(58,789)
17								
18	Allowance - Working Capital	7,346	7,346	7,346	100.00%	7,210	7,210	7,210
19								
20	Regulatory Assets	-	-	-	100.00%	-	-	-
21								
22	Regulatory Liability	-	-	-	100.00%	-	-	-
23								
24								
25	TOTAL TEST YEAR RATE BASE	$ 270,184	$ 437,598	353,891		$ 270,049	$ 437,462	$ 353,755

References:
- Columns (A) (B) (C): Company Schedule B-1
- Column (D): Column (B) / Column (A)
- Column (E): Schedule JMM-4, Column (C)
- Column (F): Column (D) X Column (E)
- Column (G): Average Of Column (E) + Column (F) / 2

UNS Electric, Inc.
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Surrebuttal Schedule JMM-4

ORIGINAL COST RATE BASE - ACC JURISDICTIONAL (Shown in Thousands)

LINE NO.	DESCRIPTION	(A) COMPANY FILED AS OCRB	(B) RUCO ADJUSTMENTS	(C) RUCO ADJUSTED AS OCRB
1	Gross Utility Plant In Service	$ 664,701	-	$ 664,701
2	Accumulated Depreciation	(296,962)	-	(296,962)
3	Net Utility Plant In Service	367,739	-	367,739
4				
5	Citizens Acquisition Discount	(97,155)	-	(97,155)
6	Less: Accu Amort Citizens Acq Discount	36,098	-	36,098
7	Net Citizens Acquisition Discount	(61,057)	-	(61,057)
8				
9	Total Net Utility Plant	306,682	-	306,682
10				
11	Deductions:			
12	Cust. Advances For Const.	$ (3,833)	-	$ (3,833)
13	Customer Deposits	(4,428)	-	(4,428)
14	Other - Investment Tax Credits ("ITC")	(422)	-	(422)
15	Accumulated Deferred Income Taxes ("ADIT")	(35,161)	-	(35,161)
16	Total Deductions	(43,844)	-	(43,844)
17				
18	Allowance - Working Capital	7,346	(135)	7,210
19				
20	Regulatory Assets	-	-	-
21				
22	Regulatory Liability	-	-	-
23				
24				
25	TOTAL OCRB	$ 270,184	$ (135)	$ 270,049

Reconciliation to RCN (Thousands of Dollars)

	OCRB	RCN Ratio for ADIT	RCN
Company RCN as Filed			$ 437,598
RUCO ADIT Adjustment #1	$ -	1.8377	-
Cash Working Capital	(135)	1	(135)
	$ (135)		$ 437,462

References:
Column [A]: Company as Filed
Column [B]: RUCO Schedule 5
Column (C): Column (A) + Column (B)

UNS Electric, Inc.
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Surrebuttal Schedule JMM-5

SUMMARY OF ORIGINAL COST RATE BASE ADJUSTMENTS
(Thousands of Dollars)

		ACC Jurisdiction			
Line No.	DESCRIPTION	(A) Company Adjusted OCRB Rebuttal	[B] Rate Base Adjustment No. 1 Reverse Net Operating Loss Carry forward Accumulated Deferred Income Tax Offset	(C) Rate Base Adjustment No. 2 Working Capital	(D) RUCO Adjusted OCRB Recommended Balances
1	Gross Utility Plant in Service	664,701	$ -	$ -	$ 664,701
2					
3	Accumulated Depreciation	(296,962)	-	-	$ (296,962)
4	Net Utility Plant in Service	$ 367,739	$ -	$ -	$ 367,739
5					
6	Citizens Acquisition Discount	$ (97,155)	$ -	$ -	$ (97,155)
7	Accumulated Amortization - Citizens Acquisition Discount	36,098	-	-	$ 36,098
8	Net Citizens Acquisition Discount	$ (61,057)	$ -	$ -	$ (61,057)
9					
10	Total Net Utility Plant	$ 306,682	$ -	$ -	$ 306,682
11					
12	Customer Advances for Construction	$ (3,833)	$ -	$ -	$ (3,833)
13					
14	Customer Deposits	(4,428)			(4,428)
15					
16	Other - Investment Tax Credits ("ITC")	(422)			(422)
17					
18	Accumulated Deferred Income Taxes ("ADIT")	(35,161)	-		(35,161)
19	Total Deductions	$ (43,844)	$ -	$ -	$ (43,844)
20					
21					
22	Allowance for Working Capital	$ 7,346	$ -	$ (135)	$ 7,210
23					
24	Regulatory Assets	-	-	-	-
25					
26	Regulatory Liabilities	-	-	-	-
27					
28	Total Original Cost Rate Base	$ 270,184	$ -	$ (135)	$ 270,049

REFERENCES:
Column (A) Company Schedule B-1
Column (B) See RBM-4
Column (D) See RBM-5
Column (E) See Column (B) through (D)

UNS Electric, Inc.
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Surrebuttal Schedule JMM-6

RATE BASE ADJUSTMENT NO. 1
Reverse Net Operating Loss Carryforward
Accumulated Deferred Income Tax Offset

		(A)	(B)	(C)
Line No.	DESCRIPTION	Company Proposed	RUCO Adjustment	RUCO As Adjusted
1	Accumulated Deferred Taxes	$ (35,161,108)	$ -	$ (35,161,108)
	ADIT NOLC Offset	$ -		
	ACC Jurisdictional Factor	0.0000		
		$ -		

References:
Column (A) Per Company Filing
Column (B) Testimony JMM
Column (C) = Column (A) + Column (B)

UNS Electric, Inc.
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Surrebuttal Schedule JMM-7

ALLOWANCE FOR WORKING CAPITAL
LEAD/LAG DAY SUMMARY

LINE NO.	DESCRIPTION	(A) COMPANY ADUSTED TEST YEAR AS FILED	(B) RUCO Adj	(C) RUCO Adjusted Results	(D) Revenue Lag Days	(E) Exp Lag Days	(F) Net Lag Days	(G) Lead Lag Factor	(H) Cash Working Capital Requiredments
1	OPERATING EXPENSES								
2	Non-Cash Expenses:								
3	Bad Debts Expense	$ 506	$ -	$ 506	-		-		-
4	Depreciation	11,406	-	11,406			-		-
5	Amortization	(3,629)	(17)	(3,646)			-		-
6	Deferred Income Taxes	4,627	-	4,627			-		-
7	Total Non-Cash Expenses	$ 12,909	(17)	12,892					-
8									
9	Other Operating Expenses:								
10	Salaries & Wages	$ 4,616	$ -	$ 4,616	35.59	23.33	12.26	0.0336	155
11	Incentive Pay	329	(48)	281	35.59	267.00	(231.41)	(0.6340)	(178)
12	Purchased Power	62,965	1,997	64,962	35.59	33.79	1.80	0.0049	318
13	Transmission Other	9,014	-	9,014	35.59	40.67	(5.08)	(0.0139)	(125)
14	Meter Reading	574	-	574	35.59	33.67	1.92	0.0053	3
15	Customer Records & Coll Exp	1,169	-	1,169	35.59	34.94	0.65	0.0018	2
16	Office Supplies and Expenses	1,005	(16)	988	35.59	50.89	(15.30)	(0.0419)	(41)
17	Injuries and Damages	750	-	750	35.59	70.52	(34.93)	(0.0957)	(72)
18	Pensions and Benefits	1,960	(319)	1,641	35.59	51.37	(15.78)	(0.0432)	(71)
19	Support Services	6,059	-	6,059	35.59	44.77	(9.18)	(0.0252)	(153)
20	Property Taxes	6,733	-	6,733	35.59	212.00	(176.41)	(0.4820)	(3,245)
21	Payroll Taxes	376	-	376	35.59	12.00	23.59	0.0646	24
22	Current Income Taxes	-	-	-	35.59	-	35.59	0.0975	-
23	Interest on Customer Deposits	7	-	7	35.59	182.50	(146.91)	(0.4025)	(3)
24	Other O&M Expenses	25,050	-	25,050	35.59	41.21	(5.62)	(0.0154)	(386)
25	Total Other Operating Exp.	$ 120,607	$ 1,614	$ 122,221					
26									
27	Total Operating Expenses	$ 133,516	$ 1,598	$ 135,114					$ (3,771)
28									
29	Other Cash Working Capital Elements:								
30	Interest on Long-Term Debt	7,859	-	7,859	35.59	89.5 $	(53.91) $	(0.1477)	(1,161)
31	Rev. Taxes and Assessments	11,717	-	11,717	35.59	49.43 $	(13.84) $	(0.0379)	(444)
32									
33		$ 19,576	$ -	$ 19,576					$ (1,605)
34									
35	TOTAL CASH WORKING CAPITAL	$ 166,001		$ 167,582					
36									
37									
38	Pro Fc Pro Forma Operating Expenses - Excluding Income Taxes	$ 128,889		$ 128,889					
39	Less: Less: Other O&M	103,839		105,437					
40		$ 25,050		$ 23,453					

	Shown in Thousands
Total RUCO	$ (5,376,263)
Total Company Rebuttal	$ (5,234,865)
Cash Working Capital Adjustment With ACC Jurisdictioanl Ratio .95717	$ (135,343)
Pre-paid D&O Insurance Adjustment With ACC Jurisdictioanl Ratio .95328	$ -
Difference	$ (135,343)

58 References:
59 Column (A): - Company Schedule B-5
60 Column (B): RUCO Operating Income Adjustments
61 Column (C): Column (A) + (B)
62 Column (D): Company Schedule B-5
63 Column (E): Company Schedule B-5
64 Column (F): Column (D) - Column (E)
65 Column (G): Column (E)/365

UNS Electric, Inc.
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Surrebuttal Schedule JMM-8

SUMMARY OF OPERATING INCOME STATEMENT - ACC JURISDICTIONAL - ADJUSTED TEST YEAR AND RUCO
(Thousands of Dollars)

LINE NO.	DESCRIPTION	(A) COMPANY REBUTTAL AS FILED	(B) RUCO TEST YEAR ADJM'TS	(C) RUCO TEST YEAR AS ADJ'D
1	Operating Revenues:			
2	Electric Retail Revenues	$ 154,888	$ 1,997	$ 156,886
3	Sales for Resale	-	-	-
4	Other Operating Revenue	1,828	-	1,828
5				-
6	TOTAL OPERATING REVENUES	156,716	1,997	158,714
7				
8	Operating Expenses:			
9	Fuel, Purchased Power and Trans	85,304	1,997	87,301
10	Other Operations and Maintenance Exp	42,229	(385)	41,845
11	Depreciation and Amortization	13,060	-	13,060
12	Taxes Other than Income Taxes	6,140	-	6,140
13	Income Taxes	1,550	146	1,696
14	Rounding Differences	-	-	-
15	TOTAL OPERATING EXPENSES	148,282	1,759	150,041
16				
17	OPERATING INCOME (LOSS)	$ 8,434	$ 239	$ 8,673

References:
Column (A): Company Schedule C-1
Column (B): RUCO Schedule 9
Column (C): Column (A) + Column (B)

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OPERATING INCOME STATEMENT - ACC JURISDICTIONAL - ADJUSTED TEST YEAR AND RUCO RECOMMENDED ADJUSTMENTS

(Thousands of Dollars)

LINE NO.	DESCRIPTION	(A) COMPANY Rebuttal AS FILED	(B) Adj. 1 Base Fuel Rates JMM-10	(C) Adj. 2 Not Used JMM-11	(D) Adj. 3 Normalize Medical and Dental Expenses JMM-12	(E) Adj. 4 Directors & Officers Ins. JMM-13	(F) Adj. 5 Wellness, Employee, Spot Award JMM-14
1	Operating Revenues:						
2	Electric Retail Revenues	$ 154,888	$ 1,997	$ -	$ -	$ -	$ -
3	Sales for Resale	-	-	-	-	-	-
4	Other Operating Revenue	1,828	-	-	-	-	-
5				-			
6	TOTAL OPERATING REVENUES	$ 156,716	$ 1,997	$ -	$ -	$ -	$ -
7							
8	Operating Expenses:						
9	Fuel, Purchased Power and Trans	$ 85,304	$ 1,997	$ -	$ -	$ -	$ -
10	Other Operations and Maintenance	42,229	-	-	(306)	-	(47)
11	Depreciation and Amortization	13,060	-	-	-	-	-
12	Taxes Other than Income Taxes	6,140	-	-	-	-	-
13	Income Taxes	1,550	-	-	-	-	-
14	Rounding Differences	0	-	-	-	-	-
15	TOTAL OPERATING EXPENSES	$ 148,282	$ 1,997	$ -	$ (306)	$ -	$ (47)
16							
17	OPERATING INCOME (LOSS)	$ 8,434	$ -	$ -	$ 306	$ -	$ 47

OPERATING INCOME STATEMENT - ACC JURISDICTIONAL - ADJUSTED TEST YEAR AND RUCO RECOMMENDED ADJUSTMENTS

(Thousands of Dollars)

(G) Adj. 6 PEP Expense JMM-15	(H) Adj. 7 Injuries and Damages JMM-16	(I) Adj. 8 EEI Dues JMM-17	(J) Adj. 9 Rate Case Expense JMM-18	(k) Adj. 10 Interest Synchronization JMM-19	(L) Adj. 11 Income Tax JMM-20	(M) RUCO as Recommended
$ -	$ -	$ -	$ -	$ -	$ -	$ 156,886
-	-	-	-	-	-	-
-	-	-	-	-	-	1,828
$ -	$ -	$ -	$ -	$ -	$ -	$ 158,714
$ -	$ -	$ -	$ -	$ -	$ -	$ 87,301
-	-	(16)	(17)		-	41,845
-	-	-	-	-	-	13,060
-	-	-	-	-	-	6,140
-	-	-	-	1	145	1,696
-	-	-	-	-	-	-
$ -	$ -	$ (16)	$ (17)	$ 1	$ 145	$ 150,041
$ -	$ -	$ 16	$ 17	$ (1)	$ (145)	$ 8,673

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OPERATING INCOME ADJUSTMENT NO. 1
BASE FUEL RATES

Line No.	DESCRIPTION	(A) COMPANY PROPOSED	(B) RUCO ADJUSTMENT	(C) RUCO AS ADJUSTED
1	Electric Retail Revenues	$ 154,888,262	$ 1,997,488	$ 156,885,750
2				
3	Fuel, Purchased Power, and Transmission	$ 85,303,918.23	$ 1,997,488	$ 87,301,407

References:
Column (A) Per Company Filing
Column (B) Testimony JMM
Column (C) = Column (A) + Column (B)

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Surrebuttal Schedule JMM-11

OPERATING INCOME ADJUSTMENT NO. 2
NOT USED

Line No.	DESCRIPTION	(A) COMPANY PROPOSED	(B) RUCO ADJUSTMENT	(C) RUCO AS ADJUSTED
1		$ -	$ -	$ -

References:
Column (A) Per Company Filing
Column (B) Testimony JMM
Column (C) = Column (A) + Column (B)

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Surrebuttal Schedule JMM-12

OPERATING INCOME ADJUSTMENT NO. 3
MEDICAL AND DENTAL EXPENSE NORMALIZATION

Line No.	DESCRIPTION	(A) COMPANY PROPOSED	(B) RUCO ADJUSTMENT	(D) RUCO AS ADJUSTED	(E) ACC Juridictional Factor	(F) ACC Juridictional RUCO ADJUSTMENT
1	Medical Expense	$ 2,205,353	$ (329,800)	$ 1,875,553	0.9603	$ (316,694)
2	Dental Expense	82,709	11,295	94,004	0.9603	$ 10,846
3	Total	$ 2,288,062	$ (318,505)	$ 1,969,557	0.9603	$ (305,848)
4						
5	RUCO's Calculation:					
6	Year	Medical Expense Amount				
7	2014	$ 2,205,353				
8	2013	1,863,496				
9	2012	1,557,810				
10	Three Year Average	$ 1,875,553				
11						
12	RUCO's Calculation:					
13	Year	Dental Expense Amount				
14	2014	$ 82,709				
15	2013	92,243				
16	2012	107,060				
17	Three Year Average	$ 94,004				

References:
Column (A) Per Company Filing
Column (B) Testimony JMM
Column (C) = Column (A) + Column (B)

UNS Electric, Inc.
Docket No. E-04204A-15-0142
Test Year Ended December 31, 2014

Surrebuttal Schedule JMM-13

OPERATING INCOME ADJUSTMENT NO. 4
OFFICERS AND DIRECTORS INSURANCE

Line No.	DESCRIPTION	(A) COMPANY PROPOSED	(B) RUCO ADJUSTMENT	(D) RUCO AS ADJUSTED	(E) ACC Juridictional Factor	(F) ACC Juridictional RUCO ADJUSTMENT
1	Officers and Directors Liability Insurance	$ -	$ -	$ -	0.9603	$ -
2						
3	RUCO's Calculation:					
4	Company Proposed	$ -				
5	Split between Ratepayers and Shareholder	50%				
6	RUCO Adjustment - Total Company	$ -				

References:
Column (A) Per Company Filing
Column (B) Testimony JMM
Column (C) = Column (A) + Column (B)

OPERATING INCOME ADJUSTMENT NO. 5
WELLNESS INCENTIVE PROGRAM, EMPLOYEE RECOGNITION, AND SPOT AWARD

Line No.	DESCRIPTION	(A) COMPANY PROPOSED	(B) RUCO ADJUSTMENT	(C) RUCO AS ADJUSTED	(E) ACC Juridictional Factor	(F) RUCO AS ADJUSTED
1	Wellnes Incentive Program	$ 15,738	$ (15,738)	$ -	0.9603	$ (15,113)
2	Employee Recognition	10,740	(10,740)	-	0.9603	(10,313)
3	Spot Awards	22,000	(22,000)	-	0.9603	(21,126)
4	Total	$ 48,478	$ (48,478)	$ -	0.9603	(46,551)

References:
Column (A) Per Company Filing
Column (B) Testimony JMM
Column (C) = Column (A) + Column (B)

UNS Electric, Inc.
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Test Year Ended December 31, 2014

Surrebuttal Schedule JMM-15

OPERATING INCOME ADJUSTMENT NO. 6
UNS SHORT-TERM INCENTIVE PROGRAM

Line No.	DESCRIPTION	(A) 2014 Company Total	(B) Company Pro Forma Adjusment	(C) Total COMPANY PROPOSED	(D) RUCO ADJUSTMENT	(E) ACC Juridictional Factor	(F) RUCO AS ADJUSTED
1	FERC						
2	0581	$ -	$ -	$ -	$ -	1.0000	$ -
3	0583	-	-	-	-	1.0000	-
4	0592	-	-	-	-	1.0000	-
5	0593	-	-	-	-	1.0000	-
6	0901	-	-	-	-	1.0000	-
7	0908	-	-	-	-	1.0000	-
8	0920	-	-	-	-	0.9603	-
10	O&M Expense	$ -	$ -	$ -	$ -		$ -
11	0408 FICA Tax	-	-	-	-	0.9601	-
12	Total	$ -	$ -	$ -	$ -		$ -
	Less: RUCO removal of Company projected costs 12,122 x acc jurisdicition ratio of .9661						$ -
	Total RUCO adjustment						$ -

References:
Column (A) Per Company Filing
Column (B) Testimony JMM
Column (C) = Column (A) + Column (B)

UNS Electric, Inc.
Docket No. E-04204A-15-0142
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Surrebuttal Schedule JMM-16

OPERATING INCOME ADJUSTMENT NO. 7
INJURIES AND DAMAGES

Line No.	UNSE Adjustment to Injuries & Damages	(A)	(B)	(C)	(D)
1	**Account Description**	**2012**	**2013**	**2014**	**Average for 3 Years**
2	Workers' Compensation	$ -	$ -	$ -	$ -
3	Workers' Compensation	-	-	-	-
4	Injuries & Damages	-	-	-	-
5					
6	Total for Three Year Period	$ -	$ -	$ -	$ -
7					
8					
9	Company Average for 3 years	$ -	Column (D) Ln 6		
10					
11	Expenses for Test Year	$ -	Column (C) Ln 6		
12					
13	Company Adjustment Using 3 Year Average	$ -	Column (A) Ln 9 - Ln 11		
14					
15	ACC Jurisdictional	96.027%			
16					
17	ACC Jurisdictional Adjustment	$ -	PER COMPANY'S Calculation		
18					
19					
20	**RUCO's Adjustment to Injuries & Damages**				
21					
22	**Account Description**	**2012**	**2013**	**2014**	**Average for 3 Years**
23	Workers' Compensation	$ -	$ -	$ -	$ -
24	Workers' Compensation	-	-	-	-
25	Injuries & Damages	-	-	-	-
26	RUCO Reduction in Injuries and Damages	-	-	-	-
27					
28	Total for Three Year Period	$ -	$ -	$ -	$ -
29					
30					
31					
32	RUCO does not believe that the Injuries and damages expense for $1,071,000 incurred at year ending 2013 should be included in the				
33	calculation for the the three year period. The expense is extraordinary in nature and should be excluded.				
34					
35	RUCO'S Average for 3 years	$ -	Column (D) Ln 28		
36					
37	Expenses for Test Year	$ -	Column (C) Ln 28		
38					
39	Company Adjustment Using 3 Year Average	$ -	Column (A) Ln 35 + Ln 37		
40					
41	ACC Jurisdictional	96.027%			
42					
43	ACC Jurisdictional Adjustment	$ -	PER RUCO's Calculation		
44					
45					
46	**TOTAL RUCO ADJUSTMENT**	$ -	Line Column (A) Ln 18 + Column (A) Ln 44		

References:
Columns (A) through (D) Lines 3 through 18 provided by Company in UDR 1.01 Workpaper Schedules.

Columns (A) through (D) Lines 21 through 47 RUCO calculations

UNS Electric, Inc.
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Surrebuttal Schedule JMM-17

OPERATING INCOME ADJUSTMENT NO. 8
EEI DUES

Line No.	DESCRIPTION	(A) TEST YEAR AMOUNT	(B) COMPANY ADJUSTMENT	(C) COMPANY PROPOSED	(D) RUCO ADJUSTMENT	(E) RUCO ACC JURISDICTIONAL ADJUSTMENT
1	EEI Membership - USWAG	$ 3,500	$ (217)	$ 3,283	$ (1,035)	$ (994)
2	UARG - Membership Dues	15,123	-	15,123	$ (15,123)	$ (14,523)
3	Total Dues Expense	$ 18,623	$ (217)	$ 18,406	$ (16,158)	$ (15,517)

RUCO's Calculation:	
EEI - Membership	$ 3,500
RUCO's Disallowance	0.3575
Amount Disallowed	$ 1,251
ACC Jurisdictional Ratio	0.9603
ACC Jurisdictional Amount	$ 1,202
Reconciliation	
$217 x .9603 Already removed by Company	$ 208
$1,035 (1,251 - 217) x .9603	994
	$ 1,202
UARG Dues $15,123 x .9603	$ 14,523

References:
Column (A) Per Company Filing
Column (B) Testimony JMM
Column (C) = Column (A) + Column (B)

UNS Electric, Inc.
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Surrebuttal Schedule JMM-18

OPERATING INCOME ADJUSTMENT NO. 9
RATE CASE EXPENSE

Line No.	DESCRIPTION	(A) COMPANY PROPOSED	(B) RUCO RECOMMENDED	(C) RUCO ADJUSTMENT
1	Rate Case Expense	$ 400,000	$ 350,000	
2	Normalization Years	3	3	
3	Rate Case Expense	$ 133,333	$ 116,667	$ (16,667)

References:
Column (A) Per Company Filing
Column (B) Testimony JMM
Column (C) = Column (A) + Column (B)

UNS Electric, Inc.
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Surrebuttal Schedule JMM-19

Operating Adjustment No. 10
Interest Synchronization

Line No.	Description	Tax Rate	[A] Company Proposed	[B] RUCO Recommended
1	Adjusted Rate Base		$ 270,184,177	$ 270,048,834
2	Weighted Cost of Debt		2.20%	2.20%
3	Synchronized Interest Deduction		$ 5,938,978	$ 5,936,003
4	Increase (Decrease) in Deductible Interest			$ (2,975)
5	State Income Taxes	5.48%		$ 163
6	Federal Taxable Income			$ (2,812)
7	Federal Income Taxes	32.14%		$ 904
8	Increase (Decrease) to Income Tax Expense			$ 1,067

References:
Column (A) Per Company Filing
Column (B) Testimony JMM
Column (C) = Column (A) + Column (B)

UNS Electric, Inc.
Docket No. E-04204A-15-0142
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Surrebuttal Schedule JMM-20

OPERATING INCOME ADJUSTMENT NO. 11
INCOME TAX EXPENSE

Line No.	RUCO Income Tax Calculation on RUCO Adjustments (Thousands of Dollars)		
1	Operating Revenues:		
2	Electric Retail Revenues	$	1,997,488
3	Sales for Resale		-
4	Other Operating Revenue		-
5	Total Operting Revenue	$	1,997,488
6			
7	Operating Expenses:		
8	Fuel, Purchased Power and Trans	$	1,997,488
9	Other Operations and Maintenance Exp	$	(384,582)
10	Depreciation and Amortization	$	-
11	Taxes Other than Income Taxes	$	-
12	Pre -Tax Operating Expenses	$	1,612,906
13	Pre -Tax Operating Income	$	384,582
14	Income Taxes	$	144,653
	Combined Effective Tax Rate from Company's C-3		37.6130%

References:
Column (A) Per Company Filing
Column (B) Testimony JMM
Column (C) = Column (A) + Column (B)

UNS Electric, Inc.
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Test Year Ended December 31, 2014

Surrebuttal Schedule JMM-21

COST OF CAPITAL - ORIGINAL COST RATE BASE
Thousands of Dollars

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED	(B) RUCO ADJUSTMENTS	(C) RUCO AS ADJUSTED	(D) PERCENT	(E) COST RATE	(F) WEIGHTED COST RATE
1	Long-term Debt	169,590	-	169,590	47.17%	4.82%	2.27%
2							
3	Common Equity	189,932	-	189,932	52.83%	9.50%	5.02%
4							
5	TOTAL CAPITAL	$ 359,522	$ -	$ 359,522	100.00%		
6							
7	WEIGHTED COST OF CAPITAL (Sum Lines 1 Thru 5)						
8							7.29%
9							

COST OF CAPITAL - FAIR VAUE RATE BASE

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED	(B) RUCO ADJUSTMENTS	(C) RUCO AS ADJUSTED	(D) PERCENT	(E) COST RATE	(F) WEIGHTED COST RATE
17	Long-term Debt	169,590	$ -	$ 169,590	47.17%	4.66%	2.20%
18							
19	Common Equity	189,932	-	189,932	52.83%	9.13%	4.82%
20							
21	TOTAL CAPITAL	$ 359,522	$ -	$ 359,522	100.00%		
22							
23	WEIGHTED COST OF CAPITAL (Sum Lines 1 Thru 5)						
24							7.02%
25							
26					Fair Value Incement		0.50%

References:
- Column (A): Company Schedule D-1
- Column (B): Testimony, RBM
- Column (C): Column (A) + Column (B)
- Column (D): Column (C), Line Item / Total Capital
- Column (E): Testimony, RBM
- Column (F): Column (D) X Column (E)

UNS ELECTRIC, INC.

DOCKET NO. E-04204A-15-0142

DIRECT TESTIMONY

OF

ROBERT B. MEASE

ON

COST OF CAPITAL

ON BEHALF OF THE

RESIDENTIAL UTILITY CONSUMER OFFICE

NOVEMBER 6, 2015

TABLE OF CONTENTS

EXECUTIVE SUMMARY

Based on the Residential Utility Consumer Office's ("RUCO") analysis of UNS Electric, Inc.'s ("UNSE") application for a permanent rate increase, filed with the Arizona Corporation Commission ("ACC" or "Commission") on May 4, 2015, RUCO recommends the following:

Cost of Equity – RUCO recommends that the Commission adopt an 8.35 percent cost of common equity. This 8.35 percent figure is the result obtained from the Discounted Cash Flow model ("DCF") and the Capital Asset Pricing Model ("CAPM") used in RUCO's cost of equity analysis, and is 200 basis points lower than UNSE's proposed 10.35 percent cost of common equity.

Cost of Debt – RUCO recommends that the Commission adopt the actual cost of long-term debt of 4.66 percent which is UNSE's actual end of test year cost of long-term debt. This compares to the cost of debt previously approved in Decision No. 74235 of 5.47 percent.

Capital Structure – RUCO recommends that the Commission adopt UNSE's actual end of test year capital structure comprised of no short-term debt, 47.17 percent long-term debt and 52.83 percent common equity.

Original Cost Rate of Return – RUCO recommends that the Commission adopt a 6.86 percent weighted average cost of capital as the original cost rate of return for UNSE. This compares to the Company's requested weighted average original cost of capital of 8.13 percent.

Fair Value Rate of Return – RUCO recommends that the Commission adopt a fair value rate of return of 5.26 percent for UNSE, which is RUCO's 6.61 percent original cost rate of return minus RUCO's recommended inflation adjustment of 1.35 percent. The method used by RUCO to arrive at this 6.61 percent figure is consistent with the methods adopted by the Arizona Corporation Commission in prior UNSE and UNS Gas, Inc. rate case proceedings.

INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My Name is Robert B. Mease. I am the Chief of Accounting and Rates for the Residential Utility Consumer Office ("RUCO") located at 1110 W. Washington, Suite 220, Phoenix, Arizona 85007.

Q. Please describe your qualifications in the field of utilities regulation and your educational background.

A. Attachment I, which is attached to this testimony, describes my educational background, work experience and regulatory matters in which I have participated. In summary, I joined RUCO in October of 2011. I graduated from Morris Harvey College in Charleston, WV and attended Kanawha Valley School of Graduate Studies. I am a Certified Public Accountant ("CPA") and currently licensed in the state of West Virginia, as well as a Certified Rate of Return Analyst ("CRRA"). My years of work experience include serving as Vice President and Controller of Energy West, Inc. a public utility and energy company located in Great Falls, Montana. While with Energy West I had responsibility for all utility filings and participated in several rate case filings on behalf of the utility. As Energy West was a publicly traded company listed on the NASDAQ Exchange I also had responsibility for all filings with the Securities and Exchange Commission.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present RUCO's recommendations for the establishment of a fair value rate of return.

Q. Is this your first case involving UNSE?

A. No. I participated in UNSE's most recent rate application filed for the test year ended December 31, 2012, and performed an analytical review of the Company's financial schedules that were included in their rate application.[1]

Q. Can you please briefly describe UNSE and its ownership structure and customer base?

A. UNS Electric is a wholly-owned subsidiary of UniSource Energy Services, a holding company owned by UNS Energy Corporation. In August of 2014 UNS Energy Corporation was purchased by Fortis, Inc. ("Fortis"). Fortis is an investor owned utility based in St. John's, Newfoundland and Labrador, Canada. UNSE's customer base is comprised of approximately 95,000 customers of which 87.00 percent are residential, approximately 12.00 percent commercial and the remaining 1.00 percent industrial

[1] See Docket No. E-04204A-12-0504; Decision No. 74235

Q. Has UNSE elected to perform a reconstruction cost new less depreciation study in this case?

A. Yes. UNSE elected to perform a reconstruction cost new less depreciation ("RCND") study and is proposing a fair value rate base ("FVRB") that is an average of the Company's original cost rate base ("OCRB") and its RCND rate base for ratemaking purposes. For this reason RUCO is recommending a fair value rate of return ("FVROR") to be applied to UNSE's FVRB.

Q. Please explain your role in RUCO's analysis of UNSE's Application.

A. I reviewed UNSE's Application and performed a cost of capital analysis to determine both an original cost rate of return ("OCROR") and a fair value rate of return ("FVROR") on the Company's invested capital. In addition to my recommended capital structure, my direct testimony will present my recommended cost of common equity and my recommended cost of debt. The recommendations contained in this testimony are based on information obtained from UNSE's Application, responses to data requests, and from market-based research that I conducted during my analysis.

SUMMARY OF TESTIMONY AND RECOMMENDATIONS

Q. Please summarize the recommendations and adjustments that you will address in your testimony.

A. Based on the results of my analysis, I am making the following recommendations:

Cost of Equity Capital – I am recommending that the Commission adopt an 8.35 percent cost of common equity. This 8.35 percent figure is the result obtained from my cost of equity analysis.

Cost of Debt – RUCO is recommending that the Commission adopt the Company's end of test year cost of long-term debt of 4.66 percent. This compares favorably to the Company's previous rate application where the cost of long-term debt was approved at 5.47 percent.

Capital Structure – I am recommending that the Commission adopt UNSE's actual end of test year capital structure comprised of 52.83 percent common equity and 47.17 percent long-term debt. The Company has no short-term debt.

Original Cost Rate of Return – I am recommending that the ACC adopt a 6.86 percent weighted average cost of capital as the original cost rate of return ("OCROR") for UNSE. This 6.86 percent figure is the weighted cost of RUCO's recommended costs of common equity and debt, and is 127 basis points lower than the 8.13 percent weighted average cost of capital being proposed by the Company.

Fair Value Rate of Return – I am recommending that the Commission adopt a fair value rate of return ("FVROR") of 5.26 percent which is my recommended 6.61 percent OCROR minus an inflation adjustment of 1.35 percent.

Q Why do you believe that RUCO's recommended 6.86 percent OCROR and 5.26 percent FVROR are appropriate rates of return for UNSE to earn on its invested capital?

A. Both the OCROR and FVROR figures that I am recommending for UNSE meet the criteria established in the landmark Supreme Court cases of Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia (262 U.S. 679, 1923) and Federal Power Commission v. Hope Natural Gas Company (320 U.S. 391, 1944). These two cases affirmed that a public utility that is efficiently and economically managed is entitled to a return on investment that instills confidence in its financial soundness, allows the utility to attract capital, and also allows the utility to perform its duty to provide service to ratepayers. The rate of return adopted for the utility should also be comparable to a return that investors would expect to receive from investments with similar risk. It should be noted that neither case guarantees a rate of return on a utility investment, the cases provide a utility with an opportunity to earn an appropriate return.

RUCO's COST OF EQUITY FINDINGS

Q. What is your final recommended cost of equity capital for UNSE?

A. I am recommending a cost of equity of 8.35 percent. My recommended 8.35 percent cost of equity figure is the high side of the range of results derived from my DCF and CAPM analyses, which utilized a sample of publicly traded electric companies.

Discounted Cash Flow (DCF) Method

Q. Is the DCF model an acceptable methodology used in ratemaking for public utilities?

A. Yes. Basically the DCF model, is one of the oldest and most utilized models in determining the cost of equity in many utility hearings. In a 2014 rate case filing by Potomac Electric Power, in Washington, D.C., the commission relied primarily on a DCF analysis to arrive at the authorized ROE, "finding that he DCF method produces results more reasonable than those of other calculation methods."[2]

[2] See EEI Report, page 29

Q. You stated that the commission "primarily" relied on the DCF model, should this model be relied upon exclusively in determining a utilities ROE?

A. No. While the DCF model is the most widely used and accepted model, including Arizona, it should be supplemented with additional models or calculations (i.e. CAPM model, risk assessment, comparable earnings assessment etc.) to add support to the final cost of equity analysis. The various models will produce different results depending on the economic conditions and inputs included in calculating the results. It is important to look at these alternative calculations to determine the reasonableness of the individual and overall final results.

Q. Please explain the DCF method that you used to estimate the Company's cost of equity capital.

A. The DCF method employs a stock valuation model known as the constant growth valuation model. This model is frequently referred to as the Gordon model. This DCF model is based on the premise that the current price of a given share of common stock is determined by the present value of all of future cash flows that will be generated by that share of common stock. The rate that is used to discount these cash flows back to their present value is often referred to as the investor's cost of capital (i.e. the cost at which an investor is willing to forego other investments in favor of the one that he or she has chosen).

The investor's required rate of return can be expressed as the percentage of the dividend that is paid on the stock (dividend yield) plus an expected rate of future dividend growth. This is illustrated in mathematical terms by the following formula:

$$k = \frac{D_1}{P_0} + g$$

where: k = the required return (cost of equity, equity capitalization rate),

$\frac{D_1}{P_0}$ = the dividend yield of a given share of stock calculated by dividing the expected dividend by the current market price of the given share of stock, and

g = the expected rate of future dividend growth

This formula is the basis for the standard growth valuation model that is used to determine the Company's cost of equity capital.

Q. In determining the rate of future dividend growth for the Company, what assumptions did you make?

A. There are two basic assumptions regarding dividend growth that must be made when using the DCF method. First, dividends will grow by a constant rate into perpetuity, and second, the dividend payout ratio will remain at a constant rate. Both of these assumptions are predicated on the traditional DCF model's basic underlying assumption that a company's earnings, dividends, book value and share growth all increase at the same constant rate of growth into infinity. Given these assumptions, if the dividend payout ratio remains constant, so does the earnings retention ratio (the percentage of earnings that are retained by the company as opposed to being paid out in dividends). This being the case, a company's dividend growth can be measured by multiplying its retention ratio (1 - dividend payout ratio) by its book return on equity. This can be stated as $g = b \times r$.

Q. How did you develop your dividend growth rate estimate?

A. I analyzed data on a proxy group comprised of fourteen publicly traded electric service providers.

Q. Why would you use a proxy group methodology as opposed to a direct analysis of the Company?

A. One of the problems in performing this type of analysis is that the utility applying for a rate increase is not always a publicly traded company. Although UNSE's ultimate parent company, Fortis, Inc., is publicly-traded on the Toronto, Canadian Stock Exchange, UNSE is not. Because of this situation, I used a proxy group that includes fourteen electric utilities with similar risk characteristics as UNSE in order to derive a cost of common equity for the Company.

Q. Are there any other advantages to the use of a proxy?

A. Yes. The U.S. Supreme Court ruled in Federal Power Commission v. Hope Natural Gas Company (320 U.S. 391, 1944) decision that a utility is entitled to earn a rate of return that is commensurate with the returns on investments of other firms with comparable risk. The proxy methodology used by most cost of equity analysts derives that rate of return. One other advantage to using a sample of companies is that it reduces the possible impact that any undetected biases, anomalies, or measurement errors may have on the DCF growth estimate.

Q. Are these the same fourteen electric providers included in the proxy used by UNSE's cost of equity witness?

A. Yes. The Company's that are included in my analysis are the same electricity providers included in Ms. Ann Bulkley, the Company's cost of capital witness. However I did include one additional Company that being El Paso Electric. I added the additional Company to basically have a representative sample from all regions within the U.S. Each of the fourteen electric utilities included in our respective samples are tracked in the Value Line Investment Survey's ("Value Line") Electric Utility industry segment. Value Line follows electric utilities on a regional basis and issues quarterly updates on electric utilities located in the eastern, central and western portions of the U.S. All of the companies in the proxy are engaged in the provision of regulated electric services. Attachment B of my testimony contains Value Line's most recent evaluation on each of the companies that I included in the electric proxy group that I used for my cost of common equity analysis.

Capital Asset Pricing Model (CAPM) Method

Q. Can you please describe the CAPM and the benefits of preparing this analysis?

A. The CAPM describes the relationship between a security's investment risk and its market rate of return. This relationship identifies the rate of return which investors expect a security to earn so that its market return is comparable with the market returns earned by other securities that have similar risk. The relationship is specified by the Security Market Line (SLM) that indicates the relationship between each security or portfolio's "beta" and its resulting return. Beta is an indicator of investment risk. It is a measure of the expected amount of change in a security's variability of return relative to the return variability of the overall capital market. The general form of the CAPM is:

$$K = R_f + \beta (R_m - R_f)$$

Where: K = *cost of equity*

R_f = *risk free rate*

R_m = *return on market*

β = *beta*

$R_m - R_f$ = *market risk premium*

Q. Can you please identify the strengths of using the CAPM model in your analysis?

A. The strengths of the CAPM are as follows: (1) it is based on the concept of risk and return; (2) it is company specific as it relates to the specific beta's within the industry; (3) it has widespread use as it recognizes that investors can and do diversify; (4) it's highly structured and easy to apply when using the assumptions of the model; (5) the model is formulistic and the data used in the computations is readily available; (6) it is a forward looking concept; and (7) it is a method for converting changes in interest rates to the cost of equity.

Q. What do you use for the risk-free rate?

A. The risk-free rate is generally recognized by use of U.S. Treasury securities in CAPM applications. Two general types of U.S. Treasury securities are most often used as the risk free *(Rf)* component, short-term U.S. Treasury bills and long-term U.S. Treasury bonds. I performed my CAPM calculations using the three-month average yield (July thru September 2015) for 30-year U.S. Treasury bonds. The yields on long-term Treasury bonds are used since this matches the long-term perspective of the cost of equity analyses. Over this three-month period, these bonds had an average yield of 3.01 percent.

Q. Please explain why U.S. Treasury instruments are regarded as a suitable proxy for the risk-free rate of return?

A. Investors would like to believe that U.S. Treasury securities pose no threat of default no matter what their maturity dates are as they are backed by the United States Government. However, even when using Treasury instruments those with longer maturity dates do have slightly higher yields. When an investor locks up funds in long-term T-Bonds, the investor must be compensated for future investment opportunities foregone. This is often described as maturity or interest rate risk and it can affect an investor adversely if market rates increase before the instrument matures (a rise in interest rates would decrease the value of the debt instrument). This compensation translates into higher rates of returns to the investor.

Q. What betas do you employ in your CAPM?

A. Once again, beta[3] is a measure of the relative volatility, or risk, of a particular stock in relation to the overall market. Betas less than 1 are considered less risky than the market, whereas betas greater than 1 are more risky. Utility stocks traditionally have had betas below 1. The most recent Value Line betas have been used in my analysis for each company in my proxy group.

[3] See Attachment B – Individual proxy companies beta's identified

Q. What are the results of your CAPM analysis?

A. As shown on pages 1 and 2 of Schedule RBM-6, my CAPM calculation using a geometric mean to calculate the risk premium results in an average expected return of 6.59 percent. My calculation using an arithmetic mean results in an average expected return of 7.19 percent and the results of using a geometric mean is 6.00 percent. The results obtained from my CAPM analysis exceed the current 4.60 percent yield on by 107 to 228 basis points.

Q. Please summarize the results derived under each of the methodologies presented in your testimony.

A. The following is a summary of the cost of equity capital derived under each methodology used:

METHOD	RESULTS
DCF	8.95%
CAPM	6.00% - 7.19%

Based on these results, my best estimate of an appropriate range for a cost of common equity for the Company is 6.00 percent to 8.95 percent. My final recommended cost of common equity is 8.35 percent and is slightly higher than the average of the DCF and CAPM calculations. I did not take into account the geometric mean in my calculation of cost of equity. See RBM-3 for calculations.

Q. Can you provide a comparison of the results derived from Ms. Bulkley's models and yours?

	Company Witness	RUCO
DCF – Constant Growth	9.04% – 10.35%	8.95 %
DCF – Multi-Stage	9.30% -- 9.92%	
CAPM	9.59% -- 11.10%	6.00% -- 7.19%
Risk Premium	9.70% -- 10.72%	

UNSE's PROPOSED COST OF EQUITY CAPITAL

Q. Have you reviewed UNSE's testimony on the Company-proposed cost of equity capital?

A. Yes, I have reviewed the testimony of the Company's cost of equity expert witness, Ms. Ann Bulkley.

Q. Please compare the Company-proposed cost of equity with your recommended cost of equity.

A. The Company is recommending a cost of equity capital of 10.35 percent which is 200 basis points higher than my recommended 8.35 percent cost of equity.

Q. Can you explain the primary differences behind the 200 basis point spread between the Company's ROE and the RUCO's calculations?

A. Yes I will. The primary difference is reflected in Ms. Bulkley's use of forward looking estimates <u>only</u> as opposed to the use of both historical and forward looking estimates. As she states in her testimony "The required ROE should be forward looking estimate; therefore, the analyses supporting my recommendation should rely on forward looking inputs and assumptions (e.g., projected growth rates in the DCF model, forecasted risk-free rate and Market Risk Premium in the CAPM analysis, etc.) and takes into consideration the current high valuations of utility stocks and market's expectations for higher interest rates."[4]

Q. Do you concur with Ms. Bulkley's assessment and her use of only forward looking inputs only?

A. No I don't and neither does the Arizona Corporation Commissioners. Decision No. 75265, issued on September 8, 2015, states the following, "EPCOR is also critical of RUCO's use of historical data in evaluating cost of equity, which the Company claims should be a forward-looking analysis. However, we believe that consideration of both historical and projected data is appropriate in evaluating cost of equity."[5]

[4] See Ms. Bulkley's testimony, page 7
[5] See EPCOR Water Arizona, Inc., Decision No. 75268

Q. Are there other reasons that you can identify that have created the 200 basis point differential?

A. Yes. There are several other reasons that we ROE's are substantially different.

(1) As Ms. Bulkley explained in her testimony she utilized a Risk Premium methodology that took into account UNS Electric's utility operations and compared in size to the proxy group of companies. While she did calculate a size premium she went on to say in her testimony that "While I have estimated the small size effect, I am not proposing a specific adjustment for this factor. Rather, I have considered the small size of UNS Electric in my assessment of business risks in order to determine where, within a reasonable range of returns, UNS Electric's required ROE falls."[6]

(2) Included in the Company's testimony is a calculation described as Bond Yield Plus Risk Premium Analysis. As described in Ms. Bulkley's testimony "this approach is based on the fundamental principle that equity investors bear the residual risk associated with equity ownership and therefore require a premium over the return they would have earned as a bondholder. That is, since returns to equity holders are more risky than returns to bondholders, equity investors must be compensated to bear that risk."

[6] See Ms. Bulkley's testimony, page 46

(3) Ms. Bulkley's also states that "the returns at the low end of the DCF range do not provide a sufficient risk premium to compensate equity investors for the residual risks of ownership, including the risk that they have the lowest claim on the assets and income of the Company. Because of this concern, I have not considered the low end of the range of DCF results in developing my ROE recommendation."[7]

Q. As a follow up to Ms. Bulkley's response to the previous question and her comments related to risk premium for small companies, has the ACC addressed this in previous decisions?

A. Yes. In Decision No. 75268, the Commission made the following findings; "Although a company's size may sometimes be considered as a business risk factor, for utilities of substantial size, (those having access to capital markets) it is a minimal consideration in determining business risk. Small utilities (e.g., non-class A utilities) may have substantial risk due to the inability to hire employees or contract for sufficient levels of expertise (management, technical & financial) to perform effectively and efficiently. Small utilities also have other risks such as information access, greater annual variability in operating expenses, and greater regulatory risk both due to lack of skilled rate case personnel and the percentage of operating expenses and rate base components reviewed by Staff and intervenors. Due to the latter two reasons, for any adopted return on equity the

[7] See Ms. Bulkley's testimony, page 6

distribution of actual returns is greater for small utility than for a large utility, and greater variability means greater risk. However, most of the proxy companies used in the cost of capital analyses, including EPCOR, are a conglomeration of many smaller water systems and have the capacity to attract the appropriate level of talent for proficient operation. Thus, the business risk of the EPCOR systems parallels that that of the sample companies, and **we do not believe a cost of equity adjustment for size is appropriate."**

Q. What methods did the Company witness, Ms. Bulkley, use to arrive at her cost of common equity for UNSE?

A. Ms. Bulkley used the constant growth DCF model and a multi-stage DCF. In addition, she also employed both the CAPM and risk premium methods to estimate UNSE's final cost of common equity. I did not employ the risk premium methodology because this Commission has traditionally placed more weight on the results of the DCF and CAPM.

Q. How does your recommended cost of equity capital compare with the cost of equity capital proposed by the Company?

A. The 10.35 percent cost of equity capital proposed by the Company is 200 basis points higher than the 8.35 percent cost of equity capital that I am recommending.

CURRENT ECONOMIC ENVIRONMENT

Current Economics Surrounding the Electric Utilities

Q. Does it appear that investor-owned electricity companies, as well as the utility sector in general, performed well in 2014?

A. Yes. In reviewing Edison Electric Institute's (EEI) 2014 Financial Review as published in their Annual Report of the U.S. Investor-Owned Electric Utility Industry, the electric companies are performing very well.

Q. **Can you please describe the EEI organization, and how that organization serves the electric utility industry?**

A. Yes. EEI's mission is to ensure member's success by advocating public policy, expanding market opportunities, and proving strategic business information. EEI is an association that represents all U.S. investor-owned electric companies. Their members provide electricity for 220 million Americans, operate in all 50 states and the District of Columbia, and employ more than 500,000 workers. The proxy companies that we chose in our analysis are all members of EEI. UNSE is also a member of EEI. In addition, EEI has seventy international companies as Affiliate Members and 250 industry suppliers and related organizations as Associate Members.

Q. Can you please describe the purpose of the 2014 Financial Review as discussed in the prelude to Edison Electric Institute's annual report?

A. The 2014 Financial Review is a source for critical financial data covering 48 investor-owned electric companies whose stocks are publicly traded on major U.S. stock exchanges and also includes data on six additional companies that provide regulated electric service but are not listed on U.S. stock exchanges.

Q. Briefly identify the 2014 financial highlights as presented in the Presidents Letter included in the 2014 Financial Review.

A.

> "In 2014, the EEI Index returned an average of 28.9 percent, compared to the 10.0 percent return posted by the Dow Jones Industrial Average and the S&P 500's 13.7 percent return. For 10 years ending December 31, 2014, The EEI Index's 156 percent return outpaced the Dow Jones Industrial's 114 percent return and S&P's 110 percent return."
>
> "The industry's average credit rating improved to BBB+ form BBB, the first change since 2004 when it increased from BBB-, as individual company ratings were overwhelmingly positive in 2014."
>
> "The industry's dividend yield at the end of 2014 stood at 3.3 percent, and 38 utilities, or 79 percent of the industry, increased their dividend yield last year, the largest percentage on record."

Q. Did EEI publish information on rate case applications that member companies have been involved in for year 2014?

A. Yes. Investor-owned electric utilities filed 58 rate cases in 2014. The average requested ROE was the lowest requested in their history and the awarded ROE was the lowest in their data reaching back to 1990.

Q. Has there been updates published by EEI for rate case activity related to investor-owned members for year 2015?

A. Yes. The Rate Case Summary report issued by EEI for the second quarter of 2015 stated that the average awarded ROE continued to be at record lows and consistent with the downward trend extending over more three decades.

Q In the EEI 2014 annual report was there any mention of the purchase of UNS by Fortis?

A. Yes. "UNS said joining Fortis enhances the financial strength of its local utility operations, and provides additional support for long-term investment."

Q. Did the Company comment on the acquisition by Fortis, Inc. and the affects on its long-term investment?

A. Yes. Mr. Hutchens, in his testimony states "I also would like to point out that the average cost of debt used in the Company revenue requirement of 4.66 percent is 22% lower than the cost of debt approved in the last rate case. This reduction in the Company's debt costs resulted from constructive regulatory outcomes, steady improvements in UNS Electric's financial condition, a strong credit rating and favorable capital market conditions. UNS Electric's increase to an A3 rating after being acquired by Fortis Inc. puts the Company in position to access the capital markets on favorable terms, which will help to reduce the amount of future borrowing costs that need to be recovered from customers.

General Economic Conditions

Q. Please explain why it is necessary to consider the current economic environment when performing a cost of equity capital analysis for a regulated utility.

A. Consideration of the economic environment is necessary because trends in interest rates, present and projected levels of inflation, and the overall state of the U.S. economy determine the rates of return that investors earn on their invested funds. Each of these factors represent potential risks that must be weighed when estimating the cost of equity capital for a regulated utility and are, most often, the same factors considered by individuals who are also investing in non-regulated entities.

Q. Has the Fed's quantitative easing actions resulted in lower yields on long-term Treasury instruments?

A. Yes. Despite a recent rise in the yields of longer-term instruments (Attachment C), mainly due to uncertainty over when the Fed will reverse its policy of quantitative easing, the yields on various treasury and utility instruments are currently at historic lows.

Q. Can you please explain how general economic and financial conditions are considered in the determination of the cost of capital for a public utility?

A. Yes. The cost of capital is determined in part by the current and future economic and financial conditions. The level of economic activity; the stage of the business cycle; the trend in interest rates, and the level of inflation or expansion all play an important factor in determining the cost of capital. While there are other factors involved these are the most important and at any point in time each can have an influence on the cost of capital.

Q. Can you describe the recent trends in economic conditions and their impact on capital costs over the past thirty years?

A. Yes. Since the early 1980's through the end of 2007 the United States economy had been relatively stable. This period had been characterized by longer economic expansions, small contractions, low and/or declining inflation, and declining interest rates and other capital costs. However, in 2008 and 2009, the economy declined as a result of the mortgage crisis and had a negative effect on the financial markets both in the US and international financial markets. This decline was described as the worst financial crisis since the Great Depression and has been referred to as the "Great Recession." Since 2008, the U.S. and other governments implemented unprecedented actions to attempt to correct or minimize the scope and effects of this worldwide recession.

The recession bottomed out in mid-2009 and the economy began to slowly expand again, initially at a slow rate but has escalated at a much quicker rate. This is evidenced by the unemployment rate reducing from 6.7 at the end of 2013 to 5.6 percent at the end of December, 2014. Arizona's unemployment rate hasn't recovered quite as well as the national average and at the end of December, 2014 was 6.8 percent. The length of this most recent recession and the slow recovery indicate that the impact may be felt for an extended period of time.

Q. Can you please describe how the economic and financial indicators were examined and how they relate generally to the cost of capital?

A. Schedule RBM-7 identifies relevant economic data such Gross Domestic Product ("GDP"), Industrial Production Growth, Unemployment, Consumer Price Index ("CPI") and Producer Price Index. These schedules also show that 2007 was sixth year of economic expansion and the economy entered into a significant decline as indicated in the GDP negative expansion for year 2008 and the increase in unemployment rates. Since 2010, the economy began to rebound, however, overall economic growth continues to be slower than the initial period of prior expansions.

Since 2008, the CPI has been 3 percent or lower, with 2014 being only 1.1 percent. The annual rate of inflation has generally been declining over the past several business cycles and continues as evidenced by 2014 annual inflation rate of 1.7 percent and the projected 2015 rate which appears to be less that year 2014. The current levels of inflation are at the lowest levels over the past 35 years and are indicative of lower capital costs.

Q. What have been the trends in interest rates over the four prior business cycles and at the current time?

A. Schedule RBM-6 shows that interest rates rose sharply to record levels in 1975-1981, when the inflation rate was high and generally rising. Interest rates declined substantially as did inflation rates during the remainder of the 1980s and throughout the 1990s. Interest rates declined even further from 2000-2005 and for the years 2009 through 2014, interest rates have been the lowest since prior to 1975. Since 2008, the Federal Reserve has lowered the Federal Funds rate in 2012 and 2013 both U.S. and corporate bond yields declined to their lowest levels in more than 35 years. Interest rates have risen slightly from those lows since the beginning of 2013. Even with the recent increases, both government and corporate lending rates remain at historically low levels through 2014, and have continued through year 2015.

Q. What do the economic indicators show for trends of common share prices?

A. Schedule RBM-7 show that stock prices were essentially stagnant during the high inflation/high interest rate environment of the late 1970s and early 1980s. Beginning in 1983 a significant upward trend in stock prices began. However, the beginning of the recent financial crisis saw stock prices decline significantly and stock prices in 2008 and early 2009 were down significantly from peak 2007 levels, reflecting the financial/economic crisis. Beginning in the second quarter of 2009, prices have recovered substantially and have ultimately reached and exceeded the levels achieved prior to the beginning of the "crash" and the DOW Jones Industrial average has reached all-time highs.

Q. What conclusions can be reached from your discussion of economic and financial conditions?

A. The most recent downturn in the economy has resulted in a decline in the investor expectation of returns. This is evident in several ways: 1) lower interest rates on bank deposits; 2) lower interest rates on U.S. Treasury and corporate bonds; and, 3) lower increases in Social Security cost of living benefits. While unemployment has reduced substantially, the average median income of families has reduced as well. Finally, as noted above, utility bond interest rates are currently at levels below those prevailing prior to the financial crisis of late 2008 to early 2009 and are near the lowest levels in the past 35 years. While the economy is recovering from this latest recession, it is recovering slower than expected. Slower recovery means that the results of the traditional cost of equity models are lower than prior to the recession. This is evidenced and supported by the EEI 2014 Financial Report identifying the rate case activity during 2014 and that authorized rates of return on equity are the lowest since 1990.

Q. What is the current outlook for the economy?

A. Information published by the FOMC indicates that economic activity has been expanding at a moderate pace during 2015, household spending has been increasing, the housing sector has improved and that business fixed investment has also been increasing. However, inflation has continued to run below the Committee's long-run objective, partly reflecting declines in energy pricing and non-energy imports. The unemployment rate is held steady with slight improvements during 2015. The Committee expects that, with appropriate policy accommodation, economic activity will expand at a moderate pace, with labor markets continuing to improve. Inflation is expected to remain near its recent low level in the near term but expects inflation to rise gradually toward the 2 percent over the medium term. When the Committee decides to begin to remove policy accommodation, it will take a balanced approach consistent with its longer-term goals of maximum employment and inflation of 2 percent. It is anticipated that, even after employment and inflation are near consistent levels, economic conditions may, for some time, warrant keeping the target federal funds rate below levels that is considered normal.

Q. How has Arizona fared in terms of the overall economy and home foreclosures?

A. Arizona was one of the states hit hardest during the Great Recession and has lagged during the current recovery. During the period between 2006 and 2009, statewide construction spending fell by 40.00 percent. According to information provided by Irvine, California-based RealtyTrac, Arizona was ranked third in the nation behind California and Nevada in terms of home foreclosures with the largest number of foreclosures occurring in Maricopa, Pinal and Pima Counties.

Q. What is the current unemployment situation in Arizona during this period of economic recovery?

A. According to information published on October 30, 2015, the seasonally adjusted unemployment rate for Arizona has increased from 6 percent in April, 2015, to 6.3 percent in September, 2015. This compare the national unemployment rate of 5.1 percent for the period ending in September, 2015. I believe it is safe to say that Arizona's economy is recovering at a much slower pace that the national average.

COST OF DEBT AND CAPITAL STRUCTURE

Q. What cost of long-term debt are you recommending for UNSE?

A. I am recommending that the Commission adopt UNSE's actual end of test year cost of long-term debt of 4.66 percent.

Q. Please describe the Company-proposed capital structure.

A. The Company is proposing an adjusted end of test year capital structure comprised of no short-term debt, 47.17 percent long-term debt and 52.83 percent common equity.

Q. How does the Company-proposed capital structure compare with the capital structures of the electric companies that comprise your sample?

A. The Company-proposed capital structure, Schedule RBM-2, is virtually identical to the average capital structure of the electric companies included in my sample.

Q. What capital structure are you recommending for UNSE?

A. I am recommending that the Commission adopt the Company's actual end of test year capital structure comprised of zero short-term debt, 47.17 percent long-term debt and 52.83 percent long-term common equity, which is essentially the same as the capital structure being proposed by UNSE.

WEIGHTED COST OF CAPITAL AND FAIR VALUE RATE OF RETURN

Q. What original cost weighted average cost of capital are you recommending for UNSE?

A. Based on my recommended capital structure, comprised of 47.17 percent long-term debt and 52.53 percent common equity, I am recommending an original cost weighted average cost of capital of 6.61 percent, Schedule RBM-1. This is the weighted average cost of my recommended cost of long-term debt of 4.66 percent and my recommended 8.35 percent cost of common equity.

Q. What fair value rate of return are you recommending for UNSE?

A. I am recommending a FVROR of 5.26 percent, RBM-1, which is 166 basis points lower than my OCROR of 6.61 percent. My recommended FVROR satisfies the fair value requirement of the Arizona Constitution which the Commission must follow when setting rates for investor owned utilities such as UNSE.

Q. Why are you recommending a FVROR that is different from your OCROR?

A. Because UNSE elected not to use the Company's original cost rate base ("OCRB") as its fair value rate base ("FVRB") in this case. Instead, UNSE performed a reconstruction cost new less depreciation ("RCND") study to restate the value, or reproduction cost, of the Company's OCRB. As is the normal ratemaking practice in Arizona, the Company averaged the values of its OCRB and its RCND rate base to arrive at a FVRB that is higher than the OCRB. This is because the value of the FVRB reflects the impact of inflation and other factors which tend to contribute to an upward growth in value over time. Since the difference in the value of the OCRB and the FVRB represents inflation, as opposed to additional investor supplied capital, an OCROR which includes an inflation component cannot be applied to the FVRB. To do so would result in a double counting of inflation. For this reason it is necessary to remove the inflation component that is included in the OCROR.

Q. Does your silence on any of the issues, matters or findings addressed in the testimony of Ms. Bulkley or any other witness for UNSE constitute your acceptance of their positions on such issues, matters or findings?

A. No, it does not.

Q. Does this conclude your testimony on UNSE?

A. Yes, it does.

UNS Electric, Inc.
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<u>SCHEDULE #</u>

RBM - 1	WEIGHTED AVERAGE COST OF CAPITAL
RBM - 2	COST OF LONG TERM DEBT
RBM - 3	COST OF COMMON EQUITY
RBM - 4	INFLATION ADJUSTMENT
RBM - 5	DCF COST OF EQUITY CAPITAL
RBM - 6	CAPM COST OF EQUITY CAPITAL
RBM - 7	ECONOMIC INDICATORS

ATTACHMENTS

B	VALUE LINE REPORTS
C	YAHOO FINANCE ANALYSTS REPORTS / STOCK PRICES
D	ECONOMIC INDICATORS REPORTS

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Schedule RBM-1

WEIGHTED AVERAGE COST OF CAPITAL

LINE NO.	DESCRIPTION	(A) CAPITALIZATION PER COMPANY	(B) RUCO ADJUSTMENTS	(C) RUCO ADJUSTED CAPITALIZATION	(D) CAPITAL RATIO	(E) COST	(F) WEIGHTED COST
1	Long - Term Debt	$ 169,590	$ -	$ 169,590	47.17%	4.66%	2.20%
2	Short - Term Debt	-	-	-	-	-	-
3	Common Equity	189,932	-	189,932	52.83%	8.35%	4.41%
4	TOTAL CAPITALIZATION	$ 359,522	$ -	$ 359,522	100.00%		6.61%
5	Inflation Adjustment						0.25%
6	ORIGINAL COST WEIGHTED AVERAGE COST OF CAPITAL						6.86%

REFERENCES:
COLUMN (A): COMPANY SCHEDULE D-1; SCHEDULE RBM-2
COLUMN (B): TESTIMONY RBM
COLUMN (C): COLUMN (A) + COLUMN (B)
COLUMN (D): COLUMN (C) LINE 1 ÷ COLUMN (C), LINE 4
COLUMN (E): LINE 1 - COMPANY SCHEDULE D-1; SCHEDULE RBM-2
COLUMN (E): LINE 3 - SCHEDULE RBM-3
COLUMN (F): COLUMN (D) x COLUMN (E)

FAIR VALUE WEIGHTED AVERAGE COST OF CAPITAL

LINE NO.		(A) CAPITALIZATION	(B) RUCO	(C) RUCO ADJUSTED	(D) CAPITAL	(E) COST	(F) WEIGHTED COST
7	LONG-TERM DEBT	$ 169,590	$ -	$ 169,590	47.17%	3.31%	1.56%
8	COMMON EQUITY	189,932	-	189,932	52.83%	7.00%	3.70%
9	TOTAL CAPITALIZATION	$ 359,522	$ -	$ 359,522	100.00%		5.26%
10	COLUMN (A) THROUGH (D) SEE ABOVE						
11	COLUMN (E), LINE 7 SEE RBM-2						

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Schedule RBM-2

COST OF LONG TERM and SHORT TERM DEBT (thousands of US dollars)

LINE NO.	LONG TERM DEBT DESCRIPTION	End of Test Year (Actual) (A) Actual as of DEC. 31, 2014	(B) Annual Interest	(C) Annual Cost Rate Long Term Debt	End of Test Year (Proposed) (D) Proposed as of DEC. 31, 2014	(E) Annual Interest	(F) RUCO ADJUSTED BALANCE
	Fixed Rate Debt:						
1	6.50% Senior Unsecured Notes due 08/15	$ 50,000	$ 3,250	6.50%	$ -	$ -	$ -
2	7.10% Senior Unsecured Notes Series B due 08/23	50,000	3,550	7.10%	50,000	3,550	7.10%
3	3.22% Senior Unsecured Notes Series A due 08/27	-	-	-	80,000	2,576	3.22%
4	3.95% Senior Unsecured Notes Series B due 04/45	-	-	-	50,000	1,975	3.95%
5	Total Fixed Rate Debt	100,000	6,800	6.80%	180,000	8,101	4.50%
6	**Variable Rate Debt:**						
7	4 Year Term Loan due 08/15	30,000	629	2.10%	-	-	-
8	Total Variable Rate Debt	30,000	629	2.10%	-	-	-
9	**Total Long-Term Debt (Ln 5 + Ln 8)**	$ 130,000	$ 7,429	5.71%	$ 180,000	$ 8,101	4.50%
10	**Unamortized Debt Discount, Premium**						
11	Expense and Loss on Reacquired Debt	(410)	-		(1,246)		
12	**Amortization of Debt Discount and**						
13	Expense and Loss on Reacquired Debt	-	182		-	169	
14	**Credit Facility Commitment Fee**	-	51		-	63	
15	**Total Long Term Debt - Net of expenses (Ln 9 less Ln 11, 13, 14)**	129,590	7,662		178,754	$ 8,333	
16	**Total Cost Long Term Debt (Col. B / Col. A) (Col. E / Col. F)**			5.91%			4.66%
	SHORT TERM DEBT						
17	Revolving Line of Credit	$ 40,000	$ 513	1.28%	$ -	$ -	$ -
18	Total Debt Actual - End of Test Year	$ 169,590	$ 8,175	4.82%			
19	Total Debt Proposed - End of Test Year				$ 178,754	$ 8,333	4.66%
20	LESS: RECOMMENDED FAIR VALUE INFLATION ADJUSTMENT						-1.35%
21	COST OF LONG-TERM DEBT - FAIR VALUE (LINE 19 - LINE 20)						3.31%

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SCHEDULE RBM-3

COST OF COMMON EQUITY ESTIMATE

LINE NO.			
1	DCF METHODOLOGY		
2	DCF - SINGLE-STAGE CONSTANT GROWTH MODEL ESTIMATE	8.95%	SCHEDULE RBM-4
3	CAPM METHODOLOGY		
4	CAPM - GEOMETRIC MEAN ESTIMATE	6.00%	SCHEDULE RBM-6, PAGE 1 OF 2
5	CAPM - ARITHMETIC MEAN ESTIMATE	7.19%	SCHEDULE RBM-6, PAGE 2 OF 2
6	AVERAGE OF DCF AND CAPM ARITHEMETIC ESTIMATES	6.59%	(LINE 4 + LINE 5) / 2
7	PREMLINIARY COST OF COMMON EQUITY ESTIMATE	8.07%	TESTIMONY, RBM
8	FINAL ADJUSTMENT	0.28%	TESTIMONY, RBM
9	FINAL COST OF COMMON EQUITY	8.35%	
10	LESS: RECOMMENDED FAIR VALUE INFLATION ADJUSTMENT	-1.35%	SCHEDULE RBM-4
11	COST OF COMMON EQUITY ESTIMATE - FAIR VALUE	7.00%	LINE 8 - LINE 9

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SCHEDULE RBM-4

INFLATION ADJUSTMENT TO RUCO'S RECOMMENDED ORIGINAL COST OF EQUITY CAPITAL

LINE NO.	(A) YEAR	(B) VALUE TIPS	(C) VALUE BONDS	(D) DIFFERENCE
1	2009	1.66%	3.26%	1.61%
2	2010	1.15%	3.22%	2.06%
3	2011	0.55%	2.78%	2.23%
4	2012	0.42%	1.78%	1.36%
5	2013	0.80%	2.10%	1.30%
6	2014	0.49%	1.10%	0.61%
7	2015	0.54%	1.02%	0.48%
8				
9	RECOMMENDED FAIR VALUE INFLATION ADJUSTMENT - AVERAGE COLUMN (D)			1.35%

REFERENCES

COLUMNS (A) THRU (C), LINES 1 THRU 9: FEDERAL RESERVE BANK
COLUMN (D): COLUMN (C) - COLUMN (D)
COLUMNS (B) THRU (D), LINE 10: AVERAGE OF LINES 1 THRU 7
COLUMN (D), LINE 11: TESTIMONY - RBM

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SCHEDULE RBM-5

DCF 90 DAY CONSTANT GROWTH

LINE NO.	STOCK SYMBOL	COMPANY NAME	(A) ESTIMATED DIVIDEND (PER SHARE)	/	(B) AVERAGE STOCK PRICE (PER SHARE)	=	(C) DIVIDEND YIELD	(D) PROJECTED DIVIDEND YIELD	(E) FIVE YEAR GROWTH VALUE LINE	(F) FIVE YEAR GROWTH YAHOO FINANCE	(G) AVERAGE EARNINGS GROWTH	(H) ROE LOW	(I) ROE MEAN	(J) ROE HIGH
1	ALE	ALLETE, Inc.	$ 2.02	/	48.28	=	4.18%	4.28%	4.00%	5.50%	4.75%	8.27%	9.03%	9.80%
2	AEP	American Electric Power Company	$ 2.12	/	55.29	=	3.83%	3.93%	5.00%	4.63%	4.82%	8.55%	8.74%	8.93%
3	DUK	Duke Energy Corporation	$ 3.30	/	72.04	=	4.58%	4.67%	3.50%	4.04%	3.77%	8.16%	8.44%	8.71%
4	EE	EL Paso Electric	$ 1.18	/	35.62	=	3.31%	3.41%	5.00%	7.00%	6.00%	8.40%	9.41%	10.43%
5	EDE	Empire District Electric Company	$ 1.04	/	22.11	=	4.70%	4.79%	3.00%	4.00%	3.50%	7.77%	8.29%	8.80%
6	ES	Eversource Energy	$ 1.67	/	47.84	=	3.49%	3.60%	6.50%	5.80%	6.15%	9.39%	9.75%	10.10%
7	GXP	Great Plains Energy Inc.	$ 0.98	/	25.42	=	3.86%	3.97%	6.00%	6.37%	6.19%	9.97%	10.16%	10.35%
8	IDA	IDACORP, Inc.	$ 1.88	/	60.13	=	3.13%	3.20%	6.00%	4.00%	5.00%	7.19%	8.20%	9.22%
9	OTTR	Otter Tail Corporation	$ 1.23	/	26.28	=	4.69%	4.78%	1.50%	6.00%	3.75%	6.22%	8.53%	10.83%
10	PNW	Pinnacle West Capital Corporation	$ 2.38	/	60.93	=	3.91%	3.99%	3.50%	5.37%	4.44%	7.47%	8.43%	9.38%
11	PNM	PNM Resources, Inc.	$ 0.80	/	25.85	=	3.09%	3.24%	10.00%	8.60%	9.30%	11.83%	12.54%	13.25%
12	POR	Portland General Electric Company	$ 1.20	/	34.97	=	3.43%	3.51%	5.50%	3.92%	4.71%	7.42%	8.22%	9.03%
13	SO	Southern Company	$ 2.17	/	43.63	=	4.97%	5.06%	3.00%	3.58%	3.29%	8.05%	8.35%	8.64%
14	WR	Westar Energy, Inc.	$ 1.44	/	36.66	=	3.93%	3.99%	3.00%	3.40%	3.20%	6.99%	7.19%	7.39%
		AVERAGE					3.94%	4.03%	4.68%	5.16%	4.92%	8.26%	8.95%	9.63%

AVERAGE OF LOW, MEAN AND HIGH 8.95%

REFERENCES:
COLUMN (A); Annualized Dividends per Value Line
COLUMN (B): AVERAGE STOCK PRICES, SEE TESTIMONY ATTACHMENT ((C)
COLUMN (C): COLUMN (A) / COLUMN (B)
COLUMN (D): COLUMN (C) X (1+.05 COLUMN (G))
COLUMN (G) AVERAGE COLUMN (E) AND (F)

BASED ON A GEOMETRIC MEAN:

LINE NO.	STOCK SYMBOL	COMPANY NAME	k	=	r_f	+ [	ß	x (	r_m	-	r_f	)]	=	(B) EXPECTED RETURN
							(A)							
1	ALE	ALLETE, Inc.	k	=	3.01%	+ [	0.80	x (	10.10%	-	6.10%	)]	=	6.21%
2	AEP	American Electric Power Company, Inc.	k	=	3.01%	+ [	0.70	x (	10.10%	-	6.10%	)]	=	5.81%
3	DUK	Duke Energy Corporation	k	=	3.01%	+ [	0.60	x (	10.10%	-	6.10%	)]	=	5.41%
4	EE	EL Paso Electric	k	=	3.01%	+ [	0.75	x (	10.10%	-	6.10%	)]	=	6.01%
5	EDE	Empire District Electric Company	k	=	3.01%	+ [	0.70	x (	10.10%	-	6.10%	)]	=	5.81%
6	ES	Eversource Energy	k	=	3.01%	+ [	0.75	x (	10.10%	-	6.10%	)]	=	6.01%
7	GXP	Great Plains Energy Inc.	k	=	3.01%	+ [	0.85	x (	10.10%	-	6.10%	)]	=	6.41%
8	IDA	IDACORP, Inc.	k	=	3.01%	+ [	0.80	x (	10.10%	-	6.10%	)]	=	6.21%
9	OTTR	Otter Tail Corporation	k	=	3.01%	+ [	0.85	x (	10.10%	-	6.10%	)]	=	6.41%
10	PNW	Pinnacle West Capital Corporation	k	=	3.01%	+ [	0.70	x (	10.10%	-	6.10%	)]	=	5.81%
11	PNM	PNM Resources, Inc.	k	=	3.01%	+ [	0.85	x (	10.10%	-	6.10%	)]	=	6.41%
12	POR	Portland General Electric Company	k	=	3.01%	+ [	0.80	x (	10.10%	-	6.10%	)]	=	6.21%
13	SO	Southern Company	k	=	3.01%	+ [	0.55	x (	10.10%	-	6.10%	)]	=	5.21%
14	WR	Westar Energy, Inc.	k	=	3.01%	+ [	0.75	x (	10.10%	-	6.10%	)]	=	6.01%
15	AVERAGE						0.75							6.00%

REFERENCES:
COLUMN (A): SHARPE LITNER CAPITAL ASSET PRICING MODEL ("CAPM") FORMULA

$k = r_f + [ß (r_m - r_f)]$

WHERE: k = THE EXPECTED RETURN ON A GIVEN SECURITY
r_f = RATE OF RETURN ON A RISK FREE ASSET PROXY (a)
ß = THE BETA COEFFICIENT OF A GIVEN SECURITY
r_m = PROXY FOR THE MARKET RATE OF RETURN (b)
r_f = PROXY FOR THE RISK FREE RATE ON LONG-TERM TREASURIES (b)

COLUMN (B): EXPECTED RATE OF RETURN USING THE CAPM FORMULA

BASED ON AN ARITHMETIC MEAN:

LINE NO.	STOCK SYMBOL	COMPANY NAME	k	=	r_f	+ [	(A) ß	x (	r_m	-	r_f	)] =	(B) EXPECTED RETURN
1	ALE	ALLETE, Inc.	k	=	3.01%	+ [	0.80	x (	12.00%	-	6.40%	)] =	7.49%
2	AEP	American Electric Power Company, Inc.	k	=	3.01%	+ [	0.70	x (	12.00%	-	6.40%	)] =	6.93%
3	DUK	Duke Energy Corporation	k	=	3.01%	+ [	0.60	x (	12.00%	-	6.40%	)] =	6.37%
4	EE	EL Paso Electric	k	=	3.01%	+ [	0.75	x (	12.00%	-	6.40%	)] =	7.21%
5	EDE	Empire District Electric Company	k	=	3.01%	+ [	0.70	x (	12.00%	-	6.40%	)] =	6.93%
6	ES	Eversource Energy	k	=	3.01%	+ [	0.75	x (	12.00%	-	6.40%	)] =	7.21%
7	GXP	Great Plains Energy Inc.	k	=	3.01%	+ [	0.85	x (	12.00%	-	6.40%	)] =	7.77%
8	IDA	IDACORP, Inc.	k	=	3.01%	+ [	0.80	x (	12.00%	-	6.40%	)] =	7.49%
9	OTTR	Otter Tail Corporation	k	=	3.01%	+ [	0.85	x (	12.00%	-	6.40%	)] =	7.77%
10	PNW	Pinnacle West Capital Corporation	k	=	3.01%	+ [	0.70	x (	12.00%	-	6.40%	)] =	6.93%
11	PNM	PNM Resources, Inc.	k	=	3.01%	+ [	0.85	x (	12.00%	-	6.40%	)] =	7.77%
12	POR	Portland General Electric Company	k	=	3.01%	+ [	0.80	x (	12.00%	-	6.40%	)] =	7.49%
13	SO	Southern Company	k	=	3.01%	+ [	0.55	x (	12.00%	-	6.40%	)] =	6.09%
14	WR	Westar Energy, Inc.	k	=	3.01%	+ [	0.75	x (	12.00%	-	6.40%	)] =	7.21%
15	AVERAGE						$\boxed{0.75}$						7.19%

REFERENCES:
COLUMN (A): SHARPE LITNER CAPITAL ASSET PRICING MODEL ("CAPM") FORMULA

$$k = r_f + [\,ß\,(r_m - r_f)\,]$$

WHERE: k = THE EXPECTED RETURN ON A GIVEN SECURITY
r_f = RATE OF RETURN ON A RISK FREE ASSET PROXY (a)
ß = THE BETA COEFFICIENT OF A GIVEN SECURITY
r_m = PROXY FOR THE MARKET RATE OF RETURN (b)
r_f = PROXY FOR THE RISK FREE RATE ON LONG-TERM TREASURIES (b)

COLUMN (B): EXPECTED RATE OF RETURN USING THE CAPM FORMULA

UNS Electric, Inc.
Test Year Ended December 31, 2014
Docket No. E-04204A-15-0142

SCHEDUL E RBM-7

LINE NO.	YEAR	(A) CHANGE IN CPI	(B) CHANGE IN GDP (1996 $)	(C) PRIME RATE	(D) FED. DISC. RATE	(E) FED. FUNDS RATE	(F) 91-DAY T-BILLS	(G) 30-YR T-BONDS	(H) A-RATED UTIL. BOND YIELD	(I) Baa-RATED UTIL. BOND YIELD
1	1990	5.39%	1.90%	10.01%	6.98%	8.10%	7.50%	7.49%	9.86%	10.06%
2	1991	4.25%	-0.20%	8.46%	5.45%	5.69%	5.38%	5.38%	9.36%	9.55%
3	1992	3.03%	3.30%	6.25%	3.25%	3.52%	3.43%	3.43%	8.69%	8.86%
4	1993	2.96%	2.70%	6.00%	3.00%	3.02%	3.00%	3.00%	7.59%	7.91%
5	1994	2.61%	4.00%	7.14%	3.60%	4.21%	4.25%	4.25%	8.31%	8.63%
6	1995	2.81%	2.50%	8.83%	5.21%	5.83%	5.49%	5.49%	7.89%	8.29%
7	1996	2.93%	3.70%	8.27%	5.02%	5.30%	5.01%	5.01%	7.75%	8.17%
8	1997	2.34%	4.50%	8.44%	5.00%	5.46%	5.06%	5.06%	7.60%	8.12%
9	1998	1.55%	4.20%	8.35%	4.92%	5.35%	4.78%	4.78%	7.04%	7.27%
10	1999	2.19%	4.50%	7.99%	4.62%	4.97%	4.64%	4.64%	7.62%	7.88%
11	2000	3.38%	3.70%	9.23%	5.73%	6.24%	5.82%	5.82%	8.24%	8.36%
12	2001	2.83%	0.80%	6.92%	3.41%	3.88%	3.40%	5.95%	7.59%	8.02%
13	2002	1.59%	1.60%	4.67%	1.17%	1.67%	1.61%	5.38%	7.41%	7.98%
14	2003	2.27%	2.50%	4.12%	2.03%	1.13%	1.01%	4.92%	6.18%	6.64%
15	2004	2.68%	3.60%	4.34%	2.34%	1.35%	1.37%	5.03%	5.77%	6.20%
16	2005	3.39%	2.90%	6.16%	4.19%	3.22%	3.15%	4.57%	5.38%	5.78%
17	2006	3.24%	2.80%	7.97%	5.96%	4.97%	4.73%	4.91%	5.94%	6.30%
18	2007	2.85%	2.90%	8.05%	5.86%	5.02%	4.36%	4.84%	6.07%	6.24%
19	2008	3.84%	-6.80%	5.09%	2.39%	1.92%	1.37%	4.28%	6.34%	6.64%
20	2009	-0.36%	5.00%	3.25%	0.50%	0.00% - 0.25%	0.15%	4.08%	5.84%	6.87%
21	2010	1.64%	2.80%	3.25%	0.72%	0.00% - 0.25%	0.13%	4.25%	5.50%	5.98%
22	2011	3.00%	1.70%	3.25%	0.75%	0.00% - 0.25%	0.05%	3.93%	5.06%	5.58%
23	2012	1.70%	2.20%	3.25%	0.75%	0.00% - 0.25%	0.08%	2.92%	3.99%	4.42%
24	2013	1.10%	2.40%	3.25%	0.75%	0.00% - 0.25%	0.05%	3.24%	4.19%	4.60%
25	2014	1.25%	2.65%	3.25%	7.50%	0.00% - 0.25%	6.00%	3.90%	4.25%	4.65%

REFERENCES:
COLUMN (A): 1990 - CURRENT, U.S. DEPARTMENT OF LABOR, BUREAU OF LABOR STATISTICS WEB SITE
COLUMN (B): 1990 - CURRENT, U.S. DEPARTMENT OF COMMERCE, BUREAU OF ECONOMIC ANALYSIS
COLUMN (C) THROUGH (G): 1990 - 2003, FEDERAL RESERVE BANK OF ST. LOUIS WEB SITE
COLUMN (C) THROUGH (D): CURRENT, THE VALUE LINE INVESTMENT SURVEY

COLUMN (F) THROUGH (I): CURRENT, THE VALUE LINE INVESTMENT SURVEY
COLUMN (H) THROUGH (I): 1990 - 2000, MOODY'S PUBLIC UTILITY REPORTS
COLUMN (H) THROUGH (I): 2001, MERGENT 2002 PUBLIC UTILITY MANUAL
COLUMN (H) THROUGH (I): 2003 MERGENT NEWS REPORTS

ATTACHMENT A

ATTACHMENT A

ROBERT B. MEASE, CPA, CRRA
Education and Professional Qualifications

EDUCATION

Bachelors Degree Business Administration / Accounting - Morris Harvey College.

Attended West Virginia School of Graduate Studies and studied Accounting and Public Administration

Attended numerous courses and seminars for Continuing Professional Educational purposes.

WORK EXPERIENCE

Controller
Knives of Alaska, Inc., Diamond Blade, LLC, and Alaska Expedition Company.

Financial Manager / CFO
All Saints Camp & Conference Center

Energy West, Inc.
Vice President, Controller

- Led team that succeeded in obtaining a $1.5 million annual utility rate increase
- Coached accountants for proper communication techniques with Public Service Commission, supervised 9 professional accountants
- Developed financial models used to negotiate an $18 million credit line
- Responsible for monthly, quarterly and annual financial statements for internal and external purposes, SEC filings on a quarterly and annual basis, quarterly presentations to Board of Directors and shareholders during annual meetings, coordinated annual audit
- Communication with senior management team, supervised accounting staff and resolved all accounting issues, reviewed expenditures related to capital projects
- Monitored natural gas prices and worked with senior buyers to ensure optimal price obtained

Junkermier, Clark, Campanella, Stevens
Consulting Staff

- Established a consulting practice that generated approximately $160k the first year of existence
- Prepared business plan and projections for inclusion in clients financing documents
- Prepared written reports related to consulting engagements performed
- Developed models used in financing documents and made available for other personnel to use
- Performed Profit Enhancement engagements
- Participated during audit of large manufacturing client for two reporting years

Prior to 1999, held various positions: TMC Sales, Inc. as **Vice President / Controller**, with American Agri-Technology Corporation as **Vice President / CFO** and with Union Carbide Corporation as **Accounting Manager. (Union Carbide was a multi-national Fortune 500 Company that was purchased by Dow Chemical)**

PROFESSIONAL AFFILIATIONS

Past Member - Institute of Management Accountants
Member - American Institute of CPA's
Member – Society of Utility and Regulatory Financial Analysts
Past Member –WV Society of CPA's and Montana Society of CPA's

RESUME OF RATE CASE AND REGULATORY PARTICIPATION WITH RUCO

Utility Company	Docket No.
Arizona Water Company (Eastern Group)	W-01445A-11-0310
Pima Utility Company	W-02199A-11-0329 et al.
Tucson Electric Power Company	E-01933A-12-0291
Arizona Water Company (Northern Group)	W-01445A-12-0348
UNS Electric	E-04204A-12-0504
Global Water	W-01212A-12-0309 et al.
LPSCO	SW-01428A-13-0042 et al.
Johnson Utilities	WS-02987A-13-0477
Johnson Utilities	WS-02987A-08-0180
APS	E-01345A-11-0224
EPCOR Water Arizona, Inc.	WS-01303A-09-0343
Utility Source, LLC	WS-04235A-13-0331
EPCOR Water Arizona, Inc.	WS-01303A-14-0010
EPCOR Water, Purchase of Willow Valley Water, Co.	W-01732A-15-0131

ATTACHMENT B

ALLETE NYSE-ALE

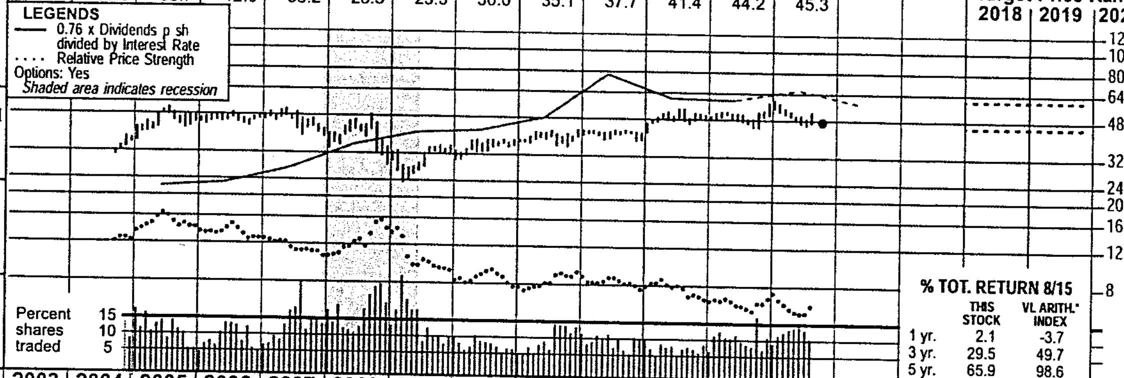
RECENT PRICE 47.32 | P/E RATIO 14.1 (Trailing: 15.7; Median: 16.0) | RELATIVE P/E RATIO 0.81 | DIV'D YLD 4.4% | VALUE LINE

TIMELINESS 3 Raised 4/24/15
SAFETY 2 New 10/1/04
TECHNICAL 3 Raised 9/18/15
BETA .80 (1.00 = Market)

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
High:	37.5	51.7	49.3	51.3	49.0	35.3	37.9	42.5	42.7	54.1	58.0	59.7
Low:	30.8	35.7	42.6	38.2	28.3	23.3	30.0	35.1	37.7	41.4	44.2	45.3

Target Price Range 2018 | 2019 | 2020

LEGENDS
— 0.76 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



2018-20 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	60	(+25%)	10%
Low	45	(-5%)	4%

Insider Decisions

	O	N	D	J	F	M	A	M	J
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	1	0	0	1	0	0	0
to Sell	0	0	1	0	1	2	1	1	1

Institutional Decisions

	4Q2014	1Q2015	2Q2015
to Buy	97	117	117
to Sell	90	77	79
Hld's(000)	32344	33487	35643

% TOT. RETURN 8/15

	THIS STOCK	VL ARITH.* INDEX
1 yr.	2.1	-3.7
3 yr.	29.5	49.7
5 yr.	65.9	98.6

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	© VALUE LINE PUB. LLC	18-20
--	--	--	--	--	25.30	24.50	25.23	27.33	24.57	21.57	25.34	24.75	24.40	24.60	24.77	*27.75*	*29.05*	Revenues per sh	*34.00*
--	--	--	--	--	2.97	3.85	4.14	4.42	4.23	3.57	4.35	4.91	5.01	5.35	5.68	*6.30*	*6.40*	"Cash Flow" per sh	*7.75*
--	--	--	--	--	1.35	2.48	2.77	3.08	2.82	1.89	2.19	2.65	2.58	2.63	2.90	*3.30*	*3.20*	Earnings per sh A	*4.00*
--	--	--	--	--	.30	1.25	1.45	1.64	1.72	1.76	1.76	1.78	1.84	1.90	1.96	*2.02*	*2.10*	Div'd Decl'd per sh B ■ †	*2.40*
--	--	--	--	--	2.12	1.95	3.37	6.82	9.24	9.05	6.95	6.38	10.30	7.93	12.48	*5.70*	*4.75*	Cap'l Spending per sh	*5.50*
--	--	--	--	--	21.23	20.03	21.90	24.11	25.37	26.41	27.26	28.78	30.48	32.44	35.06	*37.30*	*38.45*	Book Value per sh C	*42.50*
--	--	--	--	--	29.70	30.10	30.40	30.80	32.60	35.20	35.80	37.50	39.40	41.40	45.90	*49.00*	*49.25*	Common Shs Outst'g D	*50.00*
--	--	--	--	--	25.2	17.9	16.5	14.8	13.9	16.1	16.0	14.7	15.9	18.6	17.2	*Bold figures are*		Avg Ann'l P/E Ratio	*13.5*
--	--	--	--	--	1.33	.95	.89	.79	.84	1.07	1.02	.92	1.01	1.05	.91	*Value Line*		Relative P/E Ratio	*.85*
--	--	--	--	--	.9%	2.8%	3.2%	3.6%	4.4%	5.8%	5.0%	4.6%	4.5%	3.9%	3.9%	*estimates*		Avg Ann'l Div'd Yield	*4.5%*

CAPITAL STRUCTURE as of 6/30/15
Total Debt $1390.4 mill. Due in 5 Yrs $281.9 mill.
LT Debt $1272.4 mill. LT Interest $57.3 mill.
(LT interest earned: 3.9x)
Leases, Uncapitalized Annual rentals $13.4 mill.

Pension Assets-12/14 $544.2 mill.
Oblig. $714.5 mill.
Pfd Stock None

Common Stock 48,850,462 shs.

MARKET CAP: $2.3 billion (Mid Cap)

2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016		18-20
737.4	767.1	841.7	801.0	759.1	907.0	928.2	961.2	1018.4	1136.8	*1360*	*1430*	Revenues ($mill)	*1700*
68.0	77.3	87.6	82.5	61.0	75.3	93.8	97.1	104.7	124.8	*160*	*155*	Net Profit ($mill)	*195*
28.4%	37.5%	34.8%	34.3%	33.7%	37.2%	27.6%	28.1%	21.5%	22.6%	*17.0%*	*14.0%*	Income Tax Rate	*14.0%*
.4%	1.4%	6.6%	5.8%	12.8%	8.9%	2.7%	5.3%	4.4%	6.3%	*3.0%*	*2.0%*	AFUDC % to Net Profit	*2.0%*
39.1%	35.1%	35.6%	41.6%	42.8%	44.2%	44.3%	43.7%	44.6%	44.2%	*44.0%*	*43.0%*	Long-Term Debt Ratio	*41.5%*
60.9%	64.9%	64.4%	58.4%	57.2%	55.8%	55.7%	56.3%	55.4%	55.8%	*56.0%*	*57.0%*	Common Equity Ratio	*58.5%*
990.6	1025.6	1153.5	1415.4	1625.3	1747.6	1937.2	2134.6	2425.9	2882.2	*3250*	*3315*	Total Capital ($mill)	*3625*
860.4	921.6	1104.5	1387.3	1622.7	1805.6	1982.7	2347.6	2576.5	3286.4	*3675*	*3750*	Net Plant ($mill)	*4075*
8.0%	8.6%	8.6%	6.7%	4.8%	5.4%	6.0%	5.6%	5.3%	5.2%	*6.0%*	*5.5%*	Return on Total Cap'l	*6.5%*
11.3%	11.6%	11.8%	10.0%	6.6%	7.7%	8.7%	8.1%	7.8%	7.8%	*8.5%*	*8.0%*	Return on Shr. Equity	*9.0%*
11.3%	11.6%	11.8%	10.0%	6.6%	7.7%	8.7%	8.1%	7.8%	7.8%	*8.5%*	*8.0%*	Return on Com Equity E	*9.0%*
5.2%	5.0%	5.8%	3.9%	.5%	1.5%	2.9%	2.3%	2.2%	2.5%	*3.5%*	*2.5%*	Retained to Com Eq	*3.5%*
54%	57%	51%	61%	93%	81%	66%	71%	72%	67%	*61%*	*67%*	All Div'ds to Net Prof	*61%*

ELECTRIC OPERATING STATISTICS

	2012	2013	2014
% Change Retail Sales (KWH)	+1.1	-1.1	+.5
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	5.24	5.45	6.09
Capacity at Peak (Mw)	1790	1793	1985
Peak Load, Winter (Mw) F	1633	1646	1637
Annual Load Factor (%)	79.0	NA	NA
% Change Customers (avg.)	+.5	NA	NA
Fixed Charge Cov. (%)	341	306	345

ANNUAL RATES

of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '12-'14 to '18-'20
Revenues	-.5%	--	*5.5%*
"Cash Flow"	6.0%	5.5%	*6.5%*
Earnings	7.0%	1.0%	*6.5%*
Dividends	NMF	2.0%	*4.0%*
Book Value	4.5%	5.0%	*4.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2012	240.0	216.4	248.8	256.0	961.2
2013	263.8	235.6	251.0	268.0	1018.4
2014	296.5	260.7	288.9	290.7	1136.8
2015	320.0	323.3	*355*	*361.7*	*1360*
2016	*350*	*345*	*365*	*370*	*1430*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2012	.66	.39	.78	.75	2.58
2013	.83	.35	.63	.82	2.63
2014	.80	.40	.97	.73	2.90
2015	.85	.46	*.97*	*1.02*	*3.30*
2016	*.90*	*.45*	*.90*	*.95*	*3.20*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.445	.445	.445	.445	1.78
2012	.46	.46	.46	.46	1.84
2013	.475	.475	.475	.475	1.90
2014	.49	.49	.49	.49	1.96
2015	.505	.505	.505		

BUSINESS: ALLETE, Inc. is the parent of Minnesota Power, which supplies electricity to 146,000 customers in northeastern MN, & Superior Water, Light & Power in northwestern WI. Electric rev. breakdown: taconite mining/processing, 27%; paper/wood products, 9%; other industrial, 7%; residential, 12%; commercial, 13%; wholesale, 10% other, 22%. ALLETE Clean Energy owns renewable energy projects. Acq'd U.S. Water Services 2/15. Has real estate operation in FL. Generating sources: coal & lignite, 56%; wind, 7%; other, 3%; purchased, 34%. Fuel costs: 31% of revs. '14 deprec. rate: 2.9%. Has 1,600 employees. Chairman, President & CEO: Alan R. Hodnik. Inc.: MN. Address: 30 West Superior St., Duluth, MN 55802-2093. Tel.: 218-279-5000. Internet: www.allete.com.

