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AZ CORP COMMISSION
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Transcript Exhibit(s)

Docket #(s): E-01345A-05-0816

E-01345A-05-0826

E-01345A-05-0827

Arizona Corporation Commission
DOCKETED
DEC 29 2006

DOCKETED BY

Exhibit #: AZ-ICE 1, Kroger 1, WRA1, WRA2, FEA1-FEA5, AUIA1, AUIA2, Sweep1-Sweep3, PDMC/AECC1-PDMC/AECC6, Mundell 1-Mundell 3, Solar 1, Solar 3-Solar 6, Solar 8-Solar 10, Solar 12, Solar 13, Mayes 1-Mayes 3, Hatch-Miller 1-Hatch-Miller 6

(Part 9 of 9)

EXHIBIT
AZ-ICE-1
Admitted

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

JEFF HATCH-MILLER, Chairman
WILLIAM MUNDELL
MIKE GLEASON
KRISTIN K. MAYES
BARRY WONG

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 RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND TO AMEND DECISION NO. 67744)	) DOCKET NO. E-01345A-05-0816

Direct Testimony of

Lee W. Tanner

On behalf of Arizona Interfaith Coalition on Energy

Docket No. E-01345A-05-0816

August 31, 2006

Q. PLEASE STATE YOUR NAME.

My name is Lee W. Tanner. Both my home and my business are located in Phoenix, Arizona.

Q. BY WHOM ARE YOU EMPLOYED AND WHO DO YOU REPRESENT IN YOUR TESTIMONY?

My company is ElectriSol, Ltd. I am appearing on behalf of Arizona Interfaith Coalition on Energy (AZ-ICE) and serve on the AZ-ICE Board of Directors.

Q. WOULD YOU PROVIDE SOME INFORMATION ON THE ARIZONA INTERFAITH COALITION ON ENERGY AND DESCRIBE ITS INTEREST IN THIS PROCEEDING.

For over twenty years, AZ-ICE has been – and continues to be -- a broad-based organization of religious congregations and other communities of worship throughout Arizona. AZ-ICE's interest in this proceeding is to maintain the fair and equitable rate structure it helped establish in rate hearings before the Arizona Corporation Commission in prior years.

Q. WAS YOUR TESTIMONY PREPARED BY YOU OR UNDER YOUR DIRECTION?

Yes.

Q. WHAT IS THE SUBSTANCE OF YOUR TESTIMONY AND RECOMMENDATIONS?

Fifteen years ago, AZ-ICE intervened in consecutive APS rate hearings and was instrumental in establishing rates E- 20 through 24. We did this to correct the obvious inequities and punitive nature of the rate structure at that time toward houses of worship and other primarily off-peak customers of APS.

The proposed rate request eliminates rates E-21 through -24 and freezes E-20 (allowing for possible future elimination). In short, this proposed rate represents a return to a rate structure, which is prejudicial and harmful to houses of worship and other off-peak customers. AZ-ICE has already fought this fight – successfully fought this fight – and sees no reason to return to the 'bad old days'.

AZ-ICE recommends that E-21 through 24 be retained and that the freeze on E-20 be denied.

Q. DOES THIS COMPLETE YOUR COMMENTS?

Yes. Thank you for considering the AZ-ICE position and recommendation.

_____
Lee W. Tanner

EXHIBIT
Kroger-1
Admitted

BEFORE THE

ARIZONA CORPORATION COMMISSION

In the Matter of the Application of	)
Arizona Public Service Company for	)
A Hearing to Determine the Fair Value of the	) Docket No. E-01345A-05-0816
Utility Property of the Company for Ratemaking	)
Purposes, to Fix a Just and Reasonable Rate of Return	)
Thereon, To Approve Rate Schedules Designed to	)
Develop Such Return and to Amend Decision No. 67744	)

DIRECT TESTIMONY

AND EXHIBITS

OF

STEPHEN J. BARON

ON BEHALF OF THE

KROGER CO.

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

September 2006

BEFORE THE

ARIZONA CORPORATION COMMISSION

In the Matter of the Application of	)	
Arizona Public Service Company for	)	
A Hearing to Determine the Fair Value of the	)	**Docket No. E-01345A-05-0816**
Utility Property of the Company for Ratemaking	)	
Purposes, to Fix a Just and Reasonable Rate of Return	)	
Thereon, To Approve Rate Schedules Designed to	)	
Develop Such Return and to Amend Decision No. 67744	)	

TABLE OF CONTENTS

I. INTRODUCTION 1

II. REVENUE ALLOCATION AND COST OF SERVICE 9

III. RATE E-32 RATE DESIGN 20

BEFORE THE

ARIZONA CORPORATION COMMISSION

In the Matter of the Application of	)	
Arizona Public Service Company for	)	
A Hearing to Determine the Fair Value of the	)	**Docket No. E-01345A-05-0816**
Utility Property of the Company for Ratemaking	)	
Purposes, to Fix a Just and Reasonable Rate of Return	)	
Thereon, To Approve Rate Schedules Designed to	)	
Develop Such Return and to Amend Decision No. 67744	)	

DIRECT TESTIMONY OF STEPHEN J. BARON

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Stephen J. Baron. My business address is J. Kennedy and Associates, Inc. ("Kennedy and Associates"), 570 Colonial Park Drive, Suite 305, Roswell, Georgia 30075.

Q. What is your occupation and by who are you employed?

A. I am the President and a Principal of Kennedy and Associates, a firm of utility rate, planning, and economic consultants in Atlanta, Georgia.

1

2 **Q. Please describe briefly the nature of the consulting services provided by**
3 **Kennedy and Associates.**

4

5 A. Kennedy and Associates provides consulting services in the electric and gas utility
6 industries. Our clients include state agencies and industrial electricity consumers.
7 The firm provides expertise in system planning, load forecasting, financial analysis,
8 cost-of-service, and rate design. Current clients include the Georgia and Louisiana
9 Public Service Commissions, and industrial consumer groups throughout the United
10 States.

11

12 **Q. Please state your educational background.**

13

14 A. I graduated from the University of Florida in 1972 with a B.A. degree with high
15 honors in Political Science and significant coursework in Mathematics and
16 Computer Science. In 1974, I received a Master of Arts Degree in Economics, also
17 from the University of Florida. My areas of specialization were econometrics,
18 statistics, and public utility economics. My thesis concerned the development of an
19 econometric model to forecast electricity sales in the State of Florida, for which I
20 received a grant from the Public Utility Research Center of the University of

Florida. In addition, I have advanced study and coursework in time series analysis and dynamic model building.

Q. Please describe your professional experience.

A. I have more than thirty years of experience in the electric utility industry in the areas of cost and rate analysis, forecasting, planning, and economic analysis.

Following the completion of my graduate work in economics, I joined the staff of the Florida Public Service Commission in August of 1974 as a Rate Economist. My responsibilities included the analysis of rate cases for electric, telephone, and gas utilities, as well as the preparation of cross-examination material and the preparation of staff recommendations.

In December 1975, I joined the Utility Rate Consulting Division of Ebasco Services, Inc. as an Associate Consultant. In the seven years I worked for Ebasco, I received successive promotions, ultimately to the position of Vice President of Energy Management Services of Ebasco Business Consulting Company. My responsibilities included the management of a staff of consultants engaged in providing services in the areas of econometric modeling, load and energy

forecasting, production cost modeling, planning, cost-of-service analysis, cogeneration, and load management.

I joined the public accounting firm of Coopers & Lybrand in 1982 as a Manager of the Atlanta Office of the Utility Regulatory and Advisory Services Group. In this capacity I was responsible for the operation and management of the Atlanta office. My duties included the technical and administrative supervision of the staff, budgeting, recruiting, and marketing as well as project management on client engagements. At Coopers & Lybrand, I specialized in utility cost analysis, forecasting, load analysis, economic analysis, and planning.

In January 1984, I joined the consulting firm of Kennedy and Associates as a Vice President and Principal. I became President of the firm in January 1991.

During the course of my career, I have provided consulting services to more than thirty utility, industrial, and Public Service Commission clients, including three international utility clients.

I have presented numerous papers and published an article entitled "How to Rate Load Management Programs" in the March 1979 edition of "Electrical World." My

article on "Standby Electric Rates" was published in the November 8, 1984 issue of "Public Utilities Fortnightly." In February of 1984, I completed a detailed analysis entitled "Load Data Transfer Techniques" on behalf of the Electric Power Research Institute, which published the study.

I have presented testimony as an expert witness in Arizona, Arkansas, Colorado, Connecticut, Florida, Georgia, Indiana, Kentucky, Louisiana, Maine, Michigan, Minnesota, Maryland, Missouri, New Jersey, New Mexico, New York, North Carolina, Ohio, Pennsylvania, Texas, West Virginia, Federal Energy Regulatory Commission and in United States Bankruptcy Court. A list of my specific regulatory appearances can be found in Baron Exhibit ____ (SJB-1)

Q. Have you previously presented testimony in an Arizona Public Service Company ("APS") rate proceeding?

A. Yes. I filed testimony in the prior case, Docket No. E-01345-03-0437, on the issues of cost of service, the allocation of the proposed rate increase and rate design.

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying on behalf of the Kroger Co. Kroger has approximately 36 stores in the APS service territory operating under the names Fry's, Fred Meyer and Smith's. These stores consume in excess of 100 million kWhs per year on the APS system.

Q. What is the purpose of your testimony?

A. I will be presenting testimony on a number of cost of service and rate design issues that affect Kroger's service on APS Rate Schedule E-32. In general, I support the APS four coincident peak ("4 CP") cost of service study that it filed in this case.[1] As I will discuss, the study indicates substantial differences between the rates paid by some customers and the cost to provide service. In particular, residential customers are currently receiving very substantial dollar subsidies from general service customers. Despite this finding, the Company's proposed increases to its Residential and General Service rate classes do not attempt to provide any mitigation to this disparity between cost of service and rates; the Company is essentially proposing a uniform 21.3% increase to all customers, except irrigation pumping and some lighting schedules. I will address this issue and recommend that the Commission consider the class cost of service results in its determination of the increases to each rate schedule.

[1] Kroger is not presenting testimony on the Company's requested revenue increase in this case. For purposes of my testimony, I have utilized the APS requested increase of $450 million. This should not be construed as an endorsement of the Company's requested increase.

With regard to rate design, I will discuss the APS's proposed increases to the various charges of rate E-32. I have already noted that the Company is essentially proposing a uniform percentage increase to general service customers, despite the fact that the Company's cost of service study shows that rate E-32 customers are paying substantially above cost of service at present rates. On top of this unjustified increase, the Company is proposing to increase higher load factor E-32 customers by even greater percentage amounts than the average retail increase of 21.3%. I will discuss the Company's proposed increase to the rate E-32 demand and energy charges and recommend a more reasonable alternative to recover the Commission authorized increase to rate E-32.

Q. Would you please summarize your recommendations?

A. Yes.

- **The APS 4 CP class cost of service study is a reasonable basis to evaluate the relationship of the Company's rates, compared to the underlying cost of service. Based on the test year 4 CP study, there are large subsidies being paid by general service customers to the residential class. APS has not made any attempt in this case to reduce these disparities and move rates towards cost of service. In fact, dollar subsidies are actually being increased under the Company's proposed rates, which effectively reflect a uniform percentage increase to residential and general service classes of 21.4%.**

- **It is appropriate to make some progress towards eliminating the subsidies contained in present rates in this case. A reasonable and balanced approach**

would be to reduce class subsidies by 25% as a means of moving towards the objective of setting rates based on cost of service. Eliminating 25% of the current dollar subsidies would result in an increase to residential customers of $262.8 million (24%), while producing a $178.6 million increase or 18% to the general service class, assuming that the Company received its entire revenue increase.

- **I recommend that the revenue increase in this case be allocated such that 25% of the current dollar subsidies are reduced at proposed rates. This recommendation, if adopted, would move rates towards cost of service in a measured manner.**

- **APS is proposing to increases in its Rate E-32 delivery and generation charges in a manner that will adversely affect larger, higher load factor customers. There is no support for the Company's proposed rate design changes, based on an evaluation of the unit cost of service results filed in this case. Rate E-32 delivery charges and generation charges should be increased by an equal percentage amount, consistent with the dollar increases proposed by the Company for total delivery charges and total generation charges. This recommendation is revenue neutral to the Company, does not affect any other rate classes and results in more reasonable increases to general service customer bills, compared to the Company's proposal.**

II. REVENUE ALLOCATION AND COST OF SERVICE

Q. Have you reviewed the Company's 12 month ending September 2005 test year cost of service study filed in this proceeding?

A. Yes. The Company is utilizing a 4 coincident peak cost of service study in this proceeding. APS has traditionally used a 4 CP allocation method because of the pronounced demands on the system during the summer months. This appears to be a reasonable methodology for allocating APS production and transmission related costs. As noted by APS witness David Rumulo in response to data request UTI 3-164,

> **Production-related facilities are designed and built to enable APS to meet its system peak load. Therefore, they are allocated on the basis of the average of the system peak demands occurring in the months of June, July, August and September ("4CP").**

Q. Do you believe that the Company's 4 CP cost of service study provides a reasonable basis to evaluate the relationship between the rates being charge each rate class and the underlying cost of providing service to these customers?

A. Yes.[2] The purpose of an embedded, fully allocated class cost of service study is to assess the reasonableness of a utility's rates, in relation to the underlying cost of providing service to the customers on each rate class. As a matter of policy, it is both efficient and equitable to establish rates on the basis of the cost of service and, to the extent feasible, move rates towards cost of service in a rate case in which a utility is requesting a change in revenues. In other words, a rate case, such as the current APS proceeding, is an opportunity to evaluate the Company's rates and make incremental adjustments so that, over time, each class will pay rates reflecting cost of service. In so doing, rates paid by each customer will provide efficient "price signals" reflecting the resource cost of meeting customer demands. In addition, cost based rates provide an equitable basis to assign the Company's overall revenue requirement to customers. In this manner, customers in one rate class do not pay or receive unjustified monetary subsidies from other rate customers.

Q. How do the Company's current rates compare to the underlying cost of service?

A. A good measure of this rate versus cost relationship is the relative class rates of return at present rates. This measurement, which is the ratio of a class's rate of

[2] However, as I will more fully explain in my testimony, the Company's allocation of OATT transmission expenses are based on a uniform allocation to rate classes on a kWh basis. This overstates the allocation of cost to general service customers.

return relative to the average retail earned rate of return, provides a good summary of the rate versus cost relationship, based on the results of the 4 CP cost of service study.

Q. What are the relative class rate of return results produced by the Company's test year 4 CP cost of service study?

A. The table below summarizes the rates of return and the relative rate of return indices ("ROR Index") for each of the major rate classes using the results of the Company's 4 CP study.

TABLE 1
Comparison of Relative Rates of Return
4 Coincident Peak Cost of Service Study

Class	Rate of Return	Rate of Return Index
Residential	1.52%	0.59
General Svc	3.91%	1.51
Irrigation	9.30%	3.59
Street Light	2.05%	0.79
Dusk to Dawn	5.78%	2.23
Total Retail	2.59%	1.00

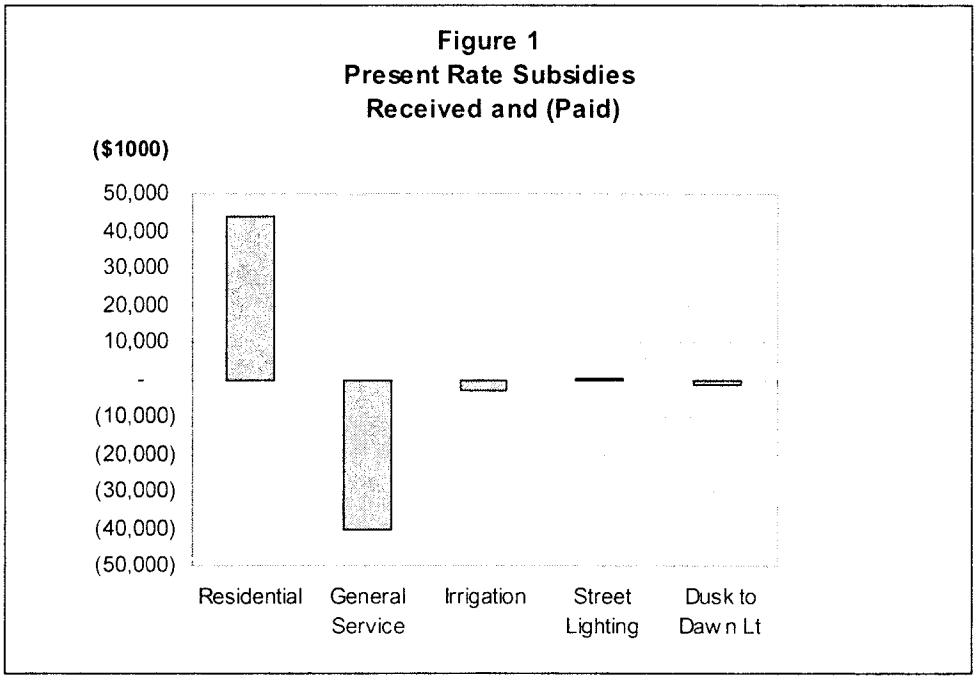
Based on these results, the residential class is paying less than 60% of its allocated cost of service under present rates, while general service customers are paying a

relative rate of return that is approximately 150% of the system average. This is a substantial difference and one that should be addressed in this rate proceeding.

Furthermore, it is worth noting that the Company has over-allocated OATT transmission expenses to general service rate schedules because of the assumption made that transmission expense allocation should follow the unbundled transmission rate design for transmission and ancillary services in retail tariffs (See APS response to UTI 3-160 d). Irrespective of the transmission cost recovery method using a uniform kWh charge, the Company incurs OATT expenses pursuant to APS OATT Schedule 11, which charges separate, and lower, transmission service rates for general service classes of service, than for residential customers. Therefore, allocating OATT transmission expenses on a uniform kWh basis overstates the allocation of these costs to general service rate classes, including rate E-32. All else being equal, the earned rates of return shown in the Company's class cost of service study are understated for general service rates and the subsidies paid by these rate schedules are even greater than the levels that I will discuss next in my testimony.

Q. Have you computed the dollar subsidies being paid and received by each rate class at present rates?

A. Yes. Figure 1 below shows the dollar subsidies paid and received at present rates. As can be seen, the residential class is receiving (shown as a positive value) over $44 million in subsidies at present rate from other rate classes. At the same time, general service customers pay annual subsidies of $40 million.



Q. Has APS made any proposals in this case that would address the substantial disparities between present rates and cost of service among its retail rate classes?

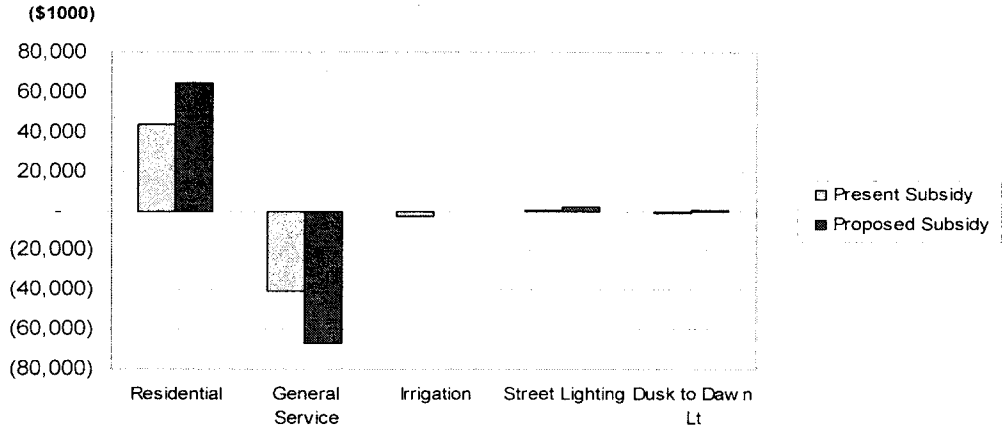
A. No. APS has not made any attempt to mitigate the cost disparities in this case. As I indicated previously, the Company is essentially proposing a uniform percentage increase for the residential and general service classes, which comprise about 98% of base revenues. This is despite the fact that the Company's own cost of service study shows that residential customers are currently paying substantially less than cost of service. Table 2 shows the proposed percentage rate increases recommended by APS in this proceeding and the resulting rate of return indices. Despite the substantial variation in relative rate of return and the concomitant subsidies being paid by general service customers, APS is recommending an equal across-the-board percentage increase for each rate class. In fact, the Company is proposing a slightly lower percentage increase to residential customers, than general service customers, who are receiving a higher than average increase.

TABLE 2
APS Proposed Rates

Class	Proposed % Increase	Proposed Subsidy
Residential	21.14%	64,344,772
General Svc	21.60%	(66,943,047)
Irrigation	0.14%	(269,809)
Street Light	24.11%	2,400,968
Dusk to Dawn	10.50%	467,116
Total Retail	21.14%	0

Figure 2 below shows the present and proposed dollar subsidies being recommended by APS in this case. APS is proposing to increase the subsidies received by residential customers and paid by general service customers.

Figure 2
Present and Proposed Rate Subsidies
Received and (Paid)



Q. Are you recommending that proposed rates in this case be set at cost of service, thus eliminating all subsidies?

A. No. I recognize that this would not be realistic, given the impact on residential customers. Though this would be an ideal result and one that should be recognized as a longer-term goal in future rate proceedings, I am not recommending the elimination of all subsidies in this proceeding. However, there is no justification for ignoring the cost of service results and simply increasing rates equally across-the-board as the Company has done. Some mitigation of the subsidies should be made in this case.

If the cost of service study was used directly to allocate the requested $450 million increase, residential customers would be assigned a $295 million increase (27%), while general service customers would receive a $148 million increase (15%). This is the result that would be obtained if 100% of the current subsidies were eliminated in this proceeding. Obviously, it would be unreasonable to increase residential rates by such a substantial amount in a single rate proceeding.

However, it is also unreasonable to completely ignore the results of the Company's cost of service study (and other cost of service analyses prepared by the Company in response to data requests).

Q. In light of the impact on residential customers of completely eliminating the subsidies in this proceeding, do you have an alternative recommendation that would recognize the results of the Company's cost of service study in allocating the increase?

A. Yes. I believe that it is appropriate to make some progress towards eliminating the subsidies contained in present rates in this case. A reasonable and balanced approach would be to reduce class subsidies by 25% as a means of moving towards the objective of setting rates based on cost of service. The analysis presented in Exhibit ____(SJB-2) shows the results of a 25% subsidy reduction in the allocation of the requested $450 million increase. As can be seen in the third "box" in Exhibit ____(SJB-2), eliminating 25% of the subsidy would result in an increase to residential customers of $262.8 million (24%), while producing a $178.6 million increase or 18% to the general service class. A 25% subsidy reduction criterion for allocating the approved revenue requirement increase in this case would still result in proposed rates that contain substantial subsidies, though these subsidies will be

reduced going forward. Subsequent rate cases should be used to further reduce subsidies in future periods.

Table 3 summarizes the proposed increases that I am recommending, assuming that the Company received its full rate request. Also shown are the remaining subsidies that will be received and paid, after the 25% reduction at proposed rates.

TABLE 3
Proposed Rates - 25% Subsidy Reduction

Class	Proposed % Increase	Proposed Subsidy ($1000)
Residential	24.1%	33,051
General Svc	18.0%	(30,362)
Irrigation	8.98%	(2,103)
Street Light	31.7%	341
Dusk to Dawn	17.8%	(927)
Total Retail	21.1%	0

Q. Does your recommended methodology reflect any adjustments to mitigate the impact on specific rate classes?

A. Yes. The increases recommended in Table 3 reflect a "capping" of the increase to the Street Light class at 1.5 times the system average percentage increase. Absent

1 this adjustment, the increase would have been approximately 1.8 times the system
2 average increase. Also, due to the impact of applying a 25% subsidy reduction to
3 the Dusk to Dawn lighting class, I am recommending that 100% of the subsidy to
4 this class be removed.[3]
5
6 **Q. What is your recommendation for allocating the revenue increase if the**
7 **Company is authorized a lower increase than it is requesting in this case?**
8
9 A. The recommended dollar increases to each rate class shown in exhibit__(SJB-2)
10 should be reduced on an equal percentage basis.

[3] Without this adjustment, the Dusk to Dawn lighting class would have received a very large increase, even though it is paying subsidies at present rates. This occurs because of the relationship between revenues and rate base for this class (the ratio of revenues to rate base for this class is very low, compared to the retail average relationship). APS fully eliminates the current subsidy paid and proposes an increase that results in a subsidy being received by this class at proposed rates. My recommendation is to fully eliminate the subsidy paid by this rate class.

III. RATE E-32 RATE DESIGN

Q. Have you reviewed APS' proposed Rate E-32 rate design?

A. Yes. The Company is proposing an overall increase to rate E-32 of 21.49%, which is about the average retail increase.[4] Within rate E-32, however, the Company is proposing rate design changes such that the increases to some E-32 customers will be significantly above the 21.49% average increase proposed for the rate. In particular, APS is proposing much larger increases to larger, high load factor customers taking service on rate E-32, than for lower load factor customers. Table 4 (following page) shows the proposed increases to the delivery service demand charges and the generation energy charges of the rate, for customers taking service at secondary voltage. As can be seen, the proposed percentage increase in the demand charge for demands in excess of 100 kW is 18.1%, while the increase for demands below 100 kW is only 4.9%. This has the obvious effect of increase the charges to customers above 100 kW by a much large amount, than for smaller customers.

Similarly, the Company is proposing to increase the generation energy charge for the "first 200 hours use" block by 25.5%, while the increase for all additional kWh

[4] This is despite the fact that this rate class is paying substantially above cost of service at present rates.

is being increased by 50.5%. This creates a very significant impact on rate E-32 customers who have load factors in excess of 27%. Overall, the Company's E-32 rate design proposal produces a large, disproportionate and adverse impact on high load factor customers with demands over 100 kW. There is no basis for this unequal treatment of these customers in the Company's rate design proposal.

Table 4
Rate E-32 Proposed Increases

	Present	Proposed	Increase	% Increase
DELIVERY CHARGES				
1st 100 kW	7.722	8.097	0.375	4.9%
All Additional kW	3.497	4.129	0.632	18.1%
All kWh	0.00010	0.00010	-	0.0%
GENERATION CHARGES				
Summer - 1st 200 kWh/kW	0.07239	0.09085	0.01846	25.5%
Summer - All Add'l kWh	0.03476	0.05230	0.01754	50.5%
Winter - 1st 200 kWh/kW	0.06246	0.07555	0.01309	21.0%
Winter - All Add'l kWh	0.02483	0.03700	0.01217	49.0%

Q. Has the Company provided any justification for this disparate treatment of rate E-32 customers?

A. No. First, as I discussed in the first part of my testimony, rate E-32, which contains the majority of the commercial customers and load, is paying millions of dollars of

subsidies at both present and proposed rates based on the Company's proposals in this case. The Company has, in fact, increased the subsidies paid by these customers at proposed rates. This unreasonable, inequitable and unjustified result is then being further compounded in the Company's E-32 rate design for larger, high load factor customers. These customers, who use a greater percentage of the energy use in off-peak periods, are being unreasonably penalized by the APS proposals in this case.

Q. Has the Company offered any cost of service justification for the disparate increases being proposed for rate E-32 customers?

A. Not in my opinion. With regard to the increases to the distribution demand charges, there does not appear to be any explanation. There is no justification for increasing the kW demand charges for demands in excess of 100 kW by more than three times the percentage increase to the "100 kW or below" block.

With regard to the generation energy charges, Mr. Rumolo states on page 26, at lines 4 through 7 of his testimony that the "cost emphasis is shifted to high energy use customers" and that this "will also encourage energy conservation through an

energy-driven price signal." No cost of service justification is offered for increasing the second energy block by 50.5 % and the first block by only half this amount.

Q. Does the Company's cost of service study support the delivery demand charges being proposed by the Company for rate E-32?

A. No. As shown in the Company's response to Question 2-2 of the 2nd Set of data requests of Distributed Energy Associates of Arizona, the "Index Rate of Return" at for E-32 customers at or below 100 kW is lower than the index for E-32 customers in the "101 – 400" kW block and the "401 – 999" kW block, at both present and proposed rates (attached as Baron Exhibit__(SJB-3). Though this is not the case for the "1000+" kW block, these customers only comprise about 12% of E-32 revenue requirements. Based on the cost of service study, there is no basis to increase rates for larger customers by a greater percentage than smaller customers.

Q. Does the Company's cost of service study support the generation charges being proposed by the Company for rate E-32?

A. No. The unit cost of production energy cost for rate E-32, at the Company's proposed rate of return (i.e., no subsidies) is about 6.5 cents per kWh. Table 5

below shows the unit cost (at an 8.73% rate of return) of production energy for each of the usage blocks of rate E-32.

Table 5
Rate E-32 Production Energy - Unit Cost Per kWh

	Production Energy Rev. Req)	MWh Sales	Unit Cost (cents/kWh)
<20	45,919,976	1,307,541	3.512
20-100	83,566,716	2,511,175	3.328
101-400	108,496,471	3,140,255	3.455
401-999	70,838,916	2,188,928	3.236
1000+	52,655,646	1,626,501	3.237
Total	361,477,725	10,774,400	3.355

As shown in Table 4, the proposed rate E-32 generation charge for the "all additional kWh" is 5.23 cents per kWh in the summer and 3.7 cents per kWh in the winter. Both of these rates exceed the "all hours" unit cost of production energy of 3.335 cents per kWh.[5]

Q. What do you conclude from this analysis?

A. The Company's proposed percentage increases to the generation energy charges are not reasonable. The Company's argument seems to be that increases in fuel costs

[5] The "all-hours" rate reflects the weighted average of summer and winter costs.

justify a more or less uniform "cents per kWh" increase to the generation rates, rather than uniform percentage increases. The problem with this argument is that it presupposes that the existing rates are cost based; which they are not. Therefore, the price-signal benefits cited by Mr. Rumolo require that rates reflect cost, not just that incremental changes reflect cost.

Q. What is your recommendation to address this rate design problem?

A. I recommend that the E-32 delivery charges and generation charges be increased by an equal percentage amount, consistent with the dollar increases proposed by the Company for delivery charges and generation charges. However, if the Commission reduces the E-32 revenue requirement to reflect my recommended allocation of the approved revenue increase and/or the Commission reduces the overall revenue increase, the E-32 rate elements should be reduced proportionately on a percentage basis. Table 6 below shows my recommended delivery and generation charges (for secondary voltage customers) using a uniform percentage increase to each of the two delivery charges and a uniform percentage increase to each of the two generation rates, consistent with the Company's revenue increases for E-32 delivery and generation charges. I am not recommending changes to the Company's proposed primary and secondary voltage discounts, which should be

applied to the rates shown in Table 6 to obtain primary and transmission voltage rates. Also, I am not recommending any changes to the Company's proposed E-32 rates for customer charges or for charges associated with service for customers with demands less than 20 kW.

Table 6
Rate E-32 Proposed Increases - Recommended

	Present	Proposed	Increase	% Increase
DELIVERY CHARGES				
1st 100 kW	7.722	8.376	0.654	8.5%
All Additional kW	3.497	3.793	0.296	8.5%
All kWh	0.00010	0.00010	-	0.0%
GENERATION CHARGES				
Summer - 1st 200 kWh/kW	0.07239	0.09525	0.02286	31.6%
Summer - All Add'l kWh	0.03476	0.04574	0.01098	31.6%
Winter - 1st 200 kWh/kW	0.06246	0.08218	0.01972	31.6%
Winter - All Add'l kWh	0.02483	0.03266	0.00783	31.5%

Baron Exhibit__(SJB-4), schedules 1 and 2 contain the proof of revenues supporting the proposed rates shown in Table 6. Schedule 1 shows the proof of revenues for rate E-32 using the Company's proposed rate design, while schedule 2 shows adjusted increases to the delivery and generation rates that I am recommending. As can be seen, the total revenues are identical in both schedules. Also, the total delivery charge revenues and total generation charge revenues are

1 identical for both schedules. This demonstrates that my proposed changes produce
2 identical E-32 revenues for delivery service and generation service, compared to the
3 Company's proposal.
4
5 **Q. Does that complete your testimony?**
6
7 A. Yes.

BEFORE THE

ARIZONA CORPORATION COMMISSION

In the Matter of the Application of	)	
Arizona Public Service Company for	)	
A Hearing to Determine the Fair Value of the	)	Docket No. E-01345A-05-0816
Utility Property of the Company for Ratemaking	)	
Purposes, to Fix a Just and Reasonable Rate of Return	)	
Thereon, To Approve Rate Schedules Designed to	)	
Develop Such Return and to Amend Decision No. 67744	)	

EXHIBITS

OF

STEPHEN J. BARON

ON BEHALF OF THE

KROGER CO.

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

September 2006

BEFORE THE

ARIZONA CORPORATION COMMISSION

In the Matter of the Application of	)
Arizona Public Service Company for	)
A Hearing to Determine the Fair Value of the	) Docket No. E-01345A-05-0816
Utility Property of the Company for Ratemaking	)
Purposes, to Fix a Just and Reasonable Rate of Return	)
Thereon, To Approve Rate Schedules Designed to	)
Develop Such Return and to Amend Decision No. 67744	)

EXHIBIT__(SJB-1)

OF

STEPHEN J. BARON

ON BEHALF OF THE

KROGER CO.

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

September 2006

Expert Testimony Appearances
of
Stephen J. Baron
As of August 2006

Date	Case	Jurisdict.	Party	Utility	Subject
4/81	203(B)	KY	Louisville Gas & Electric Co.	Louisville Gas & Electric Co.	Cost-of-service.
4/81	ER-81-42	MO	Kansas City Power & Light Co.	Kansas City Power & Light Co.	Forecasting.
6/81	U-1933	AZ	Arizona Corporation Commission	Tucson Electric Co.	Forecasting planning.
2/84	8924	KY	Airco Carbide	Louisville Gas & Electric Co.	Revenue requirements, cost-of-service, forecasting, weather normalization.
3/84	84-038-U	AR	Arkansas Electric Energy Consumers	Arkansas Power & Light Co.	Excess capacity, cost-of-service, rate design.
5/84	830470-EI	FL	Florida Industrial Power Users' Group	Florida Power Corp.	Allocation of fixed costs, load and capacity balance, and reserve margin. Diversification of utility.
10/84	84-199-U	AR	Arkansas Electric Energy Consumers	Arkansas Power and Light Co.	Cost allocation and rate design.
11/84	R-842651	PA	Lehigh Valley Power Committee	Pennsylvania Power & Light Co.	Interruptible rates, excess capacity, and phase-in.
1/85	85-65	ME	Airco Industrial Gases	Central Maine Power Co.	Interruptible rate design.
2/85	I-840381	PA	Philadelphia Area Industrial Energy Users' Group	Philadelphia Electric Co.	Load and energy forecast.
3/85	9243	KY	Alcan Aluminum Corp., et al.	Louisville Gas & Electric Co.	Economics of completing fossil generating unit.
3/85	3498-U	GA	Attorney General	Georgia Power Co.	Load and energy forecasting, generation planning economics.
3/85	R-842632	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Generation planning economics, prudence of a pumped storage hydro unit.
5/85	84-249	AR	Arkansas Electric Energy Consumers	Arkansas Power & Light Co.	Cost-of-service, rate design return multipliers.
5/85		City of Santa	Chamber of Commerce	Santa Clara Municipal	Cost-of-service, rate design.

Expert Testimony Appearances
of
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As of August 2006

Date	Case	Jurisdict.	Party	Utility	Subject
6/85	84-768-E-42T	Clara WV	West Virginia Industrial Intervenors	Monongahela Power Co.	Generation planning economics, prudence of a pumped storage hydro unit.
6/85	E-7 Sub 391	NC	Carolina Industrials (CIGFUR III)	Duke Power Co.	Cost-of-service, rate design, interruptible rate design.
7/85	29046	NY	Industrial Energy Users Association	Orange and Rockland Utilities	Cost-of-service, rate design.
10/85	85-043-U	AR	Arkansas Gas Consumers	Arkla, Inc.	Regulatory policy, gas cost-of-service, rate design.
10/85	85-63	ME	Airco Industrial Gases	Central Maine Power Co.	Feasibility of interruptible rates, avoided cost.
2/85	ER-8507698	NJ	Air Products and Chemicals	Jersey Central Power & Light Co.	Rate design.
3/85	R-850220	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Optimal reserve, prudence, off-system sales guarantee plan.
2/86	R-850220	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Optimal reserve margins, prudence, off-system sales guarantee plan.
3/86	85-299U	AR	Arkansas Electric Energy Consumers	Arkansas Power & Light Co.	Cost-of-service, rate design, revenue distribution.
3/86	85-726-EL-AIR	OH	Industrial Electric Consumers Group	Ohio Power Co.	Cost-of-service, rate design, interruptible rates.
5/86	86-081-E-GI	WV	West Virginia Energy Users Group	Monongahela Power Co.	Generation planning economics, prudence of a pumped storage hydro unit.
8/86	E-7 Sub 408	NC	Carolina Industrial Energy Consumers	Duke Power Co.	Cost-of-service, rate design, interruptible rates.
10/86	U-17378	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Excess capacity, economic analysis of purchased power.
12/86	38063	IN	Industrial Energy Consumers	Indiana & Michigan Power Co.	Interruptible rates.

Expert Testimony Appearances
of
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As of August 2006

Date	Case	Jurisdict.	Party	Utility	Subject
3/87	EL-86-53-001 EL-86-57-001	Federal Energy Regulatory Commission (FERC)	Louisiana Public Service Commission Staff	Gulf States Utilities, Southern Co.	Cost/benefit analysis of unit power sales contract.
4/87	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Load forecasting and imprudence damages, River Bend Nuclear unit.
5/87	87-023-E-C	WV	Airco Industrial Gases	Monongahela Power Co.	Interruptible rates.
5/87	87-072-E-G1	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Analyze Mon Power's fuel filing and examine the reasonableness of MP's claims.
5/87	86-524-E-SC	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Economic dispatching of pumped storage hydro unit.
5/87	9781	KY	Kentucky Industrial Energy Consumers	Louisville Gas & Electric Co.	Analysis of impact of 1986 Tax Reform Act.
6/87	3673-U	GA	Georgia Public Service Commission	Georgia Power Co.	Economic prudence, evaluation of Vogtle nuclear unit - load forecasting, planning.
6/87	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Phase-in plan for River Bend Nuclear unit.
7/87	85-10-22	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Methodology for refunding rate moderation fund.
8/87	3673-U	GA	Georgia Public Service Commission	Georgia Power Co.	Test year sales and revenue forecast.
9/87	R-850220	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Excess capacity, reliability of generating system.
10/87	R-870651	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Interruptible rate, cost-of-service, revenue allocation, rate design.
10/87	I-860025	PA	Pennsylvania Industrial Intervenors		Proposed rules for cogeneration, avoided cost, rate recovery.

Expert Testimony Appearances
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As of August 2006

Date	Case	Jurisdict.	Party	Utility	Subject
10/87	E-015/ GR-87-223	MN	Taconite Intervenors	Minnesota Power & Light Co.	Excess capacity, power and cost-of-service, rate design.
10/87	8702-EI	FL	Occidental Chemical Corp.	Florida Power Corp.	Revenue forecasting, weather normalization.
12/87	87-07-01	CT	Connecticut Industrial Energy Consumers	Connecticut Light Power Co.	Excess capacity, nuclear plant phase-in.
3/88	10064	KY	Kentucky Industrial Energy Consumers	Louisville Gas & Electric Co.	Revenue forecast, weather normalization rate treatment of cancelled plant.
3/88	87-183-TF	AR	Arkansas Electric Consumers	Arkansas Power & Light Co.	Standby/backup electric rates.
5/88	870171C001	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Cogeneration deferral mechanism, modification of energy cost recovery (ECR).
6/88	870172C005	PA	GPU Industrial Intervenors	Pennsylvania Electric Co.	Cogeneration deferral mechanism, modification of energy cost recovery (ECR).
7/88	88-171-EL-AIR 88-170-EL-AIR Interim Rate Case	OH	Industrial Energy Consumers	Cleveland Electric/ Toledo Edison	Financial analysis/need for interim rate relief.
7/88	Appeal of PSC	19th Judicial Docket U-17282	Louisiana Public Service Commission Circuit Court of Louisiana	Gulf States Utilities	Load forecasting, imprudence damages.
11/88	R-880989	PA	United States Steel	Carnegie Gas	Gas cost-of-service, rate design.
11/88	88-171-EL-AIR 88-170-EL-AIR	OH	Industrial Energy Consumers	Cleveland Electric/ Toledo Edison. General Rate Case.	Weather normalization of peak loads, excess capacity, regulatory policy.
3/89	870216/283 284/286	PA	Armco Advanced Materials Corp., Allegheny Ludlum Corp.	West Penn Power Co.	Calculated avoided capacity, recovery of capacity payments.

Expert Testimony Appearances
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As of August 2006

Date	Case	Jurisdict.	Party	Utility	Subject
8/89	8555	TX	Occidental Chemical Corp.	Houston Lighting & Power Co.	Cost-of-service, rate design.
8/89	3840-U	GA	Georgia Public Service Commission	Georgia Power Co.	Revenue forecasting, weather normalization.
9/89	2087	NM	Attorney General of New Mexico	Public Service Co. of New Mexico	Prudence - Palo Verde Nuclear Units 1, 2 and 3, load fore-casting.
10/89	2262	NM	New Mexico Industrial Energy Consumers	Public Service Co. of New Mexico	Fuel adjustment clause, off-system sales, cost-of-service, rate design, marginal cost.
11/89	38728	IN	Industrial Consumers for Fair Utility Rates	Indiana Michigan Power Co.	Excess capacity, capacity equalization, jurisdictional cost allocation, rate design, interruptible rates.
1/90	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Jurisdictional cost allocation, O&M expense analysis.
5/90	890366	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Non-utility generator cost recovery.
6/90	R-901609	PA	Armco Advanced Materials Corp., Allegheny Ludlum Corp.	West Penn Power Co.	Allocation of QF demand charges in the fuel cost, cost-of-service, rate design.
9/90	8278	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.	Cost-of-service, rate design, revenue allocation.
12/90	U-9346 Rebuttal	MI	Association of Businesses Advocating Tariff Equity	Consumers Power Co.	Demand-side management, environmental externalities.
12/90	U-17282 Phase IV	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, jurisdictional allocation.
12/90	90-205	ME	Airco Industrial Gases	Central Maine Power Co.	Investigation into interruptible service and rates.
1/91	90-12-03 Interim	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Interim rate relief, financial analysis, class revenue allocation.

Expert Testimony Appearances
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Stephen J. Baron
As of August 2006

Date	Case	Jurisdict.	Party	Utility	Subject
5/91	90-12-03 Phase II	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Revenue requirements, cost-of-service, rate design, demand-side management.
8/91	E-7, SUB SUB 487	NC	North Carolina Industrial Energy Consumers	Duke Power Co.	Revenue requirements, cost allocation, rate design, demand-side management.
8/91	8341 Phase I	MD	Westvaco Corp.	Potomac Edison Co.	Cost allocation, rate design, 1990 Clean Air Act Amendments.
8/91	91-372 EL-UNC	OH	Armco Steel Co., L.P.	Cincinnati Gas & Electric Co.	Economic analysis of cogeneration, avoid cost rate.
9/91	P-910511 P-910512	PA	Allegheny Ludlum Corp., Armco Advanced Materials Co., The West Penn Power Industrial Users' Group	West Penn Power Co.	Economic analysis of proposed CWIP Rider for 1990 Clean Air Act Amendments expenditures.
9/91	91-231 -E-NC	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Economic analysis of proposed CWIP Rider for 1990 Clean Air Act Amendments expenditures.
10/91	8341 - Phase II	MD	Westvaco Corp.	Potomac Edison Co.	Economic analysis of proposed CWIP Rider for 1990 Clean Air Act Amendments expenditures.
10/91	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Results of comprehensive management audit.
Note: No testimony was prefiled on this.					
11/91	U-17949 Subdocket A	LA	Louisiana Public Service Commission Staff	South Central Bell Telephone Co. and proposed merger with Southern Bell Telephone Co.	Analysis of South Central Bell's restructuring and
12/91	91-410-EL-AIR	OH	Armco Steel Co., Air Products & Chemicals, Inc.	Cincinnati Gas & Electric Co.	Rate design, interruptible rates.
12/91	P-880286	PA	Armco Advanced Materials Corp., Allegheny Ludlum Corp.	West Penn Power Co.	Evaluation of appropriate avoided capacity costs - QF projects.

Expert Testimony Appearances
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As of August 2006

Date	Case	Jurisdict.	Party	Utility	Subject
1/92	C-913424	PA	Duquesne Interruptible Complainants	Duquesne Light Co.	Industrial interruptible rate.
6/92	92-02-19	CT	Connecticut Industrial Energy Consumers	Yankee Gas Co.	Rate design.
8/92	2437	NM	New Mexico Industrial Intervenors	Public Service Co. of New Mexico	Cost-of-service.
8/92	R-00922314	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Cost-of-service, rate design, energy cost rate.
9/92	39314	ID	Industrial Consumers for Fair Utility Rates	Indiana Michigan Power Co.	Cost-of-service, rate design, energy cost rate, rate treatment.
10/92	M-00920312 C-007	PA	The GPU Industrial Intervenors	Pennsylvania Electric Co.	Cost-of-service, rate design, energy cost rate, rate treatment.
12/92	U-17949	LA	Louisiana Public Service Commission Staff	South Central Bell Co.	Management audit.
12/92	R-00922378	PA	Armco Advanced Materials Co. The WPP Industrial Intervenors	West Penn Power Co.	Cost-of-service, rate design, energy cost rate, SO_2 allowance rate treatment.
1/93	8487	MD	The Maryland Industrial Group	Baltimore Gas & Electric Co.	Electric cost-of-service and rate design, gas rate design (flexible rates).
2/93	E002/GR-92-1185	MN	North Star Steel Co. Praxair, Inc.	Northern States Power Co.	Interruptible rates.
4/93	EC92 21000 ER92-806-000 (Rebuttal)	Federal Energy Regulatory Commission	Louisiana Public Service Commission Staff	Gulf States Utilities/Entergy agreement.	Merger of GSU into Entergy System; impact on system
7/93	93-0114-E-C	WV	Airco Gases	Monongahela Power Co.	Interruptible rates.
8/93	930759-EG	FL	Florida Industrial Power Users' Group	Generic - Electric Utilities	Cost recovery and allocation of DSM costs.
9/93	M-009 30406	PA	Lehigh Valley Power Committee	Pennsylvania Power & Light Co.	Ratemaking treatment of off-system sales revenues.

Expert Testimony Appearances
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As of August 2006

Date	Case	Jurisdict.	Party	Utility	Subject
11/93	346	KY	Kentucky Industrial Utility Customers	Generic - Gas Utilities	Allocation of gas pipeline transition costs - FERC Order 636.
12/93	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	Nuclear plant prudence, forecasting, excess capacity.
4/94	E-015/ GR-94-001	MN	Large Power Intervenors	Minnesota Power Co.	Cost allocation, rate design, rate phase-in plan.
5/94	U-20178	LA	Louisiana Public Service Commission	Louisiana Power & Light Co.	Analysis of least cost integrated resource plan and demand-side management program.
7/94	R-00942986	PA	Armco, Inc.; West Penn Power Industrial Intervenors	West Penn Power Co.	Cost-of-service, allocation of rate increase, rate design, emission allowance sales, and operations and maintenance expense.
7/94	94-0035-E-42T	WV	West Virginia Energy Users Group	Monongahela Power Co.	Cost-of-service, allocation of rate increase, and rate design.
8/94	EC94 13-000	Federal Energy Regulatory Commission	Louisiana Public Service Commission	Gulf States Utilities/Entergy	Analysis of extended reserve shutdown units and violation of system agreement by Entergy.
9/94	R-00943 081 R-00943 081C0001	PA	Lehigh Valley Power Committee	Pennsylvania Public Utility Commission	Analysis of interruptible rate terms and conditions, availability.
9/94	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Evaluation of appropriate avoided cost rate.
9/94	U-19904	LA	Louisiana Public Service Commission	Gulf States Utilities	Revenue requirements.
10/94	5258-U	GA	Georgia Public Service Commission	Southern Bell Telephone & Telegraph Co.	Proposals to address competition in telecommunication markets.
11/94	EC94-7-000 ER94-898-000	FERC	Louisiana Public Service Commission	El Paso Electric and Central and Southwest	Merger economics, transmission equalization hold harmless proposals.
2/95	941-430EG	CO	CF&I Steel, L.P.	Public Service Company of Colorado	Interruptible rates, cost-of-service.

Expert Testimony Appearances
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As of August 2006

Date	Case	Jurisdict.	Party	Utility	Subject
4/95	R-00943271	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Cost-of-service, allocation of rate increase, rate design, interruptible rates.
6/95	C-00913424 C-00946104	PA	Duquesne Interruptible Complainants	Duquesne Light Co.	Interruptible rates.
8/95	ER95-112 -000	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Open Access Transmission Tariffs - Wholesale.
10/95	U-21485	LA	Louisiana Public Service Commission	Gulf States Utilities Company	Nuclear decommissioning, revenue requirements, capital structure.
10/95	ER95-1042 -000	FERC	Louisiana Public Service Commission	System Energy Resources, Inc.	Nuclear decommissioning, revenue requirements.
10/95	U-21485	LA	Louisiana Public Service Commission	Gulf States Utilities Co.	Nuclear decommissioning and cost of debt capital, capital structure.
11/95	I-940032	PA	Industrial Energy Consumers of Pennsylvania	State-wide - all utilities	Retail competition issues.
7/96	U-21496	LA	Louisiana Public Service Commission	Central Louisiana Electric Co.	Revenue requirement analysis.
7/96	8725	MD	Maryland Industrial Group	Baltimore Gas & Elec. Co., Potomac Elec. Power Co., Constellation Energy Co.	Ratemaking issues associated with a Merger.
8/96	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Revenue requirements.
9/96	U-22092	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Decommissioning, weather normalization, capital structure.
2/97	R-973877	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Competitive restructuring policy issues, stranded cost, transition charges.
6/97	Civil Action No. 94-11474	US Bank-ruptcy Court Middle District of Louisiana	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Confirmation of reorganization plan; analysis of rate paths produced by competing plans.

Expert Testimony Appearances
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As of August 2006

Date	Case	Jurisdict.	Party	Utility	Subject
6/97	R-973953	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Retail competition issues, rate unbundling, stranded cost analysis.
6/97	8738	MD	Maryland Industrial Group	Generic	Retail competition issues
7/97	R-973954	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Retail competition issues, rate unbundling, stranded cost analysis.
10/97	97-204	KY	Alcan Aluminum Corp. Southwire Co.	Big River Electric Corp.	Analysis of cost of service issues - Big Rivers Restructuring Plan
10/97	R-974008	PA	Metropolitan Edison Industrial Users	Metropolitan Edison Co.	Retail competition issues, rate unbundling, stranded cost analysis.
10/97	R-974009	PA	Pennsylvania Electric Industrial Customer	Pennsylvania Electric Co.	Retail competition issues, rate unbundling, stranded cost analysis.
11/97	U-22491	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Decommissioning, weather normalization, capital structure.
11/97	P-971265	PA	Philadelphia Area Industrial Energy Users Group	Enron Energy Services Power, Inc./ PECO Energy	Analysis of Retail Restructuring Proposal.
12/97	R-973981	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Retail competition issues, rate unbundling, stranded cost analysis.
12/97	R-974104	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Retail competition issues, rate unbundling, stranded cost analysis.
3/98 (Allocated Stranded Cost Issues)	U-22092	LA	Louisiana Public Service Commission	Gulf States Utilities Co.	Retail competition, stranded cost quantification.
3/98	U-22092		Louisiana Public Service Commission	Gulf States Utilities, Inc.	Stranded cost quantification, restructuring issues.
9/98	U-17735		Louisiana Public Service Commission	Cajun Electric Power Cooperative, Inc.	Revenue requirements analysis, weather normalization.
12/98	8794	MD	Maryland Industrial Group and	Baltimore Gas and Electric Co.	Electric utility restructuring, stranded cost recovery, rate

Expert Testimony Appearances
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As of August 2006

Date	Case	Jurisdict.	Party	Utility	Subject
			Millennium Inorganic Chemicals Inc.		unbundling.
12/98	U-23358	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Nuclear decommissioning, weather normalization, Entergy System Agreement.
5/99 (Cross-Answering Testimony)	EC-98-40-000	FERC	Louisiana Public Service Commission	American Electric Power Co. & Central South West Corp.	Merger issues related to market power mitigation proposals.
5/99 (Response Testimony)	98-426	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co.	Performance based regulation, settlement proposal issues, cross-subsidies between electric. gas services.
6/99	98-0452	WV	West Virginia Energy Users Group	Appalachian Power, Monongahela Power, & Potomac Edison Companies	Electric utility restructuring, stranded cost recovery, rate unbundling.
7/99	99-03-35	CT	Connecticut Industrial \Energy Consumers	United Illuminating Company	Electric utility restructuring, stranded cost recovery, rate unbundling.
7/99	Adversary Proceeding No. 98-1065	U.S. Bankruptcy Court	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Motion to dissolve preliminary injunction.
7/99	99-03-06	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Electric utility restructuring, stranded cost recovery, rate unbundling.
10/99	U-24182	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Nuclear decommissioning, weather normalization, Entergy System Agreement.
12/99	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative, Inc.	Ananlysi of Proposed Contract Rates, Market Rates.
03/00	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative, Inc.	Evaluation of Cooperative Power Contract Elections
03/00	99-1658-EL-ETP	OH	AK Steel Corporation	Cincinnati Gas & Electric Co.	Electric utility restructuring, stranded cost recovery, rate Unbundling.

Expert Testimony Appearances
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As of August 2006

Date	Case	Jurisdict.	Party	Utility	Subject
08/00	98-0452 E-GI	WVA	West Virginia Energy Users Group	Appalachian Power Co. American Electric Co.	Electric utility restructuring rate unbundling.
08/00	00-1050 E-T 00-1051-E-T	WVA	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Electric utility restructuring rate unbundling.
10/00	SOAH 473-00-1020 PUC 2234	TX	The Dallas-Fort Worth Hospital Council and The Coalition of Independent Colleges And Universities	TXU, Inc.	Electric utility restructuring rate unbundling.
12/00	U-24993	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Nuclear decommissioning, revenue requirements.
12/00	EL00-66-000 & ER-2854-000 EL95-33-002	LA	Louisiana Public Service Commission	Entergy Services Inc.	Inter-Company System Agreement: Modifications for retail competition, interruptible load.
04/01	U-21453, U-20925, U-22092 (Subdocket B) Addressing Contested Issues	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Jurisdictional Business Separation - Texas Restructuring Plan
10/01	14000-U	GA	Georgia Public Service Commission Adversary Staff	Georgia Power Co.	Test year revenue forecast.
11/01	U-25687	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Nuclear decommissioning requirements transmission revenues.
11/01	U-25965	LA	Louisiana Public Service Commission	Generic .	Independent Transmission Company ("Transco"). RTO rate design.
03/02	001148-EI	FL	South Florida Hospital and Healthcare Assoc.	Florida Power & Light Company	Retail cost of service, rate design, resource planning and demand side management.
06/02	U-25965	LA	Louisiana Public Service Commission	Entergy Gulf States Entergy Louisiana	RTO Issues
07/02	U-21453	LA	Louisiana Public Service Commission	SWEPCO, AEP	Jurisdictional Business Sep. - Texas Restructuring Plan.

Expert Testimony Appearances
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As of August 2006

Date	Case	Jurisdict.	Party	Utility	Subject
08/02	U-25888	LA	Louisiana Public Service Commission	Entergy Louisiana, Inc. Entergy Gulf States, Inc.	Modifications to the Inter-Company System Agreement, Production Cost Equalization.
08/02	EL01-88-000	FERC	Louisiana Public Service Commission	Entergy Services Inc. and the Entergy Operating Companies	Modifications to the Inter-Company System Agreement, Production Cost Equalization.
11/02	02S-315EG	CO	CF&I Steel & Climax Molybdenum Co.	Public Service Co. of Colorado	Fuel Adjustment Clause
01/03	U-17735	LA	Louisiana Public Service Commission	Louisiana Coops	Contract Issues
02/03	02S-594E	CO	Cripple Creek and Victor Gold Mining Co.	Aquila, Inc.	Revenue requirements, purchased power.
04/03	U-26527	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Weather normalization, power purchase expenses, System Agreement expenses.
11/03	ER03-753-000	FERC	Louisiana Public Service Commission Staff	Entergy Services, Inc. and the Entergy Operating Companies	Proposed modifications to System Agreement Tariff MSS-4.
11/03	ER03-583-000 ER03-583-001 ER03-583-002 ER03-681-000, ER03-681-001 ER03-682-000, ER03-682-001 ER03-682-002	FERC	Louisiana Public Service Commission	Entergy Services, Inc., the Entergy Operating Companies, EWO Market-Ing, L.P, and Entergy Power, Inc.	Evaluation of Wholesale Purchased Power Contracts.
12/03	U-27136	LA	Louisiana Public Service Commission	Entergy Louisiana, Inc.	Evaluation of Wholesale Purchased Power Contracts.
01/04	E-01345-03-0437	AZKroger Company	Arizona Public Service Co.	Revenue allocation rate design.	
02/04	00032071	PA	Duquesne Industrial Intervenors	Duquesne Light Company	Provider of last resort issues.
03/04	03A-436E	CO	CF&I Steel, LP and Climax Molybedenum	Public Service Company of Colorado	Purchased Power Adjustment Clause.