A development fee from a transaction will bolster ALLETE's earnings in the second half of 2015. ALLETE Clean Energy is building a wind facility that it will sell to a utility in North Dakota. The development fee from the transaction will amount to $20 million-$25 million (pretax) in the last two quarters of 2015. This will amount to $0.25-$0.30 a share, which we will *include* in our earnings presentation. As a result of this deal, ALLETE raised its earnings guidance for 2015 from $3.00-$3.20 a share to $3.20-$3.40 a share. We have raised our estimate by $0.25 a share, to $3.30. However . . .

Minnesota Power's taconite customers have lowered their production plans — and thus, their power needs. (Taconite is used in steelmaking.) These customers expect to need power for just 80% of capacity in September and 90% of capacity in the fourth quarter. This is the first time since the last recession that the taconite producers have been running well below 100%. This is why ALLETE raised its earnings target by just $0.20 a share, despite a transaction that is expected to add more than that to the bottom line. The utility will make up part of the demand shortfall by selling power on the wholesale market and trimming operating expenses, but these moves won't be enough to make up the difference.

We have trimmed our 2016 earnings estimate by a nickel a share. This is in response to the demand cutbacks by the taconite customers. More will be known at the start of December, when they announce their demand expectations for the first four months of 2016.

Minnesota Power has a major project that is on track for completion in May, and construction of another significant project is expected to begin later in 2016. The former is a $260 million upgrade to a coal-fired unit. The latter is a $345 million investment in a transmission line from northern Minnesota to the Canadian border. The utility benefits from current cost recovery for these kinds of capital spending.

ALLETE stock has a dividend yield that is a cut above average and 3- to 5-year total return potential that is just average, by utility standards.

Paul E. Debbas, CFA *September 18, 2015*

(A) Diluted EPS. Excl. nonrec. gain (loss): '04, 2¢; '05, ($1.84); gain (losses) on disc. ops.: '04, $2.57, '05, (16¢); '06, (2¢); loss from accounting change: '04, 27¢. Next egs. report due early Nov. (B) Div'ds historically paid in early Mar., June, Sept. and Dec. ■ Div'd reinvestment plan avail. † Shareholder investment plan avail. (C) Incl. deferred chgs. In '14: $7.78/sh. (D) In mill. (E) Rate base: Orig. cost deprec. Rate allowed on com. eq. in '10: 10.38%; earned on avg. com. eq., '14: 8.6%. Reg. Clim.: Avg. (F) Summer peak in '12 & '13.

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	35
Earnings Predictability	80

AMERICAN ELEC. PWR. NYSE-AEP

RECENT PRICE	54.08	P/E RATIO	15.6 (Trailing: 15.1; Median: 13.0)	RELATIVE P/E RATIO	0.89	DIV'D YLD	4.1%	VALUE LINE

TIMELINESS 3 Lowered 6/12/15

SAFETY 2 Raised 9/19/14

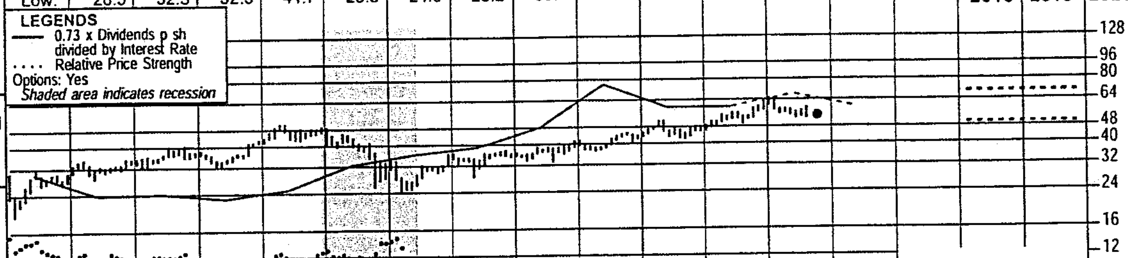
TECHNICAL 2 Raised 9/18/15

BETA .70 (1.00 = Market)

High:	35.5	40.8	43.1	51.2	49.1	36.5	37.9	41.7	45.4	51.6	63.2	65.4		
Low:	28.5	32.3	32.3	41.7	25.5	24.0	28.2	33.1	37.0	41.8	45.8	52.3		

Target Price Range 2018 | 2019 | 2020

LEGENDS
— 0.73 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



2018-20 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	70	(+30%)	10%
Low	50	(-10%)	3%

Insider Decisions

	O	N	D	J	F	M	A	M	J
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	10	0
to Sell	0	0	0	0	1	0	0	4	0

Institutional Decisions

	4Q2014	1Q2015	2Q2015
to Buy	361	338	327
to Sell	308	368	336
Hld's(000)	326985	324222	328262

Percent shares traded 15 10 5

% TOT. RETURN 8/15

	THIS STOCK	VL ARITH.* INDEX
1 yr.	4.9	-3.7
3 yr.	42.3	49.7
5 yr.	90.6	98.6

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	© VALUE LINE PUB. LLC	18-20
35.63	42.53	190.10	42.96	36.82	35.51	30.76	31.82	33.41	35.56	28.22	30.01	31.27	30.77	31.48	34.78	*34.35*	*35.10*	Revenues per sh	*39.50*
6.36	5.11	7.65	6.99	5.76	5.89	5.96	6.67	6.80	6.84	6.32	6.29	6.83	6.92	7.02	7.57	*7.75*	*8.00*	"Cash Flow" per sh	*9.25*
2.69	1.04	3.27	2.86	2.53	2.61	2.64	2.86	2.86	2.99	2.97	2.60	3.13	2.98	3.18	3.34	*3.60*	*3.65*	Earnings per sh A	*4.25*
2.40	2.40	2.40	2.40	1.65	1.40	1.42	1.50	1.58	1.64	1.64	1.71	1.85	1.88	1.95	2.03	*2.15*	*2.27*	Div'd Decl'd per sh B ■	*2.65*
4.47	5.51	5.69	5.08	3.44	4.28	6.11	8.89	8.88	9.83	6.19	5.07	5.74	6.45	7.75	8.68	*9.75*	*8.05*	Cap'l Spending per sh	*8.50*
25.79	25.01	25.54	20.85	19.93	21.32	23.08	23.73	25.17	26.33	27.49	28.33	30.33	31.37	32.98	34.37	*35.85*	*37.30*	Book Value per sh C	*42.00*
194.10	322.02	322.24	338.84	395.02	395.86	393.72	396.67	400.43	406.07	478.05	480.81	483.42	485.67	487.78	489.40	*492.00*	*494.00*	Common Shs Outst'g D	*500.00*
14.3	34.3	13.9	12.7	10.7	12.4	13.7	12.9	16.3	13.1	10.0	13.4	11.9	13.8	14.5	15.9	*Bold figures are*		Avg Ann'l P/E Ratio	*14.0*
.82	2.23	.71	.69	.61	.66	.73	.70	.87	.79	.67	.85	.75	.88	.81	.84	*Value Line*		Relative P/E Ratio	*.90*
6.2%	6.7%	5.3%	6.6%	6.1%	4.3%	3.9%	4.1%	3.4%	4.2%	5.5%	4.9%	5.0%	4.6%	4.2%	3.8%	*estimates*		Avg Ann'l Div'd Yield	*4.5%*

CAPITAL STRUCTURE as of 6/30/15
Total Debt $20683 mill. **Due in 5 Yrs** $9375 mill.
LT Debt $17761 mill. **LT Interest** $799 mill.
Incl. $2114 mill. securitized bonds. Incl. $552 mill. capitalized leases.
(LT interest earned: 4.0x)
Leases, Uncapitalized Annual rentals $293 mill.
Pension Assets-12/14 $4968 mill.
Oblig. $5225 mill.

Pfd Stock None

Common Stock 490,559,618 shs.
as of 7/23/15
MARKET CAP: $27 billion (Large Cap)

2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016		18-20
12111	12622	13380	14440	13489	14427	15116	14945	15357	17020	*17000*	*17350*	Revenues ($mill)	*19800*
1036.0	1131.0	1147.0	1208.0	1365.0	1248.0	1513.0	1443.0	1549.0	1634.0	*1675*	*1715*	Net Profit ($mill)	*2020*
29.3%	33.0%	31.1%	31.3%	29.7%	34.8%	31.7%	33.9%	36.2%	37.8%	*36.0%*	*36.0%*	Income Tax Rate	*36.0%*
5.4%	9.9%	9.8%	9.9%	10.9%	10.4%	10.6%	11.2%	7.3%	9.0%	*10.0%*	*8.0%*	AFUDC % to Net Profit	*8.0%*
54.8%	56.7%	58.3%	59.1%	54.4%	53.1%	50.7%	50.6%	51.1%	49.0%	*50.0%*	*49.5%*	Long-Term Debt Ratio	*49.5%*
44.9%	43.0%	41.4%	40.7%	45.4%	46.7%	49.3%	49.4%	48.9%	51.0%	*50.0%*	*50.5%*	Common Equity Ratio	*50.5%*
20222	21902	24342	26290	28958	29184	29747	30823	32913	33001	*35325*	*36575*	Total Capital ($mill)	*41400*
24284	26781	29870	32987	34344	35674	36971	38763	40997	44117	*46850*	*48475*	Net Plant ($mill)	*54100*
6.6%	6.7%	6.3%	6.2%	6.2%	5.7%	6.6%	6.1%	6.0%	6.3%	*6.0%*	*6.0%*	Return on Total Cap'l	*6.0%*
11.3%	11.9%	11.3%	11.2%	10.3%	9.1%	10.3%	9.5%	9.6%	9.7%	*9.5%*	*9.5%*	Return on Shr. Equity	*9.5%*
11.3%	12.0%	11.4%	11.3%	10.4%	9.1%	10.3%	9.5%	9.6%	9.7%	*10.0%*	*10.0%*	Return on Com Equity E	*10.0%*
5.2%	5.7%	5.1%	5.1%	4.6%	3.1%	4.2%	3.5%	3.7%	3.8%	*4.0%*	*3.5%*	Retained to Com Eq	*4.0%*
54%	53%	55%	55%	56%	66%	60%	63%	62%	61%	*63%*	*65%*	All Div'ds to Net Prof	*66%*

ELECTRIC OPERATING STATISTICS

	2012	2013	2014
% Change Retail Sales (KWH)	-2.1	-1.5	+1.1
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.3	+.4	+.3
Fixed Charge Cov. (%)	280	326	348

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '12-'14 to '18-'20
Revenues	-1.5%	--	3.5%
"Cash Flow"	1.5%	1.5%	4.5%
Earnings	1.5%	1.5%	5.0%
Dividends	.5%	4.0%	5.0%
Book Value	4.5%	4.5%	4.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	3625	3551	4156	3613	14945
2013	3826	3582	4176	3773	15357
2014	4648	4044	4302	4026	17020
2015	4708	3942	*4400*	*3950*	*17000*
2016	*4550*	*4150*	*4500*	*4150*	*17350*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.80	.75	1.00	.43	2.98
2013	.75	.73	1.10	.60	3.18
2014	1.15	.80	1.01	.39	3.34
2015	1.29	.88	*1.03*	*.40*	*3.60*
2016	*1.15*	*.85*	*1.20*	*.45*	*3.65*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.46	.46	.46	.47	1.85
2012	.47	.47	.47	.47	1.88
2013	.47	.49	.49	.50	1.95
2014	.50	.50	.50	.53	2.03
2015	.53	.53	.53		

BUSINESS: American Electric Power Company, Inc. (AEP), through 10 operating utilities, serves 5.3 mill. customers in Arkansas, Kentucky, Indiana, Louisiana, Michigan, Ohio, Oklahoma, Tennessee, Texas, Virginia, and West Virginia. Electric revenue breakdown: residential, 40%; commercial, 23%; industrial, 19%; wholesale, 15%; other, 3%. Sold 50% stake in Yorkshire Holdings (British utility) '01; sold SEEBOARD (British utility) '02; sold Houston Pipeline '05. Generating sources not available. Fuel costs: 36% of revenues. '14 reported deprec. rates (utility): 1.4%-8.6%. Has 18,500 employees. Chairman, President & CEO: Nicholas K. Akins. Inc.: New York. Address: 1 Riverside Plaza, Columbus, Ohio 43215-2373. Tel.: 614-716-1000. Internet: www.aep.com.

American Electric Power is waiting for the Ohio regulators to rule on the company's request for a purchased-power agreement between its nonregulated generating assets and its utilities in the state. In recent years, AEP has been moving away from nonregulated operations toward regulated businesses. A purchased-power agreement would be another step in this direction. Due to low capacity prices, the nonregulated business has declined in recent years (more below), although recent changes in the rules for the power markets ought to improve conditions somewhat. AEP isn't necessarily going to retain its nonregulated generating assets—a sale or spinoff is under consideration. There is no timetable for a decision from the commission or the company.

The company received a rate increase in Kentucky and filed a rate application in Oklahoma. Kentucky Power's tariffs were raised by $45.4 million, based on a 10.25% return on equity. Public Service of Oklahoma is seeking a hike of $172 million, based on a 10.5% ROE. New tariffs should take effect at the start of 2016.

We have raised our 2015 earnings estimate by $0.10 a share, to $3.60. Second-quarter profits were better than we expected. Management lifted its earnings guidance from $3.40-$3.60 to $3.50-$3.65. AEP's regulated operations are benefiting from rate relief and increased transmission investment. (In fact, AEP raised its 2015 capital budget for transmission by $200 million.) This is offsetting weakness in the nonregulated sector. Lower capacity payments will hurt comparisons by $0.35 a share this year, mostly in the second half.

We look for just a slight profit increase in 2016. A further decline from the nonregulated side will probably offset most of the improvement that is likely from the regulated activities.

A dividend increase is likely in the fourth quarter. We estimate that the board of directors will boost the quarterly dividend by $0.03 a share (5.7%). AEP is targeting a payout ratio of 60%-70%.

Investors should stay tuned to see what happens with the nonregulated operations. For now, the dividend yield and 3- to 5-year total return potential are near the norms for the utility industry.

Paul E. Debbas, CFA *September 18, 2015*

(A) Diluted EPS. Excl. nonrec. gains (losses): '02, ($3.86); '03, ($1.92); '04, 24¢; '05, (62¢); '06, (20¢); '07, (20¢); '08, 40¢; '10, (7¢); '11, 89¢; '12, (38¢); '13, (14¢); discont. ops.: '02, (57¢); '03, (32¢); '04, 15¢; '05, 7¢; '06, 2¢; '08, 3¢. '14 EPS don't add due to rounding. Next egs. report due late Oct. (B) Div'ds historically paid early Mar., June, Sept., & Dec. ■ Div'd reinvest. plan avail. (C) Incl. intang. In '14: $17.67/sh. (D) In mill. (E) Rate base: various. Rates all'd on com. eq.: 9.65%-10.9%; earned on avg. com. eq., '14: 9.9%. Regul. Clim.: Avg.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	55
Earnings Predictability	90

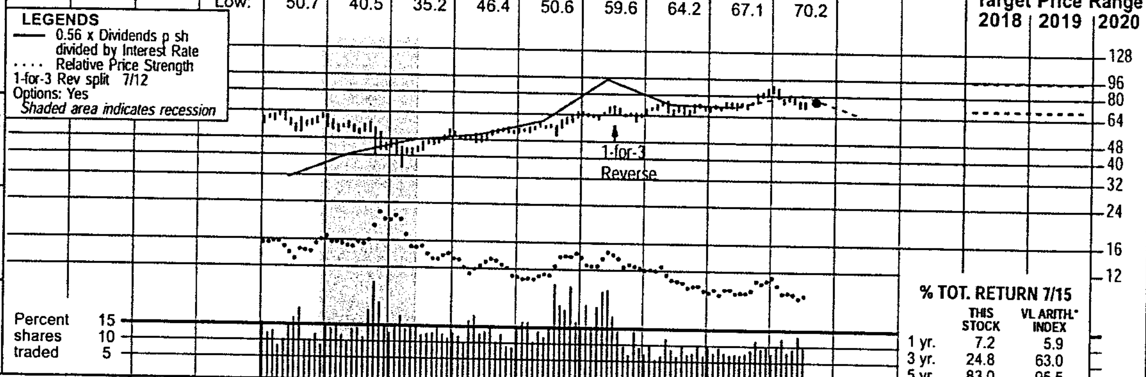
DUKE ENERGY NYSE-DUK

RECENT PRICE 75.29 | P/E RATIO 16.5 (Trailing: 18.7, Median: NMF) | RELATIVE P/E RATIO 0.91 | DIV'D YLD 4.4% | VALUE LINE

TIMELINESS 4 Lowered 8/14/15
SAFETY 2 New 6/1/07
TECHNICAL 4 Raised 8/21/15
BETA .60 (1.00 = Market)

	2007	2008	2009	2010	2011	2012	2013	2014	2015
High:	63.9	61.8	53.8	55.8	66.4	71.1	75.5	87.3	90.0
Low:	50.7	40.5	35.2	46.4	50.6	59.6	64.2	67.1	70.2

Target Price Range 2018 | 2019 | 2020



2018-20 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	95	(+25%)	10%
Low	70	(-5%)	3%

Insider Decisions

	S	O	N	D	J	F	M	A	M
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	9	0	0	0
to Sell	0	0	4	0	0	3	0	0	5

Institutional Decisions

	3Q2014	4Q2014	1Q2015
to Buy	431	469	472
to Sell	423	460	494
Hld's(000)	392694	390171	391310

% TOT. RETURN 7/15

	THIS STOCK	VL ARITH.* INDEX
1 yr.	7.2	5.9
3 yr.	24.8	63.0
5 yr.	83.0	95.5

Duke Energy Corporation, in its current configuration, began trading on January 3, 2007, the day after it spun off its midstream gas operations into a new company, Spectra Energy (NYSE: SE). Duke Energy shareholders received half a share of Spectra Energy for each Duke share held. In July of 2012, Duke acquired Progress Energy and effected a 1-for-3 reverse split. Data for the "old" Duke are not shown because they are not comparable.

2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	© VALUE LINE PUB. LLC	18-20
--	25.32	30.24	31.15	29.18	32.22	32.63	27.88	34.84	33.84	***35.40***	***36.95***	Revenues per sh	***41.75***
--	7.86	8.11	7.34	7.58	8.49	8.68	6.80	8.56	9.11	***9.75***	***10.20***	"Cash Flow" per sh	***11.25***
--	2.76	3.60	3.03	3.39	4.02	4.14	3.71	3.98	4.13	***4.45***	***4.80***	Earnings per sh A	***5.25***
--	--	2.58	2.70	2.82	2.91	2.97	3.03	3.09	3.15	***3.24***	***3.36***	Div'd Decl'd per sh B ■	***3.80***
--	8.07	7.43	10.35	9.85	10.84	9.80	7.81	7.83	7.62	***11.05***	***11.85***	Cap'l Spending per sh	***11.75***
--	62.30	50.40	49.51	49.85	50.84	51.14	58.04	58.54	57.81	***58.50***	***59.90***	Book Value per sh C	***64.25***
--	418.96	420.62	423.96	436.29	442.96	445.29	704.00	706.00	707.00	***688.00***	***689.00***	Common Shs Outst'g D	***692.00***
--	--	16.1	17.3	13.3	12.7	13.8	17.5	17.4	17.9	***Bold figures are***		Avg Ann'l P/E Ratio	***16.0***
--	--	.85	1.04	.89	.81	.87	1.11	.98	.95	***Value Line***		Relative P/E Ratio	***1.00***
--	--	4.4%	5.2%	6.2%	5.7%	5.2%	4.7%	4.4%	4.3%	***estimates***		Avg Ann'l Div'd Yield	***4.5%***
--	10607	12720	13207	12731	14272	14529	19624	24598	23925	***24350***	***25450***	Revenues ($mill)	***28750***
--	1080.0	1522.0	1279.0	1461.0	1765.0	1839.0	2136.0	2813.0	2934.0	***3090***	***3325***	Net Profit ($mill)	***3735***
--	29.4%	31.9%	32.5%	34.4%	32.6%	31.3%	30.2%	32.6%	30.6%	***32.5%***	***32.5%***	Income Tax Rate	***32.5%***
--	6.9%	7.2%	16.0%	17.5%	22.7%	23.2%	22.3%	8.8%	7.2%	***9.0%***	***8.0%***	AFUDC % to Net Profit	***8.0%***
--	41.0%	30.9%	38.7%	42.6%	44.3%	45.1%	47.0%	48.0%	47.7%	***49.0%***	***50.0%***	Long-Term Debt Ratio	***52.5%***
--	59.0%	69.1%	61.3%	57.4%	55.7%	54.9%	52.9%	52.0%	52.3%	***51.0%***	***50.0%***	Common Equity Ratio	***47.5%***
--	44220	30697	34238	37863	40457	41451	77307	79482	78088	***78825***	***81350***	Total Capital ($mill)	***93700***
--	41447	31110	34036	37950	40344	42661	68558	69490	70046	***75300***	***79750***	Net Plant ($mill)	***92500***
--	3.1%	6.0%	4.8%	4.9%	5.5%	5.6%	3.6%	4.6%	4.8%	***5.0%***	***5.0%***	Return on Total Cap'l	***5.0%***
--	4.1%	7.2%	6.1%	6.7%	7.8%	8.1%	5.2%	6.8%	7.2%	***7.5%***	***8.0%***	Return on Shr. Equity	***8.5%***
--	4.1%	7.2%	6.1%	6.7%	7.8%	8.1%	5.2%	6.8%	7.2%	***7.5%***	***8.0%***	Return on Com Equity E	***8.5%***
--	4.1%	2.0%	.6%	1.1%	2.1%	2.2%	.9%	1.5%	1.7%	***2.0%***	***2.5%***	Retained to Com Eq	***2.5%***
--	--	72%	89%	84%	73%	72%	82%	78%	76%	***73%***	***70%***	All Div'ds to Net Prof	***70%***

CAPITAL STRUCTURE as of 6/30/15
Total Debt $41331 mill. Due in 5 Yrs $16418 mill.
LT Debt $36795 mill. LT Interest $1685 mill.
Incl. $1428 mill. capitalized leases. Incl. $1265 mill. nonrecourse LT debt of variable interest entities.
(LT interest earned: 3.4x)

Leases, Uncapitalized Annual rentals $205 mill.
Pension Assets-12/14 $8498 mill.
Oblig. $7966 mill.
Pfd Stock None
Common Stock 688,330,456 shs.
as of 8/4/15
MARKET CAP: $52 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2012	2013	2014
% Change Retail Sales (KWH)	-2.8	+1.3	+2.2
Avg. Indust. Use (MWH)	2675	2687	2876
Avg. Indust. Revs. per KWH (¢)	5.84	5.89	6.15
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (avg.)	+.8	+.8	+1.0
Fixed Charge Cov. (%)	263	327	315

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '12-'14 to '18-'20
Revenues	--	1.5%	4.5%
"Cash Flow"	--	1.0%	5.5%
Earnings	--	3.5%	5.0%
Dividends	--	2.5%	3.5%
Book Value	--	3.0%	1.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	3630	3577	6722	5695	19624
2013	5898	5879	6709	6112	24598
2014	6263	5708	6395	5559	23925
2015	6065	5589	*6850*	*5846*	*24350*
2016	*6350*	*5900*	*7150*	*6050*	*25450*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.86	.99	1.01	.59	3.71
2013	.89	.74	1.40	.94	3.98
2014	1.05	1.02	1.25	.81	4.13
2015	1.09	.87	*1.60*	*.89*	*4.45*
2016	*1.20*	*.95*	*1.70*	*.95*	*4.80*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.735	.735	.75	.75	2.97
2012	.75	.75	.765	.765	3.03
2013	.765	.765	.78	.78	3.09
2014	.78	.78	.795	.795	3.15
2015	.795	.795	.825		

BUSINESS: Duke Energy Corporation is a holding company for utilities with 7.1 mill. elec. customers in North Carolina, Florida, Indiana, South Carolina, Ohio, & Kentucky, and over 500,000 gas customers in Ohio & Kentucky. Owns independent power plants & has international ops. Acq'd Cinergy 4/06; spun off midstream gas ops. 1/07; acq'd Progress Energy 7/12. Elec. rev. breakdown: residential, 44%; commercial, 30%; industrial, 15%; other, 11%. Generating sources: coal, 37%; nuclear, 28%; gas, 21%; other, 1%; purchased, 13%. Fuel costs: 35% of revs. '14 reported deprec. rates: 2.4%-3.3%. Has 28,300 empls. Chairman: Ann Gray. Pres. & CEO: Lynn J. Good. Inc.: DE. Address: 550 South Tryon St., Charlotte, NC 28202-1803. Tel.: 704-382-3853. Web: www.duke-energy.com.

Duke Energy has stepped up its dividend growth rate. In recent years, the board of directors has been boosting the annual dividend by $0.06 a share. The latest increase, payable in September, doubled this rate. The latest increase was 3.8%.

The company completed a significant asset acquisition. Duke paid $1.25 billion for another utility's 700-megawatt stake in nuclear and coal-fired assets in North Carolina that Duke operates and already co-owned. The purchase should add $0.04 to share net in 2015 and $0.07-$0.08 annually starting in 2016. However . . .

We have lowered our 2015 share-earnings estimate by $0.05 a share. Second-quarter profits fell a bit short of our estimate. Also, results from Duke's operations in Brazil continue to disappoint due to the weak economy and unfavorable weather conditions. Our estimate is a bit below the company's guidance of $4.55-$4.75 a share because we include certain things, such as costs associated with the Progress Energy takeover (which Duke is still incurring, even three years later), that management excludes. On the other hand, we raised our 2016 share-net estimate by a nickel.

Duke has several significant investments pending, and more proposals are coming. It helps having sound finances. The utility is adding 650 mw of gas-fired capacity in South Carolina at a cost of $600 million. Duke plans to construct a 1,685-mw gas-fired facility in Florida at a cost of $1.5 billion. The company has announced a $1.1 billion system modernization project in the western Carolinas. It has a $1.8 billion-$2.0 billion (40%) stake in a proposed gas pipeline in the Carolinas and has taken a $225 million (7.5%) stake in another proposed pipeline to serve Florida. All of these investments should contribute to the company's profit growth in the coming years. Finally, Duke plans to resubmit a system modernization plan in Indiana after a previous $1.9 billion proposal was rejected.

This stock is untimely, but might interest income-oriented accounts. The dividend yield and 3- to 5-year total return potential are somewhat above average for a utility.

Paul E. Debbas, CFA *August 21, 2015*

(A) Dil. EPS. Excl. nonrec. losses: '12, 70¢; '13, 24¢; '14, 67¢; gains (loss) on disc. ops.: '12, 6¢; '13, 2¢; '14, (80¢); '15, 5¢. '12 & '13 EPS don't add due to chng. in shs. or rounding. Next egs. report due early Nov. (B) Div'ds paid mid-Mar., June, Sept., & Dec. ■ Div'd reinv. plan avail. (C) Incl. intang. In '14: $38.94/sh. (D) In mill., adj. for rev. split. (E) Rate base: Net orig. cost. Rates all'd on com. eq. in '13 in NC/SC: 10.2%; in '09 in OH: 10.63%; in '04 in IN: 10.3%; earned on avg. com. eq., '14: 7.0%. Reg. Climate: NC Avg.; SC, OH, IN Above Avg.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	50
Earnings Predictability	80

EL PASO ELECTRIC NYSE-EE

RECENT PRICE	35.19	P/E RATIO	18.0 (Trailing: 15.7 Median: 15.0)	RELATIVE P/E RATIO	0.96	DIV'D YLD	3.4%	VALUE LINE

TIMELINESS 4 Lowered 7/10/15

SAFETY 2 Raised 5/11/07

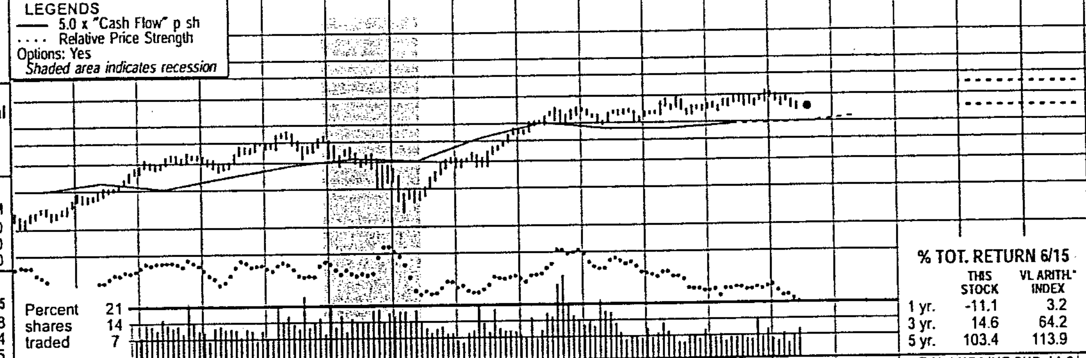
TECHNICAL 3 Lowered 7/31/15

BETA .75 (1.00 = Market)

High:	19.1	22.4	25.0	28.2	25.5	21.1	28.7	35.7	35.3	39.1	42.2	41.3
Low:	13.1	17.8	18.2	20.8	15.2	11.6	18.7	26.7	29.2	31.8	33.4	33.8

Target Price Range 2018 | 2019 | 2020

LEGENDS
—— 5.0 x "Cash Flow" p sh
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



2018-20 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	45	(+30%)	10%
Low	35	(Nil)	4%

Insider Decisions

	S	O	N	D	J	F	M	A	M
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	1	0	0	0	0	0	0

Institutional Decisions

	3Q2014	4Q2014	1Q2015
to Buy	69	87	88
to Sell	76	72	74
Hld's(000)	40115	39006	38975

% TOT. RETURN 6/15

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-11.1	3.2
3 yr.	14.6	64.2
5 yr.	103.4	113.9

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	© VALUE LINE PUB. LLC	18-20
9.96	13.70	15.40	13.91	13.97	14.95	16.70	17.75	19.43	23.15	18.85	20.61	22.97	21.26	22.11	22.74	***21.00***	***22.15***	Revenues per sh	26.75
2.79	3.21	3.43	2.99	3.00	3.27	3.05	3.44	3.86	4.16	4.07	5.15	6.05	5.66	5.65	5.87	***5.95***	***6.35***	"Cash Flow" per sh	7.75
.86	1.09	1.27	.57	.64	.69	.76	1.27	1.63	1.73	1.50	2.07	2.48	2.26	2.20	2.27	***1.95***	***2.20***	Earnings per sh A	2.75
--	--	--	--	--	--	--	--	--	--	--	--	.66	.97	1.05	1.11	***1.17***	***1.23***	Div'd Decl'd per sh B	1.40
1.28	1.70	1.85	1.75	2.03	1.94	2.28	2.73	4.63	5.36	5.95	5.27	5.90	6.70	7.18	8.50	***7.90***	***7.75***	Cap'l Spending per sh	7.25
7.36	8.05	9.01	9.20	10.51	11.23	11.56	12.60	14.76	15.47	16.45	19.04	19.03	20.57	23.44	24.39	***25.10***	***26.00***	Book Value per sh C	29.50
57.26	51.20	49.99	49.61	47.56	47.40	48.14	46.00	45.15	44.88	43.92	42.57	39.96	40.11	40.27	40.36	***40.50***	***40.65***	Common Shs Outst'g D	41.10
9.9	10.6	11.0	23.0	18.3	22.0	26.7	16.9	15.3	11.9	10.8	10.7	12.6	14.5	15.9	16.4	*Bold figures are*	*Value Line*	Avg Ann'l P/E Ratio	14.5
.56	.69	.56	1.26	1.04	1.16	1.42	.91	.81	.72	.72	.68	.79	.92	.89	.86		*estimates*	Relative P/E Ratio	.90
--	--	--	--	--	--	--	--	--	--	--	--	2.1%	3.0%	3.0%	3.0%			Avg Ann'l Div'd Yield	3.5%

CAPITAL STRUCTURE as of 3/31/15
Total Debt $1207.6 mill. Due in 5 Yrs $156.6 mill.
LT Debt $1134.2 mill. LT Interest $68.2 mill.
(LT interest earned: 2.6x)

Leases, Uncapitalized Annual rentals $1.4 mill.
Pension Assets-12/14 $272.9 mill. Oblig. $341.1 mill.

Pfd Stock None

Common Stock 40,392,332 shs. as of 4/30/15

MARKET CAP: $1.4 billion (Mid Cap)

2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016		18-20
803.9	816.5	877.4	1038.9	828.0	877.3	918.0	852.9	890.4	917.5	***850***	***900***	Revenues ($mill)	1100
36.6	61.4	74.8	77.6	66.9	90.3	103.5	90.8	88.6	91.4	***80.0***	***90.0***	Net Profit ($mill)	115
33.7%	29.8%	31.6%	32.8%	33.1%	36.1%	34.2%	34.1%	33.0%	31.0%	***33.0%***	***33.0%***	Income Tax Rate	33.0%
15.8%	8.0%	15.9%	20.4%	24.3%	22.1%	17.6%	22.4%	24.1%	30.8%	***25.0%***	***22.0%***	AFUDC % to Net Profit	13.0%
52.3%	51.5%	49.6%	53.8%	52.7%	51.2%	51.8%	54.8%	51.4%	53.5%	***56.0%***	***56.0%***	Long-Term Debt Ratio	56.5%
47.7%	48.5%	50.4%	46.2%	47.3%	48.8%	48.2%	45.2%	48.6%	46.5%	***44.0%***	***44.0%***	Common Equity Ratio	43.5%
1167.5	1195.8	1321.6	1503.9	1527.7	1660.1	1576.7	1824.5	1943.5	2118.4	***2300***	***2415***	Total Capital ($mill)	2800
1291.7	1332.2	1450.6	1595.6	1756.0	1865.8	1947.1	2102.3	2257.5	2488.4	***2645***	***2790***	Net Plant ($mill)	3050
4.9%	6.6%	7.1%	6.7%	6.0%	7.0%	8.3%	6.5%	6.1%	5.7%	***5.0%***	***5.5%***	Return on Total Cap'l	6.0%
6.6%	10.6%	11.2%	11.2%	9.3%	11.1%	13.6%	11.0%	9.4%	9.3%	***8.0%***	***8.5%***	Return on Shr. Equity	9.5%
6.6%	10.6%	11.2%	11.2%	9.3%	11.1%	13.6%	11.0%	9.4%	9.3%	***8.0%***	***8.5%***	Return on Com Equity E	9.5%
6.6%	10.6%	11.2%	11.2%	9.3%	11.1%	10.0%	6.3%	4.9%	4.8%	***3.0%***	***4.0%***	Retained to Com Eq	4.5%
--	--	--	--	--	--	26%	43%	47%	49%	***59%***	***55%***	All Div'ds to Net Prof	50%

ELECTRIC OPERATING STATISTICS

	2012	2013	2014
% Change Retail Sales (KWH)	+.7	+.4	-1.6
Avg. Indust. Use (MWH)	21659	21908	21505
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	1765	1852	1879
Peak Load, Summer (Mw)	1688	1750	1766
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+1.5	+1.3	+1.3
Fixed Charge Cov. (%)	302	280	251

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '12-'14 to '18-'20
Revenues	4.5%	1.5%	3.5%
"Cash Flow"	6.5%	7.5%	5.0%
Earnings	13.5%	6.5%	3.5%
Dividends	--	--	5.0%
Book Value	8.5%	8.0%	4.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	168.6	228.3	267.2	188.8	852.9
2013	177.3	240.1	282.7	190.3	890.4
2014	185.5	251.8	283.6	196.6	917.5
2015	163.7	***225***	***286.3***	***175***	***850***
2016	***175***	***240***	***300***	***185***	***900***

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.08	.77	1.29	.12	2.26
2013	.19	.72	1.26	.03	2.20
2014	.11	.75	1.30	.10	2.27
2015	.09	***.61***	***1.15***	***.10***	***1.95***
2016	***.15***	***.70***	***1.20***	***.15***	***2.20***

Cal-endar	QUARTERLY DIVIDENDS PAID B Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	--	.22	.22	.22	.66
2012	.22	.25	.25	.25	.97
2013	.25	.265	.265	.265	1.05
2014	.265	.28	.28	.28	1.11
2015	.28	.295			

BUSINESS: El Paso Electric Company (EPE) provides electric service to 400,000 customers in an area of approximately 10,000 square miles in the Rio Grande valley in western Texas (68% of revenues) and southern New Mexico (19% of revenues), including El Paso, Texas and Las Cruces, New Mexico. Wholesale is 13% of revenues. Electric revenue breakdown by customer class not available. Generating sources: nuclear, 47%; gas, 35%; coal, 5%; purchased, 13%. Fuel costs: 34% of revenues. '14 reported depreciation rate: 2.6%. Has about 1,000 employees. Chairman: Charles A. Yamarone. CEO: Thomas V. Shockley, III. President: Mary Kipp. Inc.: Texas. Address: Stanton Tower, 100 North Stanton, El Paso, Texas 79901. Tel.: 915-543-5711. Internet: www.epelectric.com.

El Paso Electric Company has filed a general rate case in New Mexico. The utility is seeking a rate increase of $8.6 million (7.1%), based on a return of 9.95% on a common-equity ratio of 49.29%. Since EPE's last rate case in the state, which took effect at the start of 2010, the company has added nearly $1.3 billion of rate base, including the first two units (88 megawatts each) of a four-unit gas-fired generating station. New tariffs are expected to take effect early in the second quarter of 2016.

As this report was going to press, the utility was planning to put forth a rate application in Texas shortly. The amount it will request was unknown. As in New Mexico, new rates are expected to go into effect by the early second period of 2016.

Regulatory lag will affect the company's earnings this year and next. EPE is incurring costs (such as depreciation) associated with the two new generating units mentioned above, but these facilities are not reflected in the utility's rates. Accordingly, profits will almost certainly decline materially this year. The company's share-earnings guidance for 2015 is $1.75-$2.15, which includes $0.31-$0.37 of regulatory lag. Assuming reasonable rate treatment and less regulatory lag in 2016, earnings will likely make a partial recovery.

The last two units of the aforementioned project are expected to begin operating in 2016. One should come on line in the first half of the year, the other in the second half. The total cost is estimated at $374 million. EPE will file rate cases in New Mexico and Texas to place these two units in the rate base.

As we had expected, the board of directors raised the dividend in the second quarter. The increase was $0.06 a share (5.4%) annually. EPE expects to hike the disbursement at a rate of 4%-6% annually over the next several years. The company's modest payout ratio gives the board plenty of room to boost the dividend.

The untimely stock's dividend yield is below average for a utility. Although we project solid dividend growth through 2018-2020, total return potential is just a bit above average for this industry.

Paul E. Debbas, CFA *July 31, 2015*

(A) Diluted earnings. Excl. nonrecurring gains (losses): '99, (38¢); '01, (4¢); '03, 81¢; '04, 4¢; '05, (2¢); '06, 13¢; '10, 24¢. '14 earnings don't add to full-year total due to rounding. Next earnings report due early Aug. (B) Initial dividend declared 4/11; payment dates in late March, June, Sept., and Dec. (C) Incl. deferred charges. In '14: $112.1 mill., $2.78/sh. (D) In millions. (E) Rate allowed on common equity in TX in '12: none specified; in NM in '10: none specified; earned on average common equity, '14: 9.5%. Regulatory Climate: Average.

Company's Financial Strength	B++
Stock's Price Stability	90
Price Growth Persistence	80
Earnings Predictability	85

EMPIRE DISTRICT NYSE-EDE

RECENT PRICE 21.13 | P/E RATIO 16.3 (Trailing: 16.3, Median: 16.0) | RELATIVE P/E RATIO 0.93 | DIV'D YLD 5.0% | VALUE LINE

TIMELINESS 4 Raised 8/28/15
SAFETY 2 Raised 3/23/12
TECHNICAL 3 Raised 9/11/15
BETA .70 (1.00 = Market)

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
High:	23.5	25.0	25.1	26.1	23.5	19.4	22.5	23.3	22.0	24.3	31.2	31.5
Low:	19.5	19.3	20.3	21.1	14.9	11.9	17.6	18.0	19.5	20.6	22.0	20.7

Target Price Range 2018 | 2019 | 2020

2018-20 PROJECTIONS

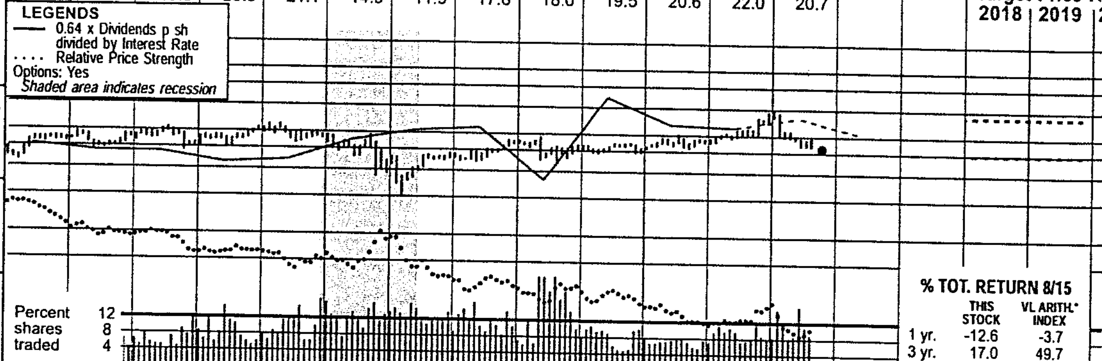
	Price	Gain	Ann'l Total Return
High	30	(+40%)	13%
Low	20	(-5%)	4%

Insider Decisions

	O	N	D	J	F	M	A	M	J
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	1	0	0	1	0	0	0	0

Institutional Decisions

	4Q2014	1Q2015	2Q2015
to Buy	63	70	65
to Sell	63	65	65
Hld's(000)	21381	20494	20421



% TOT. RETURN 8/15

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-12.6	-3.7
3 yr.	17.0	49.7
5 yr.	36.8	98.6

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	© VALUE LINE PUB. LLC	18-20
13.94	14.78	13.37	13.56	13.03	12.67	14.80	13.67	14.59	15.25	13.04	13.02	13.74	13.11	13.81	15.00	*13.65*	*14.00*	Revenues per sh	*16.00*
2.89	3.12	2.19	2.43	2.48	2.22	2.45	2.75	2.69	2.91	2.72	2.85	3.21	2.99	3.14	3.45	*3.45*	*3.55*	"Cash Flow" per sh	*4.25*
1.13	1.35	.59	1.19	1.29	.86	.92	1.41	1.09	1.17	1.18	1.17	1.31	1.32	1.48	1.55	*1.30*	*1.45*	Earnings per sh A	*1.75*
1.28	1.28	1.28	1.28	1.28	1.28	1.28	1.28	1.28	1.28	1.28	1.28	.64	1.00	1.01	1.03	*1.05*	*1.07*	Div'd Decl'd per sh B ▪ †	*1.20*
4.14	7.61	4.02	3.43	2.65	1.64	2.83	3.97	5.46	6.28	4.07	2.63	2.44	3.22	3.60	4.91	*4.20*	*2.55*	Cap'l Spending per sh	*3.50*
13.48	13.65	13.58	14.59	15.17	14.76	15.08	15.49	16.04	15.56	15.75	15.82	16.53	16.90	17.43	18.02	*18.20*	*18.70*	Book Value per sh C	*20.25*
17.37	17.60	19.76	22.57	24.98	25.70	26.08	30.25	33.61	33.98	38.11	41.58	41.98	42.48	43.04	43.48	*44.00*	*46.00*	Common Shs Outst'g D	*47.50*
21.7	17.7	33.9	16.2	15.8	24.8	24.5	15.9	21.7	17.3	14.3	16.8	15.8	15.8	15.0	16.2	*Bold figures are*		Avg Ann'l P/E Ratio	*13.5*
1.24	1.15	1.74	.88	.90	1.31	1.30	.86	1.15	1.04	.95	1.07	.99	1.01	.84	.85	*Value Line*		Relative P/E Ratio	*.85*
5.2%	5.4%	6.4%	6.6%	6.3%	6.0%	5.7%	5.7%	5.4%	6.3%	7.6%	6.5%	3.1%	4.8%	4.5%	4.1%	*estimates*		Avg Ann'l Div'd Yield	*5.0%*

CAPITAL STRUCTURE as of 6/30/15
Total Debt $900.4 mill. Due in 5 Yrs $213.6 mill.
LT Debt $803.1 mill. LT Interest $41.7 mill.
Incl. $3.7 mill. capitalized leases.
(LT interest earned: 3.0x)
Leases, Uncapitalized Annual rentals $.7 mill.
Pension Assets-12/14 $192.7 mill. Oblig. $251.9 mill.

Pfd Stock None

Common Stock 43,723,355 shs. as of 7/31/15

MARKET CAP: $925 million (Small Cap)

2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016		18-20
386.2	413.5	490.2	518.2	497.2	541.3	576.9	557.1	594.3	652.3	*600*	*645*	Revenues ($mill)	*765*
23.8	39.9	33.2	39.7	41.3	47.4	55.0	55.7	63.4	67.1	*55.0*	*65.0*	Net Profit ($mill)	*85.0*
33.4%	35.4%	30.3%	32.5%	32.5%	39.2%	38.4%	38.0%	37.1%	36.9%	*37.5%*	*38.0%*	Income Tax Rate	*37.5%*
2.4%	10.7%	23.1%	31.5%	34.2%	21.5%	.9%	3.5%	9.4%	14.8%	*10.0%*	*3.0%*	AFUDC % to Net Profit	*6.0%*
51.0%	49.7%	50.1%	53.6%	51.6%	51.3%	49.9%	49.1%	49.8%	50.6%	*51.0%*	*52.0%*	Long-Term Debt Ratio	*50.0%*
49.0%	50.3%	49.9%	46.4%	48.4%	48.7%	50.1%	50.9%	50.2%	49.4%	*49.0%*	*48.0%*	Common Equity Ratio	*50.0%*
803.3	931.0	1081.1	1140.4	1240.3	1350.7	1386.2	1409.4	1493.6	1586.5	*1640*	*1800*	Total Capital ($mill)	*1925*
896.0	1031.0	1178.9	1342.8	1459.0	1519.1	1563.7	1657.6	1751.9	1910.3	*2000*	*2020*	Net Plant ($mill)	*2125*
4.7%	5.9%	4.7%	5.2%	5.2%	5.1%	5.5%	5.4%	5.6%	5.5%	*5.0%*	*5.0%*	Return on Total Cap'l	*5.5%*
6.0%	8.5%	6.2%	7.5%	6.9%	7.2%	7.9%	7.8%	8.5%	8.6%	*7.0%*	*7.5%*	Return on Shr. Equity	*9.0%*
6.0%	8.5%	6.2%	7.5%	6.9%	7.2%	7.9%	7.8%	8.5%	8.6%	*7.0%*	*7.5%*	Return on Com Equity E	*9.0%*
NMF	.8%	NMF	NMF	NMF	NMF	4.1%	1.9%	2.7%	2.9%	*1.5%*	*2.0%*	Retained to Com Eq	*3.0%*
NMF	90%	117%	109%	109%	110%	49%	76%	68%	66%	*80%*	*74%*	All Div'ds to Net Prof	*67%*

ELECTRIC OPERATING STATISTICS

	2012	2013	2014
% Change Retail Sales (KWH)	-3.2	+1.3	+1.3
Avg. Industrial Use (MWH)	2913	2943	2981
Avg. Industrial Rev/KWH (¢)	7.66	7.93	8.21
Capacity at Peak (Mw)	1391	1377	1326
Peak Load, Summer (Mw)	1142	1080	1162
Annual Load Factor (%)	52.2	56.2	52.8
% Change Customers (avg.)	+.6	+.5	+.3
Fixed Charge Cov. (%)	314	331	334

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '12-'14 to '18-'20
Revenues	.5%	-.5%	*2.5%*
"Cash Flow"	3.0%	3.0%	*5.0%*
Earnings	2.5%	5.0%	*3.0%*
Dividends	-2.5%	-4.5%	*3.0%*
Book Value	1.5%	2.0%	*2.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	137.2	131.6	159.2	129.1	557.1
2013	151.1	136.6	157.5	149.1	594.3
2014	179.7	149.8	171.5	151.3	652.3
2015	164.5	134.5	*160*	*141*	*600*
2016	*180*	*145*	*170*	*150*	*645*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.23	.25	.60	.23	1.32
2013	.30	.27	.56	.35	1.48
2014	.48	.26	.55	.26	1.55
2015	.34	.15	*.56*	*.25*	*1.30*
2016	*.34*	*.25*	*.59*	*.27*	*1.45*

Cal-endar	QUARTERLY DIVIDENDS PAID B ▪ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.32	.32	--	--	.64
2012	.25	.25	.25	.25	1.00
2013	.25	.25	.25	.255	1.01
2014	.255	.255	.255	.26	1.03
2015	.26	.26	.26		

BUSINESS: The Empire District Electric Company supplies electricity to 169,000 customers in a 10,000 sq. mi. area in southwestern Missouri (90% of retail elec. revs.), Kansas (5%), Oklahoma (3%), & Arkansas (2%). Acquired Missouri Gas (44,000 customers) 6/06. Supplies water service (4,000 customers) and has a small fiber-optics operation. Elec. rev. breakdown: residential, 45%; commercial, 32%; industrial, 16%; other, 7%. Generating sources: coal, 47%; gas, 27%; hydro, 1%; purch., 25%. Fuel costs: 37% of revenues. '14 reported depr. rate: 3.0%. Has about 750 employees. Chairman: D. Randy Laney. President & CEO: Bradley P. Beecher. Inc.: KS. Address: 602 S. Joplin Ave., P.O. Box 127, Joplin, MO 64802-0127. Tel.: 417-625-5100. Internet: www.empiredistrict.com.

Empire District Electric received an electric rate increase in Missouri. The state regulators approved a settlement calling for a $17.1 million (3.9%) rate hike. This was a "black box" agreement in which an allowed return on equity was not specified. The increase enabled Empire District Electric to place an environmental upgrade to a coal-fired plant in the rate base. Additionally, the utility will now be able to recover a portion of any changes in transmission costs through its fuel adjustment clause. New tariffs took effect on July 26th.

The utility plans to file another electric rate case in Missouri in the fourth quarter of 2015. Empire District Electric will need to place a 100-megawatt plant expansion in the rate base. This project is expected to be completed in the first half of 2016 at a cost of $165 million-$175 million. New tariffs will take effect in late 2016.

Regulatory lag will continue to affect Empire District Electric's earnings through 2016. Because the aforementioned environmental upgrade was completed in late 2014, but wasn't recovered in rates until July of this year, earnings declined in the first half of 2015. The lag in recovering the plant expansion will also hold back earnings next year. We have cut our 2015 profit estimate by $0.10 a share because June-quarter results fell short of our estimate. Our revised estimate is at the low end of the company's targeted range of $1.30-$1.45 a share. We are sticking with our 2016 forecast of $1.45 a share.

We look for a dividend increase in the fourth quarter. We think the board of directors will boost the annual disbursement by two cents a share (1.9%), the same increase as in each of the past two years.

This untimely stock has been one of the poorest performers among electric utilities so far in 2015. Year to date, the price is down about 30%, but is still within our 2018-2020 Target Price Range. We think this underperformance is mainly due to a lessening of takeover speculation. The dividend yield and 3- to 5-year total return potential are above average, by utility standards.

Paul E. Debbas, CFA *September 18, 2015*

(A) Diluted earnings. Excl. loss from discontinued operations: '06, 2¢. '12 EPS don't add due to rounding. Next earnings report due late Oct. (B) Div'ds historically paid in mid-Mar., June, Sept. and Dec. Div'ds suspended 3Q '11, reinstated 1Q '12. ▪ Div'd reinvestment plan avail. (3% discount). † Shareholder investment plan avail. (C) Incl. intangibles. In '14: $5.93/sh. (D) In mill. (E) Rate base: Deprec. orig. cost. Rate allowed on com. eq. in MO in '15: none specified; earned on avg. com. eq., '14: 8.7%. Regulatory Climate: Average.

Company's Financial Strength	B++
Stock's Price Stability	90
Price Growth Persistence	30
Earnings Predictability	85

EVERSOURCE ENERGY NYSE-ES

RECENT PRICE 50.41 | P/E RATIO 17.1 (Trailing: 17.5; Median: 17.0) | RELATIVE P/E RATIO 0.94 | DIV'D YLD 3.5% | VALUE LINE

TIMELINESS 3 Lowered 8/14/15

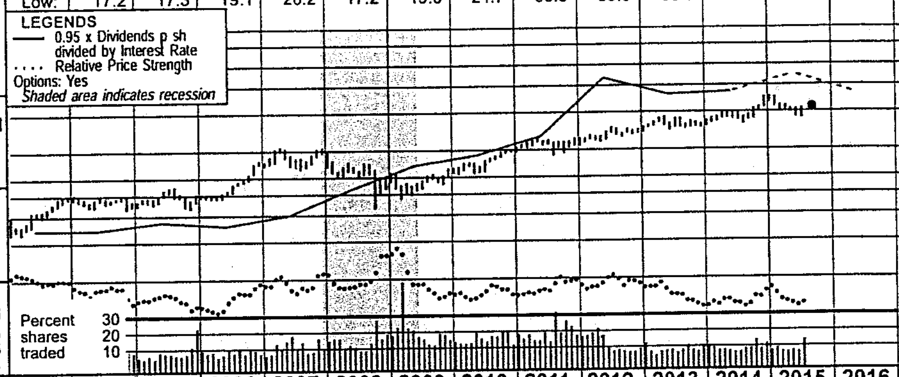
SAFETY 1 Raised 5/22/15

TECHNICAL 4 Lowered 8/7/15

BETA .75 (1.00 = Market)

High:	20.3	22.0	28.9	33.6	31.6	26.5	32.2	36.5	40.9	45.7	56.7	56.8
Low:	17.2	17.3	19.1	26.2	17.2	19.0	24.7	30.0	33.5	38.6	41.3	44.6

LEGENDS
— 0.95 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



Target Price Range 2018 | 2019 | 2020

120, 100, 80, 64, 48, 32, 24, 20, 16, 12, 8

2018-20 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	60	(+20%)	8%
Low	45	(-10%)	2%

Insider Decisions

	S	O	N	D	J	F	M	A	M
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	1	0	0	0	0	0	2	0	1

Institutional Decisions

	3Q2014	4Q2014	1Q2015
to Buy	200	233	203
to Sell	213	211	255
Hld's(000)	215261	223425	223824

Percent shares traded 30, 20, 10

% TOT. RETURN 7/15

	THIS STOCK	VL ARITH.* INDEX
1 yr.	17.0	5.9
3 yr.	38.3	63.0
5 yr.	111.8	95.5

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	© VALUE LINE PUB. LLC	18-20
33.91	40.86	52.82	40.89	47.53	51.82	41.85	44.64	37.27	37.22	30.97	27.76	25.21	19.98	23.16	24.42	*25.95*	*26.20*	Revenues per sh	*28.00*
5.68	3.39	10.48	6.32	5.80	5.00	5.46	3.69	4.82	6.16	4.96	5.68	4.88	4.03	5.22	4.56	*5.30*	*5.60*	"Cash Flow" per sh	*7.00*
d1.14	d.20	1.37	1.08	1.24	.91	.98	.82	1.59	1.86	1.91	2.10	2.22	1.89	2.49	2.58	*2.90*	*3.05*	Earnings per sh A	*3.75*
.10	.40	.45	.53	.58	.63	.68	.73	.78	.83	.95	1.03	1.10	1.32	1.47	1.57	*1.67*	*1.78*	Div'd Decl'd per sh B ■	*2.10*
2.50	2.88	3.40	3.86	4.31	4.85	5.89	5.49	7.14	8.06	5.17	5.41	6.08	4.69	4.62	5.06	*5.80*	*6.65*	Cap'l Spending per sh	*6.25*
15.80	15.43	16.27	17.33	17.73	17.80	18.46	18.14	18.65	19.38	20.37	21.60	22.65	29.41	30.49	31.47	*32.65*	*33.90*	Book Value per sh C	*38.25*
131.87	143.82	130.13	127.56	127.70	129.03	131.59	154.23	156.22	155.83	175.62	176.45	177.16	314.05	315.27	316.98	*318.00*	*319.00*	Common Shs Outst'g D	*322.00*
--	--	14.1	16.1	13.4	20.8	19.8	27.1	18.7	13.7	12.0	13.4	15.4	19.9	16.9	17.9	*Bold figures are*		Avg Ann'l P/E Ratio	*14.0*
--	--	.72	.88	.76	1.10	1.05	1.46	.99	.82	.80	.85	.97	1.27	.95	.95	*Value Line*		Relative P/E Ratio	*.90*
.6%	1.9%	2.3%	3.0%	3.5%	3.3%	3.5%	3.3%	2.6%	3.2%	4.2%	3.6%	3.2%	3.5%	3.5%	3.4%	*estimates*		Avg Ann'l Div'd Yield	*4.0%*

CAPITAL STRUCTURE as of 3/31/15
Total Debt $9851.2 mill. **Due in 5 Yrs** $3813.7 mill.
LT Debt $8602.1 mill. **LT Interest** $372.5 mill.
(LT interest earned: 4.7x)

Leases, Uncapitalized Annual rentals $20.1 mill.
Pension Assets-12/14 $4126.5 mill.
Oblig. $5486.2 mill.
Pfd Stock $155.6 mill. **Pfd Div'd** $7.6 mill.
Incl. 2,324,000 shs $1.90-$3.28 rates ($50 par) not subject to mandatory redemption.
Common Stock 317,647,540 shs.
as of 4/30/15
MARKET CAP: $16 billion (Large Cap)

2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016		18-20
5507.3	6884.4	5822.2	5800.1	5439.4	4898.2	4465.7	6273.8	7301.2	7741.9	*8250*	*8350*	Revenues ($mill)	*9050*
128.5	126.2	251.5	296.2	335.6	377.8	400.3	533.0	793.7	827.1	*935*	*990*	Net Profit ($mill)	*1220*
30.8%	--	30.3%	29.7%	34.9%	36.6%	29.9%	34.0%	35.0%	36.2%	*36.0%*	*36.0%*	Income Tax Rate	*36.0%*
17.4%	21.5%	13.9%	15.8%	4.6%	7.1%	8.6%	2.3%	1.4%	2.4%	*4.0%*	*4.0%*	AFUDC % to Net Profit	*3.0%*
63.2%	58.7%	59.2%	60.4%	57.2%	55.1%	53.4%	43.7%	44.3%	45.9%	*46.0%*	*46.5%*	Long-Term Debt Ratio	*46.5%*
35.1%	39.7%	39.2%	38.1%	41.5%	43.6%	45.3%	55.4%	54.8%	53.2%	*53.0%*	*53.0%*	Common Equity Ratio	*53.0%*
6923.2	7052.0	7431.1	7926.2	8629.5	8741.8	8856.0	16675	17544	18738	*19600*	*20400*	Total Capital ($mill)	*23200*
6417.2	6242.2	7229.9	8207.9	8840.0	9567.7	10403	16605	17576	18647	*19900*	*21350*	Net Plant ($mill)	*25500*
3.5%	2.9%	5.0%	5.4%	5.4%	5.8%	5.9%	4.2%	5.5%	5.3%	*5.5%*	*6.0%*	Return on Total Cap'l	*6.5%*
5.0%	4.3%	8.3%	9.4%	9.1%	9.6%	9.7%	5.7%	8.1%	8.2%	*9.0%*	*9.0%*	Return on Shr. Equity	*10.0%*
5.1%	4.3%	8.4%	9.6%	9.2%	9.8%	9.8%	5.7%	8.2%	8.2%	*9.0%*	*9.0%*	Return on Com Equity E	*10.0%*
1.5%	.3%	4.3%	5.3%	4.7%	5.0%	5.0%	1.6%	3.4%	3.5%	*4.0%*	*4.0%*	Retained to Com Eq	*4.5%*
72%	94%	50%	45%	50%	49%	50%	72%	59%	58%	*57%*	*58%*	All Div'ds to Net Prof	*56%*

ELECTRIC OPERATING STATISTICS

	2012	2013	2014
% Change Retail Sales (KWH)	+47.0	+1.0	-1.6
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Winter (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+59.8	NA	NA
Fixed Charge Cov. (%)	320	427	426

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '12-'14 to '18-'20
Revenues	-7.0%	-8.5%	*3.5%*
"Cash Flow"	-2.0%	-3.0%	*7.0%*
Earnings	8.0%	5.5%	*8.5%*
Dividends	9.5%	11.5%	*6.5%*
Book Value	5.5%	9.5%	*4.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	1099	1628	1861	1684	6273.8
2013	1995	1635	1892	1777	7301.2
2014	2290	1677	1892	1881	7741.9
2015	2513	1817	*2000*	*1920*	*8250*
2016	*2500*	*1850*	*2050*	*1950*	*8350*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.56	.15	.66	.55	1.89
2013	.72	.54	.66	.56	2.49
2014	.74	.40	.74	.69	2.58
2015	.80	.65	*.80*	*.65*	*2.90*
2016	*.85*	*.65*	*.85*	*.70*	*3.05*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.275	.275	.275	.275	1.10
2012	.294	.343	.343	.343	1.32
2013	.3675	.3675	.3675	.3675	1.47
2014	.3925	.3925	.3925	.3925	1.57
2015	.4175	.4175			

BUSINESS: Eversource Energy (formerly Northeast Utilities) is the parent of utilities that have 3.1 million electric, 504,000 gas customers. Supplies power to most of Connecticut and gas to part of Connecticut; supplies power to three fourths of New Hampshire's population; supplies power to western Massachusetts and parts of eastern Massachusetts & gas to central & eastern Massachusetts. Acquired NSTAR 4/12. Electric revenue breakdown: residential, 49%; commercial, 38%; industrial, 5%; other, 8%. Fuel costs: 39% of revenues. '14 reported deprec. rates: 2.7%-3.3%. Has 8,200 employees. Chairman, President & CEO: Thomas J. May. Inc.: MA. Address: 300 Cadwell Drive, Springfield, MA 01104. Tel.: 413-785-5871. Internet: www.eversource.com.

Eversource Energy should post solid earnings increases this year and next. The company is reducing operating and maintenance expenses as it attains further benefits from the merger with NSTAR in 2012. Rate relief is another factor. Electric rates in Connecticut were raised in late 2014, and a gas rate case is pending in Massachusetts (see below). Eversource's gas utilities are benefiting from customer conversions from oil heat to gas heat. And, despite a reduction in the allowed return on equity for transmission, the company's investment in this area is another source of growth. Our 2015 earnings estimate, which we raised by $0.05 a share after Eversource reported June-period results, is at the upper end of the company's guidance of $2.75-$2.90. The same factors that are lifting earnings this year should remain in place in 2016. Our profit forecast of $3.05 a share would produce a 5% increase over the estimated 2015 figure.

A gas rate case is pending in Massachusetts. Eversource is seeking a $23 million (5.5%) increase, based on a 10.25% return on a 52.94% common-equity ratio. A ruling from the state commission is expected in the fourth quarter, with new tariffs taking effect at the start of 2016.

Eversource is awaiting a commission ruling on a settlement in New Hampshire. If approved, the utility would sell its generating assets in the state. These have a book value of $650 million and are contributing $0.09-$0.10 to annual share net. It would recover its stranded costs through the issuance of securitized bonds. A decision is expected by yearend.

Two major projects would enhance the company's long-term growth. Eversource wants to build a $1.4 billion transmission line that would be connected to Québec. It hopes to begin construction in late 2016, with an in-service date in the first half of 2019. The company also has a 40% stake in a proposed $3 billion pipeline to increase the supply of gas to New England. The partners hope to have it in service in time for the winter of 2018-2019.

This stock has a dividend yield that is somewhat below the utility mean. Total return potential to 2018-2020 is unspectacular, despite good dividend growth prospects.

Paul E. Debbas, CFA *August 21, 2015*

(A) Diluted EPS. Excl. nonrec. gains (losses): '02, 10¢; '03, (32¢); '04, (7¢); '05, ($1.36); '08, (19¢); '10, 9¢. '12 EPS don't add due to chng. in shs., '13 & '14 due to rounding. Next earnings report due early Nov. (B) Div'ds historically paid late Mar., June, Sept., & Dec. ■ Div'd reinvestment plan avail. (C) Incl. def'd chgs. In '14: $23.89/sh. (D) In mill. (E) Rate allowed on com. eq. in MA: '11, 9.6%; in CT: (elec.) '15, 9.02%; (gas) '15, 9.5%; in NH: '10, 9.67%; earn. on avg. com. eq., '14: 8.4%. Regul. Clim.: CT, Below Avg.; NH, Avg.; MA, Above Avg.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	80
Earnings Predictability	85

GREAT PLAINS EN'GY NYSE-GXP

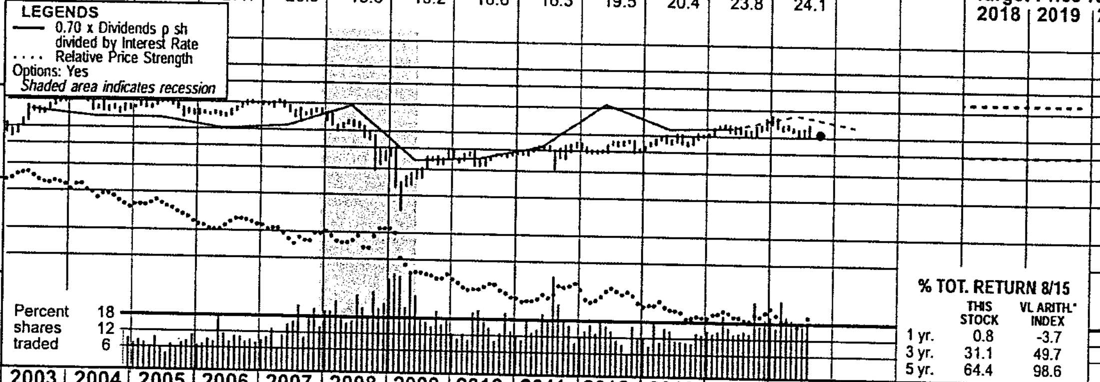
RECENT PRICE 24.77 | P/E RATIO 16.7 (Trailing: 16.9; Median: 16.0) | RELATIVE P/E RATIO 0.95 | DIV'D YLD 4.2% | VALUE LINE

TIMELINESS 5 Lowered 6/19/15
SAFETY 3 Lowered 12/26/08
TECHNICAL 3 Raised 9/11/15
BETA .85 (1.00 = Market)

High:	35.7	32.8	32.8	33.4	29.3	20.5	19.9	22.1	22.8	24.9	29.5	30.3			
Low:	27.9	27.1	27.1	26.9	15.6	10.2	16.6	16.3	19.5	20.4	23.8	24.1			

Target Price Range 2018 | 2019 | 2020

LEGENDS
— 0.70 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



2018-20 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	35	(+40%)	12%
Low	20	(-20%)	Nil

Insider Decisions

	O	N	D	J	F	M	A	M	J
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	0	0	0	9	0	0	0

Institutional Decisions

	4Q2014	1Q2015	2Q2015
to Buy	132	125	122
to Sell	125	148	125
Hld's(000)	119797	121848	130044

Percent shares traded 18 / 12 / 6

% TOT. RETURN 8/15

	THIS STOCK	VL ARITH.* INDEX
1 yr.	0.8	-3.7
3 yr.	31.1	49.7
5 yr.	64.4	98.6

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	© VALUE LINE PUB. LLC	18-20
14.50	18.02	23.61	26.91	31.04	33.13	34.85	33.30	37.89	14.00	14.51	16.62	17.03	15.05	15.90	16.66	*16.20*	*17.45*	Revenues per sh	*19.50*
3.63	4.63	4.70	4.40	4.69	4.75	4.54	3.86	4.24	3.09	3.27	4.12	3.51	3.45	4.01	4.01	*4.00*	*4.65*	"Cash Flow" per sh	*6.00*
1.26	2.05	1.59	2.04	2.27	2.46	2.18	1.62	1.86	1.16	1.03	1.53	1.25	1.35	1.62	1.57	*1.40*	*1.75*	Earnings per sh A	*2.00*
1.66	1.66	1.66	1.66	1.66	1.66	1.66	1.66	1.66	1.66	.83	.83	.84	.86	.88	.94	*1.00*	*1.06*	Div'd Decl'd per sh B ■	*1.20*
2.97	6.67	4.38	1.91	2.19	2.66	4.49	6.05	6.15	8.86	6.49	4.76	3.40	4.01	4.42	5.10	*5.25*	*3.90*	Cap'l Spending per sh	*3.75*
13.97	14.88	12.59	13.58	13.82	15.35	16.37	16.70	18.18	21.39	20.62	21.26	21.74	21.75	22.58	23.26	*23.65*	*24.35*	Book Value per sh C	*26.75*
61.91	61.91	61.91	69.20	69.26	74.37	74.74	80.35	86.23	119.26	135.42	135.71	136.14	153.53	153.87	154.16	*154.50*	*154.75*	Common Shs Outst'g D	*155.50*
20.0	12.4	15.9	11.1	12.2	12.6	14.0	18.3	16.3	20.5	16.0	12.1	16.1	15.5	14.2	16.5	*Bold figures are*		Avg Ann'l P/E Ratio	*13.5*
1.14	.81	.81	.61	.70	.67	.75	.99	.87	1.23	1.07	.77	1.01	.99	.80	.87	*Value Line*		Relative P/E Ratio	*.85*
6.6%	6.5%	6.6%	7.3%	6.0%	5.4%	5.5%	5.6%	5.5%	7.0%	5.0%	4.5%	4.1%	4.1%	3.8%	3.6%	*estimates*		Avg Ann'l Div'd Yield	*4.6%*
						2604.9	2675.3	3267.1	1670.1	1965.0	2255.5	2318.0	2309.9	2446.3	2568.2	*2500*	*2700*	Revenues ($mill)	*3050*
						164.2	127.6	159.2	119.5	135.6	211.7	174.4	199.9	250.2	242.8	*220*	*270*	Net Profit ($mill)	*320*
						18.7%	27.0%	30.7%	34.5%	25.0%	31.7%	32.7%	34.3%	34.0%	32.3%	*33.0%*	*35.0%*	Income Tax Rate	*35.0%*
						2.1%	8.4%	10.6%	46.8%	57.0%	25.7%	3.9%	3.3%	10.4%	12.8%	*9.0%*	*2.0%*	AFUDC % to Net Profit	*2.0%*
						47.5%	30.6%	40.7%	49.7%	53.2%	50.2%	47.8%	44.9%	50.0%	49.0%	*51.0%*	*47.5%*	Long-Term Debt Ratio	*48.0%*
						50.9%	67.5%	57.9%	49.6%	46.2%	49.2%	51.6%	54.4%	49.4%	50.4%	*48.5%*	*52.0%*	Common Equity Ratio	*51.5%*
						2403.3	1988.4	2709.8	5146.2	6044.5	5867.6	5741.2	6135.8	7029.1	7113.1	*7530*	*7260*	Total Capital ($mill)	*8075*
						2765.6	3066.2	3444.5	6081.3	6651.1	6892.3	7053.5	7402.1	7746.4	8279.6	*8695*	*8850*	Net Plant ($mill)	*9025*
						8.2%	7.9%	7.5%	3.5%	3.9%	5.3%	5.0%	5.0%	5.0%	4.7%	*4.0%*	*5.0%*	Return on Total Cap'l	*5.0%*
						13.0%	9.2%	9.9%	4.6%	4.8%	7.2%	5.8%	5.9%	7.1%	6.7%	*6.0%*	*7.0%*	Return on Shr. Equity	*7.5%*
						13.3%	9.4%	10.1%	4.6%	4.8%	7.3%	5.8%	5.9%	7.2%	6.7%	*6.0%*	*7.0%*	Return on Com Equity E	*7.5%*
						3.2%	NMF	.9%	NMF	.9%	3.4%	2.0%	2.2%	3.2%	2.7%	*2.0%*	*3.0%*	Retained to Com Eq	*3.0%*
						76%	104%	91%	NMF	81%	54%	66%	63%	55%	60%	*70%*	*61%*	All Div'ds to Net Prof	*61%*

CAPITAL STRUCTURE as of 6/30/15
Total Debt $4291.1 mill. Due in 5 Yrs $1961.8 mill.
LT Debt $3486.7 mill. LT Interest $180.2 mill.
(LT interest earned: 2.7x)

Leases, Uncapitalized Annual rentals $14.2 mill.
Pension Assets-12/14 $730.0 mill.
Oblig. $1186.8 mill.
Pfd Stock $39.0 mill. Pfd Div'd $1.6 mill.
390,000 shs. 3.80% to 4.50% (all $100 par & cum.), callable from $101 to $103.70.
Common Stock 154,333,594 shs.
as of 8/3/15
MARKET CAP: $3.8 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2012	2013	2014
% Change Retail Sales (KWH)	-1.8	+.2	+.4
Avg. Indust. Use (MWH)	1443	1424	1455
Avg. Indust. Revs. per KWH (¢)	6.23	6.80	6.79
Capacity at Peak (Mw)	6719	NA	NA
Peak Load, Summer (Mw)	5653	NA	NA
Annual Load Factor (%)	49.6	NA	NA
% Change Customers (avg.)	+.2	+.7	+.9
Fixed Charge Cov. (%)	235	267	261

ANNUAL RATES

of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '12-'14 to '18-'20
Revenues	-6.5%	-6.5%	3.5%
"Cash Flow"	-2.0%	1.5%	8.0%
Earnings	-4.0%	2.5%	5.0%
Dividends	-6.0%	-8.5%	6.0%
Book Value	4.5%	2.5%	3.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	479.7	603.6	746.2	480.4	2309.9
2013	542.2	600.3	765.0	538.8	2446.3
2014	585.1	648.4	782.5	552.2	2568.2
2015	549.1	609.0	*800*	*541.9*	*2500*
2016	*600*	*650*	*850*	*600*	*2700*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	d.07	.41	.95	.03	1.35
2013	.17	.41	.93	.11	1.62
2014	.15	.34	.95	.12	1.57
2015	.12	.28	*.90*	*.10*	*1.40*
2016	*.20*	*.40*	*1.00*	*.15*	*1.75*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.2075	.2075	.2075	.2125	.84
2012	.2125	.2125	.2125	.2175	.86
2013	.2175	.2175	.2175	.23	.88
2014	.23	.23	.23	.245	.94
2015	.245	.245	.245		

BUSINESS: Great Plains Energy Incorporated is a holding company for Kansas City Power & Light and two other subsidiaries, which supply electricity to 838,000 customers in western Missouri (71% of revenues) and eastern Kansas (29%). Acq'd Aquila 7/08. Sold Strategic Energy (energy-marketing subsidiary) in '08. Electric revenue breakdown: residential, 40%; commercial, 39%; industrial, 9%; other, 12%. Generating sources: coal, 64%; nuclear, 13%; wind, 1%; gas & oil, 1%; purchased, 21%. Fuel costs: 29% of revs. '14 reported deprec. rate (utility): 3.0%. Has 2,900 employees. Chairman: Michael J. Chesser. President & CEO: Terry Bassham. Inc.: Missouri. Address: 1200 Main St., Kansas City, Missouri 64105. Tel.: 816-556-2200. Internet: www.greatplainsenergy.com.

Great Plains Energy's largest utility subsidiary has received a rate order in Missouri. Kansas City Power & Light had asked the Missouri commission for a rate increase of $112.7 million (14.9%), based on a return of 10.3% on a 50.09% common-equity ratio. The regulators granted the utility a hike of $89.7 million (11.7%), based on a 9.5% return on a 50.09% common-equity ratio. They instituted a fuel adjustment clause, but did not grant other mechanisms KCP&L sought. New tariffs took effect in mid-September.

KCP&L was expecting a decision on its rate case in Kansas as this report was going to press. The utility was requesting a raise of $67.3 million (12.5%), based on a 10.3% return on a 50.48% common-equity ratio. New tariffs would take effect at the start of October.

A major construction project is going well. KCP&L has a 50% stake in a coal-fired facility that is undergoing an environmental upgrade. This investment is a key reason why the utility filed the aforementioned rate cases. The latest expectation is that it will come in 6% below the budget of $615 million for KCP&L's share of the project.

Earnings are likely to decline this year. Regulatory lag for costs such as property taxes and transmission expense has been a problem for the company for several years, which explains why earned returns on equity have been mediocre. Our earnings estimate of $1.40 a share is near the low end of Great Plains Energy's targeted range of $1.35-$1.60 a share.

Rate relief should produce higher profits in 2016. Another positive factor is the economic improvement that the company's utilities are seeing in their service area. We forecast that Great Plains Energy will achieve its highest share net since 2007.

We think the board of directors will raise the dividend in the fourth quarter. We look for a raise of $0.015 a share (6.1%) in the quarterly disbursement, the same as a year ago.

The dividend yield and 3- to 5-year total return potential of untimely Great Plains Energy stock are about average, for a utility. The recent price is within our 2018-2020 Target Price Range.

Paul E. Debbas, CFA *September 18, 2015*

(A) Dil. EPS. Excl. nonrec. gains (losses): '00, 49¢; '01, ($2.01); '02, (5¢); '03, 29¢; '04, (7¢); '09, 12¢; gain (losses) on disc. ops.: '03, (13¢); '04, 10¢; '05, (3¢); '08, 35¢. '12 EPS don't add due to change in shs., '14 due to rounding. Next earnings report due early Nov. (B) Div'ds historically paid in mid-Mar., June, Sept. & Dec. ■ Div'd reinvest. plan avail. (C) Incl. intang. In '14: $7.81/sh. (D) In mill. (E) Rate base: Fair value. Rate all'd on com. eq. in MO in '15: 9.5%; in KS in '13: 9.5%; earned on avg. com. eq., '14: 6.8%. Regulatory Climate: Average.

Company's Financial Strength	B+
Stock's Price Stability	95
Price Growth Persistence	5
Earnings Predictability	70

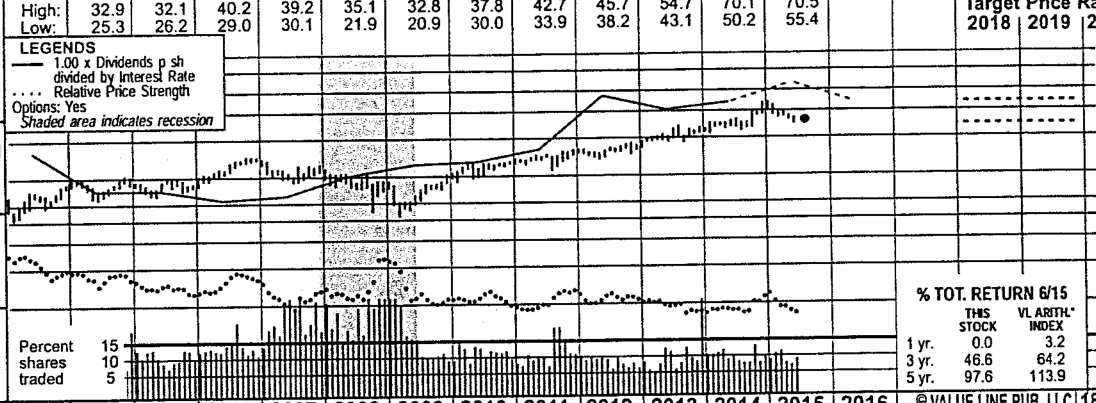
IDACORP, INC. NYSE-IDA

RECENT PRICE	57.88	P/E RATIO	15.9 (Trailing: 15.3 / Median: 14.0)	RELATIVE P/E RATIO	0.85	DIV'D YLD	3.4%	VALUE LINE

TIMELINESS **3** Lowered 5/15/15
SAFETY **2** Raised 8/2/13
TECHNICAL **3** Lowered 7/24/15
BETA .80 (1.00 = Market)

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
High:	32.9	32.1	40.2	39.2	35.1	32.8	37.8	42.7	45.7	54.7	70.1	70.5
Low:	25.3	26.2	29.0	30.1	21.9	20.9	30.0	33.9	38.2	43.1	50.2	55.4

Target Price Range
2018 | 2019 | 2020



2018-20 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	70	(+20%)	8%
Low	55	(-5%)	2%

Insider Decisions

	S	O	N	D	J	F	M	A	M
to Buy	0	0	0	0	0	1	2	0	0
Options	0	0	1	0	0	0	0	0	0
to Sell	1	1	3	3	1	2	2	1	1

Institutional Decisions

	3Q2014	4Q2014	1Q2015
to Buy	70	93	106
to Sell	106	97	92
Hld's(000)	36655	38077	37715

% TOT. RETURN 6/15

	THIS STOCK	VL ARITH.* INDEX
1 yr.	0.0	3.2
3 yr.	46.6	64.2
5 yr.	97.6	113.9

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	© VALUE LINE PUB. LLC	18-20
17.50	27.10	150.10	24.43	20.41	20.00	20.15	21.23	19.51	20.47	21.92	20.97	20.55	21.55	24.81	25.51	*25.45*	*26.05*	Revenues per sh	*27.95*
4.50	5.63	5.63	4.08	3.50	4.12	3.87	4.58	4.11	4.27	5.07	5.23	5.74	5.84	6.21	6.49	*6.45*	*6.70*	"Cash Flow" per sh	*7.15*
2.43	3.50	3.35	1.63	.96	1.90	1.75	2.35	1.86	2.18	2.64	2.95	3.36	3.37	3.64	3.85	*3.65*	*3.80*	Earnings per sh A	*3.90*
1.86	1.86	1.86	1.86	1.70	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.37	1.57	1.76	*1.91*	*2.03*	Div'd Decl'd per sh B† ■	*2.25*
2.95	3.73	4.78	3.53	3.89	4.73	4.53	5.16	6.39	5.19	5.26	6.85	6.76	4.78	4.68	5.45	*6.05*	*6.05*	Cap'l Spending per sh	*6.00*
20.02	21.82	23.15	23.01	22.54	23.88	24.04	25.77	26.79	27.76	29.17	31.01	33.19	35.07	36.84	38.85	*40.70*	*42.60*	Book Value per sh C	*47.05*
37.61	37.61	37.63	38.02	38.34	42.22	42.66	43.63	45.06	46.92	47.90	49.41	49.95	50.16	50.23	50.27	*50.30*	*50.30*	Common Shs Outst'g D	*50.30*
12.7	10.9	11.4	18.9	26.5	15.5	16.7	15.1	18.2	13.9	10.2	11.8	11.5	12.4	13.4	14.7	*Bold figures are*	*Value Line*	Avg Ann'l P/E Ratio	*16.0*
.72	.71	.58	1.03	1.51	.82	.89	.82	.97	.84	.68	.75	.72	.79	.75	.78	*estimates*		Relative P/E Ratio	*1.00*
6.0%	4.9%	4.9%	6.0%	6.7%	4.1%	4.1%	3.4%	3.5%	4.0%	4.5%	3.4%	3.1%	3.3%	3.2%	3.1%			Avg Ann'l Div'd Yield	*3.6%*

CAPITAL STRUCTURE as of 3/31/15
Total Debt $1906.2 mill. Due in 5 Yrs $264.5 mill.
LT Debt $1741.7 mill. LT Interest $81.0 mill.
(LT interest earned: 3.4x)

Pension Assets-12/14 $559.7 mill.
Oblig. $844.8 mill.

Pfd Stock None

Common Stock 50,347,339 shs.
as of 4/24/15

MARKET CAP: $2.9 billion (Mid Cap)

2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016		18-20
859.5	926.3	879.4	960.4	1049.8	1036.0	1026.8	1080.7	1246.2	1282.5	*1280*	*1310*	Revenues ($mill)	*1405*
63.7	100.1	82.3	98.4	124.4	142.5	166.9	168.9	182.4	193.5	*185*	*190*	Net Profit ($mill)	*195*
16.9%	13.3%	14.3%	16.3%	15.2%	NMF	NMF	13.4%	28.3%	8.1%	*23.0%*	*23.0%*	Income Tax Rate	*30.0%*
4.7%	4.0%	9.7%	10.2%	10.5%	19.7%	22.8%	7.1%	4.2%	4.4%	*7.5%*	*8.0%*	AFUDC % to Net Profit	*9.5%*
50.0%	45.2%	48.9%	47.6%	50.2%	49.3%	45.6%	45.5%	46.6%	45.3%	*45.0%*	*45.0%*	Long-Term Debt Ratio	*45.0%*
50.0%	54.8%	51.1%	52.4%	49.8%	50.7%	54.4%	54.5%	53.4%	54.7%	*55.0%*	*55.0%*	Common Equity Ratio	*55.0%*
2048.8	2052.8	2364.2	2485.9	2807.1	3020.4	3045.2	3225.4	3465.9	3567.6	*3660*	*3840*	Total Capital ($mill)	*4330*
2314.3	2419.1	2616.6	2758.2	2917.0	3161.4	3406.6	3536.0	3665.0	3833.5	*4095*	*4300*	Net Plant ($mill)	*4975*
4.5%	6.2%	4.7%	5.3%	5.7%	6.0%	6.7%	6.5%	6.4%	6.6%	*6.5%*	*6.0%*	Return on Total Cap'l	*5.5%*
6.2%	8.9%	6.8%	7.6%	8.9%	9.3%	10.1%	9.6%	9.9%	9.9%	*9.0%*	*9.0%*	Return on Shr. Equity	*8.5%*
6.2%	8.9%	6.8%	7.6%	8.9%	9.3%	10.1%	9.6%	9.9%	9.9%	*9.0%*	*9.0%*	Return on Com Equity E	*8.5%*
1.3%	4.3%	2.4%	3.4%	4.8%	5.5%	6.5%	5.7%	5.6%	5.4%	*4.5%*	*4.0%*	Retained to Com Eq	*3.5%*
80%	51%	64%	55%	46%	41%	36%	41%	43%	46%	*52%*	*53%*	All Div'ds to Net Prof	*58%*

ELECTRIC OPERATING STATISTICS

	2012	2013	2014
% Change Retail Sales (KWH)	+2.6	+3.8	+1.4
Avg. Indust. Use (MWH)	N/A	N/A	N/A
Avg. Indust. Revs. per KWH (¢)	4.63	5.21	5.68
Capacity at Peak (Mw)	N/A	N/A	N/A
Peak Load, Summer (Mw)	3245	3407	3184
Annual Load Factor (%)	N/A	N/A	N/A
% Change Customers (yr-end)	+1.1	+1.5	+1.4
Fixed Charge Cov. (%)	283	329	287

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '12-'14 to '18-'20
Revenues	1.0%	3.0%	*2.5%*
"Cash Flow"	4.5%	6.5%	*2.5%*
Earnings	9.0%	10.0%	*1.0%*
Dividends	--	5.5%	*6.0%*
Book Value	5.0%	6.0%	*4.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	241.1	254.7	334.0	250.9	1080.7
2013	264.9	303.9	381.1	296.3	1246.2
2014	292.7	317.7	382.2	289.8	1282.5
2015	279.4	*335.6*	*395*	*270*	*1280*
2016	*295*	*335*	*395*	*285*	*1310*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.50	.71	1.84	.33	3.37
2013	.70	.93	1.46	.55	3.64
2014	.55	.89	1.73	.69	3.85
2015	.47	*.85*	*1.83*	*.50*	*3.65*
2016	*.70*	*.80*	*1.80*	*.50*	*3.80*

Cal-endar	QUARTERLY DIVIDENDS PAID B† ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.30	.30	.30	.30	1.20
2012	.33	.33	.33	.38	1.37
2013	.38	.38	.38	.43	1.57
2014	.43	.43	.43	.47	1.76
2015	.47	.47			

BUSINESS: IDACORP, Inc. is the holding company for Idaho Power, a utility that operates 17 hydroelectric generation developments, 3 natural gas-fired plants, and partly owns three coal plants across Idaho, Oregon, Wyoming, and Nevada. Service territory covers 24,000 square miles, serving 516,000 business customers. Sells electricity in Idaho (95% of revenues) and Oregon (5%). Revenue breakdown: residential, 45%; commercial, 27%; industrial, 16%; other, 12%. Fuel sources: hydro, 35%; thermal, 40%; purchased power, 25%. '14 depr rate: 3.8%. Has 2,021 employees. Chairman: Robert A. Tinstman. President & CEO: Darrel T. Anderson. Incorp: Idaho. Address: 1221 W. Idaho St., Boise, ID 83702. Telephone: 208-388-2200. Internet: www.idacorpinc.com.

Unseasonably warm weather took a toll on first-quarter results at IDACORP's principal operating subsidiary. That unit, electric utility Idaho Power, contributes the vast majority of IDA's revenues and earnings. Warmer-than-normal weather across much of the northwest United States was largely responsible for a decrease in residential sales in the March term. (Idaho Power had approximately 516,000 customers at year-end 2014, and roughly 428,000 of those customers, or 83%, were residential.)

The timing of certain operating and maintenance expenses has also hindered the bottom line. Increased thermal plant maintenance and rising hydroelectric costs reduced first-quarter operating income by $3.0 million, compared with the same period in 2014. Moreover, depreciation expense swelled by $1.2 million, from the year earlier, due to ongoing capital additions. On the plus side, the aforementioned negative factors were offset, at least partially, by Idaho Power's continued customer growth, which contributed $1.9 million to operating income. For the full year, management expects operating and maintenance expense of $340 million–$350 million, capital expenditures of $300 million–$310 million, with share net likely coming in between $3.65 and $3.80.

We expect a 6% dividend increase in 2016, and an average 5% annual raise to decade's end. The payout was held at $1.20 per share for eight years, a streak that was finally broken in 2012. Since then, the board has raised the dividend an average of roughly 12% annually, with the distribution on pace for $1.88 per share in the current year. The yield is below average for an electric utility, but is well above the *Value Line* median, and the payout remains well covered, at approximately 52% of projected 2015 earnings.

Long-term total return potential here is limited. The share price has fluctuated quite a bit over the past 12 months, by the standard of an electric utility stock, ranging between about $50 and $70 over that span. On the plus side, the equity garners a decent mark for Safety (2, Above Average), and earns good scores for Price Stability, Price Growth Persistence, and Earnings Predictability.

Sharif Abdou *July 31, 2015*

(A) EPS diluted. Excl. nonrecurring gains (loss): '00, 22¢; '03, 26¢; '05, (24¢); '06, 17¢. Egs. may not sum to total due to rounding. Next earnings report due in early November.

(B) Div'ds historically paid in late Feb., May, Aug., and Nov. ■ Div'd reinvestment plan avail. † Shareholder investment plan avail. (C) Incl. deferred debits. In '14: $25.26/sh. (D) In mill.

(E) Rate Base: Net original cost. Rate allowed on com. eq. in Idaho in '11: 9.5%-10.5%; earned on avg. system com. eq., '14: 9.9%. Regulatory Climate: Above Average.

Company's Financial Strength	B++
Stock's Price Stability	95
Price Growth Persistence	85
Earnings Predictability	95

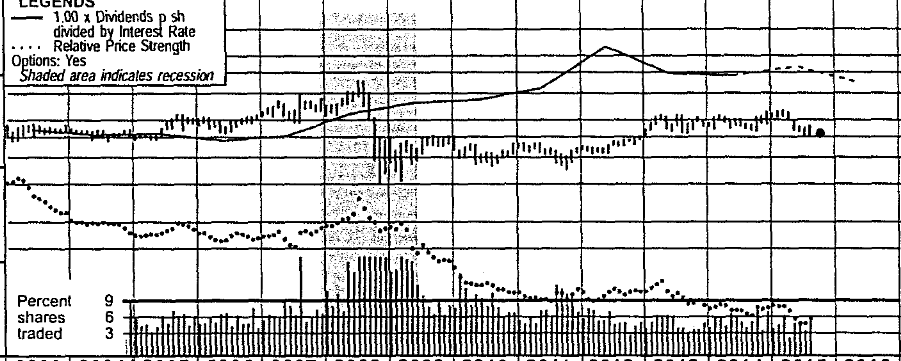
OTTER TAIL CORP. NDQ-OTTR

RECENT PRICE	P/E RATIO		RELATIVE P/E RATIO	DIV'D YLD	
25.83	15.4	(Trailing: 17.9, Median: 23.0)	0.88	4.8%	VALUE LINE

TIMELINESS 4 Lowered 5/15/15
SAFETY 3 Lowered 12/24/10
TECHNICAL 3 Raised 9/11/15
BETA .85 (1.00 = Market)

High:	27.5	32.0	31.9	39.4	46.2	25.4	25.4	23.5	25.3	31.9	32.7	33.4
Low:	23.8	24.0	25.8	29.0	15.0	15.5	18.2	17.5	20.7	25.2	26.5	24.8

Target Price Range 2018 | 2019 | 2020



2018-20 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	50	(+95%)	21%
Low	30	(+15%)	8%

Insider Decisions

	O	N	D	J	F	M	A	M	J
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	1	0	0	0
to Sell	0	1	1	0	0	0	0	0	0

Institutional Decisions

	4Q2014	1Q2015	2Q2015
to Buy	64	50	49
to Sell	41	58	53
Hld's(000)	12708	12560	12614

% TOT. RETURN 8/15

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-5.5	-3.7
3 yr.	29.5	49.7
5 yr.	76.5	98.6

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	© VALUE LINE PUB. LLC	18-20
19.48	23.45	26.53	27.75	29.28	30.45	35.59	37.43	41.50	37.06	29.03	31.08	29.86	23.76	24.63	21.48	*21.20*	*22.05*	Revenues per sh	*29.15*
2.91	3.21	3.40	3.44	3.30	2.88	3.35	3.39	3.55	2.81	2.76	2.60	2.36	2.71	3.02	3.09	*3.15*	*3.60*	"Cash Flow" per sh	*4.50*
1.45	1.60	1.68	1.79	1.51	1.50	1.78	1.69	1.78	1.09	.71	.38	.45	1.05	1.37	1.55	*1.60*	*1.75*	Earnings per sh A	*2.25*
.99	1.02	1.04	1.06	1.08	1.10	1.12	1.15	1.17	1.19	1.19	1.19	1.19	1.19	1.19	1.21	*1.23*	*1.25*	Div'd Decl'd per sh B ■	*1.32*
1.37	1.85	2.17	2.95	1.97	1.72	2.04	2.35	5.43	7.51	4.95	2.38	2.04	3.20	4.53	4.40	*4.20*	*4.35*	Cap'l Spending per sh	*4.75*
10.30	10.87	11.33	12.25	12.98	14.81	15.80	16.67	17.55	19.14	18.78	17.57	15.83	14.43	14.75	15.39	*16.05*	*16.65*	Book Value per sh C	*18.10*
23.85	23.85	24.65	25.59	25.72	28.98	29.40	29.52	29.85	35.38	35.81	36.00	36.10	36.17	36.27	37.22	*38.00*	*39.00*	Common Shs Outst'g D	*42.00*
13.9	13.5	16.4	16.0	17.8	17.3	15.4	17.3	19.0	30.1	31.2	55.1	47.5	21.7	21.1	18.8	*Bold figures are*		Avg Ann'l P/E Ratio	*18.0*
.79	.88	.84	.87	1.01	.91	.82	.93	1.01	1.81	2.08	3.51	2.98	1.38	1.19	.99	*Value Line*		Relative P/E Ratio	*1.15*
4.9%	4.7%	3.8%	3.7%	4.0%	4.2%	4.1%	3.9%	3.5%	3.6%	5.4%	5.7%	5.6%	5.2%	4.1%	4.1%	*estimates*		Avg Ann'l Div'd Yield	*3.3%*

CAPITAL STRUCTURE as of 6/30/15
Total Debt $541.6 mill. Due in 5 Yrs $87.0 mill.
LT Debt $498.4 mill. LT Interest $28.0 mill.
(LT interest earned: 3.5x)

Leases, Uncapitalized Annual rentals $7 mill.
Pension Assets-12/14 $244.6 mill. Oblig. $311.7 mill.
Pfd Stock None

Common Stock 37,591,785 shs.
as of 7/31/15
MARKET CAP: $975 million (Small Cap)

2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016		18-20
1046.4	1105.0	1238.9	1311.2	1039.5	1119.1	1077.9	859.2	893.3	799.3	*805*	*860*	Revenues ($mill)	*1225*
52.9	50.8	54.0	35.1	26.0	13.6	16.4	39.0	50.2	56.9	*60.0*	*70.0*	Net Profit ($mill)	*95.0*
34.6%	34.8%	34.1%	30.0%	--	--	14.5%	5.2%	21.3%	22.5%	*25.0%*	*25.0%*	Income Tax Rate	*25.0%*
1.7%	1.9%	4.2%	6.1%	4.0%	.6%	3.8%	1.7%	1.7%	3.6%	*3.0%*	*4.0%*	AFUDC % to Net Profit	*5.0%*
35.0%	33.5%	38.9%	32.9%	38.8%	40.2%	44.6%	44.0%	42.1%	46.5%	*46.5%*	*46.5%*	Long-Term Debt Ratio	*48.0%*
62.9%	64.5%	59.4%	65.6%	59.8%	58.4%	54.0%	54.4%	57.9%	53.5%	*53.5%*	*53.5%*	Common Equity Ratio	*52.0%*
738.2	763.0	882.1	1032.5	1124.4	1083.3	1058.9	959.2	924.4	1071.3	*1135*	*1210*	Total Capital ($mill)	*1460*
697.1	718.6	854.0	1037.6	1098.6	1108.7	1077.5	1049.5	1167.0	1268.5	*1350*	*1450*	Net Plant ($mill)	*1750*
8.3%	7.7%	7.2%	4.3%	3.4%	2.7%	3.2%	5.7%	6.7%	6.7%	*6.5%*	*7.0%*	Return on Total Cap'l	*7.5%*
11.0%	10.0%	10.0%	5.1%	3.8%	2.1%	2.8%	7.3%	9.4%	9.9%	*10.0%*	*11.0%*	Return on Shr. Equity E	*12.5%*
11.2%	10.2%	10.2%	5.1%	3.8%	2.0%	2.7%	7.3%	9.3%	9.9%	*10.0%*	*11.0%*	Return on Com Equity	*12.5%*
4.2%	3.3%	3.5%	NMF	NMF	NMF	NMF	NMF	1.2%	2.2%	*2.0%*	*3.0%*	Retained to Com Eq	*5.0%*
63%	68%	66%	108%	NMF	NMF	NMF	113%	87%	78%	*79%*	*71%*	All Div'ds to Net Prof	*59%*

ELECTRIC OPERATING STATISTICS

	2012	2013	2014
% Change Retail Sales (KWH)	-1.1	+5.8	+4.6
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Winter (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	NA	NA	NA
Fixed Charge Cov. (%)	257	359	336

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '12-'14 to '18-'20
Revenues	-2.0%	-8.5%	*4.0%*
"Cash Flow"	-1.0%	-.5%	*7.5%*
Earnings	-2.0%	2.0%	*9.0%*
Dividends	1.0%	--	*1.5%*
Book Value	1.0%	-4.5%	*3.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	219.9	211.4	215.3	212.6	859.2
2013	218.0	212.4	229.8	233.1	893.3
2014	215.0	194.4	196.5	193.4	799.3
2015	202.8	188.2	*205*	*209*	*805*
2016	*215*	*210*	*215*	*220*	*860*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.28	.19	.13	.47	1.05
2013	.41	.21	.41	.35	1.37
2014	.59	.27	.43	.28	1.55
2015	.37	.36	*.44*	*.43*	*1.60*
2016	*.45*	*.35*	*.48*	*.47*	*1.75*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.298	.298	.298	.298	1.19
2012	.298	.298	.298	.298	1.19
2013	.298	.298	.298	.298	1.19
2014	.303	.303	.303	.303	1.21
2015	.308	.308	.308		

BUSINESS: Otter Tail Corporation is the parent of Otter Tail Power Company, which supplies electricity to over 130,000 customers in Minnesota (50% of retail elec. revs.), North Dakota (42%), and South Dakota (8%). Electric rev. breakdown, '14: residential, 32%; commercial & farms, 37%; industrial, 25%; other, 6%. Fuel costs: 16.6% of revenues. Also has operations in manufacturing and plastics. 2014 depr. rate: 2.9%. Has 1,893 employees. Off. and dir. own 1.4% of common stock; Cascade Investment, LLC, 9.3%; Vanguard Group, Inc., 6.6%; BlackRock, Inc., 5.5% (2/15 Proxy). CEO: Charles MacFarlane. Inc.: MN. Address: 215 South Cascade St., P.O. Box 496, Fergus Falls, Minnesota 56538-0496. Telephone: 866-410-8780. Internet: www.ottertail.com.