Expert Testimony Appearances
of
Stephen J. Baron
As of August 2006

Date	Case	Jurisdict.	Party	Utility	Subject
04/04	2003-00433 2003-00434	PA	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co. Kentucky Utilities Co.	Cost of Service Rate Design
0-6/04	03S-539E	CO	Cripple Creek, Victor Gold Mining Co., Goodrich Corp., Holcim (U.S.,), Inc., and The Trane Co.	Aquila, Inc.	Cost of Service, Rate Design Interruptible Rates
06/04	R-00049255	PA	PP&L Industrial Customer Alliance PPLICA	PPL Electric Utilities Corp.	Cost of service, rate design, tariff issues and transmission service charge.
10/04	04S-164E	CO	CF&I Steel Company, Climax Mines	Public Service Company of Colorado	Cost of service, rate design, Interruptible Rates.
03/05	Case No. 2004-00426 Case No. 2004-00421	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Louisville Gas & Electric Co.	Environmental cost recovery.
06/05	050045-EI	FL	South Florida Hospital and Healthcare Assoc.	Florida Power & Light Company	Retail cost of service, rate design
07/05	U-28155	LA	Louisiana Public Service Commission Staff	Entergy Louisiana, Inc. Entergy Gulf States, Inc.	Independent Coordinator of Transmission – Cost/Benefit
09/05	Case Nos. 05-0402-E-CN 05-0750-E-PC	WVA	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Environmental cost recovery, Securitization, Financing Order
01/06	2005-00341	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Cost of service, rate design, transmission expenses. Congestion Cost Recovery Mechanism
03/06	U-22092	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Separation of EGSI into Texas and Louisiana Companies.
04/06	U-25116	LA	Louisiana Public Service Commission Staff	Entergy Louisiana, Inc.	Transmission Prudence Investigation
06/06	R-00061346 C0001-0005	PA	Duquesne Industrial Intervenors & IECPA	Duquesne Light Co.	Cost of Service, Rate Design, Transmission Service Charge, Tariff Issues
06/06	R-00061366 R-00061367 P-00062213 P-00062214		Met-Ed Industrial Energy Users Group and Penelec Industrial Customer Alliance	Metropolitan Edison Co. Pennsylvania Electric Co.	Generation Rate Cap, Transmission Service Charge, Cost of Service, Rate Design, Tariff Issues
07/06	U-22092 Sub-J	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Separation of EGSI into Texas and Louisiana Companies.

Expert Testimony Appearances
of
Stephen J. Baron
As of August 2006

Date	Case	Jurisdict.	Party	Utility	Subject
07/06	Case No. 2006-00130 Case No. 2006-00129	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Louisville Gas & Electric Co.	Environmental cost recovery.

BEFORE THE

ARIZONA CORPORATION COMMISSION

In the Matter of the Application of	)	
Arizona Public Service Company for	)	
A Hearing to Determine the Fair Value of the	)	Docket No. E-01345A-05-0816
Utility Property of the Company for Ratemaking	)	
Purposes, to Fix a Just and Reasonable Rate of Return	)	
Thereon, To Approve Rate Schedules Designed to	)	
Develop Such Return and to Amend Decision No. 67744	)	

EXHIBIT__(SJB-2)

OF

STEPHEN J. BARON

ON BEHALF OF THE

KROGER CO.

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

September 2006

ARIZONA PUBLIC SERVICE COMPANY
Computation of Rate Increase Necessary to Reduce Class Subsidy by 25%
Adjusted to Cap Street Lighting at 1.5x System Avg, Dusk to Dawn Subsidy to 0

	Total ACC Jurisdiction	Residential	General Service	Irrigation	Street Lighting	Dusk to Dawn Lt
COST OF SERVICE AT PRESENT RATES						
REVENUES FROM RATES	2,066,144,726	1,058,729,739	967,398,538	20,966,540	12,913,053	6,136,856
PROFORMA TO REVENUES FROM RATES	61,177,173	30,821,291	29,741,269	(102,439)	431,212	285,840
Revenue (Existing Rates)	2,127,321,899	1,089,551,030	997,139,807	20,864,101	13,344,265	6,422,696
TOTAL OPERATING EXPENSES	3,324,685,995	1,676,708,745	1,586,753,006	34,232,906	20,364,595	6,626,743
OTHER ELECTRIC REVENUE	1,313,268,572	624,903,158	662,981,779	15,739,104	8,074,267	1,570,264
Net Operating Expenses	2,011,417,422	1,051,805,586	923,771,226	18,493,802	12,290,329	5,056,479
Net Operating Income	115,904,477	37,745,444	73,368,581	2,370,299	1,053,936	1,366,217
Rate Base	4,466,696,503	2,489,739,662	1,876,563,795	25,474,477	51,298,118	23,620,451
Rate of Return	2.59%	1.52%	3.91%	9.30%	2.05%	5.78%
Rate of Return Index	1.000	0.584	1.507	3.586	0.792	2.229
Subsidy at Present Rate of Return	0	44,068,565	(40,483,012)	(2,804,384)	454,762	(1,235,931)
Percentage Increase		4.04%	-4.06%	-13.44%	3.41%	-19.24%
Increase to Equalized Proposed Rate of Return	449,616,818	294,685,284	148,411,542	(240,128)	5,618,421	1,141,699
Percentage Increase		27.05%	14.88%	-1.15%	42.10%	17.78%
APS Proposed Percentage Increases	21.14%	21.14%	21.60%	0.14%	24.11%	10.50%
Proposed Class Rate Increase	449,616,818	230,340,512	215,354,589	29,681	3,217,452	674,583
Less: Incremental Income Taxes	(175,575,367)	(89,947,970)	(84,095,967)	(11,590)	(1,256,415)	(263,425)
Net Income @ proposed rates	389,945,927	178,137,986	204,627,202	2,388,389	3,014,974	1,777,376
Rate of Return @ proposed rates	8.73%	7.15%	10.90%	9.38%	5.88%	7.52%
Rate of Return Index	1.000	0.820	1.249	1.074	0.673	0.862
Subsidy at Company Proposed Rates	0	64,344,772	(66,943,047)	(269,809)	2,400,968	467,116
Kroger Proposed Subsidy (75% of Present)	0	33,051,424	(30,362,259)	(2,103,288)	341,071	(926,948)
Adjustment	-	1,118,944	843,370	11,449	(1,046,815)	(926,948)
Required Rate Increase	449,616,818	262,752,805	179,617,170	1,874,609	4,230,535	1,141,699
Percentage Increase	21.14%	24.12%	18.01%	8.98%	31.70%	17.78%
Net Income with Kroger Subsidy Reduction	389,945,927	197,893,278	182,845,246	3,512,873	3,632,447	2,062,083
Rate of Return	8.73%	7.95%	9.74%	13.79%	7.08%	8.73%
Rate of Return Index		0.910	1.116	1.580	0.811	1.000

BEFORE THE

ARIZONA CORPORATION COMMISSION

In the Matter of the Application of	)	
Arizona Public Service Company for	)	
A Hearing to Determine the Fair Value of the	)	Docket No. E-01345A-05-0816
Utility Property of the Company for Ratemaking	)	
Purposes, to Fix a Just and Reasonable Rate of Return	)	
Thereon, To Approve Rate Schedules Designed to	)	
Develop Such Return and to Amend Decision No. 67744	)	

EXHIBIT__(SJB-3)

OF

STEPHEN J. BARON

ON BEHALF OF THE

KROGER CO.

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

September 2006

ARIZONA PUBLIC SERVICE COMPANY

Present Rates verus Proposed Rates
Comparison of Rates of Return
Test Year Ending September 30, 2005

	Present Rates		Proposed Rates	
	Rate of Return	Index Rate of Return	Rate of Return	Index Rate of Return
A. GJ				
Total Company	2.90%	1.00	8.05%	1.00
Total Retail	2.59%	0.89	8.73%	1.08
All Other	4.51%	1.55	4.51%	0.56
B. GE-1				
Total Retail	2.59%	0.89	8.73%	1.08
Total Residential	1.52%	0.52	7.15%	0.89
Total General Service	3.91%	1.35	10.90%	1.35
E-38,221 (Water Pumping)	9.30%	3.20	9.40%	1.17
Street Lighting	2.05%	0.71	5.87%	0.73
Dusk to Dawn	5.78%	1.99	7.52%	0.93
C. GE-2				
Total General Service	3.91%	1.35	10.90%	1.35
E-20 (Church Rate)	8.47%	2.92	8.73%	1.08
E-30, E-32 (0-20 kW)	3.56%	1.23	7.09%	0.88
E-32 (21-100 kW)	4.88%	1.68	10.35%	1.29
E-32 (101-400 kW)	6.12%	2.11	14.31%	1.78
E-32 (401-999 kW)	6.12%	2.11	16.03%	1.99
E-32 (1,000+ kW)	-0.20%	-0.07	8.62%	1.07
E-34	0.07%	0.03	8.73%	1.08
E-35	-2.79%	-0.96	8.73%	1.08
D. GE-3				
Total Residential	1.52%	0.52	7.15%	0.89
Residential E-10	1.42%	0.49	8.74%	1.09
Residential E-12	3.18%	1.09	7.62%	0.95
Residential EC-1	0.44%	0.15	7.66%	0.95
Residential ET-1	0.83%	0.28	7.03%	0.87
Residential ECT-1R	-0.06%	-0.02	5.09%	0.63

BEFORE THE

ARIZONA CORPORATION COMMISSION

In the Matter of the Application of	)	
Arizona Public Service Company for	)	
A Hearing to Determine the Fair Value of the	)	Docket No. E-01345A-05-0816
Utility Property of the Company for Ratemaking	)	
Purposes, to Fix a Just and Reasonable Rate of Return	)	
Thereon, To Approve Rate Schedules Designed to	)	
Develop Such Return and to Amend Decision No. 67744	)	

EXHIBIT__(SJB-4)

OF

STEPHEN J. BARON

ON BEHALF OF THE

KROGER CO.

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

September 2006

ARIZONA PUBLIC SERVICE

Summary Proof of Revenue - E-32 w/EPR-2, EPR-4 & E-51 (Supplemental)

	Billing Units	Present Rates	Present Revenues	Proposed Rates	Proposed Revenues	Revenue Increase	Percent Increase
CUSTOMER CHARGES							
Basic Service Charge	37,680,256	0.108	4,069,468	0.108	4,069,468	-	0.00%
Metering Self-Cont	33,076,901	0.345	11,411,531	0.345	11,411,531	-	0.00%
Metering Instrument Rated	4,555,200	0.904	4,117,900	0.904	4,117,900	-	0.00%
Metering Primary	47,790	2.696	128,843	2.696	128,843	-	0.00%
Metering Transmission	365	22.192	8,100	22.192	8,100	-	0.00%
Meter Reading	37,680,256	0.058	2,185,455	0.058	2,185,455	-	0.00%
Billing	37,680,256	0.064	2,411,536	0.064	2,411,536	-	0.00%
Totalized 1Pt	135	500.00	67,500	500.00	67,500	-	0.00%
Totalized 2Pt	24	1,000.00	24,000	1,000.00	24,000	-	0.00%
DELIVERY CHARGES							
20 kW or Less							
Summer - kW (not billed)	435,474	-	-	-	-		
Summer - 1st 5000 kWh	642,509,491	0.03309	21,260,639	0.03595	23,098,216	1,837,577	8.64%
Summer - All Additional kWh	46,407,502	0.00859	398,640	0.01085	503,521	104,881	26.31%
Winter - kW (not billed)	2,134,981	-	-	-	-		
Winter - 1st 5000 kWh	574,240,294	0.03302	18,961,415	0.03588	20,603,742	1,642,327	8.66%
Winter - All Additional kWh	36,252,992	0.00852	308,875	0.01078	390,807	81,932	26.53%
Primary Discount kWh	4,657,358	(0.00282)	(13,134)	(0.00289)	(13,460)	(326)	2.48%
Over 20 kW							
1st 100 kW	13,789,826	7.722	106,485,039	8.097	111,656,223	5,171,185	4.86%
All Additional kW	11,443,708	3.497	40,018,645	4.129	47,251,068	7,232,423	18.07%
Primary Discount kW	874,981	(0.620)	(542,489)	(0.620)	(542,489)	-	0.00%
Transmission Discount kW	14,008	(3.490)	(48,888)	(3.490)	(48,888)	-	0.00%
All kWh	9,273,401,778	0.00010	927,340	0.00010	927,340	-	0.00%
GENERATION CHARGES							
20 kW or Less							
Summer - 1st 5000 kWh	642,509,491	0.05894	37,869,509	0.07707	49,518,206	11,648,697	30.76%
Summer - All Additional kWh	46,407,502	0.03163	1,467,869	0.04909	2,278,144	810,275	55.20%
Winter - 1st 5000 kWh	574,240,294	0.04901	28,143,517	0.06177	35,470,823	7,327,306	26.04%
Winter - All Additional kWh	36,252,992	0.02170	786,690	0.03379	1,224,989	438,299	55.71%
Over 20 kW							
Summer - 1st 200 kWh/kW	2,646,322,771	0.07239	191,567,305	0.09085	240,418,424	48,851,118	25.50%
Summer - All Add'l kWh	2,598,931,792	0.03476	90,338,869	0.05230	135,924,133	45,585,264	50.46%
Winter - 1st 200 kWh/kW	2,085,969,825	0.06246	130,289,675	0.07555	157,595,020	27,305,345	20.96%
Winter - All Add'l kWh	1,942,177,391	0.02483	48,224,265	0.03700	71,860,563	23,636,299	49.01%
TRANSMISSION CHARGES							
All kWh	10,572,812,057	0.00476	50,326,585	0.00476	50,326,585	-	0.00%
SYSTEM BENEFITS CHARGES							
All kWh	10,572,812,057	0.00213	22,520,090	0.00186	19,665,430	(2,854,659)	-12.68%
TOTAL BEFORE ADJUSTMENTS			813,714,791		992,532,733	178,817,943	21.98%
ADJUSTMENTS TO REVENUE TARGET							
Summer - Weather Adj	24,638,000	0.0704524	1,735,806	0.0889832	2,192,367	456,561	26.30%
Winter - Weather Adj	32,853,000	0.0608770	1,999,991	0.0740483	2,432,709	432,719	21.64%
Summer - Customer Adj	103,828,000	0.0887201	9,211,627	0.1087201	11,288,187	2,076,560	22.54%
Winter - Customer Adj	200,342,000	0.0787201	15,770,935	0.0920474	18,440,954	2,670,019	16.93%
Summer - DSM Adj	(23,922,647)	0.0568161	(1,359,191)	0.0768161	(1,837,644)	(478,453)	35.20%
Winter - DSM Adj	(18,699,472)	0.0468161	(875,436)	0.0601434	(1,124,649)	(249,214)	28.47%
Actual less Rebill adj Which includes EPR-2 & EPR-4			4,302,470				
Less EPR-2 and EPR-4			(121,130)				
Transmission portion of Regulatory Assessment			80,345				
TOTAL ADJUSTED REVENUES			844,460,209		1,023,924,658	179,464,449	21.25%

ARIZONA PUBLIC SERVICE

Summary Proof of Revenue - E-32 w/EPR-2, EPR-4 & E-51 (Supplemental)

	Billing Units	Present Rates	Present Revenues	Proposed Rates	Proposed Revenues	Revenue Increase	Percent Increase
CUSTOMER CHARGES							
Basic Service Charge	37,680,200	0.108	4,069,462	0.108	4,069,462	-	0.00%
Metering Self-Cont	33,076,848	0.345	11,411,513	0.345	11,411,513	-	0.00%
Metering Instrument Rated	4,555,200	0.904	4,117,900	0.904	4,117,900	-	0.00%
Metering Primary	47,787	2.696	128,834	2.696	128,834	-	0.00%
Metering Transmission	365	22.192	8,100	22.192	8,100	-	0.00%
Meter Reading	37,680,200	0.058	2,185,452	0.058	2,185,452	-	0.00%
Billing	37,680,200	0.064	2,411,533	0.064	2,411,533	-	0.00%
DELIVERY CHARGES							
20 kW or Less							
Summer - kW (not billed)	435,474	-	-	-	-		
Summer - 1st 5000 kWh	642,509,442	0.03309	21,260,637	0.03595	23,098,214	1,837,577	8.64%
Summer - All Additional kWh	46,401,863	0.00859	398,592	0.01085	503,460	104,868	26.31%
Winter - kW (not billed)	2,134,981	-	-	-	-		
Winter - 1st 5000 kWh	574,240,294	0.03302	18,961,415	0.03588	20,603,742	1,642,327	8.66%
Winter - All Additional kWh	36,252,992	0.00852	308,875	0.01078	390,807	81,932	26.53%
Primary Discount kWh	4,657,358	(0.00282)	(13,134)	(0.00289)	(13,460)	(326)	2.48%
Over 20 kW							
1st 100 kW	13,789,644	7.722	106,483,631	8.376	115,502,058	9,018,427	8.47%
All Additional kW	11,440,814	3.497	40,008,527	3.793	43,395,008	3,386,481	8.46%
Primary Discount kW	874,799	(0.620)	(542,375)	(0.620)	(542,375)	-	0.00%
Transmission Discount kW	14,008	(3.490)	(48,888)	(3.490)	(48,888)	-	0.00%
All kWh	9,271,939,956	0.00010	927,194	0.00010	927,194	-	0.00%
GENERATION CHARGES							
20 kW or Less							
Summer - 1st 5000 kWh	642,509,442	0.05894	37,869,507	0.07707	49,518,203	11,648,696	30.76%
Summer - All Additional kWh	46,401,863	0.03163	1,467,691	0.04909	2,277,867	810,177	55.20%
Winter - 1st 5000 kWh	574,240,294	0.04901	28,143,517	0.06177	35,470,823	7,327,306	26.04%
Winter - All Additional kWh	36,252,992	0.02170	786,690	0.03379	1,224,989	438,299	55.71%
Over 20 kW							
Summer - 1st 200 kWh/kW	2,645,954,966	0.07239	191,540,680	0.09525	252,027,210	60,486,531	31.58%
Summer - All Add'l kWh	2,598,442,155	0.03476	90,321,849	0.04574	118,852,744	28,530,895	31.59%
Winter - 1st 200 kWh/kW	2,085,722,472	0.06246	130,274,226	0.08218	171,404,673	41,130,447	31.57%
Winter - All Add'l kWh	1,941,820,365	0.02483	48,215,400	0.03266	63,419,853	15,204,453	31.53%
TRANSMISSION CHARGES							
All kWh	10,571,344,548	0.00476	50,319,600	0.00476	50,319,600	-	0.00%
SYSTEM BENEFITS CHARGES							
All kWh	10,571,344,548	0.00213	22,516,964	0.00186	19,662,701	(2,854,263)	-12.68%
TOTAL BEFORE TOTALIZED CHG			813,533,389		992,327,216	178,793,827	21.98%
TOTALIZED CHARGES							
Subtotal for 1% Charge		6,595,833	65,958	8,223,872	82,239	16,280	24.68%
Per Point Charge - 1 Pt	135	500.00	67,500	500.00	67,500	-	0.00%
Subtotal for 2% Charge		1,197,155	23,943	1,490,598	29,812	5,869	24.51%
Per Point Charge - 2 Pt	24	1,000.00	24,000	1,000.00	24,000	-	0.00%
TOTAL REVENUES			813,714,791		992,530,767	178,815,976	21.98%
ADJUSTMENTS TO REVENUE TARGET							
Summer - Weather Adj	24,638,000	0.0704524	1,735,806	0.0889832	2,192,367	456,561	26.30%
Winter - Weather Adj	32,853,000	0.0608770	1,999,991	0.0740483	2,432,709	432,719	21.64%
Summer - Customer Adj	103,828,000	0.0887201	9,211,627	0.1087201	11,288,187	2,076,560	22.54%
Winter - Customer Adj	200,342,000	0.0787201	15,770,935	0.0920474	18,440,954	2,670,019	16.93%
Summer - DSM Adj	(23,922,647)	0.0568161	(1,359,191)	0.0768161	(1,837,644)	(478,453)	35.20%
Winter - DSM Adj	(18,699,472)	0.0468161	(875,436)	0.0601434	(1,124,649)	(249,214)	28.47%
Actual less Rebill adj. Which includes EPR-2 & EPR-4			4,302,470				
Less EPR-2 and EPR-4			(121,130)				
Transmission portion of Regulatory Assessment			80,345				
TOTAL ADJUSTED REVENUES			844,460,209		1,023,922,691	179,462,483	21.25%

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

JEFF HATCH-MILLER, Chairman
WILLIAM A. MUNDELL
MIKE GLEASON
KRISTIN K. MAYES
BARRY WONG

EXHIBIT
WRA-1
admitted

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 RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND TO AMEND DECISION NO. 67744.	DOCKET NO. E-01345A-05-0816

Direct Testimony of

David Berry

Western Resource Advocates

August 18, 2006

Direct Testimony of David Berry
Docket No. E-01345A-05-0816

Table of Contents

Introduction	1
Green Power Tariffs	2
Using Renewable Energy as a Hedge against High Natural Gas Prices	7
Demand Side Management to Reduce Urban Heat Island Effects	15
Environmental Improvement Charge (EIC)	17
Climate Change and the EIC	20
Summary of Recommendations	27

List of Exhibits

Qualifications of David Berry	DB-1
Natural Gas Prices Paid by Electric Power Sector and Break-Even Gas Prices for Wind and Geothermal Energy	DB-2
Renewable Energy Prices in the West Compared to APS' Forecast Gas Cost	DB-3
APS Renewable Energy	DB-4
Wind Generating Capacity as Percentage of Total Generating Capacity	DB-5
Energy Savings from Heat Island Reduction Measures – Phoenix Area	DB-6
APS Historical and Projected CO_2 Emissions	DB-7

Introduction

Q. Please state your name and business address.

A. My name is David Berry. My business address is P.O. Box 1064, Scottsdale, Arizona 85252-1064.

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

A. I am Senior Policy Advisor for Western Resource Advocates.

Q. Please describe Western Resource Advocates.

A. Founded in 1989, Western Resource Advocates (WRA) is a non-profit environmental law and policy organization dedicated to restoring and protecting the natural environment of the Interior American West. We have developed strategic programs in three areas: water, energy and lands. We meet our goals in collaboration with other environmental and community groups and by developing solutions that are appropriate to the environmental, economic and cultural framework of the region. Western Resource Advocates has been involved in Arizona utility regulatory issues for about 15 years.

Q. What are your professional qualifications for presenting testimony in this docket?

A. Exhibit DB-1 summarizes my experience and education.

Q. What is the purpose of your testimony?

A. I am testifying on behalf of WRA and address the following topics:

- APS' proposed green power tariffs;
- Renewable energy as a hedge against high natural gas prices;
- Demand side management to reduce urban heat island effects;
- APS' proposed Environmental Improvement Charge (EIC);
- Development of a climate change policy, possibly in conjunction with the EIC.

Q. What are the major themes of your testimony?

A. APS faces high fuel and purchased power costs due to customer growth and higher fuel prices. Mr. Ewen (p. 6) indicates that the combined effect on APS' fuel expenses

is $299 million.[1] The Commission should use this opportunity to build on actions taken in Decision No. 67744 to reduce APS' and ratepayers' exposure to high fuel costs by increasing the extent to which APS obtains low cost, stably priced energy from renewable resources and pursues cost effective energy efficiency programs. In addition, the Commission should use this Docket to encourage reduction of the environmental impact of power generation, including emissions of greenhouse gases.

Green Power Tariffs

Q. Please describe APS' proposed green power tariffs.

A. APS proposes two green power tariffs (Schedules GPS-1 and GPS-2, Attachments GAD-3 and GAD-4 to Mr. DeLizio's testimony). Under these tariffs, residential and non-residential customers have the option to buy green power from eligible resources such as solar, biomass, wind, geothermal, and small hydro resources. The existing solar partners tariff (which sells 15 kWh blocks of solar energy for a premium of $0.18 per kWh) would be frozen (Mr. Fox, p. 22).

APS' proposed green power premium is $0.03 per kWh and would be paid in addition to the otherwise applicable rate. The premium represents the net costs of non-distributed renewable energy above the cost of conventional generation (APS responses to data request WRA 1-1 and WRA 1-2) and was calculated by dividing the projected funding that would be provided by the proposed Renewable Energy Standard (RES) surcharge for non-distributed generation over the period 2006 through 2015 by the amount of non-distributed renewable energy required by the proposed RES from 2006 through 2015 (Mr. Fox, p. 21, APS response to data request WRA 1-2).

There are two green power options: a) customers can buy 25 kWh blocks of electricity per month for $0.75 per block, or b) customers can buy a set percentage of their monthly kWh consumption from green resources. For example, if a customer elected to buy 100% green power, a premium of $0.03 per kWh would be added to the monthly bill. If a customer elected to buy 10% green power, a premium of $0.003 per kWh would be added to all kWh consumed (10% of $0.03 per kWh). The percentages must be 100%, 50%, 30% or 10% of the electricity consumed.

Q. What is the relationship between RES and green power tariff resources as envisioned by APS?

A. In general, the resources used to meet the RES could also be used to serve green power customers. However, APS states (response to data request WRA 1-3) that it

[1] In Docket No. E-01345A-06-0009, APS' emergency rate case, Mr. Ewen indicates that APS' projected fuel costs have declined as natural gas prices have fallen from previous levels.

will record and report revenues from the green power tariff separately from the proposed RES tariff and any other tariffs. APS further indicates that funds collected from both the green power tariff and the RES tariff will be pooled to leverage purchasing power and to reduce fluctuations in demand for renewable energy resources as might occur with a resource dedicated solely to the green power tariff. APS also indicates that green power kilowatt hours will not be counted toward compliance with the RES and will be reported separately from RES resources.

Q. Are green power tariffs used in other jurisdictions?

A. Yes. The National Renewable Energy Laboratory estimates that in 2004, there were 324,000 residential and 8,100 non-residential customers of utility green power programs nationwide.[2] The median customer participation rate in utility green power programs is about 1%, but the top programs enroll around 4% or more of their customers.

Q. Does green power necessarily result in higher rates?

A. No. Public Service Company of Colorado's wind energy service rate adjustment effective November 1, 2005 was negative for several months because the cost of the wind energy was less than the cost of the electric commodity adjustment and the air quality improvement rider.[3] As a second example, Oklahoma Gas and Electric Company's green power premium is $0.001 per kWh but green power kWh are exempt from the fuel cost adjustment.[4] In June 2006, green power customers saved $16.60 for every 1000 kWh of green power purchased because the green power cost less than the fuel cost adjustment.

Q. Does WRA support the concept of green power tariffs for APS?

A. Yes. However, the terms and conditions of APS' proposed green power tariffs should be revised and clarified to make the tariffs successful and beneficial.

Q. Please describe the revisions and clarifications of the green power tariffs that WRA recommends.

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[2] Lori Bird and Blair Swezey, *Green Power Marketing in the United States: A Status Report (Eighth Edition)*, Golden, CO: National Renewable Energy Laboratory, NREL/TP-620-38994, 2005, Tables 2 and 3.

[3] Public Service Company of Colorado, Tariff Sheets Nos. 91 and 91A

[4] Oklahoma Gas and Electric Company, Schedule GPWR, Sheet Nos. 56.0 – 56.2.

A. There are several features of APS' proposed green power tariff that should be modified or clarified.

First, green power kWh should be exempt from the RES surcharge for the green power portion of consumption as green power customers will have already made an active commitment to renewable energy.

Green power kWh should also be excluded from the EIC because the green power does not contribute to the emissions that are to be reduced via the Environmental Improvement Charge. Green power kWh are excluded from the Environmental Improvement Charge according to the proposed Schedule EIC. However, Mr. DeLizio's testimony indicates that green power customers would pay the EIC as part of their standard rate which they must pay in addition to the green power premium (p. 4, starting at line 19).

Second, the determination of the green power "premium" needs to be revised as explained below. As proposed by APS, a fixed $0.03 per kWh premium would apply whether conventional fossil fuel costs are high or low, even though renewable energy resources might cost less than high priced natural gas resources, for example.

Third, the green power premium should be based upon costs of specific renewable energy projects (not projected RES funding as proposed by APS) and should be reviewed and approved by the Commission as the mix of renewable energy projects changes. As explained further below, APS should propose resetting the green power cost component as it acquires new resources to serve additional green customer load.[5]

Fourth, the green power tariff should not be available until APS has adequate renewable energy to serve green power customers. However, the start date for green power service should be no later than one year after the effective date of the Commission's order in this rate case.

Fifth, the minimum block size for customers desiring green power should be 100 kWh per month to meet Green-e default standards. The proposed 25 kWh block size is too small. APS' percentage proposal is satisfactory. Further, APS should seek Green-e certification for its green power product so that green power customers can be sure their purchases will be independently audited to verify that they were not used for RES compliance.[6]

[5] APS indicated that it may need to revise the green power premium if RES funds do not match projected funds (response to data request WRA 1-2.)

[6] Center for Resource Solutions, *Green-e Accreditation of Utility Green Pricing Programs, National Default Criteria*, December 15, 2004 (Version I). APS has not decided whether it will seek Green-e certification (response to WRA 1-6).

Sixth, APS should submit public annual reports to the Commission detailing renewable energy acquired for the green power program by technology (e.g., wind, landfill gas, geothermal, etc.), customer enrollment by class (residential, commercial, industrial, other), green power kWh sales, green power revenues, and green power costs. These reports could be submitted as part of APS' RES reports.

Q. What process should be used to set the green power premium?

A. I recommend that APS select a set of low cost, stably priced renewable energy resources to serve green power customers and, within six months of the effective date of the Commission's decision in this case, propose a green power premium for the Commission's consideration reflecting the costs of the renewable energy resources and APS' avoided costs as described below. APS should seek renewable energy resources with fixed or stable prices that do not vary with the price of natural gas or spot market electricity prices. The resources can be a subset of those used to meet RES requirements. For marketing purposes it seems desirable that APS select lower cost renewable resources from its portfolio of non-distributed resources used to meet RES requirements.

Q. How should the green power premium be calculated?

A. The green power premium would be added to the otherwise applicable rate, excluding the RES surcharge and the EIC, as indicated above. The premium should be determined as follows: Premium = G – B – P – A, where:

G = the (total) cost per kWh of the green power,
B = the base power supply cost
P = the power supply adjustor, and
A = allowance for capacity credits associated with the green power.[7]

For example, if the green power cost, G, is $0.042 per kWh, B = $0.031904 per kWh (APS' proposed base fuel recovery rate per Mr. Ewen, p. 6, although APS may modify its proposed rate), P = $0.00, and A = $0.005 per kWh, the green power premium would be $0.005096 per kWh. The values for G, P, and A are illustrative.

Q. How can customers be informed of the green power premium in a way to minimize confusion?

A. The premium could be presented relative to standard rates with no power supply adjustor (P = $0.00) since the effect of the adjustor is arithmetically cancelled out as

[7] The renewable resources would, in general, have some capacity value which would displace conventional capacity needs.

explained below. Using the example from above, the green power premium would be $0.005096 per kWh added to base rates excluding the power supply adjustor so that green power customers are exempt from the power supply adjustor.

Q. Why should green power customers be exempt from the power supply adjustor?

A. APS' (variable) power supply costs are the base power supply cost plus the power supply adjustor (which can be positive or negative). Because green power consumption avoids conventional power supply, the conventional power supply costs should not be included in the rates paid by green power customers. Mathematically, rate changes due to the power supply adjustor are subtracted from the standard rate (which includes the power supply adjustor) when applying the green power premium and hence the power supply adjustment cancels out. To illustrate, consider two hypothetical cases using the formula presented above:

case a. **High fuel prices**. Suppose the otherwise applicable rate is $0.07 per kWh, which includes the base power supply rate of $0.031904 per kWh. In addition, assume the power supply adjustor is +$0.01 per kWh. The total rate paid by a regular customer is therefore $0.08 per kWh ($0.07 + $0.01). Assume the green power costs $0.042 per kWh and the capacity credit allowance is $0.005 per kWh. The green power customer pays an effective premium of -$0.004904 per kWh using the formula presented above (premium = $0.042 - $0.031904 - $0.01 - $0.005). The combined cost to the green power customer is the otherwise applicable rate including the power supply adjustor plus the green power premium for a total of $0.075096 per kWh ($0.07 + $0.01 - $0.004904). Note that during a period of high conventional fuel costs, the green power customer pays a lower rate than regular customers.

case b. **Lower fuel prices**. Suppose the otherwise applicable rate is $0.07 per kWh, including the base power supply rate of $0.031904 per kWh. In addition, assume the power supply adjustor is -$0.01 per kWh. The total rate paid by a regular customer is therefore $0.06 per kWh ($0.07 - $0.01). Assume the green power costs $0.042 per kWh and the capacity credit allowance is $0.005 per kWh. The green power customer pays an effective premium of +$0.015096 per kWh using the formula presented above (premium = $0.042 - $0.031904 - [-$0.01] - $0.005). The combined cost to the green power customer is the otherwise applicable rate including the power supply adjustor plus the green power premium for a total of $0.075096 per kWh ($.07 - $0.01 + $0.015096), the same amount as case a, above. That is, the green power customer pays a constant rate, unaffected by the power supply adjustor. Note that during a period of low conventional fuel costs, the green power customers pays a higher rate than regular customers.

Q. What should happen as APS' renewable energy resources designated for the green power program become fully subscribed?

A. As the set of renewable resources approaches full subscription, APS should designate an additional set of renewable resources and, if necessary, propose a new premium to the Commission reflecting the cost of the new mix of resources. Customers desiring to subscribe when existing renewable resources are fully subscribed should be put on a waiting list until the additional resources become available.

Q. What should happen if APS acquires too much renewable energy compared to its green power sales?

A. Excess renewable energy could be used to meet APS' RES requirements, assuming that the renewable energy meets RES requirements, or APS could use the excess energy as part of its purchased power portfolio for serving all of its retail customers.

Using Renewable Energy as a Hedge against High Natural Gas Prices

Q. Does APS use large quantities of natural gas to generate electricity?

A. Yes. APS forecasts that it will consume about 65 million MMBtu of natural gas in 2006 in its own power plants for its own load (Ewen workpaper PME_WP3, p. 6). In addition, APS will purchase power generated from natural gas.

Q. What prices have been paid by the electric power sector for natural gas?

A. Exhibit DB-2 (upper panel) shows natural gas prices paid by the US electric power sector from 1992 through 2005 in constant year 2005 dollars per MMBtu and a forecast price for 2006.[8] Note the significant increase in prices in the last few years. In 2005, the electric power sector paid over $8.00 per MMBtu.

Q. How does APS utilize its gas-fired generating units?

A. APS has gas-fired combustion turbines, steam plants, and combined cycle plants. In general, natural gas-fired generation is APS' marginal resource. That is, it is APS' highest cost conventional generation and gas-fired plants would, in general, be the first to be backed off if alternative resources are available. Mr. Ewen's workpapers

[8] Data from Energy Information Administration, *Short Term Energy Outlook*, December 2005 through July 2006, Table A4. Forecast price is from the *Short Term Energy Outlook*, August 2006. Prices were translated to constant dollars using the gross domestic product implicit price deflator published by the Bureau of Economic Analysis.

(PME_WP3, p. 3) and APS' response to Utilitech's data request UTI-15-354 c and d suggest that APS uses natural gas generation in most hours of the year. The Red Hawk and West Phoenix combined cycle units are the largest users of natural gas.

Q. What can be accomplished by hedging against high natural gas costs?

A. A hedge would consist of actions intended to reduce a utility's and its ratepayers' exposure to uncertain high fossil fuel costs. Utilities can and do use financial hedges such as forward purchases, futures, and options in such situations. A utility can also reduce its need to obtain gas-fired generation by substituting energy efficiency or renewable resources for gas-fired generation, thereby reducing its exposure to high gas costs.

Q. Should APS hedge against the high cost of natural gas with renewable resources?

A. Yes. APS faces a long term exposure to high fossil fuel prices and should pursue a long term risk management strategy that goes beyond what it can accomplish through financial hedging of gas prices. Low cost, stably priced renewable resources would reduce APS' exposure to high gas prices by displacing gas-fired generation and would cost less than natural gas-fired resources when gas prices are high.

Q. What prices are utilities paying for renewable energy?

A. Exhibit DB-3 shows prices reported publicly for large scale wind projects in the west in 2005.[9] Wind energy produced at good sites sold for less than about $0.035 per kWh in 2005. Exhibit DB-3 also shows prices for new wind energy projects starting generation from late 2005 through 2007.[10] Prices for these new wind projects are higher than prices for older projects in part because of shortages of equipment and higher costs for construction materials. The equipment shortages may be temporary if demand for wind turbines grows more slowly in the future, manufacturing capacity increases, or competition among developers becomes more intense. In such cases,

[9] Prices from utilities' 2005 FERC Form 1 and Testimony of Gary Swarts, Before the Public Utilities Commission of Colorado, In the Matter of the Application of Public Service Company of Colorado for Approval of Lamar Wind Energy Supply Agreement and for the Rate Mechanism to Recover the Costs of the Agreement, August 21, 2002, p. 7.

[10] Sources: Los Angeles Department of Water and Power purchase from the Pleasant Valley Wind Energy Center in Wyoming (reported by Reuters, June 6, 2006), Nebraska Public Power District purchase from the Ainsworth Wind Energy Facility (reported by the Nebraska Energy Office, March 2006), Austin Energy purchase from Res American Developments (reported in the Austin American-Statesman, April 6, 2006) assuming a capacity factor of 35%, and contract between Spanish Fork Wind Park 2 LLC and PacifiCorp, dated June 20, 2006 (Utah Public Service Commission Docket No. 06-035-76, Exhibit A).

prices for new projects might fall. The Exhibit also shows prices for several Salton Sea area geothermal contracts with deliveries starting in 2005 to 2007.[11]

Q. How do renewable energy costs compare with APS' cost of generating electricity with natural gas?

A. APS' projected fuel cost of generating electricity from APS' natural gas units is shown in Exhibit DB-3. Wind and geothermal energy projects are generating electricity at prices competitive with APS' projected fuel costs for generating electricity with natural gas.

Q. What would the price of natural gas have to be for renewable energy to be less costly?

A. Exhibit DB-2 (lower panel) shows the midpoints of ranges of break-even prices of natural gas for wind resources at 2005 prices, for new wind resources at the higher 2006 prices, and for geothermal resources at recent prices for Salton Sea area projects. The break-even prices shown in the Exhibit are the natural gas prices at which the cost of renewable energy equals the avoided energy and capacity costs of natural gas-fired generation. The cost of wind energy includes wind integration costs.

The break-even prices are plotted against the percentage of conventional generation which is displaced by renewable energy that would have otherwise been generated using natural gas. The chart assumes that the remaining percentage of displaced generation would have been generated with coal.[12]

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[11] Geothermal contract prices from: Ormat Technologies press releases dated December 13, 2005 and June 14, 2006, MidAmerican Energy Holdings press release dated June 6, 2006. Prices shown are for the first year of the contracts. Prices escalate at a fixed rate (1% or 1.5% per year) after the first year.

[12] Wind and geothermal energy contract costs are those shown in Exhibit DB-3, excluding the Nebraska contract whose price is more reflective of 2005 conditions. The Exhibit excludes the contracts negotiated by APS in 2005 to acquire 145 MW of renewable resources. Incremental transmission revenue requirements in excess of transmission that would otherwise have been needed for new conventional generation capacity are assumed to equal APS' OATT charges for point to point service. Wind energy costs also include costs of wind integration, that is, the utility's costs of maintaining a reliable system when intermittent wind resources are fed into the grid. Wind integration costs were taken from J. Smith, E. DeMeo, B. Parsons, and M. Milligan, "Wind Power Impacts on Electric Power System Operating Costs: Summary and Perspective on Work to Date." Golden, CO: National Renewable Energy Laboratory NREL/CP-500-35946, 2004.

The average heat rate of the gas-fired power plants displaced by renewable resources is assumed to be 8,480 Btu/kWh and the average heat rate of the displaced coal generation is assumed to be 10,838 Btu/kWh. The cost of coal is assumed to be $1.62 per MMBtu at the displaced coal plants. Variable O&M costs for the displaced gas generation was assumed to be $1.93 per MWh and for the displaced coal generation was assumed to be $4.28 per MWh, based on Energy Information Administration cost estimates contained in its *Annual Energy Outlook 2005*.

When the price of natural gas paid by the electric power sector is above the break-even price, renewable energy costs less. In recent years, gas prices have been sufficiently high that many wind and some geothermal energy resources are cheaper alternatives, especially as the percentage of time that gas-fired generation is displaced by renewable energy increases.

Future natural gas prices are uncertain, so it is appropriate to regard renewable energy resources as hedges against high gas prices in the future. The hedge value of renewable resources is enhanced when utilities purchase renewable energy at a fixed or stable price that is not tied to the price of natural gas. Wind, geothermal, and biomass contracts often feature fixed or stable prices.

Q. How can the Commission ensure that APS pursues a policy to reduce its exposure to high natural gas prices by increasing its use of renewable energy?

A. I recommend that APS be directed to obtain at least 1,300 GWH per year of stably priced renewable energy under long term contracts (at least 15 years) starting within the period 2008 to 2010.[13] This 1,300 GWH per year is in addition to the renewable energy required by Decision No. 67744. (Decision No. 67744 required APS to seek at least 100 MW of renewable energy generating capacity in 2005 and to seek to acquire at least 10% of its annual incremental peak capacity needs from renewable resources).

The 1,300 GWH is proposed because it is feasible and, when combined with the previous commitment, provides a significant hedge against high gas prices. With regard to feasibility, the renewable energy industry is active in the Southwest. For example, the industry has added about 400 MW of wind generation capacity in New Mexico between 2003 and 2005 (generating about 1200 GWH per year), has about 520 MW of geothermal production capacity in southern California (generating

For wind generation, the capacity factor is assumed to be 35%. For geothermal generation, the capacity factor is assumed to be 90%.

The conventional generating capacity that can be avoided by deploying renewable energy resources is assumed to consist of gas-fired combustion turbines, the conventional resource with the lowest capital cost per kW of generating capacity. The capacity value of wind generation is assumed to be 25% of the nameplate capacity of the wind generators. The capacity value of geothermal energy is assumed to be 100% of the nameplate net capacity of the geothermal plant. The capital cost of a new combustion turbine is assumed to be $421 per kW (the purchase price of Sundance) and the capital recovery factor is assumed to be 15%.

[13] The 1300 GWH represents generation delivered to APS' transmission system before additional losses are incurred. If all the proposed renewable energy came from wind resources, approximately 425 MW of wind generation capacity would be needed. If all the renewable energy came from geothermal resources, approximately 165 MW of net geothermal generation capacity would be needed.

roughly 3900 GWH per year) with a potential for up to about 2000 more MW of capacity, and is developing a 35 MW biomass project in New Mexico.[14] In addition, the proposed level of renewable energy is large enough to result in significant displacement of gas generation and hence to result in a useful hedge against high gas costs as discussed further below.

I am proposing a three year "window" for starting the acquisition of the low cost, stably priced renewable energy to allow APS adequate time to obtain needed transmission capacity, to take advantage of market conditions such as the availability of production tax credits, and to work around shortages of equipment and materials.

I also recommend that APS file for Commission review, within 4 months of the date of the Decision in this Docket, a plan for acquiring the renewable energy. Prior to filing the plan, APS should consult, in a collaborative manner, with interested parties to this case to obtain input on development of the plan. Additionally, I recommend that APS file reports with the Commission by March 1, 2009, March 1, 2010, and March 1, 2011 describing its progress in meeting these goals and proposing actions to make up any deficiencies in meeting the goals, including acquisition of needed transmission capacity.

Q. Does APS have any experience acquiring low cost renewable resources as a hedge against high gas prices?

A. Yes. As a result of Decision No. 67744, APS arranged to acquire 145 MW of wind, geothermal, and biomass resources (Decision No. 68296). APS also agreed to add additional renewable energy so that the nameplate capacity of the renewable energy equals 10% of APS' increase in capacity needs, but these additional resources have not yet been acquired for years beyond 2008.

Q. Has APS sought other conventional resources for next three to eight years?

A. Yes. On January 24, 2006, APS issued a request for proposals for unit-specific base load generating capacity of 100 MW to 500 MW per unit for deliveries beginning as early as 2009 but starting no later than 2014.

Q. Suppose APS conducts a request for proposals for renewable energy but believes that it cannot use the resulting bids to reasonably hedge against high natural gas prices

[14] Data sources: American Wind Energy Association, New Mexico Wind Energy Development, Geothermal Energy Association, www.geo-energy.org/information/plantsNow/ca/caAll.asp, California Energy Commission, "California Geothermal Resources," April 2005, CEC-500-2005-070, pp. 5-8, and Santa Fe *New Mexican*, July 31, 2006.

because of transmission constraints, low natural gas prices, or other conditions. What should APS do?

A. I recommend that APS include in its March 1 reports, described above, a detailed description of the problems encountered and recommended solutions. The Commission should then review APS' report and set a course of action for APS.

Q. Please compare your recommendation in this case with APS' commitments arising out of the previous settlement agreement (Decision No. 67744).

A. Exhibit DB-4 shows the relative amounts of renewable energy from the initial acquisition under Decision No. 67744, the additional amounts APS is supposed to seek under Decision No. 67744,[15] and WRA's recommended resources in this docket. From 2010 through 2016, APS would obtain between 6% and 7% of its energy from low cost, stably priced renewable energy resources as a result of this recommendation and the requirements of Decision No. 67744. During this same time period, renewable energy generating capacity would be between 6% and 7% of APS' own-load peak demand assuming the capacity factor for the mix of renewable energy resources is 50% and using APS' own-load peak demand forecast provided in response to Staff data request EAA 4-16.

Q. How much of APS' natural gas generation would be displaced by energy from renewable resources under your proposal and Decision No. 67744?

A. APS expects that about 26% of its own-load generation in 2006 would come from gas-fired power plants (Ewen workpaper PME_WP3, p. 3). Renewable energy would constitute less than 7% of APS' retail sales over the next several years (Exhibit DB-4). Therefore, the renewable energy would displace roughly a quarter of the gas generation that APS would otherwise produce.

Q. Isn't the Renewable Energy Standard sufficient for APS to hedge against high fossil fuel prices with renewable resources?

A. No, not for APS. The RES has not yet been adopted by the Commission. The pending RES renewable energy requirements are not maximums or caps on the amount of renewable energy a utility can acquire. My proposal accelerates the RES schedule because APS needs to hedge against high gas prices as quickly as possible. In 2010, APS would obtain about 6.4% of its energy from non-distributed renewable energy resources under my proposal plus commitments made in Decision No. 67744 (Exhibit DB-4). In contrast, APS would need to obtain only 2% of its energy from

[15] Exhibit DB-4 assumes that APS adds 27 MW of renewable energy generating capacity with an average 50% capacity factor each year.

non-distributed renewable energy resources under the RES in 2010. To the extent that renewable energy resources obtained as a gas price hedge are eligible for the RES, I recommend that they be counted toward meeting APS' RES obligations. APS could bank renewable energy in excess of the RES for use in later years in meeting the RES.

Q. How could APS recover the costs of the renewable energy?

A. I recommend that APS recover the costs through its power supply adjustor. However, to the extent that APS uses any of the renewable energy to meet its RES requirements, APS could recover costs via the RES cost recovery tariff approved by the Commission, consistent with APS' approved RES implementation plan.

Q. What are the effects of introducing large amounts of intermittent resources like wind on system reliability?

A. If my proposal is adopted, about 7% of APS' energy and about 7% of APS' peak load would come from renewable resources, but not all of that 7% would be from intermittent renewable resources. Thus, the amount of intermittent renewable energy introduced into APS' system would be fairly modest.

I examined several recent studies of the effects of wind energy on system reliability. Each location will be somewhat idiosyncratic, but the studies all concluded that, with wind penetration levels of 10% or even more, reliability effects are small and can be readily addressed.

The New York State Energy Research and Development Authority (NYSERDA) sponsored one such study assuming that 10% of peak load generation was provided by wind turbines (3300 MW).[16] The study (p. 2.6) found that:

- The increase in forecasting error due to wind generation for the purpose of unit commitment can be accommodated by existing processes and resources;
- The effect of wind generation on load following could be accommodated by existing processes and resources;
- No change in spinning reserve would be needed;
- The grid may meet regulation criteria with existing regulating capability;
- State of the art wind generators reduce post-fault voltage dips.

[16] GE Energy, *The Effects of Integrating Wind Power on Transmission System Planning, Reliability, and Operations, Report on Phase 2: System Performance Evaluation*, prepared for the New York State Energy Research and Development Authority, March 4, 2005.

The NYSERDA study concluded that "it is expected that the [New York State Bulk Power System] can reliably accommodate at least 10% penetration, 3,300 MW, of wind generation with only minor adjustments to its existing planning, operation, and reliability practices... [assuming that] wind farms would include state-of-the-art technology, with reactive power, voltage regulation, and [low voltage ride through] capabilities..." (p. 2.16).

The National Renewable Energy Laboratory reviewed several studies of the effect of wind energy on the costs of reliably operating power systems (i.e., costs of unit commitment, load following so as to have adequate reserve capacity available to ramp units up and down to follow load shapes with wind plants on line, and regulation to maintain control within standards).[17] Wind penetrations varied from under 1% to 20% or more of peak load. Costs of regulation, load following, and unit commitment combined ranged from $1.47 per MWh to $5.50 per MWh.

In a Colorado study, the cost of integrating wind generation into the Public Service Company of Colorado system (regulation, load following, unit commitment and scheduling, and gas supply system impacts), was $3.51 per MWh when wind penetration is 10% and $4.77 per MWh when wind penetration is 15%.[18]

Based on these detailed modeling analyses, I conclude that the costs of integrating moderate amounts of wind energy, so as to operate a reliable system, are small. I included these integration costs in my analysis shown in Exhibit DB-2.

Q. Please compare the methods used in the studies cited above with APS' method for estimating wind integration costs.

A. In evaluating projects submitted in response to its 2005 request for proposals for renewable energy, APS assumed that it would incur costs for spinning reserves equivalent to 25% of the MW of wind generation capacity in order to maintain sufficient levels of system reliability. (APS responses to data requests WRA 4-2 and WRA 5-1). In his letter to Commissioner Mayes dated July 19, 2006, Mr. Davis stated that APS' cost of spinning reserves for wind integration is between $10 per MWh and $20 per MWh.[19] These costs are well above those determined from detailed analyses of the effects of intermittent wind resources on regulation, load

[17] J.C. Smith et al., "Wind Power Impacts on Electric Power System Operating Costs: Summary and Perspective on Work to Date," National Renewable Energy Laboratory, NREL/CP-500-35946, March 2004.

[18] EnerNex Corporation, *Wind Integration Study for Public Service Company of Colorado*, report to Xcel Energy, Knoxville, TN, 2006, Table 4.

[19] Letter from Jack Davis, President, APS, to Commissioner Kristin K. Mayes, dated July 19, 2006 re: Calculation of Above Market Cost for Wind Energy. The letter was docketed in Docket Nos. E-01345-05-0816 and RE-00000C-05-0030.

following, unit commitment, and other operational factors in other jurisdictions where the penetration of wind energy was assumed to be as high as 20% of peak load. The difference in wind integration costs may be due to differences in APS' assumptions about the amount of spinning reserve needed to maintain a reliable system and other studies' modeling conclusions about the amount of additional spinning reserve needed (e.g., in the NYSERDA study cited above, no additional spinning reserve was needed). I recommend that, going forward, APS should either base its integration costs on detailed modeling studies of other utilities or conduct a similar detailed modeling analysis of its own system.

Q. Does wind generation comprise a significant percentage of generation in other states?

A. Yes. Exhibit DB-5 shows wind generation capacity as a percentage of total generating capacity in states with at least 100 MW of wind generating capacity. Wind generation capacity accounts for over 6% of total generating capacity in three states (New Mexico, Minnesota, and Iowa).

Q. Are there any environmental benefits of your proposed additions to APS' portfolio of renewable resources?

A. Yes, air emissions would be reduced. Assuming that 90% of the renewable energy displaces natural gas generation and 10% displaces coal-fired generation, and assuming the July 28, 2006 price for tradable carbon dioxide emission allowances in the European Union (a mandatory market involving 10,000 large industrial and power generation establishments), the avoided carbon dioxide emissions would be valued at $12.7 million per year. At the price of carbon dioxide credits at the Chicago Climate Exchange (a much smaller voluntary market with only a few dozen members) on the same date, the avoided carbon dioxide emissions would be valued at $2.7 million per year. Also, the value of avoided sulfur dioxide emissions priced at the August 2006 futures price on the Chicago Climate Exchange on July 28, 2006 would be about $0.24 million per year. Thus, the renewable energy has an additional benefit, relative to the displaced conventional generation, of several million dollars per year over and above the value of the renewable energy as a hedge against high fossil fuel prices.

Demand Side Management to Reduce Urban Heat Island Effects

Q. What is the urban heat island effect?

A. Urban areas typically exhibit higher temperatures than comparable rural areas because of the large amounts of pavement and buildings which absorb heat. In a hot climate, like that of Phoenix, the higher temperatures lead to increased use of air

conditioning and require increased generation of electricity from intermediate and peaking power plants. Phoenix has become hotter over time.[20]

Figure 1 of APS' report, *APS Investigation into Rate Designs Conducive to Conservation and DSM*, dated November 2005, and included in David Rumolo's testimony, as Attachment DJR_9, pertains to APS' hourly demand on the system peak day of 2004. Among other things, the heat island effect causes demand for electricity to remain high after sunset as seen in the Figure.

Q. How can APS reduce the urban heat island effect and thereby reduce loads during peak hours?

A. I recommend that APS pursue a demand side management program that encompasses:

- Shade from trees or other vegetation and shade structures – including commercial and residential area street trees, trees in urban parks, and parking lot trees. Vegetation also promotes cooling through evapotranspiration.
- Cool building surfaces which reflect more heat than commonly used surfaces; cool surfaces include green roofs that have vegetation on them.
- Cool pavements which reflect more heat than commonly used pavement.

Exhibit DB-6 shows an estimate of energy savings from heat island reduction measures in the Phoenix area for several building types.

Q. How should an urban heat island reduction program be incorporated into APS' demand side management activities?

A. APS already has residential and non-residential demand side management (DSM) programs that focus on individual buildings. These programs can reduce the effects of urban heat islands, but they are limited in what they can accomplish because participants are scattered around APS' service territory. In areas of new construction, builders and contractors could apply cool roofs, cool pavements, and shading to all or nearly all the new development. But such a program, if it were carried out, would not affect existing development. Therefore, it is desirable to also concentrate cool roofs, cool pavements, and shading in one or more existing, densely built-up neighborhoods.

I recommend that the Commission direct APS to include an urban heat island reduction program in APS' DSM portfolio. APS should use the existing DSM collaborative process to refine the program concept, identify the products and services

[20] L. Baker, L. Brazel, N. Selover, C. Martin, N. McIntyre, F. Steiner, A. Nelson, and L. Musacchio, "Urbanization and Warming of Phoenix (Arizona, USA): Impacts, Feedbacks, and Mitigation," *Urban Ecosystems*, vol., 6 (2002): 183-203.

to be provided (e.g., incentives, financial assistance, education, training, etc.), identify target markets (e.g., municipalities), and develop a budget and implementation schedule. To assist the collaborative, APS should initially conduct a brainstorming session for APS, collaborative members, and urban planners and landscape architects who could advise the collaborative. Funds should be included in the budget to invite outside experts to assist the collaborative. The resulting heat island reduction program plan should then be submitted to the Commission for pre-approval in a manner similar to that required of other APS DSM programs.

Environmental Improvement Charge (EIC)

Q. Does electric power production and delivery affect the environment?

A. Yes. Power generation and transmission have a variety of effects on air quality, water quality, water withdrawals, views, wildlife, etc. For example, during 2005, APS' air emissions from generation included:[21]

- 2,109 tons of carbon monoxide
- 18.3 million tons of carbon dioxide
- 34,383 tons of nitrogen oxides
- 16,801 tons of sulfur dioxide
- 2,241 tons of particulate matter (PM10)
- 0.247 tons of lead
- 0.36 tons of mercury.

Q. Please describe APS' proposed Environmental Improvement Charge.

A. APS proposes an EIC to overcome regulatory lag in recovery of substantial costs associated with environmental expenditures (Fox, p. 9, DeLizio, p. 3). The costs to be recovered through the EIC are investment and expenses associated with installation and maintenance of the environmental upgrades at APS' generation facilities (DeLizio, pp. 3-4). The proposed tariff (Schedule EIC, Attachment GAD-1) indicates that costs would be associated with environmental improvements implemented on or after January 1, 2004 for which costs have not been fully recovered, ongoing environmental improvement projects, or prospective environmental improvement projects designed to comply with environmental standards required by federal, state, tribal, or local laws or regulations, including water, waste, and air standards. The air standards include limits for SO_2, NOx, particulate matter, volatile organic compounds, and mercury.

[21] Pinnacle West Capital Corporation, *2005 Corporate Responsibility Report.* Figures pertain to APS ownership of generation.

In response to data request WRA 1-11, APS indicated that it may use the EIC for cost recovery for voluntarily reducing pollution associated with power production. APS stated that:

> *"the process for government environmental mandates often takes many years even after the science is understood to require emission reductions and the technology is available to achieve them. Where emission reductions or activities are needed to protect the environment and public health, we anticipate recovery through the EIC, including those costs necessary for complying with existing laws and anticipated future requirements. We believe this proactive approach is in the best interests of our customers and Arizona."*

Costs to be entered into the EIC account are return on capital, depreciation, operation and maintenance expenses, property taxes, and associated income taxes (DeLizio, p. 4 and Schedule EIC). At the time of a rate case, unrecovered costs could be put into base rates and the EIC would be reduced commensurately (DeLizio, pp. 6-7).

The initial costs to be recovered are those for the Cholla power plant (Fox, Attachment EZF-1): bag houses, low NOx burners, and scrubbers for the three units owned by APS. Projects would be carried out between 2004 and 2009 at a capital cost of $134.9 million (plus O&M costs). The initial charge would be $0.000152 per kWh, although APS indicated that the charge might be revised because capital costs were revised to about $160 million (response to Staff data request MJR 3-5).

The EIC rate would be applied to all retail kWh sold with a few exceptions set forth in Schedule EIC. APS would file annual requests for updates and true-ups of the EIC by March 15. Staff would review the proposals and the Commission would have to act by June 15 of each year or else the new EIC rate goes into effect automatically (DeLizio, p. 5, Attachment GAD-2), subject to a subsequent true-up. Over or under collections would accrue interest at a rate equal to APS' pre-tax cost of capital (DeLizio, p. 6, Attachment GAD-2, APS response to data request WRA 1-15).

Q. What environmental improvements does APS expect from the proposed controls at the Cholla plant?

A. APS expects reductions in sulfur dioxide emissions at Units 1 and 3, reductions in nitrogen oxide emissions at all three units, reductions in particulate emissions at Unit 1, and reductions in mercury emissions at Units 1 and 3 (APS response to data request WRA 1-8). Sulfur dioxide emissions cause respiratory illness, create haze, and react with other substances in the air to form acids which damage plants, soils, lakes and streams, and damage buildings and monuments. Nitrogen oxides contribute to the formation of ground level ozone in the presence of sunlight and this ozone in turn causes respiratory illnesses. Nitrogen oxides also contribute to acid rain similar to sulfur dioxide, form nitric acid which causes respiratory illnesses, affect water quality

in coastal estuaries, contribute to eutrophication of water bodies, impair visibility, and cause biological mutations. Particulate emissions affect respiratory health, reduce visibility, and damage buildings and monuments. Mercury, in the form of methylmercury, impairs neurological development in humans and can cause death, reduced fertility, slower growth, and abnormal behavior in wildlife. Elemental mercury, when breathed as a vapor, causes numerous toxic effects.

Q. Has the Commission authorized charges similar to the EIC?

A. Yes. The Commission authorized a DSM charge for APS in Decision No. 67744 (Settlement Agreement paragraph 43) and authorized a surcharge for the Environmental Portfolio Standard. The Commission is also considering a surcharge for the proposed Renewable Energy Standard.

Q. Does WRA support APS' proposed EIC?

A. In general, WRA supports the concept of the EIC for several reasons:

- Some resource choices have greater environmental impacts than others and the EIC makes the attributes of those choices more apparent to APS, the Commission, and ratepayers. The costs of the Cholla improvements add about $1 per MWH to the costs of operating the Cholla plant.[22]
- Utilities should not be discouraged from complying with environmental regulations or pursuing beneficial environmental goals through fear of disallowances for doing the right thing.
- Utilities should be encouraged to take actions that reduce environmental damages caused by power generation, including compliance with regulations, actions taken in anticipation of future regulation, or societally beneficial responses to environmental issues for which no regulation is imminent.
- The EIC reduces the risk to APS of complying with environmental regulations by increasing the likelihood of timely cost recovery.

Q. Do you recommend any changes to the EIC as proposed by APS?

A. Yes. APS should be able to recover the costs of voluntarily reducing emissions beyond those mandated by government regulation, upon Commission approval of specific projects. Reduced pollution improves human health and reduces the impacts of power generation on the environment. Additionally, voluntarily reducing

[22] Calculated by dividing the revenue adjustment for the test year due to the EIC (Schedule H-1) by the kWh produced by Cholla Units 1-3 in 2005 as reported in APS' FERC Form 1: $4,315,000/4,608,054 MWh.

environmental impacts is becoming a part of normal business activity. For example, leading electric utilities and other energy companies have voluntarily acted to reduce their emissions of carbon dioxide.[23] Therefore, Schedule EIC should be modified to include voluntary environmental improvements.

Q. What costs should be excluded from recovery through the EIC?

A. I recommend that the Commission not allow recovery of penalties assessed for non-compliance with environmental regulations. APS has indicated that it does not expect to recover such fines through the EIC (response to data request WRA1-9).

Climate Change and the EIC

Q. Should environmental improvements include reductions of greenhouse gas emissions?

A. Yes. Increased concentrations of greenhouse gases in the atmosphere are contributing to global climate change. Scientific evidence on human-caused climate change is persuasive:[24]

- "Greenhouse gases are accumulating in Earth's atmosphere as a result of human activities, causing surface air temperatures and subsurface ocean temperatures to rise."
- "The surface warming trends are solidly grounded in observational science and consistent with human-induced pressures."
- "There is new and stronger evidence that most of the warming observed over the last 50 years is attributable to human activities."
- "The scientific consensus is clearly expressed in the reports of the Intergovernmental Panel on Climate Change (IPCC). … [T]he evidence for human modification of climate is compelling. … This analysis shows that scientists publishing in the peer-reviewed literature agree with IPCC, the National Academy of Sciences, and the public statements of their professional societies. Politicians, economists, journalists, and others may have the

[23] For example, Cinergy (Ceres, *Electric Power Climate Risk Disclosure*, 2005); American Electric Power and Entergy (Innovest Strategic Value Advisors, Carbon Disclosure Project, *Carbon Finance and the Global Equity Markets,* 2003).

[24] Sources for the following quotes are: Committee on the Science of Climate Change, National Research Council, "Climate Change Science: An Analysis of Some Key Questions," National Academy Press, 2001, p. 1. Stephen H. Schneider, presentation to the U.S. Senate Committee on Commerce, Science and Transportation Hearing on 'The Case for Climate Change Action,', October 1, 2003, p. 2. Intergovernmental Panel on Climate Change (IPCC), *Climate Change 2001, Synthesis Report*, Summary for Policymakers, p. 5. Naomi Oreskes, "The Scientific Consensus on Climate Change," *Science*, December 3, 2004, vol., 306, number 5702, p. 1686.

impression of confusion, disagreement, or discord among climate scientists, but that impression is incorrect."

Greenhouse gases consist of carbon dioxide, methane, nitrous oxide, and several industrial chemicals. Carbon dioxide is the most important anthropogenic source of increased greenhouse gas concentrations.

Impacts of increased concentrations of greenhouse gases in the atmosphere include increases in temperature, rising sea levels, changes in precipitation patterns, and more extreme weather phenomena (e.g., drought, floods).[25] As a result, food and water resources, ecosystems, biodiversity, human settlements, and human health will all be affected at enormous cost. Components of climate change may occur abruptly or gradually. In sum, reductions in greenhouse gas emissions would constitute an environmental improvement.

Q. Will APS face costs of reducing greenhouse gas emissions?

A. Yes. In general, it is prudent to expect that APS will incur costs to either comply with future state or federal greenhouse gas emission regulations or voluntarily pursue corporate policies to reduce its greenhouse gas emissions. Proposals and policies at the federal and state level to reduce greenhouse gas emissions include, for example:

- Proposed federal legislation, such as: the McCain-Lieberman Climate Stewardship Act of 2003 (S. 139) and the McCain-Lieberman Climate Stewardship and Innovation Act of 2005 (S. 1151) which would cap emissions of carbon dioxide; and multi-pollutant bills such as S. 556 (2002) and S. 150 (109th Congress) which would set a cap on carbon dioxide emissions from electric power generators.
- The Regional Greenhouse Gas Initiative (RGGI) among Connecticut, Delaware, Maine, New Hampshire, New Jersey, New York, and Vermont which is intended to stabilize carbon dioxide emissions from the region's power plants at current levels from 2009 to the start of 2015 followed by a 10% reduction in emissions by 2019.
- The Governor of New Mexico's Executive Order 05-033, *Climate Change and Greenhouse Gas Reduction*, which set targets for reducing greenhouse gas emissions to year 2000 levels by 2012, 10% below 2000 levels by 2020, and 75% below 2000 levels by 2050. APS obtains electricity from coal-fired power plants located in New Mexico.
- Arizona Climate Change Advisory Group, *Climate Change Action Plan*, draft, July 2006.

[25] Intergovernmental Panel on Climate Change (IPCC), Climate Change 2001. In particular, see the volumes subtitled, *Summary for Policymakers*, and *The Scientific Basis*. Hadley Centre, "Stabilising Climate to Avoid Dangerous Climate Change," 2005.

APS may, in the future, propose to include recovery of the costs of greenhouse gas emission reduction activities in the EIC or in base rates.

Q. What is APS' possible cost exposure?

A. APS is currently seeking new base load power supplies. Selection of resources which emit large amounts of carbon dioxide will expose APS and its ratepayers to significant cost risk over a long time period. A new pulverized coal plant would emit about 1850 pounds of carbon dioxide per MWh generated. Based on recent activity in greenhouse gas markets, offsetting such emission levels might cost between $5 per metric ton and $30 per metric ton.[26] Thus, APS would face costs between about $0.0042 per kWh and about $0.025 per kWh in addition to fuel costs, operating and maintenance costs, depreciation, and return on investment. Adding a new 400 MW pulverized coal plant with an 85% capacity factor to APS' generation portfolio exposes APS to annual costs of about $12.5 million to $75 million. Coal plants may place long term burdens on ratepayers.

Q. Would APS be at risk for other costs associated with greenhouse gas regulation?

A. Yes. If APS completes installation of a new pulverized coal plant in, for example, 2012, that plant would normally recover depreciation and return on investment for at least 30 years, i.e., through 2042. However, if the effects of climate change are found to be abrupt and dangerous in the next 10 to 20 years, the federal government or state governments may act quickly and decisively to reduce carbon dioxide emissions. As a result, APS may be required to shut down coal-fired power plants, thereby stranding some of its investment.

Q. What are APS' carbon dioxide emissions?

A. Exhibit DB-7 shows APS' historical and forecast carbon dioxide emissions. APS is reducing its carbon dioxide emissions intensity (pounds per MWh) through around

[26] There are several markets for greenhouse gas emission reduction credits. The European Union Allowance market covers about 10,000 large industrial and power generating sources. The Chicago Climate Exchange is a voluntary market with about 41 members. Members commit to an emissions reduction target and if they do not meet the target they must acquire allowances or project-based offsets. There are also international markets in Certified Emission Reductions, Verified Emission Reductions, and Emission Reduction Units. Most of the projects generating these reductions are located in Asia and consist of hydrofluorcarbon destruction projects, landfill gas projects and coal mine methane projects. As of August 2, 2006, the price of European Union Allowances was about $21 per metric ton of carbon dioxide and the price of vintage 2006 carbon financial instruments on the Chicago Climate Exchange was $4.40 per metric ton.

2010, but total emissions are increasing. If APS acquires more conventional coal generation in the future, both emissions and emissions intensity are likely to increase.

Q. What actions are states taking to reduce greenhouse gas emissions from power generation?

A. The RGGI mentioned above is a salient example. As a second example, the California Public Utilities Commission is investigating the adoption of a greenhouse gas emissions performance standard that is no higher than the greenhouse gas emission levels of a combined cycle natural gas turbine.[27] As a third example, the Oregon Energy Facility Siting Council set a carbon dioxide emission performance standard for natural gas baseload plants and all non-baseload plants at 0.675 pounds of carbon dioxide per kWh, which is lower than what can be obtained from such plants, requiring offsets or other actions to meet the standard.[28]

Q. What actions are utilities and other companies taking to manage greenhouse gas risks?

A. The following elements are important in developing, analyzing, and implementing greenhouse gas emission risk management strategies:

- Assignment of responsibilities for greenhouse gas emission management to specific utility managers and to the board of directors.
- Provision of incentives for utility managers to responsibly and effectively manage greenhouse gas emissions.
- Preparation of an inventory and historical time line of greenhouse gas emissions from power generation, transportation, transmission, and other utility activities.
- Incorporation of a variety of public input into the development and analysis of greenhouse gas risk strategies.
- Analysis of greenhouse gas emission risks by such means as including a range of adders for emission compliance costs for each resource option to be considered in long range plans.
- Consideration of non-traditional coal options which significantly reduce carbon dioxide emissions into the atmosphere such as integrated gasification combined cycle (IGCC) technology with carbon capture and sequestration.

[27] California Public Utilities Commission, Policy Statement on Greenhouse Gas Performance Standards, October 6, 2005. Such a policy would preclude significant importation of electricity generated by conventional coal-fired power plants without carbon capture and sequestration.

[28] www.oregon.gov/energy/siting/docs/ccnewst.pdf

- Consideration of off-site greenhouse gas emission reduction strategies such as purchasing tradable verifiable emission reduction credits, offsets, and long term verifiable sequestration of carbon dioxide in forests or soil, for example.
- Reduction of greenhouse gas emissions through energy efficiency, greater use of renewable energy, increased power plant efficiency, and other means.
- Commitments to greenhouse gas emission reduction targets.
- Regular public reporting of greenhouse gas emissions and management activities.

Q. Has APS undertaken actions to manage greenhouse gas emissions?

A. APS has taken some actions. It set a corporate target for 2010 of reducing carbon intensity (pounds of carbon dioxide emissions per MWh) by 10% relative to year 2000 ("Excellence 2010: Owning the Challenge"), estimated historical and projected carbon dioxide emissions, and estimated sulphur hexafluoride emissions. Further, APS has announced a pilot program to produce natural gas from coal using hydrogasification (press release July 5, 2006). In response to WRA data request WRA 1-24, asking APS to describe how greenhouse gas emissions are incorporated in investment and resource decisions made by APS' and Pinnacle West's senior managers and board of directors, APS stated:

> "When considering resource options APS includes the cost of compliance with existing legislation and considers the potential for evolving environmental policy."

No further details were provided.

Q. What actions do you recommend that the Commission take at this time to foster prudent climate change policies for APS whose costs may be recovered through the EIC or base rates?

A. Broadly speaking, APS should explicitly and fully take into account greenhouse gas emission risks when making resource decisions and should actively manage the risks associated with greenhouse gas emissions. With regard to the current rate case, I recommend that the Commission direct APS to complete the following tasks:

Task 1. **Management Plan**. Prepare, with public input, a greenhouse gas emissions management plan that: a) updates its inventory of greenhouse gas emissions, historical trends in greenhouse gas emissions and forecasts of greenhouse gas emissions, b) identifies senior managers responsible for greenhouse gas emission analyses and risk management, c) analyzes the financial and cost risks APS faces as a result of greenhouse gas emissions, d) identifies and analyzes risk management strategies, and e) outlines how APS will incorporate the preceding elements into its resource planning and

selection activities going forward. This management plan should be submitted to the Commission no later than 18 months after the Commission's decision in this case.

Task 2. **Carbon Emission Reduction Study**. Conduct, with public input and with the assistance of outside expertise, an analysis of the applicability of coal technologies with significantly reduced carbon dioxide emissions, including, but not limited to, IGCC with carbon capture and sequestration, and the hydrogasification technology APS plans to pursue on a pilot basis. The analysis should address the current status of and expected future progress in carbon dioxide emission reduction and carbon capture and sequestration options, including costs of technologies reviewed. The study should also address the extent to which traditional utility regulation should be modified to encourage adoption of carbon dioxide emission reduction technologies and carbon capture and sequestration technologies. This analysis should be completed within 12 months of the Commission's decision in this case and should be used in Task 1. APS and participating members of the public should regularly review the work of the outside experts and provide input into the study.

Task 3. **Commitment and Action Plan**. Prepare, with public input, a long term greenhouse gas commitment and an associated action plan for Commission review and approval. The long term commitment and action plan should address at a minimum: emissions covered, enforceability, incentives, benchmarks, targets and associated schedules, duration of the commitment, methods of implementation, estimated costs, cost recovery through the EIC or by other means, measurements of implementation progress, and conditions under which targets may be revised. The commitment and action plan should be submitted to the Commission at the same time as the management plan set forth in Task 1.

Q. What type of Commission review of the management plan, carbon emission reduction study, commitment, and action plan do you recommend?

A. The Commission should review and either approve, approve with modifications, or disapprove the management plan, carbon emission reduction study, and company commitment and action plan. This review should combine all three tasks into one review and may be accomplished at an open meeting or hearing. If the Commission disapproves the management plan, carbon emission reduction study, or commitment and action plan, it should provide direction on how to proceed with climate change risk management and associated cost recovery.

Q. What should the Commission do if APS acquires or commits to acquire additional supply side resources prior to Commission approval of APS' climate change plans, analyses, and commitments?

A. Because acquisition of new fossil fuel resources will lock in long term emissions of more greenhouse gases, I recommend a three step process. First, APS should fully evaluate the potential costs of complying with greenhouse gas emission requirements or similar requirements that may be imposed by government for each resource that it considers. The January 2006 request for proposals (RFP) for base load resources speaks very generally about considering environmental impacts of resource options. APS should request more environmental information on bids before making a final selection under this RFP, including information on bidders' willingness to bear the cost of complying with future greenhouse gas regulations or to acquire offsets of carbon dioxide emissions. Second, no more than 30 days after committing to any new resources, APS should file with the Commission its evaluation of its potential cost exposure associated with future greenhouse gas emission requirements, its analysis of the resource options considered, and the reasons for selecting the winning resources. This filing may include confidential information. Third, at the time APS requests recovery of the costs of complying with any greenhouse gas emission requirements applicable to those resources or costs of voluntary emission reduction goals, the Commission should consider the prudence of APS' selection of the resources by reviewing APS' evaluation of the potential compliance costs at the time it evaluated its resource options and selected specific resources.

There is precedent for such a policy. In Decision No. 65347 (dated November 1, 2002), the Commission ordered that, as a condition of constructing Springerville Unit 4, the developers of Springerville Units 3 and 4, and not Tucson Electric Power Company ratepayers, should bear any risk of the costs of possible regulation of carbon dioxide emissions in the future (Finding of Fact 45).

Q. What are your recommendations concerning the public input proposed above?

A. APS would be responsible for conducting the tasks, submitting the reports, and adopting a company commitment to greenhouse gas reductions. A collaborative consisting of interested parties to this case should be established by the Commission at the time of the Commission's decision in this case. The collaborative would meet regularly with APS, provide advice to APS and its consultants, and review APS' drafts and proposals for carrying out the work inherent in each Task. I recommend that the same collaborative members be involved in all three Tasks. The input provided by the collaborative would be similar to that provided by the DSM collaborative which was established in Decision No. 67744. Participation in the collaborative does not imply that a party accepts APS' plans, analyses, or commitments, but it does reduce the likelihood of serious disagreements and misunderstandings and it provides APS with a wider range of input than it might otherwise obtain.

Q. If the Commission rejects the EIC, would your recommendations on the climate change plans, studies, and commitments presented above remain the same?

A. Yes.

Summary of Recommendations

Q. Please summarize WRA's recommendations.

A. With regard to APS' green power tariff:

- The Commission should approve a green power tariff but the tariff should be modified from APS' proposal as described below.
- Charges for green power should exclude the RES charge and the Environmental Improvement Charge.
- The premium for green power, which is added to the otherwise applicable rate, should be calculated as the cost per kWh of green power minus the base power supply cost, minus the power supply adjustor, and minus an allowance for capacity credits associated with the green power.
- APS should not offer green power until it has adequate renewable energy to serve green power customers, provided that the start date for green power service should be no later than one year after the Commission's decision in this case.
- The minimum block size for green power (in the kWh option) should be 100 kWh per month.
- APS should select a set of low cost, stably priced renewable energy resources to serve green power customers.
- Within six months of the Commission's decision in this case, APS should propose to the Commission a green power premium based on the specific resources it selects and should propose revising the tariff from time to time as cost elements change.
- APS should seek Green–e certification for its green power product.
- APS should submit annual green power reports covering renewable energy acquired by technology, customer enrollment by class, kWh green power sales, green power revenues, and green power costs. These reports could be submitted as part of APS' RES reports.
- If the green power tariff becomes oversubscribed relative to the amount of green power resources, APS should put new applicants on a waiting list until it has acquired sufficient green power resources. Costs of energy from green power resources in excess of green power sales could be used to meet RES requirements or could be recovered in APS' purchased power costs.

With regard to using renewable energy as a hedge against high natural gas prices:

- The Commission should direct APS to acquire 1,300 GWH per year of low cost, stably priced renewable energy under long term contracts starting within the period from 2008 through 2010 and continuing for at least 15 years. This

renewable energy is in addition to that obtained in compliance with Decision No. 67744.

- APS should file for Commission review, within 4 months of the date of the Commission's decision in this case, a renewable energy acquisition plan that incorporates input from interested parties obtained via a collaborative process.
- APS should file reports with the Commission by March 1 of 2009, 2010, and 2011 describing its progress in meeting the goals and proposing actions to make up any deficiencies in meeting the goals. The Commission may set a course of action to deal with problems and deficiencies in meeting the goal.
- APS should recover the costs of the renewable energy either through the RES (if the resources are eligible) or through its power supply adjustor.
- APS should either base its wind integration costs on detailed modeling studies of other utilities or conduct a similar detailed modeling analysis of its own system.

With regard to demand side management to reduce urban heat island effects:

- APS should propose an urban heat island reduction program as part of its DSM portfolio. This program should be developed using input from the DSM collaborative and outside experts and should focus on geographically contiguous areas as opposed to individual buildings scattered around urban areas.

With regard to the Environmental Improvement Charge:

- The Commission should approve APS' proposed EIC and expand its scope to include, upon Commission approval of specific projects, voluntary environmental improvements.
- The Commission should not allow recovery of penalties assessed for non-compliance with environmental regulations.

With regard to climate change and the EIC:

- The Commission should direct APS to prepare, with public input obtained in a collaborative process, a climate change management plan, a carbon emission reduction study, and a climate change commitment and action plan, and deliver the plans and studies to the Commission within 18 months of the Commission's decision in this case. The Commission should review the plans and studies and approve, approve with modifications, or disapprove APS' plans. If the Commission disapproves the plans it should provide direction on how to proceed with climate change risk management and associated cost recovery.

- If APS acquires any new supply side resources before the Commission has approved a climate change management plan, related analyses, commitments, and action plans for APS, I recommend a three step process. First, APS should fully evaluate the potential costs of complying with greenhouse gas emission requirements or similar requirements that may be imposed by government for

each resource that it considers. Second, no more than 30 days after committing to any new resources, APS should file with the Commission its evaluation of its potential cost exposure associated with future greenhouse gas emission requirements, its analysis of the of resource options considered, and the reasons for selecting the winning resources. This filing may include confidential information. Third, at the time APS requests recovery of the costs of complying with any greenhouse gas emission requirements applicable to those resources or costs of voluntary emission reduction goals, the Commission should consider the prudence of APS' selection of the resources by reviewing APS' evaluation of the potential compliance costs at the time it evaluated its resource options and selected specific resources.

Q. Does this conclude your direct testimony?

A. Yes.

Qualifications of David Berry

Education:

B.A.	Syracuse University (Geography)
M.A. & Ph. D.	University of Pennsylvania (Regional Science)

Employment History:

- Western Resource Advocates, Senior Policy Advisor (2001 - present)
- Navigant Consulting, Inc., Senior Engagement Manager (1997-2001)
- Arizona Corporation Commission, Chief Economist and Chief, Economics and Research (1985 – 1996)
- Boston University, Department of Urban Affairs and Planning, Lecturer (1981-1985)
- Abt Associates, Inc., Senior Analyst (1979-1985)
- University of Illinois, Department of Urban and Regional Planning, Visiting Assistant Professor (1977-1979)
- University of Pennsylvania, Regional Science Department, Lecturer (1974 –1977)
- Regional Science Research Institute, Research Associate (1972-1977)
- US Army (1969-1971)

Testimony and Public Comment:

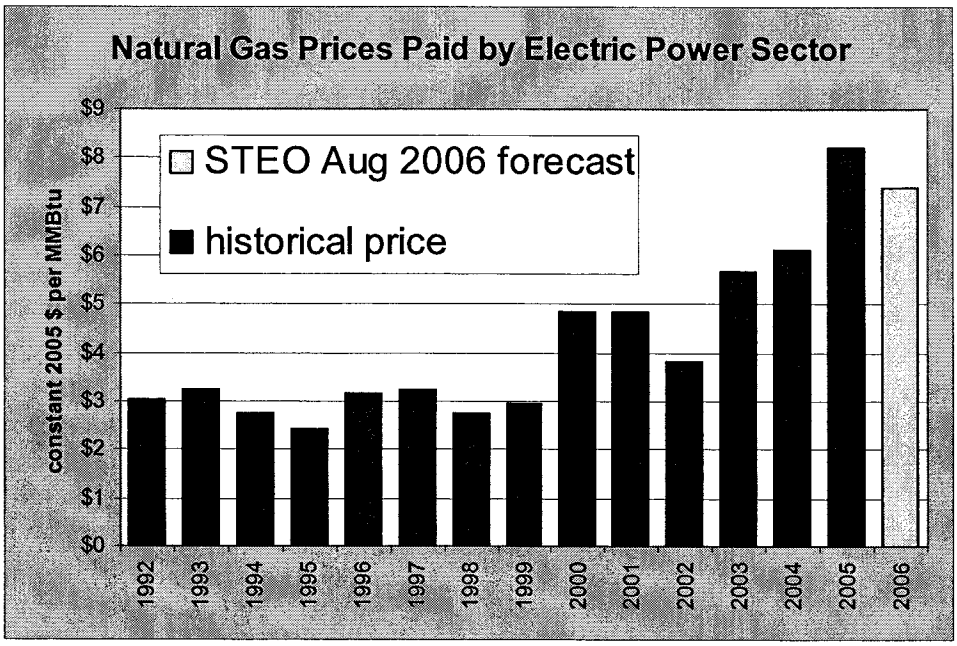
- Before the Maine Land Use Regulation Commission
- Before the Arizona Corporation Commission
- Before the New Mexico Public Regulation Commission
- Before the Public Utilities Commission of Nevada

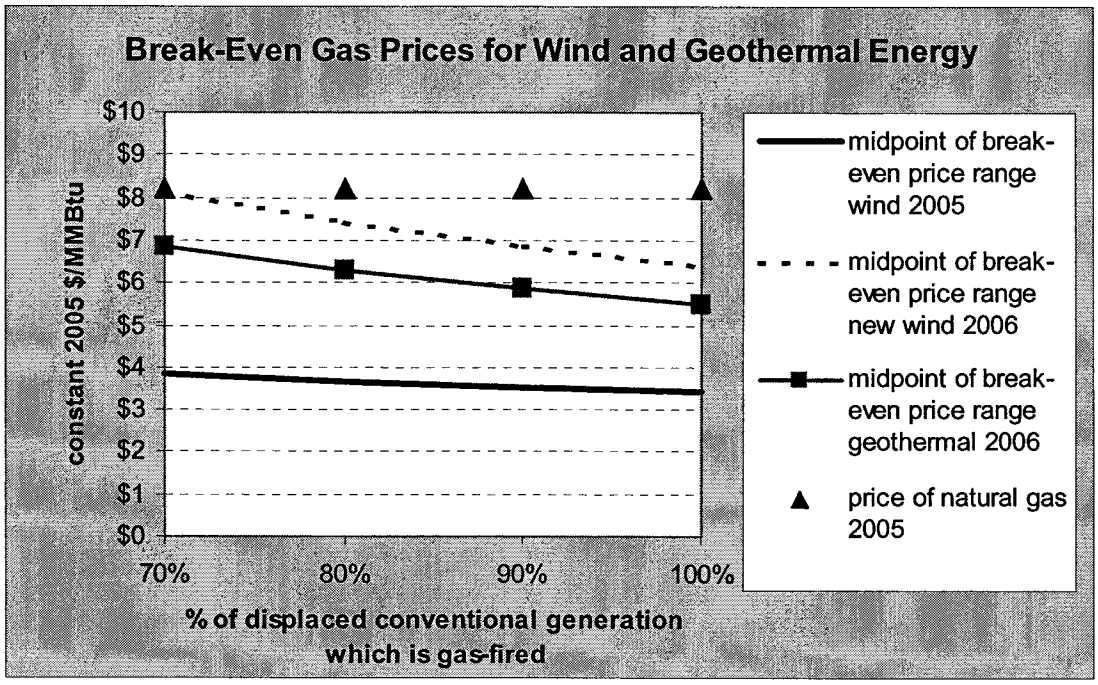
Articles in:

- *Ecological Economics*
- *Energy Policy*
- *Journal of the American Planning Association*
- *Local Environment*
- *Solar Today*
- *NRRI Quarterly Bulletin*
- *The Electricity Journal*
- *Journal of Economic Issues*
- *Public Utilities Fortnightly*
- *Journal of Environmental Management*
- *Business Economics*
- *American Journal of Economics and Sociology*
- *Water Spectrum*
- *Geographical Perspectives*
- *Strategic Planning for Energy and the Environment*
- *National Tax Journal*
- *Policy Sciences*
- *Natural Resources Journal*
- *Water International*
- *Growth and Change*
- *Home Energy*
- *Professional Geographer*
- *Public Management*
- Chapters in books and proceedings

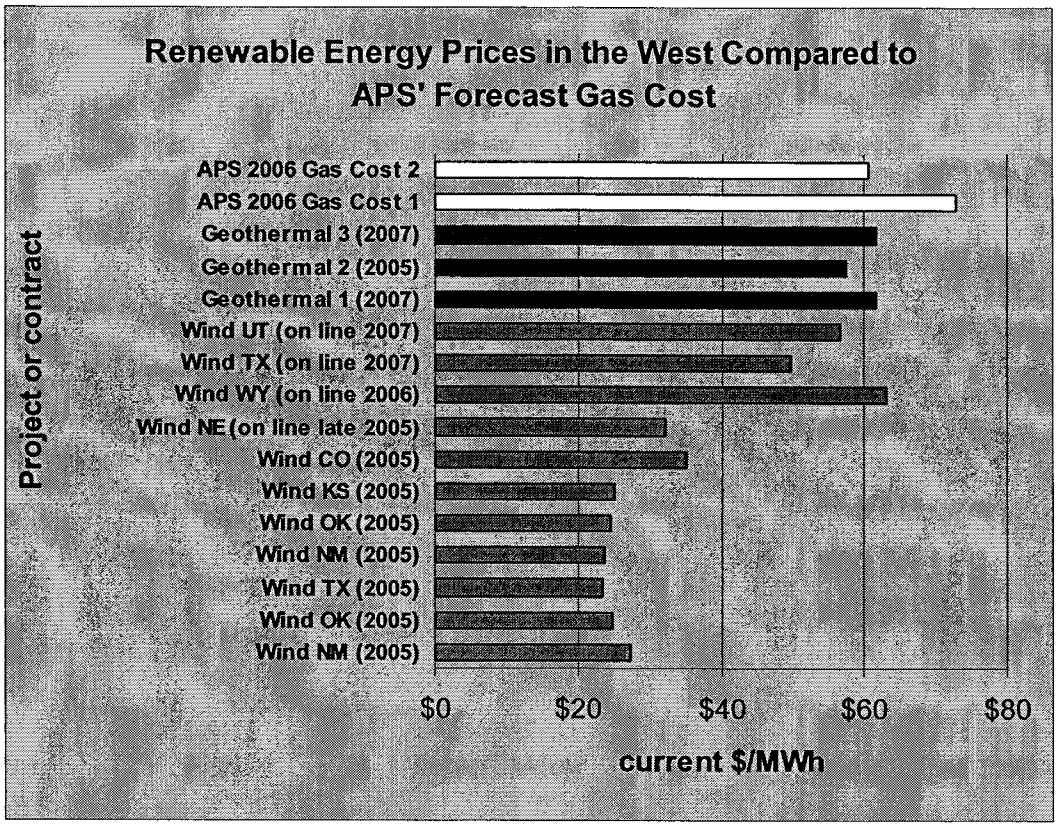
Service on Boards and Advisory Groups

- Scottsdale Library Advisory Board (2003-2005)
- Governor's Energy Efficiency and Renewable Energy Working Group (2004-2005)
- Arizona Comparative Environmental Risk Project (1993-1995)



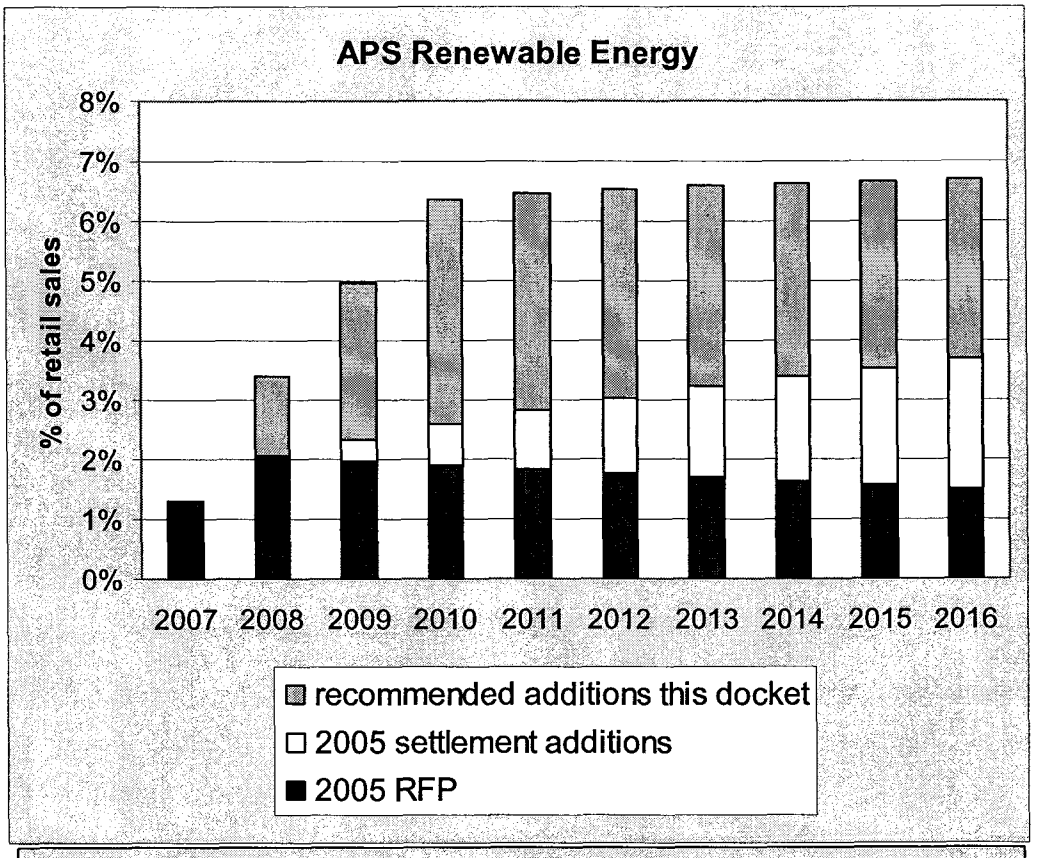


The break-even prices are the natural gas prices at which the cost of renewable energy equals the avoided energy and capacity costs of natural gas-fired generation. The cost of wind energy includes wind integration costs. When the price of natural gas paid by the electric power sector is above the break-even price, renewable energy costs less. In recent years, gas prices have been sufficiently high that many wind energy resources and some geothermal resources are cheaper alternatives. Future natural gas prices are uncertain, so it is appropriate to regard renewable energy resources as hedges against high gas prices in the future. The hedge value of renewable resources is enhanced when utilities purchase renewable energy at a fixed or stable price that is not tied to the price of natural gas. See testimony narrative for assumptions used to prepare the chart.



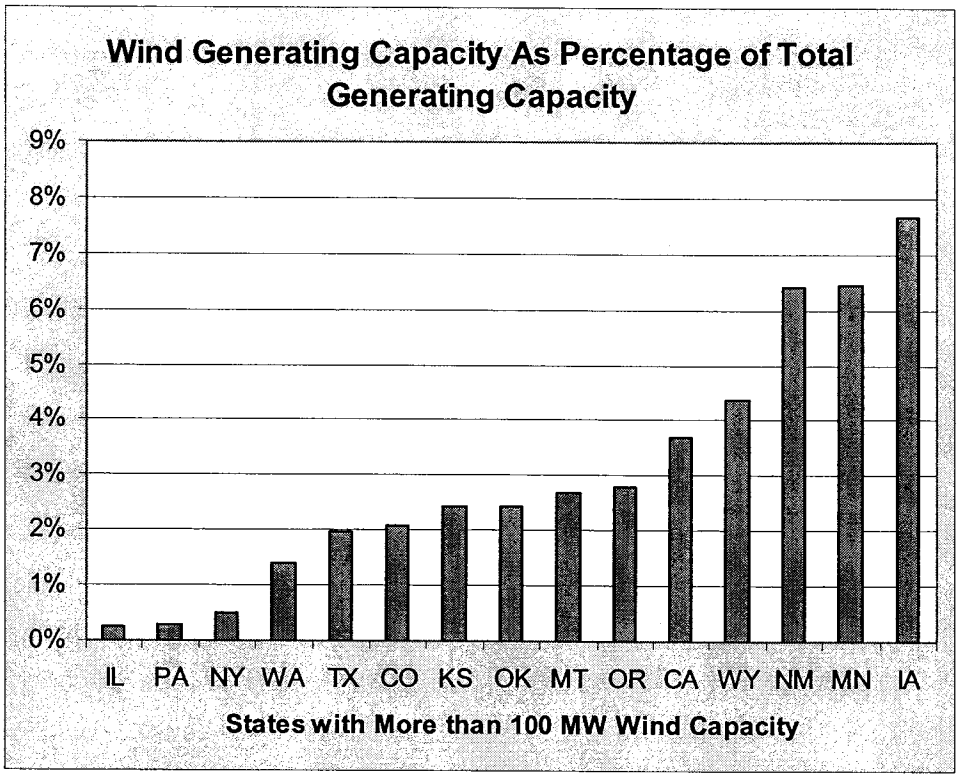
Prices are:

- Wind energy prices paid in 2005 for projects in various western states
- Wind energy prices for new projects starting operations in late 2005 or later
- Geothermal contracts (Salton Sea area) starting in 2005 or later
- APS average cost of natural gas fuel expense for APS' own load for 2006: includes gas transportation cost and subtracts gas hedge from fuel cost.
  - APS 2006 Gas Cost 1 is calculated from Peter Ewen's workpapers PME_WP3, pages 1, 3
  - APS 2006 Gas Cost 2 is calculated from APS' revised cost projections provided in its response to data request LCG 2-1



Explanation of Graph

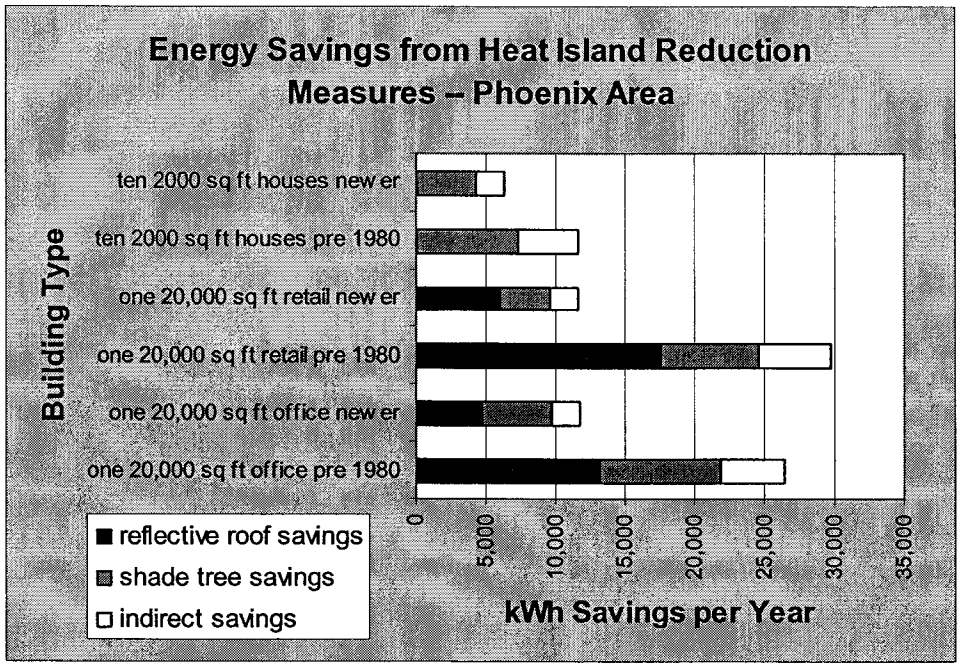
1. Retail sales are assumed to grow at historical rate (1980-2005). Transmission and distribution losses from renewable energy generation are assumed to be 5% of generation.
2. ***2005 RFP*** assumes APS will obtain all the energy expected under the biogas, geothermal, and wind contracts resulting from the 2005 RFP process (Decision Nos. 67744 and 68296 as modified in APS data response WRA1-18). Percentage declines over time because energy amount is constant and retail sales grow.
3. ***2005 settlement additions*** pertain to renewable energy corresponding to 10% of capacity additions per the previous settlement agreement (Decision No. 67744), APS' response to WRA data request WRA 2-1 and APS' response to Staff data request EAA 4-16. Effect of additions is cumulative over time.
4. ***Recommended additions*** pertain to renewable energy acquisitions that would be obtained if WRA's recommendations in this docket were adopted by the Commission. Additional renewable resources are assumed to be phased in over three years. Then the percentage in the graph declines over time because energy amount is constant and retail sales grow.



Data Sources

Wind generating capacity from American Wind Energy Association, "Wind Energy Projects throughout the United States of America," as of December 31, 2005.

Total generating capacity from Energy Information Administration, *Electric Power Annual* database for 2004 (most recent data available). Capacity refers to summer capacity (MW) and includes coal, dual fired, hydro, natural gas, nuclear, other gas, other renewables, petroleum, pumped storage, and other capacity for electric utilities, independent power producers, and combined heat and power.



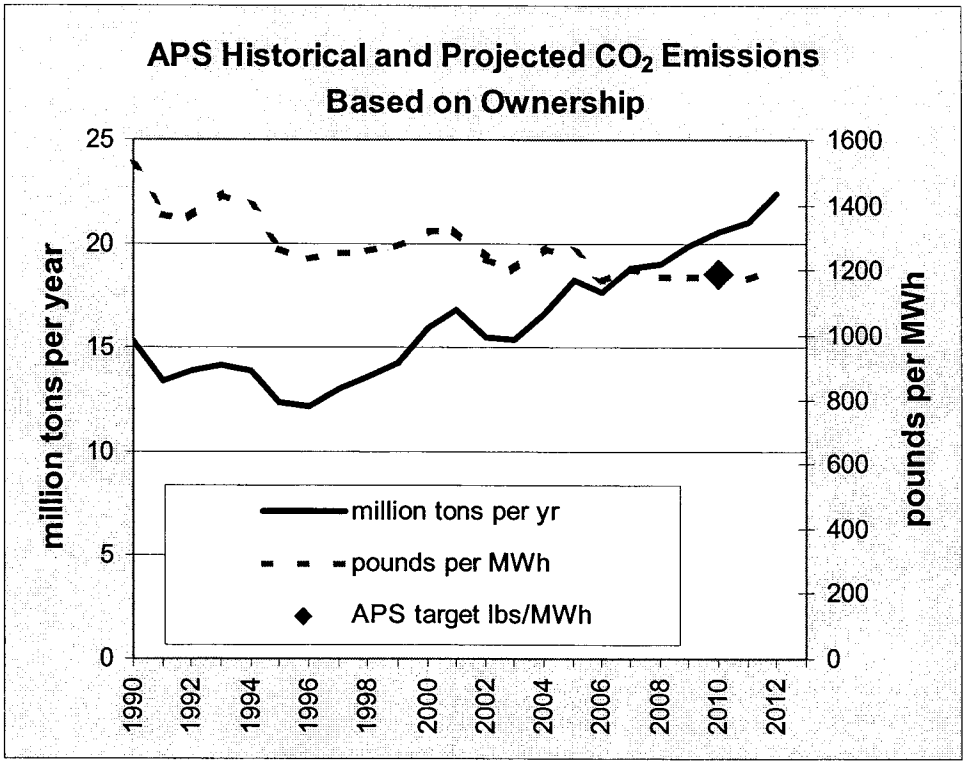
Source: H. Akbari and S. Konopacki, "Calculating energy-saving potentials of heat-island reduction strategies," *Energy Policy* 33 (2005): 721-756.

Assumptions for DSM measures are as follows:

- Solar reflective roofs are commercially available for office buildings and retail stores, but are not widely available for residential applications with sloping roofs. Therefore, savings for reflective roofs for residential applications are not shown.
- Shade trees are placed on south and west walls near windows: 4 trees per house, 8 trees per office, and 10 trees per retail store.
- Indirect savings represent impact of street and other urban trees and reflective building surfaces and pavements.

Buildings are classified by vintage because newer buildings tend to be more energy efficient.

Buildings assume electric heat. Savings for gas heated buildings are very similar.



Source: APS' responses to WRA data requests 3-2, 3-3, and 3-4.

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

JEFF HATCH-MILLER, Chairman
WILLIAM A. MUNDELL
MIKE GLEASON
KRISTIN K. MAYES
BARRY WONG

EXHIBIT
WRA-2
admitted

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 RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND TO AMEND DECISION NO. 67744.	DOCKET NO. E-01345A-05-0816

Surrebuttal Testimony of

David Berry

Western Resource Advocates

September 27, 2006

aps 2005-2006 db surrebuttal.doc

Surrebuttal Testimony of David Berry
Docket No. E-01345A-05-0816

Table of Contents

Introduction	1
Demand Side Management to Reduce the Urban Heat Island Effect	1
Green Power	4
Renewable Energy	7
Environmental Issues	9

Introduction

Q. Please state your name and business address.

A. My name is David Berry. My business address is P.O. Box 1064, Scottsdale, Arizona 85252-1064.

Q. Did you file direct testimony in this Docket?

A. Yes, on behalf of Western Resource Advocates (WRA).

Q. What is the purpose of your surrebuttal testimony?

A. My surrebuttal testimony addresses issues raised by Arizona Public Service Company (APS) in its rebuttal testimony filed September 15, 2006. In particular, I address:

- Demand side management to reduce the urban heat island effect (rebuttal testimony of Teresa Orlick);
- Green power (rebuttal testimony of Greg DeLizio and Barbara Lockwood);
- The role of renewable energy in APS' portfolio (rebuttal testimony of Barbara Lockwood and Patrick Dinkel);
- Environmental issues, namely the Environmental Improvement Charge (EIC) and the greenhouse gas studies recommended by WRA (rebuttal testimony of Ed Fox).

Demand Side Management to Reduce the Urban Heat Island Effect

Q. Did WRA recommend a demand side management (DSM) program to reduce the urban heat island effect?

A. Yes.

Q. What is APS' response to this proposal?

A. Ms. Orlick (pp. 12 to 14) indicated that APS would schedule a DSM Collaborative meeting that would include a presentation about Arizona State University's research on mitigating the heat island effect, that an urban heat island effect program could be incorporated into the existing non-residential DSM programs as a custom efficiency component, and that Staff had found that the (retrofit) cool roofs component of an urban heat island reduction program was not cost effective (Decision No. 68488, Staff

Interim Report, January 18, 2006, p. 33). Ms. Orlick also stated (p. 14) that APS believes that the research underway at Arizona State University's Global Institute of Sustainability should yield substantial results before proceeding down the path of developing an entire heat island effect DSM program.

Q. What is WRA's response to Ms. Orlick's rebuttal testimony?

A. WRA is pleased that APS is willing to consider a heat island reduction program and to bring in outside experts to inform the Collaborative. I believe that the program would benefit from the following features:

1. Inclusion of practitioners in urban planning and landscape architecture, a representative from the Center for Urban Forest Research at the US Forest Service's Pacific Southwest Research Station (if available), and a representative from the Heat Island Group at the Lawrence Berkeley National Laboratory (if available) in the Collaborative meetings on the urban heat island reduction program in addition to the researchers from Arizona State University proposed by Ms. Orlick.

2. Actively seeking out one or more specific neighborhoods in which to geographically concentrate a large number of urban heat island reduction measures so as to capture both direct and indirect savings from shade trees, cool roofs, and cool pavements and to achieve a high level of energy savings. In this respect the urban heat island reduction program would differ from typical DSM programs in which DSM measures are applied to customers scattered around APS' service territory. Further, implementation of the urban heat island reduction program would likely require cooperation of a municipality as street trees and pavement are program elements. APS and its experts may be actively involved in the selection of candidate neighborhoods and in the design of the customer efficiency measures so as to maximize the cost effectiveness of the program.

3. Expeditious implementation of the urban heat island reduction program. There has been over a decade of research on urban heat island reduction.[1] It is not necessary to delay several years for more research to be completed before designing a cost effective urban heat island reduction program.

Q. Does WRA have a position on whether the urban heat island reduction program is incorporated into existing approved DSM programs?

A. Ms. Orlick's proposal to include the urban heat island reduction program as a custom program within existing nonresidential programs is appropriate.

Q. What specific DSM measures would be included in an urban heat island reduction program?

A. Measures would typically include shade trees, cool roofs, and cool pavements, although the specific mix will have to be determined by the Collaborative and APS. As indicated in my direct testimony (pp. 16 –17, and Exhibit DB-6), energy savings can be obtained from shade trees, cool roofs, and indirect effects due to urban vegetation, reflective building surfaces, and cool pavements.

I am aware that Staff has concerns over the cost of cool roofs as explained in Decision 68488 (page 33 of Staff's January 18, 2006 report). Staff found that in retrofit applications, cool roofs were not cost effective on non-residential structures, and Staff found that for new roofs the marginal cost of reflective coatings was zero or negative, leading Staff to conclude that incentives in such applications were not needed. I would urge APS and the Collaborative to try to select candidate neighborhoods for the heat island reduction program so as to develop a cost effective

[1] Examples include: E. Gregory McPherson, "Evaluating the Cost Effectiveness of Shade Trees for Demand-Side Management," *The Electricity Journal*, vol. 6, no. 9 (November 1993), 57-65. James Simpson, "Urban Forest Impacts on Regional Cooling and Heating Energy Use: Sacramento County Case Study," *Journal of Arboriculture*, vol. 24, no. 4 (July 1998): 201-214. Brian Stone and Michael Rodgers, "Urban Form and Thermal Efficiency: How the Design of Cities Influences the Urban Heat Island Effect," *Journal of the American Planning Association*, vol. 67, no. 2 (Spring 2001): 186-198. E. Gregory McPherson, "Cooling Urban Heat Islands with Sustainable Landscapes," in Rutherford Platt, Rowan Rowntree, and Pamela Muick, eds., *The Ecological City*, Amherst, University of Massachusetts Press, 1994. H. Akbari and S. Konopacki, "Calculating Energy-Saving Potentials of Heat-Island Reduction Strategies," *Energy Policy* vol. 33 no. 6 (April 2005): 721-756. U.S. Environmental Protection Agency, *Cooling our Communities*, 1992. Anthony Brazel and Katherine Crewe, "Preliminary Test of a Surface Heat Island Model (SHIM) and Implications for a Desert Urban Environment, Phoenix, Arizona," *Journal of the Arizona-Nevada Academy of Science*, vol. 34, no. 2 (2002): 98-105. Kim Clark and David Berry, "House Characteristics and the Effectiveness of Energy Conservation Measures," *Journal of the American Planning Association*, vol. 61 (Summer 1995) 386-395.

program. Cool roofs should be part of the list of measures considered as the incremental cost may be zero for structures that would need new roofs anyway and because the energy savings at new and existing structures should account for indirect effects. Cost benefit analyses for candidate locations should also consider the age of existing structures as older buildings produce much larger savings from cool roofs than newer buildings.[2] The role of incentives for cool roofs and other program measures will have to be assessed by the Collaborative, taking into account Staff's previous findings.

Green Power

Q. What was WRA's position on APS' initial green power proposal?

A. WRA supported the concept but recommended refinements to APS' initial proposal (direct testimony, pp. 2-7).

Q. Has APS proposed changes to its initial green power tariff?

A. Yes. Mr. DeLizio and Ms. Lockwood propose several changes:

- The premium has been changed to $0.01 per kWh (Mr. DeLizio, p. 7), taking into account the costs of one geothermal project and two wind projects and taking into account APS' avoided costs as filed on June 30, 2006 (Ms. Lockwood pp. 5-6, Mr. DeLizio, pp. 7-8).
- The block size for the block option is increased from 25 kWh per month to 100 kWh per month (Mr. DeLizio, p. 7).
- As new renewable energy resources are used after the initial green power resources are fully subscribed, APS may file new green power rates reflecting the new resource costs and the most recent approved avoided cost filing (Mr. DeLizio, p. 8). Apparently the new green power rates would apply only to customers who had not subscribed under the initial green power tariff. The initial subscribers would continue to be served under schedules GPS-1A and GPS-2A (Mr. DeLizio, pp. 8-9).
- Green power kWh would be excluded from the Environmental Portfolio Standard charge and EIC charge, but all other kWh consumed by green power customers would be subject to these charges (Mr. DeLizio, p. 9).
- Green power kWh would be subject to the Power Supply Adjustment, the Transmission Cost Adjustment, the Competition Rules Compliance Charge, and the Demand Side Management Adjustment (Mr. DeLizio, p. 9).
- APS will provide reports on customer participation, kWh sales, and revenue in its annual EPS/RES filings (Ms. Lockwood, p. 6).

[2] H. Akbari and S. Konopacki, "Calculating Energy-Saving Potentials of Heat-Island Reduction Strategies," *Energy Policy* 33 (2005): 721-756.

- APS will pursue Green-e certification for its green power products (Ms. Lockwood, pp. 6-7).

Q. What is WRA's response to these proposed revisions to the green power service?

A. WRA appreciates APS' willingness to refine the green power option. We are also cognizant of the need for a practical, workable tariff that meets customers' needs. All of the changes proposed by APS are an advance over APS' original proposal. However, several additional improvements and clarifications are desirable:

1. WRA believes that the premium should reflect the stable cost of renewable energy minus the fluctuating cost of conventional generation. Thus, in periods of high fossil fuel prices, for example, green power might be less costly than conventional generation, resulting in an effective premium that is negative. This feature has been characterized as a "best practice" for green power programs.[3] Therefore, under APS' proposal contained in its rebuttal testimony, the green power tariffs should be further revised to allow for regular changes to the rates to reflect updates to APS' avoided costs.[4]
2. Instead of multiple green power tariffs as proposed by APS, it would be simpler for APS and its customers to have one set of green power tariffs whose rates are regularly reviewed and revised as avoided costs change and as the renewable energy mix changes.
3. APS should be using new renewable resources to serve green power customers and not simply re-sell, at a premium, renewable resources it has already committed to. The Green-e Renewable Electricity Certification Program, National Standard Version 1.3, Section III. D indicates that "Green-e certified products must be comprised of eligible renewable generation over and above anything required by state or federal RPS requirements. Renewable energy or RECs [renewable energy certificates] may NOT be used in a Green-e certified product under the following circumstances: The REC or the electricity from which the RECs are derived is being used simultaneously to meet a local, state or federal energy mandate or other legal requirement…." WRA believes that this is good public policy even if a utility does not seek Green-e certification. Thus, the kWh APS actually uses to serve green power customers should not also be used to

[3] Center for Resource Solutions, *Regulator's Handbook on Renewable Energy Programs and Tariffs*, March 2006, p. 11, www.resource-solutions.org.

[4] APS files avoided costs every two years in compliance with the Public Utility Regulatory Policies Act of 1978, Title II, Section 210. The most recent filing with the Director of the Utilities Division was on June 30, 2006. This filing could be used for avoided costs although other information may be suitable as well.

meet the RES requirements,[5] the commitments made under Decision No. 67744, or the requirements of any renewable energy program adopted in this Docket such as WRA's 1300 GWH per year proposal or the Interwest Energy Alliance proposal (direct testimony of Amanda Ormond, pp. 6-7).[6]

4. The Green-e program requires that percentage products for residential customers must offset at least 25 percent of a residential customer's electricity usage above and beyond any state mandated renewable portfolio standard.[7] As currently proposed, residential customers could obtain only 10 percent of their kWh from the green power program. This discrepancy needs to be addressed.

Q. What is WRA's recommendation regarding the revised green power tariff?

A. The Commission should accept APS' revised green power tariff with the following modifications:

1. The green power tariffs should indicate that APS may re-file rates annually to reflect changes in avoided costs or the mix of renewable resources[8] or both if any changes are needed. Thus, all green power customers would be served under a single set of block and percent rates.
2. Green power kWh should be in addition to kWh used to meet RES requirements, in addition to kWh used to meet APS' renewable energy commitments contained in Decision No. 67744, and in addition to the requirements of any renewable energy program adopted in this Docket such as WRA's 1300 GWH per year proposal or the Interwest Energy Alliance's proposal.
3. The green power percent schedule should be modified so as to apply the 10 percent option only to non-residential customers.

[5] APS has indicated that it would use the same resources to meet RES requirements and to serve green power customers, but that kWh used to serve green power customers would not be counted toward the RES requirements (response to data requests WRA 1-3 and 1-4). WRA believes that this policy is acceptable.

[6] The Green-e Renewable Electricity Certification Program, National Standard Version 1.3, Section III B, indicates that a Green-e certified product may include only renewable energy that was generated in the calendar year in which the product is sold, the first three months of the following calendar year, or the last six months of the prior calendar year.

[7] Green-e Renewable Electricity Certification Program, National Standard Version 1.3, Section III A.

[8] To be eligible for Green-e certification, a renewable energy resource must have been placed in operation (generating electricity) on or after January 1, 1997: Green-e Renewable Electricity Certification Program, National Standard Version 1.3, Section II E.

Renewable Energy

Q. What did WRA recommend regarding an increased role for renewable energy for APS?

A. WRA proposed that renewable energy be used as a hedge against high costs of natural gas used for generating electricity (pp. 7-15). I recommended, among other things, that the Commission direct APS to acquire 1,300 GWH per year of low cost, stably priced renewable energy under long term contracts starting within the period 2008 through 2010 and continuing for at least 15 years. This renewable energy is in addition to that obtained in compliance with Decision No. 67744. I also recommended (p. 12) that APS include in regular reports a detailed description of any problems encountered in acquiring renewable energy as a hedge against high fossil fuel prices and offer proposed solutions. The Commission would review APS' reports and set a course of action for APS to deal with any problems. WRA continues to recommend the steps described above.

Q. What is APS' perspective on the increased role of renewable energy in its portfolio?

A. Mr. Dinkel (rebuttal, p. 2) notes that renewable energy should make up a larger percentage of APS' generation portfolio. Ms. Lockwood (p. 9) indicates that APS supports the intent of the draft Renewable Energy Standard (RES) rules and believes that the RES rulemaking is the proper forum for addressing renewable energy.

Q. Is this rate case an appropriate forum for the Commission to consider the role of renewable energy in APS' portfolio?

A. Yes. Much of the cost increase that APS proposes to recover through rates is due to higher fuel costs. To the extent that APS caps its exposure to high fossil fuel costs through use of renewable energy, rate increases can be capped. Moreover, the RES rules, as proposed, do not create a sufficient hedge against high natural gas costs quickly enough (WRA direct testimony, p. 12).

Q. What issues did APS raise in response to WRA's recommendation?

A. WRA's direct testimony indicates that low cost, stably priced renewable energy can be a cost effective hedge in general. However, Mr. Dinkel (rebuttal, p. 2) is concerned that renewable energy may not be a cost effective hedge against high natural gas prices for APS because renewable energy might cost more than conventional generation in that particular case.