Otter Tail reported mixed results for the June quarter. The top line declined roughly 3% on a year-over-year basis. The softness was broad based, as revenue decreased in each of the company's three operating segments. Still, greater transmission tariff revenues provided support at Otter Tail Power Company. Moreover, the bottom line benefited from lower operating and maintenance expenses. Overall, share net of $0.36 compared favorably with the prior-year tally.

Subsidiary BTD Manufacturing has acquired Impulse Manufacturing for $30.5 million. The addition of this Georgia-based company will allow BTD to accelerate its plans to expand into the southeastern United States. The acquisition is expected to be accretive to earnings in 2016.

Challenges will likely persist in the near term, but we expect solid overall performance going forward. Net income for the electric segment this year should increase at a moderate rate. This line ought to benefit from rider recovery increases, greater sales to pipeline customers, and a decline in plant maintenance costs. That said, this should be partly offset by softness in retail sales due to milder-than-normal weather, a decline in transmission revenue, and an increase in depreciation, property tax expense, and short-term interest costs. Elsewhere, earnings from the Manufacturing and Plastics segments may well decline for 2015. Softness in various end markets served by BTD's customers should continue to hurt performance at the Manufacturing line. A decrease in sales of polyvinyl chloride pipe will likely hurt results at the Plastics business, but this ought to be partly offset by lower material costs.

These shares are ranked to lag the overall market for the coming six to 12 months. This stock has traded lower over the past six months, and the weakness may well continue going forward. But patient, income-seeking accounts may want to take a closer look. Earnings growth ought to pick up at Otter Tail as demand improves down the road. This equity offers solid total return potential for the pull to late decade, which is supported by a healthy dividend yield.

Michael Napoli, CFA *September 18, 2015*

(A) Diluted earnings. Excl. nonrecurring gains (losses): '99, 34¢; '10, (44¢); '11, 26¢; '13, 2¢; gains (losses) from discont. operations: '04, 8¢; '05, 33¢; '06, 1¢; '11, ($1.11); '12, ($1.22); '13, 2¢; '14, 2¢. Earnings may not sum due to rounding. Next earnings report due early November. (B) Div'ds historically paid in early March, June, Sept., and Dec. ■ Div'd reinvestment plan avail. (C) Incl. intangibles. In '14: $42.7 mill., $1.15/sh. (D) In mill. (E) Regulatory Climate: MN, ND, Average; SD, Above Average.

Company's Financial Strength	B+
Stock's Price Stability	85
Price Growth Persistence	15
Earnings Predictability	50

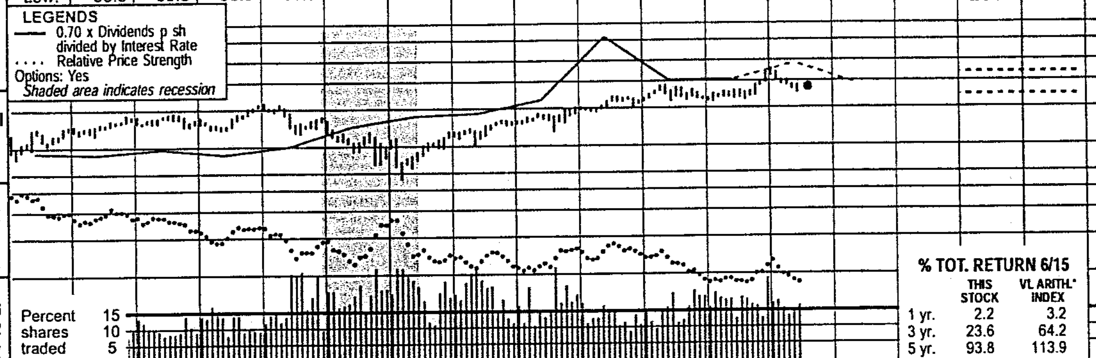
PINNACLE WEST NYSE-PNW

RECENT PRICE	59.96	P/E RATIO	15.6 (Trailing: 16.7 Median: 15.0)	RELATIVE P/E RATIO	0.83	DIV'D YLD	4.1%	VALUE LINE

TIMELINESS **3** Lowered 10/10/14
SAFETY **1** Raised 5/3/13
TECHNICAL **3** Lowered 7/24/15
BETA .70 (1.00 = Market)

High:	45.8	46.7	51.0	51.7	42.9	38.0	42.7	48.9	54.7	61.9	71.1	73.3
Low:	36.3	39.8	38.3	36.8	26.3	22.3	32.3	37.3	45.9	51.5	51.2	56.0

Target Price Range 2018 | 2019 | 2020



2018-20 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	70	(+15%)	8%
Low	55	(-10%)	3%

Insider Decisions

	S	O	N	D	J	F	M	A	M
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	5	3	0	0	1	0	0

Institutional Decisions

	3Q2014	4Q2014	1Q2015
to Buy	171	191	182
to Sell	163	188	194
Hld's(000)	88791	88401	86769

% TOT. RETURN 6/15

	THIS STOCK	VL ARITH.* INDEX
1 yr.	2.2	3.2
3 yr.	23.6	64.2
5 yr.	93.8	113.9

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	© VALUE LINE PUB. LLC	18-20
28.57	43.50	53.66	28.90	30.87	31.59	30.16	34.03	35.07	33.37	32.50	30.01	29.67	30.09	31.35	31.58	*31.55*	*32.75*	Revenues per sh	*36.50*
7.73	7.99	8.72	7.01	7.33	6.93	5.76	9.70	9.29	8.13	8.08	6.85	7.52	7.92	8.15	8.09	*8.75*	*9.10*	"Cash Flow" per sh	*10.25*
3.18	3.35	3.68	2.53	2.52	2.58	2.24	3.17	2.96	2.12	2.26	3.08	2.99	3.50	3.66	3.58	*3.85*	*3.95*	Earnings per sh A	*4.50*
1.33	1.43	1.53	1.63	1.73	1.83	1.93	2.03	2.10	2.10	2.10	2.10	2.10	2.67	2.23	2.33	*2.44*	*2.56*	Div'd Decl'd per sh B ■	*2.95*
4.05	7.76	12.27	9.81	7.60	5.86	6.39	7.59	9.37	9.46	7.64	7.03	8.26	8.24	9.36	8.38	*9.85*	*9.90*	Cap'l Spending per sh	*9.75*
26.00	28.09	29.46	29.44	31.00	32.14	34.57	34.48	35.15	34.16	32.69	33.86	34.98	36.20	38.07	39.50	*40.95*	*42.30*	Book Value per sh C	*47.00*
84.83	84.83	84.83	91.26	91.29	91.79	99.08	99.96	100.49	100.89	101.43	108.77	109.25	109.74	110.18	110.57	*111.00*	*111.50*	Common Shs Outst'g D	*118.00*
11.9	11.3	12.0	14.4	14.0	15.8	19.2	13.7	14.9	16.1	13.7	12.6	14.6	14.3	15.3	15.9	**Bold figures are**	**Value Line**	Avg Ann'l P/E Ratio	*13.5*
.68	.73	.61	.79	.80	.83	1.02	.74	.79	.97	.91	.80	.92	.91	.86	.84	**estimates**		Relative P/E Ratio	*.85*
3.5%	3.8%	3.5%	4.5%	4.9%	4.5%	4.5%	4.7%	4.8%	6.2%	6.8%	5.4%	4.8%	5.3%	4.0%	4.1%			Avg Ann'l Div'd Yield	*4.8%*

CAPITAL STRUCTURE as of 3/31/15
Total Debt $3699.4 mill. Due in 5 Yrs $1474.1 mill.
LT Debt $3281.3 mill. LT Interest $165.9 mill.
Incl. $13.4 mill. Palo Verde sale leaseback lessor notes.
(LT interest earned: 4.8x)
Leases, Uncapitalized Annual rentals $18.0 mill.
Pension Assets-12/14 $2615.4 mill. Oblig. $3078.7 mill.

Pfd Stock None

Common Stock 110,748,842 shs. as of 4/24/15
MARKET CAP: $6.6 billion (Large Cap)

2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016		18-20
2988.0	3401.7	3523.6	3367.1	3297.1	3263.6	3241.4	3301.8	3454.6	3491.6	*3500*	*3650*	Revenues ($mill)	*4300*
223.2	317.1	298.8	213.6	229.2	330.4	328.2	387.4	406.1	397.6	*430*	*445*	Net Profit ($mill)	*540*
36.2%	33.0%	33.6%	23.4%	36.9%	31.9%	34.0%	36.2%	34.4%	34.2%	*35.0%*	*35.0%*	Income Tax Rate	*35.0%*
10.4%	11.1%	14.8%	17.5%	11.2%	11.7%	12.8%	9.7%	10.0%	11.6%	*9.0%*	*9.0%*	AFUDC % to Net Profit	*7.0%*
43.2%	48.4%	47.0%	46.8%	50.4%	45.3%	44.1%	44.6%	40.0%	41.0%	*44.5%*	*45.0%*	Long-Term Debt Ratio	*44.5%*
56.8%	51.6%	53.0%	53.2%	49.6%	54.7%	55.9%	55.4%	60.0%	59.0%	*55.5%*	*55.0%*	Common Equity Ratio	*55.5%*
6033.4	6678.7	6658.7	6477.6	6686.6	6729.1	6840.9	7171.9	6990.9	7398.7	*8200*	*8610*	Total Capital ($mill)	*10025*
7577.1	7881.9	8436.4	8916.7	9257.8	9578.8	9962.3	10396	10889	11194	*11750*	*12275*	Net Plant ($mill)	*14200*
5.0%	6.2%	5.9%	4.7%	4.8%	6.5%	6.4%	6.8%	7.1%	6.4%	*6.5%*	*6.5%*	Return on Total Cap'l	*6.5%*
6.5%	9.2%	8.5%	6.2%	6.9%	9.0%	8.6%	9.8%	9.7%	9.1%	*9.5%*	*9.5%*	Return on Shr. Equity	*9.5%*
6.5%	9.2%	8.5%	6.2%	6.9%	9.0%	8.6%	9.8%	9.7%	9.1%	*9.5%*	*9.5%*	Return on Com Equity E	*9.5%*
1.0%	3.4%	2.5%	.3%	.7%	3.1%	2.8%	4.1%	4.1%	3.5%	*3.5%*	*3.5%*	Retained to Com Eq	*3.5%*
85%	63%	70%	96%	89%	66%	68%	58%	58%	62%	*63%*	*64%*	All Div'ds to Net Prof	*64%*

ELECTRIC OPERATING STATISTICS

	2012	2013	2014
% Change Retail Sales (KWH)	-.2	-.2	-1.8
Avg. Indust. Use (MWH)	647	644	659
Avg. Indust. Revs. per KWH (¢)	7.86	8.21	8.26
Capacity at Peak (Mw)	8864	8398	9259
Peak Load, Summer (Mw)	7207	6927	7007
Annual Load Factor (%)	48.8	50.0	48.6
% Change Customers (yr-end)	+1.3	+1.4	+1.2
Fixed Charge Cov. (%)	397	419	404

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '12-'14 to '18-'20
Revenues	--	-1.5%	*3.0%*
"Cash Flow"	1.5%	-1.0%	*4.0%*
Earnings	3.5%	8.0%	*4.0%*
Dividends	3.5%	3.0%	*3.5%*
Book Value	2.0%	2.0%	*3.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	620.6	878.6	1109.5	693.1	3301.8
2013	686.6	915.8	1152.4	699.8	3454.6
2014	686.2	906.3	1172.7	726.4	3491.6
2015	671.2	*925*	*1178.8*	*725*	*3500*
2016	*700*	*975*	*1225*	*750*	*3650*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	d.07	1.12	2.21	.24	3.50
2013	.22	1.18	2.04	.22	3.66
2014	.14	1.19	2.20	.05	3.58
2015	.14	*1.25*	*2.26*	*.20*	*3.85*
2016	*.15*	*1.30*	*2.30*	*.20*	*3.95*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.525	.525	.525	.525	2.10
2012	.525	.525	.525	.545	2.12
2013	.545	.545	.545	.5675	2.20
2014	.5675	.5675	.5675	.595	2.30
2015	.595	.595			

BUSINESS: Pinnacle West Capital Corporation is a holding company for Arizona Public Service Company (APS), which supplies electricity to 1.1 million customers in most of Arizona, except about half of the Phoenix metro area, the Tucson metro area, and Mohave County in northwestern Arizona. Discontinued SunCor real estate subsidiary in '10. Electric revenue breakdown: residential, 48%; commercial, 39%; industrial, 5%; other, 9%. Generating sources: coal, 34%; nuclear, 27%; gas & other, 17%; purchased, 22%. Fuel costs: 34% of revenues. Has 6,400 employees. '14 reported deprec. rate: 2.8%. Chairman, President & CEO: Donald E. Brandt. Inc.: AZ. Address: 400 North Fifth St., P.O. Box 53999, Phoenix, AZ 85072-3999. Tel.: 602-250-1000. Internet: www.pinnaclewest.com.

Pinnacle West's utility subsidiary is awaiting a regulatory ruling from the Arizona commission. In early April, Arizona Public Service proposed increasing the monthly fixed charge for residential customers from about $5 to about $21. The utility is concerned that nonsolar customers are subsidizing solar users under the current rate structure. An administrative law judge will weigh in on this matter before the commission issues its order. There is no time frame for conclusion of these proceedings.

The utility plans to add some generating capacity by late decade. APS intends to build 510 megawatts of gas-fired capacity at a cost of $500 million. It will retire some older units that amount to 220 mw, for a net capacity addition of 290 mw. Pending the receipt of an environmental permit, construction is expected to begin next year, with completion of the project planned for 2019.

We estimate that earnings will rise at a high single-digit pace in 2015. APS received a $57.1 million rate increase at the start of the year in order to place a newly purchased asset (a stake in Units 4 and 5 of the Four Corners coal-fired plant) in the rate base. In addition, the utility receives current cost recovery for certain kinds of capital spending, such as electric transmission. Our earnings estimate remains at the midpoint of Pinnacle West's targeted range of $3.75-$3.95 a share.

We forecast a lesser profit increase in 2016. The regulatory mechanisms mentioned above should benefit the company. However, although customer growth is likely to exceed the 1% level, volume is expected to advance at just 0.5% due to the effects of conservation.

Finances are strong. The fixed-charge coverage is well above the industry average. The common-equity ratio is among the highest of any utility, and APS is earning near its allowed return on equity. All told, Pinnacle West merits a Financial Strength rating of A+.

Top-quality Pinnacle West stock has a dividend yield that is roughly equal to the utility mean. Although we project decent dividend growth over the period to 2018-2020, total return potential is only average for the group.

Paul E. Debbas, CFA *July 31, 2015*

(A) Diluted EPS. Excl. nonrec. losses: '02, 77¢; '09, $1.45; excl. gains (losses) from discontinued ops.: '00, 22¢; '05, (36¢); '06, 10¢; '08, 28¢; '09, (13¢); '10, 18¢; '11, 10¢; '12, (5¢). Next earnings report due early Aug. (B) Div'ds historically paid in early Mar., June, Sept., & Dec. There were 5 declarations in '12. ■ Div'd reinvestment plan avail. (C) Incl. deferred charges. In '14: $12.30/sh. (D) In mill. (E) Rate base: Fair value. Rate allowed on com. eq. in '12: 10%; earned on avg. com. eq., '14: 9.3%. Regulatory Climate: Average.

Company's Financial Strength	A+
Stock's Price Stability	100
Price Growth Persistence	65
Earnings Predictability	70

PNM RESOURCES NYSE-PNM

RECENT PRICE	25.30	P/E RATIO	16.3 (Trailing: 16.6; Median: 16.0)	RELATIVE P/E RATIO	0.87	DIV'D YLD	3.2%	VALUE LINE

TIMELINESS **3** Lowered 6/19/15

SAFETY **3** Lowered 5/9/08

TECHNICAL **5** Lowered 7/31/15

BETA .85 (1.00 = Market)

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
High:	26.1	30.5	32.1	34.3	21.7	13.1	14.0	19.2	22.5	24.5	31.6	31.2	
Low:	18.7	23.8	22.5	21.0	7.6	5.9	10.8	12.8	17.3	20.1	23.5	24.4	

2018-20 PROJECTIONS

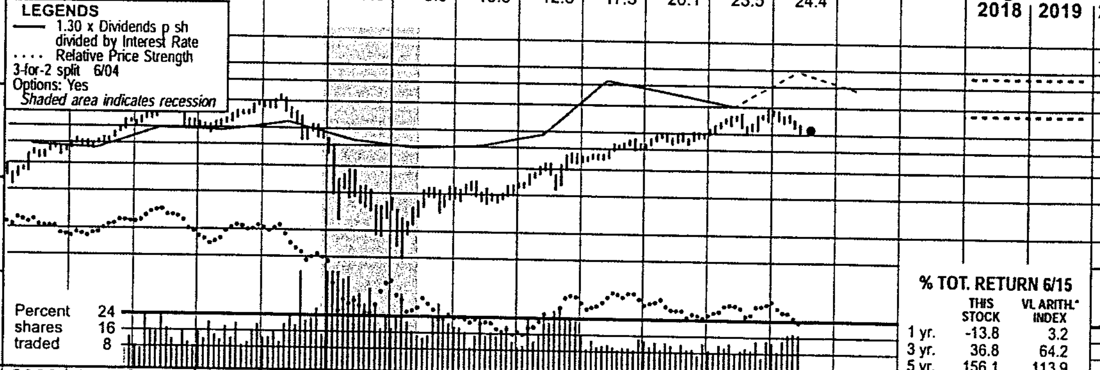
	Price	Gain	Ann'l Total Return
High	45	(+80%)	18%
Low	30	(+20%)	8%

Insider Decisions

	S	O	N	D	J	F	M	A	M
to Buy	0	0	0	0	0	0	1	0	0
Options	0	0	0	0	0	0	4	0	0
to Sell	0	0	0	0	0	0	4	0	0

Institutional Decisions

	3Q2014	4Q2014	1Q2015
to Buy	86	109	108
to Sell	101	93	110
Hld's(000)	71291	71113	69125



Target Price Range

2018 | 2019 | 2020

% TOT. RETURN 6/15

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-13.8	3.2
3 yr.	36.8	64.2
5 yr.	156.1	113.9

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	© VALUE LINE PUB. LLC	18-20
18.96	27.46	40.09	19.92	24.11	26.54	30.19	32.25	24.92	22.65	19.01	19.31	21.35	16.85	17.42	18.03	18.25	18.75	Revenues per sh	20.30
2.82	3.16	4.31	2.83	3.05	3.14	3.56	3.57	2.54	1.76	2.32	2.67	3.18	3.38	3.51	3.67	3.70	3.85	"Cash Flow" per sh	4.70
1.29	1.55	2.61	1.07	1.15	1.43	1.56	1.72	.76	.11	.58	.87	1.08	1.31	1.41	1.49	1.55	1.65	Earnings per sh A	2.35
.53	.53	.53	.57	.61	.63	.79	.86	.91	.61	.50	.50	.50	.58	.68	.74	.80	.85	Div'd Decl'd per sh B ■†	1.15
1.56	2.50	4.51	4.09	2.78	2.25	3.07	4.04	5.94	3.99	3.32	3.25	4.10	3.88	4.37	5.78	5.50	5.50	Cap'l Spending per sh	5.50
14.74	15.76	17.25	16.60	17.84	18.19	18.70	22.09	22.03	18.89	18.90	17.60	19.62	20.05	20.87	21.61	22.10	22.70	Book Value per sh C	25.50
61.05	58.68	58.68	58.68	60.39	60.46	68.79	76.65	76.81	86.53	86.67	86.67	79.65	79.65	79.65	79.65	80.00	80.00	Common Shs Outst'g D	80.00
9.5	8.5	7.3	15.1	14.7	15.0	17.4	15.6	35.6	NMF	18.1	14.0	14.5	15.0	16.1	18.1	Bold figures are		Avg Ann'l P/E Ratio	16.0
.54	.55	.37	.82	.84	.79	.93	.84	1.89	NMF	1.21	.89	.91	.95	.90	.90	Value Line		Relative P/E Ratio	1.00
4.4%	4.1%	2.8%	3.5%	3.6%	2.9%	2.9%	3.2%	3.4%	4.9%	4.8%	4.1%	3.2%	3.0%	3.0%	3.5%	estimates		Avg Ann'l Div'd Yield	3.3%

CAPITAL STRUCTURE as of 3/31/15
Total Debt $2225.0 mill. Due in 5 Yrs $1112 mill.
LT Debt $1791.9 mill. LT Interest $110 mill.
(LT interest earned: 2.4x)
Pension Assets-12/14 $657.6 mill. Oblig. $587.7 mill.

Pfd Stock $11.5 mill. Pfd Div'd $.5 mill.
115,293 shs. 4.58%, $100 par w/o mandatory redemption. Sinking fund began 2/1/84.

Common Stock 79,653,624 shs. as of 4/24/15

MARKET CAP: $2.0 billion (Mid Cap)

2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016		18-20
2076.8	2471.7	1914.0	1959.5	1647.7	1673.5	1700.6	1342.4	1387.9	1435.9	1460	1500	Revenues ($mill)	1625
106.6	122.1	59.9	8.1	53.5	80.0	96.6	105.6	113.5	119.6	125	135	Net Profit ($mill)	190
31.1%	24.7%	5.1%	40.4%	30.4%	32.6%	38.8%	31.4%	31.6%	36.7%	35.0%	35.0%	Income Tax Rate	35.0%
15.6%	4.1%	--	--	6.4%	7.1%	8.8%	7.2%	1.3%	1.3%	1.5%	2.5%	AFUDC % to Net Profit	8.0%
57.4%	50.9%	42.0%	45.6%	48.7%	50.4%	51.5%	50.9%	50.0%	48.8%	52.0%	53.0%	Long-Term Debt Ratio	53.5%
42.3%	48.8%	57.6%	54.0%	51.0%	49.2%	48.1%	48.7%	49.7%	51.2%	48.0%	47.0%	Common Equity Ratio	46.5%
3044.4	3470.7	2935.8	3025.4	3214.9	3100.3	3245.6	3277.9	3344.0	3363.6	3695	3845	Total Capital ($mill)	4385
2984.1	3761.9	2935.4	3192.0	3332.4	3444.4	3627.1	3746.5	3933.9	4270.0	4335	4555	Net Plant ($mill)	5270
4.7%	4.9%	3.4%	1.9%	3.1%	4.2%	4.5%	5.1%	5.2%	5.3%	5.0%	5.0%	Return on Total Cap'l	6.0%
8.2%	7.2%	3.5%	.5%	3.2%	5.2%	6.1%	6.6%	6.8%	6.9%	7.0%	7.5%	Return on Shr. Equity	9.5%
8.2%	7.2%	3.5%	.5%	3.2%	5.2%	6.1%	6.6%	6.8%	6.9%	7.0%	7.5%	Return on Com Equity E	9.5%
4.3%	3.7%	NMF	NMF	.4%	2.2%	3.3%	3.8%	3.7%	3.5%	3.5%	3.5%	Retained to Com Eq	5.0%
48%	49%	117%	NMF	86%	58%	47%	43%	45%	49%	51%	51%	All Div'ds to Net Prof	49%

ELECTRIC OPERATING STATISTICS F

	2012	2013	2014
% Change Retail Sales (KWH)	-1.6	-2.9	-2.1
Avg. Indust. Use (MWH)	N/A	N/A	N/A
Avg. Indust. Revs. per KWH (¢)	N/A	N/A	N/A
Capacity at Peak (Mw)	2537	2572	2707
Peak Load, Summer (Mw)	1948	2008	1948
Annual Load Factor (%)	N/A	N/A	N/A
% Change Customers (yr-end)	+.4	+.7	+.6
Fixed Charge Cov. (%)	225	241	250

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '11-'13 to '18-'20
Revenues	-4.0%	-7.0%	1.5%
"Cash Flow"	--	5.0%	5.0%
Earnings	-2.5%	8.0%	9.0%
Dividends	.5%	-6.0%	10.0%
Book Value	1.5%	-1.0%	3.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	305.4	323.9	390.4	322.7	1342.4
2013	317.7	347.6	399.7	322.9	1387.9
2014	328.9	346.2	413.9	346.9	1435.9
2015	332.9	355	440	332.1	1460
2016	345	360	440	355	1500

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.17	.33	.69	.13	1.31
2013	.18	.38	.64	.21	1.41
2014	.18	.39	.68	.24	1.49
2015	.21	.40	.75	.19	1.55
2016	.25	.40	.75	.25	1.65

Cal-endar	QUARTERLY DIVIDENDS PAID B ■† Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.125	.125	.125	.125	.50
2012	.145	.145	.145	.145	.58
2013	.145	.165	.165	.165	.64
2014	.185	.185	.185	.185	.74
2015	.20	.20			

BUSINESS: PNM Resources is an investor-owned holding company of energy and energy related businesses. Primary subsidiaries include Public Service Company of New Mexico (PNM) and Texas-New Mexico Power Company (TNMP), which generate, transmit, and distribute electricity in New Mexico and Texas. Sold First Choice Energy (9/11) and gas utility operations (1/09). Electric rev. breakdown '14: residential, 37%; commercial, 37%; industrial, 6%; other, 20%. Fuels: coal, 56.8%; nuclear, 30.4%; gas/oil, 12.2%; solar, .5%. Fuel costs: 49% of revs. '14 depr. rate: 3.3%. Has 1,881 employees. Chrmn., Pres. & CEO: Patricia K. Collawn. Inc.: NM. Address: 414 Silver Ave. SW, Albuquerque, NM. 87102. Tel.: 505-241-2700. Internet: www.pnmresources.com.

PNM Resources appealed the future test-year ruling to the New Mexico Supreme Court. The company's rate case was reviewed in April by the examiner, which recommended rejection since it did not comply with the future test-year rule. The utility was looking for a revenue increase of $107.4 million and a return on equity of 10.5%. There should be a ruling on the appeal within the year.

The company is about to file the San Juan Participation agreement. The related coal contract allows PNM to illustrate that its plan is the lowest-cost option for its ratepayers. The outcome of this agreement will have an impact on the San Juan units. The final order is expected at the end of 2015.

Some regulatory matters are upcoming. The utility is seeking changes to its rate design to improve the distribution of its costs in New Mexico. While new rates will probably be delayed until at least mid-2016, the company is taking the proper steps to move ahead in that time frame. Interested investors should keep an eye on this situation as it represents a potential catalyst for PNM shares. Also of note, new rates would help the utility keep up with rising capital expenditures.

We are leaving our estimates intact. The company's regulatory operations have performed well of late. Recent investments in the PNM operations should bolster results in the months ahead. Additionally, rate growth in Texas has been a positive. Accordingly, we look for earnings of $1.55 a share this year and for them to advance by a dime, to $1.65 a share, next year. Looking further out, the company has some interesting prospects over the pull to 2018-2020. Efforts to develop infrastructure for clean energy represent a promising growth avenue. What's more, the aforementioned rate case could bolster results in New Mexico. Lastly, steady dividend hikes ought to sweeten the pot.

PNM stock is attractive for income-oriented investors. Indeed, this equity's yield (3.2%) coupled with its projected dividend growth rate (10%) makes PNM an interesting choice. Moreover, this issue has fallen in value since our May review. As a result, total return potential over the 3- to 5-year pull is appealing.

Richard J. Gallagher *July 31, 2015*

(A) EPS dil. Excl. n/r gains (losses): '99, 8¢; '00, 21¢; '01, (15¢); '03, 67¢; '05, (56¢); '08, ($3.77); '10, ($1.36); '11, 88¢. '13,(16); Excl. disc. ops.: '08, 42¢; '09, 78¢. Egs. may not sum due to rounding. Next egs. rpt. due late October. (B) Div'ds hist. pd. in Feb., May, Aug., Nov. ■ Div'd reinvest. plan avail. † Shareholder invest. plan avail. (C) Incl. intang. '14: $3.49/sh. (D) In mill., adjust. for split. (E) Rate base: net orig. cost. ROE allowed in '11: 10.0%; earned on avg. com. eq., '13: 10.0%. Reg. Climate: Avg. (F) Excl. First Choice.

Company's Financial Strength	B
Stock's Price Stability	80
Price Growth Persistence	30
Earnings Predictability	25

PORTLAND GENERAL NYSE-POR

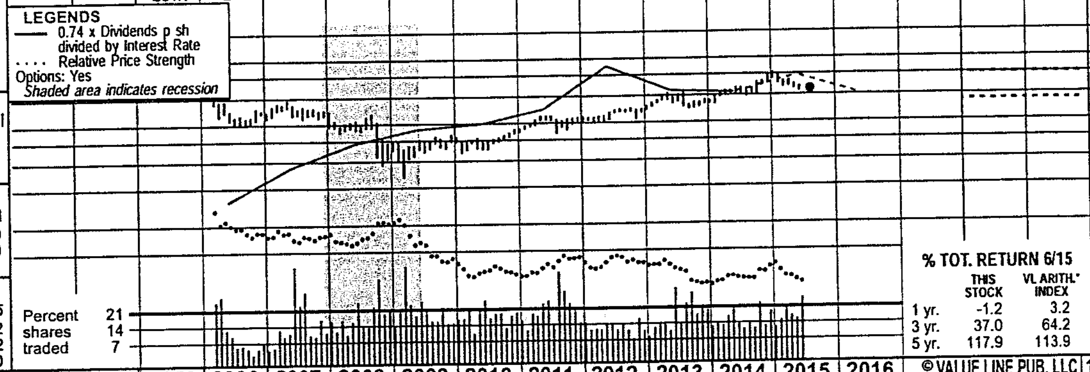
RECENT PRICE 33.99 | P/E RATIO 15.8 (Trailing: 16.4 Median: NMF) | RELATIVE P/E RATIO 0.84 | DIV'D YLD 3.6% | VALUE LINE

TIMELINESS 4 Lowered 7/17/15
SAFETY 2 Raised 5/4/12
TECHNICAL 3 Lowered 7/24/15
BETA .80 (1.00 = Market)

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
High:	35.0	31.3	27.7	21.4	22.7	26.0	28.1	33.3	40.3	41.0
Low:	24.2	25.5	15.4	13.5	17.5	21.3	24.3	27.4	29.0	33.0

Target Price Range 2018 | 2019 | 2020

LEGENDS
— 0.74 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



2018-20 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	40	(+20%)	8%
Low	30	(-10%)	1%

Insider Decisions

	S	O	N	D	J	F	M	A	M
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	0	0	0	0	1	0	1

Institutional Decisions

	3Q2014	4Q2014	1Q2015
to Buy	123	132	122
to Sell	116	127	142
Hld's(000)	83632	82456	84710

Percent shares traded 21 14 7

% TOT. RETURN 6/15

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-1.2	3.2
3 yr.	37.0	64.2
5 yr.	117.9	113.9

On April 3, 2006, Portland General Electric's existing stock (which was owned by Enron) was canceled, and 62.5 million shares were issued to Enron's creditors or the Disputed Claims Reserve (DCR). The stock began trading on a when-issued basis that day, and regular trading began on April 10, 2006. Shares issued to the DCR were released over time to Enron's creditors until all of the remaining shares were released in June, 2007.

2005[G]	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	© VALUE LINE PUB. LLC	18-20
23.14	24.32	27.87	27.89	23.99	23.67	24.06	23.89	23.18	24.29	*21.15*	*22.50*	Revenues per sh	*24.25*
4.75	4.64	5.21	4.71	4.07	4.82	4.96	5.15	4.93	6.08	*5.50*	*5.95*	"Cash Flow" per sh	*7.00*
1.02	1.14	2.33	1.39	1.31	1.66	1.95	1.87	1.77	2.18	*2.15*	*2.40*	Earnings per sh [A]	*2.75*
--	.68	.93	.97	1.01	1.04	1.06	1.08	1.10	1.12	*1.18*	*1.26*	Div'd Decl'd per sh [B] ■ †	*1.50*
4.08	5.94	7.28	6.12	9.25	5.97	3.98	4.01	8.40	12.87	*7.15*	*4.40*	Cap'l Spending per sh	*3.50*
19.15	19.58	21.05	21.64	20.50	21.14	22.07	22.87	23.30	24.43	*25.60*	*26.75*	Book Value per sh [C]	*30.50*
62.50	62.50	62.53	62.58	75.21	75.32	75.36	75.56	78.09	78.23	*88.70*	*88.90*	Common Shs Outst'g [D]	*89.50*
--	23.4	11.9	16.3	14.4	12.0	12.4	14.0	16.9	15.3	*Bold figures are*		Avg Ann'l P/E Ratio	*12.5*
--	1.26	.63	.98	.96	.76	.78	.89	.95	.81	*Value Line*		Relative P/E Ratio	*.80*
--	2.5%	3.3%	4.3%	5.4%	5.2%	4.4%	4.1%	3.7%	3.3%	*estimates*		Avg Ann'l Div'd Yield	*4.4%*
1446.0	1520.0	1743.0	1745.0	1804.0	1783.0	1813.0	1805.0	1810.0	1900.0	*1875*	*2000*	Revenues ($mill)	*2175*
64.0	71.0	145.0	87.0	95.0	125.0	147.0	141.0	137.0	175.0	*180*	*215*	Net Profit ($mill)	*255*
40.2%	33.6%	33.8%	28.7%	28.8%	30.5%	28.3%	31.4%	23.2%	26.0%	*20.0%*	*20.0%*	Income Tax Rate	*20.0%*
18.8%	33.8%	17.9%	17.2%	31.6%	17.6%	5.4%	7.1%	14.6%	33.7%	*14.0%*	*7.0%*	AFUDC % to Net Profit	*3.0%*
42.3%	43.4%	49.9%	46.2%	50.3%	53.0%	49.6%	47.1%	51.3%	52.7%	*48.5%*	*48.5%*	Long-Term Debt Ratio	*48.5%*
57.7%	56.6%	50.1%	53.8%	49.7%	47.0%	50.4%	52.9%	48.7%	47.3%	*51.5%*	*51.5%*	Common Equity Ratio	*51.5%*
2076.0	2161.0	2629.0	2518.0	3100.0	3390.0	3298.0	3264.0	3735.0	4037.0	*4405*	*4625*	Total Capital ($mill)	*5300*
2436.0	2718.0	3066.0	3301.0	3858.0	4133.0	4285.0	4392.0	4880.0	5679.0	*6010*	*6085*	Net Plant ($mill)	*6000*
4.6%	4.7%	6.9%	5.0%	4.5%	5.4%	6.2%	5.9%	5.1%	5.8%	*5.5%*	*6.0%*	Return on Total Cap'l	*6.0%*
5.3%	5.8%	11.0%	6.4%	6.2%	7.9%	8.8%	8.2%	7.5%	9.2%	*8.0%*	*9.0%*	Return on Shr. Equity	*9.5%*
5.3%	5.8%	11.0%	6.4%	6.2%	7.9%	8.8%	8.2%	7.5%	9.2%	*8.0%*	*9.0%*	Return on Com Equity [E]	*9.5%*
5.3%	3.5%	6.6%	2.0%	1.5%	3.0%	4.1%	3.5%	2.9%	4.6%	*3.5%*	*4.5%*	Retained to Com Eq	*4.5%*
--	39%	40%	69%	76%	62%	54%	57%	61%	50%	*54%*	*52%*	All Div'ds to Net Prof	*53%*

CAPITAL STRUCTURE as of 3/31/15
Total Debt $2456 mill. Due in 5 Yrs $822 mill.
LT Debt $2134 mill. LT Interest $113 mill.
(LT interest earned: 2.3x)
Leases, Uncapitalized Annual rentals $10 mill.

Pension Assets-12/14 $591 mill. Oblig. $777 mill.

Pfd Stock None

Common Stock 78,344,941 shs. as of 4/22/15

MARKET CAP: $2.7 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2012	2013	2014
% Change Retail Sales (KWH)	-.8	+1.2	-.8
Avg. Indust. Use (MWH)	16409	16258	16577
Avg. Indust. Revs. per KWH (¢)	5.26	4.84	5.13
Capacity at Peak (Mw)	4173	4380	4910
Peak Load, Winter (Mw) [F]	3597	3869	3866
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.7	+.9	+.7
Fixed Charge Cov. (%)	270	239	248

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '12-'14 to '18-'20
Revenues	--	-2.0%	.5%
"Cash Flow"	--	3.0%	4.5%
Earnings	--	3.0%	6.0%
Dividends	--	2.5%	5.5%
Book Value	--	2.0%	4.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	479.0	413.0	450.0	463.0	1805.0
2013	473.0	403.0	435.0	499.0	1810.0
2014	493.0	423.0	484.0	500.0	1900.0
2015	473.0	*440*	*485*	*477*	*1875*
2016	*525*	*460*	*505*	*510*	*2000*

Cal-endar	EARNINGS PER SHARE [A] Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.65	.34	.50	.38	1.87
2013	.65	.13	.40	.59	1.77
2014	.73	.43	.47	.55	2.18
2015	.62	*.45*	*.50*	*.58*	*2.15*
2016	*.80*	*.47*	*.53*	*.60*	*2.40*

Cal-endar	QUARTERLY DIVIDENDS PAID [B] ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.26	.26	.265	.265	1.05
2012	.265	.265	.27	.27	1.07
2013	.27	.27	.275	.275	1.09
2014	.275	.275	.28	.28	1.11
2015	.28	.28	.30		

BUSINESS: Portland General Electric Company (PGE) provides electricity to 844,000 customers in 52 cities in a 4,000-square-mile area of Oregon, including Portland and Salem. The company is in the process of decommissioning the Trojan nuclear plant, which it closed in 1993. Electric revenue breakdown: residential, 47%; commercial, 34%; industrial, 12%; other, 7%. Generating sources: coal, 21%; gas, 16%; hydro, 8%; wind, 6%; purchased, 49%. Fuel costs: 38% of revenues. '14 reported depreciation rate: 3.6%. Has 2,600 employees. Chairman: Jack E. Davis. President and Chief Executive Officer: James J. Piro. Incorporated: Oregon. Address: 121 S.W. Salmon Street, Portland, Oregon 97204. Telephone: 503-464-8000. Internet: www.portlandgeneral.com.

Portland General Electric has settled most issues of its rate case. The utility is seeking a rate hike of $17.8 million, which would take effect at the start of 2016. PGE is building a 440-megawatt gas-fired generating plant, which is expected to go on line in the second quarter of 2016 at a cost of $450 million. The utility is asking for an additional tariff hike of $84.7 million that would take effect when the new generating facility becomes used and useful. The application is based on a return of 9.9% on a common-equity ratio of 50%. PGE has reached a settlement with the staff of the Oregon Public Utility Commission (OPUC) and some intervenors on all issues except one that is related to power costs. However, details of the settlement will not be available for at least a few weeks. The OPUC's order is expected in late 2015.

The board of directors raised the dividend significantly. It increased the quarterly disbursement by two cents a share (7.1%). This was by far the biggest hike since PGE reemerged as a public company in 2006. There was plenty of room for the directors to boost the dividend, considering that the payout ratio remains near the low end of the company's targeted range of 50%-70%. PGE has established a goal of 5%-7% annual dividend growth.

We have lowered our 2015 earnings estimate by $0.15 a share. The utility's service area had the warmest winter on record, which reduced profits by $0.20 a share versus normal weather. Management has cut its earnings guidance by $0.15, to $2.05-$2.20 a share. PGE believes it can make up part of the lost income through cost reductions.

We forecast much higher profits next year. This is based on the expectation of rate relief from the aforementioned rate case, and the assumption that the winter weather patterns will be normal.

This untimely stock's dividend yield and 3- to 5-year total return potential are slightly below the utility averages. The stock's valuation might well reflect some takeover speculation, but we would not buy it in the hope of a buyout. A takeover attempt more than 10 years ago proved to be unsuccessful.

Paul E. Debbas, CFA *July 31, 2015*

(A) Diluted EPS. Excl. nonrecurring loss: '13, 42¢. Next earnings report due late Oct. (B) Dividends paid mid-Jan., Apr., July, and Oct. ■ Dividend reinvestment plan avail. † Shareholder investment plan avail. (C) Incl. deferred charges. In '14: $6.31/sh. (D) In mill. (E) Rate base: Net original cost. Rate allowed on com. eq. in '15: 9.68%; earned on avg. com. eq., '14: 9.4%. Regulatory Climate: Below Average. (F) Summer peak in '12. (G) '05 per-share data are pro forma, based on shares outstanding when stock began trading in '06.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	55
Earnings Predictability	65

SOUTHERN COMPANY NYSE-SO

RECENT PRICE	P/E RATIO	(Trailing / Median)	RELATIVE P/E RATIO	DIV'D YLD	
45.91	16.5	(Trailing: 17.1 / Median: 16.0)	0.91	4.8%	VALUE LINE

TIMELINESS 4 Lowered 7/17/15
SAFETY 2 Lowered 2/21/14
TECHNICAL 5 Lowered 8/7/15
BETA .55 (1.00 = Market)

High:	34.0	36.5	37.4	39.3	40.6	37.6	38.6	46.7	48.6	48.7	51.3	53.2		
Low:	27.4	31.1	30.5	33.2	29.8	26.5	30.8	35.7	41.8	40.0	40.3	41.4		

Target Price Range 2018 | 2019 | 2020

2018-20 PROJECTIONS

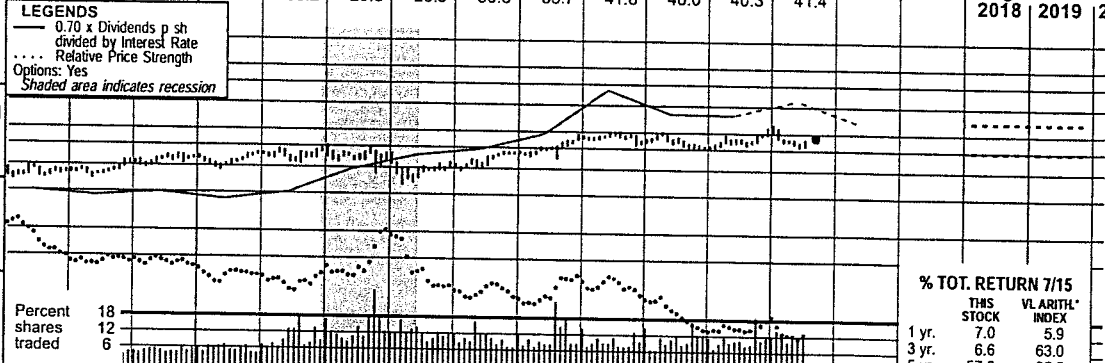
	Price	Gain	Ann'l Total Return
High	55	(+20%)	9%
Low	40	(-15%)	2%

Insider Decisions

	S	O	N	D	J	F	M	A	M
to Buy	0	0	0	0	0	0	0	0	1
Options	1	3	1	1	0	3	0	0	0
to Sell	1	3	1	1	0	3	0	0	0

Institutional Decisions

	3Q2014	4Q2014	1Q2015
to Buy	454	515	504
to Sell	370	382	444
Hld's(000)	450922	462861	452667



% TOT. RETURN 7/15

	THIS STOCK	VL ARITH.* INDEX
1 yr.	7.0	5.9
3 yr.	6.6	63.0
5 yr.	57.3	95.5

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	© VALUE LINE PUB. LLC	18-20
17.40	14.78	14.54	14.73	15.31	16.05	18.28	19.24	20.12	22.04	19.21	20.70	20.41	19.06	19.26	20.34	20.05	21.05	Revenues per sh	24.00
4.17	3.89	3.55	3.46	3.53	3.65	4.03	4.01	4.22	4.43	4.43	4.51	4.91	5.18	5.27	5.28	5.35	5.60	"Cash Flow" per sh	6.50
1.83	2.01	1.61	1.85	1.97	2.06	2.13	2.10	2.28	2.25	2.32	2.36	2.55	2.67	2.70	2.77	2.80	2.95	Earnings per sh A	3.50
1.34	1.34	1.34	1.36	1.39	1.42	1.48	1.54	1.60	1.66	1.73	1.80	1.87	1.94	2.01	2.08	2.15	2.22	Div'd Decl'd per sh B ■ †	2.43
3.85	3.27	3.75	3.79	2.72	2.85	3.20	4.01	4.65	5.10	5.70	4.85	5.23	5.54	6.16	6.58	7.35	6.00	Cap'l Spending per sh	6.50
13.82	15.69	11.43	12.16	13.13	13.86	14.42	15.24	16.23	17.08	18.15	19.21	20.32	21.09	21.43	21.98	22.55	23.25	Book Value per sh C	26.00
665.80	681.16	698.34	716.40	734.83	741.50	741.45	746.27	763.10	777.19	819.65	843.34	865.13	867.77	887.09	907.78	911.00	913.00	Common Shs Outst'g D	919.00
14.3	13.2	14.6	14.6	14.8	14.7	15.9	16.2	16.0	16.1	13.5	14.9	15.8	17.0	16.2	16.0	Bold figures are		Avg Ann'l P/E Ratio	13.5
.82	.86	.75	.80	.84	.78	.85	.87	.85	.97	.90	.95	.99	1.08	.91	.85	Value Line		Relative P/E Ratio	.85
5.1%	5.0%	5.7%	5.0%	4.7%	4.7%	4.4%	4.5%	4.4%	4.6%	5.5%	5.1%	4.6%	4.3%	4.6%	4.7%	estimates		Avg Ann'l Div'd Yield	5.2%

CAPITAL STRUCTURE as of 3/31/15
Total Debt $26078 mill. Due in 5 Yrs $10464 mill.
LT Debt $21093 mill. LT Interest $778 mill.
(LT interest earned: 5.0x)
Leases, Uncapitalized Annual rentals $100 mill.
Pension Assets-12/14 $9690 mill. Ob $10909 mill.
Pfd Stock $1352 mill. Pfd Div'd $68 mill.
Incl. 1 mill. shs. 4.2%-5.44% cum. pfd. ($100 par); 12 mill. shs. 5.2%-5.83% cum. pfd. ($1 par); 2 mill. shs. 6.0% noncum. pfd. ($25 par); 4 mill. shs. 5.6%-6.5% noncum. pfd. ($100 par); 14 mill. shs. 5.63%-6.5% noncum. pfd. ($1 par).
Common Stock 908,261,371 shs.
MARKET CAP: $42 billion (Large Cap)

2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016		18-20
13554	14356	15353	17127	15743	17456	17657	16537	17087	18467	18250	19200	Revenues ($mill)	22000
1621.0	1608.0	1782.0	1807.0	1910.0	2040.0	2268.0	2415.0	2439.0	2567.0	2635	2765	Net Profit ($mill)	3300
26.9%	32.7%	31.9%	33.6%	31.9%	33.5%	35.0%	35.6%	34.8%	33.8%	33.0%	33.0%	Income Tax Rate	33.0%
4.4%	4.8%	9.5%	12.3%	14.9%	13.7%	10.2%	9.4%	11.6%	13.9%	14.0%	13.0%	AFUDC % to Net Profit	12.0%
53.2%	50.8%	51.2%	53.9%	53.2%	51.2%	50.0%	49.9%	51.5%	49.5%	53.0%	55.0%	Long-Term Debt Ratio	57.5%
44.3%	46.2%	44.9%	42.6%	43.6%	45.7%	47.1%	47.3%	45.8%	47.3%	44.0%	42.5%	Common Equity Ratio	40.5%
24131	24618	27608	31174	34091	35438	37307	38653	41483	42142	46450	49925	Total Capital ($mill)	59200
29480	31092	33327	35878	39230	42002	45010	48390	51208	54868	59275	62375	Net Plant ($mill)	70000
8.2%	8.2%	7.9%	7.1%	6.9%	7.0%	7.2%	7.3%	6.8%	7.1%	6.5%	6.5%	Return on Total Cap'l	6.5%
14.4%	13.3%	13.2%	12.6%	12.0%	11.8%	12.2%	12.5%	12.1%	12.1%	12.0%	12.0%	Return on Shr. Equity	13.0%
14.9%	13.8%	14.0%	13.1%	12.4%	12.2%	12.5%	12.8%	12.5%	12.5%	12.5%	13.0%	Return on Com Equity E	13.5%
4.6%	3.8%	4.3%	3.5%	3.2%	3.0%	3.4%	3.6%	3.2%	3.2%	3.0%	3.0%	Retained to Com Eq	4.0%
70%	73%	70%	74%	75%	77%	73%	73%	75%	75%	76%	75%	All Div'ds to Net Prof	69%

ELECTRIC OPERATING STATISTICS

	2012	2013	2014
% Change Retail Sales (KWH)	-2.3	+.3	+3.3
Avg. Indust. Use (MWH)	3229	3277	3384
Avg. Indust. Revs. per KWH (¢)	5.94	6.08	6.37
Capacity at Yearend (Mw)	45750	45502	46549
Peak Load, Summer (Mw) F	35479	33557	37234
Annual Load Factor (%)	59.5	63.2	59.6
% Change Customers (yr-end)	+.5	+.7	+.8
Fixed Charge Cov. (%)	416	423	417

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '12-'14 to '18-'20
Revenues	2.5%	-1.0%	3.5%
"Cash Flow"	4.0%	3.5%	3.5%
Earnings	3.5%	3.5%	4.5%
Dividends	4.0%	4.0%	3.0%
Book Value	5.0%	4.5%	3.0%

Cal-endar	QUARTERLY REVENUES (mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	3604	4181	5049	3703	16537
2013	3897	4246	5017	3927	17087
2014	4644	4467	5339	4017	18467
2015	4183	4337	5580	4150	18250
2016	4400	4700	5800	4300	19200

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.42	.71	1.11	.43	2.67
2013	.47	.66	1.08	.49	2.70
2014	.66	.68	1.08	.36	2.77
2015	.56	.71	1.16	.37	2.80
2016	.55	.80	1.20	.40	2.95

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.455	.4725	.4725	.4725	1.87
2012	.4725	.49	.49	.49	1.94
2013	.49	.5075	.5075	.5075	2.01
2014	.5075	.525	.525	.525	2.08
2015	.525	.5425			

BUSINESS: The Southern Company, through its subsidiaries, supplies electricity to 4.5 million customers in about 120,000 square miles of Georgia, Alabama, Florida, and Mississippi. Also has competitive generation business. Electric revenue breakdown: residential, 37%; commercial, 31%; industrial, 19%; other, 13%. Retail revenues by state: Georgia, 51%; Alabama, 33%; Florida, 9%; Mississippi, 7%. Generating sources: coal, 39%; oil & gas, 37%; nuclear, 15%; hydro, 3%; purchased, 6%. Fuel costs: 36% of revenues. '14 reported deprec. rate (utility): 3.1%. Has 26,400 employees. Chairman, President and CEO: Thomas A. Fanning. Inc.: Delaware. Address: 30 Ivan Allen Jr. Blvd., N.W., Atlanta, Georgia 30308. Tel.: 404-506-5000. Internet: www.southerncompany.com.

Southern Company's Mississippi Power subsidiary has filed a general rate case. Mississippi Power is building a coal gasification plant that has experienced significant cost overruns. It is now expected to cost almost $5 billion. (The latest nonrecurring charge, in the June quarter, reduced share net by $0.02.) The project is already producing some electricity, but won't be completed until the second quarter of 2016. After the state Supreme Court found that a rate hike in 2013 (which put a cost cap of $2.88 billion on the project) was illegal, the commission ordered the utility to refund $353 million that it collected since then. (This benefited cash flow, but was not included in earnings, so there won't be charge for the refund.) Accordingly, Mississippi Power has filed for an interim rate hike of $159 million (18%), based on a 9.7% return on a 50% common-equity ratio, until it can get permanent tariffs in place.

The company's nuclear construction project has also had some delays and cost overruns. The latest estimate for the two units that Georgia Power is building at the Vogtle station is $7.5 billion (including financing costs) for the two units that are scheduled for completion in June of 2019 and 2020. This doesn't necessarily mean that the utility will have to take a writedown. It might be able to recoup some of the overruns from its contractors.

We estimate just a modest earnings increase in 2015. The March-quarter comparison was tough, due in part to an unusually cold winter in the first period of 2014. However, the company is benefiting from rate relief, the economic recovery in its service territory, and investments by the Southern Power nonutility subsidiary. Our estimate is within the company's guidance of $2.76-$2.88 a share.

We forecast a stronger profit increase in 2016. Rate relief, higher kilowatt-hour sales, and growth at Southern Power should continue to benefit the company.

Southern Company stock is untimely, but offers one of the highest dividend yields of any utility issue. The valuation reflects the construction risk the company is facing. Total return potential to 2018-2020 is no better than the industry average, however.

Paul E. Debbas, CFA *August 21, 2015*

(A) Diluted EPS. Excl. nonrec. gain (losses): '03, 6¢; '09, (25¢); '13, (83¢); '14, (59¢); '15, (2¢). '14 EPS don't add due to rounding. Next earnings report due late Oct. (B) Div'ds historically paid in early Mar., June, Sept., and Dec. ■ Div'd reinvest. plan avail. † Shareholder invest. plan avail. (C) Incl. def'd charges. In '14: $7.92/sh. (D) In mill. (E) Rate base: AL, MS, fair value; FL, GA, orig. cost. All'd return on com. eq. (blended): 12.5%; earn. on avg. com. eq., '14: 12.7%. Reg. Clim.: GA, AL Above Avg.; MS, FL Avg. (F) Winter peak in '14.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	40
Earnings Predictability	100

WESTAR ENERGY NYSE-WR

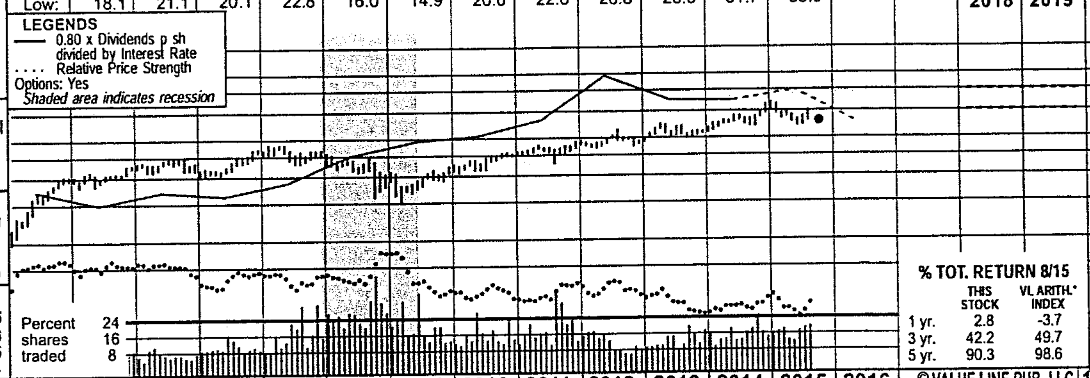
RECENT PRICE 35.94 | P/E RATIO 15.2 (Trailing: 15.8; Median: 14.0) | RELATIVE P/E RATIO 0.87 | DIV'D YLD 4.0% | VALUE LINE

High:	22.9	25.0	27.2	28.6	25.9	22.3	25.9	29.0	33.0	35.0	43.2	44.0		
Low:	18.1	21.1	20.1	22.8	16.0	14.9	20.6	22.6	26.8	28.6	31.7	33.9		

Target Price Range 2018 | 2019 | 2020

TIMELINESS 3 Lowered 12/12/14
SAFETY 2 Raised 4/1/05
TECHNICAL 2 Raised 9/18/15
BETA .75 (1.00 = Market)

LEGENDS
—— 0.80 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



2018-20 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	50	(+40%)	12%
Low	40	(+10%)	7%

Insider Decisions

	O	N	D	J	F	M	A	M	J
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	1	0	0	0	5	0	1	0

Institutional Decisions

	4Q2014	1Q2015	2Q2015
to Buy	157	134	146
to Sell	136	155	125
Hld's(000)	96912	97474	97324

Percent shares traded 24 16 8

% TOT. RETURN 8/15

	THIS STOCK	VL ARITH.* INDEX
1 yr.	2.8	-3.7
3 yr.	42.2	49.7
5 yr.	90.3	98.6

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	© VALUE LINE PUB. LLC	18-20
30.21	33.80	31.20	24.77	20.06	17.02	18.23	18.37	18.09	16.98	17.04	18.34	17.27	17.88	18.48	19.76	*19.85*	*19.75*	Revenues per sh	*20.75*
7.51	6.96	5.32	4.77	3.77	3.12	3.28	3.94	3.77	3.14	3.59	4.24	3.97	4.30	4.41	4.55	*4.70*	*4.95*	"Cash Flow" per sh	*5.25*
1.48	.89	d.58	1.00	1.48	1.17	1.55	1.88	1.84	1.31	1.28	1.80	1.79	2.15	2.27	2.35	*2.25*	*2.45*	Earnings per sh A	*3.00*
2.14	1.44	1.20	1.20	.87	.80	.92	.98	1.08	1.16	1.20	1.24	1.28	1.32	1.36	1.40	*1.44*	*1.50*	Div'd Decl'd per sh B■†	*1.65*
4.09	4.40	3.37	1.89	2.06	2.19	2.45	3.95	7.84	8.65	5.26	4.82	5.55	6.40	6.08	6.47	*7.00*	*7.20*	Cap'l Spending per sh	*8.15*
27.83	27.20	25.97	13.68	14.23	16.13	16.31	17.62	19.14	20.18	20.59	21.25	22.03	22.89	23.88	25.02	*25.60*	*26.35*	Book Value per sh C	*29.25*
67.40	70.08	70.08	71.51	72.84	86.03	86.84	87.39	95.46	108.31	109.07	112.13	125.70	126.50	128.25	131.69	*130.00*	*135.00*	Common Shs Outst'g E	*140.00*
17.2	20.6	--	14.0	10.8	17.4	14.8	12.2	14.1	17.0	14.9	13.0	14.8	13.4	14.0	15.4	*Bold figures are*		Avg Ann'l P/E Ratio	*15.0*
.98	1.34	--	.76	.62	.92	.79	.66	.75	1.02	.99	.83	.93	.85	.79	.81	*Value Line*		Relative P/E Ratio	*.95*
8.4%	7.9%	5.8%	8.6%	5.5%	3.9%	4.0%	4.3%	4.2%	5.2%	6.3%	5.3%	4.8%	4.6%	4.3%	3.9%	*estimates*		Avg Ann'l Div'd Yield	*3.7%*

CAPITAL STRUCTURE as of 6/30/15
Total Debt $3398.8 mill. Due in 5 Yrs $725.0 mill.
LT Debt $3091.7 mill. LT Interest $55.0 mill.
(LT interest earned: 2.8x)

Pension Assets 12/14 $661 mill. Oblig. $914 mill.

Pfd Stock None

Common Stock 137,412,152 shs.
MARKET CAP: $4.9 billion (Mid Cap)

2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016		18-20
1583.3	1605.7	1726.8	1839.0	1858.2	2056.2	2171.0	2261.5	2370.7	2601.7	*2580*	*2665*	Revenues ($mill)	*2800*
134.9	165.3	168.4	136.8	141.3	203.9	214.0	275.1	292.5	313.3	*295*	*335*	Net Profit ($mill)	*420*
31.0%	25.4%	27.5%	24.8%	29.4%	29.0%	35.2%	30.9%	33.1%	31.9%	*30.0%*	*30.0%*	Income Tax Rate	*30.0%*
--	--	10.4%	--	--	--	--	--	10.4%	10.0%	*10.0%*	*10.0%*	AFUDC % to Net Profit	*10.0%*
52.1%	50.0%	50.6%	49.8%	53.4%	53.6%	49.5%	51.2%	50.0%	50.0%	*50.0%*	*50.0%*	Long-Term Debt Ratio	*50.0%*
47.2%	49.3%	48.9%	49.7%	46.1%	46.0%	50.1%	48.8%	50.0%	50.0%	*50.0%*	*50.0%*	Common Equity Ratio	*50.0%*
3000.4	3124.2	3738.3	4400.1	4866.8	5180.9	5531.0	5938.2	6131.1	6596.2	*6650*	*6800*	Total Capital ($mill)	*7500*
3947.7	4071.6	4803.7	5533.5	5771.7	6309.5	6745.4	7335.7	7848.5	8441.5	*8500*	*8500*	Net Plant ($mill)	*9000*
6.2%	6.7%	5.8%	4.2%	4.4%	5.5%	5.3%	6.0%	6.1%	6.0%	*6.0%*	*6.0%*	Return on Total Cap'l	*6.0%*
9.4%	10.6%	9.1%	6.2%	6.2%	8.5%	7.7%	9.5%	9.6%	9.5%	*9.5%*	*9.5%*	Return on Shr. Equity	*9.5%*
9.5%	10.7%	9.2%	6.2%	6.3%	8.5%	7.7%	9.4%	9.6%	9.5%	*9.5%*	*9.5%*	Return on Com Equity D	*9.5%*
4.3%	5.5%	4.3%	1.2%	.8%	3.1%	2.7%	4.0%	4.2%	4.3%	*4.0%*	*4.0%*	Retained to Com Eq	*4.0%*
55%	49%	53%	80%	87%	63%	65%	57%	56%	55%	*61%*	*59%*	All Div'ds to Net Prof	*55%*

ELECTRIC OPERATING STATISTICS

	2012	2013	2014
% Change Retail Sales (KWH)	-1.5	+3.6	+1.5
Avg. Indust. Use (MWH)	5588	5407	5747
Avg. Indust. Revs. per KWH (¢)	6.60	6.47	6.72
Capacity at Peak (Mw)	6557	6671	6698
Peak Load, Summer (Mw)	5411	5489	5226
Annual Load Factor (%)	56.0	55.9	56.2
% Change Customers (yr-end)	+.2	+.2	+.2
Fixed Charge Cov. (%)	319	323	332

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '12-'14 to '18-'20
Revenues	-1.0%	1.5%	2.5%
"Cash Flow"	1.5%	5.0%	4.5%
Earnings	6.5%	9.0%	6.0%
Dividends	3.5%	3.5%	3.0%
Book Value	5.0%	3.5%	5.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	475.7	566.3	695.8	523.7	2261.5
2013	546.2	569.6	695.0	559.9	2370.7
2014	628.6	612.7	764.0	596.4	2601.7
2015	590.8	589.6	*784*	*615.6*	*2580*
2016	*650*	*645*	*775*	*595*	*2665*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.21	.48	1.09	.37	2.15
2013	.40	.52	1.04	.31	2.27
2014	.52	.40	1.10	.33	2.35
2015	.38	.46	*1.05*	*.36*	*2.25*
2016	*.50*	*.45*	*1.15*	*.35*	*2.45*

Cal-endar	QUARTERLY DIVIDENDS PAID B■† Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.31	.32	.32	.32	1.27
2012	.32	.33	.33	.33	1.31
2013	.33	.34	.34	.34	1.35
2014	.34	.35	.35	.35	1.39
2015	.36	.36	.36		

BUSINESS: Westar Energy, Inc., formerly Western Resources, is the parent of Kansas Gas & Electric Company. Westar supplies electricity to 700,000 customers in Kansas. Electric revenue sources: residential and rural, 41%; commercial, 38%; industrial, 21%. Sold investment in ONEOK in 2003 and 85% ownership in Protection One in 2004. 2014 depreciation rate: 3.9%. Estimated plant age: 16 years. Fuels: coal, 48%; nuclear, 8%; gas, 44%. Has 2,411 employees. BlackRock Inc owns 7.2% of common; The Vanguard Group owns 6.3%; Stowers Institute owns 5.7% (4/15 proxy). CEO and Pres.: Mark A. Ruelle. Inc.: Kansas. Addr.: 818 South Kansas Avenue, Topeka, Kansas 66612. Telephone: 785-575-6300. Internet: www.westarenergy.com.

Westar Energy's rate case before the Kansas Corporation Commission (KCC) has taken a turn. In March, the utility sought to raise customer rates 8%, or $152 million, but has since cut that number by half, to about a 4% hike, or $78 million. The case is now under review by the KCC, which has until October 28th to accept, decline, or revise the proposed agreement. Management believes that the increases are necessary to help cover the cost of plant upgrades and regulatory compliance. The company also proposed a five-year, $220 million plan to upgrade its electrical grid and a 10% annual profit for shareholders.

Costs for the recently completed air quality controls at the La Cygne Energy Center came in $22 million below expectations. This was the primary reason that management revised its rate requests lower. The company also spent less than originally forecasted on the life extension of the Wolf Creek facility.

New regulation from the Environmental Protection Agency (EPA) should prompt further overhauls. The Clean Power Plan is a set of rules meant to limit the amount of carbon emissions from utilities. The plan was announced just a few weeks ago and will likely be challenged in the courts by several different opponents. However, carbon emissions regulation is not going away, and management seems cognizant of the fact that it needs to upgrade its coal-based plants to cleaner energy, like natural gas.

Lower oil prices have been a drag lately. Industrial customers, such as chemical manufacturers and pipeline operators, have taken a big hit due to lower oil prices and have thus cut their energy usage by several megawatts. On the positive side, refineries and consumer discretionary-based customers remain in good shape. Management also announced that a large confectionery company is planning a big expansion that should add a few megawatts to sales.

At recent prices, Westar's dividend yield is around average for electric utilities. That said, conservative investors may still want to look here as the combination of appreciation potential and safety is still attractive.

Daniel Henigson *September 18, 2015*

(A) EPS diluted from 2010 onward. Excl. non-recur. gains (losses): '99, ($1.31); '00, $1.07; '01, 27¢; '02, ($12.06); '03, 77¢; '08, 39¢; '11, 14¢. Earnings may not sum due to rounding. Next egs. rep't due early November. (B) Div'ds paid in early Jan., April, July, and Oct. ■ Div'd reinvest. plan avail. † Shareholder invest. plan avail. (C) Incl. reg. assets. In 2014: $6.48/sh. (D) Rate base determined: fair value; Rate allowed on common equity in '14: 10.0%; earned on avg. com. eq., '14: 9.5%. Regul. Clim.: Avg. (E) In mill.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	75
Earnings Predictability	90

ATTACHMENT C

Thu, Oct 29, 2015, 6:17PM EDT - U.S. Markets closed Report an Issue

Dow 0.13%

ALLETE, Inc. (ALE) - NYSE

49.90 0.43(0.85%) 4:02PM EDT

Analyst Estimates

Get Analyst Estimates for: GO

Earnings Est	Current Qtr. Sep 15	Next Qtr. Dec 15	Current Year Dec 15	Next Year Dec 16
Avg. Estimate	1.02	0.88	3.26	3.37
No. of Analysts	6.00	5.00	5.00	7.00
Low Estimate	0.95	0.71	3.05	3.27
High Estimate	1.11	0.99	3.35	3.60
Year Ago EPS	0.97	0.73	2.99	3.26

Next Earnings Date: Nov 3, 2015 - Set a Reminder

Revenue Est	Current Qtr. Sep 15	Next Qtr. Dec 15	Current Year Dec 15	Next Year Dec 16
Avg. Estimate	354.00M	353.00M	1.27B	1.33B
No. of Analysts	1	1	5	5
Low Estimate	354.00M	353.00M	1.11B	1.15B
High Estimate	354.00M	353.00M	1.35B	1.47B
Year Ago Sales	288.90M	290.70M	1.14B	1.27B
Sales Growth (year/est)	22.50%	21.40%	11.40%	5.10%

Earnings History	Sep 14	Dec 14	Mar 15	Jun 15
EPS Est	0.72	0.68	0.87	0.50
EPS Actual	0.97	0.73	0.91	0.48
Difference	0.25	0.05	0.04	-0.02
Surprise %	34.70%	7.40%	4.60%	-4.00%

EPS Trends	Current Qtr. Sep 15	Next Qtr. Dec 15	Current Year Dec 15	Next Year Dec 16
Current Estimate	1.02	0.88	3.26	3.37
7 Days Ago	1.02	0.88	3.26	3.37
30 Days Ago	1.00	0.91	3.25	3.39
60 Days Ago	1.00	0.91	3.25	3.39
90 Days Ago	1.03	0.83	3.13	3.39

EPS Revisions	Current Qtr. Sep 15	Next Qtr. Dec 15	Current Year Dec 15	Next Year Dec 16
Up Last 7 Days	1	0	0	0
Up Last 30 Days	1	0	0	0
Down Last 30 Days	0	0	0	0
Down Last 90 Days	N/A	N/A	N/A	N/A

Growth Est	ALE	Industry	Sector	S&P 500
Current Qtr.	5.20%	0.90%	-27.20%	3.30%
Next Qtr.	20.50%	-7.30%	90.60%	8.10%
This Year	9.00%	5.50%	32.60%	-1.60%
Next Year	3.40%	6.10%	22.40%	9.40%
Past 5 Years (per annum)	6.79%	N/A	N/A	N/A
Next 5 Years (per annum)	5.50%	7.41%	6.67%	6.10%
Price/Earnings (avg. for comparison categories)	15.67	37.89	20.76	16.34
PEG Ratio (avg. for comparison categories)	2.85	13.73	6.72	2.94

Currency in USD.

ALLETE, Inc. (ALE) - NYSE

49.90 0.43(0.85%) 4:02PM EDT

Historical Prices

Get Historical Prices for: GO

Set Date Range

Start Date: Jul 1 2015 Eg. Jan 1, 2010
End Date: Sep 30 2015

Daily
Weekly
Monthly
Dividends Only

Get Prices

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Prices

Date	Open	High	Low	Close	Volume	Adj Close*
Sep 30, 2015	49.47	50.65	49.38	50.49	283,900	50.49
Sep 29, 2015	50.14	50.62	49.24	49.32	252,100	49.32
Sep 28, 2015	50.01	50.50	49.03	50.13	328,600	50.13
Sep 25, 2015	49.46	51.13	49.25	50.20	250,900	50.20
Sep 24, 2015	48.70	49.54	48.37	49.43	181,800	49.43
Sep 23, 2015	48.33	48.78	48.18	48.73	203,400	48.73
Sep 22, 2015	48.15	48.66	47.91	48.22	169,200	48.22
Sep 21, 2015	48.69	48.83	48.36	48.49	111,500	48.49
Sep 18, 2015	48.36	49.15	48.25	48.32	367,500	48.32
Sep 17, 2015	48.39	49.46	48.19	48.83	143,700	48.83
Sep 16, 2015	48.12	48.81	47.84	48.49	119,700	48.49
Sep 15, 2015	48.06	48.15	47.64	48.05	100,900	48.05
Sep 14, 2015	48.17	48.58	47.87	47.98	97,600	47.98
Sep 11, 2015	47.59	48.16	46.76	48.14	160,200	48.14
Sep 10, 2015	47.48	47.98	47.34	47.69	199,700	47.69
Sep 9, 2015	47.62	47.76	47.29	47.46	248,900	47.46
Sep 8, 2015	46.94	47.38	46.26	47.32	191,300	47.32
Sep 4, 2015	46.27	46.51	46.14	46.38	161,900	46.38
Sep 3, 2015	46.74	46.90	45.86	46.67	149,700	46.67
Sep 2, 2015	46.63	46.64	45.99	46.57	271,100	46.57
Sep 1, 2015	47.54	47.54	45.91	46.23	235,400	46.23
Aug 31, 2015	47.62	47.79	46.88	47.78	293,000	47.78
Aug 28, 2015	47.65	48.13	47.12	47.80	146,100	47.80
Aug 27, 2015	47.55	47.79	46.94	47.61	268,300	47.61
Aug 26, 2015	47.60	47.60	46.31	47.41	235,600	47.41
Aug 25, 2015	48.89	49.20	46.61	46.64	301,600	46.64
Aug 24, 2015	48.99	49.99	48.19	48.46	278,900	48.46
Aug 21, 2015	50.29	51.40	49.03	50.65	294,600	50.65
Aug 20, 2015	51.41	52.12	51.27	51.42	175,100	51.42
Aug 19, 2015	51.32	51.84	51.01	51.69	151,100	51.69
Aug 18, 2015	51.71	52.08	51.37	51.55	152,900	51.55
Aug 17, 2015	51.67	52.49	51.36	51.93	207,000	51.93
Aug 14, 2015	51.14	51.72	50.76	51.68	171,400	51.68
Aug 13, 2015	50.92	51.63	50.71	51.17	349,200	51.17
Aug 12, 2015	50.46	51.33	50.22	50.98	207,800	50.98
Aug 12, 2015			0.505 Dividend			
Aug 11, 2015	50.71	51.23	50.36	51.10	288,900	50.59
Aug 10, 2015	51.49	51.49	50.67	50.69	266,800	50.19
Aug 7, 2015	49.93	51.60	49.93	51.21	372,000	50.70
Aug 6, 2015	49.44	50.10	49.10	50.05	229,500	49.56

Aug 5, 2015	49.01	49.93	48.89	49.48	401,800	48.99
Aug 4, 2015	49.98	49.98	48.61	48.80	318,600	48.32
Aug 3, 2015	48.33	48.74	48.06	48.41	209,400	47.93
Jul 31, 2015	48.29	48.65	48.15	48.29	305,000	47.81
Jul 30, 2015	47.75	48.33	47.53	47.93	282,300	47.46
Jul 29, 2015	48.00	48.10	47.67	47.85	243,200	47.38
Jul 28, 2015	47.61	48.07	47.47	48.00	242,200	47.53
Jul 27, 2015	46.16	47.77	46.16	47.53	247,400	47.06
Jul 24, 2015	45.68	46.64	45.54	46.23	563,200	45.77
Jul 23, 2015	46.89	47.07	45.29	45.66	302,900	45.21
Jul 22, 2015	46.67	47.37	46.64	46.94	155,000	46.48
Jul 21, 2015	47.24	47.51	46.53	46.75	159,200	46.29
Jul 20, 2015	47.70	47.92	46.73	47.30	346,500	46.83
Jul 17, 2015	47.97	48.28	47.73	47.77	267,500	47.30
Jul 16, 2015	47.57	48.29	47.57	48.10	399,300	47.62
Jul 15, 2015	47.44	47.51	47.16	47.45	385,100	46.98
Jul 14, 2015	47.78	48.18	47.44	47.50	256,100	47.03
Jul 13, 2015	48.08	48.40	47.75	47.87	176,900	47.40
Jul 10, 2015	47.64	48.40	47.43	48.06	216,700	47.59
Jul 9, 2015	48.43	49.30	47.31	47.54	309,100	47.07
Jul 8, 2015	47.92	48.38	47.92	48.30	355,100	47.82
Jul 7, 2015	47.33	48.32	47.00	48.10	281,000	47.62
Jul 6, 2015	47.14	47.47	46.70	47.30	346,900	46.83
Jul 2, 2015	46.69	47.41	46.65	47.20	225,500	46.73
Jul 1, 2015	46.51	46.53	45.99	46.47	353,700	46.01

* Close price adjusted for dividends and splits.

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Currency in USD.

Thu. Oct 29, 2015, 6:24PM EDT - U.S. Markets closed Report an Issue

Dow 0.13%

American Electric Power Co., Inc. (AEP) - NYSE

56.21 0.86(1.51%) 4:04PM EDT

After Hours : **56.21** 0.00 (0.00%) 4:33PM EDT

Analyst Estimates

Get Analyst Estimates for: GO

Earnings Est	Current Qtr. Dec 15	Next Qtr. Mar 16	Current Year Dec 15	Next Year Dec 16
Avg. Estimate	0.52	1.16	3.73	3.72
No. of Analysts	13.00	7.00	22.00	22.00
Low Estimate	0.48	1.00	3.62	3.61
High Estimate	0.61	1.27	3.82	3.82
Year Ago EPS	0.48	1.28	3.43	3.73

Revenue Est	Current Qtr. Dec 15	Next Qtr. Mar 16	Current Year Dec 15	Next Year Dec 16
Avg. Estimate	4.09B	4.57B	17.51B	17.34B
No. of Analysts	7	6	13	15
Low Estimate	3.83B	4.04B	16.44B	15.50B
High Estimate	4.47B	4.92B	19.22B	18.84B
Year Ago Sales	4.00B	4.70B	17.00B	17.51B
Sales Growth (year/est)	2.20%	-2.80%	3.00%	-1.00%

Earnings History	Dec 14	Mar 15	Jun 15	Sep 15
EPS Est	0.50	1.10	0.81	1.01
EPS Actual	0.48	1.28	0.88	1.06
Difference	-0.02	0.18	0.07	0.05
Surprise %	-4.00%	16.40%	8.60%	5.00%

EPS Trends	Current Qtr. Dec 15	Next Qtr. Mar 16	Current Year Dec 15	Next Year Dec 16
Current Estimate	0.52	1.16	3.73	3.72
7 Days Ago	0.49	1.12	3.66	3.73
30 Days Ago	0.51	1.12	3.61	3.74
60 Days Ago	0.50	1.15	3.59	3.71
90 Days Ago	0.51	1.13	3.59	3.71

EPS Revisions	Current Qtr. Dec 15	Next Qtr. Mar 16	Current Year Dec 15	Next Year Dec 16
Up Last 7 Days	5	2	11	3
Up Last 30 Days	8	2	22	5
Down Last 30 Days	1	2	0	6
Down Last 90 Days	N/A	N/A	N/A	N/A

Growth Est	AEP	Industry	Sector	S&P 500
Current Qtr.	8.30%	0.90%	-27.20%	3.30%
Next Qtr.	-9.40%	-7.30%	90.60%	8.10%
This Year	8.70%	5.50%	32.60%	-1.60%
Next Year	-0.30%	6.10%	22.40%	9.40%
Past 5 Years (per annum)	4.63%	N/A	N/A	N/A
Next 5 Years (per annum)	4.63%	7.41%	6.67%	6.10%
Price/Earnings (avg. for comparison categories)	15.30	37.89	20.76	16.34
PEG Ratio (avg. for comparison categories)	3.30	13.73	6.72	2.94

Currency in USD

American Electric Power Co., Inc. (AEP) - NYSE

56.21 0.86(1.51%) 4:04PM EDT

After Hours : 56.21 0.00 (0.00%) 4:33PM EDT

Historical Prices

Get Historical Prices for: GO

Set Date Range

Start Date: Jul 1 2015 Eg. Jan 1, 2010
End Date: Sep 29 2015

Daily
Weekly
Monthly
Dividends Only

Get Prices

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Prices

Date	Open	High	Low	Close	Volume	Adj Close*
Sep 29, 2015	55.99	56.39	55.74	56.13	2,617,100	56.13
Sep 28, 2015	55.94	56.52	55.46	55.86	2,360,600	55.86
Sep 25, 2015	55.59	56.55	55.19	55.99	2,661,700	55.99
Sep 24, 2015	54.85	55.60	54.74	55.46	3,732,400	55.46
Sep 23, 2015	54.81	55.11	54.51	55.02	1,863,700	55.02
Sep 22, 2015	55.38	55.65	54.60	54.72	3,535,100	54.72
Sep 21, 2015	55.73	55.94	55.35	55.60	2,823,100	55.60
Sep 18, 2015	55.50	56.33	55.34	55.48	3,782,900	55.48
Sep 17, 2015	54.67	56.44	54.54	55.87	5,213,500	55.87
Sep 16, 2015	53.98	54.72	53.84	54.63	4,544,500	54.63
Sep 15, 2015	53.78	54.02	53.39	53.85	2,421,600	53.85
Sep 14, 2015	53.87	54.24	53.60	53.68	2,057,300	53.68
Sep 11, 2015	53.29	53.81	53.04	53.78	1,804,500	53.78
Sep 10, 2015	53.41	53.87	53.18	53.39	2,170,300	53.39
Sep 9, 2015	54.36	54.48	53.27	53.37	2,593,300	53.37
Sep 8, 2015	53.23	54.09	53.23	54.08	3,135,200	54.08
Sep 4, 2015	52.96	53.07	52.29	52.54	2,595,300	52.54
Sep 3, 2015	53.05	53.53	53.00	53.35	2,339,600	53.35
Sep 2, 2015	53.38	53.41	52.46	53.01	2,459,000	53.01
Sep 1, 2015	53.74	53.93	52.65	52.99	3,281,700	52.99
Aug 31, 2015	54.55	54.69	53.82	54.29	3,581,600	54.29
Aug 28, 2015	54.85	55.38	54.07	54.90	2,105,500	54.90
Aug 27, 2015	54.58	54.93	54.11	54.91	2,895,400	54.91
Aug 26, 2015	53.53	54.21	52.80	54.01	4,401,100	54.01
Aug 25, 2015	55.02	55.65	53.00	53.02	4,959,600	53.02
Aug 24, 2015	55.29	56.77	53.03	54.83	5,634,700	54.83
Aug 21, 2015	57.97	58.36	57.22	57.29	3,929,400	57.29
Aug 20, 2015	58.42	59.18	58.12	58.37	1,854,700	58.37
Aug 19, 2015	58.01	58.96	57.82	58.80	2,319,000	58.80
Aug 18, 2015	58.20	58.37	57.96	58.27	1,954,000	58.27
Aug 17, 2015	58.19	58.67	57.99	58.35	2,192,300	58.35
Aug 14, 2015	57.57	58.21	57.09	58.20	1,933,500	58.20
Aug 13, 2015	57.33	57.74	56.88	57.55	1,873,100	57.55
Aug 12, 2015	56.85	57.77	56.60	57.57	2,444,800	57.57
Aug 11, 2015	56.70	57.38	56.46	56.85	2,379,900	56.85
Aug 10, 2015	56.81	57.07	56.54	56.71	2,508,800	56.71
Aug 7, 2015	56.15	57.08	55.78	56.77	2,036,900	56.77
Aug 6, 2015	56.03	56.32	55.34	56.26	2,204,900	56.26
Aug 6, 2015	56.59	56.85	56.24 0.53 Dividend	56.65	2,305,200	56.12

Aug 4, 2015	57.03	57.14	56.28	56.39	2,200,000	55.86
Aug 3, 2015	56.78	57.25	56.65	57.06	2,458,600	56.53
Jul 31, 2015	56.79	57.22	56.48	56.57	2,414,600	56.04
Jul 30, 2015	55.66	56.61	55.57	56.32	1,994,100	55.79
Jul 29, 2015	55.75	56.00	55.38	55.94	2,497,200	55.42
Jul 28, 2015	55.64	56.03	55.52	55.89	2,687,100	55.37
Jul 27, 2015	54.66	56.03	54.62	55.74	2,789,900	55.22
Jul 24, 2015	54.51	54.78	54.17	54.60	3,025,400	54.09
Jul 23, 2015	55.33	55.33	54.22	54.59	3,534,300	54.08
Jul 22, 2015	54.97	55.55	54.89	55.21	3,186,400	54.69
Jul 21, 2015	55.50	55.58	54.65	54.89	2,201,300	54.38
Jul 20, 2015	55.58	55.70	55.05	55.54	2,747,500	55.02
Jul 17, 2015	56.11	56.36	55.71	55.72	2,824,500	55.20
Jul 16, 2015	55.72	56.45	55.62	56.36	2,497,000	55.83
Jul 15, 2015	55.20	55.68	54.99	55.68	2,418,800	55.16
Jul 14, 2015	55.39	55.67	54.99	55.19	1,929,500	54.67
Jul 13, 2015	55.67	55.90	54.88	55.34	2,215,500	54.82
Jul 10, 2015	55.45	55.99	55.21	55.56	2,806,400	55.04
Jul 9, 2015	56.10	56.33	55.23	55.52	3,339,400	55.00
Jul 8, 2015	55.80	56.37	55.75	56.03	2,975,000	55.51
Jul 7, 2015	54.80	56.50	54.74	56.08	4,446,500	55.56
Jul 6, 2015	54.09	54.55	54.02	54.53	3,266,700	54.02
Jul 2, 2015	53.52	54.33	53.51	54.23	2,125,300	53.72
Jul 1, 2015	53.00	53.37	52.76	53.29	2,664,500	52.79

* Close price adjusted for dividends and splits.

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Currency in USD.

Duke Energy Corporation (DUK) - NYSE

71.57 0.02(0.03%) 4:03PM EDT

After Hours : **71.57** 0.00 (0.00%) 5:29PM EDT

Analyst Estimates

Get Analyst Estimates for: GO

Earnings Est	Current Qtr. Sep 15	Next Qtr. Dec 15	Current Year Dec 15	Next Year Dec 16
Avg. Estimate	1.52	0.92	4.63	4.86
No. of Analysts	16.00	13.00	21.00	23.00
Low Estimate	1.41	0.79	4.53	4.69
High Estimate	1.63	1.13	4.72	4.95
Year Ago EPS	1.40	0.86	4.55	4.63

Next Earnings Date: Nov 5, 2015 - Set a Reminder

Revenue Est	Current Qtr. Sep 15	Next Qtr. Dec 15	Current Year Dec 15	Next Year Dec 16
Avg. Estimate	6.87B	6.28B	24.91B	25.69B
No. of Analysts	7	6	15	17
Low Estimate	6.60B	5.80B	24.10B	24.51B
High Estimate	7.62B	6.98B	25.71B	26.87B
Year Ago Sales	6.40B	5.56B	23.92B	24.91B
Sales Growth (year/est)	7.50%	12.90%	4.10%	3.10%

Earnings History	Sep 14	Dec 14	Mar 15	Jun 15
EPS Est	1.52	0.88	1.14	0.99
EPS Actual	1.40	0.86	1.24	0.95
Difference	-0.12	-0.02	0.10	-0.04
Surprise %	-7.90%	-2.30%	8.80%	-4.00%

EPS Trends	Current Qtr. Sep 15	Next Qtr. Dec 15	Current Year Dec 15	Next Year Dec 16
Current Estimate	1.52	0.92	4.63	4.86
7 Days Ago	1.51	0.92	4.64	4.87
30 Days Ago	1.54	0.90	4.64	4.90
60 Days Ago	1.52	0.89	4.63	4.90
90 Days Ago	1.54	0.93	4.67	4.93

EPS Revisions	Current Qtr. Sep 15	Next Qtr. Dec 15	Current Year Dec 15	Next Year Dec 16
Up Last 7 Days	0	0	0	0
Up Last 30 Days	0	4	3	0
Down Last 30 Days	1	1	3	3
Down Last 90 Days	N/A	N/A	N/A	N/A

Growth Est	DUK	Industry	Sector	S&P 500
Current Qtr.	8.60%	0.90%	-27.20%	3.30%
Next Qtr.	7.00%	-7.30%	90.60%	8.10%
This Year	1.80%	5.50%	32.60%	-1.60%
Next Year	5.00%	6.10%	22.40%	9.40%
Past 5 Years (per annum)	1.02%	N/A	N/A	N/A
Next 5 Years (per annum)	4.04%	7.41%	6.67%	6.10%
Price/Earnings (avg. for comparison categories)	15.45	37.89	20.76	16.34
PEG Ratio (avg. for comparison categories)	3.82	13.73	6.72	2.94

Currency in USD.

Duke Energy Corporation (DUK) - NYSE

71.57 0.02(0.03%) 4:03PM EDT

After Hours : **71.57** 0.00 (0.00%) 5:29PM EDT

Historical Prices

Get Historical Prices for: GO

Set Date Range

Start Date: Jul 1 2015 Eg. Jan 1, 2010

End Date: Sep 30 2015

◉ Daily
○ Weekly
○ Monthly
○ Dividends Only

Get Prices

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Prices

Date	Open	High	Low	Close	Volume	Adj Close*
Sep 30, 2015	70.95	72.02	70.65	71.94	3,202,100	71.94
Sep 29, 2015	70.44	70.90	70.04	70.73	2,782,500	70.73
Sep 28, 2015	70.59	71.26	70.34	70.45	3,002,400	70.45
Sep 25, 2015	70.31	71.42	69.91	70.71	3,295,700	70.71
Sep 24, 2015	68.87	70.47	68.65	70.32	3,735,500	70.32
Sep 23, 2015	69.18	69.36	68.46	69.09	1,922,600	69.09
Sep 22, 2015	69.58	70.04	68.94	69.15	3,380,300	69.15
Sep 21, 2015	69.30	70.18	69.25	70.05	2,510,900	70.05
Sep 18, 2015	69.25	70.06	69.18	69.45	5,265,100	69.45
Sep 17, 2015	69.23	70.98	69.02	69.91	4,192,900	69.91
Sep 16, 2015	68.92	69.42	68.63	69.18	3,410,400	69.18
Sep 15, 2015	68.36	68.90	67.69	68.59	2,993,200	68.59
Sep 14, 2015	68.40	68.86	68.11	68.31	2,127,800	68.31
Sep 11, 2015	67.64	68.36	67.27	68.34	3,046,100	68.34
Sep 10, 2015	68.20	68.50	67.49	67.74	3,222,600	67.74
Sep 9, 2015	69.63	69.76	68.10	68.21	3,263,100	68.21
Sep 8, 2015	68.80	69.37	68.54	69.36	2,882,800	69.36
Sep 4, 2015	68.70	68.90	67.98	68.26	3,287,700	68.26
Sep 3, 2015	69.54	69.74	69.03	69.28	2,324,700	69.28
Sep 2, 2015	69.68	69.78	68.67	69.16	3,497,900	69.16
Sep 1, 2015	70.26	70.29	68.66	69.05	3,813,100	69.05
Aug 31, 2015	71.84	72.35	70.35	70.91	4,336,000	70.91
Aug 28, 2015	72.60	72.60	71.16	72.39	3,015,900	72.39
Aug 27, 2015	72.23	72.82	71.70	72.52	4,732,000	72.52
Aug 26, 2015	71.22	71.94	70.53	71.74	6,537,400	71.74
Aug 25, 2015	73.27	74.12	70.15	70.21	5,528,100	70.21
Aug 24, 2015	74.66	75.19	72.03	72.44	7,434,200	72.44
Aug 21, 2015	76.15	77.53	75.87	76.71	6,022,900	76.71
Aug 20, 2015	76.78	77.45	76.25	76.77	3,740,000	76.77
Aug 19, 2015	76.10	77.39	75.61	77.21	4,419,200	77.21
Aug 18, 2015	76.39	76.49	76.00	76.24	2,678,300	76.24
Aug 17, 2015	76.45	76.94	76.14	76.52	2,401,600	76.52
Aug 14, 2015	75.37	76.48	75.14	76.37	2,455,800	76.37
Aug 13, 2015	75.38	75.83	74.67	75.58	2,690,600	75.58
Aug 12, 2015	74.40	76.05	74.22	75.56	4,380,600	75.56
Aug 12, 2015			0.825 Dividend			
Aug 11, 2015	75.04	75.88	74.57	75.29	3,431,800	74.46
Aug 10, 2015	75.15	75.41	74.59	74.81	3,594,500	73.99
Aug 6, 2015	73.98	75.98	73.65	75.85	6,698,600	73.03

Aug 5, 2015	74.20	74.49	73.66	73.98	1,979,300	73.17
Aug 4, 2015	74.88	74.88	73.77	73.92	2,413,800	73.11
Aug 3, 2015	74.30	75.08	74.29	74.96	2,754,400	74.14
Jul 31, 2015	74.20	74.93	74.03	74.22	2,761,200	73.41
Jul 30, 2015	72.75	73.68	72.68	73.45	2,479,200	72.65
Jul 29, 2015	72.93	73.27	72.41	73.11	2,797,100	72.31
Jul 28, 2015	72.80	73.38	72.68	73.13	3,242,800	72.33
Jul 27, 2015	71.76	73.31	71.75	73.00	3,104,000	72.20
Jul 24, 2015	71.57	72.02	71.25	71.69	1,817,700	70.90
Jul 23, 2015	72.26	72.31	71.02	71.56	3,358,700	70.78
Jul 22, 2015	72.46	73.02	72.29	72.37	3,316,600	71.58
Jul 21, 2015	73.20	73.20	72.02	72.42	2,939,800	71.63
Jul 20, 2015	73.60	73.78	72.77	73.27	2,897,000	72.47
Jul 17, 2015	74.49	74.74	73.50	73.57	3,779,600	72.76
Jul 16, 2015	74.11	74.99	74.07	74.81	3,137,300	73.99
Jul 15, 2015	73.70	74.15	73.36	74.02	2,521,500	73.21
Jul 14, 2015	74.56	74.81	73.50	73.80	3,372,500	72.99
Jul 13, 2015	74.57	74.94	73.94	74.35	2,796,000	73.54
Jul 10, 2015	74.38	75.17	73.98	74.37	2,381,600	73.56
Jul 9, 2015	74.95	75.23	73.69	74.07	4,500,100	73.26
Jul 8, 2015	74.83	75.57	74.70	74.79	2,918,900	73.97
Jul 7, 2015	73.22	75.71	73.22	75.27	6,836,500	74.45
Jul 6, 2015	72.37	73.00	72.22	72.85	2,830,200	72.05
Jul 2, 2015	71.68	72.64	71.43	72.53	3,377,400	71.74
Jul 1, 2015	70.80	71.12	70.24	71.08	2,372,500	70.30

* Close price adjusted for dividends and splits.

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Currency in USD.

El Paso Electric Co. (EE)- NYSE

38.31 0.49(1.26%) 4:02PM EDT

Analyst Estimates

Get Analyst Estimates for: GO

Earnings Est	Current Qtr. Sep 15	Next Qtr. Dec 15	Current Year Dec 15	Next Year Dec 16
Avg. Estimate	1.20	0.10	1.98	2.56
No. of Analysts	3.00	1.00	5.00	5.00
Low Estimate	1.15	0.10	1.95	2.50
High Estimate	1.30	0.10	2.00	2.65
Year Ago EPS	1.30	0.10	2.27	1.98

Next Earnings Date: Nov 4, 2015 - Set a Reminder

Revenue Est	Current Qtr. Sep 15	Next Qtr. Dec 15	Current Year Dec 15	Next Year Dec 16
Avg. Estimate	NaN	NaN	911.04M	938.53M
No. of Analysts			2	2
Low Estimate	NaN	NaN	895.57M	937.26M
High Estimate	NaN	NaN	926.50M	939.80M
Year Ago Sales	NaN	NaN	601.72M	911.04M
Sales Growth (year/est)	N/A	N/A	51.40%	3.00%

Earnings History	Sep 14	Dec 14	Mar 15	Jun 15
EPS Est	1.31	0.11	0.12	0.60
EPS Actual	1.30	0.10	0.09	0.52
Difference	-0.01	-0.01	-0.03	-0.08
Surprise %	-0.80%	-9.10%	-25.00%	-13.30%

EPS Trends	Current Qtr. Sep 15	Next Qtr. Dec 15	Current Year Dec 15	Next Year Dec 16
Current Estimate	1.20	0.10	1.98	2.56
7 Days Ago	1.20	0.10	1.98	2.56
30 Days Ago	1.23	0.10	1.98	2.56
60 Days Ago	1.23	0.10	1.98	2.56
90 Days Ago	1.23	0.10	2.00	2.58

EPS Revisions	Current Qtr. Sep 15	Next Qtr. Dec 15	Current Year Dec 15	Next Year Dec 16
Up Last 7 Days	0	0	0	0
Up Last 30 Days	0	0	0	0
Down Last 30 Days	0	0	0	0
Down Last 90 Days	N/A	N/A	N/A	N/A

Growth Est	EE	Industry	Sector	S&P 500
Current Qtr.	-7.70%	0.90%	-27.20%	3.30%
Next Qtr.	0.00%	-7.30%	90.60%	8.10%
This Year	-12.80%	5.50%	32.60%	-1.60%
Next Year	29.30%	6.10%	22.40%	9.40%
Past 5 Years (per annum)	-11.96%	N/A	N/A	N/A
Next 5 Years (per annum)	7.00%	7.41%	6.67%	6.10%
Price/Earnings (avg. for comparison categories)	19.68	37.89	20.76	16.34
PEG Ratio (avg. for comparison categories)	2.81	13.73	6.72	2.94

Currency in USD.

El Paso Electric Co. (EE) - NYSE

38.31 0.49(1.26%) 4:02PM EDT

Historical Prices

Get Historical Prices for: GO

Set Date Range

Start Date: Jul 1 2015 Eg. Jan 1, 2010
End Date: Sep 30 2015

◉ Daily
○ Weekly
○ Monthly
○ Dividends Only

Get Prices

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Prices

Date	Open	High	Low	Close	Volume	Adj Close*
Sep 30, 2015	36.68	37.00	36.45	36.82	125,700	36.82
Sep 29, 2015	36.52	36.92	36.32	36.48	113,200	36.48
Sep 28, 2015	36.28	36.66	36.17	36.55	113,500	36.55
Sep 25, 2015	36.21	36.83	35.76	36.28	157,500	36.28
Sep 24, 2015	35.39	36.19	35.31	36.11	121,700	36.11
Sep 23, 2015	35.52	35.71	35.15	35.52	159,500	35.52
Sep 22, 2015	35.63	35.94	35.22	35.48	141,600	35.48
Sep 21, 2015	35.52	35.95	35.28	35.81	96,300	35.81
Sep 18, 2015	35.25	35.87	35.05	35.41	262,600	35.41
Sep 17, 2015	34.82	35.95	34.75	35.65	131,100	35.65
Sep 16, 2015	34.69	35.11	34.66	34.96	209,400	34.96
Sep 15, 2015	34.21	34.75	34.17	34.68	114,900	34.68
Sep 14, 2015	34.55	34.70	34.13	34.19	271,700	34.19
Sep 14, 2015			0.295 Dividend			
Sep 11, 2015	34.28	34.73	34.21	34.72	70,700	34.43
Sep 10, 2015	34.64	34.90	34.32	34.37	103,000	34.08
Sep 9, 2015	35.20	35.85	34.60	34.66	119,100	34.37
Sep 8, 2015	34.68	35.14	34.33	35.07	127,700	34.77
Sep 4, 2015	34.18	34.33	33.90	34.20	119,800	33.91
Sep 3, 2015	34.59	35.17	34.29	34.56	188,000	34.27
Sep 2, 2015	34.78	34.78	34.12	34.36	202,400	34.07
Sep 1, 2015	34.98	35.11	34.17	34.45	188,800	34.16
Aug 31, 2015	35.92	35.92	34.95	35.40	176,600	35.10
Aug 28, 2015	35.52	36.03	35.12	35.99	191,700	35.68
Aug 27, 2015	35.49	35.67	34.80	35.61	138,400	35.31
Aug 26, 2015	35.28	35.30	34.51	35.19	134,100	34.89
Aug 25, 2015	36.32	36.34	34.67	34.71	289,200	34.42
Aug 24, 2015	36.09	36.26	35.72	35.81	234,500	35.51
Aug 21, 2015	37.65	37.96	36.91	37.30	224,100	36.98
Aug 20, 2015	37.40	38.08	37.21	37.76	171,200	37.44
Aug 19, 2015	37.47	38.05	36.92	37.74	112,800	37.42
Aug 18, 2015	37.78	38.07	37.67	37.75	128,700	37.43
Aug 17, 2015	37.82	38.32	37.69	38.03	107,200	37.71
Aug 14, 2015	37.22	37.85	37.10	37.82	102,000	37.50
Aug 13, 2015	37.11	37.63	36.85	37.31	219,800	36.99
Aug 12, 2015	36.71	37.31	36.71	37.23	84,600	36.91
Aug 11, 2015	36.37	36.89	36.26	36.86	90,600	36.55
Aug 10, 2015	36.72	36.92	36.35	36.40	112,400	36.09
Aug 7, 2015	36.06	36.81	35.93	36.62	198,200	36.31
Aug 6, 2015	36.31	36.76	35.85	36.29	135,500	35.98

Aug 5, 2015	35.94	36.52	35.94	36.35	157,300	36.04
Aug 4, 2015	36.43	36.43	35.85	35.94	142,300	35.63
Aug 3, 2015	36.41	36.68	36.10	36.47	134,400	36.16
Jul 31, 2015	36.29	36.73	36.16	36.43	238,400	36.12
Jul 30, 2015	35.50	36.31	35.50	36.02	161,600	35.71
Jul 29, 2015	35.59	35.77	35.41	35.65	133,900	35.35
Jul 28, 2015	35.34	35.65	35.06	35.61	113,900	35.31
Jul 27, 2015	34.75	35.37	34.75	35.35	295,700	35.05
Jul 24, 2015	34.63	34.93	34.62	34.72	167,900	34.43
Jul 23, 2015	35.02	35.08	34.43	34.77	234,400	34.47
Jul 22, 2015	35.06	35.75	34.98	35.00	350,000	34.70
Jul 21, 2015	35.54	35.69	35.05	35.19	109,300	34.89
Jul 20, 2015	36.08	36.08	35.48	35.60	256,500	35.30
Jul 17, 2015	36.54	36.54	35.98	36.08	205,700	35.77
Jul 16, 2015	36.01	36.71	35.51	36.65	112,800	36.34
Jul 15, 2015	36.07	36.16	35.65	36.04	147,100	35.73
Jul 14, 2015	36.26	36.35	35.93	36.09	85,700	35.78
Jul 13, 2015	36.46	36.70	35.95	36.30	136,200	35.99
Jul 10, 2015	35.84	36.54	35.77	36.45	137,800	36.14
Jul 9, 2015	35.99	36.12	35.63	35.78	197,000	35.48
Jul 8, 2015	36.10	36.54	35.79	35.98	210,400	35.67
Jul 7, 2015	35.80	36.50	35.48	36.26	213,600	35.95
Jul 6, 2015	35.48	35.91	35.33	35.74	109,300	35.44
Jul 2, 2015	35.15	35.68	35.13	35.67	129,900	35.37
Jul 1, 2015	34.68	35.02	34.41	34.86	130,400	34.56

* Close price adjusted for dividends and splits.

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Currency in USD.

The Empire District Electric Company (EDE) - NYSE

23.41 0.58(2.42%) 4:00PM EDT

Analyst Estimates

Earnings Est	Current Qtr. Sep 15	Next Qtr. Dec 15	Current Year Dec 15	Next Year Dec 16
Avg. Estimate	0.59	0.31	1.39	1.51
No. of Analysts	3.00	2.00	4.00	4.00
Low Estimate	0.57	0.29	1.38	1.47
High Estimate	0.60	0.33	1.40	1.55
Year Ago EPS	0.55	0.26	1.55	1.39

Next Earnings Date: Oct 29, 2015 - Set a Reminder

Revenue Est	Current Qtr. Sep 15	Next Qtr. Dec 15	Current Year Dec 15	Next Year Dec 16
Avg. Estimate	161.57M	170.94M	653.99M	681.59M
No. of Analysts	1	1	4	4
Low Estimate	161.57M	170.94M	631.43M	655.76M
High Estimate	161.57M	170.94M	676.10M	716.00M
Year Ago Sales	171.51M	151.40M	652.30M	653.99M
Sales Growth (year/est)	-5.80%	12.90%	0.30%	4.20%

Earnings History	Sep 14	Dec 14	Mar 15	Jun 15
EPS Est	0.45	0.26	0.34	0.24
EPS Actual	0.55	0.26	0.34	0.15
Difference	0.10	0.00	0.00	-0.09
Surprise %	22.20%	0.00%	0.00%	-37.50%

EPS Trends	Current Qtr. Sep 15	Next Qtr. Dec 15	Current Year Dec 15	Next Year Dec 16
Current Estimate	0.59	0.31	1.39	1.51
7 Days Ago	0.59	0.31	1.39	1.51
30 Days Ago	0.55	0.35	1.39	1.51
60 Days Ago	0.55	0.35	1.39	1.51
90 Days Ago	0.52	0.30	1.39	1.51

EPS Revisions	Current Qtr. Sep 15	Next Qtr. Dec 15	Current Year Dec 15	Next Year Dec 16
Up Last 7 Days	1	0	0	0
Up Last 30 Days	1	0	0	0
Down Last 30 Days	0	1	0	0
Down Last 90 Days	N/A	N/A	N/A	N/A

Growth Est	EDE	Industry	Sector	S&P 500
Current Qtr.	7.30%	58.20%	-27.20%	3.30%
Next Qtr.	19.20%	80.90%	90.60%	8.10%
This Year	-10.30%	9.70%	32.60%	-1.60%
Next Year	8.60%	11.50%	22.40%	9.40%
Past 5 Years (per annum)	2.41%	N/A	N/A	N/A
Next 5 Years (per annum)	4.00%	5.81%	6.67%	6.10%
Price/Earnings (avg. for comparison categories)	17.21	-5.34	20.76	16.34
PEG Ratio (avg. for comparison categories)	4.30	5.67	6.72	2.94

Currency in USD.

The Empire District Electric Company (EDE)- NYSE

23.41 0.58(2.42%) 4:00PM EDT

Historical Prices

Get Historical Prices for: GO

Set Date Range

Start Date: Jul 1 2015 Eg. Jan 1, 2010
End Date: Sep 30 2015

- (●) Daily
- ( ) Weekly
- ( ) Monthly
- ( ) Dividends Only

Get Prices

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Prices

Date	Open	High	Low	Close	Volume	Adj Close*
Sep 30, 2015	21.99	22.13	21.77	22.03	203,300	22.03
Sep 29, 2015	21.97	22.12	21.82	21.90	174,900	21.90
Sep 28, 2015	22.00	22.21	21.88	21.95	184,100	21.95
Sep 25, 2015	22.02	22.31	21.85	22.04	167,300	22.04
Sep 24, 2015	21.62	22.05	21.60	22.03	113,500	22.03
Sep 23, 2015	21.69	21.81	21.61	21.73	117,300	21.73
Sep 22, 2015	21.74	21.99	21.51	21.65	129,700	21.65
Sep 21, 2015	21.78	22.01	21.65	21.84	106,400	21.84
Sep 18, 2015	21.63	21.98	21.61	21.78	255,900	21.78
Sep 17, 2015	21.63	22.13	21.50	21.84	132,400	21.84
Sep 16, 2015	21.46	21.70	21.40	21.67	173,600	21.67
Sep 15, 2015	21.32	21.54	21.13	21.48	160,300	21.48
Sep 14, 2015	21.28	21.46	21.23	21.30	98,400	21.30
Sep 11, 2015	21.05	21.30	20.98	21.28	89,000	21.28
Sep 10, 2015	21.04	21.22	21.02	21.09	166,300	21.09
Sep 9, 2015	21.19	21.45	21.00	21.05	182,300	21.05
Sep 8, 2015	20.99	21.14	20.96	21.13	125,400	21.13
Sep 4, 2015	20.88	21.01	20.69	20.76	146,500	20.76
Sep 3, 2015	20.94	21.17	20.92	21.01	119,300	21.01
Sep 2, 2015	21.18	21.32	20.84	20.92	131,400	20.92
Sep 1, 2015	21.33	21.40	20.92	21.03	232,400	21.03
Aug 31, 2015	21.72	21.72	21.33	21.65	239,900	21.65
Aug 28, 2015	21.80	21.95	21.52	21.78	146,300	21.78
Aug 28, 2015			0.26 Dividend			
Aug 27, 2015	21.91	22.09	21.73	22.02	213,600	21.76
Aug 26, 2015	22.11	22.11	21.55	21.93	240,500	21.67
Aug 25, 2015	22.64	22.67	21.76	21.79	316,400	21.53
Aug 24, 2015	22.64	22.77	22.30	22.31	348,200	22.05
Aug 21, 2015	23.03	23.50	22.92	23.28	222,100	23.01
Aug 20, 2015	23.46	23.81	23.40	23.42	135,500	23.14
Aug 19, 2015	23.58	23.78	23.41	23.65	131,700	23.37
Aug 18, 2015	23.77	23.87	23.58	23.65	142,300	23.37
Aug 17, 2015	23.75	23.99	23.67	23.86	108,400	23.58
Aug 14, 2015	23.53	23.77	23.40	23.77	88,000	23.49
Aug 13, 2015	23.60	23.75	23.44	23.56	144,400	23.28
Aug 12, 2015	23.21	23.72	23.21	23.66	139,600	23.38
Aug 11, 2015	23.08	23.47	22.99	23.38	163,500	23.10
Aug 10, 2015	23.23	23.47	22.99	23.04	204,300	22.77
Aug 7, 2015	23.00	23.55	22.84	23.25	262,500	22.98
Aug 6, 2015	23.05	23.14	22.76	23.08	184,800	22.81

Aug 5, 2015	22.81	23.17	22.80	23.04	160,400	22.77
Aug 4, 2015	23.19	23.19	22.73	22.81	229,000	22.54
Aug 3, 2015	23.07	23.38	23.05	23.17	227,600	22.90
Jul 31, 2015	22.73	23.24	22.66	23.01	272,900	22.74
Jul 30, 2015	22.46	22.68	22.37	22.51	207,200	22.24
Jul 29, 2015	22.34	22.50	22.20	22.46	198,900	22.19
Jul 28, 2015	22.43	22.43	22.15	22.34	253,700	22.08
Jul 27, 2015	21.81	22.43	21.81	22.38	199,300	22.12
Jul 24, 2015	21.70	21.93	21.56	21.84	187,200	21.58
Jul 23, 2015	21.93	22.04	21.52	21.72	345,600	21.46
Jul 22, 2015	21.91	22.17	21.82	22.00	127,800	21.74
Jul 21, 2015	22.15	22.20	21.89	21.96	210,900	21.70
Jul 20, 2015	22.58	22.58	22.16	22.22	153,700	21.96
Jul 17, 2015	22.82	22.82	22.55	22.58	137,700	22.31
Jul 16, 2015	22.58	22.92	22.58	22.85	201,500	22.58
Jul 15, 2015	22.50	22.59	22.31	22.58	109,300	22.31
Jul 14, 2015	22.63	22.70	22.43	22.54	134,700	22.27
Jul 13, 2015	22.69	22.89	22.34	22.63	162,000	22.36
Jul 10, 2015	22.49	22.90	22.47	22.63	287,700	22.36
Jul 9, 2015	22.66	22.69	22.22	22.40	281,400	22.14
Jul 8, 2015	22.62	22.89	22.42	22.56	243,300	22.29
Jul 7, 2015	22.48	22.82	22.44	22.71	297,300	22.44
Jul 6, 2015	22.15	22.40	22.01	22.37	266,700	22.11
Jul 2, 2015	22.16	22.38	22.09	22.19	216,400	21.93
Jul 1, 2015	21.76	22.03	21.68	21.99	263,400	21.73

* Close price adjusted for dividends and splits.

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Currency in USD.

Eversource Energy (ES)- NYSE

50.76 0.21(0.41%) 4:00PM EDT

After Hours : 50.76 0.00 (0.00%) 5:27PM EDT

Analyst Estimates

Earnings Est	Current Qtr. Sep 15	Next Qtr. Dec 15	Current Year Dec 15	Next Year Dec 16
Avg. Estimate	0.77	0.68	2.87	3.03
No. of Analysts	13.00	11.00	16.00	18.00
Low Estimate	0.72	0.62	2.80	2.95
High Estimate	0.80	0.74	2.92	3.11
Year Ago EPS	0.75	0.72	2.75	2.87

Next Earnings Date: Nov 2, 2015 - Set a Reminder

Revenue Est	Current Qtr. Sep 15	Next Qtr. Dec 15	Current Year Dec 15	Next Year Dec 16
Avg. Estimate	2.03B	1.72B	8.07B	8.27B
No. of Analysts	6	5	12	12
Low Estimate	1.92B	1.19B	7.62B	7.70B
High Estimate	2.09B	2.01B	8.42B	8.73B
Year Ago Sales	1.89B	1.88B	7.74B	8.07B
Sales Growth (year/est)	7.40%	-8.60%	4.20%	2.50%

Earnings History	Sep 14	Dec 14	Mar 15	Jun 15
EPS Est	0.75	0.69	0.80	0.56
EPS Actual	0.75	0.72	0.81	0.66
Difference	0.00	0.03	0.01	0.10
Surprise %	0.00%	4.30%	1.30%	17.90%

EPS Trends	Current Qtr. Sep 15	Next Qtr. Dec 15	Current Year Dec 15	Next Year Dec 16
Current Estimate	0.77	0.68	2.87	3.03
7 Days Ago	0.77	0.68	2.87	3.03
30 Days Ago	0.77	0.68	2.87	3.04
60 Days Ago	0.76	0.70	2.86	3.04
90 Days Ago	0.78	0.71	2.86	3.05

EPS Revisions	Current Qtr. Sep 15	Next Qtr. Dec 15	Current Year Dec 15	Next Year Dec 16
Up Last 7 Days	1	1	1	0
Up Last 30 Days	1	2	3	1
Down Last 30 Days	1	2	0	2
Down Last 90 Days	N/A	N/A	N/A	N/A

Growth Est	ES	Industry	Sector	S&P 500
Current Qtr.	2.70%	0.90%	-27.20%	3.30%
Next Qtr.	-5.60%	-7.30%	90.60%	8.10%
This Year	4.40%	5.50%	32.60%	-1.60%
Next Year	5.60%	6.10%	22.40%	9.40%
Past 5 Years (per annum)	5.88%	N/A	N/A	N/A
Next 5 Years (per annum)	5.85%	7.41%	6.67%	6.10%
Price/Earnings (avg. for comparison categories)	17.76	37.89	20.76	16.34
PEG Ratio (avg. for comparison categories)	3.04	13.73	6.72	2.94

Currency in USD.

Thu, Oct 29, 2015, 6:41PM EDT - U.S. Markets closed Report an Issue

Dow 0.13%

Eversource Energy (ES) - NYSE

50.76 0.21 (0.41%) 4:00PM EDT

After Hours : **50.76** 0.00 (0.00%) 5:27PM EDT

Historical Prices

Get Historical Prices for: GO

Set Date Range

Start Date: Jul 1 2015 Eg. Jan 1, 2010

End Date: Sep 30 2015

(•) Daily
( ) Weekly
( ) Monthly
( ) Dividends Only

Get Prices

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Prices

Date	Open	High	Low	Close	Volume	Adj Close*
Sep 30, 2015	49.26	50.66	49.11	50.62	2,548,000	50.62
Sep 29, 2015	49.21	49.77	49.11	49.30	2,489,100	49.30
Sep 28, 2015	48.83	49.20	48.67	49.09	1,996,300	49.09
Sep 25, 2015	48.33	49.37	47.94	48.89	1,730,300	48.89
Sep 24, 2015	47.59	48.24	47.46	48.17	2,264,400	48.17
Sep 23, 2015	47.48	47.88	47.28	47.72	1,617,100	47.72
Sep 22, 2015	47.33	47.68	47.09	47.47	1,604,800	47.47
Sep 21, 2015	47.37	47.66	47.15	47.51	1,441,900	47.51
Sep 18, 2015	47.43	48.08	47.09	47.22	3,555,500	47.22
Sep 17, 2015	46.81	48.33	46.57	47.66	2,969,500	47.66
Sep 16, 2015	46.65	46.93	46.46	46.71	1,929,500	46.71
Sep 15, 2015	46.35	46.82	46.07	46.70	1,764,600	46.70
Sep 14, 2015	46.08	46.47	45.97	46.25	1,129,300	46.25
Sep 11, 2015	45.35	46.09	45.14	46.09	2,064,000	46.09
Sep 10, 2015	45.30	45.91	45.30	45.50	1,707,500	45.50
Sep 10, 2015	0.418 Dividend					
Sep 9, 2015	46.51	46.62	45.78	45.87	1,724,700	45.45
Sep 8, 2015	46.14	46.57	46.07	46.48	1,710,000	46.06
Sep 4, 2015	46.03	46.18	45.63	45.74	1,494,700	45.32
Sep 3, 2015	46.36	46.61	46.17	46.46	2,073,400	46.04
Sep 2, 2015	46.54	46.62	45.88	46.15	2,330,800	45.73
Sep 1, 2015	46.72	46.75	45.83	46.07	2,329,300	45.65
Aug 31, 2015	48.12	48.29	46.89	47.24	2,731,700	46.81
Aug 28, 2015	48.50	48.77	47.54	48.29	1,550,300	47.85
Aug 27, 2015	48.37	48.62	47.87	48.59	1,263,400	48.15
Aug 26, 2015	47.60	48.19	47.06	48.08	1,617,400	47.64
Aug 25, 2015	49.24	49.72	47.21	47.25	2,158,200	46.82
Aug 24, 2015	49.33	50.61	48.68	48.92	3,000,900	48.47
Aug 21, 2015	51.50	51.75	51.01	51.04	1,713,700	50.57
Aug 20, 2015	51.44	52.15	51.30	51.62	1,366,900	51.15
Aug 19, 2015	51.32	51.79	51.02	51.68	1,534,400	51.21
Aug 18, 2015	51.39	51.64	51.17	51.47	1,803,300	51.00
Aug 17, 2015	51.23	51.74	51.12	51.61	1,257,000	51.14
Aug 14, 2015	50.84	51.22	50.54	51.18	885,600	50.71
Aug 13, 2015	50.61	51.03	50.20	50.79	1,413,800	50.33
Aug 12, 2015	50.42	51.15	50.10	50.91	1,289,200	50.45
Aug 11, 2015	50.07	50.68	49.86	50.41	1,189,100	49.95
Aug 10, 2015	49.97	50.18	49.80	50.02	1,834,800	49.56
Aug 6, 2015	49.28	49.62	48.68	49.50	2,582,900	49.08

Aug 5, 2015	49.29	49.55	49.08	49.24	836,600	48.79
Aug 4, 2015	49.83	49.83	49.02	49.10	1,004,300	48.65
Aug 3, 2015	49.77	50.22	49.58	49.85	1,810,000	49.40
Jul 31, 2015	49.57	49.99	49.07	49.72	1,996,100	49.27
Jul 30, 2015	48.13	48.87	48.03	48.77	1,360,800	48.33
Jul 29, 2015	48.10	48.34	47.81	48.29	1,170,600	47.85
Jul 28, 2015	47.87	48.18	47.64	48.12	1,310,500	47.68
Jul 27, 2015	47.27	48.11	47.27	47.87	1,207,300	47.43
Jul 24, 2015	47.29	47.56	47.04	47.21	2,538,800	46.78
Jul 23, 2015	47.82	47.82	46.96	47.35	2,689,100	46.92
Jul 22, 2015	47.64	48.44	47.36	47.83	3,469,100	47.39
Jul 21, 2015	47.58	47.68	46.93	47.52	1,683,300	47.09
Jul 20, 2015	47.85	47.89	47.21	47.58	1,259,900	47.15
Jul 17, 2015	48.30	48.49	47.85	47.92	1,246,800	47.48
Jul 16, 2015	47.68	48.40	47.58	48.30	1,080,400	47.86
Jul 15, 2015	47.30	47.86	47.07	47.72	1,946,800	47.29
Jul 14, 2015	47.04	47.35	46.89	47.30	1,322,000	46.87
Jul 13, 2015	47.15	47.39	46.81	47.04	1,331,700	46.61
Jul 10, 2015	46.74	47.37	46.54	46.89	1,830,700	46.46
Jul 9, 2015	47.25	47.35	46.24	46.73	2,986,100	46.30
Jul 8, 2015	47.28	47.77	46.89	47.13	3,002,700	46.70
Jul 7, 2015	46.55	47.75	46.53	47.38	3,802,800	46.95
Jul 6, 2015	44.88	46.55	44.64	46.31	7,597,500	45.89
Jul 2, 2015	45.97	46.56	45.79	46.51	1,839,700	46.09
Jul 1, 2015	45.53	45.73	45.34	45.57	1,798,900	45.15

* Close price adjusted for dividends and splits.

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Currency in USD.

Great Plains Energy Incorporated (GXP) - NYSE

27.41 0.23(0.83%) 4:03PM EDT

Analyst Estimates

Get Analyst Estimates for: GO

Earnings Est	Current Qtr. Sep 15	Next Qtr. Dec 15	Current Year Dec 15	Next Year Dec 16
Avg. Estimate	0.88	0.19	1.49	1.81
No. of Analysts	9.00	6.00	12.00	12.00
Low Estimate	0.83	0.15	1.42	1.75
High Estimate	0.90	0.22	1.54	1.90
Year Ago EPS	0.95	0.12	1.57	1.49

Next Earnings Date: Nov 5, 2015 - Set a Reminder

Revenue Est	Current Qtr. Sep 15	Next Qtr. Dec 15	Current Year Dec 15	Next Year Dec 16
Avg. Estimate	796.85M	638.28M	2.58B	2.71B
No. of Analysts	4	4	9	9
Low Estimate	771.40M	562.70M	2.48B	2.56B
High Estimate	823.00M	723.27M	2.66B	2.77B
Year Ago Sales	782.50M	552.20M	2.57B	2.58B
Sales Growth (year/est)	1.80%	15.60%	0.30%	5.10%

Earnings History	Sep 14	Dec 14	Mar 15	Jun 15
EPS Est	0.97	0.13	0.11	0.30
EPS Actual	0.95	0.12	0.12	0.28
Difference	-0.02	-0.01	0.01	-0.02
Surprise %	-2.10%	-7.70%	9.10%	-6.70%

EPS Trends	Current Qtr. Sep 15	Next Qtr. Dec 15	Current Year Dec 15	Next Year Dec 16
Current Estimate	0.88	0.19	1.49	1.81
7 Days Ago	0.88	0.19	1.49	1.81
30 Days Ago	0.89	0.18	1.50	1.82
60 Days Ago	0.93	0.15	1.50	1.82
90 Days Ago	0.94	0.13	1.51	1.83

EPS Revisions	Current Qtr. Sep 15	Next Qtr. Dec 15	Current Year Dec 15	Next Year Dec 16
Up Last 7 Days	1	0	0	0
Up Last 30 Days	1	0	0	0
Down Last 30 Days	1	1	2	1
Down Last 90 Days	N/A	N/A	N/A	N/A

Growth Est	GXP	Industry	Sector	S&P 500
Current Qtr.	-7.40%	0.90%	-27.20%	3.30%
Next Qtr.	58.30%	-7.30%	90.60%	8.10%
This Year	-5.10%	5.50%	32.60%	-1.60%
Next Year	21.50%	6.10%	22.40%	9.40%
Past 5 Years (per annum)	8.93%	N/A	N/A	N/A
Next 5 Years (per annum)	6.37%	7.41%	6.67%	6.10%
Price/Earnings (avg. for comparison categories)	18.81	37.89	20.76	16.34
PEG Ratio (avg. for comparison categories)	2.95	13.73	6.72	2.94

Currency in USD.

Great Plains Energy Incorporated (GXP) - NYSE

27.41 0.23(0.83%) 4:03PM EDT

Historical Prices

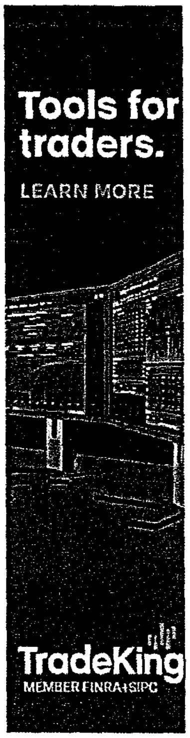
Get Historical Prices for: GO

Set Date Range

Start Date: Jul 1 2015 Eg. Jan 1, 2010
End Date: Sep 30 2015

◉ Daily
○ Weekly
○ Monthly
○ Dividends Only

Get Prices



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Prices

Date	Open	High	Low	Close	Volume	Adj Close*
Sep 30, 2015	26.63	27.08	26.34	27.02	2,084,200	27.02
Sep 29, 2015	26.32	26.52	26.22	26.49	1,893,600	26.49
Sep 28, 2015	26.16	26.43	26.08	26.28	1,342,900	26.28
Sep 25, 2015	26.05	26.58	25.86	26.25	1,388,500	26.25
Sep 24, 2015	25.66	26.04	25.66	25.99	895,900	25.99
Sep 23, 2015	25.49	25.87	25.45	25.76	1,085,900	25.76
Sep 22, 2015	25.52	25.68	25.22	25.51	1,297,100	25.51
Sep 21, 2015	25.76	25.97	25.60	25.67	1,531,300	25.67
Sep 18, 2015	25.29	25.95	25.29	25.66	1,817,400	25.66
Sep 17, 2015	25.38	26.04	25.01	25.72	1,386,600	25.72
Sep 16, 2015	25.13	25.40	25.00	25.36	1,242,400	25.36
Sep 15, 2015	25.00	25.15	24.77	25.05	1,200,200	25.05
Sep 14, 2015	24.99	25.18	24.91	24.96	1,045,900	24.96
Sep 11, 2015	24.49	24.93	24.40	24.91	851,100	24.91
Sep 10, 2015	24.54	24.96	24.52	24.60	1,461,200	24.60
Sep 9, 2015	24.88	24.95	24.51	24.56	1,254,500	24.56
Sep 8, 2015	24.49	24.84	24.34	24.77	1,702,800	24.77
Sep 4, 2015	24.43	24.49	24.08	24.21	1,171,800	24.21
Sep 3, 2015	24.36	24.71	24.29	24.66	1,713,400	24.66
Sep 2, 2015	24.53	24.58	24.16	24.30	1,315,300	24.30
Sep 1, 2015	24.54	24.68	24.15	24.28	1,201,200	24.28
Aug 31, 2015	25.08	25.18	24.63	24.92	1,238,700	24.92
Aug 28, 2015	25.18	25.45	25.02	25.27	949,000	25.27
Aug 27, 2015	25.06	25.36	24.90	25.35	1,402,600	25.35
Aug 26, 2015	24.96	24.99	24.30	24.90	2,186,400	24.90
Aug 26, 2015	0.245 Dividend					
Aug 25, 2015	25.79	25.80	24.69	24.72	2,333,200	24.47
Aug 24, 2015	25.74	26.09	25.23	25.39	2,808,600	25.14
Aug 21, 2015	26.86	26.98	26.49	26.50	2,078,500	26.24
Aug 20, 2015	27.02	27.33	26.92	27.01	891,900	26.74
Aug 19, 2015	27.01	27.33	26.86	27.22	1,026,700	26.95
Aug 18, 2015	27.22	27.38	27.13	27.15	622,600	26.88
Aug 17, 2015	27.16	27.46	27.01	27.35	765,200	27.08
Aug 14, 2015	26.80	27.22	26.73	27.15	743,600	26.88
Aug 13, 2015	26.83	26.98	26.58	26.88	859,900	26.61
Aug 12, 2015	26.38	26.99	26.38	26.93	1,367,500	26.66
Aug 11, 2015	26.28	26.67	26.04	26.52	1,507,700	26.26
Aug 10, 2015	26.40	26.71	26.18	26.23	1,367,500	25.97
Aug 7, 2015	25.86	26.73	25.86	26.42	1,635,400	26.16
Aug 6, 2015	26.17	26.19	25.70	25.89	1,822,600	25.63

Aug 5, 2015	25.99	26.23	25.87	26.12	985,100	25.86
Aug 4, 2015	26.17	26.31	25.79	25.85	819,000	25.59
Aug 3, 2015	26.20	26.40	26.00	26.17	779,300	25.91
Jul 31, 2015	26.14	26.32	25.88	26.11	686,500	25.85
Jul 30, 2015	25.63	26.03	25.48	25.83	1,013,200	25.57
Jul 29, 2015	25.39	25.71	25.28	25.70	958,500	25.45
Jul 28, 2015	25.21	25.46	25.01	25.44	1,288,200	25.19
Jul 27, 2015	24.73	25.29	24.69	25.19	796,800	24.94
Jul 24, 2015	24.74	24.85	24.62	24.74	795,900	24.49
Jul 23, 2015	24.88	24.89	24.53	24.73	1,248,100	24.48
Jul 22, 2015	24.89	25.12	24.85	24.96	782,200	24.71
Jul 21, 2015	25.24	25.30	24.82	24.83	1,127,400	24.58
Jul 20, 2015	25.47	25.47	25.13	25.29	576,200	25.04
Jul 17, 2015	25.66	25.74	25.46	25.49	1,122,100	25.24
Jul 16, 2015	25.30	25.75	25.18	25.73	1,231,700	25.47
Jul 15, 2015	25.10	25.18	24.92	25.18	1,163,000	24.93
Jul 14, 2015	25.22	25.34	25.06	25.10	1,040,200	24.85
Jul 13, 2015	25.40	25.52	25.08	25.20	1,398,400	24.95
Jul 10, 2015	25.05	25.40	24.81	25.30	2,452,900	25.05
Jul 9, 2015	25.45	25.48	24.79	24.83	2,698,000	24.58
Jul 8, 2015	25.58	25.68	25.33	25.38	1,213,000	25.13
Jul 7, 2015	25.07	25.72	25.04	25.61	1,374,200	25.36
Jul 6, 2015	24.83	25.01	24.63	25.01	845,700	24.76
Jul 2, 2015	24.74	24.95	24.61	24.78	762,300	24.53
Jul 1, 2015	24.24	24.55	24.13	24.51	1,550,900	24.27

* Close price adjusted for dividends and splits.

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Currency in USD.

Thu, Oct 29, 2015, 6:46PM EDT - U.S. Markets closed Report an Issue

IdaCorp, Inc. (IDA) - NYSE

66.44 1.68(2.47%) 4:00PM EDT

Analyst Estimates

Get Analyst Estimates for: GO

Earnings Est	Current Qtr. Sep 15	Next Qtr. Dec 15	Current Year Dec 15	Next Year Dec 16
Avg. Estimate	1.54	0.54	3.86	3.87
No. of Analysts	3.00	2.00	3.00	3.00
Low Estimate	1.44	0.45	3.84	3.80
High Estimate	1.67	0.63	3.90	3.92
Year Ago EPS	1.73	0.69	3.85	3.86

Next Earnings Date: Oct 29, 2015 - Set a Reminder

Revenue Est	Current Qtr. Sep 15	Next Qtr. Dec 15	Current Year Dec 15	Next Year Dec 16
Avg. Estimate	NaN	NaN	1.27B	1.28B
No. of Analysts			2	2
Low Estimate	NaN	NaN	1.25B	1.26B
High Estimate	NaN	NaN	1.29B	1.30B
Year Ago Sales	NaN	NaN	1.28B	1.27B
Sales Growth (year/est)	N/A	N/A	-1.30%	1.40%

Earnings History	Sep 14	Dec 14	Mar 15	Jun 15
EPS Est	1.57	0.58	0.58	1.07
EPS Actual	1.73	0.69	0.47	1.31
Difference	0.16	0.11	-0.11	0.24
Surprise %	10.20%	19.00%	-19.00%	22.40%

EPS Trends	Current Qtr. Sep 15	Next Qtr. Dec 15	Current Year Dec 15	Next Year Dec 16
Current Estimate	1.54	0.54	3.86	3.87
7 Days Ago	1.54	0.54	3.86	3.87
30 Days Ago	1.61	0.45	3.86	3.87
60 Days Ago	1.61	0.45	3.86	3.87
90 Days Ago	1.65	0.49	3.81	3.87

EPS Revisions	Current Qtr. Sep 15	Next Qtr. Dec 15	Current Year Dec 15	Next Year Dec 16
Up Last 7 Days	0	0	0	0
Up Last 30 Days	0	0	0	0
Down Last 30 Days	1	0	0	0
Down Last 90 Days	N/A	N/A	N/A	N/A

Growth Est	IDA	Industry	Sector	S&P 500
Current Qtr.	-11.00%	0.90%	-27.20%	3.30%
Next Qtr.	-21.70%	-7.30%	90.60%	8.10%
This Year	0.30%	5.50%	32.60%	-1.60%
Next Year	0.30%	6.10%	22.40%	9.40%
Past 5 Years (per annum)	8.15%	N/A	N/A	N/A
Next 5 Years (per annum)	4.00%	7.41%	6.67%	6.10%
Price/Earnings (avg. for comparison categories)	18.13	37.89	20.76	16.34
PEG Ratio (avg. for comparison categories)	4.53	13.73	6.72	2.94

Currency in USD.

Thu, Oct 29, 2015, 6:45PM EDT - U.S. Markets closed Report an Issue

IdaCorp, Inc. (IDA) - NYSE

66.44 1.68 (2.47%) 4:00PM EDT

Historical Prices

Get Historical Prices for: GO

Set Date Range

Start Date: Jul 1 2015 Eg. Jan 1, 2010
End Date: Sep 30 2015

- Daily
- Weekly
- Monthly
- Dividends Only

Get Prices

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Prices

Date	Open	High	Low	Close	Volume	Adj Close*
Sep 30, 2015	63.81	64.85	63.50	64.71	306,200	64.71
Sep 29, 2015	63.71	64.15	63.37	63.71	243,700	63.71
Sep 28, 2015	63.59	64.13	63.44	63.62	276,400	63.62
Sep 25, 2015	63.35	64.94	63.13	63.63	366,000	63.63
Sep 24, 2015	61.50	63.38	61.50	63.25	346,800	63.25
Sep 23, 2015	61.40	61.83	60.85	61.70	196,400	61.70
Sep 22, 2015	61.15	61.72	60.95	61.23	212,000	61.23
Sep 21, 2015	61.59	62.11	61.32	61.42	197,500	61.42
Sep 18, 2015	60.35	61.65	60.24	61.35	819,800	61.35
Sep 17, 2015	59.92	61.42	59.59	60.75	188,000	60.75
Sep 16, 2015	58.96	60.11	58.88	60.01	286,400	60.01
Sep 15, 2015	58.90	59.22	58.69	58.75	390,500	58.75
Sep 14, 2015	59.03	59.35	58.75	59.00	130,100	59.00
Sep 11, 2015	57.81	58.71	57.69	58.70	153,800	58.70
Sep 10, 2015	58.24	58.74	57.83	57.99	188,700	57.99
Sep 9, 2015	58.88	59.57	58.24	58.28	207,200	58.28
Sep 8, 2015	58.23	58.94	58.13	58.79	298,800	58.79
Sep 4, 2015	57.42	57.85	57.23	57.60	231,900	57.60
Sep 3, 2015	58.08	58.31	57.81	58.05	167,300	58.05
Sep 2, 2015	58.17	58.43	57.35	57.78	176,900	57.78
Sep 1, 2015	58.50	58.79	57.35	57.61	227,200	57.61
Aug 31, 2015	60.01	60.50	58.68	59.37	230,300	59.37
Aug 28, 2015	60.52	60.61	59.43	60.19	174,100	60.19
Aug 27, 2015	60.08	60.51	59.55	60.47	220,000	60.47
Aug 26, 2015	59.79	59.98	58.31	59.80	284,600	59.80
Aug 25, 2015	61.97	61.97	58.78	58.84	366,500	58.84
Aug 24, 2015	61.42	61.80	60.34	60.58	529,300	60.58
Aug 21, 2015	62.82	63.86	62.49	63.17	445,800	63.17
Aug 20, 2015	63.55	64.42	63.26	63.71	268,900	63.71
Aug 19, 2015	63.56	64.23	63.11	63.96	227,200	63.96
Aug 18, 2015	64.06	64.32	63.60	63.89	158,800	63.89
Aug 17, 2015	63.67	64.52	63.59	64.37	232,900	64.37
Aug 14, 2015	63.25	63.82	62.94	63.69	176,600	63.69
Aug 13, 2015	62.96	63.64	62.50	63.33	155,800	63.33
Aug 12, 2015	62.30	63.17	62.30	63.07	179,100	63.07
Aug 11, 2015	61.77	62.73	61.68	62.46	131,900	62.46
Aug 10, 2015	61.96	62.41	61.76	61.92	323,500	61.92
Aug 7, 2015	60.70	62.11	60.63	61.90	276,500	61.90
Aug 6, 2015	60.97	61.21	60.38	61.02	232,600	61.02
Aug 5, 2015	60.90	61.43	60.14	60.98	207,400	60.98

Aug 4, 2015	61.81	61.81	60.49	60.61	285,300	60.61
Aug 3, 2015	61.85	62.33	61.17	61.75	270,100	61.75
Aug 3, 2015			0.47 Dividend			
Jul 31, 2015	62.01	62.63	61.53	62.11	257,400	61.64
Jul 30, 2015	60.46	62.20	60.10	61.32	735,700	60.86
Jul 29, 2015	59.42	60.57	59.08	60.46	379,800	60.00
Jul 28, 2015	59.18	59.74	58.86	59.68	242,200	59.23
Jul 27, 2015	57.97	59.20	57.97	59.18	180,800	58.73
Jul 24, 2015	57.91	58.49	57.86	58.08	298,100	57.64
Jul 23, 2015	58.43	58.72	57.47	58.13	407,100	57.69
Jul 22, 2015	57.95	58.98	57.95	58.63	244,300	58.19
Jul 21, 2015	58.27	58.61	57.72	57.88	246,700	57.44
Jul 20, 2015	58.37	58.45	57.83	58.13	149,300	57.69
Jul 17, 2015	58.83	59.21	58.43	58.50	167,300	58.06
Jul 16, 2015	58.16	59.09	58.16	59.00	174,600	58.55
Jul 15, 2015	57.94	58.20	57.45	58.20	120,100	57.76
Jul 14, 2015	58.20	58.43	57.79	57.99	150,700	57.55
Jul 13, 2015	58.06	58.60	57.94	58.14	248,700	57.70
Jul 10, 2015	57.50	58.53	57.35	58.07	316,500	57.63
Jul 9, 2015	58.94	59.10	57.34	57.55	373,100	57.11
Jul 8, 2015	58.98	59.49	58.69	58.94	238,100	58.49
Jul 7, 2015	58.20	59.40	58.00	59.21	219,000	58.76
Jul 6, 2015	57.12	57.93	56.49	57.83	247,500	57.39
Jul 2, 2015	57.03	57.49	56.71	57.34	186,000	56.91
Jul 1, 2015	56.26	56.62	55.96	56.59	207,600	56.16

* Close price adjusted for dividends and splits.

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Currency in USD.

Otter Tail Corporation (OTTR) - NasdaqGS

27.78 0.16(0.57%) 4:00PM EDT

Analyst Estimates

Get Analyst Estimates for: GO

Earnings Est	Current Qtr. Sep 15	Next Qtr. Dec 15	Current Year Dec 15	Next Year Dec 16
Avg. Estimate	0.44	0.47	1.63	1.72
No. of Analysts	2.00	2.00	2.00	2.00
Low Estimate	0.43	0.43	1.60	1.70
High Estimate	0.44	0.50	1.66	1.74
Year Ago EPS	0.43	0.38	1.55	1.63

Next Earnings Date: Nov 2, 2015 - Set a Reminder

Revenue Est	Current Qtr. Sep 15	Next Qtr. Dec 15	Current Year Dec 15	Next Year Dec 16
Avg. Estimate	202.65M	198.95M	792.65M	830.95M
No. of Analysts	2	2	2	2
Low Estimate	198.50M	198.20M	787.80M	822.90M
High Estimate	206.80M	199.70M	797.50M	839.00M
Year Ago Sales	242.37M	193.41M	799.26M	792.65M
Sales Growth (year/est)	-16.40%	2.90%	-0.80%	4.80%

Earnings History	Sep 14	Dec 14	Mar 15	Jun 15
EPS Est	0.41	0.45	0.55	0.23
EPS Actual	0.43	0.38	0.37	0.36
Difference	0.02	-0.07	-0.18	0.13
Surprise %	4.90%	-15.60%	-32.70%	56.50%

EPS Trends	Current Qtr. Sep 15	Next Qtr. Dec 15	Current Year Dec 15	Next Year Dec 16
Current Estimate	0.44	0.47	1.63	1.72
7 Days Ago	0.44	0.47	1.63	1.72
30 Days Ago	0.42	0.47	1.62	1.72
60 Days Ago	0.42	0.47	1.62	1.72
90 Days Ago	0.41	0.56	1.56	1.75

EPS Revisions	Current Qtr. Sep 15	Next Qtr. Dec 15	Current Year Dec 15	Next Year Dec 16
Up Last 7 Days	1	0	1	0
Up Last 30 Days	1	0	1	0
Down Last 30 Days	0	0	0	0
Down Last 90 Days	N/A	N/A	N/A	N/A

Growth Est	OTTR	Industry	Sector	S&P 500
Current Qtr.	2.30%	0.90%	-27.20%	3.30%
Next Qtr.	23.70%	-7.30%	90.60%	8.10%
This Year	5.20%	5.50%	32.60%	-1.60%
Next Year	5.50%	6.10%	22.40%	9.40%
Past 5 Years (per annum)	44.19%	N/A	N/A	N/A
Next 5 Years (per annum)	6.00%	7.41%	6.67%	6.10%
Price/Earnings (avg. for comparison categories)	17.52	37.89	20.76	16.34
PEG Ratio (avg. for comparison categories)	2.92	13.73	6.72	2.94

Currency in USD.

Otter Tail Corporation (OTTR)- NasdaqGS
27.78 0.16(0.57%) 4:00PM EDT

Historical Prices

Get Historical Prices for: GO

Set Date Range

Start Date: Jul 1 2015 Eg. Jan 1, 2010
End Date: Sep 30 2015

(•) Daily
( ) Weekly
( ) Monthly
( ) Dividends Only

Get Prices

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Prices

Date	Open	High	Low	Close	Volume	Adj Close*
Sep 30, 2015	25.97	26.17	25.74	26.06	73,900	26.06
Sep 29, 2015	26.08	26.23	25.80	25.84	52,700	25.84
Sep 28, 2015	26.03	26.34	25.94	26.10	124,900	26.10
Sep 25, 2015	26.14	26.60	26.01	26.17	94,900	26.17
Sep 24, 2015	25.49	26.08	25.49	26.02	52,600	26.02
Sep 23, 2015	25.34	25.67	25.31	25.60	58,300	25.60
Sep 22, 2015	25.55	25.69	25.32	25.42	63,300	25.42
Sep 21, 2015	26.01	26.12	25.67	25.85	48,300	25.85
Sep 18, 2015	25.51	26.11	25.51	25.88	149,800	25.88
Sep 17, 2015	25.79	26.36	25.70	25.92	73,500	25.92
Sep 16, 2015	25.56	25.99	25.56	25.83	56,300	25.83
Sep 15, 2015	25.39	25.62	25.20	25.51	53,300	25.51
Sep 14, 2015	25.68	25.68	25.22	25.29	41,500	25.29
Sep 11, 2015	25.37	25.56	25.20	25.51	72,100	25.51
Sep 10, 2015	25.51	25.82	25.46	25.54	69,700	25.54
Sep 9, 2015	25.98	25.98	25.42	25.46	93,000	25.46
Sep 8, 2015	25.64	25.96	25.57	25.83	59,700	25.83
Sep 4, 2015	25.29	25.67	25.05	25.30	98,700	25.30
Sep 3, 2015	25.45	25.73	25.24	25.43	78,700	25.43
Sep 2, 2015	25.45	25.58	25.26	25.41	80,000	25.41
Sep 1, 2015	25.42	25.58	25.18	25.22	101,000	25.22
Aug 31, 2015	25.75	25.89	25.31	25.81	88,500	25.81
Aug 28, 2015	25.52	25.84	25.27	25.82	101,600	25.82
Aug 27, 2015	25.88	26.21	25.41	25.68	88,500	25.68
Aug 26, 2015	25.38	25.82	25.09	25.77	83,000	25.77
Aug 25, 2015	26.33	26.36	24.90	24.90	129,600	24.90
Aug 24, 2015	25.62	26.67	25.51	25.53	127,600	25.53
Aug 21, 2015	26.50	27.20	26.43	26.70	135,800	26.70
Aug 20, 2015	27.08	27.53	26.94	26.98	91,400	26.98
Aug 19, 2015	27.14	27.47	26.65	27.27	79,100	27.27
Aug 18, 2015	27.63	27.67	27.23	27.32	72,100	27.32
Aug 17, 2015	27.65	27.85	27.52	27.76	68,900	27.76
Aug 14, 2015	27.46	27.82	27.08	27.82	98,400	27.82
Aug 13, 2015	27.88	27.96	27.49	27.59	90,300	27.59
Aug 12, 2015	27.82	28.04	27.69	27.95	70,000	27.95
Aug 12, 2015	0.308 Dividend					
Aug 11, 2015	27.81	28.22	27.70	28.19	66,700	27.88
Aug 10, 2015	27.92	28.24	27.81	27.98	102,600	27.67
Aug 7, 2015	27.78	28.20	27.75	27.86	120,300	27.56
Aug 6, 2015	27.91	28.08	27.55	28.01	66,800	27.70

Aug 5, 2015	28.01	28.23	27.72	27.80	88,400	27.50
Aug 4, 2015	26.20	28.34	25.95	27.99	183,500	27.68
Aug 3, 2015	26.00	26.06	25.28	25.75	105,200	25.47
Jul 31, 2015	25.76	26.24	25.73	25.92	87,100	25.64
Jul 30, 2015	25.69	26.13	25.66	25.82	52,500	25.54
Jul 29, 2015	25.64	25.88	25.58	25.81	51,200	25.53
Jul 28, 2015	25.95	26.35	25.65	25.76	74,800	25.48
Jul 27, 2015	24.90	26.00	24.82	25.89	92,900	25.61
Jul 24, 2015	25.56	25.89	25.35	25.40	110,000	25.12
Jul 23, 2015	26.39	26.39	25.55	25.66	71,600	25.38
Jul 22, 2015	26.43	26.67	26.24	26.30	49,600	26.01
Jul 21, 2015	26.60	26.92	26.33	26.44	59,000	26.15
Jul 20, 2015	27.12	27.29	26.61	26.74	58,300	26.45
Jul 17, 2015	27.45	27.45	27.05	27.06	53,400	26.76
Jul 16, 2015	27.24	27.62	27.24	27.38	52,500	27.08
Jul 15, 2015	27.20	27.28	27.04	27.19	45,800	26.89
Jul 14, 2015	27.14	27.36	27.04	27.16	47,900	26.86
Jul 13, 2015	27.19	27.46	27.04	27.22	60,300	26.92
Jul 10, 2015	26.90	27.28	26.90	27.13	67,200	26.83
Jul 9, 2015	27.24	27.27	26.65	26.76	68,500	26.47
Jul 8, 2015	27.12	27.45	26.93	27.05	58,700	26.75
Jul 7, 2015	27.13	27.47	27.01	27.36	67,700	27.06
Jul 6, 2015	26.77	27.17	26.68	27.05	93,500	26.75
Jul 2, 2015	26.87	27.19	26.77	27.04	61,200	26.74
Jul 1, 2015	26.66	26.76	26.50	26.73	96,400	26.44

* Close price adjusted for dividends and splits.

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Currency in USD.

Pinnacle West Capital Corporation (PNW) - NYSE

63.17 0.69(1.07%) 4:01PM EDT

After Hours : **63.17** 0.00 (0.00%) 5:27PM EDT

Analyst Estimates

Get Analyst Estimates for: GO

Earnings Est	Current Qtr. Sep 15	Next Qtr. Dec 15	Current Year Dec 15	Next Year Dec 16
Avg. Estimate	2.32	0.22	3.82	4.02
No. of Analysts	13.00	10.00	17.00	18.00
Low Estimate	2.28	0.15	3.76	3.94
High Estimate	2.40	0.27	3.86	4.10
Year Ago EPS	2.20	0.05	3.58	3.82

Next Earnings Date: Oct 30, 2015 - Set a Reminder

Revenue Est	Current Qtr. Sep 15	Next Qtr. Dec 15	Current Year Dec 15	Next Year Dec 16
Avg. Estimate	1.20B	762.30M	3.54B	3.64B
No. of Analysts	6	6	12	14
Low Estimate	1.16B	739.26M	3.44B	3.53B
High Estimate	1.24B	775.07M	3.62B	3.85B
Year Ago Sales	1.17B	726.45M	3.49B	3.54B
Sales Growth (year/est)	2.10%	4.90%	1.30%	3.00%

Earnings History	Sep 14	Dec 14	Mar 15	Jun 15
EPS Est	2.14	0.18	0.18	1.23
EPS Actual	2.20	0.05	0.14	1.10
Difference	0.06	-0.13	-0.04	-0.13
Surprise %	2.80%	-72.20%	-22.20%	-10.60%

EPS Trends	Current Qtr. Sep 15	Next Qtr. Dec 15	Current Year Dec 15	Next Year Dec 16
Current Estimate	2.32	0.22	3.82	4.02
7 Days Ago	2.32	0.22	3.82	4.02
30 Days Ago	2.31	0.24	3.83	4.02
60 Days Ago	2.31	0.24	3.83	4.02
90 Days Ago	2.31	0.23	3.83	4.02

EPS Revisions	Current Qtr. Sep 15	Next Qtr. Dec 15	Current Year Dec 15	Next Year Dec 16
Up Last 7 Days	2	0	0	0
Up Last 30 Days	3	0	0	0
Down Last 30 Days	1	3	0	0
Down Last 90 Days	N/A	N/A	N/A	N/A

Growth Est	PNW	Industry	Sector	S&P 500
Current Qtr.	5.50%	0.90%	-27.20%	3.30%
Next Qtr.	340.00%	-7.30%	90.60%	8.10%
This Year	6.70%	5.50%	32.60%	-1.60%
Next Year	5.20%	6.10%	22.40%	9.40%
Past 5 Years (per annum)	-10.44%	N/A	N/A	N/A
Next 5 Years (per annum)	5.37%	7.41%	6.67%	6.10%
Price/Earnings (avg. for comparison categories)	16.88	37.89	20.76	16.34
PEG Ratio (avg. for comparison categories)	3.14	13.73	6.72	2.94

Currency in USD.

Thu, Oct 29, 2015, 6:54PM EDT - U.S. Markets closed **Report an Issue**

Pinnacle West Capital Corporation (PNW) - NYSE

63.17 0.69(1.07%) 4:01PM EDT

After Hours : **63.17** 0.00 (0.00%) 5:27PM EDT

Historical Prices

Get Historical Prices for: GO

Set Date Range

Start Date: Jul 1 2015 Eg. Jan 1, 2010
End Date: Sep 30 2015

- (●) Daily
- ( ) Weekly
- ( ) Monthly
- ( ) Dividends Only

Get Prices

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Prices

Date	Open	High	Low	Close	Volume	Adj Close*
Sep 30, 2015	63.52	64.21	63.23	64.14	564,200	64.14
Sep 29, 2015	63.26	63.62	62.75	63.22	760,000	63.22
Sep 28, 2015	63.51	63.86	62.99	63.17	665,100	63.17
Sep 25, 2015	62.69	64.09	62.52	63.52	620,500	63.52
Sep 24, 2015	62.06	62.82	61.60	62.63	970,600	62.63
Sep 23, 2015	62.24	62.54	61.86	62.23	576,500	62.23
Sep 22, 2015	61.54	62.41	61.54	62.20	791,100	62.20
Sep 21, 2015	61.97	62.77	61.65	62.29	1,218,700	62.29
Sep 18, 2015	61.27	62.33	61.20	61.77	1,281,500	61.77
Sep 17, 2015	61.00	62.47	60.94	61.77	543,900	61.77
Sep 16, 2015	60.21	61.23	59.92	61.09	759,800	61.09
Sep 15, 2015	59.88	60.29	59.55	60.18	772,200	60.18
Sep 14, 2015	59.87	60.29	59.68	59.88	816,200	59.88
Sep 11, 2015	58.74	59.80	58.61	59.79	861,100	59.79
Sep 10, 2015	59.15	59.69	58.88	59.06	962,600	59.06
Sep 9, 2015	59.88	59.95	59.00	59.23	1,244,700	59.23
Sep 8, 2015	58.22	59.75	57.99	59.68	1,656,400	59.68
Sep 4, 2015	57.66	58.01	57.33	57.60	668,200	57.60
Sep 3, 2015	58.16	58.68	58.02	58.27	717,300	58.27
Sep 2, 2015	58.63	58.73	57.57	58.01	659,000	58.01
Sep 1, 2015	59.02	59.02	57.78	58.01	865,600	58.01
Aug 31, 2015	60.15	60.39	58.95	59.53	1,099,800	59.53
Aug 28, 2015	60.66	60.84	59.81	60.48	1,492,100	60.48
Aug 27, 2015	60.78	60.80	59.90	60.78	1,312,300	60.78
Aug 26, 2015	60.34	60.54	59.24	60.33	1,354,900	60.33
Aug 25, 2015	62.35	62.85	59.55	59.61	1,209,900	59.61
Aug 24, 2015	62.16	62.36	60.97	61.69	2,531,600	61.69
Aug 21, 2015	64.10	64.40	63.25	63.27	945,200	63.27
Aug 20, 2015	64.17	65.23	63.92	64.34	977,000	64.34
Aug 19, 2015	64.08	64.90	63.85	64.59	628,700	64.59
Aug 18, 2015	64.77	64.77	64.28	64.38	627,300	64.38
Aug 17, 2015	64.43	65.12	64.07	64.85	595,100	64.85
Aug 14, 2015	63.69	64.48	63.32	64.37	646,500	64.37
Aug 13, 2015	63.50	64.07	62.94	63.86	521,600	63.86
Aug 12, 2015	62.88	63.95	62.63	63.77	766,500	63.77
Aug 11, 2015	62.26	63.27	62.08	63.08	730,700	63.08
Aug 10, 2015	62.70	62.99	62.16	62.25	627,700	62.25
Aug 7, 2015	61.39	62.89	61.02	62.62	904,500	62.62
Aug 6, 2015	60.80	61.20	60.69	60.85	676,500	60.85

Aug 4, 2015	61.88	61.88	60.70	60.80	677,400	60.80
Aug 3, 2015	61.72	62.36	61.61	61.92	723,000	61.92
Jul 31, 2015	61.57	62.63	61.57	61.71	616,200	61.71
Jul 30, 2015	60.31	62.23	59.55	61.27	1,275,700	61.27
Jul 30, 2015			0.595 Dividend			
Jul 29, 2015	60.90	61.56	60.59	61.52	857,900	60.93
Jul 28, 2015	60.88	61.25	60.71	61.09	1,076,100	60.50
Jul 27, 2015	59.87	61.04	59.87	60.97	1,313,400	60.38
Jul 24, 2015	59.60	60.29	59.42	59.99	658,700	59.41
Jul 23, 2015	60.26	60.26	59.16	59.69	749,600	59.11
Jul 22, 2015	59.95	60.54	59.82	60.34	936,500	59.76
Jul 21, 2015	60.56	60.76	59.52	59.96	1,010,100	59.38
Jul 20, 2015	60.63	61.12	60.25	60.81	1,479,600	60.22
Jul 17, 2015	60.99	61.03	60.37	60.42	817,400	59.84
Jul 16, 2015	60.20	61.28	60.20	61.17	1,185,600	60.58
Jul 15, 2015	60.04	60.24	59.39	60.21	919,200	59.63
Jul 14, 2015	60.17	60.55	59.87	60.11	896,900	59.53
Jul 13, 2015	60.52	60.81	59.78	60.18	849,700	59.60
Jul 10, 2015	59.60	60.68	59.37	60.32	1,203,600	59.74
Jul 9, 2015	60.44	60.72	59.43	59.68	1,039,000	59.10
Jul 8, 2015	60.10	60.49	60.02	60.28	1,196,900	59.70
Jul 7, 2015	58.78	60.53	58.71	60.34	1,148,200	59.76
Jul 6, 2015	58.16	58.60	57.82	58.49	758,100	57.92
Jul 2, 2015	57.93	58.55	57.24	58.32	944,100	57.76
Jul 1, 2015	57.03	57.67	56.77	57.58	1,156,400	57.02

* Close price adjusted for dividends and splits.

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Currency in USD.

PNM Resources, Inc. (PNM) - NYSE

27.62 0.58(2.06%) 4:02PM EDT

After Hours : **27.62** 0.00 (0.00%) 4:33PM EDT

Analyst Estimates

Get Analyst Estimates for: GO

Earnings Est	Current Qtr. Sep 15	Next Qtr. Dec 15	Current Year Dec 15	Next Year Dec 16
Avg. Estimate	0.74	0.19	1.57	1.64
No. of Analysts	6.00	4.00	9.00	9.00
Low Estimate	0.68	0.13	1.55	1.60
High Estimate	0.77	0.24	1.60	1.70
Year Ago EPS	0.68	0.24	1.49	1.57

Next Earnings Date: Oct 30, 2015 - Set a Reminder

Revenue Est	Current Qtr. Sep 15	Next Qtr. Dec 15	Current Year Dec 15	Next Year Dec 16
Avg. Estimate	453.50M	336.50M	1.46B	1.52B
No. of Analysts	2	2	5	5
Low Estimate	417.00M	309.00M	1.43B	1.48B
High Estimate	490.00M	364.00M	1.48B	1.54B
Year Ago Sales	413.95M	346.84M	1.44B	1.46B
Sales Growth (year/est)	9.60%	-3.00%	1.40%	4.20%

Earnings History	Sep 14	Dec 14	Mar 15	Jun 15
EPS Est	0.66	0.23	0.18	0.41
EPS Actual	0.68	0.24	0.21	0.44
Difference	0.02	0.01	0.03	0.03
Surprise %	3.00%	4.30%	16.70%	7.30%

EPS Trends	Current Qtr. Sep 15	Next Qtr. Dec 15	Current Year Dec 15	Next Year Dec 16
Current Estimate	0.74	0.19	1.57	1.64
7 Days Ago	0.74	0.19	1.57	1.64
30 Days Ago	0.71	0.20	1.56	1.64
60 Days Ago	0.71	0.20	1.56	1.64
90 Days Ago	0.75	0.19	1.56	1.65

EPS Revisions	Current Qtr. Sep 15	Next Qtr. Dec 15	Current Year Dec 15	Next Year Dec 16
Up Last 7 Days	0	0	1	1
Up Last 30 Days	0	0	1	1
Down Last 30 Days	0	0	0	0
Down Last 90 Days	N/A	N/A	N/A	N/A

Growth Est	PNM	Industry	Sector	S&P 500
Current Qtr.	8.80%	0.90%	-27.20%	3.30%
Next Qtr.	-20.80%	-7.30%	90.60%	8.10%
This Year	5.40%	5.50%	32.60%	-1.60%
Next Year	4.50%	6.10%	22.40%	9.40%
Past 5 Years (per annum)	10.06%	N/A	N/A	N/A
Next 5 Years (per annum)	8.56%	7.41%	6.67%	6.10%
Price/Earnings (avg. for comparison categories)	18.26	37.89	20.76	16.34
PEG Ratio (avg. for comparison categories)	2.13	13.73	6.72	2.94

Currency in USD.

PNM Resources, Inc. (PNM) - NYSE

27.62 0.58(2.06%) 4:02PM EDT

After Hours : 27.62 0.00 (0.00%) 4:33PM EDT

Historical Prices

Get Historical Prices for: GO

Set Date Range

Start Date: Jul 8 2015 Eg. Jan 1, 2010

End Date: Sep 30 2015

◉ Daily
○ Weekly
○ Monthly
○ Dividends Only

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Prices

Date	Open	High	Low	Close	Volume	Adj Close*
Sep 30, 2015	27.78	28.11	27.61	28.05	918,200	28.05
Sep 29, 2015	27.32	27.77	27.30	27.65	1,351,500	27.65
Sep 28, 2015	26.98	27.45	26.93	27.24	1,301,700	27.24
Sep 25, 2015	26.74	27.35	26.54	26.92	813,700	26.92
Sep 24, 2015	26.12	26.73	26.12	26.72	635,600	26.72
Sep 23, 2015	26.04	26.35	25.92	26.25	321,600	26.25
Sep 22, 2015	26.12	26.33	25.93	26.00	452,700	26.00
Sep 21, 2015	26.16	26.38	26.08	26.21	322,600	26.21
Sep 18, 2015	25.83	26.32	25.83	26.03	739,700	26.03
Sep 17, 2015	25.71	26.38	25.55	26.12	601,400	26.12
Sep 16, 2015	25.55	25.81	25.43	25.72	615,000	25.72
Sep 15, 2015	25.61	25.67	25.34	25.56	389,000	25.56
Sep 14, 2015	25.50	25.67	25.37	25.56	416,700	25.56
Sep 11, 2015	24.85	25.41	24.85	25.41	361,600	25.41
Sep 10, 2015	25.14	25.39	24.92	24.98	461,100	24.98
Sep 9, 2015	25.44	25.57	25.13	25.16	557,100	25.16
Sep 8, 2015	25.07	25.45	24.96	25.37	601,500	25.37
Sep 4, 2015	24.90	24.97	24.65	24.80	464,900	24.80
Sep 3, 2015	25.09	25.25	25.02	25.19	415,800	25.19
Sep 2, 2015	25.16	25.16	24.84	24.99	828,800	24.99
Sep 1, 2015	25.27	25.42	24.82	24.96	731,100	24.96
Aug 31, 2015	25.84	25.85	25.19	25.61	732,000	25.61
Aug 28, 2015	25.98	26.11	25.69	25.97	683,000	25.97
Aug 27, 2015	25.74	25.99	25.48	25.96	516,500	25.96
Aug 26, 2015	25.68	25.74	25.06	25.62	584,700	25.62
Aug 25, 2015	26.53	26.53	25.14	25.24	913,500	25.24
Aug 24, 2015	26.30	26.98	25.85	25.88	955,900	25.88
Aug 21, 2015	27.14	27.60	26.98	27.17	579,800	27.17
Aug 20, 2015	27.56	27.93	27.42	27.56	377,900	27.56
Aug 19, 2015	27.60	27.94	27.41	27.75	403,400	27.75
Aug 18, 2015	27.93	27.98	27.60	27.71	456,200	27.71
Aug 17, 2015	27.78	28.17	27.60	28.08	747,500	28.08
Aug 14, 2015	27.40	27.86	27.26	27.75	696,800	27.75
Aug 13, 2015	27.28	27.54	27.01	27.42	536,000	27.42
Aug 12, 2015	26.86	27.41	26.86	27.41	464,400	27.41
Aug 11, 2015	26.69	27.08	26.58	26.98	340,700	26.98
Aug 10, 2015	26.83	27.04	26.66	26.75	424,400	26.75
Aug 7, 2015	26.37	27.00	26.23	26.85	390,700	26.85
Aug 6, 2015	26.22	26.60	26.06	26.20	502,300	26.20

Aug 4, 2015	26.47	26.51	25.96	26.07	403,600	26.07
Aug 3, 2015	26.54	26.76	26.22	26.55	566,700	26.55
Jul 31, 2015	26.45	27.20	25.39	26.38	789,000	26.38
Jul 30, 2015	25.76	26.25	25.55	26.08	624,900	26.08
Jul 30, 2015			0.20 Dividend			
Jul 29, 2015	25.68	26.04	25.54	26.00	403,600	25.80
Jul 28, 2015	25.72	25.85	25.49	25.80	478,000	25.60
Jul 27, 2015	25.17	25.84	25.17	25.70	620,300	25.50
Jul 24, 2015	25.10	25.47	25.07	25.21	704,000	25.02
Jul 23, 2015	25.34	25.34	24.86	25.19	443,900	25.00
Jul 22, 2015	25.24	25.61	25.22	25.41	332,000	25.21
Jul 21, 2015	25.78	25.80	25.19	25.30	368,100	25.11
Jul 20, 2015	26.00	26.00	25.63	25.82	370,200	25.62
Jul 17, 2015	26.16	26.37	26.00	26.02	670,700	25.82
Jul 16, 2015	25.76	26.41	25.76	26.24	628,500	26.04
Jul 15, 2015	25.78	25.88	25.54	25.71	427,200	25.51
Jul 14, 2015	25.78	25.88	25.53	25.81	606,800	25.61
Jul 13, 2015	25.60	25.86	25.51	25.74	584,700	25.54
Jul 10, 2015	25.28	25.69	25.17	25.47	465,100	25.27
Jul 9, 2015	25.76	25.87	25.19	25.25	502,100	25.06
Jul 8, 2015	25.75	25.97	25.60	25.69	620,600	25.49

* Close price adjusted for dividends and splits.

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Currency in USD.

Portland General Electric Company (POR) - NYSE

36.96 0.45(1.20%) 4:03PM EDT

Analyst Estimates

Earnings Est	Current Qtr. Dec 15	Next Qtr. Mar 16	Current Year Dec 15	Next Year Dec 16
Avg. Estimate	0.62	0.76	2.11	2.35
No. of Analysts	7.00	4.00	14.00	14.00
Low Estimate	0.58	0.62	2.07	2.29
High Estimate	0.66	0.86	2.16	2.40
Year Ago EPS	0.55	0.62	2.18	2.11

Revenue Est	Current Qtr. Dec 15	Next Qtr. Mar 16	Current Year Dec 15	Next Year Dec 16
Avg. Estimate	541.97M	557.38M	1.96B	2.05B
No. of Analysts	4	3	11	11
Low Estimate	516.97M	470.83M	1.92B	1.98B
High Estimate	596.14M	678.22M	2.09B	2.18B
Year Ago Sales	500.00M	473.00M	1.90B	1.96B
Sales Growth (year/est)	8.40%	17.80%	3.20%	4.30%

Earnings History	Dec 14	Mar 15	Jun 15	Sep 15
EPS Est	0.52	0.70	0.41	0.48
EPS Actual	0.55	0.62	0.44	0.40
Difference	0.03	-0.08	0.03	-0.08
Surprise %	5.80%	-11.40%	7.30%	-16.70%

EPS Trends	Current Qtr. Dec 15	Next Qtr. Mar 16	Current Year Dec 15	Next Year Dec 16
Current Estimate	0.62	0.76	2.11	2.35
7 Days Ago	0.59	0.76	2.14	2.36
30 Days Ago	0.58	0.75	2.14	2.36
60 Days Ago	0.58	0.77	2.14	2.37
90 Days Ago	0.58	0.77	2.14	2.37

EPS Revisions	Current Qtr. Dec 15	Next Qtr. Mar 16	Current Year Dec 15	Next Year Dec 16
Up Last 7 Days	3	0	0	1
Up Last 30 Days	5	1	0	2
Down Last 30 Days	0	0	6	2
Down Last 90 Days	N/A	N/A	N/A	N/A

Growth Est	POR	Industry	Sector	S&P 500
Current Qtr.	12.70%	0.90%	-27.20%	3.30%
Next Qtr.	22.60%	-7.30%	90.60%	8.10%
This Year	-3.20%	5.50%	32.60%	-1.60%
Next Year	11.40%	6.10%	22.40%	9.40%
Past 5 Years (per annum)	3.87%	N/A	N/A	N/A
Next 5 Years (per annum)	3.92%	7.41%	6.67%	6.10%
Price/Earnings (avg. for comparison categories)	17.73	37.89	20.76	16.34
PEG Ratio (avg. for comparison categories)	4.52	13.73	6.72	2.94

Currency in USD.

Portland General Electric Company (POR) - NYSE

36.96 0.45(1.20%) 4:03PM EDT

Historical Prices

Get Historical Prices for: GO

Set Date Range

Start Date: Jul 1 2015 Eg. Jan 1, 2010
End Date: Sep 30 2015

Daily
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Dividends Only

Get Prices

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Prices

Date	Open	High	Low	Close	Volume	Adj Close*
Sep 30, 2015	36.33	37.03	36.11	36.97	792,500	36.97
Sep 29, 2015	36.29	36.68	35.98	36.14	1,273,900	36.14
Sep 28, 2015	36.38	36.74	36.15	36.39	808,200	36.39
Sep 25, 2015	36.12	36.97	35.91	36.51	799,100	36.51
Sep 24, 2015	35.53	36.14	35.26	36.06	1,134,900	36.06
Sep 23, 2015	35.18	35.72	35.07	35.70	942,900	35.70
Sep 23, 2015	0.30 Dividend					
Sep 22, 2015	35.56	35.93	35.44	35.61	704,800	35.31
Sep 21, 2015	35.66	36.00	35.44	35.85	690,100	35.55
Sep 18, 2015	35.14	35.81	35.14	35.51	1,672,000	35.21
Sep 17, 2015	34.90	35.86	34.90	35.43	640,900	35.13
Sep 16, 2015	34.79	35.16	34.66	34.94	536,600	34.65
Sep 15, 2015	34.67	34.81	34.37	34.75	410,500	34.46
Sep 14, 2015	34.50	34.91	34.50	34.66	481,300	34.37
Sep 11, 2015	33.97	34.53	33.82	34.52	420,700	34.23
Sep 10, 2015	34.29	34.46	34.00	34.11	519,200	33.82
Sep 9, 2015	34.80	34.93	34.21	34.28	917,000	33.99
Sep 8, 2015	34.17	34.80	34.11	34.76	925,500	34.47
Sep 4, 2015	33.77	33.96	33.59	33.72	1,003,300	33.44
Sep 3, 2015	33.73	34.19	33.33	34.11	1,003,300	33.82
Sep 2, 2015	33.99	33.99	33.39	33.70	1,148,600	33.42
Sep 1, 2015	34.10	34.26	33.53	33.70	781,200	33.42
Aug 31, 2015	34.82	34.93	34.10	34.54	1,789,700	34.25
Aug 28, 2015	35.13	35.25	34.47	34.97	583,800	34.68
Aug 27, 2015	35.00	35.15	34.53	35.13	757,900	34.83
Aug 26, 2015	34.63	34.83	33.74	34.72	1,107,300	34.43
Aug 25, 2015	35.43	35.59	34.11	34.16	1,155,800	33.87
Aug 24, 2015	35.95	36.33	34.95	35.05	898,700	34.75
Aug 21, 2015	36.48	37.19	36.47	36.73	840,200	36.42
Aug 20, 2015	37.20	37.55	37.00	37.04	773,300	36.73
Aug 19, 2015	37.26	37.63	37.05	37.35	865,200	37.04
Aug 18, 2015	37.67	37.79	37.36	37.43	531,900	37.11
Aug 17, 2015	37.63	38.00	37.38	37.77	515,000	37.45
Aug 14, 2015	37.21	37.68	37.04	37.62	966,600	37.30
Aug 13, 2015	37.24	37.49	36.91	37.25	985,200	36.94
Aug 12, 2015	36.70	37.43	36.61	37.36	975,900	37.05
Aug 11, 2015	36.25	36.82	36.13	36.79	833,000	36.48
Aug 10, 2015	36.23	36.63	36.10	36.26	632,800	35.95
Aug 7, 2015	35.81	36.34	35.66	36.19	530,400	35.89
Aug 6, 2015	35.77	35.92	35.50	35.88	557,100	35.58

Aug 5, 2015	35.78	36.00	35.68	35.72	331,100	35.42
Aug 4, 2015	36.09	36.10	35.57	35.65	389,800	35.35
Aug 3, 2015	36.11	36.41	35.91	36.13	452,700	35.83
Jul 31, 2015	35.90	36.47	35.90	36.01	568,200	35.71
Jul 30, 2015	35.43	36.02	35.26	35.67	974,800	35.37
Jul 29, 2015	34.71	35.52	34.53	35.50	1,076,400	35.20
Jul 28, 2015	33.38	34.77	33.31	34.76	1,113,000	34.47
Jul 27, 2015	33.79	34.26	33.50	34.18	1,043,700	33.89
Jul 24, 2015	33.76	34.09	33.15	33.82	610,800	33.54
Jul 23, 2015	34.10	34.13	33.51	33.76	534,200	33.48
Jul 22, 2015	33.90	34.36	33.80	34.18	339,400	33.89
Jul 21, 2015	34.20	34.28	33.80	33.99	604,000	33.70
Jul 20, 2015	34.45	34.49	34.09	34.26	580,700	33.97
Jul 17, 2015	34.97	35.05	34.48	34.50	628,300	34.21
Jul 16, 2015	34.49	35.15	34.49	35.07	647,800	34.77
Jul 15, 2015	34.36	34.54	34.00	34.49	561,400	34.20
Jul 14, 2015	34.46	34.56	34.30	34.36	780,400	34.07
Jul 13, 2015	34.55	34.72	34.25	34.44	421,400	34.15
Jul 10, 2015	34.11	34.73	33.99	34.36	654,400	34.07
Jul 9, 2015	34.55	34.87	34.01	34.14	787,100	33.85
Jul 8, 2015	34.65	34.89	34.46	34.48	551,400	34.19
Jul 7, 2015	34.20	34.97	34.16	34.77	790,100	34.48
Jul 6, 2015	33.81	34.10	33.66	34.06	671,000	33.77
Jul 2, 2015	33.63	33.99	33.60	33.79	527,100	33.51
Jul 1, 2015	33.21	33.43	33.09	33.41	527,800	33.13

* Close price adjusted for dividends and splits.

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Currency in USD.

Southern Company (SO) - NYSE

44.95 0.38(0.84%) 4:03PM EDT

After Hours : **44.94** 0.01 (0.02%) 5:18PM EDT

Analyst Estimates

Get Analyst Estimates for: GO

Earnings Est	Current Qtr. Dec 15	Next Qtr. Mar 16	Current Year Dec 15	Next Year Dec 16
Avg. Estimate	0.43	0.59	2.84	2.94
No. of Analysts	11.00	7.00	21.00	20.00
Low Estimate	0.36	0.50	2.75	2.85
High Estimate	0.47	0.70	2.88	2.99
Year Ago EPS	0.38	0.56	2.80	2.84

Revenue Est	Current Qtr. Dec 15	Next Qtr. Mar 16	Current Year Dec 15	Next Year Dec 16
Avg. Estimate	4.28B	4.48B	18.69B	19.26B
No. of Analysts	7	6	16	15
Low Estimate	3.15B	3.97B	17.60B	18.15B
High Estimate	5.08B	4.95B	20.25B	20.04B
Year Ago Sales	4.05B	4.18B	18.50B	18.69B
Sales Growth (year/est)	5.80%	7.00%	1.00%	3.00%

Earnings History	Dec 14	Mar 15	Jun 15	Sep 15
EPS Est	0.38	0.58	0.69	1.16
EPS Actual	0.38	0.56	0.71	1.17
Difference	0.00	-0.02	0.02	0.01
Surprise %	0.00%	-3.40%	2.90%	0.90%

EPS Trends	Current Qtr. Dec 15	Next Qtr. Mar 16	Current Year Dec 15	Next Year Dec 16
Current Estimate	0.43	0.59	2.84	2.94
7 Days Ago	0.43	0.59	2.84	2.94
30 Days Ago	0.42	0.59	2.84	2.94
60 Days Ago	0.43	0.61	2.84	2.94
90 Days Ago	0.42	0.62	2.84	2.94

EPS Revisions	Current Qtr. Dec 15	Next Qtr. Mar 16	Current Year Dec 15	Next Year Dec 16
Up Last 7 Days	1	1	1	2
Up Last 30 Days	1	1	1	2
Down Last 30 Days	0	0	2	0
Down Last 90 Days	N/A	N/A	N/A	N/A

Growth Est	SO	Industry	Sector	S&P 500
Current Qtr.	13.20%	0.90%	-27.20%	3.30%
Next Qtr.	5.40%	-7.30%	90.60%	8.10%
This Year	1.40%	5.50%	32.60%	-1.60%
Next Year	3.50%	6.10%	22.40%	9.40%
Past 5 Years (per annum)	4.81%	N/A	N/A	N/A
Next 5 Years (per annum)	3.58%	7.41%	6.67%	6.10%
Price/Earnings (avg. for comparison categories)	15.96	37.89	20.76	16.34
PEG Ratio (avg. for comparison categories)	4.46	13.73	6.72	2.94

Currency in USD.

Southern Company (SO) - NYSE

44.95 0.38(0.84%) 4:03PM EDT

After Hours : **44.94** 0.01 (0.02%) 5:18PM EDT

Historical Prices

Get Historical Prices for: GO

Set Date Range

Start Date: Jul 1 2015 Eg. Jan 1, 2010
End Date: Sep 30 2015

- Daily (selected)
- Weekly
- Monthly
- Dividends Only

Get Prices

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Prices

Date	Open	High	Low	Close	Volume	Adj Close*
Sep 30, 2015	44.32	44.78	44.09	44.70	5,208,500	44.70
Sep 29, 2015	44.08	44.53	44.00	44.29	3,980,800	44.29
Sep 28, 2015	44.04	44.56	44.03	44.09	4,528,300	44.09
Sep 25, 2015	43.48	44.57	43.36	44.13	5,674,900	44.13
Sep 24, 2015	42.83	43.56	42.83	43.48	5,284,600	43.48
Sep 23, 2015	43.02	43.23	42.80	42.95	6,373,400	42.95
Sep 22, 2015	43.33	43.61	43.00	43.01	6,090,200	43.01
Sep 21, 2015	43.48	43.83	43.40	43.77	3,808,700	43.77
Sep 18, 2015	43.27	44.07	43.15	43.43	6,900,300	43.43
Sep 17, 2015	42.93	44.03	42.86	43.48	5,258,700	43.48
Sep 16, 2015	42.74	43.16	42.54	42.91	3,277,600	42.91
Sep 15, 2015	42.66	42.81	42.36	42.63	3,441,900	42.63
Sep 14, 2015	42.72	42.92	42.57	42.63	3,522,500	42.63
Sep 11, 2015	42.15	42.71	42.08	42.71	4,167,900	42.71
Sep 10, 2015	42.55	42.73	42.15	42.30	4,982,200	42.30
Sep 9, 2015	42.83	42.95	42.39	42.46	6,461,500	42.46
Sep 8, 2015	42.50	42.75	42.14	42.70	6,324,900	42.70
Sep 4, 2015	42.22	42.29	41.81	41.98	5,488,800	41.98
Sep 3, 2015	42.67	42.76	42.42	42.58	3,845,300	42.58
Sep 2, 2015	42.75	42.81	42.14	42.52	5,755,400	42.52
Sep 1, 2015	42.94	42.95	42.22	42.41	6,920,400	42.41
Aug 31, 2015	43.59	43.69	42.88	43.41	5,802,300	43.41
Aug 28, 2015	43.92	44.00	43.13	43.74	5,292,100	43.74
Aug 27, 2015	43.98	44.11	43.40	43.91	8,571,000	43.91
Aug 26, 2015	43.17	43.69	42.83	43.61	10,118,700	43.61
Aug 25, 2015	44.30	44.45	42.49	42.50	9,612,800	42.50
Aug 24, 2015	44.03	45.47	43.37	43.58	16,156,900	43.58
Aug 21, 2015	46.08	46.43	45.76	45.80	6,777,900	45.80
Aug 20, 2015	46.06	46.84	45.88	46.36	5,842,100	46.36
Aug 19, 2015	45.93	46.42	45.72	46.31	4,719,400	46.31
Aug 18, 2015	46.13	46.21	45.95	46.07	3,916,400	46.07
Aug 17, 2015	46.50	46.50	46.17	46.30	4,835,200	46.30
Aug 14, 2015	45.97	46.34	45.82	46.33	4,561,200	46.33
Aug 13, 2015	45.79	46.32	45.68	46.16	5,564,300	46.16
Aug 13, 2015			0.543 Dividend			
Aug 12, 2015	45.75	46.70	45.75	46.57	7,594,900	46.03
Aug 11, 2015	45.60	46.30	45.41	45.91	4,382,600	45.37
Aug 10, 2015	45.53	45.87	45.33	45.46	4,345,100	44.93
Aug 6, 2015	44.98	45.60	44.89	45.66	5,668,200	45.06

Aug 5, 2015	44.79	44.84	44.49	44.61	3,413,500	44.09
Aug 4, 2015	44.87	44.87	44.33	44.42	3,284,700	43.90
Aug 3, 2015	44.75	45.09	44.70	44.96	4,255,600	44.44
Jul 31, 2015	44.74	45.10	44.64	44.73	4,886,400	44.21
Jul 30, 2015	43.46	44.45	43.45	44.38	6,162,100	43.86
Jul 29, 2015	43.40	43.61	43.01	43.57	5,008,800	43.06
Jul 28, 2015	43.40	43.67	43.27	43.54	4,650,200	43.03
Jul 27, 2015	43.01	43.61	42.94	43.44	3,547,600	42.93
Jul 24, 2015	42.96	43.05	42.66	42.88	4,456,700	42.38
Jul 23, 2015	43.18	43.18	42.45	42.98	5,249,800	42.48
Jul 22, 2015	43.24	43.56	43.18	43.25	3,232,800	42.75
Jul 21, 2015	43.28	43.30	42.90	43.21	4,799,300	42.71
Jul 20, 2015	43.47	43.48	43.06	43.32	3,589,300	42.81
Jul 17, 2015	43.78	43.83	43.50	43.51	5,229,000	43.00
Jul 16, 2015	43.40	44.00	43.40	43.98	4,513,200	43.47
Jul 15, 2015	43.23	43.38	43.01	43.37	2,934,700	42.86
Jul 14, 2015	43.50	43.63	43.04	43.21	3,663,900	42.71
Jul 13, 2015	43.52	43.72	43.18	43.40	3,302,300	42.89
Jul 10, 2015	43.30	43.66	43.15	43.36	6,654,000	42.85
Jul 9, 2015	44.18	44.30	43.15	43.27	6,778,200	42.77
Jul 8, 2015	44.08	44.59	44.05	44.20	6,661,200	43.68
Jul 7, 2015	43.35	44.47	43.30	44.26	11,156,100	43.74
Jul 6, 2015	42.93	43.30	42.80	43.12	4,995,400	42.62
Jul 2, 2015	42.45	42.95	42.42	42.89	4,937,400	42.39
Jul 1, 2015	42.01	42.19	41.84	42.18	4,675,600	41.69

* Close price adjusted for dividends and splits.

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Currency in USD.

Westar Energy, Inc. (WR)- NYSE

39.64 0.26(0.65%) 4:04PM EDT

Analyst Estimates

Get Analyst Estimates for: GO

Earnings Est	Current Qtr. Sep 15	Next Qtr. Dec 15	Current Year Dec 15	Next Year Dec 16
Avg. Estimate	1.04	0.35	2.25	2.44
No. of Analysts	7.00	5.00	13.00	13.00
Low Estimate	0.99	0.31	2.17	2.38
High Estimate	1.15	0.39	2.30	2.55
Year Ago EPS	1.10	0.32	2.35	2.25

Next Earnings Date: Nov 3, 2015 - Set a Reminder

Revenue Est	Current Qtr. Sep 15	Next Qtr. Dec 15	Current Year Dec 15	Next Year Dec 16
Avg. Estimate	787.32M	631.18M	2.59B	2.72B
No. of Analysts	4	4	9	10
Low Estimate	764.20M	617.51M	2.44B	2.53B
High Estimate	811.76M	670.77M	2.65B	2.90B
Year Ago Sales	764.04M	596.44M	2.60B	2.59B
Sales Growth (year/est)	3.00%	5.80%	-0.40%	5.10%

Earnings History	Sep 14	Dec 14	Mar 15	Jun 15
EPS Est	1.07	0.35	0.43	0.42
EPS Actual	1.10	0.32	0.38	0.46
Difference	0.03	-0.03	-0.05	0.04
Surprise %	2.80%	-8.60%	-11.60%	9.50%

EPS Trends	Current Qtr. Sep 15	Next Qtr. Dec 15	Current Year Dec 15	Next Year Dec 16
Current Estimate	1.04	0.35	2.25	2.44
7 Days Ago	1.04	0.35	2.25	2.44
30 Days Ago	1.05	0.35	2.25	2.44
60 Days Ago	1.05	0.36	2.25	2.45
90 Days Ago	1.04	0.38	2.24	2.45

EPS Revisions	Current Qtr. Sep 15	Next Qtr. Dec 15	Current Year Dec 15	Next Year Dec 16
Up Last 7 Days	1	2	1	1
Up Last 30 Days	1	2	1	1
Down Last 30 Days	2	1	1	0
Down Last 90 Days	N/A	N/A	N/A	N/A

Growth Est	WR	Industry	Sector	S&P 500
Current Qtr.	-5.50%	0.90%	-27.20%	3.30%
Next Qtr.	9.40%	-7.30%	90.60%	8.10%
This Year	-4.30%	5.50%	32.60%	-1.60%
Next Year	8.40%	6.10%	22.40%	9.40%
Past 5 Years (per annum)	11.66%	N/A	N/A	N/A
Next 5 Years (per annum)	3.40%	7.41%	6.67%	6.10%
Price/Earnings (avg. for comparison categories)	18.11	37.89	20.76	16.34
PEG Ratio (avg. for comparison categories)	5.33	13.73	6.72	2.94

Currency in USD.

Thu, Oct 29, 2015, 7:04PM EDT - U.S. Markets closed Report an Issue

Dow 0.13% 5-DAY TREND WR

WR

Westar Energy, Inc. (WR) - NYSE

39.64 0.26(0.65%) 4:04PM EDT

Historical Prices

Get Historical Prices for: GO

Set Date Range

Start Date: Jul 1 2015 Eg. Jan 1, 2010
End Date: Sep 30 2015

◉ Daily
○ Weekly
○ Monthly
○ Dividends Only

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Prices

Date	Open	High	Low	Close	Volume	Adj Close*
Sep 30, 2015	38.06	38.49	37.87	38.44	1,000,600	38.44
Sep 29, 2015	37.88	38.11	37.61	37.88	815,400	37.88
Sep 28, 2015	38.07	38.27	37.70	37.87	984,800	37.87
Sep 25, 2015	37.67	38.53	37.47	38.08	1,290,800	38.08
Sep 24, 2015	37.20	37.74	37.03	37.59	1,145,500	37.59
Sep 23, 2015	36.93	37.34	36.92	37.31	599,800	37.31
Sep 22, 2015	37.04	37.31	36.79	36.94	571,000	36.94
Sep 21, 2015	37.21	37.53	37.08	37.23	662,600	37.23
Sep 18, 2015	36.85	37.45	36.81	37.07	1,502,200	37.07
Sep 17, 2015	36.60	37.69	36.48	37.27	991,900	37.27
Sep 16, 2015	36.25	36.74	36.01	36.67	707,000	36.67
Sep 15, 2015	36.04	36.25	35.81	36.19	726,400	36.19
Sep 14, 2015	36.24	36.44	36.00	36.03	670,400	36.03
Sep 11, 2015	35.42	36.18	35.36	36.17	975,000	36.17
Sep 10, 2015	35.50	36.03	35.45	35.55	949,700	35.55
Sep 9, 2015	36.07	36.17	35.51	35.55	905,200	35.55
Sep 8, 2015	35.43	36.00	35.43	35.94	1,271,700	35.94
Sep 4, 2015	35.44	35.58	34.90	35.05	907,000	35.05
Sep 4, 2015	0.36 Dividend					
Sep 3, 2015	35.66	36.06	35.60	35.90	898,600	35.54
Sep 2, 2015	35.81	35.93	35.20	35.59	922,900	35.23
Sep 1, 2015	36.32	36.34	35.33	35.49	1,030,900	35.13
Aug 31, 2015	36.91	36.91	36.13	36.55	1,512,900	36.18
Aug 28, 2015	37.20	37.28	36.59	37.08	841,100	36.71
Aug 27, 2015	36.85	37.18	36.47	37.17	1,063,300	36.80
Aug 26, 2015	36.22	36.77	35.74	36.68	1,491,800	36.31
Aug 25, 2015	37.53	37.63	35.92	35.94	1,453,600	35.58
Aug 24, 2015	37.67	37.85	36.96	37.15	1,701,800	36.78
Aug 21, 2015	38.97	39.29	38.68	38.68	1,289,200	38.29
Aug 20, 2015	39.41	39.74	39.20	39.24	846,300	38.85
Aug 19, 2015	39.40	39.71	39.14	39.57	1,021,700	39.17
Aug 18, 2015	39.79	40.07	39.47	39.53	1,082,800	39.13
Aug 17, 2015	39.73	40.22	39.53	39.87	1,437,700	39.47
Aug 14, 2015	39.12	39.83	39.10	39.74	2,663,100	39.34
Aug 13, 2015	38.62	39.36	38.42	39.24	1,664,300	38.85
Aug 12, 2015	38.28	39.01	38.19	38.86	1,303,500	38.47
Aug 11, 2015	37.82	38.53	37.76	38.30	1,441,700	37.92
Aug 10, 2015	37.93	38.38	37.77	37.79	1,181,700	37.41
Aug 7, 2015	37.18	38.21	36.99	37.99	1,787,500	37.61
Aug 6, 2015	37.22	37.35	36.80	37.22	1,629,200	36.85

Aug 5, 2015	37.23	37.71	37.13	37.23	1,259,900	36.86
Aug 4, 2015	37.63	37.70	37.20	37.29	766,200	36.92
Aug 3, 2015	37.73	37.99	37.57	37.77	791,300	37.39
Jul 31, 2015	37.69	37.98	37.40	37.65	1,348,900	37.27
Jul 30, 2015	36.82	37.46	36.68	37.31	1,240,500	36.94
Jul 29, 2015	36.19	36.96	36.14	36.90	1,264,800	36.53
Jul 28, 2015	35.99	36.48	35.88	36.47	1,249,400	36.10
Jul 27, 2015	35.57	36.31	35.57	36.18	604,300	35.82
Jul 24, 2015	35.47	35.68	35.41	35.56	1,215,400	35.20
Jul 23, 2015	35.75	35.86	35.06	35.51	1,291,900	35.15
Jul 22, 2015	35.60	36.06	35.60	35.82	724,300	35.46
Jul 21, 2015	35.91	36.10	35.40	35.58	931,900	35.22
Jul 20, 2015	36.25	36.27	35.77	35.99	579,900	35.63
Jul 17, 2015	36.44	36.54	36.23	36.30	912,700	35.94
Jul 16, 2015	36.09	36.60	36.01	36.55	944,400	36.18
Jul 15, 2015	35.92	36.03	35.73	36.01	846,500	35.65
Jul 14, 2015	36.23	36.48	35.89	35.93	1,161,300	35.57
Jul 13, 2015	36.67	36.82	36.02	36.17	974,400	35.81
Jul 10, 2015	36.08	36.89	36.01	36.56	2,319,400	36.19
Jul 9, 2015	36.41	36.50	35.81	36.10	1,408,300	35.74
Jul 8, 2015	36.17	36.61	36.11	36.31	1,211,900	35.95
Jul 7, 2015	35.55	36.53	35.50	36.31	1,313,100	35.95
Jul 6, 2015	35.31	35.55	35.11	35.46	1,054,400	35.10
Jul 2, 2015	34.97	35.37	34.82	35.32	1,455,900	34.97
Jul 1, 2015	34.31	34.76	34.17	34.70	1,494,200	34.35

* Close price adjusted for dividends and splits.