Q. How might APS lower the costs of renewable energy?

A. APS can take several steps to help lower the cost of renewable energy:

1. **Seek proposals not only from developer-owned projects, but also for projects that would be owned by APS.** There is some evidence that renewable energy project developers are pricing energy to approximately match the cost of generating electricity from gas-fired resources. If APS owned the facilities it may be able to lower the cost. Utility ownership of renewable energy resources is becoming more common.
2. **Get better information on wind integration costs.** These costs are likely to be smaller than the costs APS used in its evaluation of the 2005 renewable energy acquisition (direct testimony, pp. 14-15). APS' forthcoming wind integration study (Mr. Dinkel rebuttal, pp. 4-6) should address this need. Mr. Dinkel (rebuttal, p. 4) also raises the issue of the impact of intermittency of wind energy on the costs of scheduling gas purchases and this issue should be included in the wind integration study.[9]
3. **Assign only the incremental costs of transmission to renewable energy.** If APS obtains renewable energy from a geothermal resource, for example, it will need transmission service to deliver the energy to the APS system. However, it will also need less transmission service somewhere else because it does not have to transmit power from another (conventional) resource to its customers. The proper cost to assign to renewable energy is not the cost of transmission from the illustrative geothermal project, but the difference in transmission cost between that needed for the geothermal project and that transmission cost avoided by the geothermal project.

Q. Can the Commission or APS ever be sure that renewable energy will or will not be less costly than gas-fired generation in the future?

A. No. That is why low cost, stably priced renewable energy is best viewed as a <u>hedge</u> against high gas prices in an uncertain world. It is not possible to reliably forecast the price of natural gas. For example, the Energy Information Administration[10] has stated that "Natural gas generally has been the fuel with the least accurate forecasts." Table 1 of the EIA Forecast Evaluation report shows that the average absolute percent error for its *Annual Energy Outlook* forecasts of natural gas wellhead prices from 1982 to

[9] Public Service Company of Colorado investigated this gas cost impact and, for the case where wind penetration is 10 percent of peak load, found the cost to be between $1.26 per MWh of wind energy and $2.17 per MWh, depending on whether the additional benefits of gas storage are considered. EnerNex Corporation, *Wind Integration Study for Public Service Company of Colorado*, report to Xcel Energy, Knoxville, TN, 2006, pp. 22, 71-77.

[10] EIA, *Annual Energy Outlook Forecast Evaluations 2004*, p. 2.

2004 was 67.7%. The large error in gas price forecasts, especially in an era of high gas prices, underscores the hedge value of fixed or stably priced renewable energy resources relative to the uncertainty of natural gas prices. Moreover, with this kind of inaccuracy, neither utilities nor regulators can use price forecasts to effectively manage gas price risk. WRA's analysis in its direct testimony indicates that at recent natural gas prices, some renewable energy resources are less costly than conventional generation and that the renewable energy can be obtained at fixed or stable prices.

Environmental Issues

Q. Why is it important for the Commission to encourage electric utilities to reduce the environmental impacts of power generation?

A. Electric utilities have a major impact on the environment. For example, electric utilities account for the following shares of human-caused air emissions in the United States:[11]

- 33% of greenhouse gas emissions which are a cause of climate change
- 67% of sulfur dioxide emissions
- 22% of nitrogen oxides
- 43% of mercury emissions.

It is in the public interest to reduce emissions of each of these compounds and pollutants because of their environmental impacts which I described in my direct testimony (pp. 18-21). Initially, APS expects to reduce SO_2, NOx, PM10, and mercury emissions from the Cholla plant (Mr. Fox, rebuttal testimony, Attachment EZF-1RB).

Q. WRA supported APS' proposed Environmental Improvement Charge (direct testimony, pp. 17-20). Does WRA still support the EIC?

A. Yes. WRA believes that it is in the public interest to reduce the environmental impacts of power generation and for utilities, including APS, to be willing partners in reducing those environmental impacts. APS indicates that after-the-fact regulatory review for cost recovery has been a major obstacle to proactively addressing environmental issues and creates a disincentive to undertake anything more than the minimum environmental actions as late as possible (Mr. Fox, rebuttal, p. 10). Mr. Fox (p. 17) also states that regulated utilities should be provided with a process by

[11] Data from U.S. Environmental Protection Agency, *Air Pollutant Emission Trends, 1970-2002*, 2005, Table 361, U.S. Environmental Protection Agency, *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2004,* 2006, Table 2-14, U.S. Environmental Protection Agency, "Controlling Power Plant Emissions: Emissions Progress," www.epa.gov/mercury/control_emissions/emissions.htm.

which expenditures on emission reductions are deemed prudent and recoverable. APS is further concerned that its expenditures to address climate change have a risk of becoming stranded without the EIC or a similar process (Fox rebuttal, p. 17).

Because of the large environmental impact of conventional power generation, it would not be in the public interest to impede APS' practical and forward-looking efforts to reduce environmental impacts by making cost recovery uncertain or onerous.

Q. Several parties to this case have expressed concern that the EIC falls outside the scope of traditional ratemaking. Does this mean that the EIC should not be approved by the Commission?

A. No. In reaction to non-traditional aspects of furnishing electricity, the Commission has pursued innovative approaches to ratemaking. The EIC, if adopted, would fall into this category. Innovative actions considered by the Commission to pursue environmental or other objectives include a performance incentive for APS' DSM program (see direct testimony of Staff witness Anderson, pages 9-13) and the funding mechanism for the Environmental Portfolio Standard. As non-traditional issues affecting electric service emerge, it is appropriate for the Commission to develop creative means to both protect the interests of ratepayers and foster other goals such as environmental improvements.

Q. Is the EIC the only mechanism for APS to recover prudent expenditures on environmental improvements?

A. No. WRA proposed a greenhouse gas emission reduction planning process incorporating emission reduction commitments and cost recovery (direct testimony, pp. 24-26). WRA also proposed a process for demonstrating the prudence (or lack of prudence) for power supply choices made before the Commission approves APS' greenhouse gas emission reduction commitment and associated plan. WRA continues to recommend adoption of these processes regarding climate change, along with the EIC.

Q. Does this conclude your surrebuttal testimony?

A. Yes.

BEFORE THE ARIZONA CORPORATION COMMISSION

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 Ratemaking Purposes, to Fix a Just and Reasonable Rate of Return Thereon, to Approve Rate Schedules Designed to Develop Such Return, and to Amend Decision No. 67744	)	Docket No. E-01345A-05-0816 E-01345A-05-0826 E-01345A-05-0827

Testimony Summary & Testimony

Colonel Ronald J. Mozzillo

On behalf of

Federal Executive Agencies

November 28, 2006

EXHIBIT

FEA-1

Admitted

Testimony Summary of Colonel Ronald J. Mozzillo, USAF

I am Colonel Ronald J. Mozzillo, Commander, 56th Mission Support Group, Luke Air Force Base, Arizona. I lead seven squadrons encompassing over 1,800 personnel with responsibilities for all areas of base support.

The purpose of my testimony is to identify the economic impact of Luke Air Force Base on the Arizona economy, and highlight the impact of increased utility bills on Luke Air Force Base.

Luke Air Force Base is the Air Force's training ground for F-16 fighter pilots and maintainers. Last year Luke Air Force pilots flew over 50,000 flying hours supporting 36,997 sorties. In addition to our mission of training mission-ready fighter pilots and maintenance personnel, in 2005 Luke Air Force Base deployed 573 Airmen worldwide in support of contingency operations and the Global War on Terror. Luke Air Force Base supports 5377 active duty Air Force members, 1699 Air Force Reserve members and 1248 Department of the Air Force civilian employees..

In addition to the $ 358 million payroll, Luke Air Force Base employees, as well as nearly 4399 secondary jobs in the local communities have an economic impact on Arizona of approximately $1 billion per year. Luke Air Force Base executed $347 million in annual contract awards in Fiscal Year 2005. Of this amount, $10.452 million was awarded within the state of Arizona and $35.2 million was awarded to small and disadvantaged businesses, including $9.6 million to Arizona small and disadvantaged businesses.

Luke Air Force Base takes utility service on the APS E-32 and E-34 Rate Schedules. In fiscal year 2005, Luke Air Force Base paid APS about $4.2 million for electric utility service.

The funds used to pay for the utility service are operations and maintenance (O&M) funds. These funds are also used to fund military operations and maintenance. Any cost avoidance or reduction in costs Luke pays for utilities ensures funds could be utilized elsewhere for essential military operations and maintenance. Since the funding used to pay utility bills is the same funding used to fund military operations and maintenance, when utility bills increase, we must reduce spending on other areas of our military operations and maintenance. The only mechanism we have to increase our overall funding level is to request additional appropriations from Headquarters Air Force and ultimately, Congress.

BEFORE THE ARIZONA CORPORATION COMMISSION

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 Ratemaking Purposes, to Fix a Just and Reasonable Rate of Return Thereon, to Approve Rate Schedules Designed to Develop Such Return, and to Amend Decision No. 67744	)	Docket No. E-01345A-05-0816

Testimony

Of

Colonel Ronald J. Mozzillo

On behalf of

Federal Executive Agencies

September 1, 2006

Testimony of Colonel Ronald J. Mozzillo, USAF

Q. Please state your name and position:

A. I am Colonel Ronald J. Mozzillo, Commander, 56th Mission Support Group, Luke Air Force Base, Arizona. I lead seven squadrons encompassing over 1,800 personnel with responsibilities for engineering, construction, and infrastructure maintenance; explosive ordinance management; fire protection; housing management; telecommunications and computer support; security and law enforcement; contracting; supply; transportation; human resources management; professional academic education schools; family support center; youth and child care programs; mortuary and casualty services.

Q. Would you please summarize your education and professional background?

A. I have a Bachelor of Science degree in Business Administration from Youngtown State University, Ohio, and a Master of Business Administration degree from Embry Riddle University, Florida.

I am a Master Navigator with more than 2,700 flying hours in the B-52. Some of my previous assignments include: Director of Executive Support for the Deputy Chief of Staff, Air and Space Operations, and Support Group Commander, United States Military Training Mission to Saudi Arabia, Eskan Village, Kingdom of Saudi Arabia. In these positions I have become familiar with how the Air Force funds military operations, including infrastructure and utility service.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to identify the economic impact of Luke Air Force Base on the Arizona economy, and highlight the impact of increased utility bills on Luke Air Force Base.

Q. What is the military mission of Luke Air Force Base?

A. Luke Air Force Base is the Air Force's training ground for F-16 fighter pilots and maintainers. Last year Luke Air Force pilots flew over 50,000 flying hours supporting 36,997 sorties. In addition to our mission of training mission-ready fighter pilots and maintenance personnel, in 2005 Luke Air Force Base deployed 573 Airmen worldwide in support of contingency operations and the Global War on Terror. In Fiscal Year 2005, Luke graduated 367 mission-ready F-16 pilots, 76 intelligence specialists and 489 crew chiefs, who are now serving worldwide. As part of the Luke training mission, we provide training for two foreign military fighter squadrons for the countries of Taiwan and Singapore squadrons (425 FS & 21 FS). They are not "student" pilots. They are fully qualified F-16 pilots going through continuation training here taking advantage of our airspace, great flying weather and great ranges

Luke Air Force personnel are good community members, donating more than 100,000 volunteer hours in the local communities.

Q. What is the size of the workforce at Luke Air Force Base?

A. Luke Air Force Base supports 5377 active duty Air Force members, 1699 Air Force Reserve members and 1248 Department of the Air Force civilian employees..

Q. What is the impact of Luke Air Force Base on the Arizona economy?

A. In addition to the $ 358 million payroll, Luke Air Force Base impacts the state's economy with construction projects, major contracts and daily procurements, education requirements, health necessities, and commissary and exchange expenditures. In addition to Luke's work force, there are more than 100,000 base retirees, both civilian and military, who continue to have a large impact on the state's economy. Base employees, as well as nearly 4399 secondary jobs in the local communities in such fields as housing,

food and the services industries, have an economic impact on Arizona of approximately $1 billion per year.

Luke Air Force Base executed $347 million in annual contract awards in Fiscal Year 2005. Of this amount, $10.452 million was awarded within the state of Arizona and $35.2 million was awarded to small and disadvantaged businesses, including $9.6 million to Arizona small and disadvantaged businesses.

Q. Where does Luke Air Force Base purchase its electric utility service?

A. We purchase our electric utility services from Arizona Public Service Company (APS). Luke Air Force Base takes utility service on the E-32 and E-34 Rate Schedules. In fiscal year 2005, Luke Air Force Base paid APS about $4.2 million for electric utility service.

Q. What funds are used to pay Air Force utility bills?

A. The funds used to pay for the utility service provided by OG&E are operations and maintenance (O&M) funds. Operations and Maintenance funds are also used to fund military operations and maintenance. Utility bills are "must pay" bills, meaning they are among the first requirements funded and paid by the government. Any cost avoidance or reduction in costs Luke pays for utilities ensures funds could be utilized elsewhere for essential military operations and maintenance.

Q. What happens to Luke's O&M funds when there is a large increase in utility bills?

A. Since the funding used to pay utility bills is the same funding used to fund military operations and maintenance, when utility bills increase, reductions in other areas of our military operations and maintenance must be reduced. The only mechanism we have to

increase our overall funding level is to request additional appropriations from Headquarters Air Force and ultimately, Congress.

Q. Does this conclude your testimony?

A. Yes it does.

DOCKET NO. E-01345A-05-0816

SUMMARY OF TESTIMONY

DENNIS W. GOINS

I. DIRECT

In my direct testimony, I address 3 principal issues:

1. Allocation of demand-related production costs. Because summer peak demands are the principal drivers of APS' need for generating capacity, I recommend using APS' proposed 4CP methodology to allocate demand-related production costs.

2. Revenue spread. Under APS' proposed revenue spread, rates for the Residential and General Service classes move closer to cost of service (measured by movement towards a unity rate of return index). However, interclass revenue subsidies under APS' revenue spread increase by more than 50 percent—from around $44.5 million under present rates to more than $67.2 million under proposed rates. Approximately $64.3 million of the interclass subsidies created under APS' proposed revenue spread goes to Residential customers. I recommend reducing interclass revenue subsidies under APS' proposed revenue spread by half, subject to no class' receiving an increase greater than 150 percent of the average system rate increase (excluding the EIC).

3. Voltage discounts for Rate E-34. Results from APS' cost-of-service studies indicate that all voltage discounts for Rate E-34 customers should be increased—particularly the Primary Substation discount—relative to voltage discounts proposed by APS. I recommend increasing the discounts to $4.72 per kW for transmission customers, $4.04 for customers served directly from a primary substation, and $0.79 per kW for customers served from primary lines.

II. SURREBUTTAL

In my surrebuttal testimony, I address 3 principal issues:

1. Staff's recommended 4CP&A methodology to allocate fixed production costs. Under Staff's recommended 4CP&A allocation methodology, allocation factors reflect a weighted combination of each class' 4CP demand factor and its average demand factor. The methodology suffers from at least two major flaws: (1) double counting average demand in the peak demand and energy (average demand) components of the 4CP&A allocation factors, and (2) an asymmetrical allocation of fixed and variable production costs that results in higher load factor customer classes subsidizing lower load factor classes. Because of these major flaws, I recommend using APS' proposed 4CP allocation methodology.

EXHIBIT
FEA-2
Admitted

2. Allocation of energy-related costs. Results from AECC witness Kevin Higgins' hourly energy cost analysis show that the APS 4CP and Staff 4CP&A cost studies—both of which use kWh consumption unadjusted for hourly cost differentials to allocate energy costs to classes—understate the energy-related cost responsibility of Residential customers and overstate the energy-related cost responsibility of higher load factor General Service customers. I recommend using AECC's method to assign time-differentiated, energy-related production costs to customer classes—especially if the Commission requires APS to allocate fixed production costs using the 4CP&A methodology recommended by Staff.

3. Staff's revenue spread. Staff recommends using results from its 4CP&A cost study as a guide in spreading its proposed revenue increase. Staff's recommended revenue spread relies on results from a seriously flawed cost study. In addition, Staff's revenue spread exacerbates the interclass revenue subsidy problem that I discussed in my direct testimony. In particular, Staff's revenue spread increases the interclass revenue subsidy that Residential customers ***receive***—going from around $38.6 million under present rates to nearly $43.9 million. This occurs even when the subsidy is measured relative to cost responsibility determined in Staff's recommended 4CP&A cost study. I recommend that the Commission adopt the revenue spread described in my direct testimony.

STATE OF ARIZONA
BEFORE THE
ARIZONA CORPORATION COMMISSION

DOCKET NO. E-01345A-05-0816

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 RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND TO AMEND DECISION NO. 67744

DIRECT TESTIMONY OF DR. DENNIS W. GOINS ON BEHALF OF THE FEDERAL EXECUTIVE AGENCIES

September 1, 2006

EXHIBIT
FEA-3
Admitted

TABLE OF CONTENTS

	Page
INTRODUCTION AND QUALIFICATIONS	1
CONCLUSIONS	3
RECOMMENDATIONS	6
COST OF SERVICE	7
REVENUE SPREAD	9
RATE DESIGN	15
EXHIBITS	
APPENDIX A	

STATE OF ARIZONA
BEFORE THE
ARIZONA CORPORATION COMMISSION

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 RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND TO AMEND DECISION NO. 67744	)	Docket No. E-01345A-05-0816

DIRECT TESTIMONY OF
DR. DENNIS W. GOINS
ON BEHALF OF THE
FEDERAL EXECUTIVE AGENCIES

INTRODUCTION AND QUALIFICATIONS

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

A. My name is Dennis W. Goins. I operate Potomac Management Group, an economics and management consulting firm. My business address is 5801 Westchester Street, Alexandria, Virginia 22310.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I received a Ph.D. degree in economics and a Master of Economics degree from North Carolina State University. I also earned a B.A. degree with honors in economics from Wake Forest University. Following graduate school I worked as a staff economist at the North Carolina Utilities Commission. During my tenure

at the Commission I testified in numerous cases involving electric, gas, and telephone utilities on such issues as cost of service, rate design, intercorporate transactions, and load forecasting. I also served as a member of the Ratemaking Task Force in the national Electric Utility Rate Design Study sponsored by the Electric Power Research Institute (EPRI) and the National Association of Regulatory Utility Commissioners (NARUC).

Since leaving the Commission, I have worked as an economic and management consultant to firms and organizations in the private and public sectors. My assignments focus primarily on market structure, planning, pricing, and policy issues involving firms that operate in energy markets. For example, I have conducted detailed analyses of product pricing, cost of service, rate design, and interutility planning, operations, and pricing; prepared analyses related to utility mergers, transmission access and pricing, and the emergence of competitive markets; evaluated and developed regulatory incentive mechanisms applicable to utility operations; and assisted clients in analyzing and negotiating interchange agreements and power and fuel supply contracts. I have also assisted clients on electric power market restructuring issues in Arkansas, New Jersey, New York, South Carolina, Texas, and Virginia.

I have participated in more than 100 proceedings before state and federal agencies as an expert in cost of service, rate design, utility restructuring, power market planning and operations, utility mergers, utility planning and operating practices, regulatory policy, management prudence, and competitive market issues. These agencies include the Federal Energy Regulatory Commission (FERC), the General Accounting Office, the United States Court of Federal Claims, the First Judicial District Court of Montana, the Circuit Court of Kanawha County, West Virginia, and regulatory agencies in Alabama. Arizona, Arkansas, Colorado, Florida, Georgia, Idaho, Illinois, Kentucky, Louisiana, Maine, Massachusetts, Minnesota, Mississippi, New Jersey, New York, North Carolina, Ohio, Oklahoma, South Carolina, Texas, Utah, Vermont, Virginia, and

the District of Columbia. Details of my professional qualifications are presented in Appendix A.

Q. ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A. I am appearing on behalf of the Federal Executive Agencies (FEA), which is comprised of all Federal facilities served by Arizona Public Service Company (APS). Two of the larger FEA facilities are Luke Air Force Base and the Marine Corps Air Station in Yuma, both of which APS serves under Rate Schedule E-34 Extra Large General Service.

Q. WHAT ASSIGNMENT WERE YOU GIVEN WHEN YOU WERE RETAINED?

A. I was asked to undertake two primary tasks:

1. Review APS' proposed cost-of-service analyses (including pro forma adjustments) and related rates.
2. Identify any major deficiencies in the cost analyses and proposed rates and suggest recommended changes.

Q. WHAT SPECIFIC INFORMATION DID YOU REVIEW IN CONDUCTING YOUR EVALUATION?

A. I reviewed APS' application, testimony, exhibits, and responses to requests for information. I also reviewed information found on web sites operated by the Commission, and by APS and its parent company, PinnacleWest.

CONCLUSIONS

Q. WHAT CONCLUSIONS HAVE YOU REACHED?

A. On the basis of my review and evaluation, I have concluded the following:

1. Cost-of-Service. APS has proposed increasing base revenues by approximately $453.9 million (21.34 percent), which reflects a $449.6-million increase (21.14 percent) in base rates and APS' proposed $4.3-million Environmental Improvement Charge (EIC). In developing proposed rates for its retail electric services, APS first conducted a cost-of-service study for the test year ending September 30, 2005. In this cost analysis, APS allocated and/or directly assigned its costs to functional segments of its retail electric business. The test-year rate of return on retail jurisdictional rate base is 2.59 percent under present rates and 8.73 percent under proposed rates.

In allocating demand-related production and transmission costs to major customer classes, APS used the average of monthly system coincident peaks for June-September in the test year—a 4CP methodology. APS allocated costs related to distribution substations and primary distribution lines on the basis of noncoincident peak (NCP) demands. In contrast, APS allocated costs related to distribution transformers and secondary distribution lines on the basis of the sum of individual peak demands within a specific customer class.

2. Revenue Spread. APS spread its proposed revenue increase on a roughly equal-percentage, across-the-board basis, for its two largest customer groups (Residential and General Service).[1] Under APS' revenue spread, the Residential class received a 21.14 percent increase (without the EIC), while the General Service class got a 21.60 percent increase in base rates (also excluding the EIC). The Irrigation class got only a 0.14 percent increase, while the two Lighting classes got increases of 24.11 percent and 10.49 percent.

[1] Base rate revenues for these two classes comprise nearly 98 percent of total APS retail revenues.

Under APS' proposed revenue spread, rates for the Residential and General Service classes move closer to cost of service (measured by movement towards a unity rate of return index (RORI)). However, interclass revenue subsidies under APS' revenue spread increase by more than 50 percent—from around $44.5 million under present rates to more than $67.2 million under proposed rates. Approximately $64.3 million of the interclass subsidies created under APS' proposed revenue spread goes to Residential customers. That is, test-year revenues from APS' proposed Residential rates are about $64.3 million less than APS' costs (as determined in its cost-of-service study) of serving this class. APS makes up this shortfall—as well as the $2.9 million in subsidies received by Lighting customers—primarily by overcharging General Service customers (more than $66.9 million). These interclass subsidies are unjustified and should be eliminated—or at a minimum, mitigated by moving rates for each class much closer to cost of service than APS has proposed.

3. Rates E-34 and E-35. With respect to the two rates under which it serves most Extra Large General Service customers (those with average monthly demands equal to or exceeding 3 MW), APS has:

- Overcharged these customers—that is, proposed Rates E-34 and E-35 produce test-year electric sales revenues that exceed APS' cost of serving these large general service customers.[2]
- Increased the voltage discount for customers served at transmission voltages (69 kV and higher) from $4.30 per kW to $4.52 per kW. Discounts for customers served directly from a Primary Substation[3] or

[2] According to APS' response to DEAA 2-2, the RORI for both rates is 1.08 under proposed rates.
[3] This discount currently applies only to military bases taking primary service directly from an APS-owned substation.

from Primary voltage lines remain unchanged at $3.40 per kW and $0.66 per kW, respectively.

- Results from APS' cost-of-service studies indicate that all voltage discounts for Rate E-34 customers should be increased—particularly the Primary Substation discount. Failing to set the voltage discounts closer to cost of service subsidizes Secondary voltage customers served under Rate E-34 at the expense of Transmission and Primary service customers.

RECOMMENDATIONS

Q. WHAT DO YOU RECOMMEND ON THE BASIS OF THESE CONCLUSIONS?

A. I recommend that the Commission:

1. Approve APS' average 4CP methodology to allocate demand-related production and transmission costs. This methodology reflects the principal factors—coincident summer peak demands—driving the need for generation and transmission capacity on the APS system. Allocation methods that dilute the impact of APS' summer peak demands (for example, a 12CP methodology that reflects APS' test-year monthly peak demands) ignore the dominant summer peaking characteristics of the APS system and result in understating the cost responsibility of classes with relatively low load factors and high summer peak demands.

2. Reject APS' proposed revenue spread. As I noted earlier, under APS' proposal, General Service customers pay nearly $67 million in interclass revenue subsidies to Residential and Lighting customers. I recommend spreading APS' allowed revenue increase using the following guidelines:

- Reduce interclass revenue subsidies under APS' proposed revenue spread by half. For example, the Residential subsidy would be reduced by around $32 million.
- Increase rates for subsidized classes under APS' proposed rates by up to 150 percent of the average system rate increase (excluding the EIC). For example, if APS received its requested 21.14 percent increase in base revenues, the limit on increases to the Residential and two Lighting classes would be 31.71 percent. (With respect to the Residential class, only a 27.05 base rate increase would be necessary to bring the class' rates to cost of service.)
- Do not allow a rate decrease for any class—even if cost-of-service results indicate that a decrease is justified. (As I discuss later, this guideline only affects the Irrigation class.)

Spreading APS' revenue increase in this manner would move each class significantly closer to cost of service, and also create meaningful reductions in interclass revenue subsidies. Details of how to implement this revenue spread approach are presented later in my testimony.

3. Reject APS' proposed voltage discounts for Rate E-34. Instead, the Commission should approve my recommend Rate 34,[4] which modifies APS' proposed rate by moving voltage discounts closer to cost of service.

COST OF SERVICE

Q. HOW DID APS ALLOCATE ITS COSTS TO CUSTOMER CLASSES?

A. APS conducted a detailed cost-of-service study using data (adjusted in many cases) for the test year ending September 30, 2005. In this cost analysis, APS allocated and/or directly assigned its costs to functional segments of its retail

[4] I discuss my recommended Rate E-34 in detail later in my testimony. Specific charges in the rate are

electric business. The return component of APS' costs reflects a requested 8.73 percent return on its Arizona retail jurisdictional rate base (compared to 2.59 percent earned return under present rates).

Q. IS THE COST-OF-SERVICE METHODOLOGY THAT APS USED REASONABLE?

A. Yes. The methodology basically follows traditional cost classifications and allocations for major functional categories of utility service.

Q. HOW DID APS ALLOCATE DEMAND-RELATED PRODUCTION AND TRANSMISSION COSTS?

A. APS allocated demand-related production and transmission costs to major customer classes using the average of its four test-year monthly summer (June-September) coincident system peaks (a 4CP methodology). As APS noted, "Production related and Transmission related assets, and their associated costs, are generally designed and built to enable the Company to meet its system peak load."[5] APS is correct—system peaks are the principal drivers of generation and transmission capacity requirements. The 4CP approach is reasonable and should be approved since it reflects the key determinant of APS' need for bulk power facilities.

Q. WHY IS THE REASONABLENESS OF A COST-OF-SERVICE METHODOLOGY IMPORTANT?

A. Cost of service identifies and assigns cost responsibility to customer classes. Specific rates can then be developed to recover each class' cost-based revenue requirement, resulting in prices that recover the utility's cost of service in an equitable and efficient manner. If the cost-of-service methodology does not

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shown in Exhibit DWG-7.

[5] David Rumulo, direct testimony at 7:1-3.

allocate and assign cost responsibility in a reasonable manner, then interclass revenue subsidies are created and specific class rates are either over- or under-priced—thereby causing customers to make inefficient electricity investment and consumption decisions.

APS has employed a reasonable cost-of-service methodology in this case to allocate and assign costs to customer classes. However, as I discuss in more detail later, APS deviated from the results of its cost study in assigning its proposed revenue increase to customer classes.

REVENUE SPREAD

Q. SHOULD INTERCLASS REVENUE SUBSIDIES BE A PRINCIPAL FACTOR IN EVALUATING THE REASONABLENESS OF APS' REVENUE SPREAD?

A. Yes. Interclass revenue subsidies reflect the amount by which revenue from a customer class exceeds or falls short of the class' cost responsibility, which is determined in APS' class cost-of-service study. In general, a class receives (pays) an interclass subsidy if its rate revenue is less than (greater than) its assigned cost of service at the system average rate of return. The existence of large class rate of return differentials often indicates the presence of large interclass subsidies.

Q. ARE RATE OF RETURN DIFFERENTIALS SIGNIFICANT UNDER PRESENT RATES?

A. Yes. As shown in Table 1 below and Exhibit DWG-1, of the five major customer classes that APS serves, two classes—Residential and Outdoor (Street) Lighting—currently pay rates that are well below cost of service. The rate of return indexes for these classes range from 58 to 79. Their below-cost service is subsidized by General Service customers (RORI of 151) whose present rates are almost $40.5 million higher than APS' cost of service. This $40.5-million

subsidy goes to Residential customers (whose total subsidy is nearly $44.1 million) and the Outdoor Lighting class.

Table 1. Interclass Subsidies Under Present Rates ($000)

Class	RORI	Subsidy
Residential	58	44,069
General Service	151	(40,483)
Irrigation	359	(2,804)
Outdoor Lighting	79	453
Dusk to Dawn	223	(1,236)

Note: positive (negative) number reflects subsidy received (paid)
Source: Exhibit DWG-1.

Q. WHAT INCREASE IN REVENUE IS APS REQUESTING?

A. APS has requested a $453.9-million increase (21.34 percent), which reflects a $449.6-million increase (21.14 percent) in base rates and APS' proposed $4.3-million Environmental Improvement Charge (EIC).

Q. HOW DID APS SPREAD THE PROPOSED REVENUE INCREASE AMONG CUSTOMER CLASSES?

A. APS spread its proposed revenue increase on a roughly equal-percentage, across-the-board basis, for Residential (21.14 percent increase excluding the EIC) and General Service (21.60 percent increase) customers. Irrigation customers got only a 0.14 percent increase, while the two Lighting classes got increases of 24.11 percent and 10.49 percent. (See Exhibit DWG-2, page 1.)

Q. DOES THE CURRENT INTERCLASS SUBSIDY PROBLEM GET WORSE UNDER APS' PROPOSED REVENUE SPREAD?

A. Yes. Interclass subsidies under APS' proposed revenue spread increase by more than 50 percent—from around $44.5 million under present rates to more than $67.2 million under proposed rates. (See Table 2 below and Exhibit DWG-2, page 2.) Approximately $64.3 million of the interclass subsidies goes to Residential customers. That is, test-year revenues from APS' proposed Residential rates are about $64.3 million less than APS' costs (as determined in its cost-of-service study) of serving this class. APS makes up this shortfall—as well as the $2.9 million in subsidies received by Lighting customers—primarily by overcharging General Service customers (more than $66.9 million). These interclass subsidies are unjustified and should be eliminated—or at a minimum, mitigated by moving rates for each class much closer to cost of service than APS has proposed.

Table 2. Interclass Subsidies Under APS Proposed Rates ($000)

Class	RORI	Subsidy
Residential	82	64,345
General Service	125	(66,944)
Irrigation	108	(279)
Outdoor Lighting	67	2,409
Dusk to Dawn	86	469

Note: positive (negative) number reflects subsidy received (paid)
Source: Exhibit DWG-2.

Q. IS APS' REVENUE SPREAD REASONABLE?

A. No. I recognize that under APS' proposed revenue spread, rates for the Residential and General Service classes (as well as the smaller Irrigation and Lighting classes) move closer to cost of service (measured by movement towards

a unity RORI). However, because APS' revenue spread fails to move rates sufficiently close to cost of service, the interclass revenue subsidy problem is exacerbated. These interclass subsidies are unjustified and should be eliminated—or at a minimum, mitigated by moving rates for each class much closer to cost of service than APS has proposed.

Q. WHAT INCREASES WOULD BE NECESSARY TO ELIMINATE THE RESIDENTIAL AND GENERAL SERVICE INTERCLASS SUBSIDIES?

A. My analysis indicates that Residential rates would have to increase by 27.05 percent (excluding the EIC), compared to the 21.14 percent increase recommended by APS. In contrast, General Service rates would have to increase by only 14.88 percent instead of APS' recommended 21.60 percent increase. (See Exhibit DWG-3.)

Q. HAVE YOU DEVELOPED AN ALTERNATIVE REVENUE SPREAD THAT MOVES RATES CLOSER TO COST OF SERVICE?

A. Yes. I recommend that the Commission reject APS' proposed revenue spread. No set of reasonable and fair ratemaking objectives can include forcing General Service customers to pay nearly $67 million in interclass revenue subsidies to Residential and Lighting customers. To address this problem, the Commission should require APS to spread the allowed revenue increase using the following guidelines:

- Interclass revenue subsidies under APS' proposed revenue spread should be reduced by half. For example, the Residential subsidy should be reduced by around $32 million from the $64.3 million subsidy created under APS' revenue spread.
- The increase for any subsidized class under APS' proposed rates should be limited to no more than 150 percent of the average system rate increase (excluding the EIC). For example, if APS received its

requested 21.14 percent increase in base revenues, Residential rates could increase by no more than 31.71 percent. However, as I noted earlier, the increase required to bring Residential rates to cost of service would only be 27.05 percent, well below the 150-percent guideline limit.

- No class should get a base rate decrease—even if a decrease is indicated by results from cost-of-service analyses. This guideline is merely one of general fairness—when rates may go up by more than 21 percent, everyone should share some of the pain. The only class affected by this guideline is the Irrigation class—which should receive about a 1 percent decrease in rates according to APS' cost studies. (See Exhibit DWG-3.)

Q. WHAT EFFECT WOULD YOUR RECOMMENDED REVENUE SPREAD HAVE ON THE COST-TRACKING AND SUBSIDY PROBLEMS THAT APS' PROPOSAL DOES ALMOST NOTHING TO MITIGATE?

A. My proposed revenue spread would move rates for each class closer to cost of service, and also create meaningful reductions in interclass revenue subsidies. Moreover, my recommended revenue spread creates a more equitable and efficient distribution of APS' proposed sales revenue increase without imposing unjust and unreasonable increases on any class. (See Table 3 below and Exhibit DWG-4, page 1.)

Table 3. Interclass Subsidies Under FEA Proposed Spread ($000)

Class	RORI	Subsidy
Residential	90	32,170
General Service	114	(33,524)
Irrigation	108	(270)
Outdoor Lighting	79	1,391
Dusk to Dawn	92	233

Note: positive (negative) number reflects subsidy received (paid)
Source: Exhibit DWG-4.

Q. DOES YOUR RECOMMENDED REVENUE SPREAD ELIMINATE INTERCLASS SUBSIDIES?

A. No. My recommended revenue spread only reduces the subsidies by about half. As shown in Table 3 above, Residential customers would still receive a subsidy of more than $32 million, while General Service customers would still pay nearly $34 in revenue subsidies.

Q. HOW DO BASE RATE INCREASES UNDER YOUR RECOMMENDED REVENUE SPREAD COMPARE WITH APS' PROPOSED INCREASES?

A. As shown in Table 4 below and Exhibit DWG-4, page 2, the increase for Residential customers is only about 3 percentage points greater than the increase under APS' proposed revenue spread.

Table 4. Base Rate Increases Under Alternative Spreads

Class	APS	FEA
Residential	21.14%	24.09%
General Service	21.60%	18.25%
Irrigation	0.14%	0.14%
Outdoor Lighting	24.11%	31.67%
Dusk to Dawn	10.49%	14.15%

Source: Exhibit DWG-4.

Q. IF THE COMMISSION ALLOWS LESS THAN APS' REQUESTED SALES REVENUE INCREASE, HOW SHOULD THE APPROVED INCREASE BE SPREAD?

A. If APS receives a total retail base revenue increase below 21.14 percent, I recommend reducing the increase for each class while maintaining the relative increases shown under the FEA revenue spread in Table 4 above. For example, if the allowed increase is 10.57 percent (half of APS' request), the increase for Residential customers should be 12.05 percent (half of 24.09 percent). Similarly, the increase for General Service would be around 9.13 percent (or half of 18.25 percent).

RATE DESIGN

Q. DID YOU EXAMINE EACH OF APS' PROPOSED RATES IN DETAIL?

A. No. My analysis focused on Rates E-34 and E-35, the two rates under which APS serves most Extra Large General Service customers (those with average monthly demands equal to or exceeding 3 MW). However, at the present time, I am only recommending specific changes to Rate E-34.

Q. ARE APS'-PROPOSED RATES E-34 AND E-35 SET ABOVE COST OF SERVICE?

A. Yes. Data provided by APS indicate that RORIs for Rates E-34 and E-35 customers under proposed rates are 108—that is, both rates are above APS' cost of service.[6]

Q. DO THE PROPOSED RATES REFLECT CHANGES IN THE VOLTAGE DISCOUNTS THAT WERE ADOPTED IN APS' LAST GENERAL RATE CASE?

A. Yes. In its last general rate case, APS introduced voltage discounts into Rates E-34 and E-35 to track costs of serving customers at different voltages more accurately. In this case, APS has increased the voltage discount for customers served at transmission voltages (69 kV and higher) from $4.30 per kW to $4.52 per kW. However, discounts for customers served directly from a Primary Substation[7] or from Primary voltage lines remain unchanged at $3.40 per kW and $0.66 per kW, respectively.

Q. DO THESE DISCOUNTS ACCURATELY REFLECT COST DIFFERENTIALS IN SERVING RATE E-34 CUSTOMERS AT DIFFERENT VOLTAGE LEVELS OF SERVICE?

A. No. Results from APS' cost-of-service studies indicate that all voltage discounts for Rate E-34 customers should be increased—particularly the Primary Substation discount. Failing to set the voltage discounts closer to cost of service creates an intraclass subsidy for Secondary voltage customers served under Rate E-34 an the expense of Transmission and Primary service customers. For example, as shown in Table 5 below and Exhibit DWG-5, APS' cost of serving a Rate E-34

[6] See APS response to DEAA 2-2 (APS09951).
[7] This discount currently applies only to military bases taking primary service directly from an APS-owned substation.

transmission voltage customer is $4.90 per kW less than its cost of serving a Secondary voltage customer. As a result, Rate E-34's transmission voltage discount should be $4.90 per kW. However, APS has proposed a transmission voltage discount of only $4.52 per kW—effectively forcing the transmission customer to pay $0.38 per kW more than APS' lower cost of service. Similar cost differentials apply for primary voltage customers served either directly from an APS-owned substation or an APS primary line.

Table 5. APS Proposed Rate E-34 Voltage Discounts ($/kW)

Class	Cost of Service	APS Proposed	Difference
Transmission	4.90	4.52	(0.38)
Primary Substation	4.16	3.40	(0.76)
Primary Line	0.88	0.66	(0.22)

Source: Exhibit DWG-5.

Q. SHOULD THE VOLTAGE DISCOUNTS IN RATE E-34 BE INCREASED?

A. Yes. Customers served under Rate E-34 take delivery service at transmission, primary, and secondary voltages as defined by APS. The cost of serving customers at different voltages varies because of differences in the types and cost of equipment needed to deliver service and energy losses that increase as the service delivery voltage decreases. The voltage discounts in Rate E-34 should reflect these cost-of-service differences as accurately as possible.

Q. WHAT SPECIFIC CHANGES ARE YOU RECOMMENDING TO APS' PROPOSED RATE E-34?

A. I recommend that the Commission reject APS' proposed voltage discounts for Rate 34. Instead, the Commission should approve my recommended voltage discounts shown in Table 6 below and Exhibit DWG-6. These discounts

represent a significant move to removing intraclass cost subsidies within Rate E-34.

Table 6. FEA Proposed Rate E-34 Voltage Discounts ($/kW)

Class	Cost of Service	FEA Proposed	Difference
Transmission	4.90	4.72	(0.18)
Primary Substation	4.16	4.04	(0.12)
Primary Line	0.88	0.79	(0.09)

Source: Exhibit DWG-6.

Q. HAVE YOU DEVELOPED REVISIONS TO RATE E-34 THAT REFLECT YOUR RECOMMENDED VOLTAGE DISCOUNTS?

A. Yes. My recommended Rate E-34 is shown in Exhibit DWG-7. The rate reflects the higher voltage discounts I am recommending. To incorporate these higher discounts, I adjusted the unbundled demand-related delivery charges proposed by APS and left the unbundled demand-related generation charge unchanged.

Q. SHOULD THE COMMISSION APPROVE YOUR RECOMMENDED RATE E-34?

A. Yes. The Commission should approve revisions to APS' proposed Rate E-34 that incorporate more cost-based voltage discounts. My recommended changes are reasonable and justified on the basis of APS' cost of service.

Q. DOES THIS COMPLETE YOUR DIRECT TESTIMONY?

A. Yes.

STATE OF ARIZONA
BEFORE THE
ARIZONA CORPORATION COMMISSION

DOCKET NO. E-01345A-05-0816

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 RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND TO AMEND DECISION NO. 67744

EXHIBITS TO THE DIRECT TESTIMONY OF DR. DENNIS W. GOINS ON BEHALF OF THE FEDERAL EXECUTIVE AGENCIES

September 1, 2006

APPENDIX A

QUALIFICATIONS OF

DENNIS W. GOINS

DENNIS W. GOINS

PRESENT POSITION

Economic Consultant, Potomac Management Group, Alexandria, Virginia.

AREAS OF QUALIFICATION

- Competitive Market Analysis
- Costing and Pricing Energy-Related Goods and Services
- Utility Planning and Operations
- Litigation Analysis, Strategy Development, Expert Testimony

PREVIOUS POSITIONS

- Vice President, Hagler, Bailly & Company, Washington, DC.
- Principal, Resource Consulting Group, Inc., Cambridge, Massachusetts.
- Senior Associate, Resource Planning Associates, Inc., Cambridge, Massachusetts.
- Economist, North Carolina Utilities Commission, Raleigh, North Carolina.

EDUCATION

College	Major	Degree
Wake Forest University	Economics	BA
North Carolina State University	Economics	ME
North Carolina State University	Economics	PhD

RELEVANT EXPERIENCE

Dr. Goins specializes in pricing, planning, and market structure issues affecting firms that buy and sell products in electricity and natural gas markets. He has extensive experience in evaluating competitive market conditions, analyzing power and fuel requirements, prices, market operations, and transactions, developing product pricing strategies, setting rates for energy-related products and services, and negotiating power supply and natural gas contracts for private and public entities. He has participated in more than 100 cases as an expert on competitive market issues, utility restructuring, power market planning and operations, utility mergers, rate design, cost of service, and management prudence before the Federal Energy Regulatory Commission, the General Accounting Office, the First Judicial District Court of Montana, the Circuit Court of Kanawha County, West Virginia, and regulatory commissions in Alabama. Arizona, Arkansas, Colorado, Florida, Georgia, Idaho, Illinois, Kentucky, Louisiana, Maine, Massachusetts, Minnesota, Mississippi, New Jersey, New York, North Carolina, Ohio,

Oklahoma, South Carolina, Texas, Utah, Vermont, Virginia, and the District of Columbia. He has also prepared an expert report on behalf of the United States regarding pricing and contract issues in a case before the United States Court of Federal Claims.

PARTICIPATION IN REGULATORY, ADMINISTRATIVE, AND COURT PROCEEDINGS

1. Entergy Gulf States Inc., before the Public Utilities Commission of Texas, PUC Docket No. 32907 (2006), on behalf of Texas Cities, re hurricane cost recovery.
2. Entergy Gulf States Inc., before the Public Utilities Commission of Texas, PUC Docket No. 32710/ SOAH Docket No. 473-06-2307 (2006), on behalf of Texas Cities, re reconciliation of fuel and purchased power costs.
3. Florida Power & Light Company, before the Florida Public Service Commission, Docket No. 060001-EI (2006), on behalf of the U.S. Air Force (Federal Executive Agencies), re fuel and purchased power cost recovery.
4. Arizona Public Service Company, before the Arizona Corporation Commission, Docket No. E-01345A-05-0816 (2006), on behalf of the U.S. Air Force (Federal Executive Agencies), re retail cost allocation and rate design issues.
5. PacifiCorp (dba Rocky Mountain Power), before the Utah Public Service Commission, Docket No. 06-035-21 (2006), on behalf of the U.S. Air Force (Federal Executive Agencies), re rate design issues.
6. South Carolina Electric & Gas Company, before the South Carolina Public Service Commission, Docket No. 2006-2-E (2006), on behalf of CMC Steel-SC, re fuel and purchased power cost recovery.
7. Entergy Gulf States Inc., before the Public Utilities Commission of Texas, PUC Docket No. 31544/ SOAH Docket No. 473-06-0092 (2006), on behalf of Texas Cities, re transition to competition rider.
8. Idaho Power Company, before the Idaho Public Utilities Commission, Case No. IPC-E-05-28 (2006), on behalf of the U.S. Department of Energy (Federal Executive Agencies), re cost-of-service and rate design issues.
9. Alabama Power Company, before the Alabama Public Service Commission, Docket No. 18148 (2005), on behalf of SMI Steel-Alabama, re energy cost recovery.
10. Florida Power & Light Company, before the Florida Public Service Commission, Docket No. 050001-EI (2005), on behalf of the U.S. Air Force (Federal Executive Agencies), re fuel and capacity cost recovery.
11. Entergy Gulf States Inc., before the Public Utilities Commission of Texas, PUC Docket No. 31315/ SOAH Docket No. 473-05-8446 (2005), on behalf of Texas Cities, re incremental purchased capacity cost rider.

12. Florida Power & Light Company, before the Florida Public Service Commission, Docket No. 050045-EI (2005), on behalf of the U.S. Air Force (Federal Executive Agencies), re cost-of-service and interruptible rate issues.
13. Arkansas Electric Cooperative Corporation, before the Arkansas Public Service Commission, Docket No. 05-042-U (2005), on behalf of Nucor Steel and Nucor-Yamato Steel, re power plant purchase.
14. Arkansas Electric Cooperative Corporation, before the Arkansas Public Service Commission, Docket No. 04-141-U (2005), on behalf of Nucor Steel and Nucor-Yamato Steel, re cost-of-service and rate design issues.
15. Dominion North Carolina Power, before the North Carolina Utilities Commission, Docket No. E-22, Sub 412 (2005), on behalf of Nucor Steel-Hertford, re cost-of-service and interruptible rate issues.
16. Public Service Company of Colorado, before the Colorado Public Utilities Commission, Docket No. 04S-164E (2004), on behalf of the U.S. Air Force (Federal Executive Agencies), re cost-of-service and interruptible rate issues.
17. CenterPoint Energy Houston Electric, LLC, *et al.*, before the Public Utility Commission of Texas, PUC Docket No. 29526 (2004), on behalf of the Coalition of Commercial Ratepayers, re stranded cost true-up balances.
18. PacifiCorp, before the Utah Public Service Commission, Docket No. 04-035-11 (2004), on behalf of the U.S. Air Force (United States Executive Agencies), re time-of-day rate design issues.
19. Arizona Public Service Company, before the Arizona Corporation Commission, Docket No. E-01345A-03-0347 (2004), on behalf of the U.S. Air Force (Federal Executive Agencies), re retail cost allocation and rate design issues.
20. Idaho Power Company, before the Idaho Public Utilities Commission, Case No. IPC-E-03-13 (2004), on behalf of the U.S. Department of Energy (Federal Executive Agencies), re retail cost allocation and rate design issues.
21. PacifiCorp, before the Utah Public Service Commission, Docket No. 03-2035-02 (2004), on behalf of the U.S. Air Force (United States Executive Agencies), re retail cost allocation and rate design issues.
22. Dominion Virginia Power, before the Virginia State Corporation Commission, Case No. PUE-2000-00285 (2003), on behalf of Chaparral (Virginia) Inc., re recovery of fuel costs.
23. Jersey Central Power & Light Company, before the New Jersey Board of Public Utilities, BPU Docket No. ER02080506, OAL Docket No. PUC-7894-02 (2002-2003), on behalf of New Jersey Commercial Users, re retail cost allocation and rate design issues.
24. Public Service Electric and Gas Company, before the New Jersey Board of Public Utilities, BPU Docket No. ER02050303, OAL Docket No. PUC-5744-02 (2002-2003), on behalf of New Jersey Commercial Users, re retail cost allocation and rate design issues.

25. South Carolina Electric & Gas Company, before the South Carolina Public Service Commission, Docket No. 2002-223-E (2002), on behalf of SMI Steel-SC, re retail cost allocation and rate design issues.

26. Montana Power Company, before the First Judicial District Court of Montana, *Great Falls Tribune et al. v. the Montana Public Service Commission*, Cause No. CDV2001-208 (2002), on behalf of a media consortium (*Great Falls Tribune*, *Billings Gazette*, *Montana Standard*, *Helena Independent Record*, *Missoulian*, Big Sky Publishing, Inc. dba *Bozeman Daily Chronicle*, the Montana Newspaper Association, *Miles City Star*, *Livingston Enterprise*, Yellowstone Public Radio, the Associated Press, Inc., and the Montana Broadcasters Association), re public disclosure of allegedly proprietary contract information.

27. Louisville Gas & Electric *et al.*, before the Kentucky Public Service Commission, Administrative Case No. 387 (2001), on behalf of Gallatin Steel Company, re adequacy of generation and transmission capacity in Kentucky.

28. PacifiCorp, before the Utah Public Service Commission, Docket No. 01-035-01 (2001), on behalf of Nucor Steel, re retail cost allocation and rate design issues.

29. TXU Electric Company, before the Public Utilities Commission of Texas, PUC Docket No. 23640/ SOAH Docket No. 473-01-1922 (2001), on behalf of Nucor Steel, re fuel cost recovery.

30. FPL Group *et al.*, before the Federal Energy Regulatory Commission, Docket No. EC01-33-000 (2001), on behalf of Arkansas Electric Cooperative Corporation, Inc., re merger-related market power issues.

31. Entergy Mississippi, Inc., *et al.*, before the Mississippi Public Service Commission, Docket No. 2000-UA-925 (2001), on behalf of Birmingham Steel-Mississippi, re appropriate regulatory conditions for merger approval.

32. TXU Electric Company, before the Public Utilities Commission of Texas, PUC Docket No. 22350/ SOAH Docket No. 473-00-1015 (2000), on behalf of Nucor Steel, re unbundled cost of service and rates.

33. PacifiCorp, before the Utah Public Service Commission, Docket No. 99-035-10 (2000), on behalf of Nucor Steel, re using system benefit charges to fund demand-side resource investments.

34. Entergy Arkansas, Inc. *et al.*, before the Arkansas Public Service Commission, Docket No. 00-190-U (2000), on behalf of Nucor-Yamato Steel and Nucor Steel-Arkansas, re the development of competitive electric power markets in Arkansas.

35. Entergy Arkansas, Inc. *et al.*, before the Arkansas Public Service Commission, Docket No. 00-048-R (2000), on behalf of Nucor-Yamato Steel and Nucor Steel-Arkansas, re generic filing requirements and guidelines for market power analyses.

36. ScottishPower and PacifiCorp, before the Utah Public Service Commission, Docket No. 98-2035-04 (1999), on behalf of Nucor Steel, re merger conditions to protect the public interest.

37. Dominion Resources, Inc. and Consolidated Natural Gas Company, before the Virginia State Corporation Commission, Case No. PUA990020 (1999), on behalf of the City of Richmond, re market power and merger conditions to protect the public interest.
38. Houston Lighting & Power Company, before the Public Utility Commission of Texas, Docket No. 18465 (1998) on behalf of the Texas Commercial Customers, re excess earnings and stranded-cost recovery and mitigation.
39. PJM Interconnection, LLC, before the Federal Energy Regulatory Commission, Docket No. ER98-1384 (1998) on behalf of Wellsboro Electric Company, re pricing low-voltage distribution services.
40. DQE, Inc. and Allegheny Power System, Inc., before the Federal Energy Regulatory Commission, Docket Nos. ER97-4050-000, ER97-4051-000, and EC97-46-000 (1997) on behalf of the Borough of Chambersburg, re market power in relevant markets.
41. GPU Energy, before the New Jersey Board of Public Utilities, Docket No. EO97070458 (1997) on behalf of the New Jersey Commercial Users Group, re unbundled retail rates.
42. GPU Energy, before the New Jersey Board of Public Utilities, Docket No. EO97070459 (1997) on behalf of the New Jersey Commercial Users Group, re stranded costs.
43. Public Service Electric and Gas Company, before the New Jersey Board of Public Utilities, Docket No. EO97070461 (1997) on behalf of the New Jersey Commercial Users Group, re unbundled retail rates.
44. Public Service Electric and Gas Company, before the New Jersey Board of Public Utilities, Docket No. EO97070462 (1997) on behalf of the New Jersey Commercial Users Group, re stranded costs.
45. DQE, Inc. and Allegheny Power System, Inc., before the Federal Energy Regulatory Commission, Docket Nos. ER97-4050-000, ER97-4051-000, and EC97-46-000 (1997) on behalf of the Borough of Chambersburg, Allegheny Electric Cooperative, Inc., and Selected Municipalities, re market power in relevant markets.
46. CSW Power Marketing, Inc., before the Federal Energy Regulatory Commission, Docket No.ER97-1238-000 (1997) on behalf of the Transmission Dependent Utility Systems, re market power in relevant markets.
47. Central Hudson Gas & Electric Corporation *et al.*, before the New York Public Service Commission, Case Nos. 96-E-0891, 96-E-0897, 96-E-0898, 96-E-0900, 96-E-0909 (1997), on behalf of the Retail Council of New York, re stranded-cost recovery.
48. Central Hudson Gas & Electric Corporation, supplemental testimony, before the New York Public Service Commission, Case No. 96-E-0909 (1997) on behalf of the Retail Council of New York, re stranded-cost recovery.
49. Consolidated Edison Company of New York, Inc., supplemental testimony, before the New York Public Service Commission, Case No. 96-E-0897 (1997) on behalf of the Retail Council of New York, re stranded-cost recovery.

50. New York State Electric & Gas Corporation, supplemental testimony, before the New York Public Service Commission, Case No. 96-E-0891 (1997) on behalf of the Retail Council of New York, re stranded-cost recovery.
51. Rochester Gas and Electric Corporation, supplemental testimony, before the New York Public Service Commission, Case No. 96-E-0898 (1997) on behalf of the Retail Council of New York, re stranded-cost recovery.
52. Texas Utilities Electric Company, before the Public Utility Commission of Texas, Docket No. 15015 (1996), on behalf of Nucor Steel-Texas, re real-time electricity pricing.
53. Central Power and Light Company, before the Public Utility Commission of Texas, Docket No. 14965 (1996), on behalf of the Texas Retailers Association, re cost of service and rate design.
54. Carolina Power & Light Company, before the South Carolina Public Service Commission, Docket No. 95-1076-E (1996), on behalf of Nucor Steel-Darlington, re integrated resource planning.
55. Texas Utilities Electric Company, before the Public Utility Commission of Texas, Docket No. 13575 (1995), on behalf of Nucor Steel-Texas, re integrated resource planning, DSM options, and real-time pricing.
56. Arkansas Power & Light Company, *et al.*, Notice of Inquiry to Consider Section 111 of the Energy Policy Act of 1992, before the Arkansas Public Service Commission, Docket No. 94-342-4 (1995), Initial Comments on behalf of Nucor-Yamato Steel Company, re integrated resource planning standards.
57. Arkansas Power & Light Company, *et al.*, Notice of Inquiry to Consider Section 111 of the Energy Policy Act of 1992, before the Arkansas Public Service Commission, Docket No. 94-342-4 (1995), Reply Comments on behalf of Nucor-Yamato Steel Company, re integrated resource planning standards.
58. Arkansas Power & Light Company, *et al.*, Notice of Inquiry to Consider Section 111 of the Energy Policy Act of 1992, before the Arkansas Public Service Commission, Docket No. 94-342-4 (1995), Final Comments on behalf of Nucor-Yamato Steel Company, re integrated resource planning standards.
59. South Carolina Pipeline Corporation, before the South Carolina Public Service Commission, Docket No. 94-202-G (1995), on behalf of Nucor Steel, re integrated resource planning and rate caps.
60. Gulf States Utilities Company, before the United States Court of Federal Claims, *Gulf States Utilities Company v. the United States*, Docket No. 91-1118C (1994, 1995), on behalf of the United States, re electricity rate and contract dispute litigation.
61. American Electric Power Corporation, before the Federal Energy Regulatory Commission, Docket No. ER93-540-000 (1994), on behalf of DC Tie, Inc., re costing and pricing electricity transmission services.
62. Texas Utilities Electric Company, before the Public Utility Commission of Texas, Docket No. 13100 (1994), on behalf of Nucor Steel-Texas, re real-time electricity pricing.

63. Carolina Power & Light Company, *et al.*, Proposed Regulation Governing the Recovery of Fuel Costs by Electric Utilities, before the South Carolina Public Service Commission, Docket No. 93-238-E (1994), on behalf of Nucor Steel-Darlington, re fuel-cost recovery.
64. Southern Natural Gas Company, before the Federal Energy Regulatory Commission, Docket No. RP93-15-000 (1993-1995), on behalf of Nucor Steel-Darlington, re costing and pricing natural gas transportation services.
65. West Penn Power Company, *et al.*, v. State Tax Department of West Virginia, *et al.*, Civil Action No. 89-C-3056 (1993), before the Circuit Court of Kanawha County, West Virginia, on behalf of the West Virginia Department of Tax and Revenue, re electricity generation tax.
66. Carolina Power & Light Company, *et al.*, Proceeding Regarding Consideration of Certain Standards Pertaining to Wholesale Power Purchases Pursuant to Section 712 of the 1992 Energy Policy Act, before the South Carolina Public Service Commission, Docket No. 92-231-E (1993), on behalf of Nucor Steel-Darlington, re Section 712 regulations.
67. Mountain Fuel Supply Company, before the Public Service Commission of Utah, Docket No. 93-057-01 (1993), on behalf of Nucor Steel-Utah, re costing and pricing retail natural gas firm, interruptible, and transportation services.
68. Texas Utilities Electric Company, before the Public Utility Commission of Texas, Docket No. 11735 (1993), on behalf of the Texas Retailers Association, re retail cost-of-service and rate design.
69. Virginia Electric and Power Company, before the Virginia State Corporation Commission, Case No. PUE920041 (1993), on behalf of Philip Morris USA, re cost of service and retail rate design.
70. Carolina Power & Light Company, before the South Carolina Public Service Commission, Docket No. 92-209-E (1992), on behalf of Nucor Steel-Darlington.
71. Gulf States Utilities Company, before the Louisiana Public Service Commission, Docket No. U-17282, Rate Design (1992), on behalf of the Department of Energy, Strategic Petroleum Reserve.
72. Georgia Power Company, before the Georgia Public Service Commission, Docket Nos. 4091-U and 4146-U (1992), on behalf of Amicalola Electric Membership Corporation.
73. PacifiCorp, Inc., before the Federal Energy Regulatory Commission, Docket No. EC88-2-007 (1992), on behalf of Nucor Steel-Utah.
74. South Carolina Pipeline Corporation, before the South Carolina Public Service Commission, Docket No. 90-452-G (1991), on behalf of Nucor Steel-Darlington.
75. Carolina Power & Light Company, before the South Carolina Public Service Commission, Docket No. 91-4-E, 1991 Fall Hearing, on behalf of Nucor Steel-Darlington.
76. Sonat, Inc., and North Carolina Natural Gas Corporation, before the North Carolina Utilities Commission, Docket No. G-21, Sub 291 (1991), on behalf of Nucor Corporation, Inc.