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YOU ARE HERE: HOME > HISTORICAL INFLATION RATE

Historical Inflation Rate

OCTOBER 15, 2015 BY TIM MCMAHON ON LEAVE A COMMENT

The table below provides the Historical U.S. Inflation Rate data from 1914 to the Present. For a smaller table with just the inflation rate data since the year 2000, see the Current Inflation page.

The ***Inflation rate*** is calculated from the Consumer Price Index (CPI-U) which is compiled by the U.S. Bureau of Labor Statistics and is based upon a 1982-84 Base of 100. Would you like to know the real definition of inflation or how to calculate inflation? or the monthly rather than annual inflation rate? To view the actual Consumer Price Index data that this inflation data is calculated from, go to the Historical CPI table.

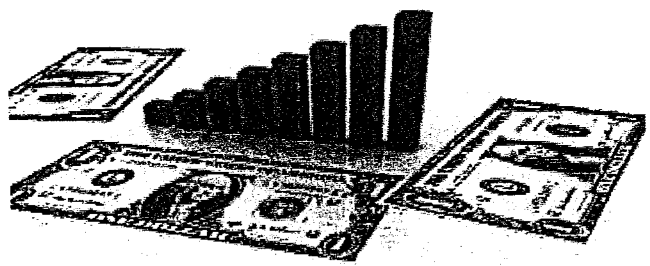
Note: Due to the width of the table, this page is best viewed full screen or as wide as possible.

To see an in depth view of the inflationary makeup of each decade:

|1913-19 | 1920-29 | 1930-39 | 1940-49 | 1950-59 | 1960-69 | |1970-79 | 1980-89 |

Coming soon | 1990-99 | 2000-09 | 2010- Present |

Jump to Bottom of InflationTable or click "year" to reverse order. Click "Ave" to sort years by Average Annual inflation rate rather than date (click again to reverse).Blank Cells indicate that the data is not available because it has not been released by the Bureau of Labor Statistics yet.



Historical Annual U.S. Inflation Rate from 1913 to the present

YEAR	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	AVE.
2015	-0.09 %	-0.03 %	-0.07 %	-0.20 %	-0.04 %	0.12 %	0.17 %	0.20 %	-0.04 %				
2014	1.58 %	1.13 %	1.51 %	1.95 %	2.13 %	2.07 %	1.99 %	1.70 %	1.66 %	1.66 %	1.32 %	0.76 %	1.62 %
2013	1.59 %	1.98 %	1.47 %	1.06 %	1.36 %	1.75 %	1.96 %	1.52 %	1.18 %	0.96 %	1.24 %	1.50 %	1.47 %
2012	2.93 %	2.87 %	2.65 %	2.30 %	1.70 %	1.66 %	1.41 %	1.69 %	1.99 %	2.16 %	1.76 %	1.74 %	2.07 %
2011	1.63 %	2.11 %	2.68 %	3.16 %	3.57 %	3.56 %	3.63 %	3.77 %	3.87 %	3.53 %	3.39 %	2.96 %	3.16 %
2010	2.63 %	2.14 %	2.31 %	2.24 %	2.02 %	1.05 %	1.24 %	1.15 %	1.14 %	1.17 %	1.14 %	1.50 %	1.64 %
2009	0.03 %	0.24 %	-0.38 %	-0.74 %	-1.28 %	-1.43 %	-2.10 %	-1.48 %	-1.29 %	-0.18 %	1.84 %	2.72 %	-0.34 %
2008	4.28 %	4.03 %	3.98 %	3.94 %	4.18 %	5.02 %	5.60 %	5.37 %	4.94 %	3.66 %	1.07 %	0.09 %	3.85 %

2007	2.08 %	2.42 %	2.78 %	2.57 %	2.69 %	2.69 %	2.36 %	1.97 %	2.76 %	3.54 %	4.31 %	4.08 %	2.85 %
2006	3.99 %	3.60 %	3.36 %	3.55 %	4.17 %	4.32 %	4.15 %	3.82 %	2.06 %	1.31 %	1.97 %	2.54 %	3.24 %
2005	2.97 %	3.01 %	3.15 %	3.51 %	2.80 %	2.53 %	3.17 %	3.64 %	4.69 %	4.35 %	3.46 %	3.42 %	3.39 %
2004	1.93 %	1.69 %	1.74 %	2.29 %	3.05 %	3.27 %	2.99 %	2.65 %	2.54 %	3.19 %	3.52 %	3.26 %	2.68 %
2003	2.60 %	2.98 %	3.02 %	2.22 %	2.06 %	2.11 %	2.11 %	2.16 %	2.32 %	2.04 %	1.77 %	1.88 %	2.27 %
2002	1.14 %	1.14 %	1.48 %	1.64 %	1.18 %	1.07 %	1.46 %	1.80 %	1.51 %	2.03 %	2.20 %	2.38 %	1.59 %
2001	3.73 %	3.53 %	2.92 %	3.27 %	3.62 %	3.25 %	2.72 %	2.72 %	2.65 %	2.13 %	1.90 %	1.55 %	2.83 %
2000	2.74 %	3.22 %	3.76 %	3.07 %	3.19 %	3.73 %	3.66 %	3.41 %	3.45 %	3.45 %	3.45 %	3.39 %	3.38 %
1999	1.67 %	1.61 %	1.73 %	2.28 %	2.09 %	1.96 %	2.14 %	2.26 %	2.63 %	2.56 %	2.62 %	2.68 %	2.19 %
1998	1.57 %	1.44 %	1.37 %	1.44 %	1.69 %	1.68 %	1.68 %	1.62 %	1.49 %	1.49 %	1.55 %	1.61 %	1.55 %
1997	3.04 %	3.03 %	2.76 %	2.50 %	2.23 %	2.30 %	2.23 %	2.23 %	2.15 %	2.08 %	1.83 %	1.70 %	2.34 %
1996	2.73 %	2.65 %	2.84 %	2.90 %	2.89 %	2.75 %	2.95 %	2.88 %	3.00 %	2.99 %	3.26 %	3.32 %	2.93 %
1995	2.80 %	2.86 %	2.85 %	3.05 %	3.19 %	3.04 %	2.76 %	2.62 %	2.54 %	2.81 %	2.61 %	2.54 %	2.81 %
1994	2.52 %	2.52 %	2.51 %	2.36 %	2.29 %	2.49 %	2.77 %	2.90 %	2.96 %	2.61 %	2.67 %	2.67 %	2.61 %
1993	3.26 %	3.25 %	3.09 %	3.23 %	3.22 %	3.00 %	2.78 %	2.77 %	2.69 %	2.75 %	2.68 %	2.75 %	2.96 %
1992	2.60 %	2.82 %	3.19 %	3.18 %	3.02 %	3.09 %	3.16 %	3.15 %	2.99 %	3.20 %	3.05 %	2.90 %	3.03 %
1991	5.65 %	5.31 %	4.90 %	4.89 %	4.95 %	4.70 %	4.45 %	3.80 %	3.39 %	2.92 %	2.99 %	3.06 %	4.25 %
1990	5.20 %	5.26 %	5.23 %	4.71 %	4.36 %	4.67 %	4.82 %	5.62 %	6.16 %	6.29 %	6.27 %	6.11 %	5.39 %
1989	4.67 %	4.83 %	4.98 %	5.12 %	5.36 %	5.17 %	4.98 %	4.71 %	4.34 %	4.49 %	4.66 %	4.65 %	4.83 %
1988	4.05 %	3.94 %	3.93 %	3.90 %	3.89 %	3.96 %	4.13 %	4.02 %	4.17 %	4.25 %	4.25 %	4.42 %	4.08 %
1987	1.46 %	2.10 %	3.03 %	3.78 %	3.86 %	3.65 %	3.93 %	4.28 %	4.36 %	4.53 %	4.53 %	4.43 %	3.66 %
1986	3.89 %	3.11 %	2.26 %	1.59 %	1.49 %	1.77 %	1.58 %	1.57 %	1.75 %	1.47 %	1.28 %	1.10 %	1.91 %
1985	3.53 %	3.52 %	3.70 %	3.69 %	3.77 %	3.76 %	3.55 %	3.35 %	3.14 %	3.23 %	3.51 %	3.80 %	3.55 %
1984	4.19 %	4.60 %	4.80 %	4.56 %	4.23 %	4.22 %	4.20 %	4.29 %	4.27 %	4.26 %	4.05 %	3.95 %	4.30 %
1983	3.71 %	3.49 %	3.60 %	3.90 %	3.55 %	2.58 %	2.46 %	2.56 %	2.86 %	2.85 %	3.27 %	3.79 %	3.22 %
1982	8.39 %	7.62 %	6.78 %	6.51 %	6.68 %	7.06 %	6.44 %	5.85 %	5.04 %	5.14 %	4.59 %	3.83 %	6.16 %
1981	11.83 %	11.41 %	10.49 %	10.00 %	9.78 %	9.55 %	10.76 %	10.80 %	10.95 %	10.14 %	9.59 %	8.92 %	10.35 %
1980	13.91 %	14.16 %	14.76 %	14.73 %	14.41 %	14.38 %	13.13 %	12.87 %	12.60 %	12.77 %	12.65 %	12.52 %	13.58 %
1979	9.28 %	9.86 %	10.09 %	10.49 %	10.85 %	10.89 %	11.26 %	11.82 %	12.18 %	12.07 %	12.61 %	13.29 %	11.22 %
1978													

Selected Interest Rates (Weekly) - H.15

Current Release (48 KB PDF)

Release Date: November 2, 2015

The weekly release is posted on Monday. Daily updates of the weekly release are posted Tuesday through Friday on this site. If Monday is a holiday, the weekly release will be posted on Tuesday after the holiday and the daily update will not be posted on that Tuesday.

November 2, 2015
H.15 Selected Interest Rates
Yields in percent per annum

Instruments	2015 Oct 26	2015 Oct 27	2015 Oct 28	2015 Oct 29	2015 Oct 30	Week Ending Oct 30	Week Ending Oct 23	2015 Oct
Federal funds (effective) 1 2 3	0.12	0.12	0.12	0.12	0.07	0.12	0.13	0.12
Commercial Paper 3 4 5 6								
Nonfinancial								
1-month	0.09	0.09	0.14	0.09	0.07	0.10	0.12	0.11
2-month	0.13	0.16	0.18	0.14	0.12	0.15	0.14	0.14
3-month	0.18	0.20	0.14	0.19	n.a.	0.18	0.18	0.18
Financial								
1-month	n.a.	0.12	n.a.	n.a.	n.a.	0.12	0.14	0.13
2-month	0.17	0.17	0.18	0.19	n.a.	0.18	0.18	0.19
3-month	0.25	0.23	0.24	0.25	0.26	0.25	0.24	0.25
Eurodollar deposits (London) 3 7								
1-month	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19
3-month	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33
6-month	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.46
Bank prime loan 2 3 8	3.25	3.25	3.25	3.25	3.25	3.25	3.25	3.25
Discount window primary credit 2 9	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75
U.S. government securities								
Treasury bills (secondary market) 3 4								
4-week	0.01	0.01	0.03	0.02	0.01	0.02	0.04	0.01
3-month	0.02	0.03	0.04	0.07	0.08	0.05	0.01	0.02
6-month	0.16	0.18	0.21	0.21	0.22	0.20	0.12	0.11
1-year	0.23	0.27	0.31	0.31	0.32	0.29	0.22	0.25
Treasury constant maturities								
Nominal 10								
1-month	0.01	0.01	0.03	0.02	0.01	0.02	0.04	0.01
3-month	0.02	0.03	0.04	0.07	0.08	0.05	0.01	0.02
6-month	0.16	0.18	0.21	0.21	0.23	0.20	0.12	0.11
1-year	0.25	0.29	0.33	0.33	0.34	0.31	0.23	0.26
2-year	0.66	0.65	0.73	0.75	0.75	0.71	0.64	0.64
3-year	0.94	0.92	1.00	1.05	1.05	0.99	0.91	0.93
5-year	1.41	1.38	1.47	1.53	1.52	1.46	1.38	1.39

7-year	1.78	1.75	1.83	1.90	1.88	1.83	1.76	1.76
10-year	2.07	2.05	2.10	2.19	2.16	2.11	2.06	2.07
20-year	2.50	2.48	2.50	2.60	2.57	2.53	2.50	2.50
30-year	2.87	2.86	2.87	2.96	2.93	2.90	2.89	2.89
Inflation indexed 11								
5-year	0.25	0.23	0.33	0.34	0.32	0.29	0.23	0.21
7-year	0.41	0.39	0.48	0.50	0.47	0.45	0.41	0.39
10-year	0.59	0.57	0.63	0.67	0.63	0.62	0.59	0.57
20-year	0.96	0.95	0.98	1.02	0.98	0.98	0.99	0.98
30-year	1.19	1.18	1.20	1.24	1.19	1.20	1.23	1.22
Inflation-indexed long-term average 12	0.96	0.95	0.99	1.02	0.98	0.98	0.99	0.97
Interest rate swaps 13								
1-year	0.50	0.49	0.50	0.55	0.56	0.52	0.48	0.49
2-year	0.75	0.73	0.75	0.84	0.85	0.79	0.73	0.75
3-year	1.00	0.96	0.99	1.10	1.11	1.03	0.98	0.99
4-year	1.22	1.17	1.21	1.32	1.33	1.25	1.20	1.21
5-year	1.41	1.36	1.40	1.50	1.51	1.44	1.39	1.40
7-year	1.71	1.67	1.70	1.80	1.81	1.74	1.71	1.71
10-year	2.01	1.97	2.00	2.08	2.09	2.03	2.01	2.01
30-year	2.51	2.47	2.51	2.56	2.56	2.52	2.54	2.53
Corporate bonds								
Moody's seasoned								
Aaa 14	3.90	3.89	3.91	4.04	3.98	3.94	3.92	3.95
Baa	5.29	5.30	5.30	5.40	5.35	5.33	5.33	5.34
State & local bonds 15				3.66		3.66	3.67	3.67
Conventional mortgages 16				3.76		3.76	3.79	3.80

n.a. Not available.

Footnotes

1. The daily effective federal funds rate is a weighted average of rates on brokered trades.

2. Weekly figures are averages of 7 calendar days ending on Wednesday of the current week; monthly figures include each calendar day in the month.

3. Annualized using a 360-day year or bank interest.

4. On a discount basis.

5. Interest rates interpolated from data on certain commercial paper trades settled by The Depository Trust Company. The trades represent sales of commercial paper by dealers or direct issuers to investors (that is, the offer side). The 1-, 2-, and 3-month rates are equivalent to the 30-, 60-, and 90-day dates reported on the Board's Commercial Paper Web page (www.federalreserve.gov/releases/cp/).

6. Financial paper that is insured by the FDIC's Temporary Liquidity Guarantee Program is not excluded from relevant indexes, nor is any financial or nonfinancial commercial paper that may be directly or indirectly affected by one or more of the Federal Reserve's liquidity facilities. Thus the rates published after September 19, 2008, likely reflect the direct or indirect effects of the new temporary programs and, accordingly, likely are not comparable for some purposes to rates published prior to that period.

7. Source: Bloomberg and CTRB ICAP Fixed Income & Money Market Products.

8. Rate posted by a majority of top 25 (by assets in domestic offices) insured U.S.-chartered commercial banks. Prime is one of several base rates used by banks to price short-term business loans.

9. The rate charged for discounts made and advances extended under the Federal Reserve's primary credit discount window program, which became effective January 9, 2003. This rate replaces that for adjustment credit, which was discontinued after January 8, 2003. For further information, see www.federalreserve.gov/boarddocs/press/bcreg/2002/200210312/default.htm. The rate reported is that for the Federal Reserve Bank of New York. Historical series for the rate on adjustment credit as well as the rate on primary credit are available at www.federalreserve.gov/releases/h15/data.htm.

10. Yields on actively traded non-inflation-indexed issues adjusted to constant maturities. The 30-year Treasury constant maturity series was discontinued on February 18, 2002, and reintroduced on February 9, 2006. From February 18, 2002, to February 9, 2006, the U.S. Treasury published a factor for adjusting the daily nominal 20-year constant maturity in order to estimate a 30-year nominal rate. The historical adjustment factor can be found at www.treasury.gov/resource-center/data-chart-center/interest-rates/. Source: U.S. Treasury.

October 15, 2015

Nonfarm Job Gains Above Historic Average; Unemployment Rate Remains Unchanged at 6.3%

Arizona's seasonally adjusted unemployment rate remained unchanged at 6.3% in September. The U.S. seasonally adjusted unemployment rate remained unchanged at 5.1% in September. A year ago, the Arizona seasonally adjusted rate was 6.6% and the U.S. rate was 5.9% (see **Figure 1**).

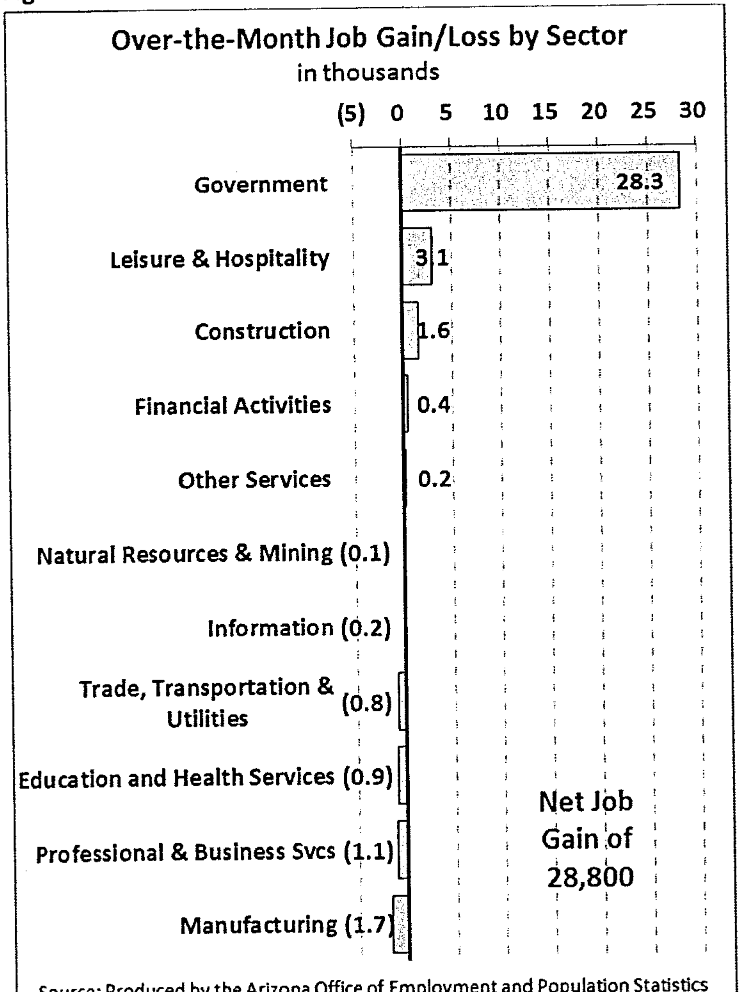
Figure 1

Arizona, U.S. Economic Indicators

Unemployment Rate (Seasonally Adj.)	*Sept'15*	*Aug'15*	*Sept'14*
United States	*5.1%*	*5.1%*	*5.9%*
Arizona	*6.3%*	*6.3%*	*6.6%*
Arizona unadjusted rate	*6.4%*	*6.8%*	*6.9%*

Arizona Nonfarm Employment (in Thousands)	*Sept'15*	*Aug'15*	*Sept'14*
Overall	*2,633.2*	*2,604.4*	*2,575.1*
Over-Month % Chg.	*1.1%*	*1.6%*	*1.0%*
Year-to-Year % Chg.	*2.3%*	*2.2%*	*1.7%*

Figure 2



Over the Month

Arizona gained 28,800 Nonfarm jobs (1.1%) in September (see **Figure 2**). This was more than the post-recessionary ('10-'14) average gain of 25,300 jobs. The Private Sector gained 500 jobs, less than the post-recessionary ('10-'14) average gain of 3,100 jobs. Government gained 28,300 jobs, with the majority of gains occurring in Local (18,900 jobs) and State (11,900 jobs) Government Education. Gains were recorded in five of the eleven sectors, while the remaining six posted losses. The largest gain was recorded in Government (28,300 jobs), followed by Leisure and Hospitality (3,100 jobs), Construction (1,600 jobs), Financial Activities (400 jobs) and Other Services (200 jobs). The largest losses occurred in Manufacturing (-1,700 jobs) and Professional and Business Services (-1,100 jobs), the majority recorded within Administrative and Support and Waste (-800 jobs) and Professional, Scientific and Technical Services (-600). Other sectors which recorded losses include Education and Health

Economy at a Glance

Arizona

Arizona

Data Series	Back Data	Apr 2015	May 2015	June 2015	July 2015	Aug 2015	Sept 2015
Labor Force Data							
Civilian Labor Force (1)		3,163.9	3,165.3	3,156.2	3,145.8	3,141.1	(P) 3,144.2
Employment (1)		2,973.1	2,981.1	2,971.5	2,954.3	2,944.3	(P) 2,947.1
Unemployment (1)		190.8	184.2	184.8	191.4	196.8	(P) 197.1
Unemployment Rate (2)		6.0	5.8	5.9	6.1	6.3	(P) 6.3
Nonfarm Wage and Salary Employment							
Total Nonfarm (3)		2,613.2	2,610.4	2,611.6	2,619.6	2,626.8	(P) 2,631.5
12-month % change		2.2	2.3	1.9	2.1	2.2	(P) 2.2
Mining and Logging (3)		12.9	12.7	12.6	12.8	12.6	(P) 12.5
12-month % change		-1.5	-2.3	-3.8	-2.3	-3.1	(P) -4.6
Construction (3)		127.7	127.0	127.2	129.6	129.2	(P) 130.3
12-month % change		0.9	1.3	2.3	4.9	5.1	(P) 6.3
Manufacturing (3)		155.5	155.9	155.4	155.3	156.3	(P) 155.0
12-month % change		-0.6	-0.5	-0.7	-0.8	-0.1	(P) -0.9
Trade, Transportation, and Utilities (3)		496.7	495.4	496.9	498.9	501.7	(P) 500.3
12-month % change		1.2	0.9	1.0	1.3	1.6	(P) 1.2
Information (3)		43.4	43.1	43.7	43.8	43.3	(P) 43.9
12-month % change		0.9	0.9	0.7	-0.2	-1.1	(P) 0.9
Financial Activities (3)		192.7	194.1	192.8	195.1	196.0	(P) 196.4
12-month % change		2.6	3.0	2.2	3.2	3.3	(P) 3.3
Professional & Business Services (3)		391.0	394.7	395.7	398.3	394.3	(P) 393.2
12-month % change		3.3	3.8	3.7	4.0	2.4	(P) 1.8
Education & Health Services (3)		391.6	391.7	394.3	393.3	397.3	(P) 395.5
12-month % change		3.5	3.3	3.8	3.2	4.0	(P) 3.5
Leisure & Hospitality (3)		293.8	294.8	292.9	295.1	295.8	(P) 299.1
12-month % change		3.1	3.4	2.7	3.5	3.3	(P) 4.2
Other Services (3)		94.4	94.3	93.6	93.7	93.2	(P) 93.6
12-month % change		7.9	7.8	7.0	6.8	6.0	(P) 5.6
Government (3)		413.5	406.7	406.5	403.7	407.1	(P) 411.7
12-month % change		0.9	1.1	-1.0	-1.5	-0.8	(P) 0.1

Footnotes
(1) Number of persons, in thousands, seasonally adjusted.
(2) In percent, seasonally adjusted.
(3) Number of jobs, in thousands, seasonally adjusted.
(P) Preliminary

Data extracted on: October 30, 2015

Source: U.S. Bureau of Labor Statistics
Note: More data series, including additional geographic areas, are available through the "Databases & Tables" tab at the top of this page.

Arizona includes the following metropolitan areas for which an Economy At A Glance table is

Economy at a Glance

United States

United States - Monthly Data

Data Series	Back Data	Apr 2015	May 2015	June 2015	July 2015	Aug 2015	Sept 2015
Unemployment Rate (1)		5.4	5.5	5.3	5.3	5.1	5.1
Change in Payroll Employment (2)		187	260	245	223	(P) 136	(P) 142
Average Hourly Earnings (3)		24.89	24.95	24.95	25.01	(P) 25.10	(P) 25.09
Consumer Price Index (4)		0.1	0.4	0.3	0.1	-0.1	-0.2
Producer Price Index (5)		-0.1	0.5	(P) 0.2	(P) 0.2	(P) 0.0	(P) -0.5
U.S. Import Price Index (6)		-0.2	1.1	0.1	(R) -1.0	(R) -1.6	(R) -0.1

Footnotes
(1) In percent, seasonally adjusted. Annual averages are available for Not Seasonally Adjusted data.
(2) Number of jobs, in thousands, seasonally adjusted.
(3) Average Hourly Earnings for all employees on private nonfarm payrolls.
(4) All items, U.S. city average, all urban consumers, 1982-84=100, 1-month percent change, seasonally adjusted.
(5) Final Demand, 1-month percent change, seasonally adjusted.
(6) All imports, 1-month percent change, not seasonally adjusted.
(R) Revised
(P) Preliminary

United States - Quarterly Data

Data Series	Back Data	3rd Qtr 2014	4th Qtr 2014	1st Qtr 2015	2nd Qtr 2015	3rd Qtr 2015
Employment Cost Index (1)		0.7	0.5	0.7	0.2	0.6
Productivity (2)		3.1	-2.2	-1.1	(R) 3.3	

Footnotes
(1) Compensation, all civilian workers, quarterly data, 3-month percent change, seasonally adjusted.
(2) Output per hour, nonfarm business, quarterly data, percent change from previous quarter at annual rate, seasonally adjusted.
(R) Revised

Data extracted on: October 30, 2015

Source: U.S. Bureau of Labor Statistics
Note: More data series, including additional geographic areas, are available through the "Databases & Tables" tab at the top of this page.

UNS

UNS Energy Corporation
88 E. Broadway Blvd., 85701
Mail Stop HQE910
PO Box 711, Tucson, Arizona 85702-0711

March 5, 2015

Docket Control
Arizona Corporation Commission
1200 West Washington Street
Phoenix, AZ 85007

Re: Notice of Compliance Filing – Credit Rating Upgrades
Docket Nos. E-04230A-14-0011 and E-01933A-14-0011

Pursuant to Condition No. 45 of the Settlement Agreement approved by the Commission in Decision No. 74689 (August 12, 2014) which requires Fortis Inc. and UNS Energy Corporation to report to the Commission and RUCO any changes in the credit ratings of Fortis Inc., UNS Energy Corporation or the Regulated Utilities, UNS Energy hereby provides notice that on February 27, 2015, Moody's Investor Service upgraded the senior secured ratings of UNS Energy Corporation to Baa1 from Baa2 and the senior unsecured and issuer ratings of Tucson Electric Power Company (TEP), UNS Gas, Inc. (UNSG) and UNS Electric, Inc. (UNSE) to A3 from Baa1.

The full report announcing credit upgrades for UNS Energy Corporation and the Regulated Utilities can be found at https://www.moodys.com/research/Moodys-upgrades-UNS-Energy-Corp-and-its-subsidiaries-outlooks-are--PR_319042.

Please contact me if you have any questions.

Sincerely,

Bradley S. Carroll
Assistant General Counsel, State Regulatory

BSC:jh

Original and 13 copies filed with Docket Control
cc: David Tenney, RUCO
Compliance Section

Rating Action: Moody's Assigns Baa1 Senior Unsecured Rating to UNS Energy's Bank Credit Facility

Global Credit Research - 24 Sep 2015

New York, September 24, 2015 -- Moody's Investors Service ("Moody's") assigned a Baa1 senior unsecured rating to UNS Energy Corporation's (UNS: Baa1 stable) new $150 million Senior Unsecured Revolving Credit and Letter of Credit Facility. The new senior unsecured credit facility will replace the existing $125 million senior secured credit facility expiring in November 2016. At the same time, Moody's assigned an A3 senior unsecured rating to Tucson Electric Power Company's (TEP: A3 stable) new $250 million senior unsecured revolving credit facility and UNS Gas, Inc. (UNSG: A3 stable) and UNS Electric, Inc.'s (UNSE: A3 stable) new $100 million joint revolving credit facility. All three facilities will expire in October 2020. Upon closing of the new credit facilities, the ratings on the existing revolving credit facilities will be withdrawn. The rating outlooks are stable.

"UNS Energy's Baa1 senior unsecured rating is the same rating as the prior senior secured rating because we did not assign any material value to the security claim under the existing credit facility because the collateral was in the form of subsidiary stock, excluding the principal subsidiary, TEP" said Jeffrey Cassella, Vice President.

RATINGS RATIONALE

UNS Energy's Baa1 senior unsecured rating is the same as UNS Energy's current senior secured rating given that the security was limited to the stock of certain subsidiaries, excluding UNS Energy's largest subsidiary, TEP. As a result, we assigned no notching lift to its security collateral and already viewed UNS Energy's credit quality to an unsecured claim within the consolidated capital structure.

UNS Energy's Baa1 rating reflects structural subordination relative to its A3 senior unsecured rated operating utility subsidiaries, TEP, UNSG, and UNSE and their improved financial profile. The rating reflects a constructive Arizona regulatory environment, which allow a suite of timely recovery mechanisms; and the expectation that financial metrics will remain stable, including UNS Energy's ratio of cash flow from operations before working capital changes (CFO pre-W/C) to debt in the low 20% range over the next few years. In addition, UNS Energy's rating reflects the stable cash flows (i.e., upstream dividends) provided by its regulated utility subsidiaries with the expectation of renewed economic growth in Arizona balanced against TEP's relatively concentrated service territory and large coal generation exposure, which they are diversifying over time.

The stable rating outlook for UNS Energy and its subsidiaries reflects our expectation that the credit supportiveness of the Arizona regulatory environment is sustained; stable cash flows continue at each subsidiary due to reasonable and timely recoveries of fuel and purchased power costs such that UNS Energy's CFO pre-W/C to debt will continue in the low 20% range, and economic growth in Arizona continues to improve.

What Could Change the Rating -- Up

UNS Energy's rating could be upgraded if the economic growth in Arizona resumes at pre-recession levels which contributes to further strengthening of financial metrics or if there was an improvement in the regulatory environment that led to meaningfully greater predictability, timeliness and/or sufficiency of rates such that financial metrics improve on a sustained basis including CFO pre-W/C to debt in the mid-20% range. UNS Energy's rating could be upgraded if its principal subsidiary, TEP, were to be upgraded.

What Could Change the Rating - Down

UNS Energy's rating outlook could be downgraded if a more contentious regulatory environment re-emerged in Arizona that resulted in a deterioration in the credit supportiveness of the regulatory framework which might include greater regulatory lag, uncertainty about the recovery of investments, further compression in rates (especially if accompanied by a rise in interest rates) or if financial metrics deteriorated such that CFO pre-W/C to debt were to decline to high teens range on a sustained basis.

Rating Assigned:

Assignments:

..Issuer: Tucson Electric Power Company

....Senior Unsecured Bank Credit Facility, Assigned A3

..Co-Issuers: UNS Electric, Inc./UNS Gas, Inc.

....Senior Unsecured Bank Credit Facility, Assigned A3

..Issuer: UNS Energy Corporation

....Senior Unsecured Bank Credit Facility, Assigned Baa1

Headquartered in Tucson, Arizona, UNS Energy, which was acquired by Fortis Inc. (Fortis: not rated) on August 15, 2014, is a utility holding company, whose principal subsidiary is Tucson Electric Power Company, a vertically integrated regulated electric utility in southern Arizona. UNS Energy is parent of UniSource Energy Services, Inc. (UES: not rated), an intermediate holding company, that holds the common stock of UNS Gas, Inc., a small regulated natural gas distribution company in Arizona, and UNS Electric, Inc., a small vertically integrated regulated electric utility in Arizona.

The principal methodology used in these ratings was Regulated Electric and Gas Utilities published in December 2013. Please see the Credit Policy page on www.moodys.com for a copy of this methodology.

REGULATORY DISCLOSURES

For ratings issued on a program, series or category/class of debt, this announcement provides certain regulatory disclosures in relation to each rating of a subsequently issued bond or note of the same series or category/class of debt or pursuant to a program for which the ratings are derived exclusively from existing ratings in accordance with Moody's rating practices. For ratings issued on a support provider, this announcement provides certain regulatory disclosures in relation to the rating action on the support provider and in relation to each particular rating action for securities that derive their credit ratings from the support provider's credit rating. For provisional ratings, this

Related Issuers

Tucson Electric Power Company

UNS Electric, Inc.

UNS Energy Corporation

Related Research

Credit Opinion: UNS Electric, Inc.

Credit Opinion: Tucson Electric Power Company

Credit Opinion: UNS Energy Corporation

Rating Action: Moody's upgrades UNS Energy Corp. and its subsidiaries; outlooks are stable

Sector Comment: US Regulated Electric and Gas Utilities: Arizona's Constructive Regulatory Environment Supports the Credit Quality of Its Investor-Owned Regulated Utilities announcement provides certain regulatory disclosures in relation to the provisional rating assigned, and in relation to a definitive rating that may be assigned subsequent to the final issuance of the debt, in each case where the transaction structure and terms have not changed prior to the assignment of the definitive rating in a manner that would have affected the rating. For further information please see the ratings tab on the issuer/entity page for the respective issuer on www.moodys.com.

For any affected securities or rated entities receiving direct credit support from the primary entity(ies) of this rating action, and whose ratings may change as a result of this rating action, the associated regulatory disclosures will be those of the guarantor entity. Exceptions to this approach exist for the following disclosures, if applicable to jurisdiction: Ancillary Services, Disclosure to rated entity, Disclosure from rated entity.

Regulatory disclosures contained in this press release apply to the credit rating and, if applicable, the related rating outlook or rating review.

Please see www.moodys.com for any updates on changes to the lead rating analyst and to the Moody's legal entity that has issued the rating.

Please see the ratings tab on the issuer/entity page on www.moodys.com for additional regulatory disclosures for each credit rating.

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MOODY'S
INVESTORS SERVICE

Print

Press Release

Release Date: October 28, 2015

For immediate release

Information received since the Federal Open Market Committee met in September suggests that economic activity has been expanding at a moderate pace. Household spending and business fixed investment have been increasing at solid rates in recent months, and the housing sector has improved further; however, net exports have been soft. The pace of job gains slowed and the unemployment rate held steady. Nonetheless, labor market indicators, on balance, show that underutilization of labor resources has diminished since early this year. Inflation has continued to run below the Committee's longer-run objective, partly reflecting declines in energy prices and in prices of non-energy imports. Market-based measures of inflation compensation moved slightly lower; survey-based measures of longer-term inflation expectations have remained stable.

Consistent with its statutory mandate, the Committee seeks to foster maximum employment and price stability. The Committee expects that, with appropriate policy accommodation, economic activity will expand at a moderate pace, with labor market indicators continuing to move toward levels the Committee judges consistent with its dual mandate. The Committee continues to see the risks to the outlook for economic activity and the labor market as nearly balanced but is monitoring global economic and financial developments. Inflation is anticipated to remain near its recent low level in the near term but the Committee expects inflation to rise gradually toward 2 percent over the medium term as the labor market improves further and the transitory effects of declines in energy and import prices dissipate. The Committee continues to monitor inflation developments closely.

To support continued progress toward maximum employment and price stability, the Committee today reaffirmed its view that the current 0 to 1/4 percent target range for the federal funds rate remains appropriate. In determining whether it will be appropriate to raise the target range at its next meeting, the Committee will assess progress--both realized and expected--toward its objectives of maximum employment and 2 percent inflation. This assessment will take into account a wide range of information, including measures of labor market conditions, indicators of inflation pressures and inflation expectations, and readings on financial and international developments. The Committee anticipates that it will be appropriate to raise the target range for the federal funds rate when it has seen some further improvement in the labor market and is reasonably confident that inflation will move back to its 2 percent objective over the medium term.

The Committee is maintaining its existing policy of reinvesting principal payments from its holdings of agency debt and agency mortgage-backed securities in agency mortgage-backed securities and of rolling over maturing Treasury securities at auction. This policy, by keeping the Committee's holdings of longer-term securities at sizable levels, should help maintain accommodative financial conditions.

When the Committee decides to begin to remove policy accommodation, it will take a balanced approach consistent with its longer-run goals of maximum employment and inflation of 2 percent. The Committee currently anticipates that, even after employment and inflation are near mandate-consistent levels, economic conditions may, for some time, warrant keeping the target federal funds rate below levels the Committee views as normal in the longer run.

Voting for the FOMC monetary policy action were: Janet L. Yellen, Chair; William C. Dudley, Vice Chairman; Lael Brainard; Charles L. Evans; Stanley Fischer; Dennis P. Lockhart; Jerome H. Powell; Daniel K. Tarullo; and John C. Williams. Voting against the action was Jeffrey M. Lacker, who preferred to raise the target range for the federal funds rate by 25 basis points at this meeting.

2015 Monetary Policy Releases

Press Release

Release Date: September 17, 2015

For immediate release

Information received since the Federal Open Market Committee met in July suggests that economic activity is expanding at a moderate pace. Household spending and business fixed investment have been increasing moderately, and the housing sector has improved further; however, net exports have been soft. The labor market continued to improve, with solid job gains and declining unemployment. On balance, labor market indicators show that underutilization of labor resources has diminished since early this year. Inflation has continued to run below the Committee's longer-run objective, partly reflecting declines in energy prices and in prices of non-energy imports. Market-based measures of inflation compensation moved lower; survey-based measures of longer-term inflation expectations have remained stable.

Consistent with its statutory mandate, the Committee seeks to foster maximum employment and price stability. Recent global economic and financial developments may restrain economic activity somewhat and are likely to put further downward pressure on inflation in the near term. Nonetheless, the Committee expects that, with appropriate policy accommodation, economic activity will expand at a moderate pace, with labor market indicators continuing to move toward levels the Committee judges consistent with its dual mandate. The Committee continues to see the risks to the outlook for economic activity and the labor market as nearly balanced but is monitoring developments abroad. Inflation is anticipated to remain near its recent low level in the near term but the Committee expects inflation to rise gradually toward 2 percent over the medium term as the labor market improves further and the transitory effects of declines in energy and import prices dissipate. The Committee continues to monitor inflation developments closely.

To support continued progress toward maximum employment and price stability, the Committee today reaffirmed its view that the current 0 to 1/4 percent target range for the federal funds rate remains appropriate. In determining how long to maintain this target range, the Committee will assess progress--both realized and expected--toward its objectives of maximum employment and 2 percent inflation. This assessment will take into account a wide range of information, including measures of labor market conditions, indicators of inflation pressures and inflation expectations, and readings on financial and international developments. The Committee anticipates that it will be appropriate to raise the target range for the federal funds rate when it has seen some further improvement in the labor market and is reasonably confident that inflation will move back to its 2 percent objective over the medium term.

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2015 Monetary Policy Releases

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Thu, Nov 5, 2015, 11:11AM EST - U.S. Markets close in 4 hrs 49 mins Report an Issue

Dow Jones Industrial Average (^DJI) - DJI

17,784.86 82.72(0.46%) 11:11AM EST

Historical Prices

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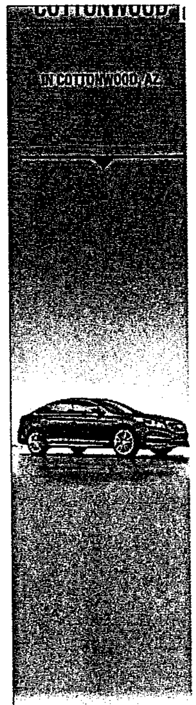

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Prices

Date	Open	High	Low	Close	Avg Vol	Adj Close*
Nov 2, 2015	17,672.62	17,977.85	17,655.02	17,867.58	130,970,000	17,867.58
Oct 1, 2015	16,278.62	17,799.96	16,013.66	17,663.54	125,215,400	17,663.54
Sep 1, 2015	16,528.03	16,933.43	15,942.37	16,284.70	138,191,400	16,284.70
Aug 3, 2015	17,696.74	17,704.76	15,370.33	16,528.03	136,560,900	16,528.03
Jul 1, 2015	17,638.12	18,137.12	17,399.17	17,689.86	97,288,100	17,689.86
Jun 1, 2015	18,017.82	18,188.81	17,576.50	17,619.51	106,622,700	17,619.51
May 1, 2015	17,859.27	18,351.36	17,733.12	18,010.68	98,613,000	18,010.68
Apr 1, 2015	17,778.52	18,175.56	17,585.01	17,840.52	109,717,100	17,840.52
Mar 2, 2015	18,134.05	18,288.63	17,579.27	17,776.12	117,725,000	17,776.12
Feb 2, 2015	17,169.99	18,244.38	17,037.76	18,132.70	97,492,600	18,132.70
Jan 2, 2015	17,823.07	17,951.78	17,136.30	17,164.95	117,091,000	17,164.95
Dec 1, 2014	17,827.27	18,103.45	17,067.59	17,823.07	104,533,600	17,823.07
Nov 3, 2014	17,390.90	17,894.83	17,278.36	17,828.24	84,050,500	17,828.24
Oct 1, 2014	17,040.46	17,395.54	15,855.12	17,390.52	131,515,200	17,390.52
Sep 2, 2014	17,097.42	17,350.64	16,934.43	17,042.90	93,944,700	17,042.90
Aug 1, 2014	16,561.70	17,153.80	16,333.78	17,098.45	74,480,800	17,098.45
Jul 1, 2014	16,828.53	17,151.56	16,563.30	16,563.30	81,479,500	16,563.30
Jun 2, 2014	16,716.85	16,978.02	16,673.65	16,826.60	87,897,100	16,826.60
May 1, 2014	16,580.26	16,735.51	16,341.30	16,717.17	83,254,700	16,717.17
Apr 1, 2014	16,458.05	16,631.63	16,015.32	16,580.84	99,044,200	16,580.84
Mar 3, 2014	16,321.71	16,505.70	16,046.99	16,457.66	104,783,300	16,457.66
Feb 3, 2014	15,697.69	16,398.95	15,340.69	16,321.71	165,366,800	16,321.71
Jan 2, 2014	16,572.17	16,573.07	15,617.55	15,698.85	110,196,600	15,698.85
Dec 2, 2013	16,087.12	16,588.25	15,703.79	16,576.66	101,710,400	16,576.66
Nov 1, 2013	15,558.01	16,174.51	15,522.18	16,086.41	94,472,500	16,086.41
Oct 1, 2013	15,132.49	15,721.00	14,719.43	15,545.75	100,898,600	15,545.75
Sep 3, 2013	14,801.55	15,709.58	14,777.48	15,129.67	124,693,500	15,129.67
Aug 1, 2013	15,503.85	15,658.43	14,760.41	14,810.31	111,977,700	14,810.31
Jul 1, 2013	14,911.60	15,634.32	14,858.93	15,499.54	125,829,500	15,499.54
Jun 3, 2013	15,123.55	15,340.09	14,551.27	14,909.60	157,952,000	14,909.60
May 1, 2013	14,839.80	15,542.40	14,687.05	15,115.57	135,470,000	15,115.57
Apr 1, 2013	14,578.54	14,887.51	14,434.43	14,839.80	139,476,300	14,839.80
Mar 1, 2013	14,054.49	14,585.10	13,937.60	14,578.54	135,001,500	14,578.54
Feb 1, 2013	13,860.58	14,149.15	13,784.01	14,054.49	140,248,900	14,054.49
Jan 2, 2013	13,104.30	13,969.99	13,104.30	13,860.58	139,489,500	13,860.58
Dec 3, 2012	13,027.73	13,365.86	12,883.89	13,104.14	140,624,500	13,104.14
Nov 1, 2012	13,099.19	13,290.75	12,471.49	13,025.58	135,952,300	13,025.58
Oct 1, 2012	13,437.66	13,661.87	13,017.37	13,096.46	124,321,900	13,096.46
Sep 4, 2012	13,092.15	13,653.24	12,977.09	13,437.13	149,906,300	13,437.13
Aug 1, 2012	13,007.47	13,330.76	12,778.90	13,090.84	103,785,200	13,090.84

Jul 2, 2012	12,879.71	13,128.64	12,492.25	13,008.68	128,766,100	13,008.68
Jun 1, 2012	12,391.56	12,898.94	12,035.09	12,880.09	148,347,600	12,880.09
May 1, 2012	13,214.16	13,338.66	12,311.56	12,393.45	147,960,900	12,393.45
Apr 2, 2012	13,211.36	13,297.11	12,710.56	13,213.63	135,138,500	13,213.63
Mar 1, 2012	12,952.29	13,289.08	12,734.86	13,212.04	153,390,000	13,212.04
Feb 1, 2012	12,632.76	13,055.75	12,632.76	12,952.07	144,731,500	12,952.07
Jan 3, 2012	12,221.19	12,841.95	12,221.19	12,632.91	157,457,500	12,632.91
Dec 1, 2011	12,046.21	12,328.47	11,735.19	12,217.56	150,864,200	12,217.56
Nov 1, 2011	11,951.53	12,187.51	11,231.43	12,045.68	169,042,800	12,045.68
Oct 3, 2011	10,912.10	12,284.31	10,404.49	11,955.01	194,929,500	11,955.01
Sep 1, 2011	11,613.30	11,716.84	10,597.14	10,913.38	219,510,400	10,913.38
Aug 1, 2011	12,144.22	12,282.42	10,604.07	11,613.53	279,694,300	11,613.53
Jul 1, 2011	12,414.34	12,753.89	12,083.45	12,143.24	166,169,500	12,143.24
Jun 1, 2011	12,569.41	12,569.49	11,862.53	12,414.34	184,383,600	12,414.34
May 2, 2011	12,810.16	12,876.00	12,309.52	12,569.79	180,300,400	12,569.79
Apr 1, 2011	12,321.02	12,832.83	12,093.89	12,810.54	184,985,500	12,810.54
Mar 1, 2011	12,226.49	12,383.46	11,555.48	12,319.73	175,563,900	12,319.73
Feb 1, 2011	11,892.50	12,391.29	11,892.50	12,226.34	180,002,100	12,226.34
Jan 3, 2011	11,577.43	12,020.52	11,573.87	11,891.93	194,415,000	11,891.93
Dec 1, 2010	11,007.23	11,625.00	11,007.23	11,577.51	152,101,300	11,577.51
Nov 1, 2010	11,120.30	11,451.53	10,929.28	11,006.02	192,471,400	11,006.02
Oct 1, 2010	10,789.72	11,247.60	10,711.12	11,118.49	189,376,100	11,118.49
Sep 1, 2010	10,016.01	10,948.88	10,016.01	10,788.05	189,500,400	10,788.05
Aug 2, 2010	10,468.82	10,719.94	9,936.62	10,014.72	198,771,300	10,014.72
Jul 1, 2010	9,773.27	10,584.99	9,614.32	10,465.94	211,975,200	10,465.94
Jun 1, 2010	10,133.94	10,594.16	9,753.84	9,774.02	235,307,700	9,774.02
May 28, 2010	10,258.00	10,258.00	10,095.90	10,136.63	487,440,000	10,136.63

* Close price adjusted for dividends and splits.

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Currency in USD.

RUCO-4
admitted

UNS ELECTRIC, INC.

DOCKET NO. E-04204A-15-0142

SURREBUTTAL TESTIMONY

OF

ROBERT MEASE

ON BEHALF OF THE

RESIDENTIAL UTILITY CONSUMER OFFICE

FEBRUARY 23, 2016

TABLE OF CONTENTS

EXECUTIVE SUMMARY

The Residential Utility Consumer Office's ("RUCO") has reviewed UNS Electric, Inc.'s ("UNSE") rebuttal testimony filed in regards to its application for a permanent rate increase, filed with the Arizona Corporation Commission ("ACC" or "Commission") on May 4, 2015, and RUCO recommends the following:

Cost of Equity – RUCO recommends that the Commission adopt a 9.13 percent cost of common equity. RUCO's recommendation of 9.13 percent is the result obtained from the Discounted Cash Flow model ("DCF") the Capital Asset Pricing Model ("CAPM") and the Comparable Earnings Mode ("CEM")l. RUCO included a Comparable Earnings Model in Its rebuttal testimony only and was not included in direct testimony. The Company's cost of capital witness continues to recommend a cost of equity of 10.35 percent even though the Company has agreed with 9.50 percent return that is being recommended by Staff and also is UNSE's current rate of return on common equity.

Cost of Debt – RUCO recommends that the Commission adopt the actual cost of long-term debt of 4.66 percent which is UNSE's actual end of test year cost of long-term debt. This compares to the cost of debt previously approved in Decision No. 74235 of 5.47 percent.

Capital Structure – RUCO recommends that the Commission adopt UNSE's actual end of test year capital structure comprised of no short-term debt, 47.17 percent long-term debt and 52.83 percent common equity.

Original Cost Rate of Return – RUCO recommends that the Commission adopt a 7.17 percent weighted average cost of capital as the original cost rate of return for UNSE. This compares to the Company's requested weighted average original cost of capital of 7.67 percent.

Fair Value Rate of Return – RUCO recommends that the Commission adopt a fair value rate of return of 5.48 percent for UNSE, which is RUCO's 7.02 percent original cost rate of return minus RUCO's recommended inflation adjustment of 1.54 percent. The method used by RUCO to arrive at this 7.02 percent figure is consistent with the methods adopted by the Arizona Corporation Commission in prior UNSE and UNS Gas, Inc. rate case proceedings.

INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My Name is Robert B. Mease. I am the Chief of Accounting and Rates for the Residential Utility Consumer Office ("RUCO") located at 1110 W. Washington, Suite 220, Phoenix, Arizona 85007.

Q. Have you previously provided testimony regarding this docket?

A. Yes. I filed testimony in this docket on November 5, 2015.

Q. What is the purpose of your surrebuttal testimony?

A. My surrebuttal testimony will address the Company's rebuttal proposals and comments pertaining to adjustments I recommended in my direct testimony. I will also briefly discuss other intervening parties who addressed cost of capital issues in this filing and will present additional adjustments that are being made by RUCO to supplement what was proposed in direct testimony.

SUMMARY OF TESTIMONY AND RECOMMENDATIONS

Q. Please summarize the recommendations and adjustments that you will address in your surrebuttal testimony.

A. Based on the results of my analysis, I am making the following recommendations:

Cost of Equity Capital – I am revising my initial cost of equity from 8.35 percent and now recommending that the Commission adopt a 9.13 percent cost of common equity. The 9.13 percent figure is the result obtained from my cost of equity analysis after the inclusion a CEM and updates and revisions to both the CAPM and DCF models.

Cost of Debt – RUCO is recommending that the Commission adopt the Company's end of test year cost of long-term debt of 4.66 percent. This compares favorably to the Company's previous rate application where the cost of long-term debt was approved at 5.47 percent.

Capital Structure – I am recommending that the Commission adopt UNSE's actual end of test year capital structure comprised of 52.83 percent common equity and 47.17 percent long-term debt. The Company has no short-term debt.

Original Cost Rate of Return – I am recommending that the ACC adopt a 7.17 percent weighted average cost of capital as the original cost rate of return ("OCROR") for UNSE. This 7.17 percent figure is the weighted cost of RUCO's recommended costs of common equity and debt, and is 59 basis points lower than the 7.72 percent weighted average cost of capital being proposed by the Company.

Fair Value Rate of Return – I am recommending that the Commission adopt a fair value rate of return ("FVROR") of 5.48 percent which is my recommended 7.02 percent OCROR minus an inflation adjustment of 1.54 percent.

Q Why do you believe that RUCO's recommended 7.02 percent OCROR and 5.48 percent FVROR are appropriate rates of return for UNSE to earn on its invested capital?

A. Both the OCROR and FVROR figures that I am recommending for UNSE meet the criteria established in the landmark Supreme Court cases of <u>Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia</u> (262 U.S. 679, 1923) and <u>Federal Power Commission v. Hope Natural Gas Company</u> (320 U.S. 391, 1944).

RUCO'S COST OF EQUITY CAPITAL

Q. What is your final recommended cost of equity capital for UNSE?

A. I am recommending a cost of equity of 9.13 percent. My cost of equity recommendation is slanted towards the high side of the range of results derived from my DCF and CAPM analyses and I have also prepared a Comparable Earnings Analysis and included the results in my final calculations.

Discounted Cash Flow (DCF) Method

Q. Is the DCF model an acceptable methodology used in ratemaking for public utilities?

A. Yes. Basically the DCF model, is one of the oldest and most utilized models in determining the cost of equity in many utility hearings. In a 2014 rate case filing by Potomac Electric Power, in Washington, D.C., the commission relied primarily on a DCF analysis to arrive at the authorized ROE, "finding that the DCF method produces results more reasonable than those of other calculation methods."[1] While the DCF model is the most widely used and accepted model, including Arizona, it should be supplemented with at least one additional model to add additional support to the final cost of equity calculation.

Q. Have you made changes to your DCF model that was filed in your direct testimony?

A. Yes. I've made modifications resulting from updates to published data from Value Line, I've reduced the number of proxy companies by two, as a result of recent mergers, that were used for comparative purposes and I've "tweaked" several on the inputs that were part of my original DCF model as filed in direct testimony.

[1] See EEI Report, page 29

Capital Asset Pricing Model (CAPM) Method

Q. Can you please describe the CAPM and the benefits of preparing this analysis?

A. The CAPM describes the relationship between a security's investment risk and its market rate of return. This relationship identifies the rate of return which investors expect a security to earn so that its market return is comparable with the market returns earned by other securities that have similar risk.

Q. Can you please identify the strengths of using the CAPM model in your analysis?

A. The strengths of the CAPM are as follows: (1) it is based on the concept of risk and return; (2) it is company specific as it relates to the specific beta's within the industry; (3) it has widespread use as it recognizes that investors can and do diversify; (4) it's highly structured and easy to apply when using the assumptions of the model; (5) the model is formulistic and the data used in the computations is readily available; (6) it is a forward looking concept; and (7) it is a method for converting changes in interest rates to the cost of equity.

Q. What are the results of your CAPM analysis?

A. As shown on pages 1 and 2 of Schedule RBM-6, my CAPM calculation using an arithmetic mean results in an average expected return of 6.84

percent and the results of using a geometric mean is 7.07 percent. I used an average of the geometric and arithmetic means in my final determination for RUCO's cost of equity recommendation.

Q. Have you made changes to your CAPM that was filed in your direct testimony?

A. Yes. I made updates and revisions to the CAPM included in this filing for the same reasons as identified on page 6 in this filing related to the DCF model revisions.

Comparable Earnings Model (Analysis)

Q. Can you please explain the purpose of a comparable earnings analysis and what companies were included in performing your analysis?

A. The CEM analysis is basically used for comparative purposes in analyzing returns expected to be earned on the original cost and book value of companies with similar risks. The companies used in my CEM are the same proxy companies that were included in my DCF and CAPM models.

Q. What period of time did you analyze and include in your analysis?

A. I used actual earnings for the years 2002 through 2014 and projected earnings as published in Value Line for the years 2015 through and including year 2020.

Q. Please summarize the results derived under each of the methodologies presented in your testimony.

A. The following is a summary of the cost of equity capital derived under each methodology used:

METHOD	RESULTS
DCF	8.33% -- 10.12%
CAPM	6.84% -- 7.07%
CEM	8.75% -- 10.00%

Based on these results, my best estimate of an appropriate range for a cost of common equity for the Company is 8.00 percent to 10.00 percent and RUCO's final cost of equity recommendation is 9.13 percent. Included in my calculation for the CAPM, I used an average of both the arithmetic and geometric means as sophisticated investors have access to both and that both are included in investment decisions. See RBM-3 for calculations.

Q. Can you provide a comparison of the results derived from Ms. Bulkley's models and yours?

	Company Witness	RUCO
DCF – Constant Growth	9.04% – 10.35%	8.33 % -- 10.12%
DCF – Multi-Stage	9.30% -- 9.92%	
CAPM	9.59% -- 11.10%	6.84% -- 7.07%
CEM		8.75% -- 10.00%

UNSE's / STAFF's / RUCO's PROPOSED COST OF EQUITY CAPITAL

Q. Have you reviewed UNSE's rebuttal testimony on the Company-proposed cost of equity capital?

A. Yes, I have reviewed the testimony of the Company's cost of equity expert witness, Ms. Ann Bulkley.

Q. Can you please compare Ms. Bulkley's cost of equity as filed in UNSE's original application to the cost of equity as recommended in the Company's rebuttal testimony?

A. Yes. Ms. Bulkley recommended a cost of equity of 10.35 percent in the Company's initial filing and continues to recommend 10.35 in her rebuttal testimony. However, she goes on to say on page 79 of her rebuttal testimony that "I understand that UNS Electric would not oppose Staff's recommendations related to the ROE and fair value increment rate underlying the FVROR as long as the overall revenue increase and rate design approved provides UNS Electric a reasonable opportunity to earn its authorized ROE."

Q. And what is Staff's cost of equity recommendation in this case?

A. As indicated in Mr. Abinah's testimony, Staff's cost of capital witness, "Staff recommends that the Commission grant UNS Electric, Inc. a 9.50 percent cost of equity and 0.50 percent fair value increment. This is the same cost of equity and fair value increment awarded UNSE in Commission Decision No. 74235, issued on December 31, 2013."

Q. Isn't this somewhat unusual for Staff to adopt a cost of equity that is a holdover from the prior rate case decision?

A. Yes, while it is unusual it does happen on occasion. RUCO has also adopted a previous approved cost of equity when the case was decided within several months prior to the newer filing and it happened to be within the same parent company.

Q. Can you briefly describe the last rate case as filed by UNSE and the final decision as it relates to cost of equity and final rate of return?

A. Yes I will. The last rate case filed by UNSE had a test year ending June 30, 2012 and the final decision was issued on December 31, 2013. The cost of capital witness in that case for UNS, Ms. Bulkley, recommended a cost of equity of 10.50 percent. The cost of capital witness for the Staff had developed a cost of equity between the ranges of 8.50 percent to 10 percent and a final recommendation for cost of equity of 9.25 percent. Staff witness also recommended the final capital structure including the cost of debt that was included in the capital structure as filed by the company and approved in the final decision.

Q. What was the Commission's final decision reached in Docket No. E-04204A-12-0504?

A. The Company, Staff and RUCO reached a settlement agreement that provided for a 9.50 cost of equity as well as the final overall fair value rate of return of 6.02. The Commission determined that the settlement agreement reached by the parties was just, fair and reasonable and was adopted in the final Decision No. 74235.

Q. Was RUCO surprised when Staff witness agreed to accept the cost of equity as recommended in the last rate case?

A. Yes, particularly since the test year in that case ended on June 30, 2012, approximately three and one-half years ago. As previously stated, accepting a prior cost of equity return from a previous decision has only occurred in very few circumstances and I'm not aware of any situation where the prior filing was in excess of three and a half years since the case was filed and in excess of two years since the case was decided.

Q. Was UNSE witness Ms. Bulkley, critical of RUCO's cost of equity recommendations in this case?

A. Yes. Ms. Bulkley was critical of RUCO's recommendations as well as the recommendations of TASC, Wal-Mart and Staff. She didn't approve of any cost of capital recommendations except for those included in her direct and rebuttal testimonies.

Q. What is your overall general response to Ms. Buckley's comments related to deficiencies she discusses in her rebuttal testimony?

A. In general, I understand that any cost of equity consultants (i.e. expert witnesses) will have differences between methodologies utilized in calculating cost of equity. Each methodology possesses its own way of examining investor behavior and no one individual method provides an exclusive foolproof formula for determining a fair return. In evaluating the cost of equity all relevant evidence should be used and weighted equally in order to minimize judgmental and measurement infirmities. In other words, you could ask ten expert witnesses to determine the cost of equity in a given rate case application and there will be ten different conclusions.

Q. Can you be more specific as to those disagreements with RUCO?

A. The Company witness(s) identified the following areas of disagreement with RUCO's cost of capital recommendations; (1) His sole reliance on a Constant Growth DCF model and his failure to consider a Multi-Stage

DCF analysis; (2) His use of projected dividend growth rates in the Constant Growth DCF model; (3) His failure to consider the full range of results in the DCF analysis; (4) His application of the CAPM and the reasonableness of his CAPM results; (5) His failure to take into consideration the higher business and regulatory risks to which UNS Electric is exposed relative to the proxy group of companies; and (6) His FVROR recommendation and the method used to derive that recommendation.

Q. What is your response to the criticisms as discussed by Ms. Bulkley related to RUCO's conclusions?

A. I am not going to address each of the areas of disagreement except to say that both the DCF and CAPM models have been updated with the latest information as provided by Value Line and Yahoo Finance, the proxy group of companies have changed as a result of two mergers, and a CEM has now been included as part of RUCO's final cost of equity calculation. As a result of these updates and revisions RUCO is now recommending a cost of equity of 9.13 percent.

Q. What about her comment of RUCO's failure to consider the higher business and regulatory risk which UNS Electric is exposed?

A. I do not agree with this comment. I've heard this comment many times in past rate cases but in this case it just simply does not relate. On page 6 of

Mr. Hutchins testimony he addresses the recent reduction in debt cost, constructive regulatory outcomes, steady improvement in UNS Electric's financial condition and a strong credit rating and favorable market conditions. When reading Mr. Hutchins testimony it's really a stretch to say that UNS Electric has a higher business and regulatory risk as those companies included as proxy companies in this case.

Q. Have you updated your cost of equity models from your direct testimony?

A. Yes, I've made adjustments to my DCF and CAPM models and have also included a CEM.

ECONOMIC ENVIRONMENT

Current Economics Surrounding the Electric Utilities

Q. Did EEI publish information on rate case applications that member companies have been involved in for year 2014?

A. Yes. Investor-owned electric utilities filed 58 rate cases in 2014. The average requested ROE was the lowest requested in their history and the awarded ROE was the lowest in their data base reaching back to 1990.

Q. Has there been updates published by EEI for rate case activity related to investor-owned members for year 2015?

A. Yes. EEI publishes rate case activity each quarter and having reviewed all four quarters for year 2015 there were forty-eight rate cases filed and the authorized ROE's continue to drop to record low levels.

Q In the EEI 2014 annual report was there any mention of the purchase of UNS by Fortis?

A. Yes. "UNS said joining Fortis enhances the financial strength of its local utility operations, and provides additional support for long-term investment."

General Economic Conditions

Q. Please explain why it is necessary to consider the current economic environment when performing a cost of equity capital analysis for a regulated utility.

A. Consideration of the economic environment is necessary because trends in interest rates, present and projected levels of inflation, and the overall state of the U.S. economy determine the rates of return that investors earn on their invested funds.

Q. Can you please explain how general economic and financial conditions are considered in the determination of the cost of capital for a public utility?

A. Yes. The cost of capital is determined in part by the current and future economic and financial conditions. The level of economic activity; the stage of the business cycle; the trend in interest rates, and the level of inflation or expansion all play an important factor in determining the cost of capital. While there are other factors involved these are the most important and at any point in time each can have an influence on the cost of capital.

Q. What is the current outlook for the economy?

A. Interest rates were increased in December 2015 for the first time since December 2008. The reasons given by the Federal Open Market Committee ("FOMC") for increasing the interest at this time were improvement in the labor market conditions during 2015, confidence that inflation will rise to 2 percent level and that the economic activity will continue to expand at a moderate pace and labor market indicators will continue to strengthen.

Q. Since the increase in interest rates by the FOMC has the market reacted as expected?

A. I don't believe it has. When reviewing the Press Release date December 26, 2015, it appears that the FOMC is skeptical of increasing interest rates again going forward. "In determining the timing and size of future adjustments to the target range for the federal funds rate, the Committee will assess realized and expected economic conditions relative to its objectives of maximum employment and 2 percent inflation. This assessment will take into account a wide range of information, including measures of labor market conditions, indicators of inflation pressures and inflation expectations, and reading on financial and international developments. In light of the current shortfall of inflation from 2 percent, the Committee will carefully monitor actual and expected progress toward its inflation goal. The Committee, expects that economic conditions will evolve in a manner that will warrant only gradual increases in the federal funds rate; the federal funds rate hike is likely to remain, for some time, below levels that are expected to prevail in the longer run."

Q. Have you read other publications discussing future inflation rates?

A. Yes. In reading the Federal Reserve Bank of San Francisco, FRBSF Fed Views, January 14, 2016, publication they are projecting inflation in year 2016 between one percent and one and one-half percent and rise gradually towards the 2 percent target as the effects of transitory shocks to energy prices and the exchange rate dissipate and as improving labor market conditions strengthen wage growth.

Q. Why do you believe that further increases in the short term may be skeptical?

A. Assuming that 2 percent inflation factor is a principle factor in further increases it could very well be several years before we see another increase in interest rates. When the interest rate was increased in December, 2015, the inflation rate was less than one percent, however, it was believed by some that the interest rates were increased for other reasons i.e. liquidity trap." (That's when families and businesses hoard cash instead of spending it. Low interest rates don't give either much incentive for investments).

Q. How has Arizona fared in terms of the overall economy and home foreclosures?

A. Arizona was one of the states hit hardest during the Great Recession and has lagged during the current recovery. During the period between 2006 and 2009, statewide construction spending fell by 40.00 percent. According to information provided by Irvine, California-based RealtyTrac, Arizona was ranked third in the nation behind California and Nevada in terms of home foreclosures with the largest number of foreclosures occurring in Maricopa, Pinal and Pima Counties.

Q. What is the current unemployment situation in Arizona during this period of economic recovery?

A. According to information published on October 30, 2015, the seasonally adjusted unemployment rate for Arizona has increased from 6 percent in April, 2015, to 6.3 percent in September, 2015. This compare the national unemployment rate of 5.1 percent for the period ending in September, 2015. For the year ending December 31, 2015, the unemployment rate in Arizona was published as 6 percent and continues to recover well below the national average. I believe it is safe to say that Arizona's economy is recovering at a much slower pace that the national average.

COST OF DEBT AND CAPITAL STRUCTURE

Q. What cost of long-term debt are you recommending for UNSE?

A. I am recommending that the Commission adopt UNSE's actual end of test year cost of long-term debt of 4.66 percent.

Q. Please describe the Company-proposed capital structure.

A. The Company is proposing an adjusted end of test year capital structure comprised of no short-term debt, 47.17 percent long-term debt and 52.83 percent common equity.

Q. How does the Company-proposed capital structure compare with the capital structures of the electric companies that comprise your sample?

A. The Company-proposed capital structure, Schedule RBM-2, is virtually identical to the average capital structure of the electric companies included in my sample.

Q. What capital structure are you recommending for UNSE?

A. I am recommending that the Commission adopt the Company's actual end of test year capital structure comprised of zero short-term debt, 47.17 percent long-term debt and 52.83 percent long-term common equity, which is essentially the same as the capital structure being proposed by UNSE.

WEIGHTED COST OF CAPITAL AND FAIR VALUE RATE OF RETURN

Q. What original cost weighted average cost of capital are you recommending for UNSE?

A. Based on my recommended capital structure, comprised of 47.17 percent long-term debt and 52.53 percent common equity, I am recommending an original cost weighted average cost of capital of 7.17 percent, Schedule RBM-1. This is the weighted average cost of my recommended cost of long-term debt of 4.66 percent and my recommended 9.13 percent cost of common equity.

Q. What fair value rate of return are you recommending for UNSE?

A. I am recommending a FVROR of 5.48 percent, RBM-1, which is 154 basis points lower than my OCROR of 7.02 percent. My recommended FVROR satisfies the fair value requirement of the Arizona Constitution which the Commission must follow when setting rates for investor owned utilities such as UNSE.

Q. Why are you recommending a FVROR that is different from your OCROR?

A. Because UNSE elected not to use the Company's original cost rate base ("OCRB") as its fair value rate base ("FVRB") in this case. Instead, UNSE performed a reconstruction cost new less depreciation ("RCND") study to restate the value, or reproduction cost, of the Company's OCRB. As is the normal ratemaking practice in Arizona, the Company averaged the values of its OCRB and its RCND rate base to arrive at a FVRB that is higher than the OCRB. This is because the value of the FVRB reflects the impact of inflation and other factors which tend to contribute to an upward growth in value over time. Since the difference in the value of the OCRB and the FVRB represents inflation, as opposed to additional investor supplied capital, an OCROR which includes an inflation component cannot be applied to the FVRB. To do so would result in a double counting of inflation. For this reason it is necessary to remove the inflation component that is included in the OCROR.

OTHER CONSIDERATIONS

Q. Has RUCO considered any other options in this case for their recommended cost of common equity?

A. Yes. RUCO would consider recommending the same for cost of common equity as both the Company and ACC Staff seem to have agreed too provided the overall revenue requirement is not greater than $15.1 million.

Q. What has the Company and Staff agreed to at this point?

A. The Company has agreed with Staff's recommendation of 9.50 percent cost of common equity and the inclusion of a 50 basis points as fair value increment which is the same as authorized in the last rate case decision. However, the Company qualified their acceptance of the Staffs proposal as follows; "As long as the overall revenue increase and rate design approved for UNS Electric provides the Company with a reasonable opportunity to actually earn a 9.5% return on equity, the Company would not oppose to the adoption of Staff's recommended values."[2]

Q. Why would RUCO consider recommending the same cost of equity as the Staff recommended and the Company appears to have accepted?

A. There are several reasons why RUCO would accept this proposal. First, after making several revisions to update the DCF and CAPM models,

[2] Rebuttal testimony of Kentton C. Grant, Pg. 8, Line 23

based on the latest information available from Value Line and Yahoo Finance, coupled with the inclusion of a CEM the difference between RUCO's final recommendation and the cost of common equity as approved in the last rate case has been reduced substantially. Second and foremost, RUCO understands that the recent revision to the accounting order pending approved by the Commission in Docket No. E-04204A-13-0476 will lower the revenue increase by approximately $3 million. That will effectively reduce UNSE's increase in revenues requested in this rate case from the Company's original request of $22.6 million. RUCO believes that the approximate $7.5 million overall reduction in total revenue increase coupled with the many issues surrounding the overall rate design, is in the best interest of ratepayers to come to agreement.

Q. Does RUCO believe that their acceptance of the cost of equity and fair value adjustment in this case bounds RUCO to the same in rate cases going forward?

A. Absolutely not. If RUCO agrees with this position in this case it does not presuppose that RUCO will recommend or agree to this return on equity or fair value increment in future rate case applications.

Q. Does this conclude your testimony on UNSE?

A. Yes, it does.

ATTACHMENT A

UNS Electric, Inc.
Test Year Ended December 31, 2014
Docket No. E-04204A-15-0142

<u>SCHEDULE #</u>

RBM - 1	WEIGHTED AVERAGE COST OF CAPITAL
RBM - 2	COST OF LONG TERM AND SHORT TERM DEBT
RBM - 3	COST OF COMMON EQUITY
RBM - 4	FAIR VALUE ADJUSTMENT
RBM - 5	DCF COST OF EQUITY CAPITAL
RBM - 6	CAPM COST OF EQUITY CAPITAL
RBM - 7	PROXY GROUP'S COMPARABLE EARNINGS ANALYSIS

<u>ATTACHMENTS</u>

A	REVISED SCHEDULES
B	VALUE LINE REPORTS - UPDATES
C	YAHOO FINANCE ANALYSTS REPORTS / STOCK PRICES

UNS Electric, Inc.
Test Year Ended December 31, 2014
Docket No. E-04204A-15-0142

Schedule RBM-1

WEIGHTED AVERAGE COST OF CAPITAL

LINE NO.	DESCRIPTION	(A) CAPITALIZATION PER COMPANY	(B) RUCO ADJUSTMENTS	(C) RUCO ADJUSTED CAPITALIZATION	(D) CAPITAL RATIO	(E) COST	(F) WEIGHTED COST
1	Long - Term Debt	$ 169,590	$ -	$ 169,590	47.17%	4.66%	2.20%
2	Short - Term Debt	-	-	-	-	-	-
3	Common Equity	189,932	-	189,932	52.83%	9.13%	4.82%
4	TOTAL CAPITALIZATION	$ 359,522	$ -	$ 359,522	100.00%		7.02%
5	Fair Value Adjustment						0.15%
6	ORIGINAL COST WEIGHTED AVERAGE COST OF CAPITAL						7.17%

REFERENCES:
COLUMN (A): COMPANY SCHEDULE D-1; SCHEDULE RBM-2
COLUMN (C): COLUMN (A) + COLUMN (B)
COLUMN (D): COLUMN (C) LINE 1 ÷ COLUMN (C), LINE 4
COLUMN (E): LINE 1 - COMPANY SCHEDULE D-1; SCHEDULE RBM-2
COLUMN (E): LINE 3 - SCHEDULE RBM-3
COLUMN (F): COLUMN (D) x COLUMN (E)

FAIR VALUE WEIGHTED AVERAGE COST OF CAPITAL

LINE NO.		(A) CAPITALIZATION	(B) RUCO	(C) RUCO ADJUSTED	(D) CAPITAL	(E) COST	(F) WEIGHTED COST
7	LONG-TERM DEBT	$ 169,590	$ -	$ 169,590	47.17%	3.12%	1.47%
8	COMMON EQUITY	189,932	-	189,932	52.83%	7.59%	4.01%
9	TOTAL CAPITALIZATION	$ 359,522	$ -	$ 359,522	100.00%		5.48%

10 COLUMN (A) THROUGH (D) SEE ABOVE

11 COLUMN (E), LINE 7 SEE RBM-2

UNS Electric, Inc.
Test Year Ended December 31, 2014
Docket No. E-04204A-15-0142

Schedule RBM-2

COST OF LONG TERM and SHORT TERM DEBT (thousands of US dollars)

LINE NO.	LONG TERM DEBT DESCRIPTION	End of Test Year (Actual) (A) Actual as of DEC. 31, 2014	(B) Annual Interest	(C) Annual Cost Rate Long Term Debt	End of Test Year (Proposed) (D) Proposed as of DEC. 31, 2014	(E) Annual Interest	(F) RUCO ADJUSTED BALANCE
	Fixed Rate Debt:						
1	6.50% Senior Unsecured Notes due 08/15	$ 50,000	$ 3,250	6.50%	$ -	$ -	$ -
2	7.10% Senior Unsecured Notes Series B due 08/23	50,000	3,550	7.10%	50,000	3,550	7.10%
3	3.22% Senior Unsecured Notes Series A due 08/27	-	-	-	80,000	2,576	3.22%
4	3.95% Senior Unsecured Notes Series B due 04/45	-	-	-	50,000	1,975	3.95%
5	Total Fixed Rate Debt	100,000	6,800	6.80%	180,000	8,101	4.50%
6	Variable Rate Debt:						
7	4 Year Term Loan due 08/15	30,000	629	2.10%	-	-	-
8	Total Variable Rate Debt	30,000	629	2.10%	-	-	-
9	Total Long-Term Debt (Ln 5 + Ln 8)	$ 130,000	$ 7,429	5.71%	$ 180,000	$ 8,101	4.50%
10	Unamortized Debt Discount, Premium						
11	Expense and Loss on Reacquired Debt	(410)	-		(1,246)		
12	Amortization of Debt Discount and						
13	Expense and Loss on Reacquired Debt	-	182		-	169	
14	Credit Facility Commitment Fee	-	51		-	63	
15	Total Long Term Debt - Net of expenses (Ln 9 less Ln 11, 13, 14)	129,590	7,662		178,754	$ 8,333	
16	Total Cost Long Term Debt (Col. B / Col. A) (Col. E / Col. F)			5.91%			4.66%
	SHORT TERM DEBT						
17	Revolving Line of Credit	$ 40,000	$ 513	1.28%	$ -	$ -	$ -
18	Total Debt Actual - End of Test Year	$ 169,590	$ 8,175	4.82%			
19	Total Debt Proposed - End of Test Year				$ 178,754	$ 8,333	4.66%
20	LESS: RECOMMENDED FAIR VALUE INFLATION ADJUSTMENT						-1.54%
21	COST OF LONG-TERM DEBT - FAIR VALUE (LINE 19 - LINE 20)						3.12%

COST OF COMMON EQUITY ESTIMATE

LINE NO.			
1	DCF METHODOLOGY		
2	DCF - SINGLE-STAGE CONSTANT GROWTH MODEL ESTIMATE	8.33% - 10.12%	SCHEDULE RBM-5
3	CAPM METHODOLOGY		
4	CAPM - GEOMETRIC MEAN ESTIMATE	7.07%	SCHEDULE RBM-6, PAGE 1 OF 2
5	CAPM - ARITHMETRIC MEAN ESTIMATE	6.84%	SCHEDULE RBM-6, PAGE 2 OF 2
6	COMPARABLE EARNINGS	8.75% - 10.00%	SCHEDULE RBM-7
7	RANGE OF DCF, CAPM ARITHEMETIC / GEOMETRIC MEANSA AND CEM ESTIMATES	8.00% - 10.00%	AVERAGE OF LINES 2 THROUGH 6
8	FINAL RUCO RECOMMENDED COST OF COMMON EQUITY	9.13%	TESTIMONY, RBM
9	LESS: RECOMMENDED FAIR VALUE INFLATION ADJUSTMENT	-1.54%	SCHEDULE RBM-4
10	COST OF COMMON EQUITY ESTIMATE - FAIR VALUE	7.59%	LINE 8 - LINE 9

UNS Electric, Inc.
Test Year Ended December 31, 2014
Docket No. E-04204A-15-0142

SCHEDULE RBM-4

INFLATION ADJUSTMENT TO RUCO'S RECOMMENDED ORIGINAL COST OF EQUITY CAPITAL

LINE NO.	(A) YEAR	(B) VALUE TIPS	(C) VALUE BONDS	(D) DIFFERENCE
1	2009	1.66%	3.26%	1.61%
2	2010	1.15%	3.22%	2.06%
3	2011	0.55%	2.78%	2.23%
4	2012	0.42%	1.78%	1.36%
5	2013	0.80%	2.10%	1.30%
6	2014	0.49%	1.60%	1.11%
7	2015	0.10%	1.20%	1.10%
8				
9	RECOMMENDED FAIR VALUE INFLATION ADJUSTMENT - AVERAGE COLUMN (D)			1.54%

REFERENCES

COLUMNS (A) THRU (C), LINES 1 THRU 9: FEDERAL RESERVE BANK
COLUMN (D): COLUMN (C) - COLUMN (D)
COLUMNS (B) THRU (D), LINE 10: AVERAGE OF LINES 1 THRU 7
COLUMN (D), LINE 11: TESTIMONY - RBM

DCF 90 DAY CONSTANT GROWTH

LINE NO.	STOCK SYMBOL	COMPANY NAME	(A) ESTIMATED DIVIDEND (PER SHARE)	/	(B) AVERAGE STOCK PRICE (PER SHARE)		(C) DIVIDEND YIELD	(D) PROJECTED DIVIDEND YIELD	(E) FIVE YEAR GROWTH VALUE LINE	(F) FIVE YEAR GROWTH YAHOO FINANCE	(G) AVERAGE EARNINGS GROWTH	(H) ROE LOW	(I) ROE MEAN	(J) ROE HIGH
1	ALE	ALLETE, Inc.	$ 2.02	/	50.48	=	4.00%	4.12%	6.50%	5.00%	5.75%	9.10%	9.87%	10.63%
2	AEP	American Electric Power Company	$ 2.24	/	57.02	=	3.93%	4.02%	5.00%	4.55%	4.78%	8.57%	8.80%	9.03%
3	EE	EL Paso Electric	$ 1.18	/	38.31	=	3.08%	3.16%	3.50%	7.00%	5.25%	6.63%	8.41%	10.19%
4	EDE	Empire District Electric Company	$ 1.04	/	25.32	=	4.11%	4.19%	3.00%	5.00%	4.00%	7.17%	8.19%	9.21%
5	ES	Eversource Energy	$ 1.67	/	50.83	=	3.29%	3.41%	8.50%	6.57%	7.54%	9.96%	10.94%	11.92%
6	GXP	Great Plains Energy Inc.	$ 1.05	/	26.88	=	3.91%	4.00%	5.00%	5.07%	5.04%	9.00%	9.04%	9.07%
7	IDA	IDACORP, Inc.	$ 2.04	/	66.88	=	3.05%	3.09%	1.00%	4.00%	2.50%	4.07%	5.59%	7.11%
8	OTTR	Otter Tail Corporation	$ 1.23	/	26.52	=	4.65%	4.82%	9.00%	6.00%	7.50%	10.79%	12.32%	13.86%
9	PNW	Pinnacle West Capital Corporation	$ 2.50	/	62.94	=	3.97%	4.06%	4.00%	4.95%	4.48%	8.05%	8.54%	9.02%
10	PNM	PNM Resources, Inc.	$ 0.88	/	29.22	=	3.01%	3.15%	9.00%	9.30%	9.15%	12.15%	12.30%	12.45%
11	POR	Portland General Electric Company	$ 1.20	/	36.44	=	3.29%	3.38%	6.00%	4.13%	5.07%	7.49%	8.44%	9.39%
13	WR	Westar Energy, Inc.	$ 1.44	/	41.54	=	3.47%	3.55%	6.00%	3.50%	4.75%	7.03%	8.30%	9.57%
		AVERAGE					3.65%	3.75%	5.54%	5.42%	5.48%	8.33%	9.23%	10.12%

AVERAGE OF LOW, MEAN AND HIGH 9.23%

REFERENCES:
COLUMN (A); ANNUALIZED DIVIDENDS PER VALUE LINE
COLUMN (B): AVERAGE STOCK PRICES, SEE TESTIMONY ATTACHMENT (C)
COLUMN (C): COLUMN (A) / COLUMN (B)
COLUMN (D): COLUMN (C) X (1+.05 COLUMN (G))
COLUMN (G) AVERAGE COLUMN (E) AND (F)

UNS Electric, Inc.
Test Year Ended December 31, 2014
CAPM COST OF EQUITY CAPITAL

BASED ON A GEOMETRIC MEAN:

LINE NO.	STOCK SYMBOL	COMPANY NAME	k	=	r_f	+ [	(A) ß	x (	r_m	-	r_f	)]	=	(B) EXPECTED RETURN
1	ALE	ALLETE, Inc.	k	=	2.50%	+ [	0.80	x (	12.00%	-	6.10%	)]	=	7.22%
2	AEP	American Electric Power Company	k	=	2.50%	+ [	0.70	x (	12.00%	-	6.10%	)]	=	6.63%
3	EE	EL Paso Electric	k	=	2.50%	+ [	0.75	x (	12.00%	-	6.10%	)]	=	6.93%
4	EDE	Empire District Electric Company	k	=	2.50%	+ [	0.70	x (	12.00%	-	6.10%	)]	=	6.63%
5	ES	Eversource Energy	k	=	2.50%	+ [	0.75	x (	12.00%	-	6.10%	)]	=	6.93%
6	GXP	Great Plains Energy Inc.	k	=	2.50%	+ [	0.85	x (	12.00%	-	6.10%	)]	=	7.52%
7	IDA	IDACORP, Inc.	k	=	2.50%	+ [	0.80	x (	12.00%	-	6.10%	)]	=	7.22%
8	OTTR	Otter Tail Corporation	k	=	2.50%	+ [	0.85	x (	12.00%	-	6.10%	)]	=	7.52%
9	PNW	Pinnacle West Capital Corporation	k	=	2.50%	+ [	0.75	x (	12.00%	-	6.10%	)]	=	6.93%
10	PNM	PNM Resources, Inc.	k	=	2.50%	+ [	0.80	x (	12.00%	-	6.10%	)]	=	7.22%
11	POR	Portland General Electric Company	k	=	2.50%	+ [	0.80	x (	12.00%	-	6.10%	)]	=	7.22%
12	WR	Westar Energy, Inc.	k	=	2.50%	+ [	0.75	x (	12.00%	-	6.10%	)]	=	6.93%
13														
14														
15														
16														
17	AVERAGE						0.78							7.07%

REFERENCES:
COLUMN (A): SHARPE LITNER CAPITAL ASSET PRICING MODEL ("CAPM") FORMULA

$k = r_f + [\,ß\,(r_m - r_f)\,]$

WHERE: k = THE EXPECTED RETURN ON A GIVEN SECURITY
r_f = RATE OF RETURN ON A RISK FREE ASSET PROXY (a)
ß = THE BETA COEFFICIENT OF A GIVEN SECURITY
r_m = PROXY FOR THE MARKET RATE OF RETURN (b)
r_f = PROXY FOR THE RISK FREE RATE ON LONG-TERM TREASURIES (b)

COLUMN (B): EXPECTED RATE OF RETURN USING THE CAPM FORMULA

UNS Electric, Inc.
Test Year Ended December 31, 2014
CAPM COST OF EQUITY CAPITAL

BASED ON AN ARITHMETIC MEAN:

LINE NO.	STOCK SYMBOL	COMPANY NAME	k	=	r_f	+ [	(A) ß	x (	r_m	-	r_f	)]	=	(B) EXPECTED RETURN
1	ALE	ALLETE, Inc.	k	=	2.50%	+ [	0.80	x (	12.00%	-	6.40%	)]	=	6.98%
2	AEP	American Electric Power Company, Inc.	k	=	2.50%	+ [	0.70	x (	12.00%	-	6.40%	)]	=	6.42%
3	EE	EL Paso Electric	k	=	2.50%	+ [	0.75	x (	12.00%	-	6.40%	)]	=	6.70%
4	EDE	Empire District Electric Company	k	=	2.50%	+ [	0.70	x (	12.00%	-	6.40%	)]	=	6.42%
5	ES	Eversource Energy	k	=	2.50%	+ [	0.75	x (	12.00%	-	6.40%	)]	=	6.70%
6	GXP	Great Plains Energy Inc.	k	=	2.50%	+ [	0.85	x (	12.00%	-	6.40%	)]	=	7.26%
7	IDA	IDACORP, Inc.	k	=	2.50%	+ [	0.80	x (	12.00%	-	6.40%	)]	=	6.98%
8	OTTR	Otter Tail Corporation	k	=	2.50%	+ [	0.85	x (	12.00%	-	6.40%	)]	=	7.26%
9	PNW	Pinnacle West Capital Corporation	k	=	2.50%	+ [	0.75	x (	12.00%	-	6.40%	)]	=	6.70%
10	PNM	PNM Resources, Inc.	k	=	2.50%	+ [	0.80	x (	12.00%	-	6.40%	)]	=	6.98%
11	POR	Portland General Electric Company	k	=	2.50%	+ [	0.80	x (	12.00%	-	6.40%	)]	=	6.98%
12	WR	Westar Energy, Inc.	k	=	2.50%	+ [	0.75	x (	12.00%	-	6.40%	)]	=	6.70%
13	AVERAGE						$\boxed{0.78}$							**6.84%**

REFERENCES:
COLUMN (A): SHARPE LITNER CAPITAL ASSET PRICING MODEL ("CAPM") FORMULA

$$k = r_f + [ß (r_m - r_f)]$$

WHERE: k = THE EXPECTED RETURN ON A GIVEN SECURITY
r_f = RATE OF RETURN ON A RISK FREE ASSET PROXY (a)
ß = THE BETA COEFFICIENT OF A GIVEN SECURITY
r_m = PROXY FOR THE MARKET RATE OF RETURN (b)
r_f = PROXY FOR THE RISK FREE RATE ON LONG-TERM TREASURIES (b)

COLUMN (B): EXPECTED RATE OF RETURN USING THE CAPM FORMULA

PROXY COMPANY'S - COMPARABLE EARNINGS COMPUTATION
RATES OF RETURN ON COMMON EQUITY

	Company	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2018 - 2020	2002 - 2020
ALE	ALLETE, Inc.	12.4%	11.9%	11.9%	11.3%	11.6%	11.8%	10.0%	6.6%	7.7%	8.7%	8.1%	7.8%	7.8%	9.0%	8.0%	9.0%	9.6%
AEP	American Electric Power Company, In	12.3%	12.4%	12.7%	11.9%	12.2%	11.7%	11.6%	11.0%	9.3%	10.7%	9.7%	9.9%	10.2%	12.1%	10.0%	10.0%	11.1%
EE	EL Paso Electric				6.6%	10.6%	11.2%	11.2%	9.3%	11.1%	13.6%	11.0%	9.4%	9.3%	8.0%	8.5%	9.5%	9.9%
EDE	Empire District Electric Company	8.4%	8.7%	5.7%	6.2%	9.2%	6.9%	7.4%	7.5%	7.4%	8.1%	7.9%	8.6%	8.8%	7.5%	7.5%	9.5%	7.8%
ES	Eversource Energy				5.1%	4.3%	8.4%	9.6%	9.2%	9.8%	9.8%	5.7%	8.2%	8.2%	8.5%	9.0%	9.5%	8.1%
GXP	Great Plains Energy Inc.	15.6%	16.6%	16.9%	13.7%	9.8%	10.6%	5.9%	4.9%	7.3%	5.8%	6.2%	7.3%	6.8%	6.0%	7.5%	7.5%	9.3%
IDA	IDACORP, Inc.	7.1%	4.2%	8.2%	7.3%	9.4%	7.1%	8.0%	9.3%	9.8%	10.5%	9.9%	10.1%	9.9%	9.0%	9.0%	8.5%	8.6%
OTTR	Otter Tail Corporation	15.2%	12.0%	10.8%	11.6%	10.4%	10.4%	5.9%	3.7%	2.1%	2.7%	6.9%	9.4%	11.6%	10.0%	11.0%	12.5%	9.1%
PNW	Pinnacle West Capital Corporation	8.6%	8.3%	8.2%	6.7%	9.2%	8.5%	6.1%	6.8%	9.3%	8.7%	9.8%	9.9%	9.5%	9.5%	9.5%	10.0%	8.7%
PNM	PNM Resources, Inc.	6.3%	6.7%	7.9%	8.6%	8.4%	3.4%	0.5%	3.1%	4.8%	5.8%	6.6%	6.9%	7.1%	7.0%	7.5%	9.5%	6.3%
POR	Portland General Electric Company				5.3%	5.9%	11.5%	6.5%	6.2%	8.0%	9.0%	8.3%	7.7%	9.0%	8.0%	9.0%	9.5%	8.0%
WR	Westar Energy, Inc.	5.0%	10.6%	7.7%	9.6%	11.1%	10.0%	6.7%	6.3%	8.6%	8.2%	9.5%	9.8%	9.9%	9.5%	9.5%	9.5%	8.8%
	Mean	10.1%	10.2%	10.0%	8.7%	9.3%	9.3%	7.5%	7.0%	7.9%	8.5%	8.3%	8.8%	9.0%	8.7%	8.8%	9.5%	8.78%
	Median	8.6%	10.6%	8.2%	8.0%	9.6%	10.2%	7.1%	6.7%	8.3%	8.7%	8.2%	9.0%	9.2%	8.8%	9.0%	9.5%	8.75%

Source: AUS Utility Reports and Value Line Investment Survey.

ATTACHMENT B

ALLETE NYSE-ALE

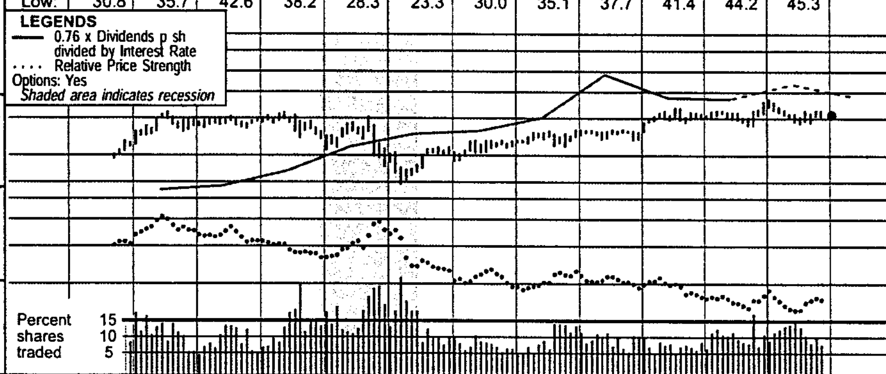
RECENT PRICE 50.15 | P/E RATIO 14.2 (Trailing: 15.3 Median: 16.0) | RELATIVE P/E RATIO 0.81 | DIV'D YLD 4.1% | VALUE LINE

TIMELINESS 3 Raised 4/24/15
SAFETY 2 New 10/1/04
TECHNICAL 2 Raised 12/18/15
BETA .80 (1.00 = Market)

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
High:	37.5	51.7	49.3	51.3	49.0	35.3	37.9	42.5	42.7	54.1	58.0	59.7
Low:	30.8	35.7	42.6	38.2	28.3	23.3	30.0	35.1	37.7	41.4	44.2	45.3

Target Price Range 2018 | 2019 | 2020

LEGENDS
— 0.76 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



2018-20 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	60	(+20%)	9%
Low	45	(-10%)	2%

Insider Decisions

	J	F	M	A	M	J	J	A	S
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	1	0	0	0	0	1	0
to Sell	0	1	2	1	1	1	0	3	1

Institutional Decisions

	1Q2015	2Q2015	3Q2015
to Buy	117	117	90
to Sell	77	79	100
Hld's(000)	33487	35643	35552

% TOT. RETURN 11/15

	THIS STOCK	VL ARITH.* INDEX
1 yr.	4.0	-2.0
3 yr.	46.1	48.1
5 yr.	77.7	71.2

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	© VALUE LINE PUB. LLC	18-20
--	--	--	--	--	25.30	24.50	25.23	27.33	24.57	21.57	25.34	24.75	24.40	24.60	24.77	*30.60*	*28.45*	Revenues per sh	*33.50*
--	--	--	--	--	2.97	3.85	4.14	4.42	4.23	3.57	4.35	4.91	5.01	5.35	5.68	*6.50*	*6.40*	"Cash Flow" per sh	*7.75*
--	--	--	--	--	1.35	2.48	2.77	3.08	2.82	1.89	2.19	2.65	2.58	2.63	2.90	*3.50*	*3.20*	Earnings per sh A	*4.00*
--	--	--	--	--	.30	1.25	1.45	1.64	1.72	1.76	1.76	1.78	1.84	1.90	1.96	*2.02*	*2.08*	Div'd Decl'd per sh B ■ †	*2.30*
--	--	--	--	--	2.12	1.95	3.37	6.82	9.24	9.05	6.95	6.38	10.30	7.93	12.48	*5.70*	*4.75*	Cap'l Spending per sh	*5.50*
--	--	--	--	--	21.23	20.03	21.90	24.11	25.37	26.41	27.26	28.78	30.48	32.44	35.06	*37.50*	*38.70*	Book Value per sh C	*43.50*
--	--	--	--	--	29.70	30.10	30.40	30.80	32.60	35.20	35.80	37.50	39.40	41.40	45.90	*49.00*	*49.25*	Common Shs Outst'g D	*50.00*
--	--	--	--	--	25.2	17.9	16.5	14.8	13.9	16.1	16.0	14.7	15.9	18.6	17.2	*Bold figures are*		Avg Ann'l P/E Ratio	*13.0*
--	--	--	--	--	1.33	.95	.89	.79	.84	1.07	1.02	.92	1.01	1.05	.91	*Value Line*		Relative P/E Ratio	*.80*
--	--	--	--	--	.9%	2.8%	3.2%	3.6%	4.4%	5.8%	5.0%	4.6%	4.5%	3.9%	3.9%	*estimates*		Avg Ann'l Div'd Yield	*4.5%*

2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016		18-20
737.4	767.1	841.7	801.0	759.1	907.0	928.2	961.2	1018.4	1136.8	*1500*	*1400*	Revenues ($mill)	*1675*
68.0	77.3	87.6	82.5	61.0	75.3	93.8	97.1	104.7	124.8	*165*	*155*	Net Profit ($mill)	*195*
28.4%	37.5%	34.8%	34.3%	33.7%	37.2%	27.6%	28.1%	21.5%	22.6%	*20.0%*	*20.0%*	Income Tax Rate	*20.0%*
.4%	1.4%	6.6%	5.8%	12.8%	8.9%	2.7%	5.3%	4.4%	6.3%	*3.0%*	*2.0%*	AFUDC % to Net Profit	*2.0%*
39.1%	35.1%	35.6%	41.6%	42.8%	44.2%	44.3%	43.7%	44.6%	44.2%	*43.5%*	*42.5%*	Long-Term Debt Ratio	*41.0%*
60.9%	64.9%	64.4%	58.4%	57.2%	55.8%	55.7%	56.3%	55.4%	55.8%	*56.5%*	*57.5%*	Common Equity Ratio	*59.0%*
990.6	1025.6	1153.5	1415.4	1625.3	1747.6	1937.2	2134.6	2425.9	2882.2	*3260*	*3330*	Total Capital ($mill)	*3675*
860.4	921.6	1104.5	1387.3	1622.7	1805.6	1982.7	2347.6	2576.5	3286.4	*3675*	*3750*	Net Plant ($mill)	*4075*
8.0%	8.6%	8.6%	6.7%	4.8%	5.4%	6.0%	5.6%	5.3%	5.2%	*6.0%*	*5.5%*	Return on Total Cap'l	*6.5%*
11.3%	11.6%	11.8%	10.0%	6.6%	7.7%	8.7%	8.1%	7.8%	7.8%	*9.0%*	*8.0%*	Return on Shr. Equity	*9.0%*
11.3%	11.6%	11.8%	10.0%	6.6%	7.7%	8.7%	8.1%	7.8%	7.8%	*9.0%*	*8.0%*	Return on Com Equity E	*9.0%*
5.2%	5.0%	5.8%	3.9%	.5%	1.5%	2.9%	2.3%	2.2%	2.5%	*4.0%*	*3.0%*	Retained to Com Eq	*3.5%*
54%	57%	51%	61%	93%	81%	66%	71%	72%	67%	*57%*	*66%*	All Div'ds to Net Prof	*59%*

CAPITAL STRUCTURE as of 9/30/15
Total Debt $1598.1 mill. Due in 5 Yrs $411.9 mill.
LT Debt $1549.0 mill. LT Interest $64.4 mill.
(LT interest earned: 4.0x)
Leases, Uncapitalized Annual rentals $13.4 mill.

Pension Assets-12/14 $544.2 mill. Oblig. $714.5 mill.

Pfd Stock None

Common Stock 48,965,562 shs.

MARKET CAP: $2.5 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2012	2013	2014
% Change Retail Sales (KWH)	+1.1	-1.1	+.5
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	5.24	5.45	6.09
Capacity at Peak (Mw)	1790	1793	1985
Peak Load, Winter (Mw) F	1633	1646	1637
Annual Load Factor (%)	79.0	NA	NA
% Change Customers (avg.)	+.5	NA	NA
Fixed Charge Cov. (%)	341	306	345

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '12-'14 to '18-'20
Revenues	-.5%	--	5.5%
"Cash Flow"	6.0%	5.5%	6.5%
Earnings	7.0%	1.0%	6.5%
Dividends	NMF	2.0%	3.0%
Book Value	4.5%	5.0%	5.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2012	240.0	216.4	248.8	256.0	961.2
2013	263.8	235.6	251.0	268.0	1018.4
2014	296.5	260.7	288.9	290.7	1136.8
2015	320.0	323.3	462.5	*394.2*	*1500*
2016	*345*	*340*	*360*	*355*	*1400*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2012	.66	.39	.78	.75	2.58
2013	.83	.35	.63	.82	2.63
2014	.80	.40	.97	.73	2.90
2015	.85	.46	1.23	*.96*	*3.50*
2016	*.90*	*.45*	*1.00*	*.85*	*3.20*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.445	.445	.445	.445	1.78
2012	.46	.46	.46	.46	1.84
2013	.475	.475	.475	.475	1.90
2014	.49	.49	.49	.49	1.96
2015	.505	.505	.505	.505	

BUSINESS: ALLETE, Inc. is the parent of Minnesota Power, which supplies electricity to 146,000 customers in northeastern MN, & Superior Water, Light & Power in northwestern WI. Electric rev. breakdown: taconite mining/processing, 27%; paper/wood products, 9%; other industrial, 7%; residential, 12%; commercial, 13%; wholesale, 10% other, 22%. ALLETE Clean Energy owns renewable energy projects. Acq'd U.S. Water Services 2/15. Has real estate operation in FL. Generating sources: coal & lignite, 56%; wind, 7%; other, 3%; purchased, 34%. Fuel costs: 31% of revs. '14 deprec. rate: 2.9%. Has 1,600 employees. Chairman, President & CEO: Alan R. Hodnik. Inc.: MN. Address: 30 West Superior St., Duluth, MN 55802-2093. Tel.: 218-279-5000. Internet: www.allete.com.

ALLETE's earnings will almost certainly wind up significantly higher in 2015, thanks to a development fee for the construction of a wind project. The company's ALLETE Clean Energy subsidiary is building a wind project that it is selling to a utility in North Dakota. The company booked a progress payment that boosted profits by $0.25 a share in the third quarter, and the final payment should add another $0.12 a share or so in the December period. Because the project management has been even stronger than expected, and Minnesota Power (ALLETE's main utility subsidiary) has cut expenses through a cost-reduction program, management raised its share-earnings target for the year from $3.20-$3.40 to $3.35-$3.50. We have raised our share-net estimate by $0.20, so it now stands at the upper end of the company's guidance.

We think earnings will decline in 2016. The comparisons will be difficult in the second half of the year because of the boost provided by the aforementioned wind project fees. In addition, activity by Minnesota Power's taconite customers has waned. (Taconite is used in steelmaking.) These large electricity users had been running at full capacity for the past several years, but are now expecting 80% of full-demand levels for the first four months of 2016. The utility might be able to make up for part of the shortfall through additional wholesale power sales. The one positive factor for the year-to-year comparisons is that the company's purchase of U.S. Water, which provides water management services to industrial customers, should be more accretive to income next year once some amortizations cease after the first quarter. Our earnings estimate is within ALLETE's targeted range of $3.10-$3.40 a share.

We think the board of directors will raise the annual dividend by $0.06 a share (3.0%) in the first period of 2016. This has been the pattern in recent years. ALLETE is targeting a payout ratio in a range of 60%-65%.

This stock's dividend yield is slightly above the utility mean. Total return potential to 2018-2020 is only average for the group, however.

Paul E. Debbas, CFA *December 18, 2015*

(A) Diluted EPS. Excl. nonrec. gain (loss): '04, 2¢; '05, ($1.84); gain (losses) on disc. ops.: '04, $2.57, '05, (16¢); '06, (2¢); loss from accounting change: '04, 27¢. Next egs. report due mid-Feb. (B) Div'ds historically paid in early Mar., June, Sept. and Dec. ■ Div'd reinvestment plan avail. † Shareholder investment plan avail. (C) Incl. deferred chgs. In '14: $7.78/sh. (D) In mill. (E) Rate base: Orig. cost deprec. Rate allowed on com. eq. in '10: 10.38%; earned on avg. com. eq., '14: 8.6%. Reg. Clim.: Avg. (F) Summer peak in '12 & '13.

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	35
Earnings Predictability	80

AMERICAN ELEC. PWR. NYSE-AEP

RECENT PRICE 55.88 | P/E RATIO 15.8 (Trailing: 15.4 Median: 13.0) | RELATIVE P/E RATIO 0.90 | DIV'D YLD 4.1% | VALUE LINE

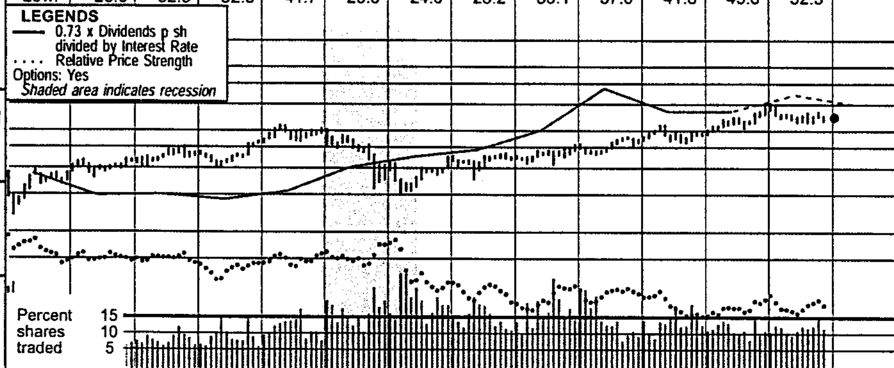
TIMELINESS **3** Lowered 6/12/15

SAFETY **2** Raised 9/19/14

TECHNICAL **2** Raised 12/18/15

BETA .70 (1.00 = Market)

High:	35.5	40.8	43.1	51.2	49.1	36.5	37.9	41.7	45.4	51.6	63.2	65.4
Low:	28.5	32.3	32.3	41.7	25.5	24.0	28.2	33.1	37.0	41.8	45.8	52.3



Target Price Range 2018 | 2019 | 2020

128 96 80 64 48 40 32 24 16 12

2018-20 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	70	(+25%)	10%
Low	50	(-10%)	2%

Insider Decisions

	J	F	M	A	M	J	J	A	S
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	10	0	0	0	0
to Sell	0	1	0	0	4	0	0	3	0

Institutional Decisions

	1Q2015	2Q2015	3Q2015
to Buy	338	327	328
to Sell	368	336	317
Hld's(000)	324222	328262	332965

% TOT. RETURN 11/15

	THIS STOCK	VL ARITH.* INDEX
1 yr.	1.1	-2.0
3 yr.	47.9	48.1
5 yr.	95.2	71.2

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	© VALUE LINE PUB. LLC	18-20
35.63	42.53	190.10	42.96	36.82	35.51	30.76	31.82	33.41	35.56	28.22	30.01	31.27	30.77	31.48	34.78	33.95	34.40	Revenues per sh	37.75
6.36	5.11	7.65	6.99	5.76	5.89	5.96	6.67	6.80	6.84	6.32	6.29	6.83	6.92	7.02	7.57	8.10	8.35	"Cash Flow" per sh	9.25
2.69	1.04	3.27	2.86	2.53	2.61	2.64	2.86	2.86	2.99	2.97	2.60	3.13	2.98	3.18	3.34	3.70	3.70	Earnings per sh A	4.25
2.40	2.40	2.40	2.40	1.65	1.40	1.42	1.50	1.58	1.64	1.64	1.71	1.85	1.88	1.95	2.03	2.15	2.27	Div'd Decl'd per sh B ■	2.65
4.47	5.51	5.69	5.08	3.44	4.28	6.11	8.89	8.88	9.83	6.19	5.07	5.74	6.45	7.75	8.68	9.75	10.45	Cap'l Spending per sh	8.50
25.79	25.01	25.54	20.85	19.93	21.32	23.08	23.73	25.17	26.33	27.49	28.33	30.33	31.37	32.98	34.37	36.00	37.50	Book Value per sh C	42.25
194.10	322.02	322.24	338.84	395.02	395.86	393.72	396.67	400.43	406.07	478.05	480.81	483.42	485.67	487.78	489.40	492.00	494.00	Common Shs Outst'g D	500.00
14.3	34.3	13.9	12.7	10.7	12.4	13.7	12.9	16.3	13.1	10.0	13.4	11.9	13.8	14.5	15.9	Bold figures are		Avg Ann'l P/E Ratio	14.0
.82	2.23	.71	.69	.61	.66	.73	.70	.87	.79	.67	.85	.75	.88	.81	.84	Value Line		Relative P/E Ratio	.90
6.2%	6.7%	5.3%	6.6%	6.1%	4.3%	3.9%	4.1%	3.4%	4.2%	5.5%	4.9%	5.0%	4.6%	4.2%	3.8%	estimates		Avg Ann'l Div'd Yield	4.5%
						12111	12622	13380	14440	13489	14427	15116	14945	15357	17020	16700	17000	Revenues ($mill)	18850
						1036.0	1131.0	1147.0	1208.0	1365.0	1248.0	1513.0	1443.0	1549.0	1634.0	1730	1745	Net Profit ($mill)	2020
						29.3%	33.0%	31.1%	31.3%	29.7%	34.8%	31.7%	33.9%	36.2%	37.8%	36.0%	36.0%	Income Tax Rate	36.0%
						5.4%	9.9%	9.8%	9.9%	10.9%	10.4%	10.6%	11.2%	7.3%	9.0%	10.0%	9.0%	AFUDC % to Net Profit	8.0%
						54.8%	56.7%	58.3%	59.1%	54.4%	53.1%	50.7%	50.6%	51.1%	49.0%	50.0%	49.5%	Long-Term Debt Ratio	49.0%
						44.9%	43.0%	41.4%	40.7%	45.4%	46.7%	49.3%	49.4%	48.9%	51.0%	50.0%	50.5%	Common Equity Ratio	51.0%
						20222	21902	24342	26290	28958	29184	29747	30823	32913	33001	35400	36675	Total Capital ($mill)	41500
						24284	26781	29870	32987	34344	35674	36971	38763	40997	44117	46725	49600	Net Plant ($mill)	54900
						6.6%	6.7%	6.3%	6.2%	6.2%	5.7%	6.6%	6.1%	6.0%	6.3%	6.0%	6.0%	Return on Total Cap'l	6.0%
						11.3%	11.9%	11.3%	11.2%	10.3%	9.1%	10.3%	9.5%	9.6%	9.7%	10.0%	9.5%	Return on Shr. Equity	9.5%
						11.3%	12.0%	11.4%	11.3%	10.4%	9.1%	10.3%	9.5%	9.6%	9.7%	10.5%	10.0%	Return on Com Equity E	10.0%
						5.2%	5.7%	5.1%	5.1%	4.6%	3.1%	4.2%	3.5%	3.7%	3.8%	4.5%	4.0%	Retained to Com Eq	4.0%
						54%	53%	55%	55%	56%	66%	60%	63%	62%	61%	61%	64%	All Div'ds to Net Prof	65%

CAPITAL STRUCTURE as of 9/30/15
Total Debt $20208 mill. Due in 5 Yrs $9052 mill.
LT Debt $17600 mill. LT Interest $792 mill.
Incl. $2114 mill. securitized bonds. Incl. $552 mill. capitalized leases.
(LT interest earned: 4.0x)
Leases, Uncapitalized Annual rentals $293 mill.
Pension Assets-12/14 $4968 mill. Oblig. $5225 mill.

Pfd Stock None

Common Stock 490,817,402 shs.
as of 10/22/15
MARKET CAP: $27 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2012	2013	2014
% Change Retail Sales (KWH)	-2.1	-1.5	+1.1
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.3	+.4	+.3
Fixed Charge Cov. (%)	280	326	348

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '12-'14 to '18-'20
Revenues	-1.5%	--	2.5%
"Cash Flow"	1.5%	1.5%	4.5%
Earnings	1.5%	1.5%	5.0%
Dividends	.5%	4.0%	5.0%
Book Value	4.5%	4.5%	4.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	3625	3551	4156	3613	14945
2013	3826	3582	4176	3773	15357
2014	4648	4044	4302	4026	17020
2015	4568	3839	4432	3861	16700
2016	4450	4050	4450	4050	17000

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.80	.75	1.00	.43	2.98
2013	.75	.73	1.10	.60	3.18
2014	1.15	.80	1.01	.39	3.34
2015	1.28	.88	1.06	.48	3.70
2016	1.15	.85	1.20	.50	3.70

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.46	.46	.46	.47	1.85
2012	.47	.47	.47	.47	1.88
2013	.47	.49	.49	.50	1.95
2014	.50	.50	.50	.53	2.03
2015	.53	.53	.53	.56	

BUSINESS: American Electric Power Company, Inc. (AEP), through 10 operating utilities, serves 5.4 mill. customers in Arkansas, Kentucky, Indiana, Louisiana, Michigan, Ohio, Oklahoma, Tennessee, Texas, Virginia, & West Virginia. Electric rev. breakdown: residential, 40%; commercial, 23%; industrial, 19%; wholesale, 15%; other, 3%. Sold 50% stake in Yorkshire Holdings (British utility) '01; SEEBOARD (British utility) '02; Houston Pipeline '05; commercial barge operation in '15. Generating sources not available. Fuel costs: 36% of revs. '14 reported deprec. rates (utility): 1.4%-8.6%. Has 18,500 employees. Chairman, President & CEO: Nicholas K. Akins. Inc.: NY. Address: 1 Riverside Plaza, Columbus, OH 43215-2373. Tel.: 614-716-1000. Internet: www.aep.com.

American Electric Power is trying to reach a settlement in Ohio about its proposed purchased-power agreement. In recent years, the company has been moving away from the nonregulated side of the business in favor of its regulated utilities. Low capacity prices have hurt the profitability of AEP's nonregulated generating assets. So, the company proposed a purchased-power agreement between some nonregulated generating assets and its utilities in Ohio. The outcome of this matter might well be determined in early 2016. A sale or spinoff of these assets is possible if a settlement is not reached. Note that another company in the state reached a settlement with the commission's staff on a similar proposal, but still faces some opposition—as does AEP.

We have raised our 2015 and 2016 earnings estimates slightly. We lifted our 2015 estimate by $0.10 a share and our 2016 forecast by $0.05 a share. Our $3.70-a-share estimate each year is within AEP's guidance of $3.67-$3.77 and $3.60-$3.80, respectively. The utilities are generally faring well, and are benefiting from rate relief. Increased investment in electric transmission is another plus for AEP. This is outweighing the aforementioned disadvantage of low capacity prices.

Public Service of Oklahoma has a rate case pending. The utility filed for a tariff hike of $172 million, based on a return of 10.5% on a common-equity ratio of 48%. New rates should take effect at the start of 2016.

The board of directors raised the dividend in the fourth quarter. The increase was $0.03 a share (5.7%) quarterly. AEP is targeting a payout ratio of 60%-70%.

The company sold its commercial barge operation. This business earned $0.03 a share in the first three quarters of 2015, which is now included in discontinued operations. The sale raised $400 million in cash, which AEP will use for its regulated utilities. The company hasn't stated whether it will book a gain or loss on the sale.

This stock's valuation is about average for a utility. The dividend yield and total return potential to 2018-2020 are close to the industry averages.

Paul E. Debbas, CFA *December 18, 2015*

(A) Diluted EPS. Excl. nonrec. gains (losses): '02, ($3.86); '03, ($1.92); '04, 24¢; '05, (62¢); '06, (20¢); '07, (20¢); '08, 40¢; '10, (7¢); '11, 89¢; '12, (38¢); '13, (14¢); discont. ops.: '02, (57¢); '03, (32¢); '04, 15¢; '05, 7¢; '06, 2¢; '08, 3¢; '15, 4¢. '14 EPS don't add due to rounding. Next egs. report due late Jan. (B) Div'ds historic. paid early Mar., June, Sept., & Dec. ■ Div'd reinvest. plan avail. (C) Incl. intang. In '14: $17.67/sh. (D) In mill. (E) Rate base: various. Rates all'd on com. eq.: 9.65%-10.9%; earn. on avg. com. eq., '14: 9.9%. Reg. Clim.: Avg.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	55
Earnings Predictability	90

EL PASO ELECTRIC NYSE-EE

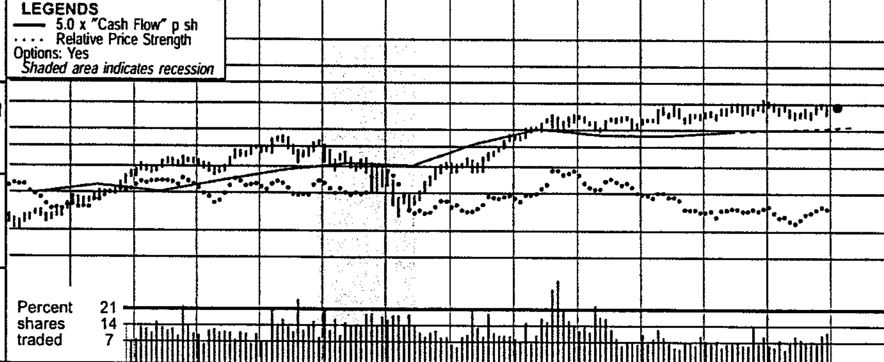
RECENT PRICE 38.70 | P/E RATIO 18.1 (Trailing: 18.3 / Median: 15.0) | RELATIVE P/E RATIO 1.10 | DIV'D YLD 3.2% | VALUE LINE

TIMELINESS 3 Raised 11/13/15
SAFETY 2 Raised 5/11/07
TECHNICAL 3 Lowered 1/1/16
BETA .75 (1.00 = Market)

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
High:	19.1	22.4	25.0	28.2	25.5	21.1	28.7	35.7	35.3	39.1	42.2	41.3
Low:	13.1	17.8	18.2	20.8	15.2	11.6	18.7	26.7	29.2	31.8	33.4	33.8

Target Price Range 2018 | 2019 | 2020

LEGENDS
— 5.0 x "Cash Flow" p sh
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



2018-20 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	45	(+15%)	7%
Low	35	(-10%)	1%

Insider Decisions

	M	A	M	J	J	A	S	O	N
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	5	0
to Sell	0	0	0	0	0	0	0	0	0

Institutional Decisions

	1Q2015	2Q2015	3Q2015
to Buy	88	76	78
to Sell	74	71	63
Hld's(000)	38975	39499	39588

% TOT. RETURN 12/15

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-0.7	-6.9
3 yr.	32.5	37.7
5 yr.	61.5	52.1

	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	© VALUE LINE PUB. LLC 18-20
Revenues per sh	9.96	13.70	15.40	13.91	13.97	14.95	16.70	17.75	19.43	23.15	18.85	20.61	22.97	21.26	22.11	22.74	21.00	22.15	26.75
"Cash Flow" per sh	2.79	3.21	3.43	2.99	3.00	3.27	3.05	3.44	3.86	4.16	4.07	5.15	6.05	5.66	5.65	5.87	6.05	6.25	8.00
Earnings per sh A	.86	1.09	1.27	.57	.64	.69	.76	1.27	1.63	1.73	1.50	2.07	2.48	2.26	2.20	2.27	2.05	2.10	2.75
Div'd Decl'd per sh B	--	--	--	--	--	--	--	--	--	--	--	--	.66	.97	1.05	1.11	1.17	1.23	1.40
Cap'l Spending per sh	1.28	1.70	1.85	1.75	2.03	1.94	2.28	2.73	4.63	5.36	5.95	5.27	5.90	6.70	7.18	8.50	7.90	7.75	7.25
Book Value per sh C	7.36	8.05	9.01	9.20	10.51	11.23	11.56	12.60	14.76	15.47	16.45	19.04	19.03	20.57	23.44	24.39	25.20	26.00	29.50
Common Shs Outst'g D	57.26	51.20	49.99	49.61	47.56	47.40	48.14	46.00	45.15	44.88	43.92	42.57	39.96	40.11	40.27	40.36	40.50	40.65	41.10
Avg Ann'l P/E Ratio	9.9	10.6	11.0	23.0	18.3	22.0	26.7	16.9	15.3	11.9	10.8	10.7	12.6	14.5	15.9	16.4	18.1		14.5
Relative P/E Ratio	.56	.69	.56	1.26	1.04	1.16	1.42	.91	.81	.72	.72	.68	.79	.92	.89	.86	.90		.90
Avg Ann'l Div'd Yield	--	--	--	--	--	--	--	--	--	--	--	--	2.1%	3.0%	3.0%	3.0%	3.1%		3.5%

CAPITAL STRUCTURE as of 9/30/15
Total Debt $1253.0 mill. Due in 5 Yrs $201.9 mill.
LT Debt $1134.3 mill. LT Interest $68.2 mill.
(LT interest earned: 2.5x)

Leases, Uncapitalized Annual rentals $1.4 mill.
Pension Assets-12/14 $272.9 mill.
Oblig. $341.1 mill.

Pfd Stock None

Common Stock 40,426,668 shs.
as of 10/31/15

MARKET CAP: $1.6 billion (Mid Cap)

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	18-20
Revenues ($mill)	803.9	816.5	877.4	1038.9	828.0	877.3	918.0	852.9	890.4	917.5	850	900	1100
Net Profit ($mill)	36.6	61.4	74.8	77.6	66.9	90.3	103.5	90.8	88.6	91.4	85.0	85.0	115
Income Tax Rate	33.7%	29.8%	31.6%	32.8%	33.1%	36.1%	34.2%	34.1%	33.0%	31.0%	30.0%	31.0%	31.0%
AFUDC % to Net Profit	15.8%	8.0%	15.9%	20.4%	24.3%	22.1%	17.6%	22.4%	24.1%	30.8%	24.0%	24.0%	13.0%
Long-Term Debt Ratio	52.3%	51.5%	49.6%	53.8%	52.7%	51.2%	51.8%	54.8%	51.4%	53.5%	52.5%	55.0%	55.5%
Common Equity Ratio	47.7%	48.5%	50.4%	46.2%	47.3%	48.8%	48.2%	45.2%	48.6%	46.5%	47.5%	45.0%	44.5%
Total Capital ($mill)	1167.5	1195.8	1321.6	1503.9	1527.7	1660.1	1576.7	1824.5	1943.5	2118.4	2155	2340	2725
Net Plant ($mill)	1291.7	1332.2	1450.6	1595.6	1756.0	1865.8	1947.1	2102.3	2257.5	2488.4	2645	2790	3050
Return on Total Cap'l	4.9%	6.6%	7.1%	6.7%	6.0%	7.0%	8.3%	6.5%	6.1%	5.7%	5.5%	5.0%	6.0%
Return on Shr. Equity	6.6%	10.6%	11.2%	11.2%	9.3%	11.1%	13.6%	11.0%	9.4%	9.3%	8.0%	8.0%	9.5%
Return on Com Equity E	6.6%	10.6%	11.2%	11.2%	9.3%	11.1%	13.6%	11.0%	9.4%	9.3%	8.0%	8.0%	9.5%
Retained to Com Eq	6.6%	10.6%	11.2%	11.2%	9.3%	11.1%	10.0%	6.3%	4.9%	4.8%	3.5%	3.5%	5.0%
All Div'ds to Net Prof	--	--	--	--	--	--	26%	43%	47%	49%	56%	59%	49%

ELECTRIC OPERATING STATISTICS

	2012	2013	2014
% Change Retail Sales (KWH)	+.7	+.4	-1.6
Avg. Indust. Use (MWH)	21659	21908	21505
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	1765	1852	1879
Peak Load, Summer (Mw)	1688	1750	1766
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+1.5	+1.3	+1.3
Fixed Charge Cov. (%)	302	280	251

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '12-'14 to '18-'20
Revenues	4.5%	1.5%	3.5%
"Cash Flow"	6.5%	7.5%	5.5%
Earnings	13.5%	6.5%	3.5%
Dividends	--	--	5.0%
Book Value	8.5%	8.0%	4.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	168.6	228.3	267.2	188.8	852.9
2013	177.3	240.1	282.7	190.3	890.4
2014	185.5	251.8	283.6	196.6	917.5
2015	163.7	219.5	289.7	177.1	850
2016	175	240	300	185	900

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.08	.77	1.29	.12	2.26
2013	.19	.72	1.26	.03	2.20
2014	.11	.75	1.30	.10	2.27
2015	.09	.52	1.40	.04	2.05
2016	.05	.65	1.25	.15	2.10

Cal-endar	QUARTERLY DIVIDENDS PAID B Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.22	.25	.25	.25	.97
2013	.25	.265	.265	.265	1.05
2014	.265	.28	.28	.28	1.11
2015	.28	.295	.295	.295	1.17
2016					

BUSINESS: El Paso Electric Company (EPE) provides electric service to 405,000 customers in an area of approximately 10,000 square miles in the Rio Grande valley in western Texas (68% of revenues) and southern New Mexico (19% of revenues), including El Paso, Texas and Las Cruces, New Mexico. Wholesale is 13% of revenues. Electric revenue breakdown by customer class not available. Generating sources: nuclear, 47%; gas, 35%; coal, 5%; purchased, 13%. Fuel costs: 34% of revenues. '14 reported depreciation rate: 2.6%. Has about 1,000 employees. Chairman: Charles A. Yamarone. President & CEO: Mary Kipp. Incorporated: Texas. Address: Stanton Tower, 100 North Stanton, El Paso, Texas 79901. Tel.: 915-543-5711. Internet: www.epelectric.com.

El Paso Electric Company has rate applications pending in Texas and New Mexico. The utility wants to place capital expenditures into the rate base, including its spending on the first two units (88 megawatts each) of a four-unit gas-fired generating station. In Texas, El Paso Electric is seeking a rate hike of $70.5 million, based on a return of 10.1% on a common-equity ratio of 49.52%. The staff of the Texas commission is recommending an increase of $54.3 million, based on a 9.5% ROE, and the city of El Paso is proposing a hike of $23.5 million, based on a 9.1% ROE. In New Mexico, El Paso Electric is asking for $6.4 million, based on a return of 9.95% on a common-equity ratio of 49.29%. The commission's staff is recommending a $3.2 million raise, based on a 9.22% ROE. Although settlements cannot be ruled out, it appears as if each case will be fully litigated, with orders being issued early in the second quarter of 2016.

We have adjusted our earnings estimates for 2015 and 2016. The first two units of the aforementioned generating plant are in service, but are not yet in the rate base. Thus, El Paso Electric is incurring costs (such as depreciation) that are not being recovered. This results in regulatory lag for the utility. We overestimated the effects of regulatory lag in the third quarter of 2015, but underestimated them in the fourth quarter of 2015 and first period of 2016. Because third-quarter profits (aided by favorable weather patterns) exceeded our expectation, we have raised our full-year estimate by $0.10 a share, to $2.05. Our revised estimate is within the company's targeted range of $1.95-$2.10 a share. On the other hand, we have cut our 2016 forecast by $0.10 a share due to our lowered expectation for the March period.

Finances are sound. The fixed-charge coverage, common-equity ratio, and return on equity are comparable with the norms for the electric utility industry.

The dividend yield of El Paso Electric stock is low, by utility standards. This reflects, in part, the company's good dividend growth prospects through 2018-2020. However, with the recent quotation within our 3- to 5-year Target Price Range (like that of many utility issues), total return potential is lackluster.

Paul E. Debbas, CFA *January 29, 2016*

(A) Diluted earnings. Excl. nonrecurring gains (losses): '99, (38¢); '01, (4¢); '03, 81¢; '04, 4¢; '05, (2¢); '06, 13¢; '10, 24¢. '14 earnings don't add to full-year total due to rounding. Next earnings report due late Feb. (B) Initial dividend declared 4/11; payment dates in late March, June, Sept., and Dec. (C) Incl. deferred charges. In '14: $112.1 mill., $2.78/sh. (D) In millions. (E) Rate allowed on common equity in TX in '12: none specified; in NM in '10: none specified; earned on average common equity, '14: 9.5%. Regulatory Climate: Average.

Company's Financial Strength	B++
Stock's Price Stability	90
Price Growth Persistence	65
Earnings Predictability	85

EMPIRE DISTRICT NYSE-EDE

RECENT PRICE 22.81 | P/E RATIO 15.7 (Trailing: 17.2, Median: 16.0) | RELATIVE P/E RATIO 0.89 | DIV'D YLD 4.6% | VALUE LINE

TIMELINESS 4 Raised 11/20/15
SAFETY 2 Raised 3/23/12
TECHNICAL 4 Lowered 12/4/15
BETA .70 (1.00 = Market)

High:	23.5	25.0	25.1	26.1	23.5	19.4	22.5	23.3	22.0	24.3	31.2	31.5				Target Price Range	
Low:	19.5	19.3	20.3	21.1	14.9	11.9	17.6	18.0	19.5	20.6	22.0	20.7				2018 2019 2020	

2018-20 PROJECTIONS

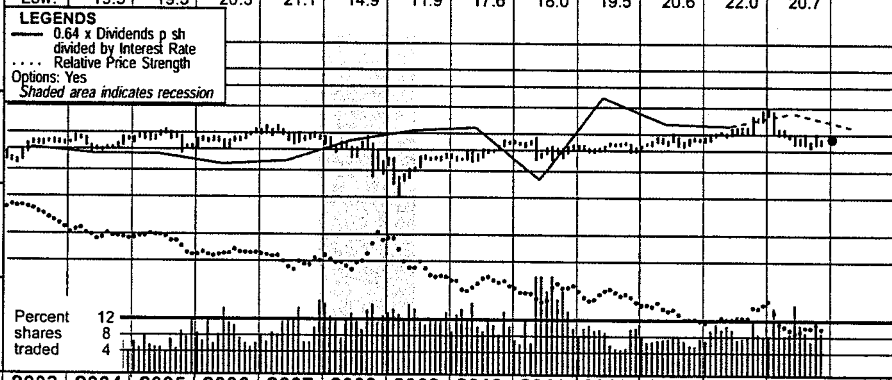
	Price	Gain	Ann'l Total Return
High	25	(+10%)	7%
Low	20	(-10%)	2%

Insider Decisions

	J	F	M	A	M	J	J	A	S
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	1	0	0	0	0	0	0	0

Institutional Decisions

	1Q2015	2Q2015	3Q2015
to Buy	70	65	68
to Sell	65	65	49
Hld's(000)	20494	20421	20727



% TOT. RETURN 11/15

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-14.1	-2.0
3 yr.	29.8	48.1
5 yr.	30.5	71.2

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	© VALUE LINE PUB. LLC	18-20
13.94	14.78	13.37	13.56	13.03	12.67	14.80	13.67	14.59	15.25	13.04	13.02	13.74	13.11	13.81	15.00	*13.85*	*14.00*	Revenues per sh	*16.00*
2.89	3.12	2.19	2.43	2.48	2.22	2.45	2.75	2.69	2.91	2.72	2.85	3.21	2.99	3.14	3.45	*3.50*	*3.60*	"Cash Flow" per sh	*4.25*
1.13	1.35	.59	1.19	1.29	.86	.92	1.41	1.09	1.17	1.18	1.17	1.31	1.32	1.48	1.55	*1.35*	*1.45*	Earnings per sh A	*1.75*
1.28	1.28	1.28	1.28	1.28	1.28	1.28	1.28	1.28	1.28	1.28	1.28	.64	1.00	1.01	1.03	*1.04*	*1.04*	Div'd Decl'd per sh B ■ †	*1.15*
4.14	7.61	4.02	3.43	2.65	1.64	2.83	3.97	5.46	6.28	4.07	2.63	2.44	3.22	3.60	4.91	*4.05*	*2.75*	Cap'l Spending per sh	*3.50*
13.48	13.65	13.58	14.59	15.17	14.76	15.08	15.49	16.04	15.56	15.75	15.82	16.53	16.90	17.43	18.02	*18.30*	*18.80*	Book Value per sh C	*20.50*
17.37	17.60	19.76	22.57	24.98	25.70	26.08	30.25	33.61	33.98	38.11	41.58	41.98	42.48	43.04	43.48	*44.00*	*46.00*	Common Shs Outst'g D	*47.50*
21.7	17.7	33.9	16.2	15.8	24.8	24.5	15.9	21.7	17.3	14.3	16.8	15.8	15.8	15.0	16.2	Bold figures are		Avg Ann'l P/E Ratio	*12.5*
1.24	1.15	1.74	.88	.90	1.31	1.30	.86	1.15	1.04	.95	1.07	.99	1.01	.84	.85	Value Line		Relative P/E Ratio	*.80*
5.2%	5.4%	6.4%	6.6%	6.3%	6.0%	5.7%	5.7%	5.4%	6.3%	7.6%	6.5%	3.1%	4.8%	4.5%	4.1%	estimates		Avg Ann'l Div'd Yield	*5.0%*

CAPITAL STRUCTURE as of 9/30/15
Total Debt $879.6 mill. Due in 5 Yrs $213.6 mill.
LT Debt $863.0 mill. LT Interest $43.9 mill.
Incl. $3.7 mill. capitalized leases.
(LT interest earned: 3.0x)
Leases, Uncapitalized Annual rentals $.7 mill.
Pension Assets-12/14 $192.7 mill. Oblig. $251.9 mill.

Pfd Stock None

Common Stock 43,787,249 shs.
as of 10/30/15

MARKET CAP: $1.0 billion (Mid Cap)

2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016		18-20
386.2	413.5	490.2	518.2	497.2	541.3	576.9	557.1	594.3	652.3	*610*	*645*	Revenues ($mill)	*765*
23.8	39.9	33.2	39.7	41.3	47.4	55.0	55.7	63.4	67.1	*55.0*	*65.0*	Net Profit ($mill)	*85.0*
33.4%	35.4%	30.3%	32.5%	32.5%	39.2%	38.4%	38.0%	37.1%	36.9%	*37.5%*	*38.0%*	Income Tax Rate	*37.5%*
2.4%	10.7%	23.1%	31.5%	34.2%	21.5%	.9%	3.5%	9.4%	14.8%	*10.0%*	*3.0%*	AFUDC % to Net Profit	*6.0%*
51.0%	49.7%	50.1%	53.6%	51.6%	51.3%	49.9%	49.1%	49.8%	50.6%	*51.0%*	*52.0%*	Long-Term Debt Ratio	*50.0%*
49.0%	50.3%	49.9%	46.4%	48.4%	48.7%	50.1%	50.9%	50.2%	49.4%	*49.0%*	*48.0%*	Common Equity Ratio	*50.0%*
803.3	931.0	1081.1	1140.4	1240.3	1350.7	1386.2	1409.4	1493.6	1586.5	*1645*	*1805*	Total Capital ($mill)	*1925*
896.0	1031.0	1178.9	1342.8	1459.0	1519.1	1563.7	1657.6	1751.9	1910.3	*1995*	*2020*	Net Plant ($mill)	*2150*
4.7%	5.9%	4.7%	5.2%	5.2%	5.1%	5.5%	5.4%	5.6%	5.5%	*5.0%*	*5.0%*	Return on Total Cap'l	*5.5%*
6.0%	8.5%	6.2%	7.5%	6.9%	7.2%	7.9%	7.8%	8.5%	8.6%	*7.5%*	*7.5%*	Return on Shr. Equity	*8.5%*
6.0%	8.5%	6.2%	7.5%	6.9%	7.2%	7.9%	7.8%	8.5%	8.6%	*7.5%*	*7.5%*	Return on Com Equity E	*8.5%*
NMF	.8%	NMF	NMF	NMF	NMF	4.1%	1.9%	2.7%	2.9%	*2.0%*	*2.0%*	Retained to Com Eq	*3.0%*
NMF	90%	117%	109%	109%	110%	49%	76%	68%	66%	*76%*	*71%*	All Div'ds to Net Prof	*64%*

ELECTRIC OPERATING STATISTICS

	2012	2013	2014
% Change Retail Sales (KWH)	-3.2	+1.3	+1.3
Avg. Industrial Use (MWH)	2913	2943	2981
Avg. Industrial Rev/KWH (¢)	7.66	7.93	8.21
Capacity at Peak (Mw)	1391	1377	1326
Peak Load, Summer (Mw)	1142	1080	1162
Annual Load Factor (%)	52.2	56.2	52.8
% Change Customers (avg.)	+.6	+.5	+.3
Fixed Charge Cov. (%)	314	331	334

BUSINESS: The Empire District Electric Company supplies electricity to 169,000 customers in a 10,000 sq. mi. area in southwestern Missouri (90% of retail elec. revs.), Kansas (5%), Oklahoma (3%), & Arkansas (2%). Acquired Missouri Gas (44,000 customers) 6/06. Supplies water service (4,000 customers) and has a small fiber-optics operation. Elec. rev. breakdown: residential, 45%; commercial, 32%; industrial, 16%; other, 7%. Generating sources: coal, 47%; gas, 27%; hydro, 1%; purch., 25%. Fuel costs: 37% of revenues. '14 reported depr. rate: 3.0%. Has about 750 employees. Chairman: D. Randy Laney. President & CEO: Bradley P. Beecher. Inc.: KS. Address: 602 S. Joplin Ave., P.O. Box 127, Joplin, MO 64802-0127. Tel.: 417-625-5100. Internet: www.empiredistrict.com.

ANNUAL RATES

of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '12-'14 to '18-'20
Revenues	.5%	-.5%	*2.5%*
"Cash Flow"	3.0%	3.0%	*5.0%*
Earnings	2.5%	5.0%	*3.0%*
Dividends	-2.5%	-4.5%	*2.0%*
Book Value	1.5%	2.0%	*2.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	137.2	131.6	159.2	129.1	557.1
2013	151.1	136.6	157.5	149.1	594.3
2014	179.7	149.8	171.5	151.3	652.3
2015	164.5	134.5	169.7	*141.3*	*610*
2016	*180*	*145*	*170*	*150*	*645*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.23	.25	.60	.23	1.32
2013	.30	.27	.56	.35	1.48
2014	.48	.26	.55	.26	1.55
2015	.34	.15	.58	*.28*	*1.35*
2016	*.34*	*.25*	*.57*	*.29*	*1.45*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.32	.32	--	--	.64
2012	.25	.25	.25	.25	1.00
2013	.25	.25	.25	.255	1.01
2014	.255	.255	.255	.26	1.03
2015	.26	.26	.26	.26	

Empire District Electric Company has filed another rate case in Missouri. The utility received a $17.1 million (3.9%) tariff hike in July, which enabled it to place an environmental project in the rate base. Now, Empire District Electric is seeking to place another project, a $165 million-$175 million upgrade to a gas-fired unit, which will add 100 megawatts of capacity, in rates. In addition, the utility earned a return on equity of just 7.2% in the 12-month period that ended on September 30th. So, the company is asking the Missouri regulators for a $33.4 million (7.3%) rate increase, based on a 9.9% return on a 49% common-equity ratio. New tariffs are expected to go into effect in September of 2016. A corresponding filing will also be made in Oklahoma, which represents a much smaller proportion of the utility's business than does Missouri. New rates should take effect 30 days after the order is implemented in Missouri.

Regulatory lag affected Empire District Electric's earnings this year, and will do so again in 2016. The assets that the utility is adding were and are being completed several months before the rate hikes took and will take effect. Thus, during that span, some costs (such as depreciation) are not being recovered in rates. This is an ongoing problem for utilities in Missouri, and helps explain the low ROEs that Empire District Electric has earned for a long time. Our 2015 earnings estimate of $1.35 a share, which is within the company's guidance of $1.30-$1.45, would produce a 13% decline from the 2014 tally. We forecast just a partial profit recovery in 2016.

The board of directors did not raise the dividend in the fourth quarter. This is in contrast to the two previous years. The board was concerned that the payout ratio is at the high end of a reasonable range for most utilities.

Untimely Empire District Electric stock has performed poorly this year. Its price has declined 23% since the start of 2015. We attribute this to a lessening of takeover speculation, not a worsening of the company's prospects. The stock's dividend yield is above average for a utility, but 3- to 5-year total return potential is unimpressive.

Paul E. Debbas, CFA *December 18, 2015*

(A) Diluted earnings. Excl. loss from discontinued operations: '06, 2¢. '12 EPS don't add due to rounding. Next earnings report due early Feb. (B) Div'ds historically paid in mid-Mar., June, Sept. and Dec. Div'ds suspended 3Q '11, reinstated 1Q '12. ■ Div'd reinvestment plan avail. (3% discount). † Shareholder investment plan avail. (C) Incl. intangibles. In '14: $5.93/sh. (D) In mill. (E) Rate base: Deprec. orig. cost. Rate allowed on com. eq. in MO in '15: none specified; earned on avg. com. eq., '14: 8.7%. Regulatory Climate: Average.

Company's Financial Strength	B++
Stock's Price Stability	90
Price Growth Persistence	25
Earnings Predictability	85

EVERSOURCE ENERGY NYSE-ES

RECENT PRICE 50.37 | P/E RATIO 17.7 (Trailing: 17.5; Median: 17.0) | RELATIVE P/E RATIO 0.99 | DIV'D YLD 3.5% | VALUE LINE

TIMELINESS 3 Lowered 8/14/15
SAFETY 1 Raised 5/22/15
TECHNICAL 1 Raised 11/20/15
BETA .75 (1.00 = Market)

High:	20.3	22.0	28.9	33.6	31.6	26.5	32.2	36.5	40.9	45.7	56.7	56.8
Low:	17.2	17.3	19.1	26.2	17.2	19.0	24.7	30.0	33.5	38.6	41.3	44.6

Target Price Range 2018 | 2019 | 2020

2018-20 PROJECTIONS

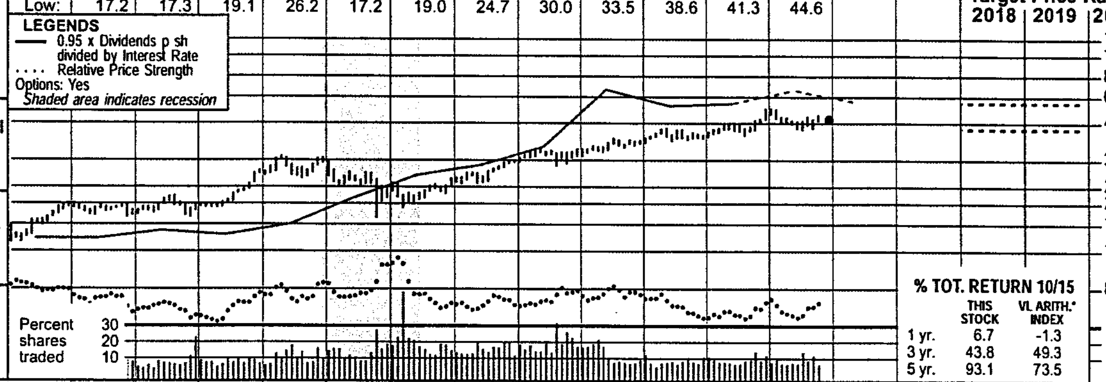
	Price	Gain	Ann'l Total Return
High	60	(+20%)	8%
Low	45	(-10%)	2%

Insider Decisions

	D	J	F	M	A	M	J	J	A
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	1
to Sell	0	0	0	2	0	1	2	0	2

Institutional Decisions

	4Q2014	1Q2015	2Q2015
to Buy	233	203	236
to Sell	211	255	206
Hld's(000)	223425	223824	226206



% TOT. RETURN 10/15

	THIS STOCK	VL ARITH.* INDEX
1 yr.	6.7	-1.3
3 yr.	43.8	49.3
5 yr.	93.1	73.5

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	© VALUE LINE PUB. LLC	18-20
33.91	40.86	52.82	40.89	47.53	51.82	41.85	44.64	37.27	37.22	30.97	27.76	25.21	19.98	23.16	24.42	*25.80*	*26.00*	Revenues per sh	*28.00*
5.68	3.39	10.48	6.32	5.80	5.00	5.46	3.69	4.82	6.16	4.96	5.68	4.88	4.03	5.22	4.56	*5.20*	*5.55*	"Cash Flow" per sh	*6.75*
d1.14	d.20	1.37	1.08	1.24	.91	.98	.82	1.59	1.86	1.91	2.10	2.22	1.89	2.49	2.58	*2.80*	*3.00*	Earnings per sh A	*3.75*
.10	.40	.45	.53	.58	.63	.68	.73	.78	.83	.95	1.03	1.10	1.32	1.47	1.57	*1.67*	*1.78*	Div'd Decl'd per sh B ■	*2.10*
2.50	2.88	3.40	3.86	4.31	4.85	5.89	5.49	7.14	8.06	5.17	5.41	6.08	4.69	4.62	5.06	*5.80*	*6.65*	Cap'l Spending per sh	*6.25*
15.80	15.43	16.27	17.33	17.73	17.80	18.46	18.14	18.65	19.38	20.37	21.60	22.65	29.41	30.49	31.47	*32.55*	*33.75*	Book Value per sh C	*38.00*
131.87	143.82	130.13	127.56	127.70	129.03	131.59	154.23	156.22	155.83	175.62	176.45	177.16	314.05	315.27	316.98	*318.00*	*319.00*	Common Shs Outst'g D	*322.00*
--	--	14.1	16.1	13.4	20.8	19.8	27.1	18.7	13.7	12.0	13.4	15.4	19.9	16.9	17.9	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*14.0*
--	--	.72	.88	.76	1.10	1.05	1.46	.99	.82	.80	.85	.97	1.27	.95	.95			Relative P/E Ratio	*.90*
.6%	1.9%	2.3%	3.0%	3.5%	3.3%	3.5%	3.3%	2.6%	3.2%	4.2%	3.6%	3.2%	3.5%	3.5%	3.4%			Avg Ann'l Div'd Yield	*4.0%*

CAPITAL STRUCTURE as of 6/30/15
Total Debt $9922.2 mill. Due in 5 Yrs $3763.9 mill.
LT Debt $8689.6 mill. LT Interest $376.3 mill.
(LT interest earned: 4.7x)

Leases, Uncapitalized Annual rentals $20.1 mill.
Pension Assets-12/14 $4126.5 mill.
Oblig. $5486.2 mill.
Pfd Stock $155.6 mill. Pfd Div'd $7.6 mill.
Incl. 2,324,000 shs $1.90-$3.28 rates ($50 par) not subject to mandatory redemption.
Common Stock 317,173,164 shs.
as of 7/31/15
MARKET CAP: $16 billion (Large Cap)

2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016		18-20
5507.3	6884.4	5822.2	5800.1	5439.4	4898.2	4465.7	6273.8	7301.2	7741.9	*8200*	*8300*	Revenues ($mill)	*9000*
128.5	126.2	251.5	296.2	335.6	377.8	400.3	533.0	793.7	827.1	*905*	*970*	Net Profit ($mill)	*1200*
30.8%	--	30.3%	29.7%	34.9%	36.6%	29.9%	34.0%	35.0%	36.2%	*37.5%*	*36.5%*	Income Tax Rate	*36.5%*
17.4%	21.5%	13.9%	15.8%	4.6%	7.1%	8.6%	2.3%	1.4%	2.4%	*4.0%*	*4.0%*	AFUDC % to Net Profit	*3.0%*
63.2%	58.7%	59.2%	60.4%	57.2%	55.1%	53.4%	43.7%	44.3%	45.9%	*46.5%*	*46.5%*	Long-Term Debt Ratio	*46.5%*
35.1%	39.7%	39.2%	38.1%	41.5%	43.6%	45.3%	55.4%	54.8%	53.2%	*53.0%*	*53.0%*	Common Equity Ratio	*53.0%*
6923.2	7052.0	7431.1	7926.2	8629.5	8741.8	8856.0	16675	17544	18738	*19575*	*20375*	Total Capital ($mill)	*23100*
6417.2	6242.2	7229.9	8207.9	8840.0	9567.7	10403	16605	17576	18647	*19900*	*21350*	Net Plant ($mill)	*25500*
3.5%	2.9%	5.0%	5.4%	5.4%	5.8%	5.9%	4.2%	5.5%	5.3%	*5.5%*	*5.5%*	Return on Total Cap'l	*6.0%*
5.0%	4.3%	8.3%	9.4%	9.1%	9.6%	9.7%	5.7%	8.1%	8.2%	*8.5%*	*9.0%*	Return on Shr. Equity	*9.5%*
5.1%	4.3%	8.4%	9.6%	9.2%	9.8%	9.8%	5.7%	8.2%	8.2%	*8.5%*	*9.0%*	Return on Com Equity E	*9.5%*
1.5%	.3%	4.3%	5.3%	4.7%	5.0%	5.0%	1.6%	3.4%	3.5%	*3.5%*	*3.5%*	Retained to Com Eq	*4.0%*
72%	94%	50%	45%	50%	49%	50%	72%	59%	58%	*59%*	*59%*	All Div'ds to Net Prof	*57%*

ELECTRIC OPERATING STATISTICS

	2012	2013	2014
% Change Retail Sales (KWH)	+47.0	+1.0	-1.6
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Winter (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+59.8	NA	NA
Fixed Charge Cov. (%)	320	427	426

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '12-'14 to '18-'20
Revenues	-7.0%	-8.5%	*3.5%*
"Cash Flow"	-2.0%	-3.0%	*6.5%*
Earnings	8.0%	5.5%	*8.5%*
Dividends	9.5%	11.5%	*6.5%*
Book Value	5.5%	9.5%	*4.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	1099	1628	1861	1684	6273.8
2013	1995	1635	1892	1777	7301.2
2014	2290	1677	1892	1881	7741.9
2015	2513	1817	1933	*1937*	*8200*
2016	*2500*	*1850*	*2000*	*1950*	*8300*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.56	.15	.66	.55	1.89
2013	.72	.54	.66	.56	2.49
2014	.74	.40	.74	.69	2.58
2015	.80	.65	.74	*.61*	*2.80*
2016	*.85*	*.65*	*.80*	*.70*	*3.00*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.275	.275	.275	.275	1.10
2012	.294	.343	.343	.343	1.32
2013	.3675	.3675	.3675	.3675	1.47
2014	.3925	.3925	.3925	.3925	1.57
2015	.4175	.4175	.4175		

BUSINESS: Eversource Energy (formerly Northeast Utilities) is the parent of utilities that have 3.1 million electric, 504,000 gas customers. Supplies power to most of Connecticut and gas to part of Connecticut; supplies power to three fourths of New Hampshire's population; supplies power to western Massachusetts and parts of eastern Massachusetts & gas to central & eastern Massachusetts. Acquired NSTAR 4/12. Electric revenue breakdown: residential, 49%; commercial, 38%; industrial, 5%; other, 8%. Fuel costs: 39% of revenues. '14 reported deprec. rates: 2.7%-3.3%. Has 8,200 employees. Chairman, President & CEO: Thomas J. May. Inc.: MA. Address: 300 Cadwell Drive, Springfield, MA 01104. Tel.: 413-785-5871. Internet: www.eversource.com.

Eversource Energy was granted a gas rate increase in Massachusetts. The regulators raised rates by $15.8 million, based on a 9.8% return on a 52.1% common-equity ratio. New tariffs will take effect at the start of 2016.

Rate relief is one reason why earnings are likely to advance significantly this year and next. Eversource is also benefiting from an electric rate hike in Connecticut that took effect in late 2014. Another factor is customer conversions from oil heat to gas heat. The company is reducing expenses, too. Even so, we have lowered our 2015 earnings estimate by $0.10 a share because the tax rate will be higher than we had expected. Our revised profit estimate is at the low end of Eversource's guidance of $2.80-$2.85 a share.

Eversource is proposing to sell its generating assets in New Hampshire. These assets have a book value of $650 million and are earning $0.09-$0.10 a share annually. If approved, the utility would recover its stranded costs by issuing securitized bonds. A decision is expected by yearend.

The company is proposing a grid modernization plan in Massachusetts. Eversource would spend $430 million through 2021. The utility would recover its costs through a tracking mechanism, rather than by filing general rate cases. A ruling from the regulators is expected in 2016.

Eversource is seeking permission to build a transmission line to Canada. When the project was proposed several years ago, it was expected to cost under $1 billion, but the latest estimate is $1.6 billion because of inflation, plus the route has changed and some of the line will be built underground. The goal is for the line to go into service in the first half of 2019.

We expect a dividend increase in the first quarter of 2016. We think the board of directors will raise the annual disbursement by $0.11 a share (6.6%).

Eversource's strong points are reflected in the share price. Although prospects for earnings and dividend growth are solid, the stock's 3- to 5-year total return potential is low. Meanwhile, the dividend yield is a bit below the industry mean.

Paul E. Debbas, CFA *November 20, 2015*

(A) Dil. EPS. Excl. nonrec. gains (losses): '02, 10¢; '03, (32¢); '04, (7¢); '05, ($1.36); '08, (19¢); '10, 9¢. '12 EPS don't add due to chng. in shs., '13 & '14 due to rounding. Next egs. report due early Feb. (B) Div'ds histor. paid late Mar., June, Sept., & Dec. ■ Div'd reinv. plan avail. (C) Incl. def'd chgs. In '14: $23.89/sh. (D) In mill. (E) Rate all'd on com. eq. in MA: (elec) '11, 9.6%; (gas) '16, 9.8%; in CT: (elec.) '15, 9.02%; (gas) '15, 9.5%; in NH: '10, 9.67%; earn. on avg. com. eq., '14: 8.4%. Reg. Clim.: CT, Below Avg.; NH, Avg.; MA, Above Avg.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	80
Earnings Predictability	85

GREAT PLAINS EN'GY NYSE-GXP

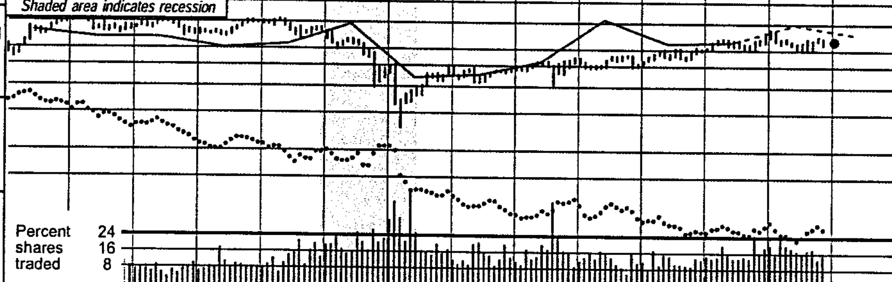
RECENT PRICE 26.56 | P/E RATIO 17.1 (Trailing: 19.8 / Median: 16.0) | RELATIVE P/E RATIO 0.97 | DIV'D YLD 4.0% | VALUE LINE

TIMELINESS 3 Raised 12/18/15
SAFETY 3 Lowered 12/26/08
TECHNICAL 1 Raised 12/18/15
BETA .85 (1.00 = Market)

High:	35.7	32.8	32.8	33.4	29.3	20.5	19.9	22.1	22.8	24.9	29.5	30.3						
Low:	27.9	27.1	27.1	26.9	15.6	10.2	16.6	16.3	19.5	20.4	23.8	24.1						

Target Price Range 2018 | 2019 | 2020

LEGENDS
— 0.70 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



2018-20 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	35	(+30%)	10%
Low	20	(-25%)	-2%

Insider Decisions

	J	F	M	A	M	J	J	A	S
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	9	0	0	0	0	0	0

Institutional Decisions

	1Q2015	2Q2015	3Q2015
to Buy	125	122	108
to Sell	148	125	134
Hld's(000)	121848	130044	125340

Percent shares traded 24 / 16 / 8

% TOT. RETURN 11/15

	THIS STOCK	VL ARITH.* INDEX
1 yr.	7.1	-2.0
3 yr.	49.3	48.1
5 yr.	76.3	71.2

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	© VALUE LINE PUB. LLC	18-20
14.50	18.02	23.61	26.91	31.04	33.13	34.85	33.30	37.89	14.00	14.51	16.62	17.03	15.05	15.90	16.66	15.85	17.10	Revenues per sh	19.25
3.63	4.63	4.70	4.40	4.69	4.75	4.54	3.86	4.24	3.09	3.27	4.12	3.51	3.45	4.01	4.01	3.95	4.60	"Cash Flow" per sh	6.00
1.26	2.05	1.59	2.04	2.27	2.46	2.18	1.62	1.86	1.16	1.03	1.53	1.25	1.35	1.62	1.57	1.35	1.75	Earnings per sh A	2.00
1.66	1.66	1.66	1.66	1.66	1.66	1.66	1.66	1.66	1.66	.83	.83	.84	.86	.88	.94	1.00	1.06	Div'd Decl'd per sh B ■	1.20
2.97	6.67	4.38	1.91	2.19	2.66	4.49	6.05	6.15	8.86	6.49	4.76	3.40	4.01	4.42	5.10	5.20	4.05	Cap'l Spending per sh	3.75
13.97	14.88	12.59	13.58	13.82	15.35	16.37	16.70	18.18	21.39	20.62	21.26	21.74	21.75	22.58	23.26	23.60	24.30	Book Value per sh C	26.75
61.91	61.91	61.91	69.20	69.26	74.37	74.74	80.35	86.23	119.26	135.42	135.71	136.14	153.53	153.87	154.16	154.50	154.75	Common Shs Outst'g D	155.50
20.0	12.4	15.9	11.1	12.2	12.6	14.0	18.3	16.3	20.5	16.0	12.1	16.1	15.5	14.2	16.5	Bold figures are		Avg Ann'l P/E Ratio	13.5
1.14	.81	.81	.61	.70	.67	.75	.99	.87	1.23	1.07	.77	1.01	.99	.80	.87	Value Line		Relative P/E Ratio	.85
6.6%	6.5%	6.6%	7.3%	6.0%	5.4%	5.5%	5.6%	5.5%	7.0%	5.0%	4.5%	4.1%	4.1%	3.8%	3.6%	estimates		Avg Ann'l Div'd Yield	4.6%

CAPITAL STRUCTURE as of 9/30/15
Total Debt $4105.7 mill. Due in 5 Yrs $1472.6 mill.
LT Debt $3763.5 mill. LT Interest $188.9 mill.
(LT interest earned: 2.4x)

Leases, Uncapitalized Annual rentals $14.2 mill.
Pension Assets-12/14 $730.0 mill. Oblig. $1186.8 mill.
Pfd Stock $39.0 mill. Pfd Div'd $1.6 mill.
390,000 shs. 3.80% to 4.50% (all $100 par & cum.), callable from $101 to $103.70.
Common Stock 154,369,354 shs. as of 11/2/15
MARKET CAP: $4.1 billion (Mid Cap)

2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016		18-20
2604.9	2675.3	3267.1	1670.1	1965.0	2255.5	2318.0	2309.9	2446.3	2568.2	2450	2650	Revenues ($mill)	3000
164.2	127.6	159.2	119.5	135.6	211.7	174.4	199.9	250.2	242.8	215	275	Net Profit ($mill)	315
18.7%	27.0%	30.7%	34.5%	25.0%	31.7%	32.7%	34.3%	34.0%	32.3%	35.0%	35.0%	Income Tax Rate	35.0%
2.1%	8.4%	10.6%	46.8%	57.0%	25.7%	3.9%	3.3%	10.4%	12.8%	5.0%	2.0%	AFUDC % to Net Profit	2.0%
47.5%	30.6%	40.7%	49.7%	53.2%	50.2%	47.8%	44.9%	50.0%	49.0%	51.0%	47.5%	Long-Term Debt Ratio	48.0%
50.9%	67.5%	57.9%	49.6%	46.2%	49.2%	51.6%	54.4%	49.4%	50.4%	48.5%	52.0%	Common Equity Ratio	51.5%
2403.3	1988.4	2709.8	5146.2	6044.5	5867.6	5741.2	6135.8	7029.1	7113.1	7525	7255	Total Capital ($mill)	8050
2765.6	3066.2	3444.5	6081.3	6651.1	6892.3	7053.5	7402.1	7746.4	8279.6	8690	8875	Net Plant ($mill)	9050
8.2%	7.9%	7.5%	3.5%	3.9%	5.3%	5.0%	5.0%	5.0%	4.7%	4.0%	5.0%	Return on Total Cap'l	5.0%
13.0%	9.2%	9.9%	4.6%	4.8%	7.2%	5.8%	5.9%	7.1%	6.7%	6.0%	7.0%	Return on Shr. Equity	7.5%
13.3%	9.4%	10.1%	4.6%	4.8%	7.3%	5.8%	5.9%	7.2%	6.7%	6.0%	7.5%	Return on Com Equity E	7.5%
3.2%	NMF	.9%	NMF	.9%	3.4%	2.0%	2.2%	3.2%	2.7%	1.5%	3.0%	Retained to Com Eq	3.0%
76%	104%	91%	NMF	81%	54%	66%	63%	55%	60%	73%	60%	All Div'ds to Net Prof	62%

ELECTRIC OPERATING STATISTICS

	2012	2013	2014
% Change Retail Sales (KWH)	-1.8	+.2	+.4
Avg. Indust. Use (MWH)	1443	1424	1455
Avg. Indust. Revs. per KWH (¢)	6.23	6.80	6.79
Capacity at Peak (Mw)	6719	NA	NA
Peak Load, Summer (Mw)	5653	NA	NA
Annual Load Factor (%)	49.6	NA	NA
% Change Customers (avg.)	+.2	+.7	+.9
Fixed Charge Cov. (%)	235	267	261

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '12-'14 to '18-'20
Revenues	-6.5%	-6.5%	3.5%
"Cash Flow"	-2.0%	1.5%	8.0%
Earnings	-4.0%	2.5%	5.0%
Dividends	-6.0%	-8.5%	6.0%
Book Value	4.5%	2.5%	3.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	479.7	603.6	746.2	480.4	2309.9
2013	542.2	600.3	765.0	538.8	2446.3
2014	585.1	648.4	782.5	552.2	2568.2
2015	549.1	609.0	781.4	510.5	2450
2016	600	650	850	550	2650

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	d.07	.41	.95	.03	1.35
2013	.17	.41	.93	.11	1.62
2014	.15	.34	.95	.12	1.57
2015	.12	.28	.82	.13	1.35
2016	.20	.40	1.00	.15	1.75

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.2075	.2075	.2075	.2125	.84
2012	.2125	.2125	.2125	.2175	.86
2013	.2175	.2175	.2175	.23	.88
2014	.23	.23	.23	.245	.94
2015	.245	.245	.245	.2625	

BUSINESS: Great Plains Energy Incorporated is a holding company for Kansas City Power & Light and two other subsidiaries, which supply electricity to 844,000 customers in western Missouri (71% of revenues) and eastern Kansas (29%). Acq'd Aquila 7/08. Sold Strategic Energy (energy-marketing subsidiary) in '08. Electric revenue breakdown: residential, 40%; commercial, 39%; industrial, 9%; other, 12%. Generating sources: coal, 64%; nuclear, 13%; wind, 1%; gas & oil, 1%; purchased, 21%. Fuel costs: 29% of revs. '14 reported deprec. rate (utility): 3.0%. Has 2,900 employees. Chairman: Michael J. Chesser. President & CEO: Terry Bassham. Inc.: Missouri. Address: 1200 Main St., Kansas City, Missouri 64105. Tel.: 816-556-2200. Internet: www.greatplainsenergy.com.

Great Plains Energy's largest utility subsidiary received a rate order in Kansas. Kansas City Power & Light was granted a tariff hike of $48.7 million (9.0%), based on a return of 9.3% on a common-equity ratio of 50.48%. New rates took effect at the start of October. KCP&L also received a rate increase of $89.7 million (11.8%), based on a 9.5% return on a 50.09% common-equity ratio, in mid-September.

There were good and bad aspects to the rate orders. KCP&L received more than 75% of what it requested, and will earn a return on its entire investment in an environmental upgrade to a coal-fired plant. The utility was also granted a fuel-adjustment mechanism in Missouri. (It already had one in Kansas.) However, the company did not get other regulatory mechanisms it sought in Missouri, and is disappointed with the low allowed ROEs. It has appealed these issues to the courts in Missouri and Kansas.

We have cut our 2015 earnings estimate by a nickel a share. Third-quarter profits fell short of our estimate. Management narrowed its share-earnings guidance from $1.35-$1.60 to $1.35-$1.45, and our revised profit estimate is at the low end of this range. In recent years, the company has been earning mediocre ROEs due to the effects of regulatory lag. The rate orders came too late to have much effect on earnings this year, but . . .

We continue to expect a significant profit increase in 2016. The rate orders should help the utility reduce (but won't eliminate) the regulatory lag problem. Our forecast would result in a 30% bottom-line increase over our 2015 estimate. Great Plains Energy will put forth 2016 guidance in its conference call in late February.

The board of directors has raised the dividend. The board boosted the annual disbursement by $0.07 a share (7.1%), effective with the fourth-quarter payment. Great Plains is now targeting a payout ratio in a range of 55%-70%, but wants to narrow this to 60%-70% after 2016.

Great Plains Energy stock has an average dividend yield for a utility. With the recent price near the midpoint of our 3- to 5-year Target Price Range, total return potential is low.

Paul E. Debbas, CFA *December 18, 2015*

(A) Dil. EPS. Excl. nonrec. gains (losses): '00, 49¢; '01, ($2.01); '02, (5¢); '03, 29¢; '04, (7¢); '09, 12¢; gain (losses) on disc. ops.: '03, (13¢); '04, 10¢; '05, (3¢); '08, 35¢. '12 EPS don't add due to change in shs., '14 due to rounding. Next earnings report due late Feb. (B) Div'ds historically paid in mid-Mar., June, Sept. & Dec. ■ Div'd reinvest. plan avail. (C) Incl. intang. In '14: $7.81/sh. (D) In mill. (E) Rate base: Fair value. Rate all'd on com. eq. in MO in '15: 9.5%; in KS in '15: 9.3%; earned on avg. com. eq., '14: 6.8%. Regulatory Climate: Average.

Company's Financial Strength	B+
Stock's Price Stability	95
Price Growth Persistence	5
Earnings Predictability	75

IDACORP, INC. NYSE-IDA

RECENT PRICE	67.59	P/E RATIO	17.8 (Trailing: 17.2, Median: 14.0)	RELATIVE P/E RATIO	1.09	DIV'D YLD	3.0%	VALUE LINE

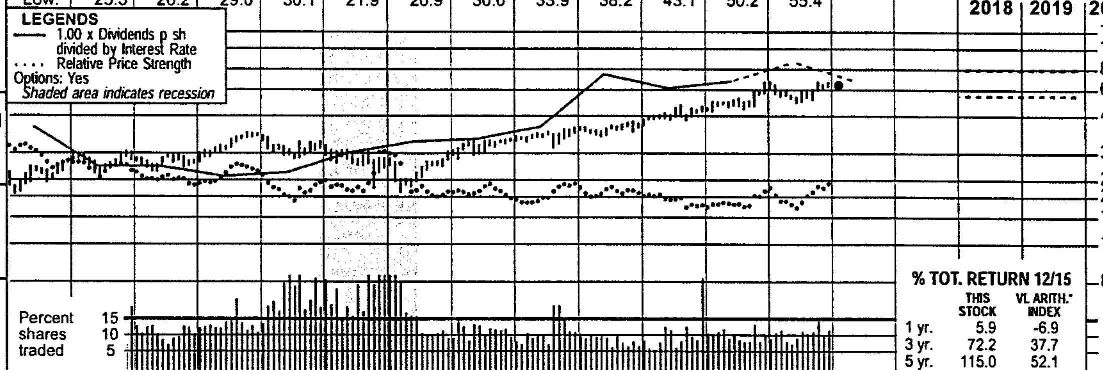
TIMELINESS 3 Lowered 5/15/15

SAFETY 2 Raised 8/2/13

TECHNICAL 3 Lowered 12/4/15

BETA .80 (1.00 = Market)

High:	32.9	32.1	40.2	39.2	35.1	32.8	37.8	42.7	45.7	54.7	70.1	70.5
Low:	25.3	26.2	29.0	30.1	21.9	20.9	30.0	33.9	38.2	43.1	50.2	55.4



Target Price Range 2018 | 2019 | 2020

2018-20 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	80	(+20%)	7%
Low	60	(-10%)	1%

Insider Decisions

	M	A	M	J	J	A	S	O	N
to Buy	2	0	0	1	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	2	1	1	1	1	0	1	1	1

Institutional Decisions

	1Q2015	2Q2015	3Q2015
to Buy	106	101	106
to Sell	92	100	95
Hld's(000)	37715	37671	67529

Percent shares traded 15 10 5

% TOT. RETURN 12/15

	THIS STOCK	VL ARITH.* INDEX
1 yr.	5.9	-6.9
3 yr.	72.2	37.7
5 yr.	115.0	52.1

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	© VALUE LINE PUB. LLC	18-20
17.50	27.10	150.10	24.43	20.41	20.00	20.15	21.23	19.51	20.47	21.92	20.97	20.55	21.55	24.81	25.51	*24.95*	*26.05*	Revenues per sh	*27.95*
4.50	5.63	5.63	4.08	3.50	4.12	3.87	4.58	4.11	4.27	5.07	5.23	5.74	5.84	6.21	6.49	*6.45*	*6.70*	"Cash Flow" per sh	*7.50*
2.43	3.50	3.35	1.63	.96	1.90	1.75	2.35	1.86	2.18	2.64	2.95	3.36	3.37	3.64	3.85	*3.83*	*3.95*	Earnings per sh A	*4.25*
1.86	1.86	1.86	1.86	1.70	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.37	1.57	1.76	1.92	*2.03*	Div'd Decl'd per sh B† ■	*2.45*
2.95	3.73	4.78	3.53	3.89	4.73	4.53	5.16	6.39	5.19	5.26	6.85	6.76	4.78	4.68	5.45	*6.05*	*6.05*	Cap'l Spending per sh	*6.00*
20.02	21.82	23.15	23.01	22.54	23.88	24.04	25.77	26.79	27.76	29.17	31.01	33.19	35.07	36.84	38.85	*40.70*	*42.60*	Book Value per sh C	*47.05*
37.61	37.61	37.63	38.02	38.34	42.22	42.66	43.63	45.06	46.92	47.90	49.41	49.95	50.16	50.23	50.27	*50.30*	*50.30*	Common Shs Outst'g D	*50.30*
12.7	10.9	11.4	18.9	26.5	15.5	16.7	15.1	18.2	13.9	10.2	11.8	11.5	12.4	13.4	14.7	*16.4*		Avg Ann'l P/E Ratio	*16.0*
.72	.71	.58	1.03	1.51	.82	.89	.82	.97	.84	.68	.75	.72	.79	.75	.78	*.83*		Relative P/E Ratio	*1.00*
6.0%	4.9%	4.9%	6.0%	6.7%	4.1%	4.1%	3.4%	3.5%	4.0%	4.5%	3.4%	3.1%	3.3%	3.2%	3.1%	3.1%		Avg Ann'l Div'd Yield	*3.6%*
						859.5	926.3	879.4	960.4	1049.8	1036.0	1026.8	1080.7	1246.2	1282.5	*1255*	*1310*	Revenues ($mill)	*1405*
						63.7	100.1	82.3	98.4	124.4	142.5	166.9	168.9	182.4	193.5	*195*	*200*	Net Profit ($mill)	*215*
						16.9%	13.3%	14.3%	16.3%	15.2%	NMF	NMF	13.4%	28.3%	8.1%	*23.0%*	*23.0%*	Income Tax Rate	*30.0%*
						4.7%	4.0%	9.7%	10.2%	10.5%	19.7%	22.8%	7.1%	4.2%	4.4%	*7.5%*	*8.0%*	AFUDC % to Net Profit	*9.5%*
						50.0%	45.2%	48.9%	47.6%	50.2%	49.3%	45.6%	45.5%	46.6%	45.3%	*45.0%*	*45.0%*	Long-Term Debt Ratio	*45.0%*
						50.0%	54.8%	51.1%	52.4%	49.8%	50.7%	54.4%	54.5%	53.4%	54.7%	*55.0%*	*55.0%*	Common Equity Ratio	*55.0%*
						2048.8	2052.8	2364.2	2485.9	2807.1	3020.4	3045.2	3225.4	3465.9	3567.6	*3660*	*3840*	Total Capital ($mill)	*4330*
						2314.3	2419.1	2616.6	2758.2	2917.0	3161.4	3406.6	3536.0	3665.0	3833.5	*4095*	*4300*	Net Plant ($mill)	*4975*
						4.5%	6.2%	4.7%	5.3%	5.7%	6.0%	6.7%	6.5%	6.4%	6.6%	*6.5%*	*6.0%*	Return on Total Cap'l	*5.5%*
						6.2%	8.9%	6.8%	7.6%	8.9%	9.3%	10.1%	9.6%	9.9%	9.9%	*9.0%*	*9.0%*	Return on Shr. Equity	*8.5%*
						6.2%	8.9%	6.8%	7.6%	8.9%	9.3%	10.1%	9.6%	9.9%	9.9%	*9.0%*	*9.0%*	Return on Com Equity E	*8.5%*
						1.3%	4.3%	2.4%	3.4%	4.8%	5.5%	6.5%	5.7%	5.6%	5.4%	*4.5%*	*4.0%*	Retained to Com Eq	*3.5%*
						80%	51%	64%	55%	46%	41%	36%	41%	43%	46%	*52%*	*53%*	All Div'ds to Net Prof	*58%*

CAPITAL STRUCTURE as of 9/30/15
Total Debt $1741.9 mill. **Due in 5 Yrs** $264.5 mill.
LT Debt $1741.9 mill. **LT Interest** $81.0 mill.
(LT interest earned: 3.4x)

Pension Assets-12/14 $559.7 mill. **Oblig.** $844.8 mill.

Pfd Stock None

Common Stock 50,340,688 shs. as of 10/23/15

MARKET CAP: $3.4 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2012	2013	2014
% Change Retail Sales (KWH)	+2.6	+3.8	+1.4
Avg. Indust. Use (MWH)	N/A	N/A	N/A
Avg. Indust. Revs. per KWH (¢)	4.63	5.21	5.68
Capacity at Peak (Mw)	N/A	N/A	N/A
Peak Load, Summer (Mw)	3245	3407	3184
Annual Load Factor (%)	N/A	N/A	N/A
% Change Customers (yr-end)	+1.1	+1.5	+1.4

Fixed Charge Cov. (%)	283	329	287

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '12-'14 to '18-'20
Revenues	1.0%	3.0%	*2.5%*
"Cash Flow"	4.5%	6.5%	*2.5%*
Earnings	9.0%	10.0%	*1.0%*
Dividends	--	5.5%	*6.0%*
Book Value	5.0%	6.0%	*4.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	241.1	254.7	334.0	250.9	1080.7
2013	264.9	303.9	381.1	296.3	1246.2
2014	292.7	317.7	382.2	289.8	1282.5
2015	279.4	336.3	369.2	*270.1*	*1255*
2016	*295*	*335*	*395*	*285*	*1310*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.50	.71	1.84	.33	3.37
2013	.70	.93	1.46	.55	3.64
2014	.55	.89	1.73	.69	3.85
2015	.47	1.31	1.46	*.59*	*3.83*
2016	*.55*	*1.20*	*1.63*	*.57*	*3.95*

Cal-endar	QUARTERLY DIVIDENDS PAID B† ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.33	.33	.33	.38	1.37
2013	.38	.38	.38	.43	1.57
2014	.43	.43	.43	.47	1.76
2015	.47	.47	.47	.51	1.92
2016					

BUSINESS: IDACORP, Inc. is the holding company for Idaho Power, a regulated electric utility that serves more than 520,000 customers throughout a 24,000-square-mile area in southern Idaho and eastern Oregon. Operates 17 hydroelectric projects on the Snake River and its tributaries. Also owns three natural gas-fired plants in Idaho and has stakes in three coal-fired facilities (in NV, OR, and WY). Revenue breakdown: residential, 45%; commercial, 27%; industrial, 16%; other, 12%. Fuel sources: hydro, 35%; coal, 34%; natural gas, 7%; purchased power, 24%. '14 depr. rate: 3.8%. Has 2,021 employees. Chairman: Robert A. Tinstman. Pres. & CEO: Darrel T. Anderson. Inc.: Idaho. Address: 1221 W. Idaho St., Boise, ID 83702. Tel.: 208-388-2200. Web: www.idacorpinc.com.

We now suspect that 2015 was a slightly down year for IDACORP. Previously, it looked like the electricity provider to some 500,000 customers in Idaho and Oregon could perhaps eke out a small bottom-line gain for the year that was. However, tough tax-rate comparisons, in particular, probably made for a modest falloff in share net.

The outlook for 2016 seems pretty decent, though. To wit, recent projections point to increased economic activity and population growth within the utility's service area, both of which augur well for power demand. Notably, growth in gross area product (i.e., regional GDP) was recently expected to accelerate from 4.8% in 2015 to around 6.3% over the next 12 months. Meantime, housing construction, including both single-family and multi-family builds, was also forecasted to experience a pick up of sorts.

Major capital investments should drive longer-term rate-base and earnings expansion. Case in point, IDACORP still plans to participate in the construction of a 500-kilovolt transmission line that would run from a substation near Melba, Idaho to Boardman, Oregon. The project is currently slated for completion in 2022 and is expected to cost up to $1.2 billion, some 21% of which would be IDACORP's stake. Importantly, the Boardman line should offer fairly stable power supply in the event that dry conditions limit hydroelectric capacity.

IDACORP has increased its quarterly dividend by 70%, to $0.51 a share, over the past four years. And more increases are likely on the way. Indeed, management recently urged the utility's board of directors to sign off on annual increases of 5% or more (likely above the level of sustainable earnings growth), so that the payout ratio approaches the higher end of a recently targeted range of between 50% and 60%.

IDACORP shares are ranked 3 (Average) for relative year-ahead price performance. At the recent quotation, long-term total return potential doesn't stand out, either. With much of the good news seemingly already reflected in the stock price, we would look elsewhere for utility industry exposure.

Nils C. Van Liew *January 29, 2016*

(A) EPS diluted. Excl. nonrecurring gains (loss): '00, 22¢; '03, 26¢; '05, (24¢); '06, 17¢. Egs. may not sum to total due to rounding. Next earnings report due in early February. (B) Div'ds historically paid in late Feb., May, Aug., and Nov. ■ Div'd reinvestment plan avail. † Shareholder investment plan avail. (C) Incl. deferred debits. In '14: $25.26/sh. (D) In mill. (E) Rate Base: Net original cost. Rate allowed on com. eq. in Idaho in '11: 9.5%-10.5%; earned on avg. system com. eq., '14: 9.9%. Regulatory Climate: Above Average.

Company's Financial Strength	B++
Stock's Price Stability	95
Price Growth Persistence	85
Earnings Predictability	95

OTTER TAIL CORP. NDQ-OTTR

RECENT PRICE 26.56 | P/E RATIO 16.2 (Trailing: 18.6; Median: 23.0) | RELATIVE P/E RATIO 0.92 | DIV'D YLD 4.7% | VALUE LINE

TIMELINESS 4 Lowered 11/20/15

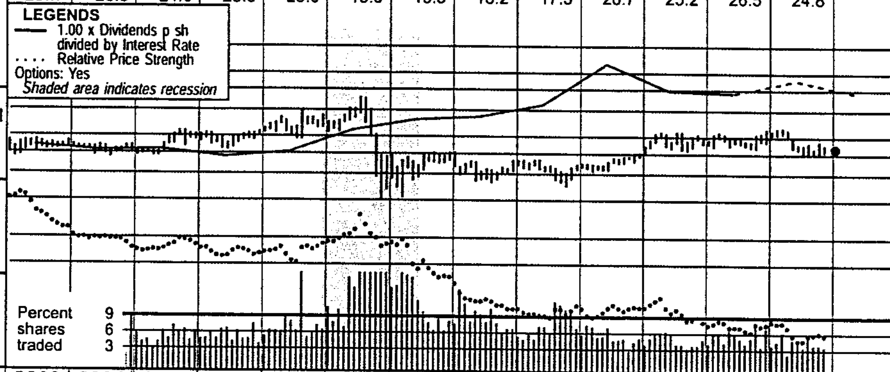
SAFETY 3 Lowered 12/24/10

TECHNICAL 4 Lowered 12/11/15

BETA .85 (1.00 = Market)

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
High:	27.5	32.0	31.9	39.4	46.2	25.4	25.4	23.5	25.3	31.9	32.7	33.4
Low:	23.8	24.0	25.8	29.0	15.0	15.5	18.2	17.5	20.7	25.2	26.5	24.8

LEGENDS
— 1.00 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



Target Price Range 2018 | 2019 | 2020

2018-20 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	50	(+90%)	20%
Low	30	(+15%)	7%

Insider Decisions

	J	F	M	A	M	J	J	A	S
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	1	0	0	0	0	0	0
to Sell	0	0	0	0	0	0	0	1	0

Institutional Decisions

	1Q2015	2Q2015	3Q2015
to Buy	50	49	53
to Sell	58	53	50
Hld's(000)	12560	12614	12771

Percent shares traded 9 6 3

% TOT. RETURN 11/15

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-3.3	-2.0
3 yr.	24.7	48.1
5 yr.	63.7	71.2

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	© VALUE LINE PUB. LLC	18-20
19.48	23.45	26.53	27.75	29.28	30.45	35.59	37.43	41.50	37.06	29.03	31.08	29.86	23.76	24.63	21.48	*21.05*	*21.80*	Revenues per sh	*29.15*
2.91	3.21	3.40	3.44	3.30	2.88	3.35	3.39	3.55	2.81	2.76	2.60	2.36	2.71	3.02	3.09	*3.15*	*3.60*	"Cash Flow" per sh	*4.50*
1.45	1.60	1.68	1.79	1.51	1.50	1.78	1.69	1.78	1.09	.71	.38	.45	1.05	1.37	1.55	*1.60*	*1.75*	Earnings per sh A	*2.25*
.99	1.02	1.04	1.06	1.08	1.10	1.12	1.15	1.17	1.19	1.19	1.19	1.19	1.19	1.19	1.21	*1.23*	*1.25*	Div'd Decl'd per sh B ■	*1.32*
1.37	1.85	2.17	2.95	1.97	1.72	2.04	2.35	5.43	7.51	4.95	2.38	2.04	3.20	4.53	4.40	*4.20*	*4.35*	Cap'l Spending per sh	*4.75*
10.30	10.87	11.33	12.25	12.98	14.81	15.80	16.67	17.55	19.14	18.78	17.57	15.83	14.43	14.75	15.39	*16.05*	*16.65*	Book Value per sh C	*18.10*
23.85	23.85	24.65	25.59	25.72	28.98	29.40	29.52	29.85	35.38	35.81	36.00	36.10	36.17	36.27	37.22	*38.00*	*39.00*	Common Shs Outst'g D	*42.00*
13.9	13.5	16.4	16.0	17.8	17.3	15.4	17.3	19.0	30.1	31.2	55.1	47.5	21.7	21.1	18.8	*Bold figures are*		Avg Ann'l P/E Ratio	*18.0*
.79	.88	.84	.87	1.01	.91	.82	.93	1.01	1.81	2.08	3.51	2.98	1.38	1.19	.99	*Value Line*		Relative P/E Ratio	*1.15*
4.9%	4.7%	3.8%	3.7%	4.0%	4.2%	4.1%	3.9%	3.5%	3.6%	5.4%	5.7%	5.6%	5.2%	4.1%	4.1%	*estimates*		Avg Ann'l Div'd Yield	*3.3%*

2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016		18-20
1046.4	1105.0	1238.9	1311.2	1039.5	1119.1	1077.9	859.2	893.3	799.3	*800*	*850*	Revenues ($mill)	*1225*
52.9	50.8	54.0	35.1	26.0	13.6	16.4	39.0	50.2	56.9	*60.0*	*70.0*	Net Profit ($mill)	*95.0*
34.6%	34.8%	34.1%	30.0%	--	--	14.5%	5.2%	21.3%	22.5%	*25.0%*	*25.0%*	Income Tax Rate	*25.0%*
1.7%	1.9%	4.2%	6.1%	4.0%	.6%	3.8%	1.7%	1.7%	3.6%	*3.0%*	*4.0%*	AFUDC % to Net Profit	*5.0%*
35.0%	33.5%	38.9%	32.9%	38.8%	40.2%	44.6%	44.0%	42.1%	46.5%	*45.5%*	*45.5%*	Long-Term Debt Ratio	*47.0%*
62.9%	64.5%	59.4%	65.6%	59.8%	58.4%	54.0%	54.4%	57.9%	53.5%	*54.5%*	*54.5%*	Common Equity Ratio	*53.0%*
738.2	763.0	882.1	1032.5	1124.4	1083.3	1058.9	959.2	924.4	1071.3	*1120*	*1190*	Total Capital ($mill)	*1435*
697.1	718.6	854.0	1037.6	1098.6	1108.7	1077.5	1049.5	1167.0	1268.5	*1400*	*1500*	Net Plant ($mill)	*1750*
8.3%	7.7%	7.2%	4.3%	3.4%	2.7%	3.2%	5.7%	6.7%	6.7%	*6.5%*	*7.0%*	Return on Total Cap'l	*8.0%*
11.0%	10.0%	10.0%	5.1%	3.8%	2.1%	2.8%	7.3%	9.4%	9.9%	*10.0%*	*11.0%*	Return on Shr. Equity E	*12.5%*
11.2%	10.2%	10.2%	5.1%	3.8%	2.0%	2.7%	7.3%	9.3%	9.9%	*10.0%*	*11.0%*	Return on Com Equity	*12.5%*
4.2%	3.3%	3.5%	NMF	NMF	NMF	NMF	NMF	1.2%	2.2%	*2.0%*	*3.0%*	Retained to Com Eq	*5.0%*
63%	68%	66%	108%	NMF	NMF	NMF	113%	87%	78%	*79%*	*71%*	All Div'ds to Net Prof	*59%*

CAPITAL STRUCTURE as of 9/30/15
Total Debt $585.5 mill. Due in 5 Yrs $87.0 mill.
LT Debt $498.3 mill. LT Interest $28.0 mill.
(LT interest earned: 3.4x)

Leases, Uncapitalized Annual rentals $7 mill.
Pension Assets-12/14 $244.6 mill. Oblig. $311.7 mill.
Pfd Stock None

Common Stock 37,743,953 shs.
as of 10/31/15
MARKET CAP: $1.0 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2012	2013	2014
% Change Retail Sales (KWH)	-1.1	+5.8	+4.6
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Winter (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	NA	NA	NA
Fixed Charge Cov. (%)	257	.359	336

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '12-'14 to '18-'20
Revenues	-2.0%	-8.5%	*4.0%*
"Cash Flow"	-1.0%	-.5%	*7.5%*
Earnings	-2.0%	2.0%	*9.0%*
Dividends	1.0%	--	*1.5%*
Book Value	1.0%	-4.5%	*3.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	219.9	211.4	215.3	212.6	859.2
2013	218.0	212.4	229.8	233.1	893.3
2014	215.0	194.4	196.5	193.4	799.3
2015	202.8	188.2	200.0	*209*	*800*
2016	*215*	*205*	*210*	*220*	*850*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.28	.19	.13	.47	1.05
2013	.41	.21	.41	.35	1.37
2014	.59	.27	.43	.28	1.55
2015	.37	.36	.42	*.45*	*1.60*
2016	*.42*	*.35*	*.48*	*.50*	*1.75*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.298	.298	.298	.298	1.19
2012	.298	.298	.298	.298	1.19
2013	.298	.298	.298	.298	1.19
2014	.303	.303	.303	.303	1.21
2015	.308	.308	.308	.308	

BUSINESS: Otter Tail Corporation is the parent of Otter Tail Power Company, which supplies electricity to over 130,000 customers in Minnesota (50% of retail elec. revs.), North Dakota (42%), and South Dakota (8%). Electric rev. breakdown, '14: residential, 32%; commercial & farms, 37%; industrial, 25%; other, 6%. Fuel costs: 16.6% of revenues. Also has operations in manufacturing and plastics. 2014 depr. rate: 2.9%. Has 1,893 employees. Off. and dir. own 1.4% of common stock; Cascade Investment, LLC, 9.3%; Vanguard Group, Inc., 6.6%; BlackRock, Inc., 5.5% (2/15 Proxy). CEO: Charles MacFarlane. Inc.: MN. Address: 215 South Cascade St., P.O. Box 496, Fergus Falls, Minnesota 56538-0496. Telephone: 866-410-8780. Internet: www.ottertail.com.

Shares of Otter Tail have traded in a fairly narrow range in recent months, following a selloff earlier in the year. The company reported modest top-line growth for the September period. Electric revenue increased at a good pace, but this was partly offset by lower Product Sales revenue. Still, operating expenses remained muted. Excluding a discontinued gain of $0.07 per share in the prior-year period, earnings from continuing operations would have advanced nicely.

The Electric segment should perform well going forward. Otter Tail Power Company is benefiting from rider recovery increases, greater costs recovered, and healthy customer demand. Earnings from capital investments should also grow. The utility continues to analyze the Environmental Protection Agency's Clean Power Plan to regulate carbon dioxide from existing power plants. Otter Tail will not know the rule's impact on its business until implementation plans are formulated at the state level.

Near-term prospects elsewhere appear mixed. Performance at the Plastics business may well continue to be hurt by weakness in the price of polyvinyl chloride pipe, owing to lower resin prices. Still, we expect a lower cost of product sold will benefit earnings here. Meantime, results at metal fabricator subsidiary BTD Manufacturing should continue to be affected by weakness in agriculture and energy markets, and a reduction in scrap-metal revenue related to lower commodity prices. Performance at this line ought to improve down the road, assuming a more favorable operating climate. Upon completion, the expansion of BTD's Minnesota facilities should enable this business to improve sales by expanding its services. The recent acquisition of Georgia-based Impulse Manufacturing brings strong fabrication capabilities and allows BTD to accelerate its plans to expand into the Southeast to serve that region's growing customer base.

This stock is untimely. But we envision healthy improvement in revenues and share earnings for the company out to 2018-2020. From the recent quotation, this issue offers good total return potential for the coming years. This is supported by a healthy dividend yield.