77. Northern States Power Company, before the Minnesota Public Utilities Commission, Docket No. E002/GR-91-001 (1991), on behalf of North Star Steel-Minnesota.
78. Gulf States Utilities Company, before the Louisiana Public Service Commission, Docket No. U-17282, Phase IV-Rate Design (1991), on behalf of the Department of Energy, Strategic Petroleum Reserve.
79. Houston Lighting & Power Company, before the Public Utility Commission of Texas, Docket No. 9850 (1990), on behalf of the Department of Energy, Strategic Petroleum Reserve.
80. General Services Administration, before the United States General Accounting Office, Contract Award Protest (1990), Solicitation No. GS-00P-AC87-91, Contract No. GS-00D-89-B5D-0032, on behalf of Satilla Rural Electric Membership Corporation, re cost of service and rate design.
81. Carolina Power & Light Company, before the South Carolina Public Service Commission, Docket No. 90-4-E (1990 Fall Hearing), on behalf of Nucor Steel-Darlington, re fuel-cost recovery.
82. Gulf States Utilities Company, before the Louisiana Public Service Commission, Docket No. U-17282, Phase III-Rate Design (1990), on behalf of the Department of Energy, Strategic Petroleum Reserve, re cost of service and rate design.
83. Atlanta Gas Light Company, before the Georgia Public Service Commission, Docket No. 3923-U (1990), on behalf of Herbert G. Burris and Oglethorpe Power Corporation, re anticompetitive pricing schemes.
84. Ohio Edison Company, before the Ohio Public Utilities Commission, Case No. 89-1001-EL-AIR (1990), on behalf of North Star Steel-Ohio, re cost of service and rate design.
85. Gulf States Utilities Company, before the Louisiana Public Service Commission, Docket No. U-17282, Phase III-Cost of Service/Revenue Spread (1989), on behalf of the Department of Energy, Strategic Petroleum Reserve.
86. Northern States Power Company, before the Minnesota Public Utilities Commission, Docket No. E002/GR-89-865 (1989), on behalf of North Star Steel-Minnesota.
87. Gulf States Utilities Company, before the Louisiana Public Service Commission, Docket No. U-17282, Phase III-Rate Design (1989), on behalf of the Department of Energy, Strategic Petroleum Reserve.
88. Utah Power & Light Company, before the Utah Public Service Commission, Case No. 89-039-10 (1989), on behalf of Nucor Steel-Utah and Vulcraft, a division of Nucor Steel.
89. Soyland Power Cooperative, Inc. v. Central Illinois Public Service Company, Docket No. EL89-30-000 (1989), before the Federal Energy Regulatory Commission, on behalf of Soyland Power Cooperative, Inc., re wholesale contract pricing provisions
90. Gulf States Utilities Company, before the Public Utility Commission of Texas, Docket No. 8702 (1989), on behalf of the Department of Energy, Strategic Petroleum Reserve.

91. Houston Lighting and Power Company, before the Public Utility Commission of Texas, Docket No. 8425 (1989), on behalf of the Department of Energy, Strategic Petroleum Reserve.
92. Northern Illinois Gas Company, before the Illinois Commerce Commission, Docket No. 88-0277 (1989), on behalf of the Coalition for Fair and Equitable Transportation, re retail gas transportation rates.
93. Carolina Power & Light Company, before the South Carolina Public Service Commission, Docket No. 79-7-E, 1988 Fall Hearing, on behalf of Nucor Steel-Darlington, re fuel-cost recovery.
94. Potomac Electric Power Company, before the District of Columbia Public Service Commission, Formal Case No. 869 (1988), on behalf of Peoples Drug Stores, Inc., re cost of service and rate design.
95. Carolina Power & Light Company, before the South Carolina Public Service Commission, Docket No. 88-11-E (1988), on behalf of Nucor Steel-Darlington.
96. Northern States Power Company, before the Minnesota Public Utilities Commission, Docket No. E-002/GR-87-670 (1988), on behalf of the Metalcasters of Minnesota.
97. Ohio Edison Company, before the Ohio Public Utilities Commission, Case No. 87-689-EL-AIR (1987), on behalf of North Star Steel-Ohio.
98. Carolina Power & Light Company, before the South Carolina Public Service Commission, Docket No. 87-7-E (1987), on behalf of Nucor Steel-Darlington.
99. Gulf States Utilities Company, before the Louisiana Public Service Commission, Docket No. U-17282, Phase I (1987), on behalf of the Strategic Petroleum Reserve.
100. Gulf States Utilities Company, before the Public Utility Commission of Texas, Docket No. 7195 (1987), on behalf of the Strategic Petroleum Reserve.
101. Gulf States Utilities Company, before the Federal Energy Regulatory Commission, Docket No. ER86-558-006 (1987), on behalf of Sam Rayburn G&T Cooperative.
102. Utah Power & Light Company, before the Utah Public Service Commission, Case No. 85-035-06 (1986), on behalf of the U.S. Air Force.
103. Houston Lighting & Power Company, before the Public Utility Commission of Texas, Docket No. 6765 (1986), on behalf of the Strategic Petroleum Reserve.
104. Central Maine Power Company, before the Maine Public Utilities Commission, Docket No. 85-212 (1986), on behalf of the U.S. Air Force.
105. Gulf States Utilities Company, before the Public Utility Commission of Texas, Docket Nos. 6477 and 6525 (1985), on behalf of North Star Steel-Texas.
106. Ohio Edison Company, before the Ohio Public Utilities Commission, Docket No. 84-1359-EL-AIR (1985), on behalf of North Star Steel-Ohio.
107. Utah Power & Light Company, before the Utah Public Service Commission, Case No. 84-035-01 (1985), on behalf of the U.S. Air Force.

108. Central Vermont Public Service Corporation, before the Vermont Public Service Board, Docket No. 4782 (1984), on behalf of Central Vermont Public Service Corporation.

109. Gulf States Utilities Company, before the Louisiana Public Service Commission, Docket No. U-15641 (1983), on behalf of the Strategic Petroleum Reserve.

110. Southwestern Power Administration, before the Federal Energy Regulatory Commission, Rate Order SWPA-9 (1982), on behalf of the Department of Defense.

111. Public Service Company of Oklahoma, before the Federal Energy Regulatory Commission, Docket Nos. ER82-80-000 and ER82-389-000 (1982), on behalf of the Department of Defense.

112. Central Maine Power Company, before the Maine Public Utilities Commission, Docket No. 80-66 (1981), on behalf of the Commission Staff.

113. Bangor Hydro-Electric Company, before the Maine Public Utilities Commission, Docket No. 80-108 (1981), on behalf of the Commission Staff.

114. Oklahoma Gas & Electric, before the Oklahoma Corporation Commission, Docket No. 27275 (1981), on behalf of the Commission Staff.

115. Green Mountain Power, before the Vermont Public Service Board, Docket No. 4418 (1980), on behalf of the PSB Staff.

116. Williams Pipe Line, before the Federal Energy Regulatory Commission, Docket No. OR79-1 (1979), on behalf of Mapco, Inc.

117. Boston Edison Company, before the Massachusetts Department of Public Utilities, Docket No. 19494 (1978), on behalf of Boston Edison Company.

118. Duke Power Company, before the North Carolina Utilities Commission, Docket No. E-7, Sub 173, on behalf of the Commission Staff.

119. Duke Power Company, before the North Carolina Utilities Commission, Docket No. E-100, Sub 32, on behalf of the Commission Staff.

120. Virginia Electric & Power Company, before the North Carolina Utilities Commission, Docket No. E-22, Sub 203, on behalf of the Commission Staff.

121. Virginia Electric & Power Company, before the North Carolina Utilities Commission, Docket No. E-22, Sub 170, on behalf of the Commission Staff.

122. Southern Bell Telephone Company, before the North Carolina Utilities Commission, Docket No. P-5, Sub 48, on behalf of the Commission Staff.

123. Western Carolina Telephone Company, before the North Carolina Utilities Commission, Docket No. P-58, Sub 93, on behalf of the Commission Staff.

124. Natural Gas Ratemaking, before the North Carolina Utilities Commission, Docket No. G-100, Sub 29, on behalf of the Commission Staff.

125. General Telephone Company of the Southeast, before the North Carolina Utilities Commission, Docket No. P-19, Sub 163, on behalf of the Commission Staff.

126. Carolina Power and Light Company, before the North Carolina Utilities Commission, Docket No. E-2, Sub 264, on behalf of the Commission Staff.

127. Carolina Power and Light Company, before the North Carolina Utilities Commission, Docket No. E-2, Sub 297, on behalf of the Commission Staff.

128. Duke Power Company, *et al.*, Investigation of Peak-Load Pricing, before the North Carolina Utilities Commission, Docket No. E-100, Sub 21, on behalf of the Commission Staff.

129. Investigation of Intrastate Long Distance Rates, before the North Carolina Utilities Commission, Docket No. P-100, Sub 45, on behalf of the Commission Staff.

STATE OF ARIZONA
BEFORE THE
ARIZONA CORPORATION COMMISSION

DOCKET NO. E-01345A-05-0816

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 RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND TO AMEND DECISION NO. 67744

SURREBUTTAL TESTIMONY OF DR. DENNIS W. GOINS ON BEHALF OF THE FEDERAL EXECUTIVE AGENCIES

EXHIBIT
FEA-4
Admitted

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TABLE OF CONTENTS

Page

INTRODUCTION 1

CONCLUSIONS 2

RECOMMENDATIONS 4

DEMAND-RELATED COST ALLOCATION 5

ENERGY-RELATED COST ALLOCATION 9

REVENUE SPREAD 10

STATE OF ARIZONA
BEFORE THE
ARIZONA CORPORATION COMMISSION

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 RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND TO AMEND DECISION NO. 67744	)	Docket No. E-01345A-05-0816

SURREBUTTAL TESTIMONY OF DR. DENNIS W. GOINS ON BEHALF OF THE FEDERAL EXECUTIVE AGENCIES

INTRODUCTION

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

A. My name is Dennis W. Goins. I operate Potomac Management Group, an economics and management consulting firm. My business address is 5801 Westchester Street, Alexandria, Virginia 22310.

Q. DID YOU PREVIOUSLY FILE DIRECT TESTIMONY IN THIS CASE?

A. Yes.

Q. ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A. I am appearing on behalf of the Federal Executive Agencies (FEA) served by Arizona Public Service Company (APS).

Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

A. The purpose of my testimony is to address certain issues raised in the direct testimony of Staff witnesses Erinn A. Andreasen and Michael L. Brosch. In particular, I focus on their recommendations regarding a variant of the peak and average allocation methodology and Ms. Andreasen's recommended revenue spread. In addition, I provide comments on the energy cost allocation methodology proposed by AECC's witness Kevin C. Higgins.

CONCLUSIONS

Q. WHAT CONCLUSIONS HAVE YOU REACHED ON THE BASIS OF YOUR REVIEW OF STAFF'S DIRECT TESTIMONY ON COST OF SERVICE AND REVENUE SPREAD?

A. I have concluded the following:

1. Cost-of-Service: Demand-related Cost Allocation. Staff witness Michael L. Brosch recommends rejecting APS' proposed 4CP methodology to allocate fixed production costs. Instead, Staff recommends a 4CP and Average (4CP&A) allocation methodology, under which allocation factors reflect a weighted combination of each class' 4CP demand factor and its average demand[1] factor. The apparent rationale underlying Staff's recommendation is that an energy-based allocation methodology is necessary to ensure that lower load factor classes with high seasonal demands (primarily air conditioning) are not assigned a disproportionate share of the costs of APS' baseload generators. Instead, compared to APS' 4CP methodology, the 4CP&A methodology assigns significantly more of the fixed costs in APS' production function (including the cost of baseload plants) to higher load factor General Service customers.

[1] Average demand equals annual kWh use divided by 8,760 hours.

Staff's 4CP&A methodology suffers from at least two major flaws. First, the methodology double counts average demand in the peak demand and energy (average demand) components of the 4CP&A allocation factors. This occurs because average demand is a subset of coincident peak demand. Second, although it allocates a higher percentage of fixed production costs—especially baseload plant costs— to higher load factor classes, the 4CP&A methodology does not allocate a similar higher percentage of the fuel-cost savings from baseload plants to these classes. Staff did not adjust its cost-of-service study to offset this asymmetry in allocating production costs. Instead, under Staff's 4CP&A cost study, each class is allocated average system fuel costs. As a result, higher load factor classes bear the higher capital cost of baseload plants without a fuel-cost savings offset—thereby creating an unjustified subsidy for lower load factor Residential customers.

2. Cost-of-Service: Energy-related Cost Allocation. AECC witness Kevin C. Higgins recommends modifying APS' allocation of energy-related production costs to reflect hourly energy costs differences by customer class. He does this by mathematically linking hourly energy costs to hourly kWh use by class. Results from his hourly energy cost analysis show that the APS 4CP and Staff 4CP&A cost studies—both of which use kWh consumption unadjusted for hourly cost differentials to allocate energy costs to classes—understate the energy-related cost responsibility of Residential customers and overstate the energy-related cost responsibility of higher load factor General Service customers.

3. Revenue Spread. Staff witness Erinn A. Andreasen recommends using results from Mr. Brosch's 4CP&A cost study as a guide for spreading Staff's proposed revenue increase. Staff's recommended revenue spread relies on results from a seriously flawed cost study. In addition, Staff's

revenue spread exacerbates the interclass revenue subsidy problem that I discussed in my direct testimony. In particular, Staff's revenue spread increases the interclass revenue subsidy that Residential customers ***receive***—going from around $38.6 million under present rates to nearly $43.9 million. This occurs even when the subsidy is measured relative to cost responsibility determined in Staff's recommended 4CP&A cost study. This result is similar to what happens under APS' proposed revenue spread, and in both cases General Service customers bear most of the subsidy burden—which for them goes from around $39.4 million to almost $47.5 million under Staff's revenue spread based on its 4CP&A cost study.

RECOMMENDATIONS

Q. WHAT DO YOU RECOMMEND ON THE BASIS OF THESE CONCLUSIONS?

A. I recommend that the Commission:

1. Reject Staff's proposed 4CP&A allocation methodology, and instead approve APS' average 4CP methodology to allocate fixed production costs. As I noted in my direct testimony, the 4CP methodology reflects the principal factors—coincident summer peak demands—driving the need for generation capacity on the APS system. Staff's recommended 4CP&A methodology dilutes the impact of APS' summer peak demands and ignores the dominant summer peaking characteristics of the APS system. As a result, the 4CP&A methodology understates cost responsibility for classes with relatively low load factors and high summer peak demands. Moreover, because of its serious flaws, Staff's 4CP&A cost study does not provide a reasonable basis for determining class cost of service.

2. Adopt the method proposed by AECC's witness Higgins to assign time-differentiated, energy-related production costs to customer classes—especially if the Commission requires APS to allocate fixed production costs using the 4CP&A methodology. Mr. Higgins' approach to assigning energy-related costs mitigates one of the major flaws of the 4CP&A methodology—that is, disproportionately allocating fixed baseload production costs to higher load factor General Service customers without offsetting these costs by fuel-cost savings attributable to such capacity.

3. Reject Staff's proposed revenue spread. Instead, the Commission should require APS to spread its allowed revenue increase using guidelines delineated in my direct testimony. The key elements of these guidelines are to:

- Reduce interclass revenue subsidies by half.
- Increase rates for subsidized classes by up to 150 percent of the average system rate increase (excluding the EIC).
- Not allow a rate decrease for any class—even if cost-of-service results indicate that a decrease is justified.

DEMAND-RELATED COST ALLOCATION

Q. DOES STAFF SUPPORT APS' 4CP ALLOCATION METHODOLOGY?

A. No. APS allocated fixed production costs to major customer classes using the average of its four test-year monthly summer (June-September) coincident system peaks. In contrast, Staff recommends using a 4CP&A methodology to allocate APS' fixed production costs. Under this methodology, allocation factors reflect "a weighted combination of the peak demand allocation factor used by APS, together with an average demand (or energy-based) allocation factor."[2]

[2] Michael L. Brosch, direct testimony at 13:9-11.

Q. HOW DOES THE 4CP&A METHODOLOGY DIFFER FROM THE 4CP METHODOLOGY?

A. Instead of focusing on system peaks—the principal drivers of APS' generation capacity requirements—Staff's 4CP&A methodology relies on energy (average demand) to allocate a significant portion of APS' fixed production costs. The apparent rationale underlying Staff's recommendation is that an energy-based allocation methodology is necessary to ensure that lower load factor classes with high seasonal demands (primarily air conditioning) are not assigned a disproportionate share of the costs of APS' baseload generators. Mr. Brosch states this rationale somewhat differently. He says:

> ...Even though APS is a summer peaking utility,...its generation facilities are required to serve customers during all of the non-peak hours of the year. Many of the costs incurred by APS to own, operate and maintain its power plants could be much lower if the Company were concerned only with meeting demand during the four peak hours of the year.[3]
>
> ---
>
> In my judgment, use of an energy weighted 4CP and Average production allocation approach is necessary for APS to reflect cost causation for production investment and is also reasonable for expenses because generating capacity non-fuel O&M costs are incurred both to meet peak demand and to minimize fuel and operating costs....[4]

Q. IS STAFF'S RECOMMENDED COST-OF-SERVICE METHODOLOGY REASONABLE?

A. No. The rationale underlying Staff's choice of the 4CP&A methodology is debatable. A host of factors—for example, cost, available resource options, environmental and siting constraints—influence how a utility plans and operates its system. But the factor that determines how much capacity it needs is peak

[3] Ibid. at 11:19 – 12:2.

demand. Moreover, the 4CP&A methodology suffers from at least two major flaws—one intrinsic and one that arises from Staff's failure to correct the asymmetrical allocation of energy-related production cost that occurs in its 4CP&A cost study. More specifically, the methodology:

1. Double counts average demand. Under Staff's recommended 4CP&A methodology, APS' fixed production costs are allocated on the basis of a weighted combination of average (energy) and coincident peak demands. Double-counting occurs because average demand is a subset of coincident peak demand. This double counting causes Staff to allocate a disproportionate and inequitable share of APS' fixed production costs to higher load factor classes.

   Staff could have avoided this double counting by using an average and excess demand allocation methodology that incorporates coincident peak demands. The 4CP&A methodology rests on the implicit assumption that average demand is the principal determinant of a utility's decision to build baseload plants that provide relatively low-cost energy year-round. A logical corollary is that excess demand—the difference between peak and average demands—is the principal determinant in decisions to build peaking and intermediate plants that operate fewer hours and at much higher variable cost. However, instead of advocating an average and excess demand allocation methodology that incorporates coincident peak demands, Staff proposed a 4CP&A methodology that blends average and peak demands in a manner that bears no discernible relationship between capacity planning and capacity costs allocated to customer classes.

2. Produces an asymmetrical allocation of production plant and fuel costs. Under the 4CP&A methodology, higher load factor classes are allocated a higher percentage of fixed production costs—especially baseload plant

[4] Ibid. at 14:27-31.

costs. However, the methodology does not include a mechanism to allocate a similar higher percentage of the fuel-cost savings from baseload plants to these classes. Such an adjustment is necessary to align allocated fixed and energy-related production costs. Without the adjustment, higher load factor classes that pay average fuel costs subsidize lower load factor classes that also pay average fuel costs.

Staff did not adjust its cost-of-service study to offset this asymmetrical allocation of production costs. Instead, under Staff's 4CP&A cost study, each class is allocated average system fuel costs.[5] As a result, higher load factor classes bear the higher capital cost of baseload plants without a fuel-cost savings offset—thereby creating an unjustified subsidy for lower load factor Residential customers.

Q. HAS MR. BROSCH RECOMMENDED THE 4CP&A METHODOLOGY IN ANY REGULATORY PROCEEDING IN THE PAST FIVE YEARS?

A. No. In response to a data request from FEA, Mr. Brosch did not cite any case in the past five years in which he recommended the 4CP&A methodology.[6] He noted that he had recommended the 4CP average and excess (4CPA&E) methodology, which he claims is a variant of the 4CP&A methodology. As I noted earlier, a coincident peak average and excess allocation methodology would avoid the double counting inherent in the 4CP&A methodology by treating the average and the excess demand components separately.

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[5] See Staff's response to data request FEA/Staff 1-5(a), which states: "Mr. Brosch allocated all energy-related production costs in the same manner as APS, using a non-time differentiated energy allocation factor derived from relative KWH sales among customer classes, adjusted for energy losses to the generation input level."

[6] See Staff's response to data request FEA/Staff 1-2(a).

Q. SHOULD THE COMMISSION USE STAFF'S RECOMMENDED 4CP&A COST STUDY IN DETERMINING CLASS COST OF SERVICE?

A. No. Staff's 4CP&A cost study is seriously flawed and provides no reasonable basis for determining class cost of service.

ENERGY-RELATED COST ALLOCATION

Q. WHAT APPROACH DID APS PROPOSE FOR ALLOCATING ENERGY-RELATED PRODUCTION COSTS?

A. APS proposed allocating energy-related production costs on the basis of loss-adjusted kWh sales by customer class. Under this approach, each class is allocated system average fuel costs.

Q. IN YOUR DIRECT TESTIMONY, DID YOU RECOMMEND REJECTING THE APS APPROACH ?

A. No. In my opinion, the APS approach is reasonable (but subject to improvement) when combined with a methodology that emphasizes peak demands in allocating fixed (demand-related) production costs—for example, APS' proposed 4CP allocation methodology. However, the approach is unreasonable if combined with an energy-based fixed-cost allocation methodology that links capacity planning decisions with trade-offs between capital and fuel costs—for example, Staff's recommended 4CP&A methodology.

Q. COULD THE APS APPROACH BE IMPROVED?

A. Yes. One improvement would be to link allocated fuel costs more closely to energy consumption by time of use. AECC witness Kevin C. Higgins recommends modifying APS' allocation of energy-related production costs to reflect hourly energy costs differences by customer class. In his analysis of APS'

energy costs and load data, he mathematically linked hourly energy costs to hourly kWh use by class.

Q. WHAT DID HIS ANALYSIS SHOW?

A. Results from his hourly energy cost analysis showed that the APS 4CP and Staff 4CP&A cost studies—neither of which reflects a time-differentiated energy cost allocation—understate the energy-related cost responsibility of Residential customers and overstate the energy-related cost responsibility of higher load factor General Service customers.

Q. SHOULD AECC'S TIME-DIFFERENTIATED ENERGY COST ALLOCATION APPROACH BE ADOPTED?

A. Yes, in particular if the Commission requires APS to allocate fixed production costs using the 4CP&A methodology. AECC's energy cost allocation approach mitigates one of the major flaws of the 4CP&A methodology—that is, disproportionately allocating fixed baseload production costs to higher load factor General Service customers without offsetting those costs by fuel-cost savings attributable to such capacity.

REVENUE SPREAD

Q. HOW DID STAFF SPREAD ITS RECOMMENDED REVENUE INCREASE AMONG CUSTOMER CLASSES?

A. Staff witness Erinn A. Andreasen recommended using results from Mr. Brosch's 4CP&A cost study as a guide[7] for spreading Staff's proposed $204 million (9.56 percent) revenue increase from rates.[8] In general, she proposed increases close to the system average increase for the Residential (9.69 percent) and General Service

[7] See Erinn A. Andreasen, direct testimony at 2:7-14 and 5:4-10.

[8] In her direct testimony, Ms. Andreasen obviously misspoke when she said Staff recommended a $203,993 million increase in revenue from rates. See Erinn A. Andreasen, direct testimony at 2:4. Her calculated

(9.52 percent) classes. Within each of these major classes, she recommended differential increases to bring specific rate schedules closer to cost of service as measured by results from Staff's 4CP&A cost study.

Q. DID STAFF ADDRESS THE PROBLEM OF INTERCLASS REVENUE SUBSIDIES IN ITS REVENUE SPREAD?

A. No. Ms. Andreasen did not mention interclass subsidies in her direct testimony, and made no adjustments in her proposed revenue spread to address the problem. However, she discussed relative rates of return by customer class at length.

Q. DOES THE CURRENT INTERCLASS SUBSIDY PROBLEM WORSEN UNDER STAFF'S PROPOSED REVENUE SPREAD?

A. Yes. Results from 4CP&A cost studies conducted by Staff indicate that the interclass subsidy from General Service to Residential customers goes up under Staff's revenue spread.[9] As shown in Table 1S below, the Residential subsidy increases to almost $43.9 million, while the subsidy paid by General Service customers goes to almost $47.5 million. These results are troubling since, as I noted earlier, cost responsibility as measured in Staff's 4CP&A cost study is understated for Residential customers and overstated for General Service customers. In other words, even the 4CP&A methodology cannot hide a major problem—Residential rates under Staff's revenue spread are far below cost of service, while General Service rates are well above cost of service.[10]

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revenue spread is based on an overall rate increase of approximately $204 million.

[9] Michael L. Brosch, direct testimony at Attachment MLB-3 and Staff's response to FEA/Staff 1-8.

[10] This finding is consistent with results from APS' 4CP cost study.

Table 1S. Interclass Subsidies Under Present APS Rates and Staff Proposed Revenue Spread ($000)

Class	Present Rates	Staff Spread
Residential	38,574	43,878
General Service	(39,421)	(47,466)

Note: positive (negative) number reflects subsidy received (paid)
Source: Michael L. Brosch, direct testimony, Attachment MLB-3 and Staff response to FEA/Staff 1-8.

Q. IS STAFF'S REVENUE SPREAD REASONABLE?

A. No. Staff's recommended revenue spread relies on results from a seriously flawed 4CP&A cost study that provides little useful guidance on appropriate rate increases for particular rate schedules. In addition, even if one accepted the 4CP&A methodology, Staff's revenue spread would still be unreasonable since it exacerbates the interclass revenue subsidy problem for APS' two major customer classes.

Q. SHOULD THE COMMISSION ADOPT THE STAFF'S REVENUE SPREAD?

A. No. I recommend that the Commission reject Staff's proposed revenue spread, which relies on a flawed 4CP&A cost study and also exacerbates the interclass revenue subsidy problem for major customer classes. To address these issues, the Commission should require APS to spread its allowed revenue increase using guidelines delineated in my direct testimony. The key elements of these guidelines are to.

- Reduce interclass revenue subsidies by half.
- Increase rates for subsidized classes by up to 150 percent of the average system rate increase (excluding the EIC).

- Not allow a rate decrease for any class—even if cost-of-service results indicate that a decrease is justified.

Q. DOES THIS COMPLETE YOUR SURREBUTTAL TESTIMONY?

A. Yes.

ARIZONA PUBLIC SERVICE COMPANY
Cost of Service Summary - *APS Present Rates*
Rates of Return by Customer Classification
Adjusted Test Year Ending September 30, 2005
($000)

					Total ACC Jurisdiction				
		Total Company	Total ACC Jurisdiction	All Other	Residential	General Service	Water Pumping	Outdoor Lighting	Dusk to Dawn
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
1.a.	Revenues from Rates	2,164,812	2,127,322 (a)	37,490	1,089,551 (a)	997,139 (a)	20,864 (a)	13,345 (a)	6,423 (a)
1.b.	Other Revenues	1,344,909	1,313,268	31,641	624,903	662,982	15,739	8,074	1,570
2.	Expenses	3,345,022	3,324,291 (b)	20,731	1,690,974 (b)	1,573,339 (b)	33,299 (b)	20,478 (b)	6,201 (b)
3.	Operating Income Before Income Taxes	164,699	116,299	48,400	23,240	86,782	3,304	941	1,792
4.	Income Taxes	9,952	395	9,557	(14,265)	13,414	934	(114)	426
5.	Net Operating Income	154,747	115,904	38,843	37,745	73,368	2,370	1,055	1,366
6.	Rate Base	5,327,833	4,466,697 (c)	861,136	2,489,740 (c)	1,876,564 (c)	25,475 (c)	51,298 (c)	23,620 (c)
7.	Rate of Return	2.90%	2.59%	4.51%	1.52%	3.91%	9.30%	2.06%	5.78%
				ROR Index	58	151	359	79	223
				Subsidy* Received(Paid)	44,069	(40,483)	(2,804)	453	(1,236)

Source: Schedule G-1
Supporting APS Schedules:
(a) H-1
(b) G-4
(c) G-3

* Subsidy indicates change in Rate Revenue required to earn 2.597% return on rate base.
Gross Revenue Conversion Factor = 1.6407 APS07406 Schedule C-3
COS ROR = 2.5948%

ARIZONA PUBLIC SERVICE COMPANY
SUMMARY OF BASE REVENUES BY CUSTOMER CLASSIFICATION
APS PRESENT AND PROPOSED RATES
TEST YEAR ENDING SEPTEMBER 30, 2005, ADJUSTED

		Base Revenues in the Test Year (a)		APS Proposed Increase (b)				
		(A)	(B)	(C)	(D)	(E)	(F)	
Line No.	Customer Classification	Present Rates [1] ($000)	Proposed Rates [3) 4)] ($000)	Amount ($000) (B) - (A)	% (C) / (A)	Proposed EIC [2] ($000)	Proposed Increase with EIC % [(E) + (C)] / (A)	Line No.
1	Residential	1,089,551	1,319,891	230,340	21.14%	2,012	21.33%	1
2	General Service	997,139	1,212,494	215,355	21.60%	2,233	21.82%	2
3	Irrigation/Water Pumping	20,864	20,894	30	0.14%	47	0.37%	3
4	Outdoor Lighting	13,345	16,562	3,217	24.11%	19	24.25%	4
5	Dusk to Dawn Lighting Service	6,423	7,097	674	10.49%	4	10.56%	5
6	Total Sales to Ultimate Retail Customers	2,127,322	2,576,938	449,616	21.14%	4,315	21.34%	6

Source: APS Schedule H-1
(a) Supporting Schedules: H-2

(b) Recap Schedules: A-1

NOTES TO SCHEDULE:
1) Base Revenues under Present Rates reflect adjusted test year revenues including applicable proforma adjustments.
2) The EIC is the proposed Environvental Improvement Charge.

ARIZONA PUBLIC SERVICE COMPANY
Cost of Service Summary - *APS Proposed Rates*
Rates of Return by Customer Classification
Adjusted Test Year Ending September 30, 2005
($000)

					Total ACC Jurisdiction				
		Total Company	Total ACC Jurisdiction	All Other	Residential	General Service	Irrigation	Outdoor Lighting	Dusk to Dawn
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
1.a.	Revenues from Rates	2,614,428	2,576,938 (a)	37,490	1,319,891 (a)	1,212,494 (a)	20,903 (a)	16,553 (a)	7,097 (a)
1.b.	Other Revenues	1,344,909	1,313,268	31,641	624,903	662,982	15,739	8,074	1,570
2.	Expenses	3,345,022	3,324,291 (b)	20,731	1,690,974 (b)	1,573,339 (b)	33,299 (b)	20,478 (b)	6,201 (b)
3.	Operating Income Before Income Taxes	614,315	565,915	48,400	253,820	302,137	3,343	4,149	2,466
4.	Income Taxes	185,528	175,971	9,557	75,683	97,510	949	1,139	690
5.	Net Operating Income	428,787	389,944	38,843	178,137	204,627	2,394	3,010	1,776
6.	Rate Base	5,327,833	4,466,697 (c)	861,136	2,489,740 (c)	1,876,564 (c)	25,475 (c)	51,298 (c)	23,620 (c)
7.	Rate of Return	8.05%	8.73%	4.51%	7.15%	10.90%	9.40%	5.87%	7.52%
				ROR Index	82	125	108	67	86
				Subsidy* Received(Paid)	64,345	(66,944)	(279)	2,409	469

Source: Schedule G-2
Supporting APS Schedules:
(a) H-1
(b) G-4
(c) G-3

* Subsidy indicates change in Rate Revenue required to earn 8.73% return on rate base.
Gross Revenue Conversion Factor = 1.6407 APS07406 Schedule C-3
COS ROR = 8.7300%

Class Revenue Requirement at 8.67% ROR from APS response to FEA 1-8(c), RC002681

ARIZONA PUBLIC SERVICE COMPANY
SUMMARY OF BASE REVENUES BY CUSTOMER CLASSIFICATION
APS PRESENT AND PROPOSED COST-OF-SERVICE RATES
TEST YEAR ENDING SEPTEMBER 30, 2005, ADJUSTED

		Base Revenues in the Test Year (a)		Cost-of-Service Increase (b)				
		(A)	(B)	(C)	(D)	(E)	(F)	
Line No.	Customer Classification	Present Rates [1] ($000)	Proposed Rates @ COS [3] ($000)	Amount ($000) (B) - (A)	COS Increase % (C) / (A)	Proposed EIC [2] ($000)	COS Increase with EIC % [(E) + (C)] / (A)	Line No.
1	Residential	1,089,551	1,384,233	294,682	27.05%	2,012	27.23%	1
2	General Service	997,139	1,145,549	148,410	14.88%	2,233	15.11%	2
3	Irrigation/Water Pumping	20,864	20,624	(240)	-1.15%	47	-0.93%	3
4	Outdoor Lighting	13,345	18,963	5,618	42.10%	19	42.24%	4
5	Dusk to Dawn Lighting Service	6,423	7,564	1,141	17.77%	4	17.83%	5
6	Total Sales to Ultimate Retail Customers	2,127,322	2,576,933	449,611	21.14%	4,315	21.34%	6

Source: APS response to FEA 1-3
See APS Schedule H-1
(a) Supporting Schedules: H-2

(b) See APS response to FEA 1-3

NOTES TO SCHEDULE:
1) Base Revenues under Present Rates reflect adjusted test year revenues including applicable proforma adjustments.
2) The EIC is the proposed Environvental Improvement Charge.
3) Revenues at APS proposed ROR = 8.73%

ARIZONA PUBLIC SERVICE COMPANY
Cost of Service Summary - *Proposed Rates @ 8.73% Rate of Return*
Rates of Return by Customer Classification
Adjusted Test Year Ending September 30, 2005
($000)

		Total Company	Total ACC Jurisdiction	All Other	Total ACC Jurisdiction: Residential	General Service	Irrigation	Outdoor Lighting	Dusk to Dawn
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
1.a.	Revenues from Rates	2,614,428	2,576,938 (a)	37,490	1,384,233 (a)	1,145,549 (a)	20,624 (a)	18,963 (a)	7,564 (a)
1.b.	Other Revenues	1,344,909	1,313,268	31,641	624,903	662,982	15,739	8,074	1,570
2.	Expenses	3,345,022	3,324,291 (b)	20,731	1,690,974 (b)	1,573,339 (b)	33,299 (b)	20,478 (b)	6,201 (b)
3.	Operating Income Before Income Taxes	614,315	565,915	48,400	317,345	239,189	3,247	6,539	3,010
4.	Income Taxes	185,528	175,971	9,557	99,991	75,365	1,023	2,060	948
5.	Net Operating Income	428,787	389,944	38,843	217,354	163,824	2,224	4,479	2,061
6.	Rate Base	5,327,833	4,466,697 (c)	861,136	2,489,740 (c)	1,876,564 (c)	25,475 (c)	51,298 (c)	23,620 (c)
7.	Rate of Return	8.05%	8.73%	4.51%	8.73%	8.73%	8.73%	8.73%	8.73%
				ROR Index	100	100	100	100	100
				Subsidy* Received(Paid)	0	0	0	0	0

Source: APS response to FEA 1-3
See APS Schedules G-1 and G-2

Supporting APS Schedules:
(a) Revenue Requirement @ 8.73% from DJR_WP3 (Line 22)
(b) G-4
(c) G-3

* Subsidy indicates change in Rate Revenue required to earn 8.73% return on rate base.

ARIZONA PUBLIC SERVICE COMPANY
SUMMARY OF BASE REVENUES BY CUSTOMER CLASSIFICATION
APS PRESENT RATES AND FEA PROPOSED REVENUE SPREAD
TEST YEAR ENDING SEPTEMBER 30, 2005, ADJUSTED

		Base Revenues in the Test Year (a)		FEA Proposed Spread				
		(A)	(B)	(C)	(D)	(E)	(F)	
Line No.	Customer Classification	Present Rates [1] ($000)	FEA Proposed Spread ($000)	Amount ($000) (B) - (A)	% (C) / (A)	Proposed EIC [2] ($000)	Proposed Increase with EIC % [(E) + (C)] / (A)	Line No.
1	Residential	1,089,551	1,352,064	262,513	24.09%	2,012	24.28%	1
2	General Service	997,139	1,179,073	181,934	18.25%	2,233	18.47%	2
3	Irrigation/Water Pumping	20,864	20,894	30	0.14%	47	0.37%	3
4	Outdoor Lighting	13,345	17,572	4,227	31.67%	19	31.81%	4
5	Dusk to Dawn Lighting Service	6,423	7,332	909	14.15%	4	14.21%	5
6	Total Sales to Ultimate Retail Customers	2,127,322	2,576,933	449,611	21.14%	4,315	21.34%	6

Source: APS response to FEA 1-3
See APS Schedule H-1
(a) Supporting Schedules: H-2

Guidelines: Limit on class increase = 150% system avg
Reduce Subsidies by 50%
No class gets decrease

NOTES TO SCHEDULE:
1) Base Revenues under Present Rates reflect adjusted test year revenues including applicable proforma adjustments.
2) The EIC is the proposed Environvental Improvement Charge.

ARIZONA PUBLIC SERVICE COMPANY
Cost of Service Summary - *FEA Proposed Revenue Spread*
Rates of Return by Customer Classification
Adjusted Test Year Ending September 30, 2005
($000)

					Total ACC Jurisdiction				
		Total Company	Total ACC Jurisdiction	All Other	Residential	General Service	Irrigation	Outdoor Lighting	Dusk to Dawn
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
1.a.	Revenues from Rates	2,614,428	2,576,938 (a)	37,490	1,352,064	1,179,073	20,894	17,572	7,332
1.b.	Other Revenues	1,344,909	1,313,268	31,641	624,903	662,982	15,739	8,074	1,570
2.	Expenses	3,345,022	3,324,291 (b)	20,731	1,690,974 (a)	1,573,339 (a)	33,299 (a)	20,478 (a)	6,201 (a)
3.	Operating Income Before Income Taxes	614,315	565,915	48,400	285,175	272,713	3,517	5,148	2,777
4.	Income Taxes	185,528	175,971	9,557	89,855	85,928	1,108	1,622	875
5.	Net Operating Income	428,787	389,944	38,843	195,321	186,785	2,409	3,526	1,902
6.	Rate Base	5,327,833	4,466,697	861,136	2,489,740 (b)	1,876,564 (b)	25,475 (b)	51,298 (b)	23,620 (b)
7.	Rate of Return	8.05%	8.73%	4.51%	7.85%	9.95%	9.45%	6.87%	8.05%
				ROR Index	90	114	108	79	92
				Subsidy* Received(Paid)	32,170	(33,524)	(270)	1,391	233

Source: APS response to FEA 1-3
See APS Schedule G-2

Supporting APS Schedules:
(a) G-4
(b) G-3

* Subsidy indicates change in Rate Revenue required to earn 8.73% return on rate base.
Class Revenue Requirement at 8.73% ROR from APS response to FEA 1-3
COS ROR = 8.73%
Incremental tax rate = 39.50% APS07406 Sch C-3

E-34

GENERAL SERVICE

		Distribution (Substations)	Distribution (Primary Lines)	Distribution (Transformers, Secondary & Services)
	Rate Base			
1)	Rate Base (excluding Cust. Advances & Deposits)	$5,852,168	$32,444,141	$3,470,512
2)	Regulatory Assets			
3)	Customer Accounts			
4)	Cust. Service & Info and Sales Expense			
5)	Customer Deposits	($238,963)	($1,324,799)	($141,712)
6)	Customer Advances	($133,876)	($742,204)	($79,393)
7)	Total Rate Base	$5,479,329	$30,377,138	$3,249,407
8)	Retail Earned ROR @ 8.73%			
9)	Return on Rate Base (Line 8 * Line 7)	$478,345	$2,651,924	$283,673
	Computation of Income Taxes			
10)	Weighted Cost of Long Term Debt @ 2.46%			
11)	Tax Rate @ 39.05%			
12)	Income Taxes ((Line 8-Line10)(Line 7)(Line 11))/(1-Line 11)	$220,057	$1,219,985	$130,500
	Expenses			
13)	Expenses	$1,054,176	$3,587,716	$362,995
14)	Regulatory Assets			
15)	Customer Accounts			
16)	Cust. Service & Info and Sales Expense			
17)	Total Expenses	$1,054,176	$3,587,716	$362,995
	Revenue Requirement			
18)	Return, Income Taxes, and Expenses (Line 9 + Line 12 + Line 17)	$1,752,578	$7,459,625	$777,169
19)	Less: Revenue Credits	$74,060	$311,853	$31,610
20)	Production Related Income Tax Adjustment	$0	$0	$0
21)	Out of Period Income Tax Adjustment	$12,993	$72,033	$7,705
22)	**REVENUE REQUIREMENT @8.73%**	**$1,691,511**	**$7,219,805**	**$753,264**
	E-34 Test-Year Billing kW			
23)	Secondary	858,509	858,509	858,509
24)	Primary Lines	1,339,788	1,339,788	0
25)	Substations	77,594	0	0
26)	Total	2,275,891	2,198,297	858,509
27)	**Unit Cost by Function ($/kW)**	$0.74	$3.28	$0.88

	Voltage Discounts ($/kW)	**Cost-of-Service**	**APS Proposed**	**Difference ($/kW)**
28)	Transmission	$4.90	$4.52	($0.38)
29)	Primary Substation	$4.16	$3.40	($0.76)
30)	Primary Line	$0.88	$0.66	($0.22)

Sources:
APS09255_Workpaper DJR_WP-1&WP-3.xls
APS09262_Workpaper DJR_WP-09.xls

E-34
GENERAL SERVICE

		Distribution (Substations)	Distribution (Primary Lines)	Distribution (Transformers, Secondary & Services)
	Rate Base			
1)	Rate Base (excluding Cust. Advances & Deposits)	$5,852,168	$32,444,141	$3,470,512
2)	Regulatory Assets			
3)	Customer Accounts			
4)	Cust. Service & Info and Sales Expense			
5)	Customer Deposits	($238,963)	($1,324,799)	($141,712)
6)	Customer Advances	($133,876)	($742,204)	($79,393)
7)	Total Rate Base	$5,479,329	$30,377,138	$3,249,407
8)	Retail Earned ROR @ 8.73%			
9)	Return on Rate Base (Line 8 * Line 7)	$478,345	$2,651,924	$283,673
	Computation of Income Taxes			
10)	Weighted Cost of Long Term Debt @ 2.46%			
11)	Tax Rate @ 39.05%			
12)	Income Taxes ((Line 8-Line10)(Line 7)(Line 11))/(1-Line 11)	$220,057	$1,219,985	$130,500
	Expenses			
13)	Expenses	$1,054,176	$3,587,716	$362,995
14)	Regulatory Assets			
15)	Customer Accounts			
16)	Cust. Service & Info and Sales Expense			
17)	Total Expenses	$1,054,176	$3,587,716	$362,995
	Revenue Requirement			
18)	Return, Income Taxes, and Expenses (Line 9 + Line 12 + Line 17)	$1,752,578	$7,459,625	$777,169
19)	Less: Revenue Credits	$74,060	$311,853	$31,610
20)	Production Related Income Tax Adjustment	$0	$0	$0
21)	Out of Period Income Tax Adjustment	$12,993	$72,033	$7,705
22)	**REVENUE REQUIREMENT @8.73%**	**$1,691,511**	**$7,219,805**	**$753,264**
	E-34 Test-Year Billing kW			
23)	Secondary	858,509	858,509	858,509
24)	Primary Lines	1,339,788	1,339,788	0
25)	Substations	77,594	0	0
26)	Total	2,275,891	2,198,297	858,509
27)	**Unit Cost by Function ($/kW)**	$0.74	$3.28	$0.88

	Voltage Discounts ($/kW)	**Cost-of-Service**	**FEA Proposed**	**Difference ($/kW)**
28)	Transmission	$4.90	$4.72	($0.18)
29)	Primary Substation	$4.16	$4.04	($0.12)
30)	Primary Line	$0.88	$0.79	($0.09)

Sources:
APS09255_Workpaper DJR_WP-1&WP-3.xls
APS09262_Workpaper DJR_WP-09.xls

Arizona Public Service
Docket No. E-01345A-05-0816

Rate E-34 Options

Rate E-34 Present - Bundled

BSC	Charge ($/unit)	
SCM	0.575	per day
IRM	1.134	per day
Pri	2.926	per day
Trans	22.422	per day
Demand		
Sec	12.343	per kW
Pri	11.683	per kW
PriSub	8.943	per kW
Trans	8.043	per kW
Energy	0.03183	per kWh

Discounts ($/kW)	
Primary	(0.66)
PriSub	(3.40)
Trans	(4.30)

Rate E-34 APS Proposed - Bundled

BSC	Charge ($/unit)	
SCM	0.575	per day
IRM	1.134	per day
Pri	2.926	per day
Trans	22.422	per day
Demand		
Sec	13.415	per kW
Pri	12.755	per kW
PriSub	10.015	per kW
Trans	8.895	per kW
Energy	0.04482	per kWh

Discounts ($/kW)	
Primary	(0.66)
PriSub	(3.40)
Trans	(4.52)

Rate E-34 FEA Proposed - Bundled

BSC	Charge ($/unit)	
SCM	0.575	per day
IRM	1.134	per day
Pri	2.926	per day
Trans	22.422	per day
Demand		
Sec	13.515	per kW
Pri	12.725	per kW
PriSub	9.475	per kW
Trans	8.795	per kW
Energy	0.04482	per kWh

Discounts ($/kW)	
Primary	(0.79)
PriSub	(4.04)
Trans	(4.72)

BEFORE THE ARIZONA CORPORATION COMMISSION

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 Ratemaking Purposes, to Fix a Just and Reasonable Rate of Return Thereon, to Approve Rate Schedules Designed to Develop Such Return, and to Amend Decision No. 67744	)	Docket No. E-01345A-05-0816

Testimony

Of

Colonel Ben Hancock

On behalf of

Federal Executive Agencies

September 1, 2006

EXHIBIT

FEA-5

C-Admit 11/01

Testimony of Colonel Ben Hancock

Q. Please state your name and position:

A. I am Colonel Ben D. Hancock, Commanding Officer, Marine Corps Air Station Yuma ("MCAS Yuma"), Arizona.

Q. Would you please summarize your education and professional background?

A: I am the son of a career Army Green Beret soldier. I worked full-time as a uniformed trooper with the Arizona Highway Patrol for four years while attending college. I received my Bachelor of Science degree from Arizona State University and was commissioned a Second Lieutenant in May 1983 through the Platoon Leaders Class (Air) program. After completing The Basic School I reported to the Naval Aviation Training Command and was designated a Naval Aviator in January 1986.

I began my Marine Corps career at Cherry Point, North Carolina for instruction in the AV-8B Harrier. I deployed to Iwakuni, Japan, and served a Mediterranean Sea cruise aboard the USS Guam. I flew combat mission over Kuwait and Iraq and served as the Power Line Division Officer and Quality Assurance Office in support of Operations Desert Shield and Desert Storm.

In July 1993, I was selected to fly with the U.S. Navy Blue Angels. In this capacity, I flew the F/A-18 Hornet as the Right Wingman for the 1994 and 1995 air show seasons. After serving with the Blue Angels, I served for eight months at Marine Officer Candidate School, Quantico, VA as the Academics Officer and as a Company Commander before attending Marine Corps Command and Staff College where I graduated in June 1997 with a Masters degree in Military Studies. In 2000, I attended Air War College, graduating in June 2001 with a Masters in Strategic Studies.

I served as commander of VWA-231 at Marine Corps Air Station Cherry Point, North Carolina, and assumed command of Marine Corps Air Station Yuma in July 2005.

I have accumulated over 3,600 hours of military flight time. My personal awards include three awards of the Meritorious Service Medal, Strike Flight Air Medal, three awards of the Navy and Marine Corps Commendation Medal, the Navy and Marine Corps Achievement Medal, the Combat Action Ribbon, and numerous unit and campaign awards.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to identify the economic impact of MCAS Yuma on the Arizona economy, and highlight the impact of increased utility bills on MCAS Yuma.

Q. What is the military mission of MCAS Yuma?

A: MCAS Yuma is one of the Marine Corps' premier aviation training bases. With access to 2.8 million acres of bombing and aviation training ranges and superb flying weather, MCAS Yuma supports 80 percent of the Marine Corps' air-to-ground aviation training. Each year, the air station hosts numerous units and aircraft from U.S. and NATO forces and supports over 250,000 mandays of aviation training per year.

Nestled in five square miles just southeast of Yuma, the air station is home to a number of tenant units including Marine Aviation Weapons and Tactics Squadron-1 (the Marine "Top Gun" school), Marine Aircraft Group-13, Marine Wing Support Squadron-371, Marine Fighter Training Squadron-401, Marine Air Control Squadron-1 and Combat Service Support Detachment-16.

Q. What is the size of the workforce at MCAS Yuma?

A: Approximately 5,000 Military, 1,300 Civilians, 7,300 Family members (13,600 total personnel).

Q. What is the impact of MCAS Yuma on the Arizona economy?

A: In addition to the $148,051,301 million payroll, MCAS Yuma impacts the state's economy with construction projects, major contracts and daily procurements, education requirements, health necessities, and commissary and exchange expenditures. In addition to MCAS Yuma's work force, there are more than 2,289 base retirees, both civilian and military, who continue to have a large positive impact on the state's economy. Some MCAS Yuma employees have secondary jobs in the local communities in such fields as housing, food, health care and the services industries, having an economic impact on Arizona of approximately $287,101,441 million per year.

MCAS Yuma executed $58,101,441 in annual contract awards in Fiscal Year 2005. Of this amount, $ 15,351,158 was awarded within the state of Arizona and $7,101,726 was awarded to small and disadvantaged businesses.

Q. Where does MCAS Yuma purchase its electric utility service?

A: We purchase our electric utility services from Arizona Public Service Company (APS). MCAS Yuma takes utility service on the E-32 and E-34 Rate Schedules. MCAS Yuma currently pays APS about $ 3,500,000 per year for electric utility service.

Q. What funds are used to pay Marine Corps utility bills?

A. The funds used to pay for the utility service provided by APS are operations and maintenance (O&M) funds. Operations and Maintenance funds are also used to fund military operations and other general maintenance needs. Utility bills are "must pay" bills, meaning they are among the first requirements funded and paid by the government. Any cost avoidance or reduction in costs MCAS Yuma pays for utilities ensures funds could be utilized elsewhere for essential military operations and maintenance.

Q. What happens to MCAS Yuma's O&M funds when there is a large increase in utility bills?

1

2 A. Since the funding used to pay utility bills is the same funding used to fund military
3 operations and maintenance, when utility bills increase, reductions in other areas of our
4 military operations and maintenance must be taken. The only mechanism we have to
5 increase our overall funding level is to request additional appropriations from
6 Headquarters United States Marine Corps and ultimately, Congress.
7
8 **Q. Does this conclude your testimony?**
9
10 A. Yes it does.

DIRECT TESTIMONY OF JULIE M. CANNELL

On Behalf of the Arizona Utility Investors Association

Docket No. E-01345A-05-0816

August 18, 2006

EXHIBIT
AUIA-1
admitted

TABLE OF CONTENTS

		Page
	EXECUTIVE SUMMARY	ES-1
I.	INTRODUCTION	1
II.	HOW INVESTORS EVALUATE INVESTMENTS IN UTILITY COMPANIES	4
III.	INVESTORS' PERCEPTIONS OF THE CURRENT PROCEEDING	17
IV.	POWER SUPPLY ADJUSTOR	29
V.	RETURN ON EQUITY FOR APS	32

EXHIBITS

EXHIBIT JMC-1 **PROFESSIONAL QUALIFICATIONS**

EXECUTIVE SUMMARY

OF

JULIE M. CANNELL

Based upon my 20 years of experience as a securities analyst and portfolio manager as well as my review of rating agencies' and equity analysts' perceptions of Arizona Public Service ("APS") and its parent company, Pinnacle West Capital, I conclude the 11.5% return on equity requested by APS is reasonable and comports with investors' expectations. Additionally, investors support changes to the Power Supply Adjustor which will assure more timely recovery of fuel and purchased power costs.

In the past, investors generally bought utility stocks because they wanted relatively low risk and predictable earnings as compared to other equity investments. Recent changes in the industry, however, have undermined investors' confidence in utility stocks' safety and performance predictability. Therefore, investors are beginning to demand higher returns for the capital they invest in utilities. That is particularly true when the utility's regulatory climate is uncertain.

In the views of rating agencies and equity analysts, Arizona Public Service is subject to considerable regulatory risk, which has put and continues to place downward pressure on credit ratings and stock recommendations. This is a very critical case for APS. The Company is perilously close to a further downgrade which would place it in non-investment grade territory. Debt and equity investors see APS' growth as a "two-edged sword." While, in general, it improves earnings, APS' growth demands also drive enormous capital investment requirements. Investors are closely watching the decisions made by the

Commission on the Power Supply Adjustor and Return on Equity to determine whether the Company will be granted sufficient earnings and an opportunity to improve its credit metrics. These are the twin pillars which support APS' ability to obtain capital on favorable terms and, as importantly, its ability to meet its service territory growth and to continue to provide service at reasonable rates.

Based on my experience as a securities analyst and portfolio manager, I conclude the 11.5% return on equity requested by Arizona Public Service would be perceived by rating agencies and investors as a fair and reasonable rate of return in light of the uncertainties facing the utility. As well, the changes proposed by the Company to the Power Supply Adjustor would be viewed by investors and the rating agencies as important steps to improve the timeliness and certainty of fuel and purchased power cost recovery.

DIRECT TESTIMONY OF JULIE M. CANNELL
ON BEHALF OF ARIZONA UTILITY INVESTORS ASSOCIATION
(Docket No. E-01345A-05-0816)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, EMPLOYER AND BUSINESS ADDRESS.

A. My name is Julie M. Cannell. I am the president of my own advisory firm, J.M. Cannell, Inc. My business address is P.O. Box 199, Purchase, New York 10577.

Q. PLEASE DESCRIBE YOUR PROFESSIONAL AND EDUCATIONAL BACKGROUND.

A. My firm, J.M. Cannell, Inc., provides advisory services to electric utility companies and other firms and organizations with an interest in the industry. Prior to establishing my firm in February 1997, I was employed by the New York-based investment manager, Lord Abbett & Company, from June 1978 to January 31, 1997. During my tenure with Lord Abbett, I was a securities analyst specializing in the electric utility and telecommunications services industries; portfolio manager of America's Utility Fund, an equity utility mutual fund; portfolio manager of numerous institutional equity portfolios; and co-director of Lord Abbett's Equity Research Department. Further information on my background is set forth in Exhibit JMC-1.

Q. HAVE YOU SUBMITTED TESTIMONY PREVIOUSLY BEFORE ANY STATE REGULATORY AGENCIES?

A. Yes, I have. I have submitted pre-filed testimony on behalf of investor-owned utilities before Public Service or Public Utility Commissions in the states of

1 Kansas, Missouri, Oklahoma, Pennsylvania, South Carolina, Texas and
2 Washington.

3 **Q. WHAT IS THE SCOPE OF YOUR TESTIMONY IN THIS**
4 **PROCEEDING?**

5 A. I have been asked to discuss the perspective of investors with respect to the
6 overall financial condition, including the return on equity, credit metrics and cash
7 flow for Arizona Public Service Company ("APS" or "Company") in the context
8 of the current rate case.

9 **Q. PLEASE SUMMARIZE WHAT IN YOUR EXPERIENCE ALLOWS YOU**
10 **TO PROVIDE TESTIMONY ABOUT THE VIEWPOINT OF INVESTORS.**

11 A. As a securities analyst for approximately 20 years, I specialized in the electric
12 utility industry and the individual companies comprising it. As a portfolio
13 manager, I applied that knowledge, along with investment fundamentals, toward
14 investment decisions on behalf of institutions and individual investors. Moreover,
15 I have reviewed various analyst and rating agency reports, which have addressed
16 the Company and its regulatory situation.

17 **Q. AS AN ANALYST OR PORTFOLIO MANAGER, DID YOU FOLLOW**
18 **APS OR ITS PARENT COMPANY, PINNACLE WEST CAPITAL**
19 **CORPORATION ("PINNACLE WEST")?**

20 A. Yes, I did. I monitored the Company and Pinnacle West for both Lord Abbett's
21 equity portfolios and America's Utility Fund.

22 **Q. PLEASE DESCRIBE HOW YOUR TESTIMONY IS ORGANIZED.**

23 A. There are four parts to my testimony.

1 **How Investors Evaluate Investments in Utility Companies**—This section
2 discusses why investors choose to invest in electric utilities, with particular
3 emphasis on why the regulatory climate in which the utility operates is of such
4 importance to investors. This section of the testimony also discusses why the risk
5 of investing in the electric utility industry has risen substantially in recent years
6 on an industry-wide basis and why markets today react so swiftly and strongly to
7 unfavorable news about a company.

8 **Investors' Perceptions Related to the Present Proceeding**—This section
9 reviews the investment community's perceptions of APS and Arizona regulation.
10 This review is based on a number of recent publications by rating agencies and
11 investment analysts discussing their perceptions of the rate case and the
12 Company's regulatory environment.

13 **Power Supply Adjustor**—This section discusses the emphasis which both rating
14 agencies and analysts place on timely and assured recovery of fuel and purchased
15 power costs. My conclusion is that improvements to APS' recovery mechanism
16 are a key component in stabilizing and starting to improve investors' perceptions
17 of the Company.