Michael Napoli, CFA *December 18, 2015*

(A) Diluted earnings. Excl. nonrecurring gains (losses): '99, 34¢; '10, (44¢); '11, 26¢; '13, 2¢; gains (losses) from discont. operations: '04, 8¢; '05, 33¢; '06, 1¢; '11, ($1.11); '12, ($1.22); '13, 2¢; '14, 2¢. Earnings may not sum due to rounding. Next earnings report due in February. (B) Div'ds historically paid in early March, June, Sept., and Dec. ■ Div'd reinvestment plan avail. (C) Incl. intangibles. In '14: $42.7 mill., $1.15/sh. (D) In mill. (E) Regulatory Climate: MN, ND, Average; SD, Above Average.

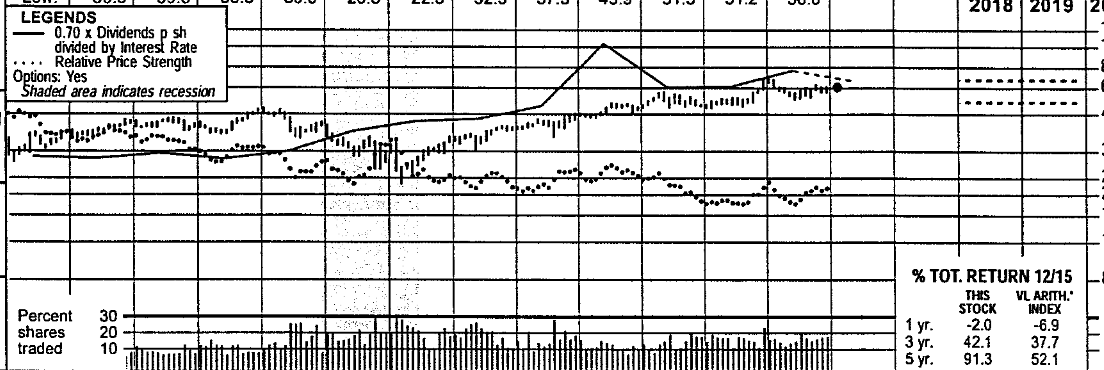
Company's Financial Strength	B+
Stock's Price Stability	85
Price Growth Persistence	15
Earnings Predictability	50

PINNACLE WEST NYSE-PNW

RECENT PRICE	64.88	P/E RATIO	16.4 (Trailing: 18.1 Median: 15.0)	RELATIVE P/E RATIO	1.00	DIV'D YLD	3.9%	VALUE LINE

TIMELINESS **3** Raised 10/16/15
SAFETY **1** Raised 5/3/13
TECHNICAL **3** Lowered 12/25/15
BETA .75 (1.00 = Market)

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
High:	45.8	46.7	51.0	51.7	42.9	38.0	42.7	48.9	54.7	61.9	71.1	73.3
Low:	36.3	39.8	38.3	36.8	26.3	22.3	32.3	37.3	45.9	51.5	51.2	56.0



2018-20 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	70	(+10%)	6%
Low	55	(-15%)	1%

Insider Decisions

	M	A	M	J	J	A	S	O	N
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	13	0
to Sell	1	0	0	1	0	0	0	0	1

Institutional Decisions

	1Q2015	2Q2015	3Q2015
to Buy	182	175	181
to Sell	194	180	175
Hld's(000)	86769	87394	89339

% TOT. RETURN 12/15

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-2.0	-6.9
3 yr.	42.1	37.7
5 yr.	91.3	52.1

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	© VALUE LINE PUB. LLC	18-20
28.57	43.50	53.66	28.90	30.87	31.59	30.16	34.03	35.07	33.37	32.50	30.01	29.67	30.09	31.35	31.58	*31.55*	*32.75*	Revenues per sh	*36.50*
7.73	7.99	8.72	7.01	7.33	6.93	5.76	9.70	9.29	8.13	8.08	6.85	7.52	7.92	8.15	8.09	*8.85*	*9.35*	"Cash Flow" per sh	*10.50*
3.18	3.35	3.68	2.53	2.52	2.58	2.24	3.17	2.96	2.12	2.26	3.08	2.99	3.50	3.66	3.58	*3.75*	*4.00*	Earnings per sh A	*4.50*
1.33	1.43	1.53	1.63	1.73	1.83	1.93	2.03	2.10	2.10	2.10	2.10	2.10	2.67	2.23	2.33	2.44	*2.56*	Div'd Decl'd per sh B ■	*2.95*
4.05	7.76	12.27	9.81	7.60	5.86	6.39	7.59	9.37	9.46	7.64	7.03	8.26	8.24	9.36	8.38	*9.90*	*10.40*	Cap'l Spending per sh	*9.75*
26.00	28.09	29.46	29.44	31.00	32.14	34.57	34.48	35.15	34.16	32.69	33.86	34.98	36.20	38.07	39.50	*40.85*	*42.25*	Book Value per sh C	*47.00*
84.83	84.83	84.83	91.26	91.29	91.79	99.08	99.96	100.49	100.89	101.43	108.77	109.25	109.74	110.18	110.57	*111.00*	*111.50*	Common Shs Outst'g D	*118.00*
11.9	11.3	12.0	14.4	14.0	15.8	19.2	13.7	14.9	16.1	13.7	12.6	14.6	14.3	15.3	15.9	*16.8*		Avg Ann'l P/E Ratio	*13.5*
.68	.73	.61	.79	.80	.83	1.02	.74	.79	.97	.91	.80	.92	.91	.86	.84	*.85*		Relative P/E Ratio	*.85*
3.5%	3.8%	3.5%	4.5%	4.9%	4.5%	4.5%	4.7%	4.8%	6.2%	6.8%	5.4%	4.8%	5.3%	4.0%	4.1%	3.9%		Avg Ann'l Div'd Yield	*4.8%*

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016		18-20
	2988.0	3401.7	3523.6	3367.1	3297.1	3263.6	3241.4	3301.8	3454.6	3491.6	*3500*	*3650*	Revenues ($mill)	*4300*
	223.2	317.1	298.8	213.6	229.2	330.4	328.2	387.4	406.1	397.6	*420*	*445*	Net Profit ($mill)	*535*
	36.2%	33.0%	33.6%	23.4%	36.9%	31.9%	34.0%	36.2%	34.4%	34.2%	*35.0%*	*34.5%*	Income Tax Rate	*34.5%*
	10.4%	11.1%	14.8%	17.5%	11.2%	11.7%	12.8%	9.7%	10.0%	11.6%	*11.0%*	*11.0%*	AFUDC % to Net Profit	*8.0%*
	43.2%	48.4%	47.0%	46.8%	50.4%	45.3%	44.1%	44.6%	40.0%	41.0%	*44.5%*	*46.5%*	Long-Term Debt Ratio	*45.5%*
	56.8%	51.6%	53.0%	53.2%	49.6%	54.7%	55.9%	55.4%	60.0%	59.0%	*55.5%*	*53.5%*	Common Equity Ratio	*54.5%*
	6033.4	6678.7	6658.7	6477.6	6686.6	6729.1	6840.9	7171.9	6990.9	7398.7	*8165*	*8765*	Total Capital ($mill)	*10175*
	7577.1	7881.9	8436.4	8916.7	9257.8	9578.8	9962.3	10396	10889	11194	*11725*	*12300*	Net Plant ($mill)	*14075*
	5.0%	6.2%	5.9%	4.7%	4.8%	6.5%	6.4%	6.8%	7.1%	6.4%	*6.0%*	*6.0%*	Return on Total Cap'l	*6.5%*
	6.5%	9.2%	8.5%	6.2%	6.9%	9.0%	8.6%	9.8%	9.7%	9.1%	*9.0%*	*9.5%*	Return on Shr. Equity	*9.5%*
	6.5%	9.2%	8.5%	6.2%	6.9%	9.0%	8.6%	9.8%	9.7%	9.1%	*9.0%*	*9.5%*	Return on Com Equity E	*9.5%*
	1.0%	3.4%	2.5%	.3%	.7%	3.1%	2.8%	4.1%	4.1%	3.5%	*3.5%*	*3.5%*	Retained to Com Eq	*3.5%*
	85%	63%	70%	96%	89%	66%	68%	58%	58%	62%	*65%*	*64%*	All Div'ds to Net Prof	*65%*

CAPITAL STRUCTURE as of 9/30/15
Total Debt $3725.8 mill. Due in 5 Yrs $1486.6 mill.
LT Debt $3257.3 mill. LT Interest $159.6 mill.
Incl. $13.4 mill. Palo Verde sale leaseback lessor notes.
(LT interest earned: 4.8x)
Leases, Uncapitalized Annual rentals $18.0 mill.
Pension Assets-12/14 $2615.4 mill.
Oblig. $3078.7 mill.

Pfd Stock None

Common Stock 110,849,752 shs.
as of 10/23/15
MARKET CAP: $7.2 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2012	2013	2014
% Change Retail Sales (KWH)	-.2	-.2	-1.8
Avg. Indust. Use (MWH)	647	644	659
Avg. Indust. Revs. per KWH (¢)	7.86	8.21	8.26
Capacity at Peak (Mw)	8864	8398	9259
Peak Load, Summer (Mw)	7207	6927	7007
Annual Load Factor (%)	48.8	50.0	48.6
% Change Customers (yr-end)	+1.3	+1.4	+1.2
Fixed Charge Cov. (%)	397	419	404

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '12-'14 to '18-'20
Revenues	--	-1.5%	*3.0%*
"Cash Flow"	1.5%	-1.0%	*4.5%*
Earnings	3.5%	8.0%	*4.0%*
Dividends	3.5%	3.0%	*3.5%*
Book Value	2.0%	2.0%	*3.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	620.6	878.6	1109.5	693.1	3301.8
2013	686.6	915.8	1152.4	699.8	3454.6
2014	686.2	906.3	1172.7	726.4	3491.6
2015	671.2	890.6	1199.1	*739.1*	*3500*
2016	*700*	*975*	*1225*	*750*	*3650*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	d.07	1.12	2.21	.24	3.50
2013	.22	1.18	2.04	.22	3.66
2014	.14	1.19	2.20	.05	3.58
2015	.14	1.10	2.30	*.21*	*3.75*
2016	*.15*	*1.30*	*2.35*	*.20*	*4.00*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.525	.525	.525	.545	2.12
2013	.545	.545	.545	.5675	2.20
2014	.5675	.5675	.5675	.595	2.30
2015	.595	.595	.595	.625	2.41
2016					

BUSINESS: Pinnacle West Capital Corporation is a holding company for Arizona Public Service Company (APS), which supplies electricity to 1.1 million customers in most of Arizona, except about half of the Phoenix metro area, the Tucson metro area, and Mohave County in northwestern Arizona. Discontinued SunCor real estate subsidiary in '10. Electric revenue breakdown: residential, 48%; commercial, 39%; industrial, 5%; other, 9%. Generating sources: coal, 34%; nuclear, 27%; gas & other, 17%; purchased, 22%. Fuel costs: 34% of revenues. Has 6,400 employees. '14 reported deprec. rate: 2.8%. Chairman, President & CEO: Donald E. Brandt. Inc.: AZ. Address: 400 North Fifth St., P.O. Box 53999, Phoenix, AZ 85072-3999. Tel.: 602-250-1000. Internet: www.pinnaclewest.com.

Pinnacle West's utility subsidiary is trying to address the issue of rate design with the Arizona Corporation Commission (ACC). Currently, about 70% of Arizona Public Service's costs of serving residential customers are fixed, but only 10% of its revenues are derived from fixed charges on customers' bills. In addition, because of the way rates are designed, nonsolar customers are subsidizing those users with rooftop solar panels. This is an industrywide problem, and APS is by no means the only utility that is concerned about this. Accordingly, the ACC is conducting hearings with APS and other utilities in the state. Not surprisingly, this has been a highly politicized question. APS will probably file a rate application at the start of June. This case will address the rate design concerns, including information gathered from the current proceedings, as well as seeking some (probably modest) rate relief. New rates (and rate design) would take effect in mid-2017.

The utility will probably begin construction of a gas-fired plant soon. The 510-megawatt facility would cost an estimated $500 million. APS would replace 290 mw of older generating capacity, thereby providing a net increase of 220 mw. This project is expected to be completed in 2019.

We look for a respectable profit increase in 2016. Every year, APS benefits from regulatory mechanisms that provide some revenue — most notably for electric transmission and a portion of the utility's lost revenues that come as a result of conservation measures. Also, the utility is seeing respectable customer growth in its service territory, along with a small amount of sales growth. Our 2016 earnings estimate is within the company's targeted range of $3.90-$4.10 a share.

Finances are strong. The fixed-charge coverage and common-equity ratio are comfortably above the industry averages. Pinnacle West merits a Financial Strength rating of A+.

This top-quality stock offers a dividend yield that is about equal to the utility mean. With the recent quotation above the midpoint of our 2018-2020 Target Price Range, total return potential over that time frame is low.

Paul E. Debbas, CFA *January 29, 2016*

(A) Diluted EPS. Excl. nonrec. losses: '02, 77¢; '09, $1.45; excl. gains (losses) from discontinued ops.: '00, 22¢; '05, (36¢); '06, 10¢; '08, 28¢; '09, (13¢); '10, 18¢; '11, 10¢; '12, (5¢). Next earnings report due mid-Feb. (B) Div'ds historically paid in early Mar., June, Sept., & Dec. There were 5 declarations in '12. ■ Div'd reinvestment plan avail. (C) Incl. deferred charges. In '14: $12.30/sh. (D) In mill. (E) Rate base: Fair value. Rate allowed on com. eq. in '12: 10%; earned on avg. com. eq., '14: 9.3%. Regulatory Climate: Average.

Company's Financial Strength	A+
Stock's Price Stability	100
Price Growth Persistence	60
Earnings Predictability	75

PNM RESOURCES NYSE-PNM

RECENT PRICE	30.55	P/E RATIO	19.1 (Trailing: 18.5; Median: 17.0)	RELATIVE P/E RATIO	1.16	DIV'D YLD	2.9%	VALUE LINE

TIMELINESS **3** Lowered 6/19/15

SAFETY **3** Lowered 5/9/08

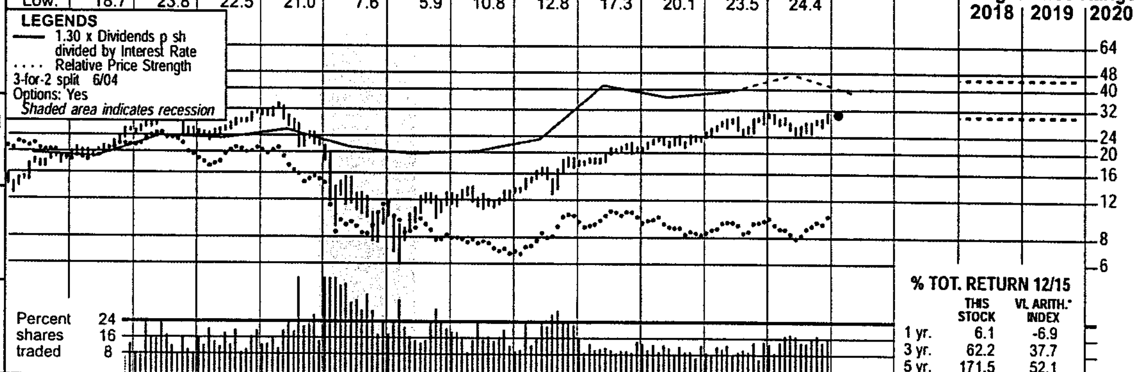
TECHNICAL **3** Raised 1/29/16

BETA .80 (1.00 = Market)

High:	26.1	30.5	32.1	34.3	21.7	13.1	14.0	19.2	22.5	24.5	31.6	31.2
Low:	18.7	23.8	22.5	21.0	7.6	5.9	10.8	12.8	17.3	20.1	23.5	24.4

Target Price Range
2018 | 2019 | 2020

LEGENDS
— 1.30 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
3-for-2 split 6/04
Options: Yes
Shaded area indicates recession



2018-20 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	45	(+45%)	*12%*
Low	30	(Nil)	*3%*

Insider Decisions

	M	A	M	J	J	A	S	O	N
to Buy	1	0	0	0	0	0	0	0	1
Options	4	0	0	0	0	0	0	0	0
to Sell	4	0	0	0	0	0	0	0	3

Institutional Decisions

	1Q2015	2Q2015	3Q2015
to Buy	108	116	99
to Sell	110	104	108
Hld's(000)	69125	69968	71254

% TOT. RETURN 12/15

	THIS STOCK	VL ARITH.* INDEX
1 yr.	6.1	-6.9
3 yr.	62.2	37.7
5 yr.	171.5	52.1

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	© VALUE LINE PUB. LLC	18-20
18.96	27.46	40.09	19.92	24.11	26.54	30.19	32.25	24.92	22.65	19.01	19.31	21.35	16.85	17.42	18.03	*18.15*	*18.75*	Revenues per sh	*20.30*
2.82	3.16	4.31	2.83	3.05	3.14	3.56	3.57	2.54	1.76	2.32	2.67	3.18	3.38	3.51	3.62	*3.70*	*3.85*	"Cash Flow" per sh	*4.70*
1.29	1.55	2.61	1.07	1.15	1.43	1.56	1.72	.76	.11	.58	.87	1.08	1.31	1.41	1.45	*1.60*	*1.65*	Earnings per sh A	*2.35*
.53	.53	.53	.57	.61	.63	.79	.86	.91	.61	.50	.50	.50	.58	.68	.76	.80	*.88*	Div'd Decl'd per sh B ■†	*1.30*
1.56	2.50	4.51	4.09	2.78	2.25	3.07	4.04	5.94	3.99	3.32	3.25	4.10	3.88	4.37	5.78	*5.50*	*5.50*	Cap'l Spending per sh	*5.50*
14.74	15.76	17.25	16.60	17.84	18.19	18.70	22.09	22.03	18.89	18.90	17.60	19.62	20.05	20.87	22.39	*22.10*	*22.70*	Book Value per sh C	*25.50*
61.05	58.68	58.68	58.68	60.39	60.46	68.79	76.65	76.81	86.53	86.67	86.67	79.65	79.65	79.65	79.65	*80.00*	*80.00*	Common Shs Outst'g D	*80.00*
9.5	8.5	7.3	15.1	14.7	15.0	17.4	15.6	35.6	NMF	18.1	14.0	14.5	15.0	16.1	18.7	*17.3*		Avg Ann'l P/E Ratio	*16.0*
.54	.55	.37	.82	.84	.79	.93	.84	1.89	NMF	1.21	.89	.91	.95	.90	.98	*.88*		Relative P/E Ratio	*1.00*
4.4%	4.1%	2.8%	3.5%	3.6%	2.9%	2.9%	3.2%	3.4%	4.9%	4.8%	4.1%	3.2%	3.0%	3.0%	2.8%	2.9%		Avg Ann'l Div'd Yield	*3.5%*

CAPITAL STRUCTURE as of 9/30/15
Total Debt $2208.0 mill. Due in 5 Yrs $1112 mill.
LT Debt $1980.4 mill. LT Interest $110 mill.
(LT interest earned: 2.4x)
Pension Assets-12/14 $657.6 mill.
Oblig. $587.7 mill.

Pfd Stock $11.5 mill. Pfd Div'd $.5 mill.
115,293 shs. 4.58%, $100 par w/o mandatory redemption. Sinking fund began 2/1/84.

Common Stock 79,653,624 shs.
as of 10/23/15
MARKET CAP: $2.4 billion (Mid Cap)

2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016		18-20
2076.8	2471.7	1914.0	1959.5	1647.7	1673.5	1700.6	1342.4	1387.9	1435.9	*1450*	*1500*	Revenues ($mill)	*1625*
106.6	122.1	59.9	8.1	53.5	80.0	96.6	105.6	113.5	116.3	*130*	*135*	Net Profit ($mill)	*190*
31.1%	24.7%	5.1%	40.4%	30.4%	32.6%	38.8%	31.4%	31.6%	34.8%	*35.0%*	*35.0%*	Income Tax Rate	*35.0%*
15.6%	4.1%	--	--	6.4%	7.1%	8.8%	7.2%	1.3%	1.3%	*1.5%*	*2.5%*	AFUDC % to Net Profit	*8.0%*
57.4%	50.9%	42.0%	45.6%	48.7%	50.4%	51.5%	50.9%	50.0%	47.8%	*52.0%*	*53.0%*	Long-Term Debt Ratio	*53.5%*
42.3%	48.8%	57.6%	54.0%	51.0%	49.2%	48.1%	48.7%	49.7%	51.9%	*48.0%*	*47.0%*	Common Equity Ratio	*46.5%*
3044.4	3470.7	2935.8	3025.4	3214.9	3100.3	3245.6	3277.9	3344.0	3437.1	*3695*	*3845*	Total Capital ($mill)	*4385*
2984.1	3761.9	2935.4	3192.0	3332.4	3444.4	3627.1	3746.5	3933.9	4270.0	*4335*	*4555*	Net Plant ($mill)	*5270*
4.7%	4.9%	3.4%	1.9%	3.1%	4.2%	4.5%	5.1%	5.2%	5.1%	*5.0%*	*5.0%*	Return on Total Cap'l	*6.0%*
8.2%	7.2%	3.5%	.5%	3.2%	5.2%	6.1%	6.6%	6.8%	6.5%	*7.0%*	*7.5%*	Return on Shr. Equity	*9.5%*
8.2%	7.2%	3.5%	.5%	3.2%	5.2%	6.1%	6.6%	6.8%	6.5%	*7.0%*	*7.5%*	Return on Com Equity E	*9.5%*
4.3%	3.7%	NMF	NMF	.4%	2.2%	3.3%	3.8%	3.7%	3.2%	*3.5%*	*3.5%*	Retained to Com Eq	*3.5%*
48%	49%	117%	NMF	86%	58%	47%	43%	45%	51%	*51%*	*51%*	All Div'ds to Net Prof	*55%*

ELECTRIC OPERATING STATISTICSF

	2012	2013	2014
% Change Retail Sales (KWH)	-1.6	-2.9	-2.1
Avg. Indust. Use (MWH)	N/A	N/A	N/A
Avg. Indust. Revs. per KWH (¢)	N/A	N/A	N/A
Capacity at Peak (Mw)	2537	2572	2707
Peak Load, Summer (Mw)	1948	2008	1948
Annual Load Factor (%)	N/A	N/A	N/A
% Change Customers (yr-end)	+.4	+.7	+.6
Fixed Charge Cov. (%)	225	241	250

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '12-'14 to '18-'20
Revenues	-3.0%	-4.5%	*1.5%*
"Cash Flow"	1.5%	9.5%	*5.0%*
Earnings	1.5%	23.5%	*9.0%*
Dividends	1.0%	--	*10.0%*
Book Value	2.0%	1.0%	*3.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	305.4	323.9	390.4	322.7	1342.4
2013	317.7	347.6	399.7	322.9	1387.9
2014	328.9	346.2	413.9	346.9	1435.9
2015	332.9	352.9	417.4	*346.8*	*1450*
2016	*345*	*360*	*440*	*355*	*1500*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.17	.33	.69	.13	1.31
2013	.18	.38	.64	.21	1.41
2014	.16	.36	.69	.24	1.45
2015	.21	.44	.76	*.19*	*1.60*
2016	*.25*	*.40*	*.75*	*.25*	*1.65*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■† Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.145	.145	.145	.145	.58
2013	.145	.165	.165	.165	.64
2014	.185	.185	.185	.185	.74
2015	.20	.20	.20	.20	.80
2016	.22				

BUSINESS: PNM Resources is an investor-owned holding company of energy and energy related businesses. Primary subsidiaries include Public Service Company of New Mexico (PNM) and Texas-New Mexico Power Company (TNMP), which generate, transmit, and distribute electricity in New Mexico and Texas. Sold First Choice Energy (9/11) and gas utility operations (1/09). Electric rev. breakdown '14: residential, 37%; commercial, 37%; industrial, 6%; other, 20%. Fuels: coal, 57%; nuclear, 30%; gas/oil, 12%; solar, 1%. Fuel costs: 49% of revenues. '14 depreciation rate: 3.3%. Has 1,881 employees. Chairman, President & CEO: Patricia K. Collawn. Inc.: NM. Address: 414 Silver Ave. SW, Albuquerque, NM. 87102. Tel.: 505-241-2700. Internet: www.pnmresources.com.

PNM Resources recently got the go-ahead from state regulators to move forward with its clean power plan. Indeed, the New Mexico Public Regulatory Commission in mid-December formally approved the utility's proposed shutdown of two coal-fired units at the San Juan Generating Station (SJGS) in the northern part of the state by the end of 2017. Meantime, the remaining (two) SJGS coal units were recently retrofitted with new emission controls, while other facilities, including a 40-megawatt solar installation, are now slated to fill the breach. Part of a broader effort to meet clean-air mandates, the moves recently needed additional approvals to proceed.

The utility recently said that it expects to earn between $1.55 and $1.76 a share in 2016. Based on a company-issued 2015 baseline ($1.56-$1.61), the target range implies as much as 13% bottom-line growth down to a modest (less than 4%) decline this year. The wide variance largely reflects the uncertain timing of a rate hike by PNM's Public Service of New Mexico (PNM) unit. Notably, a three-month implementation delay (October 1st versus July 1st) could nick earnings by 12%, or $0.21 a share.

Stretch goals include 7%-9% earnings growth through 2019. Key to reaching the mark will be PNM's ability to earn authorized returns on its regulated businesses, which isn't a given. Among additional concerns is a New Mexico economy that is highly dependent on public works projects and which has been growing at a slow pace compared to the nation as a whole.

The board of directors recently authorized a 10% dividend hike. The higher quarterly distribution ($0.22 a share) will first be paid on February 12th, to shareholders of record on January 25th. On an annualized basis, it represents a serviceable 50%-64% of PNM's targeted 2016 earnings.

Shares of PNM Resources are ranked 3 (Average) for relative year-ahead price performance. At the recent quotation, long-term total return potential doesn't stand out, either. Recent dividend hikes are encouraging, but more-competitive yields can be found elsewhere.

Nils C. Van Liew *January 29, 2016*

(A) EPS dil. Excl. n/r gains (losses): '99, 8¢; '00, 21¢; '01, (15¢); '03, 67¢; '05, (56¢); '08, ($3.77); '10, ($1.36); '11, 88¢. '13, (16); Excl. disc. ops.: '08, 42¢; '09, 78¢. Egs. may not sum due to rounding. Next egs. rpt. due late February. (B) Div'ds hist. pd. in Feb., May, Aug., Nov. ■ Div'd reinvest. plan avail. † Shareholder invest. plan avail. (C) Incl. intang. '14: $3.49/sh. (D) In mill., adjust. for split. (E) Rate base: net orig. cost. ROE allowed in '11: 10.0%; earned on avg. com. eq., '13: 10.0%. Reg. Climate: Avg. (F) Excl. First Choice.

Company's Financial Strength	B
Stock's Price Stability	85
Price Growth Persistence	45
Earnings Predictability	35

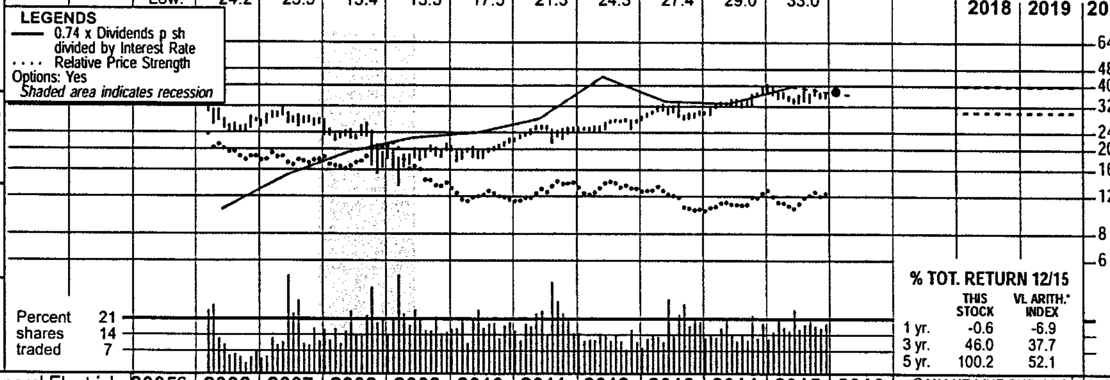
PORTLAND GENERAL NYSE-POR

RECENT PRICE	37.69	P/E RATIO	16.8 (Trailing: 18.8, Median: NMF)	RELATIVE P/E RATIO	1.02	DIV'D YLD	3.3%	VALUE LINE

TIMELINESS 3 Raised 8/14/15
SAFETY 2 Raised 5/4/12
TECHNICAL 3 Lowered 12/4/15
BETA .80 (1.00 = Market)

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
High:	35.0	31.3	27.7	21.4	22.7	26.0	28.1	33.3	40.3	41.0
Low:	24.2	25.5	15.4	13.5	17.5	21.3	24.3	27.4	29.0	33.0

Target Price Range
2018 | 2019 | 2020



2018-20 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	40	(+5%)	5%
Low	30	(-20%)	-1%

Insider Decisions

	M	A	M	J	J	A	S	O	N
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	1	0	1	0	0	0	2	0	1

Institutional Decisions

	1Q2015	2Q2015	3Q2015
to Buy	122	112	113
to Sell	142	136	110
Hld's(000)	84710	86966	86675

% TOT. RETURN 12/15

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-0.6	-6.9
3 yr.	46.0	37.7
5 yr.	100.2	52.1

On April 3, 2006, Portland General Electric's existing stock (which was owned by Enron) was canceled, and 62.5 million shares were issued to Enron's creditors or the Disputed Claims Reserve (DCR). The stock began trading on a when-issued basis that day, and regular trading began on April 10, 2006. Shares issued to the DCR were released over time to Enron's creditors until all of the remaining shares were released in June, 2007.

2005G	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	© VALUE LINE PUB. LLC	18-20
23.14	24.32	27.87	27.89	23.99	23.67	24.06	23.89	23.18	24.29	*21.10*	*22.45*	Revenues per sh	*24.25*
4.75	4.64	5.21	4.71	4.07	4.82	4.96	5.15	4.93	6.08	*5.40*	*5.90*	"Cash Flow" per sh	*7.00*
1.02	1.14	2.33	1.39	1.31	1.66	1.95	1.87	1.77	2.18	*2.05*	*2.35*	Earnings per sh A	*2.75*
--	.68	.93	.97	1.01	1.04	1.06	1.08	1.10	1.12	1.18	*1.26*	Div'd Decl'd per sh B ■ †	*1.50*
4.08	5.94	7.28	6.12	9.25	5.97	3.98	4.01	8.40	12.87	*6.80*	*5.00*	Cap'l Spending per sh	*3.25*
19.15	19.58	21.05	21.64	20.50	21.14	22.07	22.87	23.30	24.43	*25.40*	*26.45*	Book Value per sh C	*29.75*
62.50	62.50	62.53	62.58	75.21	75.32	75.36	75.56	78.09	78.23	*88.90*	*89.10*	Common Shs Outst'g D	*89.70*
--	23.4	11.9	16.3	14.4	12.0	12.4	14.0	16.9	15.3	*17.6*		Avg Ann'l P/E Ratio	*12.5*
--	1.26	.63	.98	.96	.76	.78	.89	.95	.81	*.90*		Relative P/E Ratio	*.80*
--	2.5%	3.3%	4.3%	5.4%	5.2%	4.4%	4.1%	3.7%	3.3%	3.3%		Avg Ann'l Div'd Yield	*4.4%*
1446.0	1520.0	1743.0	1745.0	1804.0	1783.0	1813.0	1805.0	1810.0	1900.0	*1875*	*2000*	Revenues ($mill)	*2175*
64.0	71.0	145.0	87.0	95.0	125.0	147.0	141.0	137.0	175.0	*175*	*210*	Net Profit ($mill)	*245*
40.2%	33.6%	33.8%	28.7%	28.8%	30.5%	28.3%	31.4%	23.2%	26.0%	*21.5%*	*21.5%*	Income Tax Rate	*21.5%*
18.8%	33.8%	17.9%	17.2%	31.6%	17.6%	5.4%	7.1%	14.6%	33.7%	*15.0%*	*7.0%*	AFUDC % to Net Profit	*3.0%*
42.3%	43.4%	49.9%	46.2%	50.3%	53.0%	49.6%	47.1%	51.3%	52.7%	*49.5%*	*49.5%*	Long-Term Debt Ratio	*49.5%*
57.7%	56.6%	50.1%	53.8%	49.7%	47.0%	50.4%	52.9%	48.7%	47.3%	*50.5%*	*50.5%*	Common Equity Ratio	*50.5%*
2076.0	2161.0	2629.0	2518.0	3100.0	3390.0	3298.0	3264.0	3735.0	4037.0	*4460*	*4675*	Total Capital ($mill)	*5325*
2436.0	2718.0	3066.0	3301.0	3858.0	4133.0	4285.0	4392.0	4880.0	5679.0	*5980*	*6110*	Net Plant ($mill)	*6025*
4.6%	4.7%	6.9%	5.0%	4.5%	5.4%	6.2%	5.9%	5.1%	5.8%	*5.0%*	*5.5%*	Return on Total Cap'l	*6.0%*
5.3%	5.8%	11.0%	6.4%	6.2%	7.9%	8.8%	8.2%	7.5%	9.2%	*7.5%*	*9.0%*	Return on Shr. Equity	*9.0%*
5.3%	5.8%	11.0%	6.4%	6.2%	7.9%	8.8%	8.2%	7.5%	9.2%	*7.5%*	*9.0%*	Return on Com Equity E	*9.0%*
5.3%	3.5%	6.6%	2.0%	1.5%	3.0%	4.1%	3.5%	2.9%	4.6%	*3.5%*	*4.5%*	Retained to Com Eq	*4.0%*
--	39%	40%	69%	76%	62%	54%	57%	61%	50%	*56%*	*53%*	All Div'ds to Net Prof	*54%*

CAPITAL STRUCTURE as of 9/30/15
Total Debt $2204 mill. **Due in 5 Yrs** $510 mill.
LT Debt $2204 mill. **LT Interest** $115 mill.
(LT interest earned: 2.0x)
Leases, Uncapitalized Annual rentals $10 mill.

Pension Assets-12/14 $591 mill.
Oblig. $777 mill.
Pfd Stock None

Common Stock 88,772,420 shs.
as of 10/16/15

MARKET CAP: $3.3 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2012	2013	2014
% Change Retail Sales (KWH)	-.8	+1.2	-.8
Avg. Indust. Use (MWH)	16409	16258	16577
Avg. Indust. Revs. per KWH (¢)	5.26	4.84	5.13
Capacity at Peak (Mw)	4173	4380	4910
Peak Load, Winter (Mw) F	3597	3869	3866
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.7	+.9	+.7
Fixed Charge Cov. (%)	270	239	248

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '12-'14 to '18-'20
Revenues	--	-2.0%	*.5%*
"Cash Flow"	--	3.0%	*4.5%*
Earnings	--	3.0%	*6.0%*
Dividends	--	2.5%	*5.5%*
Book Value	--	2.0%	*4.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	479.0	413.0	450.0	463.0	1805.0
2013	473.0	403.0	435.0	499.0	1810.0
2014	493.0	423.0	484.0	500.0	1900.0
2015	473.0	450.0	476.0	*476*	*1875*
2016	*525*	*460*	*505*	*510*	*2000*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.65	.34	.50	.38	1.87
2013	.65	.13	.40	.59	1.77
2014	.73	.43	.47	.55	2.18
2015	.62	.44	.40	*.59*	*2.05*
2016	*.80*	*.45*	*.45*	*.65*	*2.35*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.265	.265	.27	.27	1.07
2013	.27	.27	.275	.275	1.09
2014	.275	.275	.28	.28	1.11
2015	.28	.28	.30	.30	1.16
2016	.30				

BUSINESS: Portland General Electric Company (PGE) provides electricity to 852,000 customers in 52 cities in a 4,000-square-mile area of Oregon, including Portland and Salem. The company is in the process of decommissioning the Trojan nuclear plant, which it closed in 1993. Electric revenue breakdown: residential, 47%; commercial, 34%; industrial, 12%; other, 7%. Generating sources: coal, 21%; gas, 16%; hydro, 8%; wind, 6%; purchased, 49%. Fuel costs: 38% of revenues. '14 reported depreciation rate: 3.6%. Has 2,600 employees. Chairman: Jack E. Davis. President and Chief Executive Officer: James J. Piro. Incorporated: Oregon. Address: 121 S.W. Salmon Street, Portland, Oregon 97204. Telephone: 503-464-8000. Internet: www.portlandgeneral.com.

The Oregon Public Utility Commission has approved a regulatory settlement for Portland General Electric. At the start of 2016, PGE's rates were *lowered* by $15 million. The reduction reflects, in part, lower net variable power costs that are being passed through to ratepayers. Then, when the Carty gas-fired generating plant begins commercial operation (as long as this is no later than July 31st), the utility's rates would rise by $85 million. The allowed return on equity is 9.6%, and the new rates reflect a common-equity ratio of 50%. However . . .
The Carty plant has run into a construction problem. Initially, the 440-megawatt facility was expected to enter service in the second quarter of 2016 at a cost of $514 million. But the company that was building the plant went bankrupt and ceased construction. PGE took control of the site, and construction has resumed, although it took some time for it to ramp back up. What effect this will have on the cost and timing of the project is unknown. Management plans to provide an update when the utility reports earnings in mid-February.
We still expect a significant profit increase in 2016. Once Carty begins commercial operation, PGE will benefit from the associated rate relief. (At this point, we are not assuming that the delay will have a major effect on the utility's income.) Also, a year ago PGE's service area experienced its warmest winter on record. This made the first-quarter comparison easy. The utility is benefiting from growth in its service area's economy.
Is this company a takeover candidate? With increased merger and acquisition activity in the electric utility industry, PGE is considered in some circles as a prospective acquiree. However, investors should be aware that, more than 10 years ago, a proposed buyout of the company fell through. Thus, we do not advise purchase of this issue in the hope of a buyout.
This stock's dividend yield is slightly below the industry average. Although we project respectable dividend growth over the 3- to 5-year time frame, with the recent quotation above the midpoint of our 2018-2020 Target Price Range, total return potential is unappealing.
Paul E. Debbas, CFA *January 29, 2016*

(A) Diluted EPS. Excl. nonrecurring loss: '13, 42¢. Next earnings report due mid-Feb. (B) Dividends paid mid-Jan., Apr., July, and Oct. ■ Dividend reinvestment plan avail. † Shareholder investment plan avail. (C) Incl. deferred charges. In '14: $6.31/sh. (D) In mill. (E) Rate base: Net original cost. Rate allowed on com. eq. in '16: 9.6%; earned on avg. com. eq., '14: 9.4%. Regulatory Climate: Average. (F) Summer peak in '12. (G) '05 per-share data are pro forma, based on shares outstanding when stock began trading in '06.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	60
Earnings Predictability	70

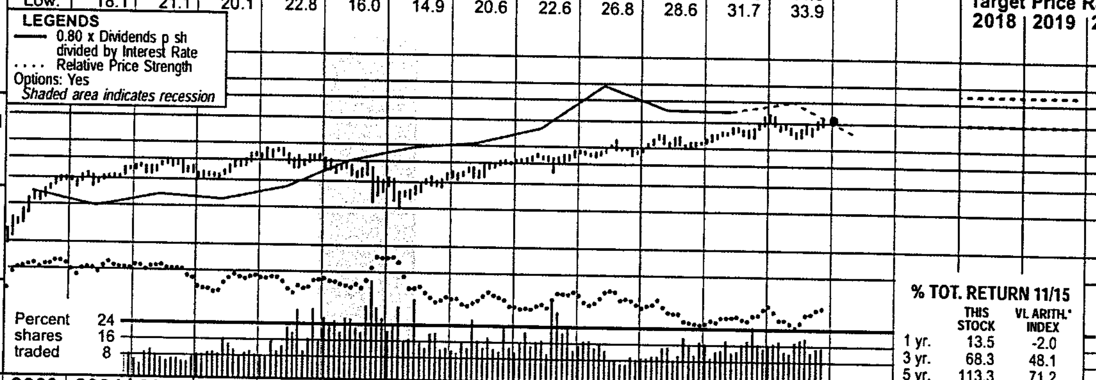
WESTAR ENERGY NYSE-WR

RECENT PRICE 41.40 | P/E RATIO 17.5 (Trailing: 19.3, Median: 14.0) | RELATIVE P/E RATIO 0.99 | DIV'D YLD 3.5% | VALUE LINE

TIMELINESS 3 Lowered 12/12/14
SAFETY 2 Raised 4/1/05
TECHNICAL 2 Raised 12/18/15
BETA .75 (1.00 = Market)

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
High:	22.9	25.0	27.2	28.6	25.9	22.3	25.9	29.0	33.0	35.0	43.2	44.0
Low:	18.1	21.1	20.1	22.8	16.0	14.9	20.6	22.6	26.8	28.6	31.7	33.9

Target Price Range 2018 | 2019 | 2020



2018-20 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	55	(+35%)	11%
Low	40	(-5%)	3%

Insider Decisions

	J	F	M	A	M	J	J	A	S
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	5	0	1	0	0	1	0

Institutional Decisions

	1Q2015	2Q2015	3Q2015
to Buy	134	146	137
to Sell	155	125	121
Hld's(000)	97474	97324	99969

% TOT. RETURN 11/15

	THIS STOCK	VL ARITH.* INDEX
1 yr.	13.5	-2.0
3 yr.	68.3	48.1
5 yr.	113.3	71.2

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	© VALUE LINE PUB. LLC	18-20
30.21	33.80	31.20	24.77	20.06	17.02	18.23	18.37	18.09	16.98	17.04	18.34	17.27	17.88	18.48	19.76	*18.45*	*18.60*	Revenues per sh	*18.70*
7.51	6.96	5.32	4.77	3.77	3.12	3.28	3.94	3.77	3.14	3.59	4.24	3.97	4.30	4.41	4.55	*4.40*	*4.75*	"Cash Flow" per sh	*5.45*
1.48	.89	d.58	1.00	1.48	1.17	1.55	1.88	1.84	1.31	1.28	1.80	1.79	2.15	2.27	2.35	*2.25*	*2.45*	Earnings per sh A	*3.10*
2.14	1.44	1.20	1.20	.87	.80	.92	.98	1.08	1.16	1.20	1.24	1.28	1.32	1.36	1.40	*1.44*	*1.50*	Div'd Decl'd per sh B■†	*1.70*
4.09	4.40	3.37	1.89	2.06	2.19	2.45	3.95	7.84	8.65	5.26	4.82	5.55	6.40	6.08	6.47	*6.50*	*7.00*	Cap'l Spending per sh	*7.95*
27.83	27.20	25.97	13.68	14.23	16.13	16.31	17.62	19.14	20.18	20.59	21.25	22.03	22.89	23.88	25.02	*25.25*	*26.75*	Book Value per sh C	*28.55*
67.40	70.08	70.08	71.51	72.84	86.03	86.84	87.39	95.46	108.31	109.07	112.13	125.70	126.50	128.25	131.69	*140.00*	*145.00*	Common Shs Outst'g E	*155.00*
17.2	20.6	--	14.0	10.8	17.4	14.8	12.2	14.1	17.0	14.9	13.0	14.8	13.4	14.0	15.4	*Bold figures are*	*Value Line*	Avg Ann'l P/E Ratio	*15.0*
.98	1.34	--	.76	.62	.92	.79	.66	.75	1.02	.99	.83	.93	.85	.79	.81	*estimates*		Relative P/E Ratio	*.95*
8.4%	7.9%	5.8%	8.6%	5.5%	3.9%	4.0%	4.3%	4.2%	5.2%	6.3%	5.3%	4.8%	4.6%	4.3%	3.9%			Avg Ann'l Div'd Yield	*3.7%*

CAPITAL STRUCTURE as of 9/30/15
Total Debt $3245.5 mill. Due in 5 Yrs $1000 mill.
LT Debt $2941.9 mill. LT Interest $120.0 mill.
(LT interest earned: 2.7x)

Pension Assets 12/14 $661 mill. Oblig. $914 mill.

Pfd Stock None

Common Stock 141,838,178 shs.
MARKET CAP: $5.9 billion (Large Cap)

2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016		18-20
1583.3	1605.7	1726.8	1839.0	1858.2	2056.2	2171.0	2261.5	2370.7	2601.7	*2580*	*2700*	Revenues ($mill)	*2900*
134.9	165.3	168.4	136.8	141.3	203.9	214.0	275.1	292.5	313.3	*315*	*355*	Net Profit ($mill)	*480*
31.0%	25.4%	27.5%	24.8%	29.4%	29.0%	35.2%	30.9%	33.1%	31.9%	*30.0%*	*30.0%*	Income Tax Rate	*30.0%*
--	--	10.4%	--	--	--	--	--	10.4%	10.0%	*10.0%*	*10.0%*	AFUDC % to Net Profit	*10.0%*
52.1%	50.0%	50.6%	49.8%	53.4%	53.6%	49.5%	51.2%	50.0%	50.0%	*50.0%*	*50.0%*	Long-Term Debt Ratio	*50.0%*
47.2%	49.3%	48.9%	49.7%	46.1%	46.0%	50.1%	48.8%	50.0%	50.0%	*50.0%*	*50.0%*	Common Equity Ratio	*50.0%*
3000.4	3124.2	3738.3	4400.1	4866.8	5180.9	5531.0	5938.2	6131.1	6596.2	*6650*	*6800*	Total Capital ($mill)	*7500*
3947.7	4071.6	4803.7	5533.5	5771.7	6309.5	6745.4	7335.7	7848.5	8441.5	*8500*	*8600*	Net Plant ($mill)	*9000*
6.2%	6.7%	5.8%	4.2%	4.4%	5.5%	5.3%	6.0%	6.1%	6.0%	*6.0%*	*6.0%*	Return on Total Cap'l	*7.0%*
9.4%	10.6%	9.1%	6.2%	6.2%	8.5%	7.7%	9.5%	9.6%	9.5%	*9.5%*	*9.5%*	Return on Shr. Equity	*9.5%*
9.5%	10.7%	9.2%	6.2%	6.3%	8.5%	7.7%	9.4%	9.6%	9.5%	*9.5%*	*9.5%*	Return on Com Equity D	*9.5%*
4.3%	5.5%	4.3%	1.2%	.8%	3.1%	2.7%	4.0%	4.2%	4.3%	*4.5%*	*4.5%*	Retained to Com Eq	*5.0%*
55%	49%	53%	80%	87%	63%	65%	57%	56%	55%	*64%*	*61%*	All Div'ds to Net Prof	*55%*

ELECTRIC OPERATING STATISTICS

	2012	2013	2014
% Change Retail Sales (KWH)	-1.5	+3.6	+1.5
Avg. Indust. Use (MWH)	5588	5407	5747
Avg. Indust. Revs. per KWH (¢)	6.60	6.47	6.72
Capacity at Peak (Mw)	6557	6671	6698
Peak Load, Summer (Mw)	5411	5489	5226
Annual Load Factor (%)	56.0	55.9	56.2
% Change Customers (yr-end)	+.2	+.2	+.2
Fixed Charge Cov. (%)	319	323	332

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '12-'14 to '18-'20
Revenues	-1.0%	1.5%	*2.5%*
"Cash Flow"	1.5%	5.0%	*4.5%*
Earnings	6.5%	9.0%	*6.0%*
Dividends	3.5%	3.5%	*3.0%*
Book Value	5.0%	3.5%	*5.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	475.7	566.3	695.8	523.7	2261.5
2013	546.2	569.6	695.0	559.9	2370.7
2014	628.6	612.7	764.0	596.4	2601.7
2015	590.8	589.6	732.8	*666.8*	*2580*
2016	*645*	*630*	*775*	*650*	*2700*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.21	.48	1.09	.37	2.15
2013	.40	.52	1.04	.31	2.27
2014	.52	.40	1.10	.33	2.35
2015	.38	.46	.97	*.44*	*2.25*
2016	*.50*	*.45*	*1.10*	*.40*	*2.45*

Cal-endar	QUARTERLY DIVIDENDS PAID B■† Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.31	.32	.32	.32	1.27
2012	.32	.33	.33	.33	1.31
2013	.33	.34	.34	.34	1.35
2014	.34	.35	.35	.35	1.39
2015	.35	.36	.36	.36	

BUSINESS: Westar Energy, Inc., formerly Western Resources, is the parent of Kansas Gas & Electric Company. Westar supplies electricity to 700,000 customers in Kansas. Electric revenue sources: residential and rural, 41%; commercial, 38%; industrial, 21%. Sold investment in ONEOK in 2003 and 85% ownership in Protection One in 2004. 2014 depreciation rate: 3.9%. Estimated plant age: 16 years. Fuels: coal, 48%; nuclear, 8%; gas, 44%. Has 2,411 employees. BlackRock Inc owns 7.2% of common; The Vanguard Group owns 6.3%; Stowers Institute owns 5.7% (4/15 proxy). CEO and Pres.: Mark A. Ruelle. Inc.: Kansas. Addr.: 818 South Kansas Avenue, Topeka, Kansas 66612. Telephone: 785-575-6300. Internet: www.westarenergy.com.

Regulators approved a $78 million rate hike for Westar Energy. The Kansas Corporation Commission accepted a 4%, or $78 million, rate increase that should help cover some of the utility's costs associated with upgrading several power plants. Westar Energy originally sought a $152 million boost, but subsequently dropped that demand to $78 million after failing to garner enough support from lawmakers. Utilities routinely ask for relatively large rate increases that often get negotiated down by legislators, so the outcome was not at all unexpected.

Much of the new revenue will cover the cost of upgrades at the La Cygne Energy Center and Wolf Creek. Improvements at La Cygne were required by federal air pollution standards. The facility received a baghouse, wet scrubber, and selective catalytic reduction (SCR) to reduce emissions. At Wolf Creek, the upgrades were tied to a decision to keep the plant in operation for 20 years longer than initially planned, until 2045.

Westar continues to modernize electricity production. The company announced plans to phase out by yearend old electrical-generating equipment at three locations. That should help reduce carbon emissions and energy waste, while also lowering operational costs at several plants. Furthermore, management will add more renewable energy production in the coming months as this appears to be a reasonable alternative to investing in more electrical-generating equipment.

We look for a dividend hike at the upcoming board meeting. The increase will likely add a penny to the quarterly distribution, in line with the pattern in recent years. Also, Westar Energy is targeting a payout ratio of 50%-60%, so we expect only moderate dividend growth potential through the 3- to 5-year period.

This stock provides a steady source of income for conservative investors. The yield is around the average for electric utilities, and the payout has been raised every year since 2003. In addition, we expect cost-control measures and higher rates to drive above-average earnings growth over the next few years. That should allow Westar to increase the dividend uninterrupted.

Daniel Henigson *December 18, 2015*

(A) EPS diluted from 2010 onward. Excl. nonrecur. gains (losses): '99, ($1.31); '00, $1.07; '01, 27¢; '02, ($12.06); '03, 77¢; '08, 39¢; '11, 14¢. Earnings may not sum due to rounding. Next egs. rep't due early February. (B) Div'ds paid in early Jan., April, July, and Oct. ■ Div'd reinvest. plan avail. † Shareholder invest. plan avail. (C) Incl. reg. assets. In 2014: $6.48/sh. (D) Rate base determined: fair value; Rate allowed on common equity in '14: 10.0%; earned on avg. com. eq., '14: 9.5%. Regul. Clim.: Avg. (E) In mill.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	75
Earnings Predictability	85

ATTACHMENT C

ALLETE, Inc. (ALE) - NYSE ★ Watchlist Like 13

53.31 **0.14(0.26%)** 1:42PM EST - NYSE Real Time Price

Analyst Estimates

Get Analyst Estimates for: GO

Earnings Est	Current Qtr. Dec 15	Next Qtr. Mar 16	Current Year Dec 15	Next Year Dec 16
Avg. Estimate	0.78	0.89	3.33	3.31
No. of Analysts	4.00	1.00	4.00	5.00
Low Estimate	0.73	0.89	3.05	3.28
High Estimate	0.82	0.89	3.44	3.36
Year Ago EPS	0.73	0.91	2.99	3.33

Next Earnings Date: Feb 18, 2016 - Set a Reminder

Revenue Est	Current Qtr. Dec 15	Next Qtr. Mar 16	Current Year Dec 15	Next Year Dec 16
Avg. Estimate	417.00M	NaN	1.33B	1.32B
No. of Analysts	1		4	4
Low Estimate	417.00M	NaN	1.21B	1.22B
High Estimate	417.00M	NaN	1.52B	1.42B
Year Ago Sales	290.70M	NaN	1.14B	1.33B
Sales Growth (year/est)	43.40%	N/A	16.60%	-0.40%

Earnings History	Dec 14	Mar 15	Jun 15	Sep 15
EPS Est	0.68	0.87	0.50	1.02
EPS Actual	0.73	0.91	0.48	1.25
Difference	0.05	0.04	-0.02	0.23
Surprise %	7.40%	4.60%	-4.00%	22.50%

EPS Trends	Current Qtr. Dec 15	Next Qtr. Mar 16	Current Year Dec 15	Next Year Dec 16
Current Estimate	0.78	0.89	3.33	3.31
7 Days Ago	0.78	0.89	3.33	3.31
30 Days Ago	0.78	0.89	3.34	3.31
60 Days Ago	0.82	0.97	3.30	3.35
90 Days Ago	0.83	0.98	3.30	3.38

EPS Revisions	Current Qtr. Dec 15	Next Qtr. Mar 16	Current Year Dec 15	Next Year Dec 16
Up Last 7 Days	0	0	0	0
Up Last 30 Days	1	0	0	0
Down Last 30 Days	0	0	0	0
Down Last 90 Days	N/A	N/A	N/A	N/A

Growth Est	ALE	Industry	Sector	S&P 500
Current Qtr.	6.80%	-10.50%	47.40%	2.90%
Next Qtr.	-2.20%	21.90%	49.80%	13.10%
This Year	11.40%	13.00%	22.80%	2.60%
Next Year	-0.60%	1.80%	8.00%	9.30%
Past 5 Years (per annum)	10.35%	N/A	N/A	N/A
Next 5 Years (per annum)	5.00%	7.67%	6.15%	4.91%
Price/Earnings (avg. for comparison categories)	16.08	8.46	19.13	19.73
PEG Ratio (avg. for comparison categories)	3.22	3.67	3.29	1.98

American Electric Power Co., Inc. (AEP) - NYSE ★ Watchlist

61.88 **0.40(0.64%)** 1:45PM EST - NYSE Real Time Price

Analyst Estimates

Get Analyst Estimates for: GO

Earnings Est	Current Qtr. Mar 16	Next Qtr. Jun 16	Current Year Dec 16	Next Year Dec 17
Avg. Estimate	1.14	0.85	3.70	3.91
No. of Analysts	12.00	12.00	23.00	18.00
Low Estimate	0.93	0.76	3.54	3.80
High Estimate	1.27	0.92	3.76	4.00
Year Ago EPS	1.28	0.88	3.69	3.70

Revenue Est	Current Qtr. Mar 16	Next Qtr. Jun 16	Current Year Dec 16	Next Year Dec 17
Avg. Estimate	4.51B	3.98B	17.21B	17.63B
No. of Analysts	7	7	15	11
Low Estimate	4.13B	3.64B	16.19B	15.90B
High Estimate	4.92B	4.46B	18.25B	18.87B
Year Ago Sales	4.70B	3.90B	16.50B	17.21B
Sales Growth (year/est)	-4.00%	2.20%	4.30%	2.50%

Earnings History	Mar 15	Jun 15	Sep 15	Dec 15
EPS Est	1.10	0.81	1.01	0.50
EPS Actual	1.28	0.88	1.06	0.48
Difference	0.18	0.07	0.05	-0.02
Surprise %	16.40%	8.60%	5.00%	-4.00%

EPS Trends	Current Qtr. Mar 16	Next Qtr. Jun 16	Current Year Dec 16	Next Year Dec 17
Current Estimate	1.14	0.85	3.70	3.91
7 Days Ago	1.14	0.85	3.71	3.91
30 Days Ago	1.16	0.86	3.71	3.90
60 Days Ago	1.15	0.87	3.72	3.91
90 Days Ago	1.16	0.87	3.72	3.90

EPS Revisions	Current Qtr. Mar 16	Next Qtr. Jun 16	Current Year Dec 16	Next Year Dec 17
Up Last 7 Days	0	2	1	2
Up Last 30 Days	2	4	4	6
Down Last 30 Days	0	0	2	1
Down Last 90 Days	N/A	N/A	N/A	N/A

Growth Est	AEP	Industry	Sector	S&P 500
Current Qtr.	-10.90%	-10.50%	47.40%	2.90%
Next Qtr.	-3.40%	21.90%	49.80%	13.10%
This Year	0.30%	13.00%	22.80%	2.60%
Next Year	5.70%	1.80%	8.00%	9.30%
Past 5 Years (per annum)	5.46%	N/A	N/A	N/A
Next 5 Years (per annum)	4.55%	7.67%	6.15%	4.91%
Price/Earnings (avg. for comparison categories)	16.84	8.46	19.13	19.73
PEG Ratio (avg. for comparison categories)	3.70	3.67	3.29	1.98

Currency in USD.

El Paso Electric Co. (EE) - NYSE ★ Watchlist

41.04 **0.25(0.61%)** 1:47PM EST - Nasdaq Real Time Price

Analyst Estimates

Earnings Est	Current Qtr. Dec 15	Next Qtr. Mar 16	Current Year Dec 15	Next Year Dec 16
Avg. Estimate	0.00	N/A	2.00	2.55
No. of Analysts	1.00	N/A	4.00	4.00
Low Estimate	0.00	N/A	1.98	2.50
High Estimate	0.00	N/A	2.03	2.58
Year Ago EPS	0.10	0.09	2.27	2.00

Next Earnings Date: Feb 24, 2016 - Set a Reminder

Revenue Est	Current Qtr. Dec 15	Next Qtr. Mar 16	Current Year Dec 15	Next Year Dec 16
Avg. Estimate	NaN	NaN	898.70M	924.37M
No. of Analysts			3	3
Low Estimate	NaN	NaN	872.00M	898.00M
High Estimate	NaN	NaN	926.50M	939.80M
Year Ago Sales	NaN	NaN	601.72M	898.70M
Sales Growth (year/est)	N/A	N/A	49.40%	2.90%

Earnings History	Dec 14	Mar 15	Jun 15	Sep 15
EPS Est	0.11	0.12	0.60	1.20
EPS Actual	0.10	0.09	0.52	1.40
Difference	-0.01	-0.03	-0.08	0.20
Surprise %	-9.10%	-25.00%	-13.30%	16.70%

EPS Trends	Current Qtr. Dec 15	Next Qtr. Mar 16	Current Year Dec 15	Next Year Dec 16
Current Estimate	0.00	N/A	2.00	2.55
7 Days Ago	0.00	0.08	2.00	2.55
30 Days Ago	0.10	0.08	2.00	2.55
60 Days Ago	0.10	0.08	2.00	2.55
90 Days Ago	0.10	0.08	2.00	2.54

EPS Revisions	Current Qtr. Dec 15	Next Qtr. Mar 16	Current Year Dec 15	Next Year Dec 16
Up Last 7 Days	0	0	0	0
Up Last 30 Days	0	0	0	0
Down Last 30 Days	0	0	0	0
Down Last 90 Days	N/A	N/A	N/A	N/A

Growth Est	EE	Industry	Sector	S&P 500
Current Qtr.	-100.00%	-10.50%	47.40%	2.90%
Next Qtr.	N/A	21.90%	49.80%	13.10%
This Year	-11.90%	13.00%	22.80%	2.60%
Next Year	27.50%	1.80%	8.00%	9.30%
Past 5 Years (per annum)	-2.74%	N/A	N/A	N/A
Next 5 Years (per annum)	7.00%	7.67%	6.15%	4.91%
Price/Earnings (avg. for comparison categories)	20.88	8.46	19.13	19.73
PEG Ratio (avg. for comparison categories)	2.98	3.67	3.29	1.98

The Empire District Electric Company (EDE) - NYSE ★ Watchlist

27.75 **0.96(3.34%)** 1:47PM EST - NYSE Real Time Price

Analyst Estimates

Earnings Est	Current Qtr. Mar 16	Next Qtr. Jun 16	Current Year Dec 16	Next Year Dec 17
Avg. Estimate	0.35	0.20	1.50	1.61
No. of Analysts	1.00	1.00	5.00	5.00
Low Estimate	0.35	0.20	1.45	1.50
High Estimate	0.35	0.20	1.55	1.75
Year Ago EPS	0.34	0.15	1.29	1.50

Revenue Est	Current Qtr. Mar 16	Next Qtr. Jun 16	Current Year Dec 16	Next Year Dec 17
Avg. Estimate	NaN	NaN	670.64M	691.86M
No. of Analysts			4	4
Low Estimate	NaN	NaN	655.76M	678.82M
High Estimate	NaN	NaN	678.10M	699.00M
Year Ago Sales	NaN	NaN	416.20M	670.64M
Sales Growth (year/est)	N/A	N/A	61.10%	3.20%

Earnings History	Mar 15	Jun 15	Sep 15	Dec 15
EPS Est	0.34	0.24	0.59	0.28
EPS Actual	0.34	0.15	0.58	0.23
Difference	0.00	-0.09	-0.01	-0.05
Surprise %	0.00%	-37.50%	-1.70%	-17.90%

EPS Trends	Current Qtr. Mar 16	Next Qtr. Jun 16	Current Year Dec 16	Next Year Dec 17
Current Estimate	0.35	0.20	1.50	1.61
7 Days Ago	N/A	N/A	1.51	1.61
30 Days Ago	N/A	N/A	1.52	1.61
60 Days Ago	N/A	N/A	1.51	1.61
90 Days Ago	N/A	N/A	1.50	1.60

EPS Revisions	Current Qtr. Mar 16	Next Qtr. Jun 16	Current Year Dec 16	Next Year Dec 17
Up Last 7 Days	0	0	0	0
Up Last 30 Days	0	0	0	0
Down Last 30 Days	0	0	1	0
Down Last 90 Days	N/A	N/A	N/A	N/A

Growth Est	EDE	Industry	Sector	S&P 500
Current Qtr.	2.90%	38.80%	47.40%	2.90%
Next Qtr.	33.30%	241.20%	49.80%	13.10%
This Year	16.30%	12.10%	22.80%	2.60%
Next Year	7.30%	9.30%	8.00%	9.30%
Past 5 Years (per annum)	2.58%	N/A	N/A	N/A
Next 5 Years (per annum)	5.00%	6.80%	6.15%	4.91%
Price/Earnings (avg. for comparison categories)	19.14	22.50	19.13	19.73
PEG Ratio (avg. for comparison categories)	3.83	6.06	3.29	1.98

Currency in USD.

Eversource Energy (ES) - NYSE ★ Watchlist

Like 13

53.87 **0.79(1.45%)** 1:53PM EST - NYSE Real Time Price

Analyst Estimates

Get Analyst Estimates for: GO

Earnings Est	Current Qtr. Mar 16	Next Qtr. Jun 16	Current Year Dec 16	Next Year Dec 17
Avg. Estimate	0.93	0.61	3.01	3.21
No. of Analysts	8.00	8.00	18.00	17.00
Low Estimate	0.80	0.50	2.97	3.14
High Estimate	1.07	0.71	3.09	3.29
Year Ago EPS	0.81	0.66	2.81	3.01

Revenue Est	Current Qtr. Mar 16	Next Qtr. Jun 16	Current Year Dec 16	Next Year Dec 17
Avg. Estimate	2.38B	1.76B	8.20B	8.42B
No. of Analysts	4	4	12	11
Low Estimate	2.19B	1.55B	7.68B	7.70B
High Estimate	2.60B	1.94B	8.61B	8.89B
Year Ago Sales	2.51B	1.87B	7.95B	8.20B
Sales Growth (year/est)	-5.20%	-5.70%	3.10%	2.60%

Earnings History	Mar 15	Jun 15	Sep 15	Dec 15
EPS Est	0.80	0.56	0.76	0.62
EPS Actual	0.81	0.66	0.75	0.60
Difference	0.01	0.10	-0.01	-0.02
Surprise %	1.30%	17.90%	-1.30%	-3.20%

EPS Trends	Current Qtr. Mar 16	Next Qtr. Jun 16	Current Year Dec 16	Next Year Dec 17
Current Estimate	0.93	0.61	3.01	3.21
7 Days Ago	0.93	0.61	3.01	3.21
30 Days Ago	0.92	0.60	3.02	3.21
60 Days Ago	0.89	0.62	3.03	3.22
90 Days Ago	0.88	0.61	3.04	3.22

EPS Revisions	Current Qtr. Mar 16	Next Qtr. Jun 16	Current Year Dec 16	Next Year Dec 17
Up Last 7 Days	0	0	0	0
Up Last 30 Days	0	2	1	1
Down Last 30 Days	0	0	1	1
Down Last 90 Days	N/A	N/A	N/A	N/A

Growth Est	ES	Industry	Sector	S&P 500
Current Qtr.	14.80%	-10.50%	47.40%	2.90%
Next Qtr.	-7.60%	21.90%	49.80%	13.10%
This Year	7.10%	13.00%	22.80%	2.60%
Next Year	6.60%	1.80%	8.00%	9.30%
Past 5 Years (per annum)	4.60%	N/A	N/A	N/A
Next 5 Years (per annum)	6.57%	7.67%	6.15%	4.91%
Price/Earnings (avg. for comparison categories)	18.16	8.46	19.13	19.73
PEG Ratio (avg. for comparison categories)	2.76	3.67	3.29	1.98

Currency in USD.

Great Plains Energy Incorporated (GXP) - NYSE ★ Watchlist

Like 14

28.49 0.31(1.08%) 2:11PM EST - Nasdaq Real Time Price

Analyst Estimates

Get Analyst Estimates for: GO

Earnings Est	Current Qtr. Dec 15	Next Qtr. Mar 16	Current Year Dec 15	Next Year Dec 16
Avg. Estimate	0.17	0.16	1.40	1.75
No. of Analysts	8.00	4.00	13.00	13.00
Low Estimate	0.13	0.13	1.35	1.70
High Estimate	0.21	0.21	1.44	1.78
Year Ago EPS	0.12	0.12	1.57	1.40

Next Earnings Date: Feb 24, 2016 - Set a Reminder

Revenue Est	Current Qtr. Dec 15	Next Qtr. Mar 16	Current Year Dec 15	Next Year Dec 16
Avg. Estimate	668.64M	593.04M	2.56B	2.69B
No. of Analysts	3	4	10	10
Low Estimate	581.64M	571.31M	2.45B	2.54B
High Estimate	723.27M	631.00M	2.66B	2.77B
Year Ago Sales	552.20M	549.10M	2.57B	2.56B
Sales Growth (year/est)	21.10%	8.00%	-0.20%	5.10%

Earnings History	Dec 14	Mar 15	Jun 15	Sep 15
EPS Est	0.13	0.11	0.30	0.88
EPS Actual	0.12	0.12	0.28	0.82
Difference	-0.01	0.01	-0.02	-0.06
Surprise %	-7.70%	9.10%	-6.70%	-6.80%

EPS Trends	Current Qtr. Dec 15	Next Qtr. Mar 16	Current Year Dec 15	Next Year Dec 16
Current Estimate	0.17	0.16	1.40	1.75
7 Days Ago	0.17	0.16	1.40	1.75
30 Days Ago	0.19	0.16	1.40	1.75
60 Days Ago	0.19	0.16	1.40	1.76
90 Days Ago	0.19	0.18	1.45	1.80

EPS Revisions	Current Qtr. Dec 15	Next Qtr. Mar 16	Current Year Dec 15	Next Year Dec 16
Up Last 7 Days	0	0	0	0
Up Last 30 Days	0	0	0	2
Down Last 30 Days	0	0	0	0
Down Last 90 Days	N/A	N/A	N/A	N/A

Growth Est	GXP	Industry	Sector	S&P 500
Current Qtr.	41.70%	-10.50%	47.40%	2.90%
Next Qtr.	33.30%	21.90%	49.80%	13.10%
This Year	-10.80%	13.00%	22.80%	2.60%
Next Year	25.00%	1.80%	8.00%	9.30%
Past 5 Years (per annum)	23.23%	N/A	N/A	N/A
Next 5 Years (per annum)	5.07%	7.67%	6.15%	4.91%
Price/Earnings (avg. for comparison categories)	20.56	8.46	19.13	19.73
PEG Ratio (avg. for comparison categories)	4.06	3.67	3.29	1.98

IDA

IdaCorp, Inc. (IDA) - NYSE ★ Watchlist

69.41 0.06(0.09%) 2:19PM EST - Nasdaq Real Time Price

Analyst Estimates

Get Analyst Estimates for: GO

Earnings Est	Current Qtr. Dec 15	Next Qtr. Mar 16	Current Year Dec 15	Next Year Dec 16
Avg. Estimate	0.64	N/A	3.86	3.89
No. of Analysts	2.00	N/A	3.00	3.00
Low Estimate	0.61	N/A	3.84	3.85
High Estimate	0.66	N/A	3.90	3.92
Year Ago EPS	0.69	0.47	3.85	3.86

Next Earnings Date: Feb 18, 2016 - Set a Reminder

Revenue Est	Current Qtr. Dec 15	Next Qtr. Mar 16	Current Year Dec 15	Next Year Dec 16
Avg. Estimate	NaN	NaN	1.27B	1.28B
No. of Analysts			2	2
Low Estimate	NaN	NaN	1.25B	1.26B
High Estimate	NaN	NaN	1.29B	1.30B
Year Ago Sales	NaN	NaN	1.28B	1.27B
Sales Growth (year/est)	N/A	N/A	-1.30%	1.40%

Earnings History	Dec 14	Mar 15	Jun 15	Sep 15
EPS Est	0.58	0.58	1.07	1.54
EPS Actual	0.69	0.47	1.31	1.46
Difference	0.11	-0.11	0.24	-0.08
Surprise %	19.00%	-19.00%	22.40%	-5.20%

EPS Trends	Current Qtr. Dec 15	Next Qtr. Mar 16	Current Year Dec 15	Next Year Dec 16
Current Estimate	0.64	N/A	3.86	3.89
7 Days Ago	0.64	N/A	3.86	3.89
30 Days Ago	0.64	N/A	3.86	3.89
60 Days Ago	0.64	N/A	3.86	3.89
90 Days Ago	0.65	N/A	3.86	3.89

EPS Revisions	Current Qtr. Dec 15	Next Qtr. Mar 16	Current Year Dec 15	Next Year Dec 16
Up Last 7 Days	0	N/A	0	0
Up Last 30 Days	0	N/A	0	0
Down Last 30 Days	0	N/A	0	0
Down Last 90 Days	N/A	N/A	N/A	N/A

Growth Est	IDA	Industry	Sector	S&P 500
Current Qtr.	-7.20%	-10.50%	47.40%	2.90%
Next Qtr.	N/A	21.90%	49.80%	13.10%
This Year	0.30%	13.00%	22.80%	2.60%
Next Year	0.80%	1.80%	8.00%	9.30%
Past 5 Years (per annum)	13.17%	N/A	N/A	N/A
Next 5 Years (per annum)	4.00%	7.67%	6.15%	4.91%
Price/Earnings (avg. for comparison categories)	17.98	8.46	19.13	19.73
PEG Ratio (avg. for comparison categories)	4.50	3.67	3.29	1.98

Otter Tail Corporation (OTTR) - NasdaqGS ★ Watchlist

28.71 0.32(1.13%) 2:21PM EST - Nasdaq Real Time Price

Analyst Estimates

Get Analyst Estimates for: GO

Earnings Est	Current Qtr. Dec 15	Next Qtr. Mar 16	Current Year Dec 15	Next Year Dec 16
Avg. Estimate	0.44	N/A	1.59	1.70
No. of Analysts	2.00	N/A	2.00	2.00
Low Estimate	0.42	N/A	1.57	1.70
High Estimate	0.45	N/A	1.60	1.70
Year Ago EPS	0.38	0.37	1.55	1.59

Next Earnings Date: Feb 8, 2016 - Set a Reminder

Revenue Est	Current Qtr. Dec 15	Next Qtr. Mar 16	Current Year Dec 15	Next Year Dec 16
Avg. Estimate	203.75M	NaN	794.05M	838.00M
No. of Analysts	2		2	2
Low Estimate	198.20M	NaN	787.80M	822.90M
High Estimate	209.30M	NaN	800.30M	853.10M
Year Ago Sales	193.41M	NaN	799.26M	794.05M
Sales Growth (year/est)	5.30%	N/A	-0.70%	5.50%

Earnings History	Dec 14	Mar 15	Jun 15	Sep 15
EPS Est	0.45	0.55	0.23	0.44
EPS Actual	0.38	0.37	0.36	0.42
Difference	-0.07	-0.18	0.13	-0.02
Surprise %	-15.60%	-32.70%	56.50%	-4.50%

EPS Trends	Current Qtr. Dec 15	Next Qtr. Mar 16	Current Year Dec 15	Next Year Dec 16
Current Estimate	0.44	N/A	1.59	1.70
7 Days Ago	0.44	0.59	1.59	1.70
30 Days Ago	0.48	0.59	1.63	1.72
60 Days Ago	0.48	0.59	1.63	1.72
90 Days Ago	0.48	0.59	1.63	1.72

EPS Revisions	Current Qtr. Dec 15	Next Qtr. Mar 16	Current Year Dec 15	Next Year Dec 16
Up Last 7 Days	0	0	0	0
Up Last 30 Days	0	0	0	0
Down Last 30 Days	0	0	0	0
Down Last 90 Days	N/A	N/A	N/A	N/A

Growth Est	OTTR	Industry	Sector	S&P 500
Current Qtr.	15.80%	-10.50%	47.40%	2.90%
Next Qtr.	N/A	21.90%	49.80%	13.10%
This Year	2.60%	13.00%	22.80%	2.60%
Next Year	6.90%	1.80%	8.00%	9.30%
Past 5 Years (per annum)	33.38%	N/A	N/A	N/A
Next 5 Years (per annum)	6.00%	7.67%	6.15%	4.91%
Price/Earnings (avg. for comparison categories)	17.92	8.46	19.13	19.73
PEG Ratio (avg. for comparison categories)	2.99	3.67	3.29	1.98

PNW

Pinnacle West Capital Corporation (PNW) - NYSE ★ Watchlist Like 6

68.06 **0.46(0.67%)** 2:21PM EST - NYSE Real Time Price

Analyst Estimates

Get Analyst Estimates for: GO

Earnings Est	Current Qtr. Dec 15	Next Qtr. Mar 16	Current Year Dec 15	Next Year Dec 16
Avg. Estimate	0.25	0.18	3.80	3.99
No. of Analysts	12.00	7.00	17.00	18.00
Low Estimate	0.15	0.11	3.76	3.90
High Estimate	0.31	0.25	3.85	4.07
Year Ago EPS	0.05	0.14	3.58	3.80

Next Earnings Date: Feb 19, 2016 - Set a Reminder

Revenue Est	Current Qtr. Dec 15	Next Qtr. Mar 16	Current Year Dec 15	Next Year Dec 16
Avg. Estimate	763.01M	697.70M	3.53B	3.62B
No. of Analysts	5	5	12	12
Low Estimate	739.26M	682.00M	3.44B	3.51B
High Estimate	784.00M	714.20M	3.62B	3.76B
Year Ago Sales	726.45M	671.22M	3.49B	3.53B
Sales Growth (year/est)	5.00%	3.90%	1.10%	2.60%

Earnings History	Dec 14	Mar 15	Jun 15	Sep 15
EPS Est	0.18	0.18	1.23	2.32
EPS Actual	0.05	0.14	1.10	2.30
Difference	-0.13	-0.04	-0.13	-0.02
Surprise %	-72.20%	-22.20%	-10.60%	-0.90%

EPS Trends	Current Qtr. Dec 15	Next Qtr. Mar 16	Current Year Dec 15	Next Year Dec 16
Current Estimate	0.25	0.18	3.80	3.99
7 Days Ago	0.25	0.18	3.80	4.00
30 Days Ago	0.23	0.19	3.79	4.01
60 Days Ago	0.23	0.19	3.79	4.01
90 Days Ago	0.23	0.19	3.79	4.01

EPS Revisions	Current Qtr. Dec 15	Next Qtr. Mar 16	Current Year Dec 15	Next Year Dec 16
Up Last 7 Days	1	0	1	0
Up Last 30 Days	4	0	3	0
Down Last 30 Days	0	0	1	1
Down Last 90 Days	N/A	N/A	N/A	N/A

Growth Est	PNW	Industry	Sector	S&P 500
Current Qtr.	400.00%	-10.50%	47.40%	2.90%
Next Qtr.	28.60%	21.90%	49.80%	13.10%
This Year	6.10%	13.00%	22.80%	2.60%
Next Year	5.00%	1.80%	8.00%	9.30%
Past 5 Years (per annum)	-0.04%	N/A	N/A	N/A
Next 5 Years (per annum)	4.95%	7.67%	6.15%	4.91%
Price/Earnings (avg. for comparison categories)	18.11	8.46	19.13	19.73
PEG Ratio (avg. for comparison categories)	3.66	3.67	3.29	1.98

PNM Resources, Inc. (PNM) - NYSE ★ Watchlist

32.10 0.04(0.11%) 2:22PM EST - Nasdaq Real Time Price

Analyst Estimates

Earnings Est	Current Qtr. Dec 15	Next Qtr. Mar 16	Current Year Dec 15	Next Year Dec 16
Avg. Estimate	0.18	0.22	1.59	1.63
No. of Analysts	7.00	1.00	9.00	9.00
Low Estimate	0.16	0.22	1.55	1.60
High Estimate	0.20	0.22	1.61	1.65
Year Ago EPS	0.24	0.21	1.49	1.59

Next Earnings Date: Feb 26, 2016 - Set a Reminder

Revenue Est	Current Qtr. Dec 15	Next Qtr. Mar 16	Current Year Dec 15	Next Year Dec 16
Avg. Estimate	376.00M	350.00M	1.46B	1.50B
No. of Analysts	2	1	5	5
Low Estimate	370.00M	350.00M	1.45B	1.40B
High Estimate	382.00M	350.00M	1.48B	1.56B
Year Ago Sales	346.84M	332.87M	1.44B	1.46B
Sales Growth (year/est)	8.40%	5.10%	1.80%	2.50%

Earnings History	Dec 14	Mar 15	Jun 15	Sep 15
EPS Est	0.23	0.18	0.41	0.74
EPS Actual	0.24	0.21	0.44	0.76
Difference	0.01	0.03	0.03	0.02
Surprise %	4.30%	16.70%	7.30%	2.70%

EPS Trends	Current Qtr. Dec 15	Next Qtr. Mar 16	Current Year Dec 15	Next Year Dec 16
Current Estimate	0.18	0.22	1.59	1.63
7 Days Ago	0.19	0.22	1.59	1.63
30 Days Ago	0.19	0.22	1.59	1.63
60 Days Ago	0.18	0.22	1.59	1.63
90 Days Ago	0.18	0.22	1.59	1.64

EPS Revisions	Current Qtr. Dec 15	Next Qtr. Mar 16	Current Year Dec 15	Next Year Dec 16
Up Last 7 Days	0	0	0	0
Up Last 30 Days	0	0	0	0
Down Last 30 Days	0	0	0	0
Down Last 90 Days	N/A	N/A	N/A	N/A

Growth Est	PNM	Industry	Sector	S&P 500
Current Qtr.	-25.00%	-10.50%	47.40%	2.90%
Next Qtr.	4.80%	21.90%	49.80%	13.10%
This Year	6.70%	13.00%	22.80%	2.60%
Next Year	2.50%	1.80%	8.00%	9.30%
Past 5 Years (per annum)	14.59%	N/A	N/A	N/A
Next 5 Years (per annum)	9.30%	7.67%	6.15%	4.91%
Price/Earnings (avg. for comparison categories)	19.99	8.46	19.13	19.73
PEG Ratio (avg. for comparison categories)	2.15	3.67	3.29	1.98

Portland General Electric Company (POR) - NYSE ★ Watchlist

Like 11

39.85 **0.38(0.94%)** 2:23PM EST - NYSE Real Time Price

Analyst Estimates

Get Analyst Estimates for: GO

Earnings Est	Current Qtr. Dec 15	Next Qtr. Mar 16	Current Year Dec 15	Next Year Dec 16
Avg. Estimate	0.62	0.73	2.09	2.34
No. of Analysts	8.00	3.00	13.00	13.00
Low Estimate	0.57	0.63	2.02	2.27
High Estimate	0.66	0.86	2.12	2.40
Year Ago EPS	0.55	0.62	2.18	2.09

Next Earnings Date: Feb 12, 2016 - Set a Reminder

Revenue Est	Current Qtr. Dec 15	Next Qtr. Mar 16	Current Year Dec 15	Next Year Dec 16
Avg. Estimate	544.39M	554.38M	1.95B	2.03B
No. of Analysts	5	3	11	11
Low Estimate	512.60M	473.04M	1.90B	1.95B
High Estimate	605.60M	682.13M	2.09B	2.18B
Year Ago Sales	500.00M	473.00M	1.90B	1.95B
Sales Growth (year/est)	8.90%	17.20%	2.80%	4.10%

Earnings History	Dec 14	Mar 15	Jun 15	Sep 15
EPS Est	0.52	0.70	0.41	0.48
EPS Actual	0.55	0.62	0.44	0.40
Difference	0.03	-0.08	0.03	-0.08
Surprise %	5.80%	-11.40%	7.30%	-16.70%

EPS Trends	Current Qtr. Dec 15	Next Qtr. Mar 16	Current Year Dec 15	Next Year Dec 16
Current Estimate	0.62	0.73	2.09	2.34
7 Days Ago	0.62	0.73	2.09	2.34
30 Days Ago	0.63	0.75	2.10	2.34
60 Days Ago	0.63	0.75	2.10	2.34
90 Days Ago	0.63	0.74	2.10	2.34

EPS Revisions	Current Qtr. Dec 15	Next Qtr. Mar 16	Current Year Dec 15	Next Year Dec 16
Up Last 7 Days	0	0	0	0
Up Last 30 Days	0	0	0	1
Down Last 30 Days	0	0	0	1
Down Last 90 Days	N/A	N/A	N/A	N/A

Growth Est	POR	Industry	Sector	S&P 500
Current Qtr.	12.70%	-10.50%	47.40%	2.90%
Next Qtr.	17.70%	21.90%	49.80%	13.10%
This Year	-4.10%	13.00%	22.80%	2.60%
Next Year	12.00%	1.80%	8.00%	9.30%
Past 5 Years (per annum)	1.06%	N/A	N/A	N/A
Next 5 Years (per annum)	4.13%	7.67%	6.15%	4.91%
Price/Earnings (avg. for comparison categories)	19.09	8.46	19.13	19.73
PEG Ratio (avg. for comparison categories)	4.62	3.67	3.29	1.98

Westar Energy, Inc. (WR) - NYSE ★ Watchlist

44.52 **0.74(1.63%)** 1:46PM EST - NYSE Real Time Price

Analyst Estimates

Get Analyst Estimates for: GO

Earnings Est	Current Qtr. Dec 15	Next Qtr. Mar 16	Current Year Dec 15	Next Year Dec 16
Avg. Estimate	0.36	0.55	2.21	2.45
No. of Analysts	8.00	3.00	12.00	13.00
Low Estimate	0.28	0.47	2.09	2.38
High Estimate	0.41	0.65	2.25	2.55
Year Ago EPS	0.32	0.38	2.35	2.21

Next Earnings Date: Feb 24, 2016 - Set a Reminder

Revenue Est	Current Qtr. Dec 15	Next Qtr. Mar 16	Current Year Dec 15	Next Year Dec 16
Avg. Estimate	639.79M	644.23M	2.56B	2.68B
No. of Analysts	3	4	10	10
Low Estimate	596.50M	627.70M	2.43B	2.52B
High Estimate	720.14M	665.57M	2.65B	2.82B
Year Ago Sales	596.44M	590.81M	2.60B	2.56B
Sales Growth (year/est)	7.30%	9.00%	-1.40%	4.60%

Earnings History	Dec 14	Mar 15	Jun 15	Sep 15
EPS Est	0.35	0.43	0.42	1.03
EPS Actual	0.32	0.38	0.46	0.97
Difference	-0.03	-0.05	0.04	-0.06
Surprise %	-8.60%	-11.60%	9.50%	-5.80%

EPS Trends	Current Qtr. Dec 15	Next Qtr. Mar 16	Current Year Dec 15	Next Year Dec 16
Current Estimate	0.36	0.55	2.21	2.45
7 Days Ago	0.36	0.55	2.21	2.45
30 Days Ago	0.37	0.55	2.21	2.45
60 Days Ago	0.38	0.51	2.22	2.45
90 Days Ago	0.38	0.51	2.22	2.44

EPS Revisions	Current Qtr. Dec 15	Next Qtr. Mar 16	Current Year Dec 15	Next Year Dec 16
Up Last 7 Days	0	0	0	0
Up Last 30 Days	0	0	0	1
Down Last 30 Days	0	0	0	0
Down Last 90 Days	N/A	N/A	N/A	N/A

Growth Est	WR	Industry	Sector	S&P 500
Current Qtr.	12.50%	-10.50%	47.40%	2.90%
Next Qtr.	44.70%	21.90%	49.80%	13.10%
This Year	-6.00%	13.00%	22.80%	2.60%
Next Year	10.90%	1.80%	8.00%	9.30%
Past 5 Years (per annum)	17.44%	N/A	N/A	N/A
Next 5 Years (per annum)	3.50%	7.67%	6.15%	4.91%
Price/Earnings (avg. for comparison categories)	20.48	8.46	19.13	19.73
PEG Ratio (avg. for comparison categories)	5.85	3.67	3.29	1.98

RUCO-5
admitted

UNS ELECTRIC, INC.

DOCKET NO. E-04204A-15-0142

DIRECT TESTIMONY

OF

LON HUBER

ON

RATE DESIGN

ON BEHALF OF THE

RESIDENTIAL UTILITY CONSUMER OFFICE

DECEMBER 9, 2015

TABLE OF CONTENTS

INTRODUCTION

Q. Please state your name, position, employer and address.

A. Lon Huber. I am a Director at Strategen Consulting LLC located at 2150 Allston Way # 210, Berkeley, CA 94704.

Q. Please state your educational background and work experience.

A. My career in the energy industry began in 2007 when I started working at a research institute housed within the University of Arizona. In 2010, I became the governmental affairs staffer for TFS Solar, a solar photovoltaic ("PV") integration company based in Tucson. I was hired by Suntech America in 2011 where I led the company's regulatory and policy efforts in numerous US states until December 2012. In 2013 I served as a consultant for the Residential Utility Consumer Office ("RUCO") on energy issues. I joined RUCO as a full time employee in January 2014. Since March 2015 I have worked at Strategen Consulting where I continue to advise RUCO on energy policy matters.

I obtained a Bachelor of Science Public Administration degree in Public Policy and Management from the University of Arizona in 2009. I also received a Masters of Business Administration from the Eller College of Management at the same university.

A full resume is attached in Exhibit One.

Q. Please state the purpose of your testimony.

A. The purpose of my testimony is to present RUCO's analysis of UNS Electric, Inc.'s (UNSE) rate design proposal in their application for a permanent rate increase filed with the Arizona Corporation Commission ("ACC" or "Commission") on May 4, 2015. Additionally, I provide several recommendations of ways to improve UNSE's proposal and ensure that it is just and reasonable for all ratepayers. My testimony will focus primarily on rate design options that affect distributed generation customers, both present and future.

Q. Please state how you approached this subject matter.

A. To the extent possible, my analysis relies on data provided by UNSE or other reputable sources. On certain subjective policy issues I received direction and guidance from the Director of RUCO. I also relied on my expertise and experience from years working in academia, the solar industry, and as a consumer advocate in Arizona. The views and recommendations expressed in this testimony are reflective of my own views, developed in consultation with RUCO. However, these views do not reflect Strategen's overall approach to rate design policy here in Arizona or elsewhere.

OVERVIEW OF THE UNSE PROPOSAL

Q. Please provide a high-level overview of UNSE's rate design proposal as it relates to RUCO's interests.

A. UNSE proposes the following rate design changes for three important customer segments:

For traditional residential customers: UNSE is proposing to increase the fixed customer charge from $10 to $20. Additionally, the Company proposes to eliminate the third volumetric rate tier in the standard residential service. UNSE is also proposing to increase the fixed customer charge from $11.50 to $20 for residential time of use and residential time of use for super peak customers.

For a select group of business customers: The Company is recommending an Economic Development Rate containing a 5 year discount for certain customers that meet a state specified criteria and an equal to or higher than 75 percent load factor.

For distributed generation customers: The Company is proposing to create a special rate for distributed generation ("DG") customers with a 0.059 cent/kWh energy volumetric energy rate, $20 fixed charge, and a 24/7 demand charge (i.e. the demand charge is assessed based on the peak usage hour, regardless of the time of day or week) ranging from $6-9.95 per kW. Finally, all energy exported to the grid is compensated at a slightly lower volumetric rate of $0.0584 kWh. Existing customers that signed up before June 1, 2015 will be grandfathered into the current rate design.

Q. Why is the Company proposing these changes?

A. The main reasons provided by the Company are as follows:[1]

1. "To align rate structures with our customers' evolving energy use."
2. "To reduce the level of cross-subsidies between customers."
3. "To give the Company an appropriate opportunity to recover its fixed costs."

[1] Page 6 and 7 of Mr. Hutchens testimony

Q. Please comment on the appropriateness of these changes

A. **Residential Customer Changes:** For standard non-DG residential customers, RUCO understands the need for proper cost recovery, especially in a service territory with slow customer growth. However, RUCO also believes that there should be balance between the risk of cost recovery for utilities, the reward to the utility, and the preservation of conservation related price signals. Moreover, UNSE's proposal to increase the fixed customer charge by 100 percent does not reflect the principle of rate gradualism. Therefore, RUCO does not believe that the proposed changes to residential customer rates are appropriate.

Economic Development Rate: If the proposed Economic Development Rate ("ED Rate") is set at an incorrect or inappropriate level, then residential customers may end up paying for additional system costs that participants in the proposed ED Rate are able to avoid. Thus, RUCO is concerned about this rate and strongly believes that it should be modified to include provisions for cost containment as well as additional studies for determining the rate.

DG Customer Changes: For new DG customers, RUCO believes the Company's proposal is not appropriate because it lacks optionality for customers, may jeopardize Renewable Energy Standard and Tariff ("REST") compliance and does not provide proper price signals to customers. Finally, for current DG customers RUCO believes grandfathering should occur upon approval of the Company's application.

Q. Does RUCO have recommendations to improve upon the Company's proposal?

A. Yes, RUCO has several suggested modifications as well as new program features. I will attempt to provide as much detail as possible on those modifications while acknowledging that additional technical and programmatic details will need to be provided by the Company or other parties at a later date

RUCO'S RATE DESIGN RECOMMENDATIONS

Q. In preparing your recommendations what guidelines and principles did you follow?

A. After consulting with the director of RUCO, I developed these recommendations according to four core guidelines:

» Do not inhibit conservation related price signals
» Do not "rock the boat" for 98% of UNS ratepayers to accommodate 2 percent of DG adopters
» Establish rates that both provide more accurate price signals to DG customers and minimize the cost shift
» Create options for future solar customers

My recommendations are also based upon the following rate design principles as laid out by James C. Bonbright in his work, "Principles of Public Utility Rates," and summarized succinctly by NARUC:[2]

» "Simplicity, understandability, public acceptability and feasibility of application and interpretation
» Stability of rates themselves, minimal unexpected changes that are seriously adverse to existing customers
» Fairness in apportioning cost of service among different consumers
» Avoidance of "undue discrimination"
» Efficiency, promoting efficient use of energy and competing products and services"

[2]http://www.naruc.org/international/Documents/Tariff%20Development%20II%20Rate%20Design%20final%20draft%20ver%201%200.pdf

Q. Did you review the Company's Cost of Service Study ("COSS")?

A. Yes.

Q. Did you make any changes to the Company's Cost of Service Study?

A. No.

Q. What is a Cost of Service Study?

A. In very simple terms, a COSS is an estimation of cost-causation by customer class, i.e. how much does it cost the utility to provide its service to each specific customer class. The reason for determining the costs incurred by the utility to serve each customer class is to assist in allocating the revenue requirement for each customer class. For each type utility, there are several generally accepted methods for conducting a COSS. There is no one "correct" COSS method, but rather a range of reasonable alternatives. This is not to suggest that COSSs are arbitrary; some allocations are clearly more reasonable than others. This is the reason a COSS should only be used as a general guide and as one of several considerations in allocating revenue requirements and designing rates.

Q. Should the COSS be the sole factor used when developing a rate design?

A. No. The COSS should only be used as a general guide and as one of several considerations when designing rates.

Q. If RUCO did not rely solely on the COSS for developing rates, what other factors did RUCO consider?

A. In addition to using the results of the COSS as a general guideline, RUCO also considered factors such as promotion of efficient electricity usage, gradualism in rate increase to mitigate rate shock, and uniformity of rates between customer classes.

Q. How did RUCO use the COSS as a guide in its rate design?

A. RUCO utilized the COSS as a basic tool, starting point or first step in its rate design. However, due to the other factors cited above, RUCO also incorporated these changes into its rate design. (See Exhibit 3 for complete rate design schedules)

Q. Does RUCO have any other general recommendations for how UNSE should revise its proposal for residential customers?

A. Yes, UNSE should revise its residential time of use ("TOU") rate to better align the rate to peak system needs in the summer. The spread between off-peak and on-peak should be larger and more effort should be taken to market and attract customers to the rate.

Q. What features do you recommend retaining for standard residential customers?

A. The fixed customer charge should remain as low as possible to retain the connection between electricity consumption and customer costs. Also the third tier of the standard residential rate should remain to send conservation related price signals to high-energy users. RUCO does not see a compelling reason to increase the fixed charge 100 percent nor eliminate the third tier. Both of these changes would increase costs for customers who use less energy. These concepts are important as UNSE looks to become more energy efficient, following the Commission's energy efficiency priorities and in preparation for possible EPA 111(d) compliance.

Q. Would RUCO be open to increasing the fixed customer charge?

A. No. RUCO believes that constant upward pressure on the fixed charge will start to erode price signals embedded in rates for policy reasons. That said, in this case, RUCO would be willing to entertain the concept of a minimum residential customer bill at a higher rate than the RUCO proposed fixed charge.

Q. What is a minimum Bill?

A. A minimum bill guarantees that UNSE will collect a basic amount of revenue if a customer's usage drops below a certain amount. It accomplishes many of the objectives of a fixed charge but without reducing energy or demand based price signals. In other words, it only looks like a fixed charge for customers with low usage. For customers with sufficient usage to overcome the minimum bill amount, there would no additional fixed charge line item on their bill.

Q. What are your recommendations regarding the Economic Development Rate?

A. This discount for qualified businesses has some merit; however, there must be some safe guards built in for the non-participating ratepayers that are helping to cover the cost of the discount. First, there must be a cap on the overall cost of the discount. RUCO recommends a total program cost cap of $3 million dollars. Second, customers receiving the discount must meaningfully participate in Demand Side Management ("DSM") programs to lower peak demand needs. The ED Rate purports to benefit non-participating customers by increasing UNSE's total kWh sales over which system costs are spread. However, this only holds true if system costs do not also increase as a result of this increased demand. Finally, a study must be conducted into the system wide benefits of this program as well as the local economic benefits within three years from approval.