18 **Return on Equity**—This section discusses APS' request for an 11.5% return on
19 equity. My conclusion is that the Company's proposal is one that investors view
20 as important and constructive—i.e., supportive of credit quality and providing a
21 fair return to equity investors. An allowed ROE of 11.5% would lead to a more
22 predictable stream of earnings and cash flow and would be viewed favorably by

1 rating agencies and the investment community at a time when favorable
2 perceptions and increased financial stability are very critical to the Company.

3 **Q. PLEASE SUMMARIZE YOUR TESTIMONY.**

4 A. This is a very important case for APS. The Company is perilously close to a
5 further downgrade which would place it in non-investment-grade territory with at
6 least one of the credit rating agencies. Debt and equity investors see APS' growth
7 as a "two-edged sword." While, in general, it improves earnings, APS' growth
8 demands also drive enormous capital investment requirements. Investors are
9 closely watching the decisions made by the Commission on subjects like the
10 Power Supply Adjustor and Return on Equity to determine whether the Company
11 will be granted sufficient earnings and an opportunity to improve its credit
12 metrics. These are the twin pillars which support APS' ability to obtain capital on
13 favorable terms and, as importantly, its ability to meet its service territory growth
14 and to continue to provide service at reasonable rates.

15 **II. HOW INVESTORS EVALUTE INVESTMENTS IN**
16 **UTILITY COMPANIES**

17 **Q. WHY IS IT IMPORTANT TO CONSIDER THE OPINIONS OF THE**
18 **INVESTMENT COMMUNITY?**

19 A. Investors provide the capital necessary to maintain and expand the Company's
20 infrastructure which, in turn, enables APS to provide reliable service to
21 customers. The terms on which the Company is able to obtain that capital have a
22 direct and measurable impact on retail electric customers and the rates they pay
23 for service. For example, if credit rating agencies such as Moody's Investors

("Moody's") or Standard & Poor's ("S&P") believe that the utility's revenues will be diminished by adverse business or regulatory decisions, those rating agencies will lower their credit ratings for the utility, which raises the cost of debt. Because the cost of debt is a component of the weighted average cost of capital, the increased costs of capital are passed on to electric customers in the form of higher rates.

These concerns and potential increased costs are not hypothetical, as the Commission knows, for APS. Late last year and early this year, rating agencies lowered APS' credit ratings, with S&P moving its rating on the Company's senior unsecured debt to only one step above so-called junk status. This comes at a time when the Company's capital requirements continue to grow to meet Arizona's need for electric power infrastructure. In a letter recently filed in this docket, APS estimates borrowing needs for the years 2007-2010 at $2.5 billion.[1]

The same is true for equity investors. If individual or institutional investors believe that the return they are offered is too low in light of the risk involved, they will either sell their stock or elect not to purchase it, which can drive the stock price down. When a utility has to go to the equity markets to obtain capital, a low stock price requires it to issue more shares of stock to obtain the same amount of money that it would have received for fewer shares if the per-share price had been higher.

The corollary is that when investors believe they are investing in or lending money to a company that enjoys fair, consistent regulation and a reasonable rate

[1] Davis letter to Commissioners, page 7, dated August 1, 2006.

of return, those investors "charge" less for their capital. When debt and equity investors charge less for their capital, utility rates remain lower. Thus, a utility and its electric customers have a shared interest in meeting the expectations of investors and credit rating agencies.

Q. ARE YOU SUGGESTING THAT THE ARIZONA CORPORATION COMMISSION SHOULD CATER TO THE DESIRES OF INVESTORS, WHOSE ORIENTATION IS TO SEEK THE HIGHEST POSSIBLE RETURNS?

A. No. I realize that the Arizona Corporation Commission ("ACC" or "Commission") has to balance the interests of both investors, who want high returns, and electric customers, who want low rates. The point is that there is an optimum cost of equity for the electric customer. If the rate is set too low, it appears that the overall cost of capital is less. In actuality, however, that serves to limit access to the capital markets by driving the cost of capital higher than it would have been had the cost of equity been set at a reasonable level in the beginning. This is particularly true for APS given its service territory's growth demands and corresponding capital needs. Thus, the Commission's decision on rate of return is not simply a zero-sum game, as electric customer groups sometimes suggest. If the rate of return is within a zone of reasonableness, both the utility and electric customers win. If the rate of return is set too low or regulatory cost recovery risk is too high, both the utility and electric customers lose because of the effect on the capital markets.

1 **Q. WHAT GOALS LEAD INVESTORS TO INVEST IN ELECTRIC**
2 **UTILITIES?**

3 A. Historically, electric utilities have been regarded as investment vehicles that
4 provide stable performance through the ups and downs of market cycles and
5 changing economic conditions. Electric utilities have typically earned a
6 reasonable return even when conditions were not favorable for other companies.
7 Accordingly, electric utility stocks have been particularly valuable holdings when
8 conditions were not favorable to investments in more volatile industry sectors. In
9 other words, investors might see greater returns from investment in other
10 industries when times were good, but they would lose less on electric utility
11 stocks when times were not good.

12 In addition, the reliability of electric utilities' earnings streams permitted most of
13 the companies to continue to pay regular dividends during both good and bad
14 economic cycles. For investors with a need for regular cash income, the prospect
15 of regular dividends has been an important consideration in making a decision to
16 invest in electric utility stocks.

17 Based on these factors, investors have traditionally viewed electric utility stocks
18 as bond substitutes. In other words, electric utility stocks have provided regular
19 cash returns in the form of dividends and the shares themselves were seen to have
20 a stable underlying value. As a result, electric utility stocks as a group have
21 tended to move closely in line with the direction of interest rates, but in an inverse
22 relationship. That is, utility stock prices rose when interest rates fell and dropped
23 when rates rose. These factors made electric utilities a preferred investment
24 during economic slowdowns or recessions. Owning them was also a way of

1 balancing the risks in a stock portfolio that included stocks in more volatile
2 industries.

3 **Q. HAVE THE RECENT CHANGES IN THE INDUSTRY INCREASED THE**
4 **RISK OF INVESTING IN ELECTRIC UTILITIES?**

5 A. Yes. Investors now understand that the predictability of the electric utility
6 industry's earnings, across the sector, has been undermined by, among other
7 things, the restructuring that has taken place in many parts of the country. These
8 risks are in addition to the risks posed by technological, economic, environmental
9 and other policy changes that affect the industry. These increased risks mean that
10 investors no longer perceive electric utilities as a group as being the "safe havens"
11 they once were.

12 Investors' goals, however, have not fundamentally changed. They still look to
13 electric utilities primarily as defensive investments. They still look for stable
14 performance and regular dividends as the reason to invest in electric utilities. But
15 investors also understand that (1) the investment risk in electric stocks generally
16 has risen significantly and (2) additional risk will frustrate investors' goals for
17 committing capital to this sector.

18 In the end, investors have a very large universe of stocks from which to select;
19 with the exception of specialty utility funds or some portfolios with specific
20 charter requirements, they have no requirement to own electric utility stocks.
21 Consequently, investors now require a higher return for investing in the electric
22 utility industry to balance the increased risk associated with it.

1 **Q. HOW DO THESE CONCERNS AFFECT APS?**

2 A. In two ways. First, markets make judgments about investment risks that apply to
3 industry sectors as a whole and utilities are now regarded generally as more risky
4 than they were historically. Then, company-specific risk factors are added to
5 sector risk.

6 **Q. IN YOUR EXPERIENCE AS AN ANALYST AND PORTFOLIO**
7 **MANAGER, COULD A PERCEIVED CHANGE IN A COMPANY'S**
8 **REGULATORY CLIMATE AFFECT YOUR INVESTMENT OPINION?**

9 A. Absolutely. During my tenure as an active investor, a utility's regulatory
10 environment was a critical factor in my assessment of its investment
11 attractiveness. An adverse regulatory decision could be a key determinant in my
12 recommendation or decision to sell a stock already owned or not make an
13 investment in one under consideration.

14 **Q. WHY IS THE PERCEPTION OF REGULATORY CLIMATE OF SUCH**
15 **IMPORTANCE TO INVESTORS?**

16 A. Equity investors today are still seeking companies that can offer stability in
17 earnings and dividends. Fixed income investors look for stable and adequate cash
18 flows to ensure payment of principal and interest when due, as indicated by stable
19 credit ratings. The ability to pay dividends and sustain credit ratings is directly
20 related to the consistency and sufficiency of a utility's earnings, which depend in
21 large part on how the utility is regulated. If there is uncertainty about whether
22 regulation will allow a utility the opportunity to earn a reasonable return or will
23 allow the utility to recover its reasonable and prudent costs, then that uncertainty

1 will lead investors to avoid holding investment positions in the utility, all other
2 things being equal.

3 As a result, investors selecting electric utility stocks today place a very high value
4 on consistent and constructive regulation. Also, with a new round of base rate
5 case filings underway in the industry, the quality of regulation is receiving
6 renewed investor attention. That heightens the need for balanced and constructive
7 rulings in this case.

8 **Q. WHO ARE TYPICAL INVESTORS IN UTILITY STOCKS?**

9 A. There are two kinds of investors: individuals, who generally seek stability and
10 income from their utility holdings, and institutions, which generally seek total
11 return (i.e., price appreciation plus dividend income) from their utility
12 investments.

13 **Q. HOW HAS THE INVESTMENT INDUSTRY ITSELF CHANGED IN**
14 **RECENT YEARS?**

15 A. In recent years, institutional investors and hedge funds have grown dramatically
16 in the amount of capital they control. This growth has had a significant impact on
17 the speed with which the market reacts to unfavorable developments. The market
18 is much more reactive and much less forgiving than it was in the past when stock
19 ownership was less concentrated. In the context of a regulatory decision,
20 investors won't necessarily wait, as they would have in the past, to see how the
21 ramifications of a decision might play out. Rather, they simply sell their shares if
22 a regulator's decision runs counter to their expectations.

1 **Q. WHY ARE INSTITUTIONAL INVESTORS OF SUCH IMPORTANCE**
2 **GENERALLY?**

3 A. Because of the sheer size of their investment positions, institutions can effectively
4 direct the course of individual securities and sometimes can move the market as a
5 whole. Institutional investors include financial institutions such as mutual funds,
6 investment companies, insurance companies, commercial and investment banks
7 and various types of public retirement funds. They approach the investment
8 selection process from the standpoint of a portfolio. An investment portfolio is a
9 collection of stocks selected to achieve the highest possible return within a
10 commensurate level of risk. Therefore, institutional investors keep electric
11 utilities in their portfolios only when such stocks contribute to achieving the
12 desired risk/return relationship.

13 Generally, the customers of institutional investors are individuals and it is they
14 who ultimately gain or suffer loss from changes in the value of the institution's
15 investments. Anyone who has a stake in a retirement plan or owns a mutual fund
16 is directly or indirectly a client of an institutional investor. But, the individuals
17 who make the decisions concerning these investments are paid money
18 managers—how they see their responsibilities to the clients they serve and the
19 way that their performance is judged has a great deal to do with how they react to
20 developments in the market.

21 **Q. WHY ARE INSTITUTIONAL INVESTORS IMPORTANT TO APS AND**
22 **PINNACLE WEST?**

23 A. Institutional investors today hold approximately 75%-80% of Pinnacle West
24 Capital's total common shares. Such investors can dramatically change the

1 market for Pinnacle West shares. Because institutional investors own large blocks
2 of shares relative to the volumes typically traded, their activity in moving in or
3 out of the Company's shares is often noticeable as a significant change in the
4 price and volume of shares being traded for Pinnacle West. This change may be
5 picked up by other institutional investors, by the investment community in general
6 and eventually by individual investors, leading to a "cascade" effect. Other
7 entities will then look to see what is driving this trend in the stock. If they see
8 support for the trend, they follow the lead of the firms that initially began to move
9 the market and by following the leaders, the late movers further strengthen the
10 trend.

11 **Q. WHY MIGHT AN INSTITUTIONAL INVESTOR CHOOSE NOT TO**
12 **HOLD INVESTMENTS IN A PARTICULAR ELECTRIC UTILITY?**

13 A. Several factors are drivers. First, institutional investors have fiduciary
14 responsibilities. For example, managers of pension assets fall under Federal
15 ERISA laws, which mandate that a portfolio manager's decisions meet the
16 so-called "prudent man" standard. He or she is expected not to make investment
17 decisions that are unduly risky or to retain stocks that are unduly risky given the
18 investment goals of the portfolio and the function of the stock within it.

19 In addition, institutional investors have performance pressures. It is not enough
20 for stocks in a portfolio simply to increase in value. Rather, relative performance
21 is what counts. Investment performance is gauged against a market proxy (such
22 as the Standard & Poor's 500 Index) or a peer group of investors (i.e., investors
23 with a similar style, such as value, growth, growth & income, small cap, etc.).

1 Mutual fund rating organizations such as Morningstar track and publicize the
2 relative performance for mutual funds and various pension consultants perform
3 the same service for their client organizations.

4 **Q. WHAT HAPPENS WHEN AN INSTITUTIONAL INVESTOR**
5 **UNDERPERFORMS?**

6 A. The results vary, but eventually, underperformance will result in lost business and
7 personnel changes. Mutual fund shareholders can sell their fund shares. A
8 pension plan sponsor can fire the professional investor or reduce the assets under
9 their investor's management. And, of course, poor performance also
10 disadvantages the individual, who has entrusted his monies to the institution for
11 management.

12 **Q. HOW LONG A PERIOD DOES AN INSTITUTIONAL INVESTOR HAVE**
13 **BEFORE PERFORMANCE BECOMES AN ISSUE?**

14 A. Again, it can vary. But there is little doubt that institutional investors no longer
15 have the luxury of a long-time horizon in which to show performance. Investors
16 want results. And with the public visibility that investment results now have
17 (through organizations such as Morningstar and the various pension consultants)
18 and the resulting performance pressure, most investment organizations are now
19 operating with a much shorter time horizon than in years past. Generally
20 speaking, a long investment time horizon today can be as short as 12-18 months.
21 So, a stock that is unlikely to perform within the prescribed time horizon is
22 usually not attractive for purchase or continued investment by an institutional
23 investor.

1 **Q. WHAT DOES THIS MEAN FOR INVESTMENTS IN PINNACLE WEST**
2 **AND APS SPECIFICALLY?**

3 A. This shortened timeframe means that if there is bad news, institutional investors
4 will react more quickly. In the instance of a rate proceeding, these investors are
5 unlikely to wait to see what the outcome of the next rate decision will be. That
6 would represent an opportunity cost to them. Rather, institutional investors are
7 now more prone just to sell their shares on the news of an adverse regulatory
8 outcome. This is not good for retail electric customers for the reasons discussed
9 earlier.

10 **Q. DO ALL INSTITUTIONAL INVESTORS FUNCTION WITHIN THE**
11 **TIME FRAMES YOU DESCRIBE?**

12 A. No. There is a type of institutional investor called a hedge fund that frequently
13 buys and sells the same stock during the course of a day.

14 **Q. WHAT IMPACT DO HEDGE FUNDS HAVE ON THE MARKET IN**
15 **GENERAL AND STOCKS IN PARTICULAR?**

16 A. Their impact can be dramatic. Hedge funds are well known for trading in
17 information; their actions are frequently event-driven. Sometimes that
18 information is factual and other times it falls into the category of rumor. Because
19 investors at hedge funds have wide information networks and are in frequent
20 communication with a broad range of other investors, they have the ability and the
21 power to create volatility which, in turn, impacts the movement of stock prices.
22 The number of hedge funds participating in the market and the funds' assets have
23 grown exponentially in recent years—recent estimates put the numbers at over
24 8,500 firms with assets of $1.26 trillion globally in 2005, with the top 134 U.S.

1 hedge funds' assets at almost $631 billion. That compares to only 610 firms with
2 $39 billion in assets in 1990. Thus, they have become a very strong force both in
3 the market and in stocks in which they are interested. When they like an industry
4 group or a stock, hedge funds can provide substantial support to stock prices.
5 But, conversely, when they become disenchanted, their tendency is to sell quickly
6 and without remorse. Although their focus is not on contributing to orderly
7 markets, hedge funds are a formidable presence in the marketplace and must be
8 reckoned with.

9 **Q. CAN YOU GIVE AN EXAMPLE OF HOW HEDGE FUNDS MIGHT**
10 **TRAFFIC IN PINNACLE WEST'S STOCK?**

11 A. Investors have been aware of the current proceeding for months. Hedge funds
12 assuredly have made assumptions about the case, including its resolution. If,
13 when the Commission's decision is announced, the details fall short of those
14 expectations, the hedge funds could put significant pressure on the stock, either
15 through outright sales or short-selling (i.e., selling stock that is borrowed in
16 anticipation that the price of the stock will drop before the borrowed stock must
17 be replaced). Hedge funds seek to get ahead of the broader market and react to
18 news before the market can. Accordingly, if hedge funds decide to make moves
19 on Pinnacle West's shares based on the order in this proceeding, they will begin
20 to do so within hours of the release of the order.

21 **Q. WHAT ROLE DO CREDIT AGENCIES PLAY IN INVESTORS'**
22 **EXPECTATIONS?**

23 A. In the wake of financial disasters, bankruptcies and the ensuing severe erosion in
24 investor confidence in the past few years, credit issues have become critically

1 important not only to fixed income investors, but also to equity investors. While
2 credit downgrades initially impacted only the most troubled companies, a
3 spillover effect soon was seen on healthy utilities. Part of this was due to the fact
4 that the rating agencies came under harsh criticism that they had failed to catch
5 problems early enough in companies such as Enron Corp. As a result, they began
6 to heighten their scrutiny of all entities under their watch and became far more
7 proactive in making rating changes. As well, "headline risk" began to come into
8 play as investors worried that—when credit problems in an industry are in the
9 headlines—any company in the sector could be vulnerable to a downgrade. Thus,
10 equity investors now closely watch the actions of the credit agencies, because any
11 change in ratings can have a significant impact on a company's stock price.

12 **Q. WHAT HAPPENS WHEN A CREDIT DOWNGRADE OCCURS?**

13 A. In the simplest terms, it becomes more expensive for a company to raise money in
14 the capital markets because a downgrade raises a company's risk profile and,
15 consequently, increases the cost of debt. And because of the increased linkage
16 these days between ratings and stock prices, the price frequently reacts—
17 sometimes quite strongly—to a downgrade. For example, Moody's cut the
18 ratings of Allegheny Energy and its subsidiaries to "junk," or below investment-
19 grade, status on October 1, 2002. The prior day, September 30, Allegheny's stock
20 price closed at $13.10. By October 8, when the company announced that it was in
21 technical default with creditors due to its inability to meet higher collateral
22 requirements prompted by the downgrade, the stock closed at $3.80. Thus, in the
23 space of a week, Allegheny's stock price—and the value of a shareholder's

1 investment—lost 71% of its value. This example is indicative of how the markets
2 now watch changes in credit ratings so closely. For APS, it indicates how the
3 ratings downgrades and any further negative ratings action can collapse stock
4 prices as well.

5 **III. INVESTORS' PERCEPTIONS OF THE CURRENT PROCEEDING**

6 **Q. HOW HAVE YOU GAUGED INVESTORS' PERCEPTIONS OF THE**
7 **ISSUES IN THIS PROCEEDING?**

8 A. To supplement my own knowledge of the industry, I have reviewed various
9 reports related to APS and Pinnacle West written by the credit rating agencies and
10 investment analysts. A clear picture of investors' perceptions emerges from these
11 reports, which is very much in keeping with my own views.

12 **Q. WHICH CREDIT AGENCY REPORTS HAVE YOU REVIEWED?**

13 A. I have examined reports written by Moody's, S&P, and Fitch Ratings ("Fitch"),
14 which are the three key credit rating agencies.

15 **Q. WHY IS A UTILITY'S REGULATORY ENVIRONMENT IMPORTANT**
16 **TO THE RATING AGENCIES?**

17 A. The rating agencies appraise companies on the basis of creditworthiness. They
18 evaluate current financial soundness and attempt to discern how that might
19 change in the future. One of the key factors in assessing a utility's financial
20 picture is the regulatory climate in which the company operates because, among
21 other things, regulators establish the returns that may be earned on the capital
22 structure and make many other decisions impacting a company's financial health.
23 Thus, a regulatory environment characterized by consistency and predictability is

one that lends itself to a company's having a sounder financial base. Conversely, a regulatory situation defined by a lack of stability has a deleterious impact on a utility's credit profile.

Q. HOW DO THE RATING AGENCIES VIEW APS AND ITS REGULATORY SITUATION?

A. While their opinions vary somewhat, all three agencies place significant emphasis on the actions of the Commission and the impact that those actions have on the Company's financial health. The agencies generally share the opinion that APS' regulatory environment is characterized by risk and uncertainty.

Q. PLEASE ELABORATE.

A. As noted in the pre-filed direct testimony of Pinnacle West and APS Chief Financial Officer Donald E. Brandt, Moody's placed the long-term ratings of APS under review for possible downgrade on January 10, 2006. As Mr. Brandt noted, "The agency declared that an uncertain regulatory environment in combination with the absence of timely recovery of increased fuel and purchased power costs precipitated this action."[2] In a report on the Company issued the following day, Moody's cited "Growth rates within the company's service territory are above the national average" as a "Credit Strength." "Credit Challenges" included "Growing territory requires increasing amounts of capital expenditures" and "Significant rate increases are required to recover costs associated with capital investments as well as increased expenses for fuel, purchased power."[3]

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[2] Pre-Filed Direct Testimony of Donald E. Brandt On Behalf of Arizona Public Service Company, Docket No. E-01345A-05-0816, January 31, 2006.
[3] Moody's Investors Service, "Credit Opinion: Arizona Public Service Company," January 11, 2006.

The agency's review of the Company and its parent resulted in a ratings downgrade on April 27, 2006. Moody's stated that its action stemmed from the recommendation of the Commission's Administrative Law Judge in APS' petition for emergency interim rate relief that was roughly half the amount sought: "The rating downgrades reflect deterioration in key financial metrics as a result of increased fuel and purchased power costs that APS is unable to recover on a timely basis."[4]

Q. DID MOODY'S OPINION ON APS CHANGE AS A RESULT OF THE ACC'S MAY 2 RULING ON APS' EMERGENCY INTERIM RATE PETITION?

A. No. The rating agency issued another credit opinion on the Company on May 9 in which it maintained the Negative Outlook and existing rating structure. While noting the May 2 Commission decision without evaluative comment, Moody's reiterated its position on the possibility of additional downgrade action in the absence of supportive and timely rate decisions in this case. As to the chance of a ratings upgrade, the agency did say that prospective supportive regulatory treatment could result in strengthened key financial ratios, which initially would likely result only in stabilizing the rating outlook.[5]

Q. WHAT IS S&P'S VIEW OF APS IN THE CONTEXT OF ARIZONA REGULATION?

A. Standard and Poor's ("S&P") also downgraded the ratings of APS and its parent in December 2005. S&P's action reduced the credit ratings to the last notch of

[4] Moody's Investors Service, "Rating Action: Moody's Downgrades Pinnacle West (Issuer Rating to Baa3) and Arizona Public Service (Sr. Uns. to Baa2); Ratings of Pinnacle West Remain Under Review," April 26, 2006.
[5] Moody's Investors Service, "Credit Opinion: Arizona Public Service Company," May 9, 2006.

1 investment grade. S&P stated that: "This action is based on increased regulatory
2 and operating risk at APS. Specifically, Standard & Poor's is concerned that the
3 Arizona Corporation Commission (ACC) is not expeditiously addressing APS'
4 growing fuel and purchased-power cost deferrals, which have grown much more
5 rapidly than expected in 2005, particularly because of elevated gas prices and the
6 utility's increased dependence on this fuel."[6]

7 S&P opined several weeks later on the fuel and purchased power recovery
8 mechanism established in the Company's last major rate case: "Regulatory
9 uncertainty is exacerbated by the establishment in 2004 of a weak power supply
10 adjuster [sic] (PSA) that exposes the utility to potential cash volatility. APS has
11 been forced to defer $170 million of fuel and purchased power costs at the end of
12 2005, an amount that may grow to as large as $250 million by the end of 2006."[7]
13 Subsequently, S&P commented on the ACC's May 2 Decision by maintaining
14 APS' ratings level and Stable Outlook. The agency noted that the Commission's
15 approval of "additional rate adders for retail customers is a step in the right
16 direction as it stems the growth of deferred balance levels. Yet deferrals are not
17 expected to be eliminated and will continue to be an ongoing concern for
18 consolidated credit quality in 2006 and 2007."[8] S&P also said that "continued
19 regulatory support will be required to determine how deferred balances will
20 ultimately be reduced."[9] The agency concluded that both APS' and Pinnacle
21 West's stable outlook is "premised on the ACC continuing to provide sustained

[6] Standard & Poor's, "Research Update: Pinnacle West Capital's, Arizona Public Service's Ratings Lowered to 'BBB-'; Outlook Stable," December 21, 2005.
[7] Standard & Poor's, "Summary: Arizona Public Service Co.," February 15, 2006.
[8] Standard & Poor's, "Summary: Arizona Public Service Co.," May 10, 2006.
[9] Ibid.

1 regulatory support that addresses permanent rate relief and manages the deferral
2 balances downward over a reasonable time frame."

3 **Q. WHAT DO YOU CONCLUDE FROM S&P'S COMMENTS?**

4 A. S&P was encouraged by the Commission's decision in early May. But, it has
5 significant concerns about the Company's Power Supply Adjustor ("PSA") and is
6 closely watching this case for constructive regulatory treatment in order to
7 maintain APS' and Pinnacle West's ratings at existing levels.

8 **Q. HOW DOES FITCH VIEW APS?**

9 A. Like the other credit rating agencies, Fitch also downgraded APS and Pinnacle
10 West. On January 30, 2006, the agency lowered the parent's ratings to BBB- and
11 APS to BBB reflecting, in part, the Commission's January 25 decision in the
12 utility's PSA proceeding and APS' "significant exposure to high and rising
13 natural gas commodity costs."[10] Fitch applauded the removal of the PSA cost cap
14 and deferred cost recovery acceleration, but noted that the "ACC bench order
15 rejecting APS' $80 million surcharge request on procedural grounds and
16 restriction of PSA adjustments to an annual reset is less favorable than Fitch had
17 anticipated in its previous ratings and is a significant source of concern for PNW
18 [Pinnacle West] and APS fixed-income investors."[11]

19 More recently, Fitch on May 5 addressed the Commission's ruling in APS'
20 emergency rate case. It cited the Commission's "supportive response to the
21 company's request," but noted that "prior rate decisions have been less

[10] Fitch Ratings, "Fitch Lowers PNW & APS' Sr. Unsecured Ratings to 'BBB-' and 'BBB', Respectively; Outlook Stable," January 30, 2006.
[11] Ibid.

1 constructive to the credit profile of APS" and referenced Fitch's January
2 downgrade actions.[12]

3 **Q. WHAT CONCLUSIONS DO YOU DRAW FROM THE RATING**
4 **AGENCIES' REPORTS?**

5 A. All three credit agencies share a concern that the Arizona regulatory backdrop is
6 challenging and uncertain for APS. They have acted on that concern by
7 downgrading the credit ratings of the utility and its parent, with S&P moving the
8 ratings to only one notch away from below investment grade and Moody's and
9 Fitch to only two notches away. Specifically, the agencies are unanimously
10 concerned about the mounting level of the Company's deferred fuel and
11 purchased power costs due to lack of timely as well as anemic regulatory
12 decisions, the limitations of the Company's PSA and the negative toll that the
13 growing deferrals are having on APS' credit metrics. Indeed, Moody's noted the
14 need for APS to have stronger financial metrics than comparably rated utilities
15 due to the challenging regulatory environment. S&P, while encouraged by May's
16 Commission action, needs to see continued constructive regulatory treatment to
17 maintain the Company's rating at existing levels. Fitch also applauded the
18 Commission's more supportive posture recently toward APS, but implied some
19 doubt about a continuation of that trend by pointing out that prior decisions have
20 been less constructive.

[12] Fitch Ratings, "Fitch Comments on PNW Subsidiary APS's Emergency PSA Rate Order," May 5, 2006.

1 **Q. PLEASE TURN YOUR ATTENTION NOW TO THE REPORTS OF**
2 **SECURITY ANALYSTS REGARDING APS. WHAT ARE THEIR**
3 **OPINIONS ABOUT THE COMPANY'S REGULATORY**
4 **CIRCUMSTANCES?**

5 A. A number of investors have commented on APS' regulatory situation and its
6 impact on the Company's investment attractiveness. They appreciate the fact that
7 the utility faces significant capital expenditures to support customer demand in its
8 fast-growing service territory. The analysts also share the opinions of the credit
9 rating agencies that the Arizona regulatory environment is challenging and
10 uncertain.

11 **Q. WHAT ARE SOME OF THE ANALYSTS' OBSERVATIONS?**

12 A. Security analysts are largely cautious on Pinnacle West's stock because of the
13 presence of regulatory risk. For example, Morgan Stanley downgraded its
14 investment opinion to "Underweight" last September due to "more expected
15 regulatory uncertainty" in the context of Arizona's traditionally "difficult
16 regulatory environment."[13] Other brokerage firms, which rate the stock
17 "Neutral," "Equal weight," or "Hold," consistently cite APS' regulatory
18 uncertainty in supporting their investment opinion. As was true of the credit
19 rating agencies, the security analysts' concerns center on the mounting level of
20 cost deferrals relating to fuel and purchased power expense, which is compounded
21 by the Commission's failure to render decisions in a timely fashion.

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[13] Morgan Stanley, "Pinnacle West: Downgrading on More Expected Regulatory Uncertainty," September 19, 2005.

1 **Q. PLEASE ELABORATE ON SOME OF THE INVESTORS' OPINIONS.**

2 A. Lehman Brothers has repeatedly characterized the Arizona regulatory
3 environment as being challenging. In its discussion of second quarter results, the
4 investment firm recently noted: "We continue to see Arizona as a challenging
5 regulatory environment, and the GRC [General Rate Case] before the ACC as
6 providing regulatory risk overhang to the stock in the near to medium term."[14]
7 Lehman, in commenting on the ACC's May 2 decision in APS' emergency
8 request, said: "Even with this recovery, in APS' own estimation there is a 35%
9 chance of a credit downgrade to junk status by one or more of the rating agencies.
10 It seems the ACC is willing to let APS skirt the line of junk status while not
11 permanently addressing fuel recovery, and using fuel recovery proceedings as
12 leverage over the company to securitize and debate APS' other costs."[15]

13 **Q. WHAT HAVE OTHER INSTITUTIONAL INVESTORS HAD TO SAY**
14 **ABOUT APS' REGULATORY SITUATION?**

15 A. J.P. Morgan stated:
16
17 "Our focus going forward will be on the regulatory front, which is
18 expected to be challenging. Although on the surface the rate case
19 appears fairly straight forward, we continue to believe it will be a
20 challenge for the company. Not only has Arizona been a difficult
21 regulatory environment historically, the magnitude of the increase
22 combined with the April rate increase and rising commodity prices
23 may be too large politically. We are maintaining our Neutral
24 rating."[16]
25
26 Harris Nesbitt also weighed in on Arizona regulation:
27

[14] Lehman Brothers, "Pinnacle West Capital: PNW Beats Street on Growth & Weather," July 21, 2006.
[15] Lehman Brothers, "Pinnacle West Capital: Skirting the Line in Arizona," May 3, 2006.
[16] J.P. Morgan, "Pinnacle West Capital Corp.: Raising 2005E EPS; Regulatory Overhang Remains," October 27, 2005.

> "**Recommendation**: We reiterate our **NEUTRAL** rating, recognizing Arizona remains a challenging regulatory jurisdiction and PNW is in the midst of a significant rate proceeding.
>
> **Details & Analysis:** While strong customer growth remains a driving force, the pressure to serve that growing demand is expected to keep PNW before the regulators for the foreseeable future. As such, we regard regulatory uncertainty as a constant for Pinnacle West, particularly since regulation in Arizona has been less constructive relative to many other states, in our opinion, although we regard recent commission decisions (discussed below) as reasonable."[17]

Q. WHAT OPINIONS DID CITIGROUP OFFER?

A. The brokerage firm clearly conveyed that APS' ongoing exposure to regulatory risk is the dominant investment factor impacting the Company and its parent. In a January 10, 2006 report, Citigroup stated, "Our '07 target multiple is a discount to the average defensive utility multiple to account for regulatory uncertainty. Overall, we believe this target multiple reflects Pinnacle's high proportion of regulated earnings and dividend growth, offset by a weak balance sheet and potential future regulatory risk."[18] The firm more specifically and forcefully addressed APS' regulatory environment several weeks later:

> "We believe that for the near-term under-recoveries are manageable through adjustor/surcharge recoveries, cash on hand and the pending equity infusion of over $200mm of Silverhawk asset sale proceeds, which closed 1/10/06. ***However, if the ACC continues to assume equity holders will finance in perpetuity the legitimate costs incurred to deliver service to Arizona ratepayers the situation could lead to a further credit downgrade (APS is already BBB-), cause bond spreads to widen, trigger collateral calls, and materially impair the company's ability to access the equity capital markets at favorable terms.***"[19] [Emphasis added]

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[17] Harris Nesbitt, "Pinnacle West Capital, Regulatory Uncertainty Continues to Pressure the Earnings Outlook," May 11, 2006.
[18] Citigroup, January 10, 2006, op. cit.
[19] Citigroup, February 2, 2006, op. cit.

1 **Q. WHAT IS THE IMPORT OF THESE ANALYSTS' COMMENTS?**

2 A. Investors are very clear in conveying that ACC actions matter significantly. They
3 are acutely aware that APS is in the midst of a general rate case, the Company
4 continues to be in an under-recovered position for its fuel and purchased power
5 expenses and the utility's need for rate relief will be ongoing. They acknowledge
6 that regulatory risk has brought and is likely to continue to keep Pinnacle West's
7 stock under pressure and is a primary reason why the analysts remain cautious in
8 their investment posture toward the Company. Given this, it is not surprising that
9 some investors are conservative in their assumptions about the ROE award.

10 **Q. HAVE INVESTORS ALSO CONVEYED THEIR EXPECTATIONS FOR A**
11 **RETURN ON EQUITY AWARD IN THE CURRENT PROCEEDING?**

12 A. Merrill Lynch's expectation is for an 11.5% ROE award: "The outlooks remains
13 heavily dependent on the pending rate case, for which we assume jurisdictional
14 rate base of $4.4B, 50% equity and an 11.5% ROE."[20] Citigroup is assuming a
15 10.5% ROE, with a downside of 10.25%.[21] Lehman Brothers' model incorporates
16 a 10.25% ROE:

17 "The new rate base of $4.4 Billion is likely to be accepted along
18 with the Equity ratio of 54.3%, as there has yet to be a case, to our
19 knowledge, in Arizona where actual equity capitalization has
20 be[sic] denied. Pro-forma equity in some cases has been used.
21 The ROE is likely to be the item that is most at risk for reduction.
22 The table below shows the EPS sensitivity to shifts in the ROE and
23 Equity Ratio:

[20] Merrill Lynch, May 10, 2006, op. cit.
[21] Citigroup, "Pinnacle West Capital Corporation, PNW: Palo Verde 1 Appears Fixed. Rate Case Next Issue," July 13, 2006.

SHIFT	EPS SENSITIVITY
-100bp in ROE	($0.24)
-1% in equity ratio	($0.05)

1 We are maintaining our 2007 EPS guidance of $3.40. We are
2 using a 10.25% ROE, equivalent to the outcome of the prior rate
3 case, at actual equity levels, in our 2007E EPS.[22]

4 **Q. ALTHOUGH MERRILL LYNCH'S FORECAST ASSUMES AN ROE**
5 **AWARD CONSISTENT WITH THE COMPANY'S REQUEST, BOTH**
6 **CITIGROUP'S AND LEHMAN BROTHERS' EXPECTATIONS ARE**
7 **BELOW THE 11.5% LEVEL. HOW DO YOU EXPLAIN THAT**
8 **DISPARITY?**

9 A. It is not surprising that some investors are conservative in their assumptions about
10 the ROE award. The estimated ROE allowances of Citigroup and Lehman
11 represent the floor of a range of expected allowances from 10.25%-12% that
12 investors would consider to be reasonable. Lehman expressly states that its
13 estimate is equivalent to the outcome of APS' last general rate case. Further, the
14 analysts' assumptions reflect uncertainty about the supportiveness of Arizona
15 regulation, particularly in the current climate of rising energy prices and interest
16 rates. Thus, they are likely erring on the side of conservatism in anticipating this
17 case's outcome. Indeed, this regulatory uncertainty is also reflected in Lehman's
18 recent ranking of state utility commissions from an investor perspective. That is
19 part of the reason that Lehman's 10.25% ROE is at the bottom of the expected
20 range of outcomes. Arizona's ranking of "Tier 5" has remained consistent in
21 Lehman's annual regulatory studies since the publication commenced in 2004.[23]

[22] Lehman Brothers, July 21, 2006, op. cit.
[23] Lehman Brothers, "They're Back! Twenty-Six Rate Cases This Year Give Rise to the Regulators," March 5, 2004; and "Hurry Up and Wait: 41 Rate Cases in Next Two Years as Companies Strive to Avoid Regulatory Lag," April 19, 2005.

1 **Q. DID LEHMAN COMMENT FURTHER ON ROE AWARDS IN**
2 **GENERAL?**

3 A. Yes. The firm presented projections for annual allowed returns on equity for the
4 industry for 2006 through 2010. For this period, Lehman is estimating an 11.3%
5 ROE award for each of those years. The firm notes, however, that "Primarily
6 because of regulatory lag and increased financing expenses, utilities suffer subpar
7 returns during periods of heavy capital investment." Further, "...as the sector
8 becomes FCF [free cash flow] neutral (by late 2005), utilities tend to earn 225 bps
9 [basis points] below their allowed ROEs. . . . As FCF trends downward through
10 2007, this implies more substantial under-earning over the next few years."
11 Lehman's projections of projected earned ROEs are: 2006, 9.02%; 2007, 8.71%;
12 2008, 9.13%; 2009, 9.57%; and 2010, 9.83%.[24]

13 **Q. WHAT ARE THE IMPLICATIONS OF LEHMAN'S INDUSTRY ROE**
14 **ANALYSIS FOR APS' REQUESTED ROE?**

15 A. There are several points to be made. First, the firm is projecting an 11.3%
16 average allowed ROE for the industry over each of the next five years. That
17 projection reinforces the likelihood that both Lehman's and Citigroup's ROE
18 estimates for the Company are conservative and represent the low end of the
19 range and that Merrill's projection of an 11.5% ROE is at the upper end of a band
20 of 10.25%-11.5% expected by investors. Second, Lehman is anticipating an
21 allowed ROE level of 11.3% over each of the next five years, but an earned ROE
22 ranging from 143 basis points on the high end (2010) to 259 basis points on the
23 low end (2007) below the allowed ROE due to cash flow pressures. The

[24] Lehman Brothers, "Capital Lessons," op. cit.

Company's free cash flow is already being pressured by significant spending on transmission and distribution infrastructure as well as by deferred fuel and purchased power expenses. In that context, the lower the return on equity that APS is *allowed*, the lower the *earned* return on equity that will actually be achieved.

IV. POWER SUPPLY ADJUSTOR

Q. YOU'VE STATED THAT BOTH THE CREDIT RATING AGENCIES AND SECURITY ANALYSTS ARE CONCERNED ABOUT APS' RISING LEVEL OF DEFERRED FUEL AND PURCHASED POWER COSTS. PLEASE ELABORATE ON THAT.

A. Recovery of fuel and purchased power costs—essential expenditures in providing electricity to customers and a major component in a utility's cost structure—is a key issue to investors. In a study I conducted for the Edison Electric Institute last year on investor perceptions of various state regulatory issues, over half the analysts believe that recovering these expenses should occur on a regular, ongoing basis without deferrals and that regulatory mechanisms should be in place to handle recovery. The remaining investors don't disagree with that opinion, but expressed worries about fuel recovery due to "sticker shock" and potential subsequent prudence reviews because of high commodity prices and increased political motivation of regulators. As to purchased power cost, the respondents also endorsed recovery, saying it was a "legitimate expense" and a "fixed obligation" that should be recovered on an "ongoing basis, with routine updating of cost."[25] The difficulty that APS continues to experience in obtaining timely

[25] J.M. Cannell, Inc., "State Utility Regulation: An Assessment of Investor Perceptions," August 2005.

1 recompense for these major elements of its cost structure, and the pressure that
2 brings to bear on the Company's financial well-being, are of paramount concern
3 to investors and a major investment negative.

4 **Q. PLEASE COMMENT ON INVESTORS' VIEWS OF THE COMPANY'S**
5 **CURRENT MECHANISM FOR FUEL AND PURCHASED POWER**
6 **RECOVERY.**

7 A. Investors, while applauding the adoption of a mechanism in APS' 2005 rate case
8 permitting some level of fuel and purchased power cost recovery (Arizona
9 previously had been one of only a limited number of states without a recovery
10 vehicle), have also recognized the limitations of the PSA.

11 **Q. DO INVESTORS' CONCERNS ABOUT THE PSA IMPACT THEIR**
12 **ASSESSMENT OF THE RISKS OF EITHER BUYING PINNACLE WEST**
13 **STOCK OR LENDING MONEY TO APS FOR ITS CAPITAL NEEDS?**

14 A. Yes. Investors almost universally rate Pinnacle West's investment attractiveness
15 neutrally, with concerns about adequate and timely cost recovery widely stated as
16 a reason for that posture. Credit rating agencies share the same concerns.

17 **Q. IN ITS FILING, APS HAS RECOMMENDED SEVERAL CHANGES TO**
18 **THE PSA. WOULD THOSE CHANGES ADDRESS THE CONCERNS**
19 **BEING RAISED BY THE INVESTMENT COMMUNITY?**

20 A. Yes, I believe they would. In particular, elimination of the $776 million fuel cost
21 cap or raising it substantially as APS suggests would remove much of the
22 uncertainty perceived as to whether prudently incurred expenses above that level
23 are recoverable. Changing the cumulative 4-mill cap on the annual PSA
24 adjustment to an annual 4-mill cap would also permit much more timely and
25 routine recovery of fuel and purchased power costs. While I personally am not

1 conversant with the details of the PSA and its specific problems, I do believe that
2 these changes to the PSA would address several investor concerns by providing
3 more certain and timely recovery of fuel and purchased power expenses.

4 **Q. ARE THERE ADDITIONAL INFERENCES TO BE DRAWN FROM**
5 **INVESTORS' VIEWS OF THE COMPANY?**

6 A. Yes. One of the key factors analysts use to evaluate the quality of a regulatory
7 climate is the consistency of a commission. Investors value certainty and
8 predictability; a lack of consistency in a commission's decisions serves to
9 increase the investment risk associated with the Company. Investors are unable to
10 anticipate reliably the future actions of a commission which has an unpredictable
11 track record of regulatory decisions. That in turn depresses valuations—i.e.,
12 lowers the price of a stock—or increases a company's cost of borrowing. In the
13 state regulatory perception study I previously cited, respondents were asked to
14 cite the regulatory factors they felt characterized a constructive environment as
15 well as a non-constructive environment. On the positive side of the ledger, one of
16 the top set of factors, comprising 18% of total responses, was a regulatory climate
17 that is "fair, stable, predictable, and consistent." The top factor cited by the
18 respondents as characterizing a non-constructive environment (45% of replies)
19 was a climate that is "arbitrary, inconsistent, and unwilling to acknowledge the
20 economic realities that utilities face." One investor summed up that type of non-
21 constructive regulation as "regulatory purgatory."[26]

[26] Ibid.

1 **Q. PLEASE SUMMARIZE THE PERSPECTIVE OF SECURITY ANALYSTS**
2 **AND OTHERS REPRESENTING THE INVESTOR VIEWPOINT ON THE**
3 **ARIZONA REGULATORY ENVIRONMENT AS IT RELATES TO APS.**

4 A. There is a general perception among investors that the regulatory environment in
5 which the Company operates is characterized by risk and uncertainty. Security
6 analysts are keenly aware that APS is facing not only a general rate case this year,
7 but also ongoing regulatory exposure in recovering deferred fuel and purchased
8 power costs. Accordingly, they have a cautious view on Pinnacle West's stock.

9 **Q. HOW DOES THIS VIEW OF REGULATORY UNCERTAINTY IMPACT**
10 **THIS CASE?**

11 A. Uniformly, the rating agencies and investment analysts viewed positively the
12 Commission's decisions in late January and early May of this year. It is equally
13 obvious, however, that they are carefully watching this case to see if the
14 Commission will continue to address positively APS' credit metrics, problems
15 with the PSA and the quantity and quality of APS' earnings. Favorable rulings on
16 case issues such as strengthening the PSA will show consistency with these earlier
17 decisions and are particularly critical given APS' shaky credit ratings.

18 **V. <u>RETURN ON EQUITY FOR APS</u>**

19 **Q. HOW DO YOU BELIEVE APS' REQUESTED RETURN ON EQUITY OF**
20 **11.5% COMPORTS WITH INVESTORS' PERCEPTIONS?**

21 A. The investment community would find an 11.5% ROE supportive for the
22 Company. It is within the range of investors' expectations for ROE allowances in
23 2006 and particularly appropriate for APS at this time for the reasons I just
24 discussed.

1 Q. **IN THE CURRENT LOW INTEREST RATE ENVIRONMENT, DO YOU**
2 **CONSIDER INVESTORS' EXPECTATIONS REGARDING THE**
3 **COMPANY'S PROSPECTIVE ROE AWARD TO BE REASONABLE?**

4 A. Yes, I do. Interest rates, though recently having reached historically low levels,
5 are once again rising. And the interest rate factor is not the only one that
6 investors are taking into account. Because of the greater risks that the industry is
7 facing, investors are now requiring a higher risk premium generally on their
8 utility investments. For APS, they see additional regulatory risk and, of course,
9 are well aware that it stands on the precipice of a non-investment grade rating.
10 An anemic ROE award at the current time would quickly reverse the earnings
11 prospects for the utility and eliminate the progress achieved in this year's
12 decisions. With already limited financial flexibility and an existing weak cash
13 flow situation relative to its investment grade status, APS' need to access the
14 capital markets will become greater as the risk of credit downgrades becomes
15 even more pronounced which, in turn, will result in a vicious negative cycle.

16 Q. **WILL A RETURN ON EQUITY AWARD THAT IS CONSISTENT WITH**
17 **INVESTOR EXPECTATIONS ALSO PROVIDE BENEFITS TO APS**
18 **CUSTOMERS?**

19 A. Absolutely. A higher ROE permits the realization of a stronger earnings stream.
20 In turn, that improves Pinnacle West's stock valuation prospects, which results in
21 a higher stock price. Thus, when APS needs to tap the equity markets for capital
22 needed to meet customer needs, it gets more for its money. Said another way,
23 each share sold brings more equity into the Company with the same commitment
24 by the Company to generate earnings and pay dividends to support the value of
25 that share. In regard to debt financing, a higher ROE awarded to APS would be

1 viewed as a sign of constructive regulation and would be positive for the
2 Company's credit rating. Importantly, in both cases, customers' rates will reflect
3 this lower cost of capital.

4 **Q. FINALLY, ARE YOU FAMILIAR WITH THE RECENT PROPOSAL TO**
5 **CREATE A SO-CALLED RATE STABILIZATION FUND?**

6 A. I have read the exchange of correspondence between Commissioner Mayes and
7 Mr. Davis on that subject.

8 **Q. DO YOU HAVE ANY REACTION TO THIS PROPOSAL FROM AN**
9 **INVESTOR'S PERSPECTIVE?**

10 A. As I understand it, this proposal would require company shareholders to assume a
11 portion of the costs directly incurred by utility customers in their consumption of
12 electricity. As a general proposition, such a regulatory policy would be viewed
13 very negatively by investors and rating agencies. Specifically, this proposal
14 would further undermine the earnings of a company whose actual ROE is far
15 below what has been authorized by this Commission and about half of the
16 national average for the industry.

17 **Q. DOES THIS COMPLETE YOUR TESTIMONY?**

18 A. Yes.

Exhibit JMC-1

JULIE M. CANNELL
P.O. Box 199
Purchase, New York 10577

BUSINESS EXPERIENCE:

1997- J.M. CANNELL, INC.

President of firm providing advisory services specializing in the electric utility industry.

1977-1997 LORD ABBETT & COMPANY, New York, New York

1995-1997 Equity Portfolio Manager. Responsibility for management and client servicing of ten institutional equity portfolios with total assets in excess of $700M. Actively and successfully involved in new institutional business marketing effort.

1994-1996 Associate Director of Equity Research. Provided oversight of departmental activities, including supervision of analysts' research efforts and support staff functions.

1992-1995 Portfolio Manager, America's Utility Fund. Full portfolio management responsibility for the fund since its May 1992 inception.

1978-1995 Securities Analyst. Sole responsibility for analysis of and stock recommendations for the electric utility and telecommunications industries. Other areas of coverage previously included housing (2 years) and pollution control (1 year).

Summer 1977 Research Assistant in Utilities.

1973-1976 UNIVERSITY OF COLORADO, Colorado Springs, Colorado

Public Services Librarian
Instructor in Bibliography to undergraduate and M.B.A. students

1971-1973 CAMERON COLLEGE, Lawton, Oklahoma.

Reference Librarian

EDUCATION:

1978	COLUMBIA UNIVERSITY, MBA - Finance
1971	EMORY UNIVERSITY, M.Ln. - Librarianship
1970	MARY BALDWIN COLLEGE, B.A. - English

MEMBERSHIPS:

Chartered Financial Analyst (C.F.A.)
CFA Institute
New York Society of Security Analysts
Wall Street Utility Group

REBUTTAL TESTIMONY OF JULIE M. CANNELL

On Behalf of the Arizona Utility Investors Association

Docket No. E-01345A-05-0816

September 15, 2006

EXHIBIT
AUIA-2
admitted

TABLE OF CONTENTS

Page

REBUTTAL SUMMARY 1

POWER SUPPLY ADJUSTOR 2

RETURN ON EQUITY 4

REBUTTAL TESTIMONY OF JULIE M. CANNELL
ON BEHALF OF ARIZONA UTILITY INVESTORS ASSOCIATION
(Docket No. E-01345A-05-0816)

Q. PLEASE STATE YOUR NAME AND BUSINESS AFFILIATION.

A. My name is Julie M. Cannell. I am president of J.M. Cannell, Inc.

Q. DID YOU PREVIOUSLY SUBMIT DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes. My direct testimony was submitted on behalf of the Arizona Utility Investors Association on August 18, 2006.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. I will respond to the return on equity ("ROE") and Power Supply Adjustor ("PSA") recommendations of the Arizona Corporation Commission Staff and the Residential Utility Consumer Office ("RUCO").

REBUTTAL SUMMARY

Q. PLEASE SUMMARIZE THE KEY POINTS OF YOUR REBUTTAL TESTIMONY.

A. While investors and, I believe, the rating agencies have responded or will respond positively to their positions on changes to the PSA, the respective 10.25% and 9.25% ROE recommendations of Commission Staff and RUCO do not meet the expectations of investors. As noted in my direct testimony, institutional investors specifying an ROE assumption for their earnings models originally weighed in at 11.5%, 10.5% and 10.25%. Recently published analyst reports providing ROE expectations brought the lower end of that range up to 10.5%. Further, it is likely that investors expect the final ROE award to be at the high end of that range given

the facts, among others, that: (1) Arizona Public Service Company ("APS" or "Company") financial position is weak; (2) the Company remains just one step above a non-investment grade rating; (3) the utility sector generally is viewed as more risky today than historically; and (4) interest rates are rising. A constructive ROE decision in this case—particularly in light of APS' enormous near-term capital needs—is absolutely vital. Should investors' expectations fail to be met on Pinnacle West's potential for growth in earnings and dividends, the cost of capital to the Company and the cost of service to ratepayers will increase dramatically.

POWER SUPPLY ADJUSTOR

Q. ARE INVESTORS CONCERNED ABOUT WEAKNESSES IN THE COMPANY'S CURRENT PSA MECHANISM AND ITS ABILITY TO RECOVER PRUDENTLY INCURRED FUEL AND PURCHASED POWER EXPENSES?

A. Yes. As I discussed in my direct testimony, fuel and purchased power cost recovery is a key issue for investors. A consistent theme throughout rating agency and analyst's negative reports and downgrades has been concerns about the Company's ability to recover on a timely basis this major cost element and need for improvements in the PSA. For example, after this Commission's Decision four months ago authorizing approximately $140 million in additional recoveries, Standard & Poor's stated it was maintaining APS' rating at just one level above non-investment grade premised upon the Commission "continuing to

provide sustained regulatory support that addresses permanent rate relief and manages the [PSA] deferral balances downward over a reasonable time frame."[1]

Q. IN THEIR TESTIMONIES, THE STAFF AND RUCO HAVE SUPPORTED CHANGES IN THE COMPANY'S CURRENT PSA MECHANISM. DO YOU BELIEVE THOSE CHANGES ARE RESPONSIVE TO INVESTORS' CONCERNS?

A. As I stated specifically in my direct testimony, I would stress that I am not familiar with the details of APS' PSA and its specific problems, but I believe Staff's and RUCO's positions are the kind of "sustained regulatory support" which investors are expecting. In the case of Staff's recommendations, UBS called them "Constructive suggestions on fuel cost recovery."[2] Bank of America expressed similar views: "[I]t is good to know that [Staff is] continuing to think about ways that could help narrow the regulatory lag between decisions and make the [PSA] mechanism more efficient."[3] While I'm not aware of any published comment on the RUCO PSA positions, I believe that its endorsement of three of the four changes to the PSA recommended by APS in its direct testimony was also viewed positively. The large unrecovered fuel and purchased power balances were a major contributing factor to the rating agency downgrades just a few months ago and it is vital that the Commission address them structurally in this case.

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[1] Standard & Poor's, "Summary: Arizona Public Service Co.," May 10, 2006.
[2] UBS, "The Rate Case Moves Forward," August 21, 2006.
[3] Bank of America, "Company News," August 21, 2006.

RETURN ON EQUITY

Q. ARE THE ROE RECOMMENDATIONS OF THE COMMISSION STAFF AND RUCO CONSISTENT WITH INVESTOR EXPECTATIONS?

A. Commission Staff Witness David Parcell proposed a 10.25% ROE and RUCO Witness Stephen Hill supported a 9.25% equity return. Neither is consistent with investors' expectations as to an appropriate ROE.

Q. HAVE INVESTOR EXPECATIONS CHANGED SINCE YOUR DIRECT TESTIMONY WAS FILED?

A. They have become slightly more optimistic about a positive outcome on this aspect of this case. As noted in my direct testimony, several investors expressly stated their expectations of ROE awards in this rate proceeding: Merrill Lynch, 11.5%; Lehman Brothers, 10.5%; and Citigroup, 10.25%. Importantly, Citigroup increased its ROE expectation from 10.25% to 10.875%, as a result of the Commission Staff's filed testimony. I believe that 10.5% now represents the floor of a range of expected allowances from 10.5% to 12% that investors consider to be reasonable. Lehman Brothers put it this way: "The [ROE] recommendations [of ACC Staff and RUCO] mark the likely worst case in this proceeding. We view fair treatment by the ACC as essential to APS' investment grade rating and attraction to equity investors."[4]

Q. HOW CRITICAL IS THIS CASE TO APS' FINANCIAL HEALTH AND ITS ABILITY TO DELIVER SERVICE TO CUSTOMERS AT REASONABLE RATES?

A. Very. As discussed extensively in my direct testimony, changes in the investment industry itself, its views of the risks of the utility sector generally and APS

[4] Lehman Brothers, "Pinnacle West Capital: Staff Testimony as Expected," August 21, 2006.

specifically as well as APS' need for large amounts of capital to finance system growth make this a uniquely important case. APS' credit metrics are shaky and it faces the very real and continuing risk of further downgrades to below investment grade. Lehman reinforced the critical importance of the current proceeding in its analysis of the Staff and RUCO recommendations: "Should the final order reflect financial parameters approximating these filings, it would be difficult for Arizona Public Service (APS), the utility subsidiary of Pinnacle West Capital Corp., to maintain investment grade ratings or provide support for the current stock value in our view. While Arizona has historically been a very difficult jurisdiction for investors, we look for a final ACC order in 2Q of 2007 to significantly improve upon Friday's [Staff and RUCO] filings."[5]

Q. WHY IS THE RANGE OF INVESTOR ROE FORECASTED OUTCOMES SO BROAD?

A. As discussed in my direct testimony, some investors are conservative in their assumptions about the ROE award. While the Commission Staff's recommendation was better than many had expected, analysts and rating agencies remain concerned about the supportiveness of Arizona regulation, particularly in the current climate of rising energy prices. I continue to believe that investors are erring on the side of conservatism in their projections regarding this case's outcome.

[5] *Ibid.*

Q. ALTHOUGH YOU BELIEVE THAT BOTH THE COMMISSION STAFF'S AND RUCO'S ROE RECOMMENDATIONS ARE BELOW THE LEVEL OF INVESTOR EXPECTATIONS, DO YOU DRAW ANY DISTINCTION BETWEEN THE TWO PROPOSALS?

A. Yes. Mr. Parcell's recommendation of 10.25% is far more sound and constructive than Mr. Hill's, and only slightly below the current level of investor expectations. In fact, Citigroup increased its ROE assumption from 10.25% to 10.875% on the basis of Staff's recommendation: "Staff's testimony regarding rate base, capital structure, and return were more constructive than expected. . . . . *We think Staff's testimony eases down-side of our previous "bid-ask" spread on earnings.* . . . Our forecast assumes that APS ultimately will earn a mid-point allowed ROE of 10.875% on a 54.5% equity ratio."[6] (Italics in original.)

Mr. Hill's proposed 9.25% ROE, however, does not even approach levels that investors would find acceptable. Additionally, Mr. Parcell supports the Company's actual capital structure which has a 54.5% equity ratio, while Mr. Hill proposes a hypothetical equity ratio of only 50%.

Q. PLEASE COMMENT ON THE RATIONALE MR. HILL OFFERS FOR CONCLUDING THAT A 9.25% ROE WOULD BE REASONABLE FOR APS.

A. In my opinion, Mr. Hill's basic premise of the Company having lower financial risk than a peer group is faulty. His testimony states: "I have estimated the equity capital cost of integrated electric utility companies to fall in a range of 9.25% to 9.75%. Within that range, I estimate the equity cost of the Company's

[6] Citigroup, "Pinnacle West Capital Corporation: PNW: Staff GRC Testimony Looks Constructive; Raising Target Price," August 21, 2006.

electric utility operations to be at the lower end of a reasonable range of equity costs for electric utilities due to the Company's lower financial risk—9.25%"[7]

Q. DOES MR. HILL'S LOWER FINANCIAL RISK ASSESSMENT ACCURATELY REFLECT THE VIEWS OF CREDIT RATING AGENCIES AND INVESTORS?

A. No. It totally disregards reality as well as the expressed opinions of credit rating agencies and investors. The Company is perilously close to a further credit rating downgrade which would place it in non-investment grade territory. As well, rating agencies and equity analysts perceive considerable regulatory risk for the Company which only adds to the financial risk. A higher risk level argues for a higher ROE, not a lower one. Mr. Hill's recommendation is precisely not the outcome that investors want to see from the Commission in this case. As my direct testimony noted, analysts were encouraged by the Commission's May 2 Decision in the Company's emergency rate case, but indicated they are watching closely for a continuation of constructive regulatory treatment. Adoption of Mr. Hill's 9.25% recommendation clearly would not be regarded as supportive.

Q. WHAT IMPACT WOULD A DISAPPOINTING ROE DECISION LIKELY HAVE?

A. An equity return decision that investors consider to be subpar would have a very deleterious impact. An inadequate outcome for risk compensation would most likely result in their unwillingness to extend capital, or to make it available at reasonable prices, during a period when APS will frequently need to access the capital markets for billions of dollars. That result will be bad for the Company

[7] Stephen G. Hill, Direct Testimony on Behalf of the Residential Utility Consumer Office, August 18, 2006, p. 3.

1 and the customer. Both are negatively impacted when APS can't access the debt
2 and equity markets on reasonable terms. With unnecessarily weak financials, the
3 Company's need to access the capital markets could become greater as the risk of
4 credit downgrades becomes even more pronounced, which, in turn, results in a
5 vicious negative cycle. That inadequate return would force the Company to
6 return prematurely to the Commission with the need for another rate increase.

7 **Q. DOES THIS COMPLETE YOUR REBUTTAL TESTIMONY?**

8 A. Yes.

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

JEFF HATCH-MILLER, Chairman
WILLIAM A. MUNDELL
MIKE GLEASON
KRISTIN K. MAYES
BARRY WONG

EXHIBIT
tabbies
SWEEP-1
admitted

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 RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND TO AMEND DECISION NO. 67744.	DOCKET NO. E-01345A-03-0816

Direct Testimony of

Jeff Schlegel
Southwest Energy Efficiency Project (SWEEP)

August 18, 2006

Direct Testimony of Jeff Schlegel, SWEEP
Docket No. E-01345A-03-0816

Table of Contents

Introduction	1
Summary of Testimony and Recommendations	2
The Public Interest: Benefits of Increasing Energy Efficiency in the APS Service Territory	4
The Energy Efficiency Standard (EES): Goals for Energy Savings and Peak Demand Reduction	4
SWEEP Estimate of Energy Savings and Funding for the APS Service Territory	6
Funding to Achieve the Energy Efficiency Standard (EES) Goals	6
DSM Funding and Cost-Recovery Mechanisms	7
Development of an EES Implementation Plan for the APS Service Territory	9
Other DSM and Pricing Approaches	9

List of Exhibits

SWEEP Energy Efficiency Program Goals and EES	JS-1
SWEEP Estimates of APS DSM Energy Efficiency Costs Per Customer	JS-2

Introduction

Q. Please state your name and business address.

A. My name is Jeff Schlegel. My business address is 1167 W. Samalayuca Drive, Tucson, Arizona 85704-3224.

Q. For whom and in what capacity are you testifying?

A. I am testifying on behalf of the Southwest Energy Efficiency Project (SWEEP). I am the Arizona Representative for SWEEP.

Q. Please describe the Southwest Energy Efficiency Project.

A. SWEEP is a public interest organization dedicated to advancing energy efficiency as a means of promoting both economic prosperity and environmental protection in the six states of Arizona, Colorado, New Mexico, Nevada, Utah, and Wyoming. SWEEP works on state energy legislation, analysis of energy efficiency opportunities and potential, expansion of state and utility energy efficiency programs as well as the design of these programs, building energy codes and appliance standards, and voluntary partnerships with the private sector to advance energy efficiency. SWEEP is collaborating with utilities, state agencies, environmental groups, universities, and energy specialists in the region. SWEEP is funded primarily by foundations, the U.S. Department of Energy, and the U.S. Environmental Protection Agency. I am the Arizona Representative for SWEEP.

Q. What are your professional qualifications?

A. I am an independent consultant specializing in policy analysis, evaluation and research, planning, and program design for energy efficiency and clean energy resources. I consult for public groups and government agencies, and I have been working in the field for over 20 years. In addition to my responsibilities with SWEEP, I am working or have worked extensively in many of the states that have effective energy efficiency programs, including California, Connecticut, Massachusetts, New Jersey, Vermont, and Wisconsin. In 1997, I received the Outstanding Achievement Award from the International Energy Program Evaluation Conference. I have represented SWEEP before the Commission since 2002.

Summary of Testimony and Recommendations

Q. Please summarize your testimony.

A. I will testify that:

- The Commission should increase energy efficiency in the Arizona Public Service Company (APS) service territory to achieve significant and cost-effective benefits for APS customers, the electric system, the economy, and the environment.

- Specifically, the Commission should set APS Demand Side Management (DSM) energy efficiency program goals in the form of an Energy Efficiency Standard (EES). The EES should require APS DSM energy efficiency programs to: (1) achieve energy savings equal to at least 5% of total energy resources needed to meet retail load in 2010, and at least 15% in 2020; and (2) reduce summer peak demand by at least 5% of total capacity resources needed to meet retail peak demand in 2010, and at least 15% in 2020. The goals of the EES are meaningful and realistic, and they can be achieved with cost-effective energy efficiency programs.

- Achieving the goals of the Energy Efficiency Standard would save consumers and businesses $1.4 billion during 2005-2020, eliminate the need for about 1,000 MW of new power plants by 2020 and the associated power line and pipeline infrastructure costs, provide 1,600 GWh of cumulative annual energy savings in 2010 and almost 7,000 GWh in 2020, reduce average annual load growth in retail energy and summer peak demand by 32% (from 3.8% to 2.6%), reduce electricity price spikes and the risks of natural gas price volatility, and reduce air pollution and the carbon emissions that cause global warming.

- Other states and utilities have achieved energy savings equivalent to or greater than the EES goals that SWEEP proposes.

- The existing Commission-approved DSM energy efficiency programs should be expanded to achieve the goals of the EES. While some additional DSM energy efficiency programs or program elements may be needed to achieve the EES goals, and may also be valuable for providing additional benefits to APS customers, the primary mechanism for achieving the EES goals should be the expansion of existing programs already approved by the Commission.

- The performance to date of the recently-approved APS DSM energy efficiency programs has been very good, and the programs are providing significant net benefits (over $4.2 million of net economic benefits in 2005).

- The Commission should authorize adequate funding to achieve the goals of the Energy Efficiency Standard (EES). SWEEP estimates that energy efficiency funding of $0.002 per kWh of retail energy sales (2 mills) will be necessary to achieve the EES goals. In 2007, the third year of the 2005-2007 Portfolio Plan, total DSM energy efficiency funding should be increased from about $25 million to $38 million, an increase of about $13 million. In 2008 and future years, total DSM energy efficiency funding should be equivalent to $0.002 (2 mills) per kWh of retail energy sales, which would be $56.8 million in 2008. The additional DSM funding for 2008 would amount to $40.8 million (the amount above the $16 million per year authorized in Decision No. 67744). Funding for any DSM demand response and load management programs should be in addition to the energy efficiency program funding.

- Energy efficiency funding and cost recovery for the additional DSM funding and the total DSM funding could be accomplished through funding in base rates, a DSM adjustment mechanism, a system benefits surcharge, amortizing or capitalizing the DSM investments over time, or a combination of funding mechanisms. SWEEP does not have a strong preference for one particular mechanism. SWEEP believes it would be best to build on the existing Commission-approved funding mechanisms (base rates and a DSM adjustment mechanism) and use a combination of mechanisms going forward.

- APS should file an implementation plan to achieve the goals of the EES, covering the 2008-2020 program years, in the spring of 2007, at the same time APS refiles the Non-Residential portion of its DSM Portfolio Plan (per Commission order). The EES Implementation Plan should be developed by APS with input from and review by the Collaborative DSM Working Group, which includes Staff and interested parties. The EES Implementation Plan would be reviewed by Staff, and then be reviewed and approved by the Commission prior to implementation for 2008 and future years.

- SWEEP supports complementary approaches such as demand response and load management programs to encourage peak load reductions, and pricing and rate designs to encourage energy efficiency and reduce peak demand. SWEEP supports these approaches as complements to effective energy efficiency policies and programs, not as replacements for cost-effective utility DSM energy efficiency programs.

The Public Interest: Benefits of Increasing Energy Efficiency

Q. What is the public interest in increasing energy efficiency in the APS service territory?

A. Increasing energy efficiency will provide significant and cost-effective benefits for APS customers (residential consumers and businesses), the electric system, the economy, and the environment. Increasing energy efficiency will save consumers and businesses money through lower electric bills, resulting in lower total costs for customers. Increasing energy efficiency will also reduce load growth, diversify energy resources, enhance the reliability of the electricity grid, reduce the amount of water used for power generation, reduce air pollution and carbon emissions, and create jobs and improve the economy. In addition, meeting a portion of load growth through increased energy efficiency can help to relieve system constraints in load pockets.

By reducing electricity demand, energy efficiency mitigates electricity and fuel price increases and reduces customer vulnerability and exposure to price volatility. Energy efficiency does not rely on any fuel and is not subject to shortages of supply or increased prices for natural gas or other fuels.

Energy efficiency is a reliable energy resource that costs less than other resources for meeting the energy needs of customers in the APS service territory. The total cost (sum of program and customer costs) for energy efficiency savings is two to three cents per lifetime kWh saved, delivered to the customer. This is significantly less than the cost of conventional generation, transmission, and distribution. The utility program cost to APS ratepayers is even lower, about one to two cents per lifetime kWh saved.

The Energy Efficiency Standard (EES): Goals for Energy Savings and Peak Demand Reduction

Q. Specifically, what actions should the Commission take to increase energy efficiency goals in the APS service territory?

A. The Commission should set APS Demand Side Management (DSM) energy efficiency program goals in the form of an Energy Efficiency Standard (EES). The EES should require APS DSM energy efficiency programs to: (1) achieve energy savings equal to at least 5% of total energy resources needed to meet retail load in 2010, and at least 15% in 2020; and (2) reduce summer peak demand by at least 5% of total capacity resources needed to meet retail peak demand in 2010, and at least 15% in 2020.

Meeting the EES goals would provide cost-effective benefits to consumers, the electric system, the economy, and the environment. And meeting the EES goals would contribute substantially to the achievement of the adopted goal of the Western Governors Association (WGA) to increase energy efficiency 20% by 2020.

Q. What benefits would result from achieving the EES goals?

A. Achieving the goals of the Energy Efficiency Standard would save consumers and businesses $1.4 billion during 2005-2020, eliminate the need for about 1,000 MW of new power plants by 2020 and the associated power line and pipeline infrastructure costs, provide 1,600 GWh of cumulative annual energy savings in 2010 and almost 7,000 GWh in 2020, reduce average annual load growth in retail energy and summer peak demand by 32% (from 3.8% to 2.6%), reduce electricity price spikes and the risks of natural gas price volatility, and reduce air pollution and the carbon emissions that cause global warming. See Exhibit JS-1.

Essentially, the EES would result in a 1,000 MW "efficiency power plant" that would provide $1.4 billion of net economic benefits to consumers, instead of building conventional power plants that would cost more and expose consumers to higher electricity prices, use precious water, and harm the environment.

Q. Are the goals of the EES reasonable and achievable?

A. Yes, the proposed EES goals are both reasonable and achievable. The goals are reasonable and achievable considering the low level of energy efficiency activities in Arizona in the past, the need to ramp up energy efficiency efforts in the early years, the high rate of load growth in the APS service territory, the significant energy efficiency potential in new construction, and the historical energy efficiency performance in leading states.

Q. Have other states or utilities achieved energy savings equivalent to the EES goals that SWEEP proposes?

A. Yes. According to a 2005 study by the American Council for an Energy Efficient Economy (ACEEE), based on 2003 data the utilities report to EIA, seven states achieved cumulative annual energy savings greater than 5% of retail energy sales.[1] In terms of 2003 cumulative annual energy savings as a percent of 2003 retail sales, the seven states saved energy equivalent to between 5.8% and 7.8% of retail sales. All seven of the states (Connecticut, California, Washington, Minnesota, Rhode Island,

[1] "ACEEE's Third National Scorecard on Utility and Public Benefits Energy Efficiency Programs: A National Review and Update of State-Level Activity" by D. York and M. Kushler; American Council for an Energy Efficient Economy, October 2005, Report Number U054; www.aceee.org.

Oregon, and Massachusetts) have continued their energy efficiency programs since 2003, therefore their cumulative energy savings in 2006 should be even higher.

Q. Is SWEEP proposing additional DSM energy efficiency programs to achieve the EES goals?

A. The existing Commission-approved DSM energy efficiency programs should be expanded to achieve the goals of the EES. While some additional DSM energy efficiency programs or program elements may be needed to achieve the EES goals, and may also be valuable for providing additional benefits to APS customers, the primary mechanism for achieving the EES goals should be the expansion of existing programs already approved by the Commission.

Q. Are the existing APS DSM programs performing adequately (to date) to be able to be expanded to achieve the EES goals?

A. Yes. The performance to date of the recently-approved APS DSM energy efficiency programs has been very good, and the programs are providing significant net benefits (over $4.2 million of net economic benefits in 2005). See Exhibit JS-1.[2]

SWEEP Estimate of Energy Savings and Funding for the APS Service Territory

Q. Has SWEEP prepared an estimate of the impact of the EES goals in terms of energy savings and associated funding in 2005 through 2020?

A. Yes. See Exhibit JS-1, which shows annual and cumulative annual energy savings, the impact of the energy savings on the forecast and load growth, the total and additional funding that SWEEP estimates will be necessary to achieve the goals, and the net economic benefits to customers. For example, total cumulative annual energy savings of 1,600 GWh are necessary to achieve the goal of 5% of total energy resources needed to meet retail load in 2010 from energy efficiency programs.

Funding to Achieve the Energy Efficiency Standard (EES) Goals

Q. What funding level will be needed to achieve the goals of the Energy Efficiency Standard proposed by SWEEP?

A. The Commission should authorize adequate funding to achieve the goals of the Energy Efficiency Standard (EES). SWEEP estimates that energy efficiency funding

[2] SWEEP plans to issue a data request to APS asking for a summary of DSM program performance to date, though closer to the date of the hearing so that the information will be timely and up-to-date.

of $0.002 per kWh of retail energy sales (2 mills) will be necessary to achieve the EES goals. In 2007, the third year of the 2005-2007 Portfolio Plan, total DSM energy efficiency funding should be increased from about $25 million to $38 million, an increase of about $13 million. In 2008 and future years, total DSM energy efficiency funding should be equivalent to $0.002 (2 mills) per kWh of retail energy sales, which would be $56.8 million in 2008. The additional DSM funding for 2008 would amount to $40.8 million (the amount above the $16 million per year authorized in Decision No. 67744).

Note that to meet the $48 million funding requirement for 2005-2007 ordered in Decision No. 67744, APS will need to increase expenditures above $16 million in 2006 and 2007 (given that APS spent less than $16 million in 2005).

Funding for any DSM demand response and load management programs should be in addition to the energy efficiency program funding..

Q. What would be the impact of the total funding level on residential customers?

A. The total energy efficiency funding level of $0.002 per kWh of retail energy sales (2 mills), if expensed annually, would amount to about $2.26 per month for the average APS residential customer, based on the test year (see Exhibit JS-2). The incremental increase due to the additional DSM funding, if expensed annually, would be $1.61 per month for the average APS residential customer (from $0.65 per month for a funding level of $16 million to $2.26 per month for the test year based on a total funding rate of $0.002 per kWh of retail energy sales).

While rates would increase slightly, the total costs to customers (bills) would decrease due to investment in cost-effective energy efficiency.

DSM Funding and Cost-Recovery Mechanisms

Q. Which DSM funding and cost-recovery mechanisms should be used to provide the additional DSM funding that will be needed to achieve the goals of the EES?

A. In general, energy efficiency funding and cost recovery could be accomplished through funding in base rates, a DSM adjustment mechanism, a system benefits surcharge, amortizing or capitalizing the DSM investments over time, or a combination of funding mechanisms.

For APS, the Commission previously authorized a two-part DSM funding and cost-recovery mechanism, with one portion of the DSM funding in base rates ($10 million) and the second portion of the DSM funding (at least $6 million) recovered using a

DSM adjustment mechanism (for the amount in excess of the base rate DSM allowance).

The two-part approach is adequate for the current level of authorized DSM funding. The Commission could choose to expand the current two-part approach or build upon it by using an additional funding mechanism for some or all of the additional funding needed to meet the goals of the EES.

Q. Are there DSM funding and cost-recovery mechanisms that would reduce the rate impacts of the DSM program funding increase in the early years of the EES?

A. Yes. The Commission could choose to amortize or capitalize a portion of the DSM expenditures, similar to how investments in power plants are recovered through customer rates over time, thereby reducing the customer rate impacts of DSM programs in the early years of the EES. For example, the Commission could spread the additional DSM costs to ratepayers across several years (e.g., 5 years) in a manner that acknowledges that the energy efficiency benefits are achieved over several years.

Q. Could a combination of DSM funding and cost-recovery mechanisms be used?

A. Yes. For example, the APS DSM energy efficiency funding of $38 million in 2007 could consist of $10 million in base rates (or possibly more depending on the 2005 base rate accrual),[3] $6 million recovered through the DSM adjustment mechanism, and the additional amount of up to $22 million (depending on the accrual of the 2005 base rates) recovered through an expansion of the existing DSM adjustment mechanism. The DSM energy efficiency funding of $56.8 million in 2008 could consist of $10 million in base rates, $16.8 million recovered through an expansion of the existing DSM adjustment mechanism, and the additional $30 million amortized over five years.

Q. Does SWEEP have a preference for a particular funding and cost-recovery mechanism in this case?

A. SWEEP is open to considering any of the above funding and cost-recovery mechanisms and combinations. SWEEP does not have a strong preference for one particular mechanism. However, any funding mechanism or combination of mechanisms should have, at a minimum, the same advantages of the two-part base rate and DSM adjustment mechanism approach in place at APS now, including but not limited to the flexibility to adjust funding outside of a rate case to meet customer

[3] In order to meet the $48 million spending requirement in 2005-2007 (Decision No. 67744), APS will need to accrue or carry forward the unexpended portion of the $10 million in base rates from 2005 for use in the 2006 or 2007 program years.

demand for cost-effective, Commission-approved DSM services, and the ability to increase DSM funding above a base amount in the event that additional DSM programs are approved by the Commission between rate cases. In addition, SWEEP believes it would be best to build on the existing funding mechanisms and use a combination of mechanisms, as in the examples above, rather than implementing a new mechanism for 100% of the DSM funding.

Development of an EES Implementation Plan for the APS Service Territory

Q. Should an EES implementation plan for the APS service territory be developed?

A. Yes. APS should file an implementation plan to achieve the goals of the EES, covering the 2008-2020 program years, in the spring of 2007, at the same time APS refiles the Non-Residential portion of its DSM Portfolio Plan (per Commission order). The EES Implementation Plan should be developed by APS with input from and review by the Collaborative DSM Working Group, which includes Staff and interested parties.

The EES Implementation Plan should include the historical DSM results for 2005-2006, and should include a forecast for the expansion of the existing Commission-approved DSM energy efficiency programs in 2007. The expansion of approved DSM programs in 2007 should proceed as a result of the order in this proceeding, and should not be postponed for the development, review, and Commission approval of the EES Implementation Plan (which should cover 2008-2020 DSM programs).

Q. What about Staff review and Commission approval of the EES Implementation Plan?

A. The EES Implementation Plan should be reviewed by Staff, and then be reviewed and approved by the Commission prior to implementation for 2008 and future years.

Since Staff will participate directly in the development of the EES Implementation Plan as part of the DSM Collaborative Working Group, SWEEP recommends that the Commission provide 60 days for Staff review of the EES Plan after it is filed by APS.

Other DSM and Pricing Approaches

Q. Are there other approaches to achieving energy savings and peak demand reductions that SWEEP recommends?

A. Yes. SWEEP supports complementary approaches such as demand response and load management programs to encourage peak load reductions, and pricing and rate designs to encourage energy efficiency and reduce peak demand. SWEEP supports

these approaches as complements to effective energy efficiency policies and programs, not as replacements for cost-effective utility DSM energy efficiency programs.

Any proposed demand response and load management programs should be described and documented in the DSM EES plan or in a separate application for program pre-approval. Funding for demand response and load management programs should be in addition to the increased DSM energy efficiency funding set forth herein. Costs for the demand response and load management programs could be recovered through a demand response tariff or through an increase in the DSM adjustment mechanism.

Q. Does that conclude your direct testimony?

A. Yes.

SWEEP Energy Efficiency Program Goals: Energy Efficiency Standard (EES) of 5% by 2010 and 15% by 2020

Comparison of Base Case vs. Energy Efficiency Standard (EES) Case for the APS Service Territory

Exhibit JS-1
August 2006

	SWEEP Proposal for EES ----->	2002	2003	2004	2005	2006	2007	2008	2009	5% Goal 2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	15% Goal 2020
1	**Base Case Retail Energy Sales (GWh)**	23,373	24,564	25,281	26,113	27,105	28,135	29,204	30,314	31,466	32,662	33,903	35,191	36,529	37,917	39,358	40,853	42,406	44,017	45,690
2	**Annual Growth Rate (%)**		5.1%	2.9%	3.3%	3.8%	3.8%	3.8%	3.8%	3.8%	3.8%	3.8%	3.8%	3.8%	3.8%	3.8%	3.8%	3.8%	3.8%	3.8%
					3.8%	Average annual growth 2002-2005				**3.8%**	Average annual growth 2006-2010						Average annual growth 2006-2020 =			**3.8%**
3	**Energy Savings Goal (% of forecast)**				0.09%	0.47%	0.90%	1.30%	1.35%	1.35%	1.35%	1.35%	1.35%	1.35%	1.35%	1.35%	1.35%	1.35%	1.35%	1.35%
4	**Annual Energy Savings, 2005-07 Plan**				23.6	127.0	132.4													
5	**Total Annual Energy Savings (GWh)**				23.6	127.0	253.2	379.7	409.2	424.8	440.9	457.7	475.1	493.1	511.9	531.3	551.5	572.5	594.2	616.8
6	**Cumulative Annual Savings (GWh)**				23.6	150.6	403.8	783.5	1,192.7	1,617.5	2,058.4	2,516.1	2,991.2	3,484.4	3,996.2	4,527.6	5,079.1	5,651.5	6,245.8	6,862.6
7	**Cumulative Annual % Savings** (relative to the forecast)				0.1%	0.6%	1.4%	2.7%	3.9%	**5.1%**	6.3%	7.4%	8.5%	9.5%	10.5%	11.5%	12.4%	13.3%	14.2%	**15.0%**
8	**EES Case Retail Energy Sales (GWh)**				26,089	26,955	27,731	28,421	29,121	29,849	30,603	31,387	32,200	33,044	33,920	34,830	35,774	36,754	37,771	38,827
9	**EES Case Annual Growth Rate (%)**				3.2%	3.3%	2.9%	2.5%	2.5%	2.5%	2.5%	2.6%	2.6%	2.6%	2.7%	2.7%	2.7%	2.7%	2.8%	2.8%
										2.6%	EES case average annual growth 2006-2010						EES case average annual growth 2006-2020 =			**2.6%**
					<---------- $48 million ---------->															
10	**Program Expenditures, 2005-07 Plan**				*$3,211*	$20,000	$24,789	*$16,000*	*$16,000*	*$16,000*	*$16,000*	*$16,000*	*$16,000*	*$16,000*	*$16,000*	*$16,000*	*$16,000*	*$16,000*	*$16,000*	*$16,000*
11	**Additional Program Expenditures ($,000)**						$13,211	$40,842	$42,243	$43,697	$45,207	$46,774	$48,400	$50,088	$51,841	$53,660	$55,548	$57,508	$59,542	$61,654
12	**Total Program Expenditures ($,000)** (based on EES case retail energy sales)				*$3,211*	$20,000	$38,000	$56,842	$58,243	$59,697	$61,207	$62,774	$64,400	$66,088	$67,841	$69,660	$71,548	$73,508	$75,542	$77,654
					<---------- $61 million ---------->															
13	**DSM Program Cost Per kWh Saved**				*$0.025*	$0.013	$0.012	$0.012	$0.012	$0.012	$0.011	$0.011	$0.011	$0.011	$0.011	$0.011	$0.011	$0.011	$0.010	$0.010
14	**Net Economic Benefits ($,000)** (societal benefits minus societal costs)				*$4,250*	$30,240	$57,456	$85,945	$88,063	$90,262	$92,545	$94,914	$97,373	$99,926	$102,575	$105,326	$108,181	$111,144	$114,220	$117,413
										$356,217	Cumulative net economic benefits, 2005-2010						Cumulative net economic benefits, 2005-2020 =			**$1,399,833**

Notes:

	Values for 2005 Program Year	Shown in *italics* in the 2005 column; data from the APS DSM Semi-Annual Reports for 2005
1	Energy Forecast	Based on APS Schedule E-7, APS Electric Operating Statistics, APS SFRs (1/31/06)
2	Annual Growth Rate (%)	3.8% annually for 2006-2020, based on the actual average annual growth rate for 2002-2005
4	Annual Energy Savings (GWh) 2005-07 Plan	283 GWh sum of first year (annual) savings for three program years (2005-2007) per the APS DSM Portfolio Plan, July 2005; consistent with Ewen testimony (94,201 MWh average savings per year)
10	Program Expenditures, 2005-07 Plan	$48 million over three years, with ramp up starting in 2005, and 2006 cost based on actual 2005 expenditures per the APS DSM Semi-Annual Reports for 2005; at least $16 million/year starting in 2008
12	Total Program Expenditures, Funding Rate	$0.0020 per kWh of retail energy sales, applied starting in 2008, with proportional estimate of funding needed for 2007, and with actual APS expenditures for 2005
	Average Life of Energy Efficiency Measures	12.15 years, consistent with the APS DSM Portfolio Plan, July 2005
14	Basis of Net Economic Benefits	2.08 benefit/cost ratio per the APS DSM Portfolio Plan, July 2005; and a ratio of societal costs to program costs = 1.4
		The benefit/cost ratio in future years could be higher due to higher avoided energy, capacity, and environmental costs, plus APS will have paid for start-up and ramp-up expenses in the early years.

APS DSM Portfolio Plan; July 2005

3,435	Lifetime GWh savings
283	First Year GWh savings (sum for 3-year period)
94,201	Annual MWh savings (per Ewen direct testimony, p. 30)
12.15	Measure life (years)
51.7	MW of peak demand reduction
$16	Million annual funding ($10 M in base rates, at least $6 M in adjustor)
$68	Million of net economic benefits (societal test) from three program years
2.08	Benefit/cost ratio

Calculation of Energy Efficiency Savings, and Savings as % of Load Growth

146,225	2006-2010	Base Case Retail Energy Sales
142,077	2006-2010	EES Case Retail Energy Sales
4,148	2006-2010	Reduction in Retail Energy Sales (GWh Savings)
32.0%	of the 2006-2010 load growth (2.6% in EES Case vs. 3.8% in Base Case)	

Calculation of % Growth in Retail Energy Sales in Base Case and EES Case

	Base	EES Case	
2005-2010	120%	114%	Growth in Retail Energy Sales
2005-2020	175%	149%	

SWEEP Estimates of APS DSM Energy Efficiency Program Costs Per Customer — **Exhibit JS-2**

Based on Schedule E-7, APS Electric Operating Statistics, in the APS SFRs (1/31/06) — August 2006

For Test Year Ending September 30, 2005

DSM Energy Efficiency Standard (EES) designed to achieve energy savings equivalent to 5% of total resource requirements in 2010, 15% in 2020.

	2005 Retail Sales (MWh)	Annual DSM Funding ($, 000)	Number of Customers	Annual DSM Cost Per Customer	Average Monthly DSM Cost Per Customer	Average Revenue Per Customer	% of Average Revenue
Residential	12,034,503	$ 24,069	886,460	$ 27.15	$ 2.26	$ 1,190.62	2.3%
Commercial	11,561,699	$ 23,123	105,454	$ 219.27	$ 18.27		
Industrial	2,376,393	$ 4,753	3,445	$ 1,379.62	$ 114.97		
Subtotal	25,972,595	$ 51,945	995,359	$ 52.19	$ 4.35		
Irrigation	25,446	$ 51	335	$ 151.92	$ 12.66		
Public Street and Highway Lighting	111,241	$ 222	814	$ 273.32	$ 22.78		
Other Public Authorities	3,615	$ 7	193	$ 37.46	$ 3.12		
Total for Retail Consumers	26,112,897	$ 52,226	996,701	$ 52.40	$ 4.37		
Estimated Funding Level for DSM Energy Efficiency =		$0.0020	per kWh of retail sales				

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

JEFF HATCH-MILLER, Chairman
WILLIAM A. MUNDELL
MIKE GLEASON
KRISTIN K. MAYES
BARRY WONG

EXHIBIT
SWEEP-2
admitted

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 RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND TO AMEND DECISION NO. 67744.	DOCKET NO. E-01345A-03-0816

Surrebuttal Testimony of

Jeff Schlegel
Southwest Energy Efficiency Project (SWEEP)

September 27, 2006

Surrebuttal Testimony of Jeff Schlegel, SWEEP
Docket No. E-01345A-03-0816

Table of Contents

Introduction	1
APS DSM Expenditures and the $48M DSM Funding Requirement	2
The Energy Efficiency Standard (EES): Goals for Energy Savings and Peak Demand Reduction	2
DSM Performance Incentives and Net Lost Revenue Recovery	6
Urban Heat Island Effect and DSM Programs	7
Climate Change	8

Introduction

Q. Please state your name and business address.

A. My name is Jeff Schlegel. My business address is 1167 W. Samalayuca Drive, Tucson, Arizona 85704-3224.

Q. For whom and in what capacity are you testifying?

A. I am testifying on behalf of the Southwest Energy Efficiency Project (SWEEP). I am the Arizona Representative for SWEEP.

Q. Did you file direct testimony in this proceeding?

A. A. Yes, I filed direct testimony on August 18, 2006.

Q. What is the purpose of your surrebuttal testimony?

A. In my surrebuttal testimony I respond to APS rebuttal testimony (Teresa Orlick), and to the direct testimony of Staff (Jerry Anderson) and Western Resource Advocates (David Berry), regarding Demand Side Management (DSM), energy efficiency, and climate change issues.

APS DSM Expenditures and the $48M Funding Requirement

Q. Will APS spend $48M on Commission-approved DSM programs by the end of 2007, as required by Decision 67744?

A. It is too soon to tell definitively. APS *may* be able to meet the requirement set forth in Decision 67744 to spend $48M by the end of 2007, depending on customer and market response to recently-implemented programs. However, it is possible that due to the newness of the programs, the time lags associated with the implementation of some large projects, and the delays in getting the programs in the field, including Staff review and Commission approval taking longer than expected,[1] APS may not meet the spending requirement.

Q. If APS does not spend $48M by the end of 2007, what should happen to the unexpended amount?

A. As APS proposed,[2] any underspending of the $48M through 2007 should be carried over and spent in subsequent years, in addition to the annual budget for each of the future program years. SWEEP requests an explicit Commission order on this issue in this proceeding, in case APS does not meet its $48M funding requirement.

SWEEP's Energy Efficiency Standard (EES) Proposal: Goals for Energy Savings and Peak Demand Reduction

Q. After reviewing the rebuttal testimony of APS,[3] has SWEEP modified its EES proposal?

A. No. The Commission should set APS DSM energy efficiency program goals in the form of an Energy Efficiency Standard (EES), as SWEEP proposed. The EES should require APS DSM energy efficiency programs to: (1) achieve energy savings equal to at least 5% of total energy resources needed to meet retail load in 2010, and at least 15% in 2020; and (2) reduce summer peak demand by at least 5% of total capacity resources needed to meet retail peak demand in 2010, and at least 15% in 2020. Meeting the EES goals would provide cost-effective benefits to consumers, the electric system, the economy, and the environment.

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[1] For example, the planned 2005 spending level was not achieved because most of the programs were not approved until 2006. See Direct Testimony of Jerry Anderson, Staff, p. 6.
[2] Rebuttal Testimony of Teresa Orlick, APS, p. 3.
[3] Rebuttal Testimony of Teresa Orlick, APS, beginning on p. 3.

Q. Apparently, APS believes it is premature to set energy (kWh) and peak demand (kW) savings goals.[4] Why is it important to set savings goals at this time?

A. It is essential to set goals to implement Commission policy. Goals help determine where we are going. Clear, multi-year goals help utilities, parties, stakeholders, and customers understand how the future electric system will meet future customer load, in a manner consistent with the policies and vision of the Commission. Savings goals for DSM energy efficiency programs, as SWEEP proposed, would clearly direct APS to achieve additional cost-effective energy efficiency savings for customers, thereby reducing total costs for customers and providing other benefits.[5]

In addition, SWEEP believes it is important to focus primarily on the *effects and impacts* of energy and utility policies for setting goals, not primarily on the funding or spending levels.

Essentially, achieving the goals of the EES would result in a 1,000 MW "efficiency power plant" that would provide $1.4 billion of net economic benefits to consumers, instead of building conventional power plants that would cost more and expose consumers to higher electricity prices, use precious water, and harm the environment. This is a goal that is important to set and essential to achieve.

Q. Are the goals of the EES reasonable and achievable?

A. Yes, the proposed EES goals are both reasonable and achievable. The goals are reasonable and achievable considering the low level of energy efficiency activities in Arizona in the past and the large number of remaining opportunities for energy savings, the high rate of load growth in the APS service territory, the significant energy efficiency potential in new construction, and the historical energy efficiency performance in leading states (as documented in my direct testimony).

Q. Are similar savings goals supported by other policy makers in the west?

A. Yes, similar savings goals are supported by other policy makers in the west. Meeting the EES goals in Arizona would contribute substantially to the achievement of the adopted goal of the Western Governors Association (WGA) to increase energy efficiency 20% by 2020. The adoption of the WGA energy efficiency goal was based

[4] Rebuttal Testimony of Teresa Orlick, APS, p. 3.

[5] Per my Direct Testimony, achieving the goals of the Energy Efficiency Standard would save consumers and businesses $1.4 billion during 2005-2020, eliminate the need for about 1,000 MW of new power plants by 2020 and the associated power line and pipeline infrastructure costs, provide 1,600 GWh of cumulative annual energy savings in 2010 and almost 7,000 GWh in 2020, reduce average annual load growth in retail energy and summer peak demand by 32% (from 3.8% to 2.6%), reduce electricity price spikes and the risks of natural gas price volatility, and reduce air pollution and the carbon emissions that cause global warming.

on a technical review by stakeholders and WGA staff, documented in the energy efficiency report for the WGA Clean and Diversified Energy (CDEAC) process.

Also, in Arizona in August 2006, a diverse group of 35 Arizona stakeholders[6] provided a consensus recommendation to set electric energy savings goals of 5% savings by 2010 and 15% savings by 2020 through demand-side programs, together with the implementation of policies and funding mechanisms needed to achieve those goals. These goals are equivalent to the EES goals proposed by SWEEP.

Q. Why is a spending requirement, as APS proposed,[7] insufficient?

A. Cost-effective savings to benefit customers are what matter most. Goals in Arizona should be focused on what matters most. Simply spending money, even cost-effectively, should not be the primary focus of future goals.

Q. Did SWEEP consider other potential goals?

A. Yes. In particular, SWEEP considered a goal or requirement that APS should capture *all* cost-effective energy and peak demand savings. Capturing all cost-effective energy efficiency would be a more aggressive savings goal than the EES, and would result in the least-cost utility system for customers.

SWEEP believes that encouraging customers to increase energy efficiency and capture cost-effective savings should be a top priority of utility systems – which would lead one towards the "capture all cost-effective savings" goal above. However, SWEEP proposed the EES goal as a meaningful next step toward capturing significantly *more* of the cost-effective energy efficiency savings, and considering that programs would need time to ramp up activities to higher levels. SWEEP certainly would support a more aggressive energy savings goal than the EES if the Commission desired even higher goals.

Q. Will APS need to design and implement additional DSM energy efficiency programs to achieve the EES goals?

A. The existing Commission-approved DSM energy efficiency programs should be expanded to achieve the goals of the EES. While some additional DSM energy efficiency programs or program elements *may* be needed to achieve the EES goals, and may also be valuable for providing additional benefits to APS customers, the

[6] Arizona Climate Change Advisory Group, *Climate Change Action Plan*, August 2006; www.azclimatechange.us; p. 50.
[7] Rebuttal Testimony of Teresa Orlick, APS, p. 4.

primary mechanism for achieving the EES goals should be the expansion of existing programs already approved by the Commission.

If APS or other parties believe additional DSM energy efficiency programs may be needed to achieve the EES goals, they are certainly free to propose such additional programs, with input from the APS DSM collaborative, for Commission review and approval. APS and other parties may also choose to propose additional or expanded program elements within approved programs. The proposals could be considered as part of the EES Implementation Plan.

Q. Is the funding level estimated by SWEEP adequate to achieve the goals of the Energy Efficiency Standard?

A. The SWEEP-proposed funding levels are estimates based on the APS DSM Portfolio Plan and approved programs, and experience in other states.[8] I acknowledge that the actual funding level necessary in any year may be slightly higher or lower than SWEEP's estimate. However, given the increase in the economies of scale with larger programs, and the nature of fixed vs. variable program costs, plus the significant opportunities in the largely-untapped APS service territory, the actual costs should be reasonably close to SWEEP's estimates. Even if the utility program costs were slightly higher than the SWEEP estimates, the cost-effective energy efficiency resources, by definition, would still be less costly (more cost-effective) than other resource options to meet customer needs, thereby still reducing total costs for customers.

The bottom line is that the Commission should authorize adequate funding to achieve the goals of the EES, subject to cost-effectiveness. If APS has significant concerns about potential costs, the cost estimates can be examined, and if necessary, revised, during the development of the EES Implementation Plan, with subsequent review by the Commission.

Q. Which DSM funding and cost-recovery mechanisms should be used to provide the additional DSM funding that will be needed to achieve the goals of the EES?

A. In general, energy efficiency funding and cost recovery could be accomplished through funding in base rates, a DSM adjustment mechanism, a system benefits surcharge, amortizing or capitalizing the DSM investments over time, or a combination of funding mechanisms.

[8] SWEEP also proposes a ramp-up to higher levels of spending, building on funding already authorized by the Commission. See Exhibit JS-1, Direct Testimony.

SWEEP agrees with APS that the two-part approach in place for APS currently[9] is adequate for the current level of authorized DSM funding. However, the Commission could choose to expand the current two-part approach or build upon it by using an additional funding mechanism for some or all of the additional funding needed to meet the goals of the EES --- including DSM funding and cost-recovery mechanisms that would reduce the rate impacts of the DSM program funding increase in the early years of the EES.

Q. Would you clarify the role and nature of the EES Implementation Plan for the APS service territory?

A. Yes. APS should file an implementation plan to achieve the goals of the EES, covering the 2008-2020 program years, in the spring of 2007, at the same time APS refiles the Non-Residential portion of its DSM Portfolio Plan (per Commission order). The EES Implementation Plan should be developed by APS with input from and review by the APS DSM collaborative, which includes Staff and interested parties.

The EES Implementation Plan should include the historical DSM results for 2005-2006, and should include a forecast for the expansion of the existing Commission-approved DSM energy efficiency programs in 2007. The expansion of approved DSM programs in 2007 should proceed as a result of the order in this proceeding, and should not be postponed for the development, review, and Commission approval of the EES Implementation Plan (which should cover 2008-2020 DSM programs, plus potentially any remaining period in 2007 after Commission review and approval).

APS is correct that it is difficult to develop an Implementation Plan covering 12 years. SWEEP clarifies that the Implementation Plan should include a two-year detailed plan (similar to the APS concept of a biennial plan) together with a more conceptual plan for the remaining period through 2020.

DSM Performance Incentives and Net Lost Revenues

Q. Does SWEEP support the DSM Performance Incentives proposed by Staff and described by APS?

A. Yes. SWEEP supports the proposed performance incentive, including the basis of 10% of net benefits (APS share), and the cap of 10% of spending. This mechanism

[9] For APS, the Commission previously authorized a two-part DSM funding and cost-recovery mechanism, with one portion of the DSM funding in base rates ($10 million) and the second portion of the DSM funding (at least $6 million) recovered using a DSM adjustment mechanism (for the amount in excess of the base rate DSM allowance).

was reviewed and supported by the DSM collaborative, and was included in the APS DSM Portfolio Plan.

SWEEP has one clarification related to the net benefits: the basis of the savings and net benefits should be based on actual installations. However, it is not necessary to wait until the results of future MER studies, associated with the specific installations, are completed and filed with the Commission. Instead, the savings values can and should be based on the results of prior MER and evaluation studies, in a system of regular updates. This is essential to ensure timely review of actual results and timely earnings for APS, thereby supporting the effectiveness of the incentive mechanism.

Q. Does SWEEP support the proforma adjustment to test year data to recover net lost revenues associated with DSM programs?

A. No. SWEEP supports the position of Staff (Anderson) that net lost revenue recovery not be allowed. SWEEP does not support the recovery of net lost revenues in any event, even if there was not a performance incentive for APS.

Urban Heat Island Effect and DSM Programs

Q. What is SWEEP's position on mitigating Urban Heat Island Effects through DSM programs?

A. SWEEP supports WRA's testimony[10] proposing mitigation of Urban Heat Island Effects in metropolitan areas through APS DSM programs. SWEEP believes that APS should either propose an Urban Heat Island Effect DSM program, or further develop an Urban Heat Island Effect program element within the already-approved programs. This decision should be made with input from the APS DSM collaborative. The DSM program or program element should be developed with input from the APS DSM collaborative and outside experts, and should focus on targeting contiguous geographic areas, as WRA proposes, rather than scattered individual buildings. APS should file the Urban Heat Island Effect program or supporting information on the program element as part of its 13-month filing in spring 2007.

[10] Direct Testimony of David Berry, WRA, p. 15.

Climate Change Management Plan and Targets for APS

Q. What should APS be required to do about managing and mitigating the risks of climate change?

A. SWEEP supports WRA's recommendations on climate change risk management.[11] Specifically, the Commission should direct APS, with collaborative input, to prepare a climate change management plan, a carbon emission reduction study, and a climate change commitment and action plan, within 12-18 months of the Commission's decision in this case. SWEEP believes some portions of the climate change plans (e.g., the updated inventory, early identification of actions and strategies to reduce climate change risk, and linkages between managing climate change risk and other policies of the Commission and activities of APS, such as DSM and support for renewable energy) should be filed sooner than within 12 months. The plans and studies should be reviewed by the Commission, and approved or modified, for APS implementation.

Q. Does that conclude your surrebuttal testimony?

A. Yes.

[11] Direct Testimony of David Berry, WRA, Summary of Recommendations, p. 28.

EXHIBIT
SWEER-3
admitted

APS

A subsidiary of Pinnacle West Capital Corporation

Brian Brumfield
Supervisor
Regulatory Affairs

Tel. 602-250-2708
Fax 602-250-3003
e-mail Brian.Brumfield@aps.com

Mail Station 9708
PO Box 53999
Phoenix, Arizona 85072-3999

October 16, 2006

RE: SOUTHWESTERN ENERGY EFFICIENCY PROJECT FIRST SET OF DATA REQUEST TO ARIZONA PUBLIC SERVICE COMPANY ("APS') UNDER DOCKET NO. E-01345A-05-0816 ET AL.

Dear Mr. Jeff Schlegel:

Enclosed is Arizona Public Service Company's ("APS") Final response to Southwestern Energy Efficiency Project's First Set of Data Request in the above docket numbers. Please note a portion of the response is competitively confidential and being provided pursuant to a Protective Agreement on a pink labeled CD.

If you or your staff have any questions, please feel free to call me.

Sincerely,

Brian Brumfield
Supervisor
Regulatory Affairs

BB/rdp

SOUTHWEST ENERGY EFFICIENCY PROJECT (SWEEP)
FIRST SET OF DATA REQUESTS
TO ARIZONA PUBLIC SERVICE COMPANY
APS RATE CASE DOCKET NO. E-01345A-05-0816
OCTOBER 6, 2006

SWEEP-APS-1-1 Please provide up-to-date APS peak demand (MW) and energy (GWh) loads and resources tables for 2005 through 2020. If loads and resources are not available through 2020, please provide up-to-date APS loads and resources tables for 2005 through at least the most recent ten year forecast of loads and resources. For the energy loads and energy resources table, for each actual or forecast year, please provide, at a minimum, the customer energy load (GWh), losses, total energy resource need, energy resource need provided by existing resources, energy resource need provided by planned additions, and energy resource need provided by additions to be determined. For the peak demand and capacity resources table, for each actual or forecast year, please provide the customer peak demand (MW), losses, reserves, total capacity need, capacity need provided by existing resources, capacity need provided by planned additions, and capacity need provided by additions to be determined. For both the peak demand and energy loads and resources tables, also document wholesale energy sales, as well as energy and capacity resources associated with wholesale energy sales and other contracts.

If an APS loads and resources table meeting the above request is already on the record, please reference it specifically.

Response:

See attached as APS08336 and APS08337. These documents are competitively confidential and are being provided to parties pursuant to an executed Protective Agreement.

Witness: Brad Albert

SOUTHWEST ENERGY EFFICIENCY PROJECT (SWEEP)
FIRST SET OF DATA REQUESTS
TO ARIZONA PUBLIC SERVICE COMPANY
APS RATE CASE DOCKET NO. E-01345A-05-0816
OCTOBER 6, 2006

SWEEP-APS-1-2 Please provide 2006 DSM energy efficiency program expenditures and commitments, by program, for the period from January 1, 2006 through September 30, 2006. For each program and for the sum of all programs, please provide the following:

Expenditures
- Total Expenditures
- Financial Incentives
- Number of Participating Customers or Units (e.g., for CFLs)
- Total Expenditures Per Participant or Unit
- Total Financial Incentives Per Participant or Unit

Commitments
- Financial Incentives for Commitments
- Number of Commitment Customers or Units
- Total Financial Incentives Per Commitment

For Projects in the Pipeline
- Financial Incentives for Pipeline Projects
- Number of Commitment Customers or Units
- Total Financial Incentives Per Pipeline Project

Response:

See attached APS08338 for the detailed breakdown of expenditures, as requested. In the attachment, we have added an additional section titled "Sub-Total: Expenditures & Commitments" to provide a more accurate view of the Incentive per Commitment. The figures under "Expenditures" are those that have been paid by APS, while the "Commitments" includes those applications and obligations that have not yet been paid by APS, but for which funds are reserved or contracts are in place. "Projects in Pipeline" includes applications that have been submitted but are still pending.

Please note that the "Total Expenditures Per Participant or Unit" is high because the DSM programs are so early in their implementation and the Total Expenditures includes start-up expenses. As more customers take part in the programs, the cost per participant will fall.

Witness: Teresa Orlick

SOUTHWEST ENERGY EFFICIENCY PROJECT (SWEEP)
FIRST SET OF DATA REQUESTS
TO ARIZONA PUBLIC SERVICE COMPANY
APS RATE CASE DOCKET NO. E-01345A-05-0816
OCTOBER 6, 2006

SWEEP-APS-1-3 Please provide total DSM energy efficiency program expenditures for each program and for the sum of all programs, for 2005-2006, for the period from the effective date of Decision No. 67744 through September 30, 2006.

Response:

Expenditures for the DSM programs are noted in the following table:

Programs	January 2005 to March 2005	April 2005 to September 2006	Total January 2005 to September 2006 [1]
Bldg Operator Training	$ 1,500	$ 22,423	$ 23,923
Consumer Products	10,850	1,803,660	1,814,510
Energy Info Services	1,500	7,029	8,529
Large Non Res Existing	15,400	654,621	670,021
Large Non Res New Const	20,137	765,368	785,505
Low Income	102,109	866,052	968,161
Meas & Evaluation	5,983	489,116	495,099
Res Existing HVAC	229,557	595,148	824,705
Res New Const	141,968	445,565	587,533
Schools	6,100	114,073	120,173
Small Business	9,900	415,165	425,065
Totals	$ 545,004	$ 6,178,219	$ 6,723,224

Note 1: Total expenditures toward DSM commitments does not include commitments or reserved funds that have not been paid yet as provided in response to SWEEP 1-2.

Witness: Teresa Orlick

SOUTHWEST ENERGY EFFICIENCY PROJECT (SWEEP)
FIRST SET OF DATA REQUESTS
TO ARIZONA PUBLIC SERVICE COMPANY
APS RATE CASE DOCKET NO. E-01345A-05-0816
OCTOBER 6, 2006

SWEEP-APS-1-4 Please provide the number of schools that have participated in the DSM energy efficiency programs, the number of schools that have committed to participate in the future, and the number of schools in the pipeline, for the period from Commission approval of the DSM programs through September 30, 2006. Please provide the information for each applicable program, and for the sum of all DSM programs in which schools are eligible to participate.

Response:

Currently, there are 14 schools applications with funding reserved and 1 school application in review; these represent 7 separate school entities. All incentives to schools will be first paid from the School budget, and the remainder of the incentive will be paid from the appropriate non-schools budget. No incentives have been paid to schools by APS to date. Of these 15 applications, 6 receive funding from the Large Existing Program, 8 from the New Construction Program, and 1 from the Small Business Program. Please see attached as APS08339.

Witness: Teresa Orlick

SOUTHWEST ENERGY EFFICIENCY PROJECT (SWEEP)
FIRST SET OF DATA REQUESTS
TO ARIZONA PUBLIC SERVICE COMPANY
APS RATE CASE DOCKET NO. E-01345A-05-0816
OCTOBER 6, 2006

SWEEP-APS-1-5 Please provide the number of compact fluorescent lamps (CFLs) implemented through the DSM energy efficiency programs in 2005. Also, please provide the number of compact fluorescent lamps (CFLs) implemented through the DSM energy efficiency programs for the period from January 1, 2006 through September 30, 2006. Please provide the number of retail stores participating in the residential lighting energy efficiency program in October 2005, December 2005, June 2006, and September 2006.

Response:

There were 362,320 compact fluorescent lamps (CFLs) implemented through the DSM energy efficiency programs in 2005. There were 747,407 CFLs implemented from January 1 through September 30, 2006.

The program has had the following retail store participation:

- Oct 2005: (37 retail locations) Costco, Lowe's, The Home Depot
- Dec. 2005: (96 retail locations) Costco, Lowe's, The Home Depot, Bashas and their affiliates
- June 2006: (130 retail locations) Big Lots, Lowe's, The Home Depot, Costco, Bashas and their affiliates, Ace Hardware, True Value stores
- Sept. 2006: (251 retail locations) The Home Depot, Lowe's, Costco, Bashas and their affiliates, Ace Hardware stores, True Value stores, Wal-Mart, Walgreen's, Albertson's/Osco

Witness: Teresa Orlick

SOUTHWEST ENERGY EFFICIENCY PROJECT (SWEEP)
FIRST SET OF DATA REQUESTS
TO ARIZONA PUBLIC SERVICE COMPANY
APS RATE CASE DOCKET NO. E-01345A-05-0816
OCTOBER 6, 2006

SWEEP-APS-1-6 Please provide the number of home builders participating in the DSM energy efficiency residential new construction program currently and the number of homes committed to participate in the program as of September 30, 2006. How many homes does APS forecast will be built in its service territory in 2006, and how many in 2007?

Response:

There are currently 4 builders participating in the DSM energy efficiency residential new construction program. There are 2803 homes committed to participate in the program as of September 30, 2006. APS forecasts that approximately 35,000 single family new homes will be built in the APS service territory in 2006 and approximately 32,000 new homes will be built in the APS service territory in 2007.

Witness: Teresa Orlick

APS RESPONSE TO SWEEP 1-2
NON RESIDENTIAL
January 1, 2006 to September 30, 2006

	Study Support	Large Existing	Large New Construction	Small Business	Schools	Energy Information Services	Building Operator Training	Sub-Total Non Res DSM	TOTAL NON RESIDENTIAL & RESIDENTIAL
Measure Based Applications									
Expenditures									
Total Expenditures		$ 552,454.64	$ 657,189.18	$ 357,105.13	$ 83,319.91	$ 2,651.27	$ 18,098.75	$ 1,670,818.88	$3,642,991.88
Financial Incentives	$ -	$ 3,457.75	$ -	$ 2,667.13	$ -	$ -	5377.5*	$ 11,502.38	$967,247.38
No. of Customers / Applications	-	3		4	-	-	9	16	750,045
Total Expenditures per Participant	$ -	$ 184,151.55	NA	$ 89,276.28	NA	NA	$ 2,010.97	$ 104,426.18	$4.86
Total Financial Incentives per Participant	NA	$ 1,152.58	NA	$ 666.78	NA	NA	$ 597.50		$1.29
Commitments									
Financial Incentives for Commitments	$ 27,375.00	$ 1,814,204.16	$ 432,091.55	$ 86,577.42	$ 89,380.00	NA	$ 13,425.00	$ 2,463,053.13	$5,795,347.13
No. of Committed Customers / Applications	4	61	14	19	15	NA	30	143	559,836
Total Financial Incentives per Commitment	$ 6,843.75	$ 29,741.05	$ 30,863.68	$ 4,556.71	$ 5,958.67	NA	$ 447.50	$17,224.15	$10.35
Sub-Total: Expenditures & Commitments									
Financial Incentives Expenditures & Commitments	$ 27,375.00	$ 1,817,661.91	$ 432,091.55	$ 89,244.55	$ 89,380.00	NA	$ 18,802.50	$ 2,474,555.51	$6,728,254.51
No. of Committed Customers / Applications	4	64	14	23	15	NA	39	159	1,307,705
Total Financial Incentives per Commitment	$ 6,843.75	$ 28,400.97	$ 30,863.68	$ 3,880.20	$ 5,958.67	NA	$ 482.12	$ 15,563.24	$5.15
For Projects in Pipeline									
Financial Incentives for Pipeline Projects	$ 2,325.00	$ 252,847.78	$ 209,687.80	$ 200.00	NA	NA	NA	$ 465,060.58	$805,052.58
No. of Committed Customers / Pending Applications	1	14	11	4	NA	NA	NA	30	884
Total Financial Incentives per Pipeline Projects	$ 2,325.00	$ 18,060.56	$ 19,062.53	$ 50.00	NA	NA	NA	$ 15,502.02	$910.69

In the BOT Program, no financial incentives are paid and the tuition reimbursement is categorized as a training expense

EIS Program has not been implemented, as potential contractor(s) have been interviewed, but not hired

Each customer application submitted is considered a as a participant in this response, some customers have submitted more than one application

Study support is paid from the Training & Technical Assistance budget category, and all study applications shown in commitments and project pipeline are in the Large Existing Program.

APS RESPONSE TO SWEEP 1-2
RESIDENTIAL
January 1, 2006 to September 30, 2006

	Energy Wise Low Income Weatherization Program		Energy Efficiency Programs			
Measure Based Applications	**Weatherization**	**Bill Assistance**	**Consumer Products**	**Res Existing HVAC**	**Res New Construction**	**Sub-Total Res DSM**
Expenditures						
Total Expenditures	$ 421,927.00	*	$ 1,005,982.00	$ 299,819.00	$ 244,445.00	$ 1,972,173.00
Financial Incentives	$ 283,576.00	$ 34,446.00	$603,383.00	$0.00	$34.340.00***	$ 955,745.00
No. of Customers / Applications	234	212	747,407	0	2,176	750,029
Total Expenditures per Participant	$946.00	$946.00	$1.34	N/A	N/A	$2.63
Total Financial Incentives per Participant	$1,212.00	$162.00	$00.81**	N/A	N/A	$1.27
Commitments						
Financial Incentives for Commitments	$865,902.00	$451,960.00	$ 635,482.00	$ 257,750.00	$ 1,121,200.00	$3,332,294.00
No. of Committed Customers / Applications	715	2,782	552,593	800	2,803	559,693
Total Financial Incentives per Commitment	$1,212.00	$162.00	$1.15	$322.19	$400.00	$5.95
Sub-Total: Expenditures & Commitments						
Financial Incentives, Expenditures & Commitments	$1,149,478.00	$486,406.00	$1,238,865.00	$257,750.00	$ 1,121,200.00	$4,253,699.00
No. of Committed Customers / Applications	949	2,994	1,300,000	800	2,803	1,307,546
Total Financial Incentives per Commitment	$1,212.00	$162.00	$ 0.95	$322.19	$400.00	$3.25
For Projects in Pipeline						
Financial Incentives for Pipeline Projects	$184,555.00	$71,395.00	N/A	$84,042.00	N/A	$339,992.00
No. of Committed Customers / Pending Applications	152	441	N/A	261	N/A	854
Total Financial Incentives per Pipeline Projects	$1,212.00	$162.00	N/A	$322.00	N/A	$398.12

* Bill Assistance expenditures are included in the Weatherization Total Expenditures.

The potential number of homes receiving weatherization and bill assistance was calculated by dividing the total amount of LIW/BA funds available minus the Program delivery costs by the respective average YTD spent/home.

Note that due to timing issues, not all financial incentive expenditures that are associated with the number of units shown are accounted for here.
** The average financial incentive per unit over the course of the program to date has been approximately$1.14/unit.

As of September 30, 800 customers have received AC rebates. These have been paid to customers by the rebate processing contractor but as of September 30th, these had not yet been processed through the APS accounting system. As of September 30th, 261 applications have been received that have not yet been processed. The total financial incentives have been estimated based on rpogram results to date.

*** Financial incentives shown are from the APS Performance Built Home program that was terminated 6/30/06. No financial incentivies have been paid yet on the APS Energy Star Homes program.