Q. Can RUCO support the Economic Development Rate without these provisions?

A. No. There is not enough information related to potential costs. In addition to the subsidy costs, RUCO does not want this program to add additional costs by driving more peak summer resource needs.

Q. What are your suggestions for Non-DG customers?

A. Please see Exhibit 2 for RUCO's recommended rates based on the Company's current rate structure, which is based on traditional rate design. Exhibit 3 is RUCO's typical residential bill analysis which shows the impacts of UNSE's current rates v. RUCO's proposed rates on residential ratepayers. RUCO has utilized the existing rate structure, allocated the percentage of revenue to each customer class based on the Company's proposed rate design, and modified the current charges to account for the elements RUCO believes should be included in the rate design.

Q. What are your recommendations regarding DG customers?

A. It can be argued that UNSE's rates are in need of modernization, especially in light of the proliferation of DG options for consumers. However, RUCO believes that UNSE's proposal for DG customers can be improved. Moreover, RUCO believes that it is possible to create a "win-win" from new advances in technology for both customers and the utility by creating options for DG and non-DG customers alike. We believe any rate design changes specific to DG customers should carefully consider unintended consequences especially given the fact that 98 percent of ratepayers in UNSE territory do not employ solar DG. As such RUCO's aim is to find a middle path that matures the rooftop solar industry while ensuring fairness for all ratepayers, balances cost-recovery with pro-conservation price signals, and which eschews the imperfect proposal proposed by UNSE. I provide three options for DG customers.

1. A non-export option.
2. An advanced DG TOU Rate.
3. Renewable Portfolio Standard ("RPS") bill credit arrangement tied to compliance.

	Non-Export Option	**Adv. DG TOU Option**	**RPS Bill Credit Option**
Rate Option:	Customer can select any of UNSE's traditional rates	Three part rate: • Minimum bill - $12 • Base Energy Rate ($0.085/kWh) • TOU Demand ($19.50/kW, 2-8pm summer peak) • Customer must be on rate for full calendar year so they do not gain the benefit of lower costs during winter but avoid higher costs during summer.	Customer can select any of UNSE's traditional rates
Export Rate:	No export of excess power to grid, therefore, no month to month carryover and no grandfathering is required. RUCO may also be open to having instantaneous exports be paid at wholesale rates.	Export rate of excess power to grid, for customers who exchange Renewable Energy Credits ("RECs") with UNSE, is $8.5 cents/kWh. For customers who does not exchange RECs with UNSE, the export rate is the Market Cost Comparable Conventional Generation ("MCCCG") rate.	Credit rate decrease over time, based on increased renewable energy capacity added to the UNSE's energy portfolio. The rate would start at 11 cents/kWh and go no lower than MCCCG rate. This credit rate would be locked in for a 20 year term. In order for a customer to take advantage of this rate, the customer would have to exchange RECs with UNSE

Q. How does RUCO propose a customer would select their plan and how would a change of plan be handled?

A. RUCO proposes that each of the DG options would be available to a new DG customer to select as their plan option at their DG install. There would be no mandatory plan or opt-out style plan. Some restrictions do apply, such as a customer who does not exchange their RECs with UNSE are no allowed to be on the RPS Bill Credit option. Additionally, customers who select the Advanced DG TOU option will need to remain on the plan for a full calendar year to avoid gaming the benefits of no demand charges during the winter while dodging the demand charge during the summer. Customers will also have the option to switch from plan to plan on an annual basis.

Q. Do these options solve all of RUCO's concerns with DG?

A. No, but RUCO fully acknowledges that subsides exist throughout our current regulated system and rate designs. These should be routinely quantified, reexamined, and debated. The existence of such cross subsidies should not mean we should ignore new ones that are fast growing. At the same time, it should not mean we must be overly zealous focusing on just one cross-subsidy when there may be larger subsidies elsewhere. RUCO would like to see incremental and gradual progress to sending more accurate price signals to customers, especially those that drive certain cost increases or decreases. In terms of DG, 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.

Q. Please describe the non-export option.

A. The non-export option simply does not allow a DG customer to export his/her generation; however, the customer can chose to be on any residential rate available to them. This option is intended to treat DG adopters in the same manner as a traditional customer. It gives DG customers the ability to reduce load behind the meter but restricts the export of electrons onto the grid. This reflects the fact that non-DG customers are distinct from DG customers since they generally do not engage in two way power flow. Moreover, there will not be any grandfathering, as is the case for the vast majority of residential customers. This offering allows solar adopters access to the same rate plans and charges of the traditional residential customer. Inadvertent exports would be kept to a reasonable minimum and not be compensated. Restricting power to the grid would be accomplished primarily through inverter curtailment. Alternatively, if the Commission believes that providing an option where a customer volunteers to restrict exports is not agreeable, RUCO may also be open to having instantaneous exports be paid at wholesale rates.

While RUCO is concerned that the retail rate may over compensate DG adopters during self-consumption, it is in the spirit of fairness to allow DG customers access to the standard rate. Moreover, RUCO anticipates that residential rates will gradually start to change in the future and become more time variant (hence our call for a more advanced TOU rate). As solar penetration increases, daytime energy may become less valuable and peak times may shift into the night. Thus, the retail rate may not be a good approximation of value; however, in the spirit of gradualism and avoiding undue discrimination RUCO recommends that this option be extended to future DG customers at this time.

Q. Please describe the "DG TOU Rate".

A. It is a three part rate, with the energy and TOU demand components intended to recover fixed costs. The three components of this rate are 1) A minimum bill 2) A Variable per kWh energy Charge and 3) a variable per kW Demand Charge covering over peak hours during summer months. The starting point for designing the DG TOU Rate was to approximate the value of south facing fixed tilt PV on the UNSE system. Absent a Commission policy in this regard, I performed a basic calculation of the cost of the next marginal unit of generation needed for the UNSE system while still acknowledging the uniqueness and intermittency of solar PV. I set this value as the base energy rate for the plan. I then created a TOU demand charge to send accurate on-peak price signals to the DG adopter while allowing for cost recovery by the company if the customer fails to reduce peak demand.

Q. Why did you feel that a special rate was necessary for DG adopters?

A. Customers with distributed generation are significantly different than traditional customers and customers that engage in energy efficiency. DG customers can:

- Mask load and their true demand for power, which is later revealed during certain times and weather conditions
- Export electrons to the distribution system
- Come in and out of needing service unlike those deploying energy efficiency measures
- Completely erase a monthly bill even when using the full suite of utility services

Q. Could this rate become available to non-DG customers?

A. The rate was designed to send accurate price signals to reduce peak summer usage. Therefore, RUCO believes that a rate such as the one being proposed can be open to other customers. Nevertheless, since this is a new rate merging different concepts together for the first time in UNSE territory, RUCO would like to place a limit on the total number of non-DG customers that engage with the rate. Therefore, a pre-specified number of customers, including those directly linked to DSM programs should be able to participate.

Q. What is a demand charge?

A. A demand charge is a mechanism for billing customers based on their peak energy usage. It is determined by multiplying a demand rate (typically expressed in $/kW) by the highest level of power drawn by the customer (often measured over the course of one hour or 15 minutes). The highest demand over a predetermined time period (e.g. afternoon peak hours of a summer month) is used for the calculation

Q. Does RUCO support demand charges for general residential customers?

A. At this point in time, RUCO firmly believes that if demand charges are implemented they should be optional for standard residential customers. RUCO also believes that such a demand charge should be limited to a window of peak usage and only to be used seasonally during those months where demand is highest. RUCO believes that it is very easy to inappropriately design demand charges, making them essentially unavoidable fixed charges that do not drive down system cost. It is far easier to design a flat demand charge, as the Company proposes, than to create a demand charge that fairly and accurately sends price signals to customers. Under UNSE's proposal, the demand charges associated with a high power draw at 3:00 am in March would be the same as a high power draw at 6:00 PM in July. This does not provide an accurate price signal to customers of system costs and reflects a poorly designed demand charge.

RUCO also believes that demand charges should only be offered in conjunction with the utility's commitment to develop and expand tools and education programs that will help customers mitigate demand. RUCO would like UNSE to commit to providing customers with these tools in their next DSM plan. This should include a commitment by UNSE to develop and propose integrated energy efficiency and demand response programs, such as those offerings discussed in the Commission's workshops on technology and innovation.

Q. **Please describe RUCO's view on grandfathering existing solar customers.**

A. RUCO thinks there are very few good choices with regard to grandfathering. Those customers that installed DG before either UNSE issued disclaimers or the conclusion of the REST incentive program should undoubtedly be grandfathered into their current rates. These customers were encouraged to go solar through Commission approved incentives and the utilities desire to meet its Renewable Energy Standard ("RES") requirements. However, since that time customers have been warned about the possibility of changes to utility rates that may adversely affect a solar PV system's economic value proposition. Nonetheless, RUCO believes that these customers may not fully understand the magnitude of the negative impact to this value proposition that may come from a rate redesign. Therefore, RUCO accepts the argument that customers between now and the conclusion of the rate case should be grandfathered into their existing rates. RUCO proposes that grandfathering extend for a 20 year term minus the number of years the system has been interconnected.

Q. How would this grandfathered rate work?

A. Customers on this rate would have the volumetric energy rate portion of the bill locked in at today's level. All other reasonable charges and adjusters would correspond directly with the standard residential rate.

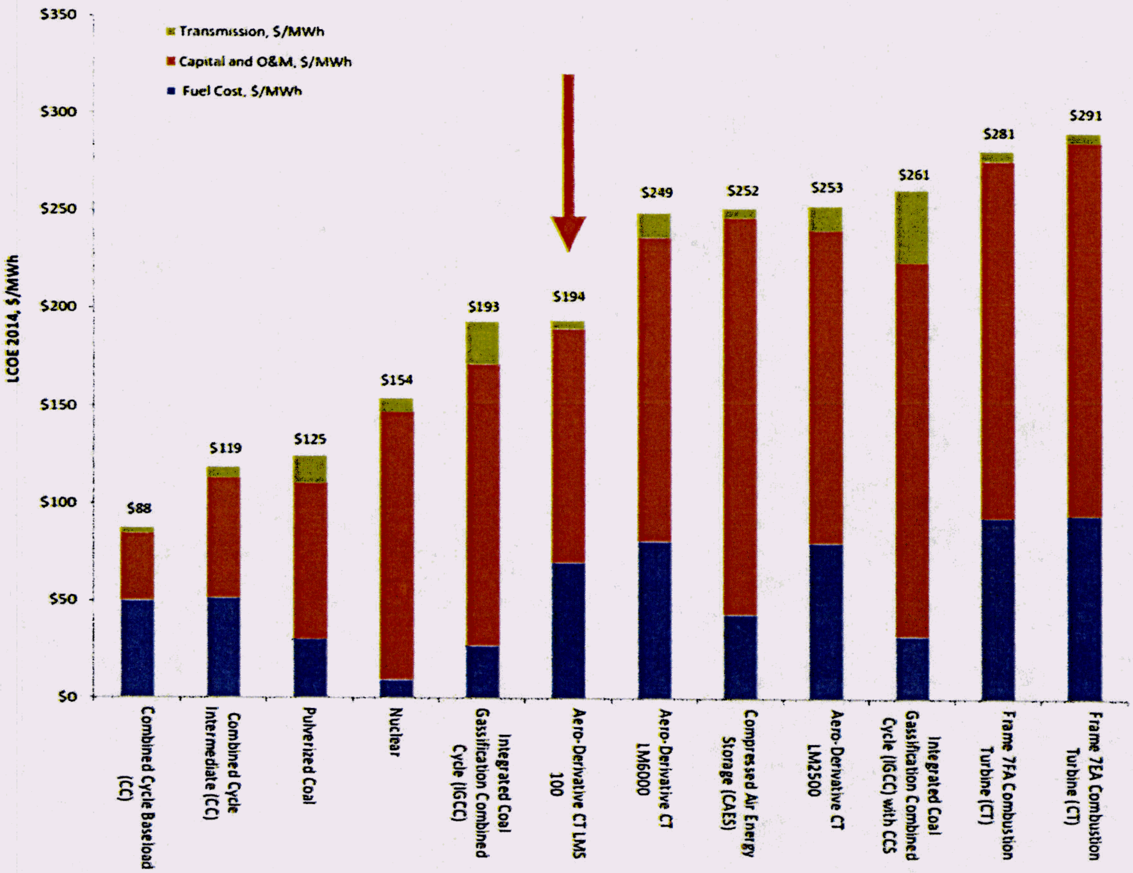
Q. Please describe in more detail how you determined the volumetric energy rate level in the rate.

A. The volumetric energy rate was determined based on an estimation of UNSE's avoided cost of generation in $/kWh. I examined the UNSE 2014 IRP plan and accessed Company provided data to understand system cost drivers and the next marginal unit of generation needed to meet system needs. Within the Integrated Resource Plan ("IRP") the Company highlights the need for a new combustion turbine (CT) in 2019. The Company notes that the levelized cost of energy ("LCOE") is 19.4 cents/kWh for a new CT. However, this value is based on the operating characteristics of a CT unit, which are not perfectly analogous to operating characteristics of Solar PV. According to the Company the capacity value of fixed tilt PV is approximately 33 percent with a corresponding capacity factor of 19 percent. Typical capacity factors for CT units range from 8 percent to 18 percent.

While CT's fairly represent the marginal costs for system capacity, they are not necessarily indicative of marginal costs for power generation (excluding fuel) from an energy-centric resource like a combined cycle natural gas unit (CCGT). Since solar PV's capacity factor is higher than a typical CT unit, it can be considered more of an energy-centric resource, akin to a CCGT. With these considerations, I computed the non-fuel energy costs (LCOE at 33 percent capacity value) of a CT (~12.9 cents/kWh). Meaning with enough PV, UNSE may be able to downsize or defer investment in a new centralized generation facility. I then relied on the Company's MCCCG calculation for the avoided energy rate.[3]

This exercise yielded an 8.5 cent/kWh rate. I took this figure to set the energy rate for the rate plan. Losses may also have to be taken into account if the Company did not include them in their LCOE and MCCCG calculations. RUCO is also open to Company suggestions on how to include kWh based adjusters to the rate in the most administratively efficient way to ensure the figure is as close to 8.5 cent/kWh as possible.

[3] http://images.edocket.azcc.gov/docketpdf/0000162403.pdf

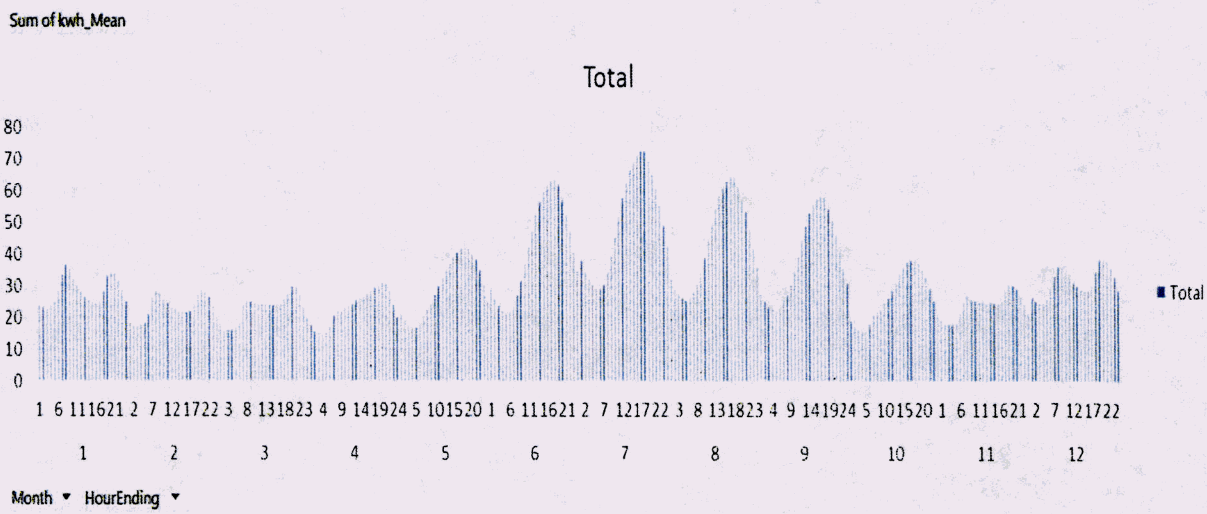


Q. How detailed was your analysis on Value and Cost of DG?

A. As there is no official Commission position or guidance on this issue and due to the fact that many of the possible cost-benefit categories are speculative in nature, rely on policy decisions, are nearly impossible to quantify, and may not have a significant impact on the final total, RUCO has taken a conservative approach and will be looking only at the major categories of benefits. In addition, RUCO believes that many of hard to quantify environmental and societal benefits are captured in the preferential treatment given to resources like solar energy. Treatment such as procurement not tied directly to demand driven need, fixed payments based on future levelized amounts, and the avoidance of any cost effectiveness tests like energy efficiency measures undergo, are examples of this preferential treatment.

Q. How did you determine the timing of the demand change?

A. Once I arrived at the figure for the levelized energy value of south facing fixed tilt PV the remaining part of the rate was fitted with a demand charge. I first took a look at overall energy and demand on the UNSE system.



As one can see from the chart above, UNSE is a summer peaking system, with peaks occurring primarily in the months from May to October. I determined the peak hours of demand for each of these months since 2011. After examining these data, it appears that the hours between 2:00 PM to 8:00 PM capture all of the top 5 percent of demand hours.

Q. How does this correspond to existing UNSE TOU offerings?

A. The months and hours I chose also correspond to what the Company current outlines for TOU based rates.

Q. Are there other details you would like to share about the DG TOU rate?

A. Yes, the demand charge would be determined by averaging the top three hours of demand occurring during each summer month from 2:00 PM to 8:00 PM. Also, I propose a minimum bill to recover customer related charges. RUCO initially proposes $12 to match the residential rate; however, given that a minimum bill has different dynamics than a fixed charge, RUCO would consider slightly increasing the minimum bill upwards. Finally, if a customer does not exchange renewable energy credits ("RECs") with the utility any excess monthly credits would be compensated at the MCCCG rate. This lower rate reflects the fact that UNSE may not be getting "green" energy from DG customers if the rights to that claim have already been sold or exchanged away to other states or companies.

Q. What if neither the non-export option nor the DG TOU rate is sufficient to spur DG adoption?

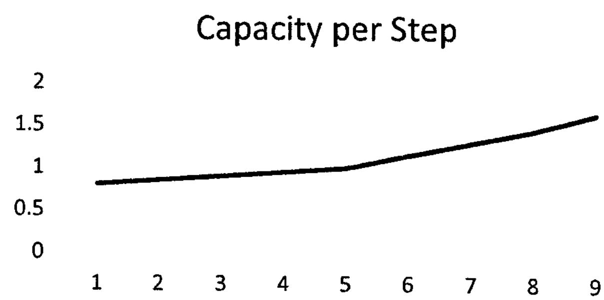
A. RUCO recognizes the DG carve-out policy put forward by the Commission to encourage residential distributed generation. With this in mind, RUCO believes that a straightforward and simple procurement mechanism be created to ensure REST compliance. This provides a third potential option as mentioned above.

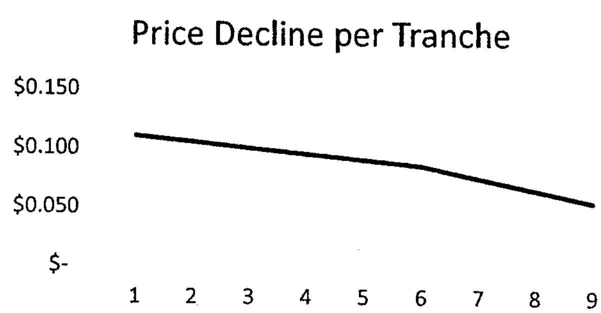
Q. Please describe the RPS credit option for DG customers?

A. It is a simple fixed crediting mechanism for the output of a PV system that is linked to a specific REST procurement target. Based on the 2016 UNSE REST implementation plan, it appears that around 10 MW of residential DG is needed to meet the Commission's 2025 goal. This amount may fluctuate depending on the number of systems installed by the end of this rate case and whether the Commission recognizes systems that have not exchanged their RECs. Exhibit 2 shows these basic calculations.

The crediting mechanism would operate much like the declining up-front incentive system the Commission used a few years ago. The credit would start at a set rate (RUCO proposes 11 cents/kWh) and would gradually decline in a predictable manner as installs increase over time. Below is an illustration of the concept and the step downs RUCO proposes:

Capacity per Tranche	Price per Tranche	
0.79406351	$	0.110
0.84369248	$	0.105
0.893321449	$	0.100
0.942950418	$	0.095
0.992579388	$	0.090
1.141466296	$	0.085
1.290353204	$	0.075
1.439240112	$	0.065
1.63775599	$	0.055





To avoid grandfathering issues and to facilitate financing, the credit rate would be fixed for 20 years. The system would be fully metered and a bill credit would be applied to a customer's bill every month. In other words, the customer's underlying rate design would not impact the economics of the transaction.

The Company would have the flexibility in each year's REST plan to recommend and adjust the terms and payment of future customers. This could include increasing the payment based on inverter capabilities or orientation of the system. Additionally, all RECs would need to be surrendered to UNSE in order to participate in this option.

Q. How would this option interface with the DG TOU rate?

A. If solar capacity is installed under the standalone DG TOU Rate (i.e. without the RPS credit), that capacity would also count towards the capacity for the REST and contribute to the step downs in the RPS credit rate. In sum, the more solar capacity that comes online, the lower the RPS credit rate for new customers.

Q. What is RUCO's anticipated ratepayer acceptance of each of the DG rate options?

A. RUCO believes that the most popular rate, at least in the beginning, will be the RPS Bill Credit option. This option provides a bridge for the industry to use in preparation for using the TOU DG Rate. With the credit rate set at $0.11/kWh and declining as additional DG capacity comes on the grid, this option most closely mirrors that of current rate design.

Customers with more sophistication and tools to control their peak loads will likely immediately select the DG TOU option. Thus, it allows the solar industry to further mature by being optional and not forcing users to be on the rate now. The solar industry will have the option of crafting tools and business plans around the advanced DG TOU, which may turn out to be more advantageous to their customers than either of the other options.

One of the benefits of the DG TOU option is that it essentially creates a floor for the offset rate of DG customers. As most DG customers in the beginning will likely choose to be on the RPS Bill Credit, and as the DG capacity hits the threshold that makes the credit rate less than the offset rate on the Advanced DG TOU ($8.5 cents/kWh), the industry can rely on the certainty provided by the Advanced DG TOU option and maintain an offset rate of $8.5 cents/kWh.

The Non-Export Option is a rate that will likely not be very popular among DG customers. This rate was designed after concurring with DG advocates who have insisted that DG customers "not be treated differently." The Non-Export option provides exactly that.

CONCLUSION

Q. Any concluding comments?

A. I believe that the rate design proposals put forward in this testimony provides benefits for all parties. Standard residential customers will see little change and hopefully will be able to take advantage of an improved TOU rate. DG customers are given three different options depending on their level of sophistication. The solar industry is able to continue selling by utilizing the RPS credit option if other options do not make economic sense at this point in time. Moreover, companies that innovate have clear price signals for how to adapt their product offerings to help customers save money on the non-export and DG TOU options. The Company's concern about fixed costs losses from DG is minimized and subsides are now more transparent.

Q. Does your silence on any of the issues, matters or findings addressed in the testimony of UNS witnesses for UNSE constitute your acceptance of their positions on such issues, matters or findings?

A. No, it does not.

Q. Does this conclude your testimony?

A. Yes it does.

EXHIBIT 1

Lon Huber
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lonmhuber@gmail.com

EDUCATION

January 2010 – May 2011
Eller College of Management - University of Arizona
Masters of Business Administration (MBA)

August 2005 – May 2009
School of Government & Public Policy - University of Arizona
Bachelor of Science - Public Policy and Management

RELEVANT WORK EXPERIENCE

Strategen Consulting
Director –March 2015 to present

Arizona's Residential Utility Consumer Office (RUCO)
Special Projects Advisor and former consultant – April 2013 to March 2015
- Responsibilities: policy analysis and design, advocacy, case testimony, constituent outreach, and financial analysis.
    - Team lead on net metering, utility-owned rooftop solar, and new resource procurement policies.

Suntech America
Manager, Regional Policy – September 2011 to December 2012
- Point person for the company in every key state solar market except California.
    - Worked to balance cost effective utility-scale solar with state distributed generation policy goals.
    - Elected by SEIA member companies to be the state lead in Arizona.

TFS Solar
Government Affairs – September 2010 to September 2011
- Created a solar financing program for faith based organizations in Tucson.
- Instrumental in forming the Southern Arizona Solar Standards Board.
- Advocated for polcies in front of ACC.

Arizona Research Institute for Solar Energy at the University of Arizona
"Founding employee" and Policy Program Associate – August 2007 to September 2010
- Helped build the institute while gaining experience with the technical attributes and challenges of various energy technologies.

Lon Huber
928-380-5540
lonmhuber@gmail.com

Congressional Fellow – D.C.

January 2009 to May 2009

- Responsibilities included weekly memos to the Congress member on energy issues, forming energy related legislation (Solar Schools Act - H.R. 4967), and creating educational presentations on energy.

COMMUNITY INVOLVEMENT

- Appointed to the Arizona Governor's Solar Task Force, 2013
- Chairman - Southern Arizona Regional Solar Partnership at the Pima Association of Governments, 2011
- Founding Chairman - University of Arizona Green Fund, 2010 to 2011
- Member of UA President's Campus Sustainability Advisory Board, 2008 to 2011
- Big Brother for a child in special needs program - Tucson Big Brothers Big Sisters, 2006 to 2008

AWARDS AND HONORS

- *Arizona Daily Star's* "40 Under 40" winner for leadership, community impact, and professional accomplishment, 2011
- University of Arizona Honors College Young Alumni Award Winner, 2011
- Outstanding Professional Staff Member – University of Arizona, 2010
- Arizona Foundation Outstanding Senior Award for the Eller College of Management, 2009
- Honors College Pillars of Excellence Award, March 2009
- Congressional Recognition Award, May 2008

EXHIBIT 2

Monthly Usage Charge	Present	Company Proposed Rates	RUCO Recommended Rates
Residential Service CARES			
Customer Charge	$ 4.900000	$ 9.000000	$ 5.903457
Energy Charge 1st 400 kWhs	0.018973	0.030810	0.028338
Energy Charge, all additional kWhs	0.035400	0.050810	0.052873
Base Power Supply Charge, all kWhs	0.064510	0.049260	0.049260
PPFAC	(0.003488)	varies monthly	varies monthly
Residential Service			
Customer Charge	10.000000	20.000000	12.258241
Energy Charge 1st 400 kWhs	0.019300	0.030810	0.030972
Energy Charge 401-1,000 kWhs	0.034350	0.050810	0.055124
Energy Charge, all additional kWhs	0.038499	0.050810	0.061782
Base Power Supply Charge, all kWhs	0.061700	0.049260	0.049260
PPFAC	(0.003488)	varies monthly	varies monthly
Residential Time of Use Rates, all kWhs			
Customer Charge	11.500000	20.000000	13.630412
Energy Charge 1st 400 kWhs	0.030350	0.030810	0.045098
Energy Charge 401-1,000 kWhs	0.030350	0.050810	0.045098
Energy Charge, all additional kWhs	0.030350	0.050810	0.045098
Base Power Supply Charge, all kWhs			
Summer On-peak, kWh	0.129605	0.101110	0.101110
Summer Off-peak, kWh	0.039605	0.033900	0.033900
Winter On-peak, kWh	0.129605	0.098960	0.098960
Winter Off-peak, kWh	0.031385	0.033579	0.033579
PPFAC Charges			
Summer On-peak, kWh	(0.003488)	varies monthly	varies monthly
Summer Off-peak, kWh	(0.003488)	varies monthly	varies monthly
Winter On-peak, kWh	(0.003488)	varies monthly	varies monthly
Winter Off-peak, kWh	(0.003488)	varies monthly	varies monthly
Residential Time of Use Rate Super Peak, all kWhs			
Customer Charge	11.500000	20.000000	14.002216
Energy Charge 1st 400 kWhs	0.025000	0.030810	0.045934
Energy Charge, all additional kWhs	0.035000	0.050810	0.052816
Base Power Supply Charge, all kWhs			
Summer On-peak, kWh	0.170000	0.149700	0.149700
Summer Off-peak, kWh	0.039700	0.038250	0.038250
Winter On-peak, kWh	0.150000	0.149700	0.149700
Winter Off-peak, kWh	0.038700	0.038250	0.038250
PPFAC Charges			
Summer On-peak, kWh	(0.003488)	varies monthly	varies monthly
Summer Off-peak, kWh	(0.003488)	varies monthly	varies monthly
Winter On-peak, kWh	(0.003488)	varies monthly	varies monthly
Winter Off-peak, kWh	(0.003488)	varies monthly	varies monthly
Residential Service Bright Arizona Community Solar			
Customer Charge	10.000000	20.000000	11.908582
Energy Charge 1st 400 kWh	0.019300	0.030810	0.022984
Energy Charge 401 -7,500 kWh	0.034350	0.050810	0.040906
Energy Charge >7,500 kWh	0.038499	0.050810	0.045847
Base Power Supply Charge, all kWhs	0.084510	0.069260	0.069260
PPFAC	(0.003488)	varies monthly	varies monthly
DG TOU Rate			
Customer Minimum Bill			12.25000
Demand Charge per kW (May to Oct. 2:00 to 8:00 PM)			19.50000
Energy Charge. kWh			0.08500

EXHIBIT 3

Monthly Usage Charge	Present	Company Proposed Rates	RUCO Recommended Rates
Residential Service CARES			
Customer Charge	$ 4.900000	$ 9.000000	$ 5.903457
Energy Charge 1st 400 kWhs	0.018973	0.030810	0.028338
Energy Charge, all additional kWhs	0.035400	0.050810	0.052873
Base Power Supply Charge, all kWhs	0.064510	0.049260	0.049260
PPFAC	(0.003488)	varies monthly	varies monthly
Residential Service			
Customer Charge	10.000000	20.000000	12.258241
Energy Charge 1st 400 kWhs	0.019300	0.030810	0.030972
Energy Charge 401-1,000 kWhs	0.034350	0.050810	0.055124
Energy Charge, all additional kWhs	0.038499	0.050810	0.061782
Base Power Supply Charge, all kWhs	0.061700	0.049260	0.049260
PPFAC	(0.003488)	varies monthly	varies monthly
Residential Time of Use Rates, all kWhs			
Customer Charge	11.500000	20.000000	13.630412
Energy Charge 1st 400 kWhs	0.030350	0.030810	0.045098
Energy Charge 401-1,000 kWhs	0.030350	0.050810	0.045098
Energy Charge, all additional kWhs	0.030350	0.050810	0.045098
Base Power Supply Charge, all kWhs			
Summer On-peak, kWh	0.129605	0.101110	0.101110
Summer Off-peak, kWh	0.039605	0.033900	0.033900
Winter On-peak, kWh	0.129605	0.098960	0.098960
Winter Off-peak, kWh	0.031385	0.033579	0.033579
PPFAC Charges			
Summer On-peak, kWh	(0.003488)	varies monthly	varies monthly
Summer Off-peak, kWh	(0.003488)	varies monthly	varies monthly
Winter On-peak, kWh	(0.003488)	varies monthly	varies monthly
Winter Off-peak, kWh	(0.003488)	varies monthly	varies monthly
Residential Time of Use Rate Super Peak, all kWhs			
Customer Charge	11.500000	20.000000	14.002216
Energy Charge 1st 400 kWhs	0.025000	0.030810	0.045934
Energy Charge, all additional kWhs	0.035000	0.050810	0.052816
Base Power Supply Charge, all kWhs			
Summer On-peak, kWh	0.170000	0.149700	0.149700
Summer Off-peak, kWh	0.039700	0.038250	0.038250
Winter On-peak, kWh	0.150000	0.149700	0.149700
Winter Off-peak, kWh	0.038700	0.038250	0.038250
PPFAC Charges			
Summer On-peak, kWh	(0.003488)	varies monthly	varies monthly
Summer Off-peak, kWh	(0.003488)	varies monthly	varies monthly
Winter On-peak, kWh	(0.003488)	varies monthly	varies monthly
Winter Off-peak, kWh	(0.003488)	varies monthly	varies monthly
Residential Service Bright Arizona Community Solar			
Customer Charge	10.000000	20.000000	11.908582
Energy Charge 1st 400 kWh	0.019300	0.030810	0.022984
Energy Charge 401 -7,500 kWh	0.034350	0.050810	0.040906
Energy Charge >7,500 kWh	0.038499	0.050810	0.045847
Base Power Supply Charge, all kWhs	0.084510	0.069260	0.069260
PPFAC	(0.003488)	varies monthly	varies monthly
Small General Service			
Customer Charge	14.500000	30.000000	16.987627
Energy Charge 1st 400 kWh	0.030176	0.039497	0.041829
Energy Charge 401 -7,500 kWh	0.041042	0.049497	0.056891
Energy Charge >7,500 kWh	0.076042	0.086950	0.105406
Base Power Supply Charge, all kWhs	0.058241	0.048610	0.048610
PPFAC	(0.003488)	varies monthly	varies monthly
Small General Service Time of Use Rates, all kWhs			
Customer Charge	16.500000	30.000000	19.641237
Energy Charge 1st 400 kWh	0.030176	0.039497	0.035921
Energy Charge 401 -7,500 kWh	0.043176	0.049497	0.051396
Energy Charge >7,500 kWh	0.076042	0.086950	0.090519
Base Power Supply ChargeS			
Summer On-peak, kWh	0.129605	0.126510	0.126510
Summer Shoulder-peak, kWh	-	-	-
Summer Off-peak, kWh	0.039605	0.033010	0.033010
Winter On-peak, kWh	0.129605	0.108510	0.108510
Winter Off-peak, kWh	0.031385	0.032910	0.032910
PPFAC Charges			
Summer On-peak, kWh	(0.003488)	varies monthly	varies monthly
Summer Off-peak, kWh	(0.003488)	varies monthly	varies monthly
Winter On-peak, kWh	(0.003488)	varies monthly	varies monthly
Winter Off-peak, kWh	(0.003488)	varies monthly	varies monthly
Medium General Service			
Customer Charge	50.000000	100.000000	46.260193
Demand Charge, per kW	12.810000	13.050000	11.851862
Energy Charge (kWhs)	0.005470	0.005500	0.005061

Base Power Supply Charge, all kWhs	0.056603	0.048440	0.044817
PPFAC	(0.003488)	varies monthly	varies monthly
Medium General Service TOU			
Customer Charge	52.000000	100.000000	50.483189
Demand Charge, per kW	12.810000	13.050000	11.898142
Energy Charge (kWhs)	0.005470	0.005500	0.005081
Base Power Supply Charge, all kWhs	-	-	-
Summer on-peak	0.114886	0.109900	0.109900
Summer off-peak	0.039886	0.033500	0.033500
Winter On-peak, kWh	0.114886	0.089900	0.089900
Winter Off-peak, kWh	0.026168	0.031600	0.031600
PPFAC Charges	(0.003488)	varies monthly	varies monthly
Large General Service			
Customer Charge	50.000000	300.000000	287.169328
Demand Charge, per kW	12.810000	12.960000	11.235704
Energy Charge (kWhs)	0.005470	0.005400	0.005169
Base Power Supply Charge, all kWhs	0.041880	0.048400	0.048400
PPFAC	(0.003488)	varies monthly	varies monthly
Large General Service TOU			
Customer Charge	52.000000	300.000000	287.169328
Demand Charge, per kW	12.810000	12.960000	11.581248
Energy Charge (kWhs)	0.005470	0.005400	0.004826
Base Power Supply Charge, all kWhs			
Summer on-peak	0.114886	0.145510	0.145510
Summer off-peak	0.039886	0.034510	0.034510
Winter On-peak, kWh	0.114886	0.124510	0.124510
Winter Off-peak, kWh	0.026168	0.032910	0.032910
PPFAC Charges			
Summer On-peak, kWh	(0.003488)	varies monthly	varies monthly
Summer Off-peak, kWh	(0.003488)	varies monthly	varies monthly
Winter On-peak, kWh	(0.003488)	varies monthly	varies monthly
Winter Off-peak, kWh	(0.003488)	varies monthly	varies monthly
Large Power Service (<69KV)			
Customer Charge <69 kV	1,200.000000	300.000000	287.169328
Customer Charge >69 kV	1,200.000000	1,200.000000	1,148.677312
Demand Charge <69kV, per kW	22.000000	12.960000	11.581248
Demand Charge >69kV, per kW	17.000000	12.480000	11.946244
Energy Charge (kWhs) <69 kV	0.000462	0.005400	0.004826
Energy Charge (kWhs) >69 kV	0.000462	0.000520	0.000498
Base Power Supply Charge, all kWhs <69 kV	0.041880	0.048400	0.048400
Base Power Supply Charge, all kWhs >69 kV	0.048410	0.048410	0.048410
PPFAC <69kV Summer	(0.003488)	varies monthly	varies monthly
PPFAC <69kV Winter	(0.003488)	varies monthly	varies monthly
PPFAC >69kV Summer	(0.003488)	varies monthly	varies monthly
PPFAC >69kV Winter	(0.003488)	varies monthly	varies monthly
Large Power Service (>69KV) TOU			
Customer Charge	1,200.000000	1,200.000000	1,148.677312
Demand Charge <69kV, per kW	22.000000	12.960000	11.581248
Demand Charge >69kV, per kW	17.000000	12.480000	11.946244
Energy Charge (kWhs)	0.000462	0.000462	0.004826
Base Power Supply Charge, all kWhs			
Summer on-peak	0.122510	0.145510	0.145510
Summer off-peak	0.032110	0.034510	0.034510
Winter on-peak	0.092110	0.124510	0.124510
Winter off-peak	0.030910	0.032910	0.032910
PPFAC Charges			
Summer On-peak, kWh	(0.003488)	varies monthly	varies monthly
Summer Off-peak, kWh	(0.003488)	varies monthly	varies monthly
Winter On-peak, kWh	(0.003488)	varies monthly	varies monthly
Winter Off-peak, kWh	(0.003488)	varies monthly	varies monthly
LARGE POWER SERVICE MINING			
Customer Charge	1,200.000000	-	-
Demand Charge, per kW	17.000000	-	-
Energy Charge (kWhs)	0.000462	-	-
Power Factor Adjustment	-	-	-
Base Power Supply Charge, all kWhs	0.041880	-	-
PPFAC	(0.003488)	varies monthly	varies monthly
Interruptible Power Service			
Customer Charge	18.000000	75.000000	18.343444
Demand Charge, per kW	5.000000	6.520000	5.234311
Energy Charge (kWhs)	0.019408	0.019790	0.020318
Base Power Supply Charge, all kWhs	0.043760	0.049821	0.049821
PPFAC	(0.003488)	varies monthly	varies monthly
Lighting Dusk to Dawn			
New 30' Wood Pole (Class 6) - Overhead	4.340000	4.680000	4.759514
New 30' Metal or Fiberglass - Overhead	8.660000	9.350000	9.497095
Existing Wood Pole - Underground	2.180000	2.350000	2.390724
New 30' Wood Pole (Class 6) - Underground	6.520000	7.040000	7.150238
New 30' Metal or Fiberglass - Underground	10.812000	11.672126	11.857112

Wattage, per Watt	0.051681	0.060516	0.057100
Lighting Base Power Supply Charge, per Watt	0.010113	0.013110	0.013110
PPFAC	(0.003488)	varies monthly	varies monthly
TOU - Small General School			
Customer Charge	16.500000	30.000000	19.641237
Energy Charge 1st 400 kWh	0.030176	0.039497	0.035921
Energy Charge 401 -7,500 kWh	0.043176	0.049497	0.090519
Energy Charge >7,500 kWh	0.076042	0.086950	0.086950
Base Power Supply ChargeS			
Summer On-peak, kWh	0.126510	0.126510	0.126510
Summer Off-peak, kWh	0.033010	0.033010	0.033010
Winter On-peak, kWh	0.108510	0.108510	0.108510
Winter Off-peak, kWh	0.032910	0.032910	0.032910
PPFAC Charges			
Summer On-peak, kWh	(0.003488)	varies monthly	varies monthly
Summer Off-peak, kWh	(0.003488)	varies monthly	varies monthly
Winter On-peak, kWh	(0.003488)	varies monthly	varies monthly
Winter Off-peak, kWh	(0.003488)	varies monthly	varies monthly
TOU - Large General School			
Customer Charge	52.000000	300.000000	287.169328
Demand Charge, per kW	12.810000	12.960000	11.581248
Energy Charge (kWhs)	0.005470	0.005400	0.004826
Base Power Supply Charge, all kWhs			
Summer on-peak	0.114886	0.145510	0.145510
Summer off-peak	0.039886	0.034510	0.034510
Winter On-peak, kWh	0.114886	0.124510	0.124510
Winter Off-peak, kWh	0.026168	0.032910	0.032910
PPFAC Charges			
Summer On-peak, kWh	(0.003488)	varies monthly	varies monthly
Summer Off-peak, kWh	(0.003488)	varies monthly	varies monthly
Winter On-peak, kWh	(0.003488)	varies monthly	varies monthly
Winter Off-peak, kWh	(0.003488)	varies monthly	varies monthly

Typical Bill Comparison - Present and Proposed Rates
RESIDENTIAL SERVICE

	BILL IMPACTS CURRENT RATES											
	Total kWh	Delivery (kWh)			Customer Charge	Delivery 0-400 kWh	Delivery 401-1,000 kWh	Delivery 1,000+ kWh	TCA	Base Fuel	PPFAC	Net Bill
		0-400	401-1,000	1,000+	$10.00	$0.01930	$0.03435	$0.03850	$0.001140	$0.064510	-$0.002139	
Xsmall	111	111	0	0	$10.00	$2.14	$0.00	$0.00	$0.13	$7.16	-$0.24	$19.19
Small	330	330	0	0	$10.00	$6.37	$0.00	$0.00	$0.38	$21.29	-$0.71	$37.33
Medium	664	400	264	0	$10.00	$7.72	$9.07	$0.00	$0.76	$42.83	-$1.42	$68.96
Large	1,144	400	600	144	$10.00	$7.72	$20.61	$5.54	$1.30	$73.80	-$2.45	$116.53
Xlarge	2,162	400	600	1,162	$10.00	$7.72	$20.61	$44.74	$2.46	$139.47	-$4.63	$220.37
Mean	830	400	430	0	$10.00	$7.72	$14.75	$0.00	$0.95	$53.51	-$1.77	$85.16
Sum	983	400	583	0	$10.00	$7.72	$20.04	$0.00	$1.12	$63.43	-$2.10	$100.20
Win	669	400	269	0	$10.00	$7.72	$9.25	$0.00	$0.76	$43.18	-$1.43	$69.48
Annual												$1,018.12

	BILL IMPACTS PROPOSED RATES													
	Total kWh	Delivery (kWh)			Customer Charge	Delivery 0-400 kWh	Delivery 401-1,000 kWh	Delivery 1,000+ kWh	TCA	Base Fuel	PPFAC	Net Bill	$ Change	% Change
		0-400	401-1,000	1,000+	$12.26	$0.03097	$0.05512	$0.06178	$0.000000	$0.049260	$0.000000			
		400	600	1000										
Xsmall	111	111	0	0	$12.26	$3.44	$0.00	$0.00	$0.00	$5.47	$0.00	$21.17	$1.97	10.3%
Small	330	330	0	0	$12.26	$10.22	$0.00	$0.00	$0.00	$16.26	$0.00	$38.74	$1.41	3.8%
Medium	664	400	264	0	$12.26	$12.39	$14.55	$0.00	$0.00	$32.71	$0.00	$71.91	$2.95	4.3%
Large	1,144	400	600	144	$12.26	$12.39	$33.07	$8.90	$0.00	$56.35	$0.00	$122.97	$6.44	5.5%
Xlarge	2,162	400	600	1,162	$12.26	$12.39	$33.07	$71.79	$0.00	$106.50	$0.00	$236.01	$15.64	7.1%
Mean	830	400	430	0	$12.26	$12.39	$23.68	$0.00	$0.00	$40.86	$0.00	$89.18	$4.02	4.7%
Sum	983	400	583	0	$12.26	$12.39	$32.16	$0.00	$0.00	$48.44	$0.00	$105.24	$5.04	5.0%
Win	669	400	269	0	$12.26	$12.39	$14.85	$0.00	$0.00	$32.98	$0.00	$72.48	$3.00	4.3%
Annual												$1,066.32	$48.21	4.7%

EXHIBIT
RUCO-6
admitted

UNS ELECTRIC, INC.

DOCKET NO. E-04204A-15-0142

SURREBUTTAL TESTIMONY

OF

LON HUBER

ON BEHALF OF THE

RESIDENTIAL UTILITY CONSUMER OFFICE

FEBRUARY 23, 2016

TABLE OF CONTENTS

ATTACHMENTS

EXECUTIVE SUMMARY - SURREBUTTAL

The Residential Utility Consumer Office ("RUCO") has reviewed the rebuttal testimony of UNS Electric, Inc. ("Company, UNS, or UNSE"), and the various interveners' direct testimony on rate design.

RUCO continues to recommend a traditional rate design for 98 percent of UNS customers and recommends three options for the 2 percent of UNSE customers that are Distributed Generation (DG) customers. RUCO is opposed to both Staff's and the Company's proposed mandatory demand rates, neither of which are in the interest of ratepayers and should be rejected by the Commission.

RUCO is perplexed as to why Staff, and now the Company, are pushing a mandatory demand rate onto residential ratepayers with such urgency. In fact, there is such a rush that customers will not even have a full year of data to understand the potential impacts of their demand charge. This is important as there are both summer and winter charges (which are illogically the same price). It seems like Staff is pursuing a policy for policy sake without considering the impact to ratepayers. In fact, it was the Company that originally held back from proposing a mandatory demand rate because they were not ready, and it was the Company that suggested safeguards for ratepayers in their rebuttal.

If Staff seeks to solve the rooftop solar issue with this mandatory demand rate, there is no need. Both the Company and RUCO agree that solar participants can be treated differently than the standard residential customer. Partial requirements customers and Full Requirements are not "similarly situated". Decades of partial requirements customers and other policies back this up. Moreover, RUCO offered a solution to the claim of discrimination by certain solar advocates should this issue become divisive. RUCO put forward a "no export" option if a solar customer seeks to be on a traditional rate. This option was approved in Hawaii and a solar customer can get the same payback, broadly speaking, if they have enough load and a properly sized system. Further, RUCO offered two other options for solar customers, a rate design for sophisticated DG adopters, and a simple fixed credit rate tied to REST compliance.

In sum, there is no justification as to why rates must change dramatically and all within a year. Instead of allowing customer choice, nearly every residential UNS ratepayer will have only a single rate plan in which they are exposed to a new charge, one they have never seen before. Add in the lack of actionable data due to old meter technology plus the lackluster education plan and one should conclude that this policy is frankly unacceptable and detrimental to residential ratepayers.

I. INTRODUCTION

Q. Please state your name for the record.

A. My name is Lon Huber.

Q. Have you previously filed testimony regarding this docket?

A. Yes, I have. I filed direct rate design testimony in this docket on December 9, 2015.

Q. What is the purpose of your surrebuttal testimony?

A. My surrebuttal testimony will primarily address the Company/Staff's position on mandatory demand rates with brief mention of other parties' positions on rate design.

Q. How is your surrebuttal testimony organized?

A. My surrebuttal testimony is presented in three sections as below:

i. Introduction

ii. Concerns with UNSE's proposed mandatory demand rate;

- a. Equity and fairness in UNSE's proposed mandatory demand rate
- b. Customer education plan and timeline
- c. Time of Use demand rate design

iii. Other concerns

- a. Concerns regarding UNSE's proposed increase in fixed charges
- b. Concerns regarding UNSE's rate design as a means to recover fixed costs.

iv. Solutions to problems with UNSE's proposed rate design

Q. Are there any corrections you would like to make at this time?

A. Yes. When formulating the demand charge for the Advanced DG rate, RUCO asked the Company to provide a breakdown of fixed costs, customer costs, and variable costs. In the response, customer costs were inadvertently placed in the fixed cost category as well as the appropriate customer category. This led to a double counting of customer costs when calculating the demand charge for the Advanced DG rate. The correct figure should be $16 per kW per month for summer months. This figure also takes into account an estimate of the small impact a six-hour time-of-use (TOU) period and a three-hour averaging may have on the ultimate demand charge level.

II. CONCERNS WITH PROPOSED MANDATORY DEMAND RATE

a. Equity and fairness in UNSE's proposed mandatory demand rate

Q. How many Small General Service and Residential customers does the Company propose to move to the new three-part rate?

The Company now proposes to move all Small General Service ("SGS") and residential customers to a demand rate.

Q. What is the Company's stated motivation for moving all customers to this mandatory demand rate instead of only some customers?

A. The Company cites equity[1] and fairness[2] as motivation for moving all customers to the proposed demand rate.

[1] See Rebuttal Testimony of H. Edwin Overcast page 2, line 12
[2] Ibid. page 10, lines 5-6

Q. Does RUCO support moving all customers to a mandatory demand rate as an equitable and fair practice?

A. No. The Company argues that all SGS and residential customers should be treated similarly under the same mandatory demand rate because "using the same rate sends the same price signals"[3] to customers with like service characteristics. Utilities treat and categorize customers into different classes based on many factors. This is true for UNSE as well. Existing examples of customer classes include, CARES discount, agricultural, etc.

The utility ratemaking principle of fairness does not require all customers to be subject to the same rates, but rather be subject to rates that are fair. The proposal to require all customers to move to a mandatory demand rate is a misguided attempt at ensuring fair treatment.

Q. Do customers prefer rate options?

A. Yes. Utilities have increasingly been offering their customers more rate options. Using OpenEI US Utility Rate database data, the average number of residential rate options offered by utilities climbed from 1.87 residential rate options in 2013 to 3.2 residential rate options per utility in 2015[4]. This increase in rate offering also leads to an increase in customer satisfaction. J.D. Power senior director of energy, Andrew Heath stated recently, "the thing that really differentiates the top utilities, they provide the customer some form of choice." Heath goes on to state the utilities that offer greater choice, experience "a significant uplift in terms of overall customer

[3] See Rebuttal Testimony of H. Edwin Overcast page 48, lines 1-2
[4] http://en.openei.org/apps/USURDB/

satisfaction.[5]" Simply, customers prefer more options and do not appreciate a 'one size fits all' rate plan.

Q. Have UNS, TEP, and APS boasted about how they offer many different rate options to their customers?

A. Yes. In the deregulation debate in 2013, all the utilities mentioned their many rate options as a reason not pursue market restructuring. In the filings, it was clear that the companies were proud of their diverse offerings.

Tucson Electric Power Company and UNS Electric, Inc. stated the following:

> "Advocates also overlook the multitude of choices available to customers served by the Companies and other regulated Arizona utilities. Our customers can choose time-of-use rates, fixed price plans, "green" energy alternatives and incentives for energy efficiency and renewable power without forgoing the consumer protections offered in our regulated system."[6]

Arizona Public Service:

> "APS offers five varieties of residential time-of-use ("TOU") rates as well as TOU options for virtually all its commercial and industrial customers, including a TOU offering for schools specifically designed at their request. The Company offers demand response and energy efficiency programs, interruptible rates (as requested by some of the Company's larger customers), special contracts, combined metering

[5] http://www.utilitydive.com/news/for-top-utilities-customer-satisfaction-hinges-on-empowerment/402618/
[6] TEP and UNSE Response Letter to Commissioners in Docket NO. E-00000 W-13-0135, page 10

and billing, and other rate or service offerings. One would be hard pressed to find any electric utility in this country that provides such a wide range of options to over one million customers."[7]

Q. Does the Company propose customer subsets for differential treatment?

A. Yes. In H. Edwin Overcast's Rebuttal testimony, he defines partial and full requirement customers and later suggests these two classes to be treated differently. Full requirement customers receive all their electricity from the utility, partial requirement customers receive some electricity for the utility, and the rest from DG. This creates two classes of customer.

In his definition of these two classes, Overcast also suggests that within the previously defined full and partial requirement classes, "Partial requirement customers differ from full requirement customers and from each other[8]". This suggests the partial requirement subset can be further refined. Thus differentiating DG and non-DG customers would not be a departure from normal ratemaking process.

Q. Could partial and full requirement customers be subject to different rate designs?

A. This is what RUCO is proposing. Two optional rates for new DG customers, as detailed later in this testimony, will allow UNSE to treat the two classes differently without being unduly discriminatory.

[7] APS Response Letter to Commissioners in Docket NO. E-00000 W-13-0135, page 2
[8] Rebuttal Testimony of H. Edwin Overcast page 10, lines 5-6

Q. Has the Company proposed applying a demand rate to a subset of their customers?

A. Yes. In fact, the Company proposed exactly this originally. In the Company's Direct Testimony mandatory three-part rates were proposed for the subset of DG customers that install distributed generation after June 1 2015, and optional for other non-DG SGS and residential customers[9].

Q. Has the Company changed its position since this initial proposal?

A. Yes. In its Rebuttal Testimony, the Company has expressed support for Staff's recommendation of a mandatory demand rate for all customers be adopted in this rate case.

Q. Why did UNSE not propose mandatory demand rates in its initial proposal?

A. In his Direct Testimony dated May 5, 2015, Dallas Dukes states "Presently, UNS Electric doesn't have the capability to measure demand for every customer and is not advocating a forced migration to such a structure at this time."[10]. Later, in his Rebuttal Testimony Dukes states, mandating all customers to move to a mandatory demand rate in the initial proposal would have been 'somewhat aggressive'[11]. It is unclear what changes occurred to reduce the demand rates to an acceptable level of aggressiveness between Dukes' two testimonies. Further demonstrating the Company's own doubt, Craig Jones states "three-part rates for all customers is a special

[9] Direct Testimony of Carmine Tilghman page 8, line 21
[10] See Direct Testimony of Dallas Dukes page 10 lines
[11] See Rebuttal Testimony of Dallas Dukes beginning on page 4, line 7

circumstance which may yield results that were unintended.[12]" Therefore, "UNS Electric could support keeping the rate design portion of this rate case open for a period of time in the event that significant unintended consequences arise that adversely affect the Company or its residential or SGS customers."[13]

Q. In RUCO's opinion, does the Company and Staff's position reflect the principle of rate gradualism?

A. No. The Company's original proposal represented a more gradual shift by moving some, but not all customers to a radically new rate design. However, the Company's present proposal is not gradual and subjects all UNS customers to this radical shift in a way that RUCO believes will be confusing and harmful.

b. Customer education plan and timeline

Q. Why will UNSE's proposed mandatory demand rate be confusing for customers?

A. Among other reasons, UNS does not have the right technology deployed to adequately inform ratepayers of their demand usage?

Q. Please explain.

A. There are two types of advanced meters generally used today, Advanced Metering Infrastructure (AMI) meters and Automatic Metering Reading

[12] See Rebuttal Testimony of Craig Jones page 6, lines 15-16
[13] See Rebuttal Testimony of Craig Jones page 6, lines 17-18

(AMR) meters. According to General Electric, a meter manufacturer with experience in both AMI and AMR meters, AMR meters are older technology that provides one-way communication from the meter to the utility, AMI meters provide two-way communication, from the utility company to the customer[14]. This means only AMI meters can interface directly with customers about their demand usage. Currently, UNSE has no AMI meters installed[15]. Therefore, UNSE does not have the optimal technology in place to support the proposed changes. While AMR meters can provide interval data, it is RUCO's understanding that the customer will not be able to receive data in a timely manner because it must first go through the Company.

Q. Have you reviewed the direct testimony of Staff witness Howard Solganick and Thomas M. Broderick?

A. Yes.

Q. Please summarize Staff's testimony as it relates to customers' ability understand and adapt to UNS' proposed new rate structure.

A. Mr. Broderick states on page 7 of his direct testimony:

> "Staff believes that new meter technology, internet communications portals, and smart phone applications have made it feasible and much easier for residential customers to understand and accept a three-part tariff than ever before."

[14] General Electric's website; http://geappliance.esecurecare.net/app/answers/detail/a_id/22/~/what-is-the-difference-between-amr-and-ami-meters%3F
[15] RUCO data request 11.3

Mr. Broderick states on page 8 of his direct testimony:

> "Staff believes there will only be a temporary challenge for residential customers to understand, accept and adapt if the Company develops and implements a customer education program. Staff requests that UNSE define and develop the details for a rate migration transition process and share with the parties in its rebuttal testimony."

Further, Mr. Solganick states on page 8 of his direct testimony:

> "As a residential customer, my electric utility provides me with access to a portal where I can view my energy consumption." Later Solganick states, "My utility also provides me (with a two-day delay) my hourly energy consumption, which is equivalent to hourly demand. From this timely information, I can determine the peak period(s) of energy usage and then decide if I wish to change my energy usage in the future."

Q. Does UNS currently have this technology to support Mr. Broderick and Mr. Solganick's conclusions?

A. Not entirely. Based on RUCO data request 11.3. UNS does not have the current technology as 90.5% have AMR meters, and few customers have AMI meters.

Q. Is there currently an internet portal that UNS customers can log into to check their usage and demand profile?

A. No.

Q. Is Staff aware that UNS customers are unable to track their usage and demand in the way that Mr. Solganick described?

A. Yes. In response to data request 1.5 from RUCO, Staff stated that Mr. Solganick "was unable to find a UNSE portal with that capability."

Q. Does Staff recognize that there will be additional costs incurred by the Company (and ultimately ratepayers) to provide access to this data?

A. Yes. Staff recognizes that "the costs to develop a portal depends on the existing capabilities of the Company's infrastructure including website, customer information system, meter data management systems and whether the website would be extended to its affiliate TEP."

Q. Did Staff estimate what these costs will be?

A. No. However, the Company estimates a cost of $650,000 in response to RUCO data request 11.4.

Q. Does RUCO have further concerns regarding UNSE's proposed usage portal?

A. Yes. Only 76.2% of Arizonans have access to high speed internet, this is below the national average of 78.1%[16]. High speed internet is vital for users to access their electricity usage. Customers could also access their usage data using a smartphone. As of October 2014, only 64% of US adults own a smartphone[17]. This leaves a sizeable portion of UNSE customers without access to their usage even if it is made available through a portal.

[16] 2013 US Census Report https://www.census.gov/history/pdf/2013comp-internet.pdf
[17] Pew Research Center Mobile Technology Factsheet (October 2014) http://www.pewinternet.org/fact-sheets/mobile-technology-fact-sheet/

Q. What is RUCO's synopsis of Staff's recommendation?

A. RUCO finds it telling that Staff admitted that it will be challenging for customers to understand, at least at first. Staff places faith in a yet to be completed education plan and new technology that hasn't been developed yet and may not ever reach a large portion of UNS customers.

Q. What does this mean for ratepayers?

A. Higher costs in the form of added infrastructure in order to meet the requirements of Staff's mandatory demand rate. As well as confused customers lacking the connectivity and the hardware to understand the new charges.

Q. Does a Company witness also question the understandability of more advanced rate designs?

A. Yes. Dr. Overcast on page 33 of his testimony speaks to this and his answer was to undertake a 'gradual process done in steps'. To reduce confusion his first suggestion was to phase out the third tier of kWh rates followed by a move to seasonal and time differentiated energy charges.[18] Noticeably, he did not mention carrying out a rapid and complete switch to a three part rate design for all residential customers as Staff and the Company proposes.

Q. Does UNSE propose a timeline for their education plan and ultimate rollout of the proposed rates?

A. Yes. Summarized as:

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[18] See Rebuttal Testimony of H. Edwin Overcast page 33 lines 15- 19

- May to June 2016. UNSE Implements transitional rates
- Present to December 2016. Analyze billing data
- May to October 2016. Customer education plan rolled out
- No later than November 2016. UNSE provides usage and demand data to customers.
- 1st quarter 2017. All residential and SGS customers moved to three-part rates and a redesigned bill introduced.[19]

Q. Does RUCO foresee issues with this timeline?

A. Yes. The proposed timeline is very tight to allow a full three months for customer demand data as proposed. All customers are expected to have AMR meters installed by the end of 2016[20]. Any setbacks will negatively impact this timeline.

Q. The timeline suggested provides some customers only three months of demand data before charging demand rates. Does RUCO feel this is adequate?

A. No. Three months of usage data will not provide enough information for customers to understand how their behavior will impact their electric bills. RUCO suggests greatly increasing this timeline before issuing bills using the new rates. The seasonal temperature variability in UNSE territory generally leads to higher usage and demand in summer, particularly due to air conditioning use. During shoulder seasons, air conditioning use is reduced, therefore demand during this time is unlikely to represent demand

[19] See Rebuttal Testimony of Dallas Dukes page 13 lines 1 - 12
[20] See Rebuttal Testimony of David Hutchens page 7, lines 10 -11.

during summer. For these reasons, RUCO takes issue with the lack of summer data available to customers. As proposed, the impact of three-part rates will not provide customers with accurate bill impacts before bills are issued.

Q. Does Staff believe it will be a challenge for residential customers to understand and accept a three-part tariff?

A. Yes. However, Staff says this challenge will be temporary if the Company implements a customer education program.

Q. Have you reviewed UNSE's Education Campaign, Exhibit DJD-R-1?

A. Yes, I have.

Q. Does RUCO have any comments about UNSE's proposed Education Campaign?

A. Yes. The listed campaign components are minimally specific and do little to ensure a customer will properly understand the changes. There is also little mention of education about demand management. RUCO feels that a complicated change such as a mandatory demand charge cannot be adequately explained using a bill insert and brochure. These are likely the only materials most customers will actually view.

Q. Does Staff explain how this education program will help customers understand and act upon their demand if they have no access to data about their demand?

A. No.

Q. Does RUCO have evidence suggesting UNSE's bill design is difficult for customers to understand?

A. Not directly, but generally it is found that customers have difficulty understanding traditional bills even without complicated demand charges. According to one study, only 39% of survey respondents were able to correctly respond to a question about the expected savings by reducing one's kWh usage[21]. The same study also found no single question in the bill interpretation section was answered correctly by more than 70% of respondents.

Q. Are there existing tools for customers to better understand energy usage and demand?

A. There are many tools to help customers understand kWh usage but few tools consider demand. Existing government programs serve as further evidence that customers cannot understand demand charges. The US government's online calculator tool for estimating appliance and home energy use only allows users to input an appliance wattage and cost per kWh[22]. Similarly, the Federal Trade Commission has adopted the recognizable yellow Energyguide label for new appliances. Both the calculator and label only consider yearly kWh performance and estimated yearly operating cost, they make no consideration for kW demand[23]. Using these tools, a reasonable customer could expect a new appliance to have a predictable impact to their estimated yearly operating cost. If the new appliance increased their peak demand, the customer would receive a

[21] Southwell, Brian G., et al (2012) Americans' Perceived and Actual Understanding of Energy
[22] http://energy.gov/energysaver/estimating-appliance-and-home-electronic-energy-use
[23] http://www.consumer.ftc.gov/articles/0072-shopping-home-appliances-use-energyguide-label

larger and unexpected bill. This represents a greater lack of customer understanding and a lack of adequate education tools.

Q. Who does RUCO believe should be responsible for demonstrating that UNSE customers will adequately comprehend the three-part tariff and understand how to manage their electricity bills?

A. RUCO believes the burden of proof is on Staff and the Company to demonstrate this.

Q. Are there other reasons why you have concerns about UNS' ability to develop and implement a customer education plan about mandatory demand charges? Please explain.

A. Yes, I have other reasons to be concerned. UNS' Residential Time-of-Use and Time-of Use-Super Peak tariffs (RES-01 TOU and RES-01 TOU SP) have very low subscription rates. During the test year, UNS reported an average of 230 customers on its Residential Time-of-Use tariff and only one customer on its Time-of-Use Super Peak tariff. This equates to less than 0.5% of residential customers. In comparison, 52% of APS customers are on time-of-use rates.[24] This raises concerns about UNS' ability to communicate to its customers about their rate offerings - especially non-standard ones - and to communicate specifically about energy usage as it relates to system peak.

[24] Ryan Randazzo (2015), Arizona leads California on time-of-use electricity plans. http://www.usatoday.com/story/money/2015/05/26/arizona-california-time-of-use-electricity/27985581/

Furthermore, given that these charges would be mandatory for all residential customers, UNS would need to execute a communication and education plan that touched all residential customers and educated them about their energy usage. Notably, UNS has faced complaints in the past when it has tried to educate a broad number of customers about their energy usage. When UNS implemented its Home Energy Reports program, it "received a number of complaints from enrollees… generally concerning the report being delivered 'unsolicited,' on an opt-out basis, rather than an opt-in."[25] These complaints were an influencing factor in UNS' decision to cancel the program.

c. Time of use demand rate design

Q. Please summarize your comments regarding the Company's proposed Time of Use rates.

A. RUCO supports a time of use rate design, however as proposed, the Time of Use demand rate does not accurately collect costs from customers as they are incurred to the utility. RUCO is also in disagreement with the company over the duration of the proposed demand peak.

[25] UNS Electric, Inc.'s Annual Demand-Side Management Progress Report, Docket No. E-00000U-14-0049

Q. Do you have comments regarding the inability of the proposed Time of Use demand rate to accurately collect costs from customers as they are incurred to UNSE?

A. Yes. The proposed rate does not differentiate demand as it contributes to seasonal peak demand. This means summer and winter peak costs are recovered as if they cost UNSE equally. Since the Company's plan is to 'recover generation costs through the demand charge' this contradicts the Company witness Dr. Overcast.[26] In his article attached to his Rebuttal Testimony, Overcast states "It will be important to develop seasonal and diurnal periods based on underlying marginal costs" [27].

Q. Please describe how UNSE's proposed demand rate peak is too long in duration.

A. UNSE's proposed peak demand times are from 2 pm to 8 pm. This is a 6-hour timeframe which customers are expected to minimize demand. This is an unreasonable expectation that regular customers can realistically monitor and reduce their usage over this timeframe, at least initially and without technology assistance. A shorter timeframe, such as 4 pm to 7 pm, is easier for customers to respond to and more accurately represents the peak demand times.

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[26] See Rebuttal Testimony of Dallas Dukes beginning on page 8, line 24
[27] Overcast, Edwin H. Smart Rates for Smart Utilities page 15

Q. Are there other effects of the peak demand rate that are not in customer's best interest?

A. Yes. UNSE cites Bonbright's principles of rate design in several instances throughout various testimony including Overcast[28]. RUCO feels this wide peak time does not represent the principle of practicality. It is simply, impractical to discourage behavior that contributes to a standard customer's peak demand for nearly all evening hours. A demand peak that is narrower would be more practical.

Q. Have you conducted in depth analysis of the customer impacts from the three part rate?

A. No, the tight timeline and limited data available, prevented me from conducting an in-depth review. Since Staff did not provide a rate schedule with details around their vision of a three part rate, I had only the time from the Company's rebuttal.

Q. In that time did you conduct any analysis?

A. Yes, but at a very high level. I found that compared to the current two part rate, the proposed three part rate provides a significant increase to the bill of lower than average users and a discount to higher than average users. Using 795 kWh per month, the monthly average as seen in UNS's 2,309 smart meter customer sample, the results are stark. Any customer between that average and 250 kWh per month in usage will be paying 21% more than under current rates. I purposely excluded very low users or else that figure would be even larger. Conversely, if a household uses over 1,500

[28] See Rebuttal Testimony of Edwin H. Overcast page 44, beginning on line 5

kWh a month they will receive a 3% discount compared to the current rate structure.

III. OTHER CONCERNS

a. Concerns with proposed increase in fixed customer charge

Q. What is the National Association of State Utility Consumer Advocates ("NASUCA")?

A. NASUCA is an association comprised of many consumer advocates from numerous states and the District of Columbia. NASUCA's members are designated by the laws of their respective jurisdictions to represent the interests of utility consumers before state and federal regulators and in the courts. RUCO is a member of NASUCA.

Q. Has NASUCA taken a position on increased fixed charges?

A. Yes. NASUCA recently adopted resolution 2015-1

Q. What does NASUCA state in resolution 2015-1, "OPPOSING GAS AND ELECTRIC UTILITY EFFORTS TO INCREASE DELIVERY SERVICE CUSTOMER CHARGES"?

A. NASUCA opposes increasing the basic service charge. I have included a copy of this resolution (see Attachment B).

Q. Does UNSE's proposed rate design include increased fixed charges?

A. Yes

Q. Does UNSE believe fixed costs should be recovered primarily through fixed charges?

A. Yes. Craig Jones argues that the proposed rates “still leave a significant percentage of the Company's fixed costs subject to recovery through volumetric rates.” but the proposed rates “are a good start in addressing appropriate fixed cost recovery.”[29] This indicates that UNSE believes fixed costs should be recovered as fixed charges, with some combination of demand charges from their customers.

Q. Does RUCO agree with UNSE's method of fixed cost recovery?

A. No. There is no fundamental reason that fixed costs must be recovered through fixed prices or unavoidable demand charges. In fact, many industries in the global economy incur fixed costs that are ultimately recovered through prices that are not fixed. For example, gasoline is priced on a volumetric basis ($ per gallon), despite the fact that there are many fixed costs associated with its production (e.g. refineries, pipelines, etc.). This is further argued by Bonbright; "“regulation should allow a fair rate of return, but not guarantee or protect a regulatee against mismanagement or adverse business conditions”[30].

[29] See Rebuttal Testimony of Craig Jones page 5, lines 12 - 14
[30] Bonbright, James Cummings (1961) Principles of Public Utility Rates page 382

Q. Other than increased fixed charges, are there other ways utilities such as UNSE could recover unrecovered fixed costs?

A. Yes, there are several. These options range from implementing new time-of-use demand rates (which is RUCO's proposal) to simply increasing UNSE's current volumetric rates.

Q. Does RUCO support increased fixed charges as a way to increase fixed cost recovery?

A. No. For reasons explained previously in our testimony, we don't support increased fixed charges. RUCO finds additional support for its argument from Bonbright: "Regulation, it is said, is a substitute for competition. Hence its objective should be to compel a regulated enterprise, despite its possession of a complete or partial monopoly, to charge rates approximating those which it would charge if free from regulation, but subject to the market forces of competition."[31] We believe there are many options, such as RUCO's proposal, that are better for customers while still ensuring greater fixed cost recovery for UNSE.

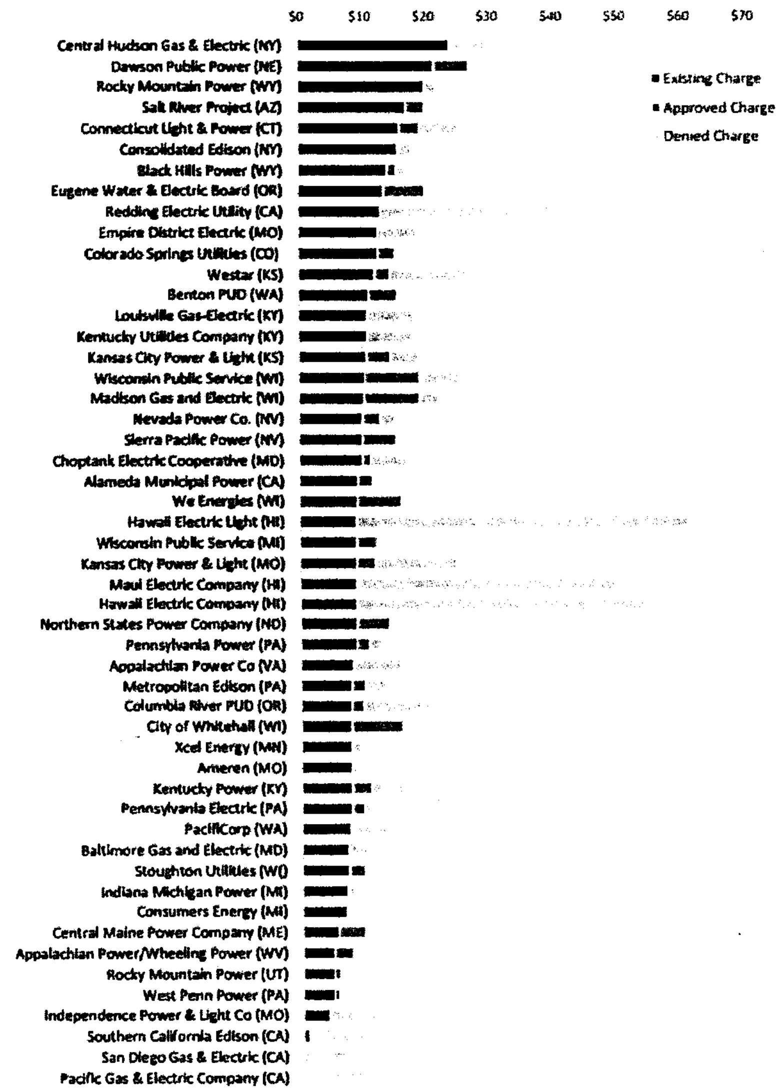
Q. Have there been other recent commission decisions regarding increased mandatory fixed charges?

A. Yes. Recent decisions by commissions in several states have either denied entirely or scaled back proposals to increase mandatory fixed charges proposed by utilities. Synapse recently analyzed 51 proposals decided between September 2014 and November 2015 and found that 41% of these proposals were rejected, and 33% were scaled back. The average

[31] Bonbright, James Cummings (1961) Principles of Public Utility Rates page 141

approved fixed charge for these decisions is $11.87[32]. These decisions are summarized below.[33]

Figure 12. Finalized decisions of utility proceedings to increase fixed charges



Notes: Denied includes settlements that did not increase the fixed charge.

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[32] Whited, M., Woolf, T., & Daniel, J. (2016). Caught in a Fix: The Problem with Fixed Charges for Electricity.

[33] Whited, M., Woolf, T., & Daniel, J. (2016). Caught in a Fix: The Problem with Fixed Charges for Electricity. p 46

Q. What are some of the reasons that these proposals were denied or scaled back?

A. There are many reasons why these proposals were denied or scaled back. Some include: concerns about reduced customer control; concerns about rate shock; concerns about inequitable impacts to low usage customers; concerns about inequitable impacts to low income customers; concerns about reduced incentives to invest in energy efficiency; and concerns about inefficient price signals.

Q. Can you provide a few example of Commission decisions?

A. Yes. When the Missouri Public Service Commission denied Ameren Missouri's request to increase its fixed charge it stated, "There are strong public policy considerations in favor of not increasing the customer charges. Residential customers should have as much control over the amount of their bills as possible so that they can reduce their monthly expenses by using less power, either for economic reasons or because of a general desire to conserve energy."[34] Similarly, when the State of Illinois Commerce Commission rejected Peoples Gas and North Shore Gas' proposals, it stated, "It is patent that high customer charges mean the Companies' lowest users bear the brunt of rate increases, and subsidize the highest energy users. Steadily increasing customer charges diminish the incentives to engage in conservation and energy efficiency because a smaller portion of

[34] Missouri Public Service Commission (2015). Report and Order in the Matter of Union Electric Company, d/b/a Ameren Missouri's Tariff to Increase Its Revenues for Electric Service. See discussion on page 76-77.

the bill is subject to variable usage charges and customer efforts to reduce usage."[35]

Q. Have you reviewed the direct testimony of the other parties in this proceeding?

A. Yes.

Q. In particular have you reviewed the direct testimony of Jeff Schlegel on behalf of Southwest Energy Efficiency Project ("SWEEP")?

A. Yes.

Q. Please comment, on SWEEP's position that the basic service charge should not be increased.

A. RUCO agrees with SWEEP that increasing the basic service charge would have the following repercussions on ratepayers:

1. It would reduce the amount of control that ratepayers have on their energy consumption and bills. Customers have no ability to decrease mandatory fixed charges on their energy bills. However, they can control and mitigate the bill impact of charges collected through volumetric rates by reducing their energy use.

2. Low use customers, many of which are elderly or on fixed incomes, will be disproportionately affected by higher fixed charges and may have to make the choice between food, medicine, or paying their electric bill.

[35] State of Illinois Commerce Commission (2015). Order North Shore Gas Company, proposed general increase in gas rates; The Peoples Gas Light and Coke Company, Proposed general increase in gas rates. See discussion on page 176.

3. UNS would have one of the highest basic service charges in the western region.[36]

Q. Is Mr. Schlegel's testimony consistent with others that have filed testimony in this docket?

A. Yes. Cynthia Zwick on behalf of the Arizona Community Action stated the following:

> "Doubling the fixed charges in low-income households will not only disincentivize saving but it would lead to customers having less control over their energy bill and more wasteful electricity use."[37]

> "High fixed charges directly reduce incentives for customers to conserve energy by reducing the payback on investments in efficient appliances, insulation, or other residential or business improvements."[38]

b. Concerns with UNSE's rate design as a means to address unrecovered fixed costs

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[36] See the Direct Testimony of SWEEP Jeffrey Schlegel starting on page 4.
[37] See page 15 of the direct testimony of Cynthia Zwick on behalf of the Arizona Community Action association regarding rate design.
[38] Ibid, page 19.

Q. Why is UNSE proposing rate design changes in this proceeding?

A. Among other reasons, UNSE is attempting to address issues associated with the recovery of its fixed costs in an era of declining energy sales and distributed generation.[39]

Q. Is UNSE's proposed rate design the only solution for addressing unrecovered fixed costs?

A. No. There are many possible rate designs that could help ensure fixed cost recovery for UNSE.

Q. Did other parties to this proceeding propose alternative rate designs intended to increase UNSE's fixed cost recovery?

A. Yes. Both Staff and RUCO proposed rate designs that are intended to increase UNSE's fixed cost recovery.

Q. As it relates to DG customers, is UNSE's rate design more closely aligned with RUCO's proposal or Staff's proposal?

A. UNSE claims Staff's proposed three-part TOU rate is "the superior rate for all customers, including DG customers[40]", however according to RUCO's data request 11.5, "the Company cannot choose one proposal over the other as it relates to the recovery of fixed costs."[41].

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[39] See Rebuttal testimony of Dallas Dukes ("Dukes"), page 2, line 22.
[40] See Rebuttal Testimony of Craig A Jones page 30, lines 19 - 20
[41] RUCO Data Request 11.5

IV. SOLUTIONS TO PROBLEMS WITH UNSE'S PROPOSED RATE DESIGN

Q. Does RUCO have constructive suggestions on how to improve the demand rates and other issues presented by parties?

A. Yes. Unlike some interveners, RUCO feels that it is valuable to put forward policy ideas that can create win-win outcomes for stakeholders.

Q. Does RUCO believe that standard rates need to evolve?

A. RUCO believes that rates need to continuingly, but gradually, evolve to reduce long-term system costs and to take advantage of new technologies. Volumetric TOU rates can accomplish most of this objective in conjunction with customer data and education. For residential customers, volumetric rates have been the norm and they are well understood. As long as one has a generally homogenized customer class they can work great.

Q. Is this rate case the best place to have this discussion?

A. No, it should be a statewide policy discussion culminating in a formal policy statement from the Commission. This will allow all stakeholders a voice into how the future of rates should be designed. For instance, this process would answer the question: should the state promote some customer choice or just one rate for nearly every customer within a customer class? This process will also prevent a gross mismatch of different policy and rate offerings by each utility in the state.

Q. Are there alternatives to high fixed charges that RUCO would like to propose?

A. Yes. RUCO believes that a minimum bill concept should be explored as a way to better address the Company's concern with fixed cost recovery of low energy users. A minimum bill can accomplish this and maintain conservation price signals that are important to RUCO and other stakeholders.

Q. Would RUCO be open to default residential TOU rate?

A. Yes. RUCO proposes the following rate design based largely on the Company's transitional TOU rate. The only change is to the on-peak and off-peak rates and a reduction of the basic service charge.

RUCO's Proposed 2-Part default TOU Rate

Basic Service Charge	$12.20	
Energy Delivery		Tier Limit
0-400 kWh	$ 0.032258	400
401-1,000 kWh	$ 0.042258	1,000
Over 1,000 kWh	$ 0.060258	
Base Power	Summer	Winter
On-Peak	$ 0.120000	$ 0.060000
Off-Peak	$ 0.060000	$ 0.030000

Q. Is RUCO working on additional revised rate schedules?

A. Yes, those will be filed in the future.

Q. Any thoughts on a demand based rate?

A. Yes. RUCO is open to an optional demand based TOU rate that any customer can select.

Q. What if the demand rate was mandatory?

A. As stated previously, RUCO is vehemently opposed to this. However, if a mandatory rate were to be adopted, RUCO would strongly suggest the following:

- Only a three-hour time window for each customer that can be staggered randomly to ensure that full six hours of peak is covered.
- More actionable and timely data must be available to the customer. This should include but not be limited to: Smart phone apps, shadow bills, pre-programed thermostats, and online portal with at least a year of past data.
- The summer charge must be higher than the winter charge. This sends more accurate price signals and reflects actual system cost drivers.
- No LFCR charge should be collected from this type of rate.

Q. Is this three hour TOU staggering a new concept?

A. No, Salt River Project (SRP) employs this tactic for their EZ-3 Price Plan.[42]

Q. While on SRP policy, did SRP strike all their residential rate plans when dealing with DG?

A. No, they created a rate specifically for DG customers.

[42] http://www.srpnet.com/prices/home/ez3.aspx

Q. Any suggestions as it relates to options for DG customers?

A. Not at this moment. RUCO is open to some modification of the three options put forward; however, RUCO continues to believe that the options provide win-win outcomes for all parties involved. First, it offers an advanced TOU rate that recovers fixed costs for the company while sending strong on-peak price signals to technology adopters. Second, it offers a simple and easy to understand fixed credit payment option to less sophisticated DG customers. This option is tied to the REST goals to ensure UNS meets its DG targets. Finally, to address the need that solar advocates stress, RUCO's third options allows a solar customer to be on any rate and offset their consumption behind the meter just like today. The only difference is that exports would be restricted.

Q. Are these options complicated?

A. No, they are straightforward to understand from a customer and installer perspective. Nothing is more simple than a fixed credit rate for 20 years as outlined in the RPS credit option. This is in stark contrast to the Company's plan of having an ever changing differential export rate tied to a PPA proxy of solar PV system possibly in another utility's service territory. How would a customer know how much they export? The Company does not provide historical interval data. Even if they could get this data after waiting a full year, how could they reasonably predict savings if the rate can change in any given year?

Q. Does this conclude your rebuttal testimony?

A. Yes.

ATTACHMENT A

Selected Company response to RUCO's data request

ARIZONA CORPORATION COMMISSION STAFF'S RESPONSES TO RESIDENTIAL UTILITY CONSUMER OFFICE'S FIRST SET OF DATA REQUESTS DOCKET NO. E-04204A-15-0142 DECEMBER 29, 2015

1.05 Rate Design – On page 8 of Staff witness Howard Solganick's testimony he states that his utility provides him with a portal so that he can monitor his usage and his neighbor's usage. Based on this statement please answer the following questions:

a. Do UNS customers currently have access to a portal so they can monitor their usage along with their neighbors?

b. If no to a., what does Mr. Solganick estimate the cost would be to implement this technology to UNS customers? In the response please include the initial set-up costs and ongoing yearly costs to maintain this portal that ratepayers will ultimately pay.

RESPONSE: **Staff witness Solganick was unable to find a UNSE portal with that capability.**

a. Staff witness Solganick recognizes that the costs to develop a portal depends on the existing capabilities of the Company's infrastructure including website, customer information system, meter data management systems and whether the website would be extended to its affiliate TEP. Therefore Mr. Solganick made no estimates, however the Company may make that estimate in its transition plan that has been requested by Staff.

b. Staff witness Solganick recognizes that the costs to develop a portal depends on the existing capabilities of the Company's infrastructure including website, customer information system, meter data management systems and whether the website would be extended to its affiliate TEP. Therefore Mr. Solganick made no estimates, however the Company may make that estimate in its transition plan that has been requested by Staff.

RESPONDENT: Howard S. Solganick, Energy Tactics & Services, Inc., 810 Persimmons Lane, Langhorn, PA 19047

UNS ELECTRIC INC.'S RESPONSE TO RUCO'S ELEVENTH SET OF DATA REQUESTS REGARDING THE 2015 UNS ELECTRIC RATE CASE
DOCKET NO. E-04204A-15-0142
February 4, 2016

RUCO 11.3

Automatic Meter Reading ("AMR") and Advanced Meter Infrastructure ("AMI") – Please answer the following questions as they relate to AMR and AMI in UNS's service territory: a. Can AMR meters supply 15 minute or 30 minute interval data to customers?

b. Please provide the total number of residential meters. In addition, please provide the number of residential AMR meters and the number of residential AMI meters.

c. If not all of the residential meters are AMR, please estimate the approximate cost to install AMI meters. Stated another way, what would the approximate costs be to replace any existing AMR meters with AMI meters.

d. Is it the Company's long-range plan to replace all AMR meters with AMI meters, if so, when would this migration be completed by?

RESPONSE:

a. UNS Electric's AMR meters can provide 15 minute or 30 minutes interval data, but UNS Electric is currently recording hourly interval data for residential customers. See UNS Electric's response to RUCO 11.4(a) for supplying the interval data to customers.

b. UNS Electric currently has 83,718 meters and 75,767 AMR meters have been installed for its residential customers. The remaining 7,951 meters are non-AMR/AMI meters.

c. UNS Electric is focused on the AMR technology and it would be overly burdensome and somewhat speculative to approximate the costs to replace any existing AMR meters with AMI.

d. It is not currently in the long-range plan to replace all AMR meters with AMI Meters.

RESPONDENT:

Chis Fleenor

WITNESS:

Craig Jones

UNS ELECTRIC INC.'S RESPONSE TO RUCO'S ELEVENTH SET OF DATA REQUESTS REGARDING THE 2015 UNS ELECTRIC RATE CASE
DOCKET NO. E-04204A-15-0142
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RUCO 11.4

Customer web portal – Please answer the following questions about web portal capabilities:

a. Does the Company currently have real time capabilities for customers to log into the Company's website and check their usage for the last 24 hours or longer? If yes, please explain?

b. If no to a., how much does the Company estimate the costs to be to implement this technology?

c. If no to a., if the Commission ordered the Company to implement this technology, how long would it take.

d. Can the Company web portal work in conjunction with an AMR meter? Or would a customer have to use an AMI meter to monitor his/her usage through the web portal?

e. If yes to d., please estimate the additional costs that must be incurred to have the AMR meters reequipped in order to communicate to the Company's web portal?

RESPONSE:

a. No. The Company's initial plan is to implement web portal capabilities that will allow Customers to access historical energy and demand interval data in multiple formats; for example, by billing period, previous 12 months and by day. The single day or 24 hour interval data will initially be available to a customer after mid-day the following day.

b. Approximately $650,000.

c. Approximately 6 months.

d. Yes, it is expected that the web portal will work with AMR meters.

e. None.

RESPONDENT:

Denise Smith / Brandy Marshall / Arunesh Mohan **WITNESS:**

Denise Smith

UNS ELECTRIC INC.'S RESPONSE TO RUCO'S ELEVENTH SET OF DATA REQUESTS REGARDING THE 2015 UNS ELECTRIC RATE CASE
DOCKET NO. E-04204A-15-0142
February 4, 2016

RUCO 11.5

Fixed Cost Recovery – Please answer the following questions about fixed cost recovery:

a. In rebuttal testimony, witness Craig Jones stated that "Staff's recommended three-part TOU rate is the superior rate for all customers, *including DG customers."* (Emphasis added). All things held equal with adjustors such as the LFCR, which rate option, according to Company calculations, recovers more fixed costs from a typical solar DG customer, Staff's three-part TOU based rate design or RUCO's DG TOU Rate?

RESPONSE:

The response to the question would vary by set of circumstances, therefore the Company cannot choose one proposal over the other as it relates to the recovery of fixed costs. Neither Commission Staff's rate, as modified by the Company, nor RUCO's proposed Option #2 rate actually reflect cost causation and neither proposal provides for adequate fixed cost recovery from customers, in general, nor from DG customers in particular. By focusing the demand charge on the peak period these rate designs fail to provide for the recovery of costs associated with the maximum demand of customers that drive distribution costs. It is likely that for solar DG customers the peak demand on the distribution system will not be at the time of the system peak hours. Rather, the demand will likely occur in off-peak hours. And in RUCO's proposal, there are also no demand costs being charged for a winter peak, which may be the maximum load period for electric heating customers and winter seasonal customers who would have free capacity above whatever small summer use they may place on the system. The net result could be a rate that overcharges for peak hours through both a demand charge and a flat energy charge if it is more than the energy cost for the utility. I believe the Company's original proposal more correctly reflected the need to capture maximum distribution demand whenever it occurs in each month. However, the proposal the Company indicated it would accept in its rebuttal position is satisfactory since the Company recognizes it is merely a start for us to move in the direction of a more sophisticated rate that requires a gradual transition and ultimately includes an on-peak demand charge, but certainly not of the magnitude suggested by RUCO.

RESPONDENT:

Craig Jones

WITNESS: Craig Jones

ATTACHMENT B

The National Association of State Utility Consumer Advocates Resolution 2015-1

THE NATIONAL ASSOCIATION OF STATE UTILITY CONSUMER ADVOCATES RESOLUTION 2015-1

OPPOSING GAS AND ELECTRIC UTILITY EFFORTS TO INCREASE DELIVERY SERVICE CUSTOMER CHARGES

Whereas, the National Association of State Utility Consumer Advocates ("NASUCA") has a long-standing interest in issues and policies that ensure access to least-cost gas and electric utility services, which are basic necessities of life in modern society; and

Whereas, in recent years, gas and electric utilities have sought to substantially increase the percentage of revenues recovered through the portion of the bill known as the customer charge, which does not change in relation to a residential customer's usage of utility service, through proposals to increase the customer charge or through the imposition of what have been called Straight Fixed Variable or SFV rates; and

Whereas, these gas and electric utilities have sought to justify such increases by arguing that all utility delivery costs are "fixed" and do not vary with the volume of energy supply delivered to customers, and that reductions in customer usage due to conservation and energy efficiency increase the risk of non-recovery of utility costs; and

Whereas, based on these arguments, these gas and electric utilities have proposed that a greater percentage of utility costs (distribution costs such as electric transformers and poles and natural gas mains, traditionally recovered through volumetric rates) should be collected from customers through flat, monthly customer charges; and

Whereas, gas and electric utilities' own embedded cost of service studies,[1] in fact, show that a substantial portion of utility delivery service costs are usage-related, and therefore, subject to variation based on customer usage of utility service; and

Whereas, increasing the fixed, customer charge through the imposition of SFV rates or other high customer charge structures creates disproportionate impacts on low-volume consumers within a rate class, such that the lowest users of gas and electric service shoulder the highest percentage of rate increases, and the highest users of utility service experience lower-than-average rate increases, and even rate decreases,[2] in some instances; and

Whereas, nationally recognized utility rate design principles call for the structuring of delivery service rates that are equitable, fair and cost-based; and

Whereas, SFV and other high customer charge rate design proposals, in which low-use customers would see greater than average increases, while high-use customers would experience lower-than-average increases and even decreases in their total distribution bill, are unjust and inconsistent with sound rate design principles; and

Whereas, data collected by the U.S. Energy Information Administration show that in a vast majority of regions called "reportable domains,"[3] low-income customers (with incomes at or below 150% of the federal poverty level) on average use less electricity than the statewide residential average and less than their higher-income counterparts;[4] and

Whereas, these data also show that in every reportable domain but one, elderly residential customers (65 years of age or older) use less electricity on average than the statewide residential average and less than their younger counterparts;[5] and

Whereas, these data also show that in a vast majority of reportable domains, minority (African American, Asian and Hispanic) utility customers on average use less electricity than the statewide residential average and less than their Caucasian counterparts;[6] and

Whereas, data from the U.S. Department of Energy's Residential Energy Consumption Survey for the Midwest Census region, show that natural gas consumption increases as income increases, and that higher incomes lead to occupation of larger sizes of housing units,[7] thereby increasing the likelihood of higher gas utility usage, and that natural gas usage increases as income increases in the vast majority of reportable domains throughout the U.S;[8] and

Whereas, given these documented usage patterns, the imposition of high customer charge or SFV rates unjustly shifts costs and disproportionately harms low-income, elderly, and minority ratepayers, in addition to low-users of gas and electric utility service in general; and

Whereas, because the imposition of high customer charge or SFV rates results in a smaller percentage of a customer's utility bill consisting of variable usage charges, customers' incentive to engage in conservation as well as federal and state energy efficiency programs is significantly reduced; and

Whereas, NASUCA supports the adoption of cost-effective energy efficiency programs as a means to reduce customer utility bills, help mitigate the need for new utility infrastructure, and provide important environmental benefits; and

Whereas, given that the imposition of high customer charge or SFV rates means that a smaller percentage of a customer's utility bill is derived from variable usage charges, the imposition of SFV-type rates reduces the ability of utility customers to manage and control the size of their utility bills;

Now, therefore, be it resolved, that NASUCA continues its long tradition of support for the universal provision of least-cost, essential residential gas and electric service for all customers;

Be it further resolved, that NASUCA *opposes* proposals by utility companies that seek to increase the percentage of revenues recovered through the flat, monthly customer charges on residential customer utility bills and the imposition of SFV rates;

Be it further resolved, that NASUCA urges state public service commissions to reject gas and electric utility rate design proposals that seek to substantially increase the percentage of revenues recovered through the flat, monthly customer charges on residential customer utility bills – proposals that disproportionately and inequitably increase the rates of low usage customers, a group that often includes low-income, elderly and minority customers, throughout the United States;

Be it further resolved, that state public service commissions should promote and adopt gas and electric rate design policy that minimizes monthly customer charges of residential gas and electric utility customers in order to ensure that delivery service rates are equitable, cost-based, least-cost, and encourage customer adoption of conservation and federal and state energy efficiency programs.

Be it further resolved that NASUCA authorizes its Executive Committee to develop specific positions and to take appropriate actions consistent with the terms of this resolution.

Submitted by Consumer Protection Committee

Approved June 9, 2015
Philadelphia, Pennsylvania

No Vote: Wyoming
Abstention: Vermont

[1]*See, e.g.*, Illinois Commerce Commission Docket No. 14-0244/0225, *Peoples Gas Light & Coke Co. – Proposed Increase in Delivery Service Rates,* PGL Ex. 14.2, p. 1, lines 8, 14, 38 and 42, col. D; Illinois Commerce Commission Docket No. 13-0384, *Commonwealth Edison Company,* AG Ex. 1.0 at 12-13, *citing* ComEd Ex. 3.01, Sch. 2A, p. 13, col. Tot. ICC, line 248.

[2]ICC Docket No. 14-0224/0225, AG Ex. AG/ELPC Ex. 3.0 at 15, 25.

[3]The U.S. Energy Information Administration's Residential Energy Consumption Survey provides detailed household energy usage and demographic data for 27 states or regions of the U.S. referred to as "reportable domains."

[4]*See* Wis. Pub. Serv. Com'n Docket No. 3270-UR-120, *Application of Madison Gas and Electric Co. for Authority to Adjust Electric and Natur4al Gas Rates,* Public Comments of John Howat, National Consumer Law Center, October 3, 2014, *citing* 2009 U.S. EIA Residential Energy Consumption Survey data by "Reportable Domain" at 5-6.

[5]*Id.* at 7-8.

[6]U.S. Energy Information Administration, 2009 Residential Energy Consumption Survey.

[7]*See* ICC Docket No. 14-0224/0225, *North Shore Gas, Peoples Gas Light & Coke Company – Proposed Increase in Gas Rates,* AG Ex. 4.0 at 11-12; AG Ex. 4.1, RDC-5, p.1-3.

[8]U.S. Energy Information Administration, 2009 Residential Energy Consumption Survey.