APS Response to SWEEP 1-4

School Summary - By Incentive	Incentives Paid	Commitments	Projects in Pipeline
Schools – School Program	$0	$89,380	$0
Schools – Large Existing Program	$0	$150,853	$4,072
Schools – New Construction Program	$0	$169,017	$0
Schools – Small Business Program	$0	$3,060	$0
Schools – Technical Studies	$0	$0	$0
Total School Funds	$0	$412,310	$4,072

Page 1 of 1

FAS 87 Pension Cost and Funded Position

EXHIBIT
tabbies
PBMC/ASCC #1
admitted

Under FAS 87, an important measure of funded position is a comparison of the fair value of assets to the accumulated benefit obligation (ABO). The ABO is the present value of accumulated benefits based on service and pay as of the measurement date.

EXHIBIT
PDMC 1
AECC - 2
Admitted

SCHEDULE 11

Retail Network Integration Transmission Service And Ancillary Services

Scheduling Coordinators shall pay APS a monthly charge for Retail Network Integration Transmission Service based on the summed total of the individual monthly charges applicable to each of the Scheduling Coordinator's aggregated individual customers. The applicable charges to be assessed to a Scheduling Coordinator's individual retail customers are set forth below:

For Transmission Service:

Retail Class	Applicable Charge
1. Residential Class: (DA-R)	$0.00417/kWh
2. General Service 0-2999 kW: (DA-GS)	
a. Demand Metered Customers	$1.271/kW
b. Non-Demand Metered Customers	$0.00340/kWh
3. Large General Service 3000 kW and above: (DA-XLGS)	$1.421/kW

For Ancillary Services:

Scheduling, System Control & Dispatch Service	Applicable Charge
1. Residential Class: (DA-R)	$0.000069/kWh
2. General Service 0-2999 kW: (DA-GS)	
a. Demand Metered Customers	$0.0208/kW
b. Non-Demand Metered Customers	$0.000056/kWh
3. Large General Service 3000 kW and above: (DA-XLGS)	$0.0236/kW

Regulation & Frequency Response Service	Applicable Charge
1. Residential Class: (DA-R)	$0.000267/kWh
2. General Service 0-2999 kW: (DA-GS)	
a. Demand Metered Customers	$0.0813/kW
b. Non-Demand Metered Customers	$0.000217/kWh

Operating Reserve – Spinning Reserve Service	Applicable Charge
1. Residential Class: (DA-R)	$0.000618/kWh
2. General Service 0-2999 kW: (DA-GS)	
a. Demand Metered Customers	$0.1879/kW
b. Non-Demand Metered Customers	$0.000502/kWh
3. Large General Service 3000 kW and above: (DA-XLGS)	$0.2124/kW

Operating Reserve-Supplemental Reserve Service	Applicable Charge
1. Residential Class: (DA-R)	$0.000078/kWh
2. General Service 0-2999 kW: (DA-GS)	
a. Demand Metered Customers	$0.0238/kW
b. Non-Demand Metered Customers	$0.000064/kWh
3. Large General Service 3000 kW and above: (DA-XLGS)	$0.0269/kW

For purposes of determining a Scheduling Coordinator's monthly charges for Retail Network Integration Transmission Service, the kWh energy or the kW demand shall be based upon the aggregated metered values for each retail customer's monthly billing cycle served by the Scheduling Coordinator. The Scheduling Coordinator's kW shall be based on the sum of the average kW supplied during the 15-minute period of maximum kW use by each retail customer with a $/kW demand charge served by the Scheduling Coordinator during the retail customer's monthly billing cycle.

Plus, APS shall assess the Scheduling Coordinator the applicable proportionate part of all sales, uses, excise, and any other similar taxes existing as of the date of this document and thereafter enacted, imposed or levied by any state, county, city, tribal, or any governmental agency solely on the sale or transfer of electric energy or service, unless the Scheduling Coordinator provides to APS a valid Exemption Certificate for the State of Arizona for all applicable municipalities.

EXHIBIT
PDMC / AECC-3
Identified

SCHEDULE 11

Retail Network Integration Transmission Service And Ancillary Services

Scheduling Coordinators shall pay APS a monthly charge for Retail Network Integration Transmission Service based on the summed total of the individual monthly charges applicable to each of the Scheduling Coordinator's aggregated individual customers. The applicable charges to be assessed to a Scheduling Coordinator's individual retail customers are set forth below:

For Transmission Service:

Retail Class	Applicable Charge
1. Residential Class: (DA-R)	$0.00417/kWh
2. General Service 0-2999 kW: (DA-GS)	
a. Demand Metered Customers	$1.271/kW
b. Non-Demand Metered Customers	$0.00340/kWh
3. Large General Service 3000 kW and above: (DA-XLGS)	$1.421/kW

For Ancillary Services:

Scheduling, System Control & Dispatch Service	Applicable Charge
1. Residential Class: (DA-R)	$0.000069/kWh
2. General Service 0-2999 kW: (DA-GS)	
a. Demand Metered Customers	$0.0208/kW
b. Non-Demand Metered Customers	$0.000056/kWh
3. Large General Service 3000 kW and above: (DA-XLGS)	$0.0236/kW

Regulation & Frequency Response Service	Applicable Charge
1. Residential Class: (DA-R)	$0.000267/kWh
2. General Service 0-2999 kW: (DA-GS)	
a. Demand Metered Customers	$0.0813/kW
b. Non-Demand Metered Customers	$0.000217/kWh
3. Large General Service 3000 kW and above: (DA-XLGS)	$0.0919/kW

Issued by: Cary Deise
Director, Transmission Planning & Operations
Issued on: ~~June 30, 2005~~November 1, 2006

Effective: September 1, 2005

For Transmission Service:

Retail Class	Applicable Charge
1. Residential Class: (DA-R)	$0.00417/kWh
2. General Service 0-2999 kW: (DA-GS)	
a. Demand Metered Customers	$1.271/kW

For Ancillary Services:

Scheduling, System Control & Dispatch Service	Applicable Charge
1. Residential Class: (DA-R)	$0.000069/kWh
2. General Service 0-2999 kW: (DA-GS)	
a. Demand Metered Customers	$0.0208/kW
b. Non-Demand Metered Customers	$0.000056/kWh
3. Large General Service 3000 kW and above: (DA-XLGS)	$0.0236/kW

Regulation & Frequency Response Service	Applicable Charge
1. Residential Class: (DA-R)	$0.000267/kWh
2. General Service 0-2999 kW: (DA-GS)	
a. Demand Metered Customers	$0.0813/kW
b. Non-Demand Metered Customers	$0.000217/kWh
3. Large General Service 3000 kW and above: (DA-XLGS)	$0.0919/kW

Issued by: Cary Deise
Director, Transmission Planning & Operations
Issued on: November 1, 2006

Effective: September 1, 2005

EXHIBIT
PDMC / AECC - 4
Admitted

BEFORE THE ARIZONA CORPORATION COMMISSION

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND TO AMEND DECISION NO. 67744	)	**Docket No. E-01345A-05-0816**

Direct Testimony of Kevin C. Higgins

on behalf of

Phelps Dodge Mining Company and

Arizonans for Electric Choice and Competition

Revenue Requirements

August 18, 2006

TABLE OF CONTENTS

Table of Contents.....i

Introduction.....1

Overview and Conclusions.....3

Revenue Requirement Adjustments.....6

Other Proposed Changes to the PSA.....14

Proposed Environmental Improvement Charge.....17

Renewable Energy Standard and Tariff.....19

ATTACHMENTS

KCH-1.....Qualifications

KCH-2.....AECC Adjustments to PWEC O&M and A&G Expense

KCH-3.....AECC Adjustments to Pension Expense

DIRECT TESTIMONY OF KEVIN C. HIGGINS

I. Introduction

Q. Please state your name and business address.

A. Kevin C. Higgins, 215 South State Street, Suite 200, Salt Lake City, Utah, 84111.

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

A. I am a Principal in the firm of Energy Strategies, LLC. Energy Strategies is a private consulting firm specializing in economic and policy analysis applicable to energy production, transportation, and consumption.

Q. On whose behalf are you testifying in this proceeding?

A. My testimony is being sponsored by Phelps Dodge Mining Company ("Phelps Dodge") and Arizonans for Electric Choice and Competition ("AECC"). AECC is a business coalition that advocates on behalf of retail electric customers in Arizona.

Q. Please describe your professional experience and qualifications.

A. My academic background is in economics, and I have completed all coursework and field examinations toward the Ph.D. in Economics at the University of Utah. In addition, I have served on the adjunct faculties of both the University of Utah and Westminster College, where I taught undergraduate and graduate courses in economics. I joined Energy Strategies in 1995, where I assist private and public sector clients in the areas of energy-related economic and policy analysis, including evaluation of electric and gas utility rate matters.

Prior to joining Energy Strategies, I held policy positions in state and local government. From 1983 to 1990, I was economist, then assistant director, for the Utah Energy Office, where I helped develop and implement state energy policy. From 1991 to 1994, I was chief of staff to the chairman of the Salt Lake County Commission, where I was responsible for development and implementation of a broad spectrum of public policy at the local government level.

Q. Have you previously testified before this Commission?

A. Yes. I have testified in a number of proceedings before this Commission, including the generic proceeding on retail electric competition (1998), the hearings on the Arizona Public Service Company ("APS") Direct Access Settlement Agreement (1999), the hearings on the TEP Direct Access Settlement Agreement (1999), the AEPCO transition charge hearings (1999), the Commission's Track A proceeding (2002), the APS adjustment mechanism proceeding (2003), the Arizona ISA proceeding (2003), the APS Rate Case (2004), the Trico Rate Case (2005), and the APS Emergency Interim Rate proceeding (2006).

Q. Have you testified before utility regulatory commissions in other states?

A. Yes. I have testified in over fifty other proceedings on the subjects of electric utility rates and regulatory policy before state utility regulators in Alaska, Colorado, Georgia, Idaho, Illinois, Indiana, Kansas, Michigan, Minnesota, Nevada, New York, Ohio, Oregon, Pennsylvania, South Carolina, Utah, Washington, West Virginia, and Wyoming. I have also participated in various Pricing Processes conducted by the Salt River Project Board.

A more detailed description of my qualifications is contained in Attachment KCH-1, attached to this testimony.

II. Overview and Conclusions

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

A. My testimony evaluates the merits of APS's general rate case filing with respect to revenue requirements and recommends certain adjustments to the Company's proposed revenue requirements that are necessary to ensure results that are just and reasonable. Relative to the wide scope of this general rate proceeding, my recommended adjustments are concentrated on a limited number of issues. Absence of comment on my part regarding a particular revenue issue does not signify support (or opposition) toward the Company's filing with respect to the non-discussed issue.

In addition, I discuss AECC's position with respect to the application of the Renewable Energy Standard and Tariff in this proceeding, as requested by Commissioner Mayes in her letter of July 17, 2006.

Q. What conclusions and recommendations have you reached in your analysis?

A. I propose the following adjustments to APS's requested revenue requirement:

- Reduce fuel expense by $67 million consistent with the modifications made by APS in the Interim proceeding;
- Reduce Administrative & General expense for the PWEC units by $11.5 million;

- Reduce Operations and Maintenance expense for the PWEC units by $3.6 million;

- Eliminate the proposed ratepayer financing of the accelerated recovery of APS's underfunded pension liability in the amount of $41.2 million;

- Deny APS's proposal to retain an additional 10 percent of the gains from hedging, thereby reducing APS's proposed revenue requirement by $8 million (at the level of fuel expense reflecting the $67 million adjustment noted in the first bullet above).

These revenue requirement adjustments total $131 million.

In addition, I recommend that:

- APS's proposal to change various components of the 90/10 sharing mechanism in the PSA be denied; and

- APS's proposal to adopt an Environmental Improvement Charge be denied.

Q. Before proceeding with the specifics of your proposals, please provide a high-level overview of this case.

A. On November 4, 2005, APS filed an Application for a general rate increase in the amount of $405 million. On December 5, 2005, Utilities Division ("Staff") Director Ernest G. Johnson filed in the docket a letter indicating that APS would make a revised filing that would incorporate data through September 30, 2005. This updated filing ("Amended Application") was made on January 31, 2006. The Amended Application, which is the subject of the instant proceeding, seeks a general rate increase of $454 million, which would result in an average rate increase of 21.34 percent.

Additionally, on January 6, 2006, APS filed for an Emergency Interim rate increase of $299 million, or 14.0, percent.[1] The Interim rate increase request was comprised entirely of the fuel and purchased power-related portion of the general rate increase request at issue in this docket. As part of the Interim request, APS sought the establishment of a new base energy rate of 3.1904 cents per kWh, and proposed to achieve this through the imposition of a surcharge in the amount of 1.1161 cents per kWh.

During the course of the Interim proceeding, APS reduced the amount of its requested Interim surcharge to 0.8676 cents per kWh, as a result of the reduction in forward fuel costs experienced between November 30, 2005 and February 28, 2006. This change reduced the Interim rate increase request by $67 million to $232 million.

After an extensive hearing on the Interim request, the Commission issued Decision No. 68685 on May 5, 2006, which adopted an Interim PSA Adjustor of 0.7 cents per kWh, effective May 1, 2006. I estimate that on an annualized basis, the Interim PSA Adjustor would recover $187 million.

Q. What is the relationship between the $454 million rate increase request at issue in this docket and the Interim PSA Adjustor that was approved on May 5, 2006?

A. APS's general rate increase request includes the revenues that are now being collected through the Interim PSA Adjustor. In other words, the Interim PSA Adjustor and the full amount of the general rate increase request are *not*

[1] Docket No. E-01345A-06-0009.

additive. The Interim PSA Adjustor should terminate at the time the new base rates, adopted as a result of the general rate proceeding, go into effect. [2]

III. Revenue Requirement Adjustments

A. Fuel Expense

Q. Please explain your proposed fuel expense adjustment.

A. In the Company's rebuttal testimony filed in the Interim proceeding, APS acknowledged that fuel and purchased power costs had declined by about one-third relative to the November 30, 2005 forward prices that form the basis for the fuel expense used in this general rate case. In his rebuttal testimony filed March 13, 2006, Company witness Peter Ewen stated that using the normalized and adjusted test year, the Company's fuel-related expense in the general rate case filing would decline by $67 million if February 28, 2006 prices held. As these prices have generally held during the subsequent months, I believe that $67 million reduction in fuel expense should be adopted in this proceeding.

Q. On what basis do you conclude that these prices generally held in subsequent months?

A. APS's data response to RUCO 4.11 indicates that on May 24, near the closing date for trades for the June 2006 through May 2007 period, the forward

[2] From a rate-impact perspective, we can view the annualized revenue increase that was awarded in the Interim proceeding as being applicable toward any general rate increase that APS may be awarded in this docket. For example, if hypothetically, APS were granted the full amount of the general rate increase it is requesting, the *incremental* increase in rates would be the difference between the total increase request of $454 million and the annualized revenue from the Interim PSA Adjustor of $187 million, i.e., $267 million. Mechanically, this would take the form of the Interim PSA Adjustor going from $187 million per year to zero, and base rates increasing by the fully-requested amount of $454 million.

prices for gas delivered to the San Juan and Permian Basins were closely aligned with the forward prices on February 28 for that same period.[3]

Q. Has APS reduced its pro-forma fuel expense in this proceeding to reflect the reduction in fuel and purchased power costs that occurred after November 30, 2005?

A. No. In response to a data request from AECC, APS indicated that the Company planned to respond to this issue in its rebuttal testimony to be filed later in this proceeding.

B. <u>PWEC Administrative & General Expense</u>

Q. Please explain your proposed adjustment to PWEC Administrative & General ("A&G") expense.

A. APS witness Laura L. Rockenberger proposes an adjustment that would recognize $20.4 million in A&G expense for the PWEC generating facilities. These generating units were allowed into APS rate base as a result of the Settlement Agreement approved by the Commission in the previous APS general rate case (Docket No. E-01345A-03-0437).

I recommend disallowing $11.5 million of this expense. The amount of A&G expense for the PWEC units proposed by Ms. Rockenberger greatly exceeds the A&G expense attributed to these units by APS in the prior rate

[3] On 2/28/06 the forward price quoted by APS for San Juan Basin gas for June 2006 through May 2007 was $6.79/MMBTU. On 5/24/06 the price for this same period was $6.81. On 2/28/06 the forward price quoted by APS for Permian Basin gas was $7.20/MMBTU. On 5/24/06 the price was $7.02. On 5/26/06, the closing date for trades for this period, these prices were largely unchanged.

1 proceeding, when the net benefit of including the PWEC units in rate base was
2 evaluated by the parties to the case, and ultimately, by the Commission.

3 **Q. Please elaborate.**

4 A. APS's proposal in the prior rate proceeding to allow the PWEC units into
5 rate base was strongly contested by a number of parties. However, after extensive
6 negotiation, the parties were ultimately able to negotiate a package that allowed
7 these units into rate base with a partial disallowance – an arrangement that was
8 subsequently approved by the Commission after careful scrutiny.

9 A major consideration in resolving this matter was the evaluation of the
10 net benefit to APS customers of allowing the PWEC units into rate base. This
11 evaluation included an analysis of the expenses associated with the units if they
12 were allowed into rate base. In that analysis, APS depicted the annual A&G costs
13 associated with the PWEC units as $8.797 million.[4] Had the A&G expense been
14 depicted as $20.4 million, as Ms. Rockenberger now proposes, it would have
15 negatively impacted the economic evaluation of allowing the PWEC units into
16 rate base, and would reasonably have been expected to impact the final package
17 negotiated by the parties and approved by the Commission. In light of this
18 consideration, I believe it is appropriate to limit the PWEC A&G expense to the
19 level depicted by APS in the prior proceeding as part of the Company's analysis
20 of the net benefits associated with bringing these units into rate base.

21 **Q. What adjustment do you recommend?**

---

[4] This amount was shown in APS Schedule DGR-8RB and was discussed on page 58 of Mr. Robinson's rebuttal testimony in response to questions from Commissioner Gleason. Mr. Robinson described the A&G entry as "a fair representation of the A&G cost for the plants."

A. My recommended adjustment to PWEC A&G expense reduces APS's proposed revenue requirement by $11.5 million and is shown on line 12, pages 1 and 2, of Attachment KCH-2.

C. PWEC Operations and Maintenance ("O&M") Expense

Q. Please explain your adjustment to PWEC Operations & Maintenance ("O&M") expense.

A. Ms. Rockenberger proposes an adjustment that would recognize $26.2 million in annual routine O&M expense and $10 million in normalized overhaul O&M expense for the PWEC generating facilities. These adjustments result in a combined O&M expense of $36.2 million per year. In the prior rate proceeding, APS depicted the combined O&M expense for the PWEC units to be $32.7 million. For the same reasons discussed with respect to A&G expense, above, I recommend limiting the annual O&M expense for the PWEC units to the amount indicated by APS in the prior rate proceeding, when the case for including the PWEC units in rate base was being advocated by the Company.

Q. Are you suggesting that because the PWEC expenses were depicted to be at a particular level when APS advocated for the units' inclusion in rate base these expense levels must remained capped or frozen thereafter?

A. No. I recognize that costs change over time. But I also believe it is important that when a case is made to adopt a course of action, and the action is consequently undertaken, continued attention should be paid to the parameters that were used in putting the case forward. That is the situation here. This rate

proceeding is following relatively close in time to the decision that allowed the PWEC units into rate base. It is reasonable, at this time, to limit the O&M and A&G expense for these units at the amounts indicated by APS in the prior rate proceeding.

Q. What is the impact of your recommended adjustment?

A. My recommended adjustment to PWEC O&M reduces APS's proposed revenue requirement by $3.6 million and is shown on line 9, pages 1 and 2, of Attachment KCH-2.

D. <u>Accelerated Recovery of Underfunded Pension Liability</u>

Q. What is APS proposing with respect to accelerated recovery of its underfunded pension liability?

A. Ms. Rockenberger indicates that as of December 31, 2004, PWCC had an underfunded pension liability of $389 million, of which 92 percent, or $358 million, was attributable to APS. According to Ms. Rockenberger, of this latter amount, $218 million is "attributable to APS ratepayers;" that is, this amount is the portion not associated with APS personnel employed in support of jointly-owned facilities.

Ms. Rockenberger proposes to increase ratepayer funding of pension expense by $41.2 million for five years to accelerate recovery of this underfunded pension liability. This would be booked as a regulatory liability, which would then be amortized for the subsequent ten years (i.e., 2012-2021) at $22 million per year.

1 **Q. What is your assessment of this proposal?**

2 A. I recommend that ratepayer funds not be used to fund this accelerated
3 recovery proposal. The $389 million underfunded pension liability referenced by
4 Ms. Rockenberger is the difference between the Potential Benefit Obligation
5 ("PBO") of $1.371 billion and the Fair Value of the assets of $982 million.
6 However, according to the actuarial study performed for PWCC by Towers Perrin
7 (September 2005), PWCC's Potential Benefit Obligation includes $233 million of
8 projected obligation due to future salary increases. Removing these projected
9 future salary increases from the PBO produces the measurement known as the
10 Accumulated Benefit Obligation ("ABO"), which equals $1.138 billion. The
11 difference between the ABO and the Fair Value of the assets is $156 million, of
12 which $87.5 million is associated with APS employees not supporting jointly-
13 owned facilities. This latter amount is much smaller than the $218 million the
14 Company is seeking to recover over five years through its accelerated recovery
15 proposal.

16 **Q. What is the significance of the ABO?**

17 A. The ABO is the present value of accumulated benefits based on service
18 and pay as of the measurement date. The Perrin Towers study describes ABO as
19 "an important measure of funded position" under FAS 87.[5]

20 **Q. Why do you oppose increasing rates $41.2 million per year to accelerate**
21 **recovery of the difference between PBO and Fair Value of the assets?**

[5] Perrin Towers Report, p. MS-6.

A. I oppose this proposal because most of the $41.2 million would be funding a projected increase in benefit obligation that is based on projected salary increases that have not yet occurred. Today's ratepayers should not have to pay millions in current rate increases to recover a projected increase in pension benefits that is associated with salary increases that have not yet been realized.

Q. What is the impact of your recommended adjustment?

A. My recommended adjustment to APS's proposal to accelerate recovery of pension expense reduces the Company's proposed revenue requirement by $41.2 million and is shown on Attachment KCH-3.

E. <u>Retention of 10 Percent of Realized Hedging Gains and Losses</u>

Q. What has APS proposed with respect to the treatment of hedging gains and losses?

A. APS has an active hedging program through which the Company manages its exposure to fuel price volatility. Aside from the Company's obligation to implement prudent procurement practices in the interest of its customers, APS has a direct financial incentive to secure hedging gains: ten percent of all energy costs above or below the baseline established for the calculation of the PSA are either absorbed by, or accrue to, the Company. Consequently, in between rate cases, ten percent of all hedging gains (or losses) flow to APS.

As explained in the direct testimony of Donald Robinson, APS is proposing to modify this arrangement by excluding ten percent of realized hedging gains and losses from the calculation of the PSA prior to the 90/10

1 sharing, as well as excluding ten percent of the hedging gains and losses from the
2 calculation of the Base Fuel Recovery Amount. In the current proceeding,
3 consistent with this proposal, APS has excluded ten percent of the gains from
4 hedging from its calculation of its proposed Base Fuel Recovery Amount of
5 3.1904 cents per kWh. This exclusion is responsible for $18.8 million of APS's
6 proposed rate increase.[6]

7 **Q. What is your assessment of this proposal?**

8 A. I recommend that it be rejected. The PSA mechanism was designed with a
9 90/10 sharing arrangement to provide APS with a direct financial incentive to
10 manage its fuel costs as capably as possible. This sharing arrangement applies to
11 hedging gains and losses just as it does to fuel and purchased power costs. I see
12 no good reason to alter the sharing percentage piecemeal by carving out a special
13 retention award for APS's hedging gains. Moreover, doing so exacerbates the
14 impact of an already-large rate increase proposal in this case.

15 **Q. What is the impact of your recommended adjustment?**

16 A. At APS's currently-proposed Base Fuel Recovery Amount of 3.1904 cents
17 per kWh, my recommended adjustment reduces APS's proposed revenue
18 requirement by $18.8 million. However, at the reduced Base Fuel Recovery
19 Amount associated with a $67 million reduction in fuel expense, which I
20 recommend above, the elimination of the hedging-gains proposal results in an
21 $8.0 million reduction in APS's proposed revenue requirement. This lower

[6] APS Response to AECC Data Request 5.2.

amount is due to the fact that, at lower fuel costs, APS's gains from hedging are reduced, all other things being equal.

IV. Other Proposed Changes to the PSA

Q. In addition to the increased retention of hedging gains and losses, what other changes has APS proposed to the PSA mechanism?

A. As discussed in Mr. Robinson's direct testimony,[7] APS proposes that:

(1) The Total Fuel Cost Cap be permanently eliminated or substantially raised;

(2) The cumulative 4 mill cap on the PSA adjustment be changed to an annual cap; and

(3) The 90/10 cost sharing be eliminated for both renewable resources and the fixed costs of PPAs acquired through competitive bidding or similar competitive processes.

Q. What is your assessment of these three proposals?

A. I recommend adoption of the first two proposals and recommend rejection of the third.

Q. Why do you support the first two proposals?

A. The first two proposals are consistent with the terms of the PSA incorporated in the Settlement Agreement that was negotiated in the prior rate case, and which Phelps Dodge and AECC supported. Phelps Dodge and AECC continue to support the PSA mechanism as originally proposed.

[7] See especially p. 22 for Mr. Robinson's summary.

Q. Why do you oppose the elimination of the 90/10 cost sharing for renewable resources and the fixed costs of PPAs acquired through competitive procurement?

A. The application of the 90/10 sharing mechanism to renewable resources and the fixed costs of PPAs was part of the overall package negotiated and approved when the PSA mechanism was put forward to the Commission as part of the Settlement Agreement in the previous general rate case. The parties had intended the PSA to be in place at least five years. I do not believe it is reasonable to change the balance of the equities in the PSA prior to the end of that five-year term absent a compelling public interest – and no such compelling public interest exists here.

With respect to the Company's obligation to purchase renewable energy, on pages 24-25 of his direct testimony, Mr. Robinson asserts that:

> In furtherance of [its] commitment to renewable energy, in Decision No. 67744 the Commission required APS to issue a Renewable RFP, seeking at least 100 MW and 250,000 MWhs of energy from renewable resources. It did so despite the fact that in many of its present applications renewable energy is significantly more expensive than conventional resources. Consistent with this Commission policy, APS should not be penalized by an automatic 10% cost disallowance when it acts in furtherance of that public policy by securing renewable resources that are not least-cost resources.

What Mr. Robinson omits from this assertion is the fact that the requirement to issue a Renewable RFP, and to seek at least 100 MW and 250,000 MWhs of energy from renewable resources, is an obligation to which APS voluntarily consented in the Settlement Agreement it signed; the Commission did not impose these requirements – APS and the other parties to the agreement

1 presented these provisions to the Commission and sought the Commission's
2 approval, which the Commission granted.
3 At the same time APS was agreeing to increased procurement of
4 renewable resources, APS was agreeing that the 90/10 sharing would apply to
5 renewable resources and the fixed costs of PPAs, all as part of having the PSA
6 mechanism adopted. Mr. Robinson now attempts to treat these components of the
7 90/10 sharing requirement in isolation, and argues for their removal from the
8 sharing provision. I disagree with this approach. These components of the 90/10
9 sharing requirement should not be viewed in isolation and removed piecemeal in
10 this case.
11 **Q. Are there other reasons for your opposition to this part of APS's proposal?**
12 A. Yes. I believe that APS's argument with respect to the fixed costs of PPAs
13 should also be rejected on its merits. Mr. Robinson claims that it is appropriate to
14 exempt the fixed cost component associated with market-acquired PPAs from the
15 sharing provision because: (1) APS may be acquiring the gas used by the
16 merchant generator, and thus would have the same incentive to do so prudently as
17 it would for the Company's own units; and (2) an exemption would place PPAs
18 on the same footing with regard to cost-recovery as APS-owned generation.
19 What this argument fails to acknowledge is that the inclusion of the fixed-
20 cost components of a PPA in an *energy* adjustor is, in the first instance, a
21 significant benefit to APS. Mr. Robinson's argument that PSAs should be placed
22 on an equal footing with APS-owned generation is justification for the removal of
23 the fixed-cost components of a PPA from the PSA *entirely* – not just from the

sharing mechanism. The most compelling aspect of this comparison is the fact that the fixed costs of APS units are not part of the PSA calculation – changes in the recovery of these costs can only be implemented in a rate proceeding. It follows, then, that placing the fixed-cost recovery of APS generation and PPA generation on an equal footing would more appropriately involve excluding the fixed-cost components of PPAs from the PSA all together.

Q. Are you proposing that the fixed-cost components of PPAs be excluded from the PSA?

A. No. I am opposing the exclusion of these components from the 90/10 sharing arrangement. I am not proposing to change the terms of the PSA negotiated in the Settlement Agreement.

V. Proposed Environmental Improvement Charge

Q. What has APS proposed with respect to an Environmental Improvement Charge?

A. As explained in the direct testimony of Edward Z. Fox and Gregory A. DeLizio, APS is seeking approval of an Environmental Improvement Charge ("EIC"), an adjustment mechanism that would recover projected costs associated with installing and maintaining environmental upgrades at APS's generation facilities. According to the Company's proposal, the costs recovered under the EIC would include, but not be limited to, return on capital, depreciation, O&M expenses, property taxes, and associated income taxes. APS proposes that the first installment of the EIC be approved as part of this proceeding. APS requests

1 adoption of a .0152 cent-per-kWh EIC that would raise $4.3 million to recover
2 planned costs associated with environmental improvements in the Company's
3 Cholla generating facility.

4 **Q. What is your assessment of this proposal?**

5 A. Allowing a "stand-alone" rate adjustment for incremental environmental
6 improvement costs is an example of "single-issue ratemaking," in which a single
7 item is permitted to impact rates in isolation from all other rate considerations. In
8 contrast, when regulatory commissions determine the appropriateness of a rate or
9 charge that a utility seeks to impose on its customers, the standard practice is to
10 review and consider all relevant factors, rather than just a single factor. Unless it
11 can be shown to involve a compelling public interest, single-issue ratemaking is
12 generally not sound regulatory policy, as it ignores the multitude of other factors
13 that otherwise influence rates, some of which could, if properly considered, move
14 rates in the opposite direction from the single-issue change. There is no
15 compelling reason to permit single-issue ratemaking in this instance.

16 **Q. Are there circumstances that warrant exceptions to preclusions against single-**
17 **issue ratemaking?**

18 A. There are certain types of cost increases that regulatory commissions have
19 come to allow without the benefit of conducting a general rate case. Because such
20 exceptions constitute a form of single-issue ratemaking, it is not unusual for
21 regulatory commissions to identify criteria that must be met for such treatment to
22 be allowed, such as whether the costs in question exhibit volatility and/or whether
23 the costs are largely outside the utility's control. In light of such criteria, the

single-issue adjustments most commonly adopted are commodity and power cost adjustment mechanisms, such as the PSA mechanism approved by the Commission in APS's last general rate proceeding.

Q. Do environmental improvement costs fit the description of "costs that are outside the utility's control" or "costs that exhibit volatility?"

A. Not really. While APS is subject to current and future provisions governing environmental quality, these provisions are long-term in nature and do not change from month to month the way fuel costs change. Moreover, as is evident in the testimony of Mr. Fox, APS intends to bring a significant amount of judgment to bear on the nature and timing of the investments it will undertake, as the Company works to stay *ahead* of the regulatory curve through a dialogue with regulators and the environmental community.

Q. Are you opposed to APS being able to recover prudently-incurred environmental improvement costs?

A. No, I am not. I am opposed to adoption of single-issue adjustment mechanisms absent a compelling public interest. The appropriate forum for establishing rates to recover prudently-incurred utility investment is a general rate proceeding in which all cost and revenue information can be considered.

VI. <u>Renewable Energy Standard and Tariff</u>

Q. In a letter to the docket dated July 17, 2006, Commissioner Kris Mayes asked the parties to provide testimony on incorporating the Renewable Energy

Standard and Tariff ("REST") into this case. What is your response to Commissioner Mayes' letter?

A. AECC participated actively in the Environmental Portfolio Standard ("EPS") workshop and REST rulemaking processes. AECC supports the utilization of cost-effective renewable energy, but has expressed concerns about the unknown cost impacts of increasing the REST Portfolio Percentage to 2.5 percent by 2010, 5 percent by 2015 and 15 percent by 2025, and has proposed the adoption of performance standards linking future increases in the Portfolio Percentage to demonstrated improvements in performance or reductions in cost-per-kWh.

With respect to specific REST Surcharges, AECC has indicated its support for the specific charges and rate design enumerated in the Sample Tariff included in Attachment A to Decision No. 68566. The Sample Tariff states:

> Unless otherwise ordered by the Commission the Renewable Energy Standard Surcharge shall be assessed monthly to every retail electric service. This monthly assessment shall be the lesser of $.00498 per kWh or:
>
> A. For residential customers, $1.05 per service,
> B. For non-residential customers, $39.00 per service,
> C. For non-residential customers whose metered demand is 3,000 kW or more for three consecutive months, $117.00 per service,
> D. For non-metered services, the lesser of (1) the load profile or otherwise estimated kWh required to provide the service in question or (2) the service's contract kWh shall be used in the calculation of the surcharge.

AECC would support adoption of these specific charges in this docket, including the caps enumerated in items A through D. AECC does not support higher charges or changes to the caps specified in the Sample Tariff.

1

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

3 A. Yes, it does.

KEVIN C. HIGGINS
Principal, Energy Strategies, L.L.C.
215 South State St., Suite 200, Salt Lake City, UT 84111

Vitae

PROFESSIONAL EXPERIENCE

Principal, Energy Strategies, L.L.C., Salt Lake City, Utah, January 2000 to present. Responsible for energy-related economic and policy analysis, regulatory intervention, and strategic negotiation on behalf of industrial, commercial, and public sector interests. Previously Senior Associate, February 1995 to December 1999.

Adjunct Instructor in Economics, Westminster College, Salt Lake City, Utah, September 1981 to May 1982; September 1987 to May 1995. Taught in the economics and M.B.A. programs. Awarded Adjunct Professor of the Year, Gore School of Business, 1990-91.

Chief of Staff to the Chairman, Salt Lake County Board of Commissioners, Salt Lake City, Utah, January 1991 to January 1995. Senior executive responsibility for all matters of county government, including formulation and execution of public policy, delivery of approximately 140 government services, budget adoption and fiscal management (over $300 million), strategic planning, coordination with elected officials, and communication with consultants and media.

Assistant Director, Utah Energy Office, Utah Department of Natural Resources, Salt Lake City, Utah, August 1985 to January 1991. Directed the agency's resource development section, which provided energy policy analysis to the Governor, implemented state energy development policy, coordinated state energy data collection and dissemination, and managed energy technology demonstration programs. Position responsibilities included policy formulation and implementation, design and administration of energy technology demonstration programs, strategic management of the agency's interventions before the Utah Public Service Commission, budget preparation, and staff development. Supervised a staff of economists, engineers, and policy analysts, and served as lead economist on selected projects.

Utility Economist, Utah Energy Office, January 1985 to August 1985. Provided policy and economic analysis pertaining to energy conservation and resource development, with an emphasis on utility issues. Testified before the state Public Service Commission as an expert witness in cases related to the above.

Acting Assistant Director, Utah Energy Office, June 1984 to January 1985. Same responsibilities as Assistant Director identified above.

Research Economist, Utah Energy Office, October 1983 to June 1984. Provided economic analysis pertaining to renewable energy resource development and utility issues. Experience includes preparation of testimony, development of strategy, and appearance as an expert witness for the Energy Office before the Utah PSC.

Operations Research Assistant, Corporate Modeling and Operations Research Department, Utah Power and Light Company, Salt Lake City, Utah, May 1983 to September 1983. Primary area of responsibility: designing and conducting energy load forecasts.

Instructor in Economics, University of Utah, Salt Lake City, Utah, January 1982 to April 1983. Taught intermediate microeconomics, principles of macroeconomics, and economics as a social science.

Teacher, Vernon-Verona-Sherrill School District, Verona, New York, September 1976 to June 1978.

EDUCATION

Ph.D. Candidate, Economics, University of Utah (coursework and field exams completed, 1981).

> Fields of Specialization: Public Finance, Urban and Regional Economics, Economic Development, International Economics, History of Economic Doctrines.

Bachelor of Science, Education, State University of New York at Plattsburgh, 1976 (cum laude).

Danish International Studies Program, University of Copenhagen, 1975.

SCHOLARSHIPS AND FELLOWSHIPS

University Research Fellow, University of Utah, Salt Lake City, Utah 1982 to 1983.
Research Fellow, Institute of Human Resources Management, University of Utah, 1980 to 1982.
Teaching Fellow, Economics Department, University of Utah, 1978 to 1980.
New York State Regents Scholar, 1972 to 1976.

EXPERT TESTIMONY

"Portland General Electric General Rate Case Filing," Public Utility Commission of **Oregon,** Docket No. UE-180. Direct testimony submitted August 9, 2006.

"2006 Puget Sound Energy General Rate Case," **Washington** Utilities and Transportation Commission, Docket Nos. UE-060266 and UG-060267. Response testimony submitted July 19, 2006.

"In the Matter of PacifiCorp, dba Pacific Power & Light Company, Request for a General Rate Increase in the Company's Oregon Annual Revenues," Public Utility Commission of **Oregon,** Docket No. UE-179. Direct testimony submitted July 12, 2006.

"Petition of Metropolitan Edison Company for Approval of a Rate Transition Plan," **Pennsylvania** Public Utilities Commission, Docket Nos. P-00062213 and R-00061366; "Petition of Pennsylvania Electric Company for Approval of a Rate Transition Plan," Docket Nos. P-0062214 and R-00061367; Merger Savings Remand Proceeding, Docket Nos. A-110300F0095 and A-110400F0040. Direct testimony submitted July 10, 2006. Rebuttal testimony submitted August 8, 2006.

"In the Matter of the Application of PacifiCorp for approval of its Proposed Electric Rate Schedules & Electric Service Regulations," **Utah** Public Service Commission, Docket No. 06-035-21. Direct testimony submitted June 9, 2006 (Test Period). Surrebuttal testimony submitted July 14, 2006.

"Joint Application of Questar Gas Company, the Division of Public Utilities, and Utah Clean Energy for the Approval of the Conservation Enabling Tariff Adjustment Option and Accounting Orders," **Utah** Public Service Commission, Docket No. 05-057-T01. Direct testimony submitted May 15, 2006.

"Central Illinois Light Company d/b/a AmerenCILCO, Central Illinois Power Company d/b/a AmerenCIPS, Illinois Power Company d/b/a AmerenIP, Proposed General Increase in Rates for Delivery Service (Tariffs Filed December 27, 2005)," **Illinois** Commerce Commission, Docket Nos. 06-0070, 06-0071, 06-0072. Direct testimony submitted March 26, 2006. Rebuttal testimony submitted June 27, 2006.

"In the Matter of Appalachian Power Company and Wheeling Power Company, both dba American Electric Power," Public Service Commission of **West Virginia**, Case No. 05-1278-E-PC-PW-42T. Direct testimony submitted March 8, 2006.

"In the Matter of Northern States Power Company d/b/a Xcel Energy for Authority to Increase Rates for Electric Service in Minnesota," **Minnesota** Public Utilities Commission, Docket No.

G-002/GR-05-1428. Direct testimony submitted March 2, 2006. Rebuttal testimony submitted March 30, 2006. Cross examined April 25, 2006.

"In the Matter of the Application of Arizona Public Service Company for an Emergency Interim Rate Increase and for an Interim Amendment to Decision No. 67744," **Arizona** Corporation Commission, Docket No. E-01345A-06-0009. Direct testimony submitted February 28, 2006. Cross examined March 23, 2006.

"In the Matter of the Applications of Westar Energy, Inc. and Kansas Gas and Electric Company for Approval to Make Certain Changes in Their Charges for Electric Service," State Corporation Commission of **Kansas**, Case No. 05-WSEE-981-RTS. Direct testimony submitted September 9, 2005. Cross examined October 28, 2005.

"In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Authority to Recover Costs Associated with the Construction and Ultimate Operation of an Integrated Combined Cycle Electric Generating Facility," Public Utilities Commission of **Ohio**," Case No. 05-376-EL-UNC. Direct testimony submitted July 15, 2005. Cross examined August 12, 2005.

"In the Matter of the Filing of General Rate Case Information by Tucson Electric Power Company Pursuant to Decision No. 62103," **Arizona** Corporation Commission, Docket No. E-01933A-04-0408. Direct testimony submitted June 24, 2005.

"In the Matter of Application of The Detroit Edison Company to Unbundle and Realign Its Rate Schedules for Jurisdictional Retail Sales of Electricity," **Michigan** Public Service Commission, Case No. U-14399. Direct testimony submitted June 9, 2005. Rebuttal testimony submitted July 1, 2005.

"In the Matter of the Application of Consumers Energy Company for Authority to Increase Its Rates for the Generation and Distribution of Electricity and Other Relief," **Michigan** Public Service Commission, Case No. U-14347. Direct testimony submitted June 3, 2005. Rebuttal testimony submitted June 17, 2005.

"In the Matter of Pacific Power & Light, Request for a General Rate Increase in the Company's Oregon Annual Revenues," Public Utility Commission of **Oregon**, Docket No. UE 170. Direct testimony submitted May 9, 2005. Surrebuttal testimony submitted June 27, 2005. Joint testimony regarding partial stipulations submitted June 2005, July 2005, and August 2005.

"In the Matter of the Application of Trico Electric Cooperative, Inc. for a Rate Increase,"

Arizona Corporation Commission, Docket No. E-01461A-04-0607. Direct testimony submitted April 13, 2005. Surrebuttal testimony submitted May 16, 2005. Cross examined May 26, 2005.

"In the Matter of the Application of PacifiCorp for Approval of its Proposed Electric Service Schedules and Electric Service Regulations," **Utah** Public Service Commission, Docket No. 04-035-42. Direct testimony submitted January 7, 2005.

"In the Matter of the Application by Golden Valley Electric Association, Inc., for Authority to Implement Simplified Rate Filing Procedures and Adjust Rates," Regulatory Commission of **Alaska**, Docket No. U-4-33. Direct testimony submitted November 5, 2004. Cross examined February 8, 2005.

"Advice Letter No. 1411 - Public Service Company of Colorado Electric Phase II General Rate Case," **Colorado** Public Utilities Commission, Docket No. 04S-164E. Direct testimony submitted October 12, 2004. Cross-answer testimony submitted December 13, 2004. Testimony withdrawn January 18, 2005, following Applicant's withdrawal of testimony pertaining to TOU rates.

"In the Matter of Georgia Power Company's 2004 Rate Case," **Georgia** Public Service Commission, Docket No. 18300-U. Direct testimony submitted October 8, 2004. Cross examined October 27, 2004.

"2004 Puget Sound Energy General Rate Case," **Washington** Utilities and Transportation Commission, Docket Nos. UE-040641 and UG-040640. Response testimony submitted September 23, 2004. Cross-answer testimony submitted November 3, 2004. Joint testimony regarding stipulation submitted December 6, 2004.

"In the Matter of the Application of PacifiCorp for an Investigation of Interjurisdictional Issues," **Utah** Public Service Commission, Docket No. 02-035-04. Direct testimony submitted July 15, 2004. Cross examined July 19, 2004.

"In the Matter of an Adjustment of the Gas and Electric Rates, Terms and Conditions of Kentucky Utilities Company," **Kentucky** Public Service Commission, Case No. 2003-00434. Direct testimony submitted March 23, 2004. Testimony withdrawn pursuant to stipulation entered May 2004.

"In the Matter of an Adjustment of the Gas and Electric Rates, Terms and Conditions of Louisville Gas and Electric Company," **Kentucky** Public Service Commission, Case No. 2003-00433. Direct testimony submitted March 23, 2004. Testimony withdrawn pursuant to stipulation entered May 2004.

"In the Matter of the Application of Idaho Power Company for Authority to Increase Its Interim and Base Rates and Charges for Electric Service," **Idaho** Public Utilities Commission, Case No. IPC-E-03-13. Direct testimony submitted February 20, 2004. Rebuttal testimony submitted March 19, 2004. Cross examined April 1, 2004.

"In the Matter of the Applications of the Ohio Edison Company, the Cleveland Electric Illuminating Company and the Toledo Edison Company for Authority to Continue and Modify Certain Regulatory Accounting Practices and Procedures, for Tariff Approvals and to Establish Rates and Other Charges, Including Regulatory Transition Charges Following the Market Development Period," Public Utilities Commission of **Ohio**, Case No. 03-2144-EL-ATA. Direct testimony submitted February 6, 2004. Cross examined February 18, 2004.

"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 Ratemaking Purposes, To Fix a Just and Reasonable Rate of Return Thereon, To Approve Rate Schedules Designed to Develop Such Return, and For Approval of Purchased Power Contract," **Arizona** Corporation Commission, Docket No. E-01345A-03-0437. Direct testimony submitted February 3, 2004. Rebuttal testimony submitted March 30, 2004. Direct testimony regarding stipulation submitted September 27, 2004. Responsive / Clarifying testimony regarding stipulation submitted October 25, 2004. Cross examined November 8-10, 2004 and November 29-December 3, 2004.

"In the Matter of Application of the Detroit Edison Company to Increase Rates, Amend Its Rate Schedules Governing the Distribution and Supply of Electric Energy, etc.," **Michigan** Public Service Commission, Case No. U-13808. Direct testimony submitted December 12, 2003 (interim request) and March 5, 2004 (general rate case).

"In the Matter of PacifiCorp's Filing of Revised Tariff Schedules," Public Utility Commission of **Oregon**, Docket No. UE-147. Joint testimony regarding stipulation submitted August 21, 2003.

"Petition of PSI Energy, Inc. for Authority to Increase Its Rates and Charges for Electric Service, etc.," **Indiana** Utility Regulatory Commission, Cause No. 42359. Direct testimony submitted August 19, 2003. Cross examined November 5, 2003.

"In the Matter of the Application of Consumers Energy Company for a Financing Order Approving the Securitization of Certain of its Qualified Cost," **Michigan** Public Service Commission, Case No. U-13715. Direct testimony submitted April 8, 2003. Cross examined April 23, 2003.

"In the Matter of the Application of Arizona Public Service Company for Approval of Adjustment Mechanisms," **Arizona** Corporation Commission, Docket No. E-01345A-02-0403. Direct testimony submitted February 13, 2003. Surrebuttal testimony submitted March 20, 2003. Cross examined April 8, 2003.

"Re: The Investigation and Suspension of Tariff Sheets Filed by Public Service Company of Colorado, Advice Letter No. 1373 – Electric, Advice Letter No. 593 – Gas, Advice Letter No. 80 – Steam," **Colorado** Public Utilities Commission, Docket No. 02S-315 EG. Direct testimony submitted November 22, 2002. Cross-answer testimony submitted January 24, 2003.

"In the Matter of the Application of The Detroit Edison Company to Implement the Commission's Stranded Cost Recovery Procedure and for Approval of Net Stranded Cost Recovery Charges," **Michigan** Public Service Commission, Case No. U-13350. Direct testimony submitted November 12, 2002.

"Application of South Carolina Electric & Gas Company: Adjustments in the Company's Electric Rate Schedules and Tariffs," Public Service Commission of **South Carolina**, Docket No. 2002-223-E. Direct testimony submitted November 8, 2002. Surrebuttal testimony submitted November 18, 2002. Cross examined November 21, 2002.

"In the Matter of the Application of Questar Gas Company for a General Increase in Rates and Charges," **Utah** Public Service Commission, Docket No. 02-057-02. Direct testimony submitted August 30, 2002. Rebuttal testimony submitted October 4, 2002.

"The Kroger Co. v. Dynegy Power Marketing, Inc.," **Federal Energy Regulatory Commission**, EL02-119-000. Confidential affidavit filed August 13, 2002.

"In the matter of the application of Consumers Energy Company for determination of net stranded costs and for approval of net stranded cost recovery charges," **Michigan** Public Service Commission, Case No. U-13380. Direct testimony submitted August 9, 2002. Rebuttal testimony submitted August 30, 2002. Cross examined September 10, 2002.

"In the Matter of the Application of Public Service Company of Colorado for an Order to Revise Its Incentive Cost Adjustment," **Colorado** Public Utilities Commission, Docket 02A-158E. Direct testimony submitted April 18, 2002.

"In the Matter of the Generic Proceedings Concerning Electric Restructuring Issues," **Arizona** Corporation Commission, Docket No. E-00000A-02-0051, "In the Matter of Arizona Public Service Company's Request for Variance of Certain Requirements of A.A.C. R14-2-1606," Docket No. E-01345A-01-0822, "In the Matter of the Generic Proceeding Concerning the Arizona Independent Scheduling Administrator," Docket No. E-00000A-01-0630, "In the Matter of Tucson Electric Power Company's Application for a Variance of Certain Electric Competition Rules Compliance Dates," Docket No. E-01933A-02-0069, "In the Matter of the Application of Tucson Electric Power Company for Approval of its Stranded Cost Recovery," Docket No. E-01933A-98-0471. Direct testimony submitted March 29, 2002 (APS variance request); May 29, 2002 (APS Track A proceeding/market power issues); and July 28, 2003 (Arizona ISA). Rebuttal

testimony submitted August 29, 2003 (Arizona ISA). Cross examined June 21, 2002 (APS Track A proceeding/market power issues) and September 12, 2003 (Arizona ISA).

"In the Matter of Savannah Electric & Power Company's 2001 Rate Case," **Georgia** Public Service Commission, Docket No. 14618-U. Direct testimony submitted March 15, 2002. Cross examined March 28, 2002.

"Nevada Power Company's 2001 Deferred Energy Case," Public Utilities Commission of **Nevada**, PUCN 01-11029. Direct testimony submitted February 7, 2002. Cross examined February 21, 2002.

"2001 Puget Sound Energy Interim Rate Case," **Washington** Utilities and Transportation Commission, Docket Nos. UE-011570 and UE-011571. Direct testimony submitted January 30, 2002. Cross examined February 20, 2002.

"In the Matter of Georgia Power Company's 2001 Rate Case," **Georgia** Public Service Commission, Docket No. 14000-U. Direct testimony submitted October 12, 2001. Cross examined October 24, 2001.

"In the Matter of the Application of PacifiCorp for Approval of Its Proposed Electric Rate Schedules and Electric Service Regulations," **Utah** Public Service Commission, Docket No. 01-35-01. Direct testimony submitted June 15, 2001. Rebuttal testimony submitted August 31, 2001.

"In the Matter of Portland General Electric Company's Proposal to Restructure and Reprice Its Services in Accordance with the Provisions of SB 1149," Public Utility Commission of **Oregon**, Docket No. UE-115. Direct testimony submitted February 20, 2001. Rebuttal testimony submitted May 4, 2001. Joint testimony regarding stipulation submitted July 27, 2001.

"In the Matter of the Application of APS Energy Services, Inc. for Declaratory Order or Waiver of the Electric Competition Rules," **Arizona** Corporation Commission, Docket No.E-01933A-00-0486. Direct testimony submitted July 24, 2000.

"In the Matter of the Application of Questar Gas Company for an Increase in Rates and Charges," **Utah** Public Service Commission, Docket No. 99-057-20. Direct testimony submitted April 19, 2000. Rebuttal testimony submitted May 24, 2000. Surrebuttal testimony submitted May 31, 2000. Cross examined June 6 & 8, 2000.

"In the Matter of the Application of Columbus Southern Power Company for Approval of Electric Transition Plan and Application for Receipt of Transition Revenues," Public Utility Commission of **Ohio**, Case No. 99-1729-EL-ETP; "In the Matter of the Application of Ohio Power Company for Approval of Electric Transition Plan and Application for Receipt of

Transition Revenues," Public Utility Commission of **Ohio**, Case No. 99-1730-EL-ETP. Direct testimony prepared, but not submitted pursuant to settlement agreement effected May 2, 2000.

"In the Matter of the Application of FirstEnergy Corp. on Behalf of Ohio Edison Company, The Cleveland Electric Illuminating Company, and the Toledo Edison Company for Approval of Their Transition Plans and for Authorization to Collect Transition Revenues," Public Utility Commission of **Ohio**, Case No. 99-1212-EL-ETP. Direct testimony prepared, but not submitted pursuant to settlement agreement effected April 11, 2000.

"2000 Pricing Process," **Salt River Project** Board of Directors, oral comments provided March 6, 2000 and April 10, 2000.

"Tucson Electric Power Company vs. Cyprus Sierrita Corporation," **Arizona** Corporation Commission, Docket No. E-000001-99-0243. Direct testimony submitted October 25, 1999. Cross examined November 4, 1999.

"Application of Hildale City and Intermountain Municipal Gas Association for an Order Granting Access for Transportation of Interstate Natural Gas over the Pipelines of Questar Gas Company for Hildale, Utah," **Utah** Public Service Commission, Docket No. 98-057-01. Rebuttal testimony submitted August 30, 1999.

"In the Matter of the Application by Arizona Electric Power Cooperative, Inc. for Approval of Its Filing as to Regulatory Assets and Transition Revenues," **Arizona** Corporation Commission, Docket No. E-01773A-98-0470. Direct testimony submitted July 30, 1999. Cross examined February 28, 2000.

"In the Matter of the Application of Tucson Electric Power Company for Approval of its Plan for Stranded Cost Recovery," **Arizona** Corporation Commission, Docket No. E-01933A-98-0471; "In the Matter of the Filing of Tucson Electric Power Company of Unbundled Tariffs Pursuant to A.A.C. R14-2-1601 et seq.," Docket No. E-01933A-97-0772; "In the Matter of the Competition in the Provision of Electric Service Throughout the State of Arizona," Docket No. RE-00000C-94-0165. Direct testimony submitted June 30, 1999. Rebuttal testimony submitted August 6, 1999. Cross examined August 11-13, 1999.

"In the Matter of the Application of Arizona Public Service Company for Approval of its Plan for Stranded Cost Recovery," **Arizona** Corporation Commission, Docket No. E-01345A-98-0473; "In the Matter of the Filing of Arizona Public Service Company of Unbundled Tariffs Pursuant to A.A.C. R14-2-1601 et seq.," Docket No. E-01345A-97-0773; "In the Matter of the Competition in the Provision of Electric Service Throughout the State of Arizona," Docket No. RE-00000C-94-0165. Direct testimony submitted June 4, 1999. Rebuttal testimony submitted July 12, 1999. Cross examined July 14, 1999.

"In the Matter of the Application of Tucson Electric Power Company for Approval of its Plan for Stranded Cost Recovery," **Arizona** Corporation Commission, Docket No. E-01933A-98-0471; "In the Matter of the Filing of Tucson Electric Power Company of Unbundled Tariffs Pursuant to A.A.C. R14-2-1601 et seq.," Docket No. E-01933A-97-0772; "In the Matter of the Application of Arizona Public Service Company for Approval of its Plan for Stranded Cost Recovery," Docket No. E-01345A-98-0473; "In the Matter of the Filing of Arizona Public Service Company of Unbundled Tariffs Pursuant to A.A.C. R14-2-1601 et seq.," Docket No. E-01345A-97-0773; "In the Matter of the Competition in the Provision of Electric Service Throughout the State of Arizona," Docket No. RE-00000C-94-0165. Direct testimony submitted November 30, 1998.

"Hearings on Pricing," **Salt River Project** Board of Directors, written and oral comments provided November 9, 1998.

"Hearings on Customer Choice," **Salt River Project** Board of Directors, written and oral comments provided June 22, 1998; June 29, 1998; July 9, 1998; August 7, 1998; and August 14, 1998.

"In the Matter of the Competition in the Provision of Electric Service Throughout the State of Arizona," **Arizona** Corporation Commission, Docket No. U-0000-94-165. Direct and rebuttal testimony filed January 21, 1998. Second rebuttal testimony filed February 4, 1998. Cross examined February 25, 1998.

"In the Matter of Consolidated Edison Company of New York, Inc.'s Plans for (1) Electric Rate/Restructuring Pursuant to Opinion No. 96-12; and (2) the Formation of a Holding Company Pursuant to PSL, Sections 70, 108, and 110, and Certain Related Transactions," **New York** Public Service Commission, Case 96-E-0897. Direct testimony filed April 9, 1997. Cross examined May 5, 1997.

"In the Matter of the Petition of Sunnyside Cogeneration Associates for Enforcement of Contract Provisions," **Utah** Public Service Commission, Docket No. 96-2018-01. Direct testimony submitted July 8, 1996.

"In the Matter of the Application of PacifiCorp, dba Pacific Power & Light Company, for Approval of Revised Tariff Schedules and an Alternative Form of Regulation Plan," **Wyoming** Public Service Commission, Docket No. 2000-ER-95-99. Direct testimony submitted April 8, 1996.

"In the Matter of the Application of Mountain Fuel Supply Company for an Increase in Rates and Charges," **Utah** Public Service Commission, Case No. 95-057-02. Direct testimony submitted June 19, 1995. Rebuttal testimony submitted July 25, 1995. Surrebuttal testimony submitted August 7, 1995.

"In the Matter of the Investigation of the Reasonableness of the Rates and Tariffs of Mountain Fuel Supply Company," **Utah** Public Service Commission, Case No. 89-057-15. Direct testimony submitted July 1990. Surrebuttal testimony submitted August 1990.

"In the Matter of the Review of the Rates of Utah Power and Light Company pursuant to The Order in Case No. 87-035-27," **Utah** Public Service Commission, Case No. 89-035-10. Rebuttal testimony submitted November 15, 1989. Cross examined December 1, 1989 (rate schedule changes for state facilities).

"In the Matter of the Application of Utah Power & Light Company and PC/UP&L Merging Corp. (to be renamed PacifiCorp) for an Order Authorizing the Merger of Utah Power & Light Company and PacifiCorp into PC/UP&L Merging Corp. and Authorizing the Issuance of Securities, Adoption of Tariffs, and Transfer of Certificates of Public Convenience and Necessity and Authorities in Connection Therewith," **Utah** Public Service Commission, Case No. 87-035-27; Direct testimony submitted April 11, 1988. Cross examined May 12, 1988 (economic impact of UP&L merger with PacifiCorp).

"In the Matter of the Application of Mountain Fuel Supply Company for Approval of Interruptible Industrial Transportation Rates," **Utah** Public Service Commission, Case No. 86-057-07. Direct testimony submitted January 15, 1988. Cross examined March 30, 1988.

"In the Matter of the Application of Utah Power and Light Company for an Order Approving a Power Purchase Agreement," **Utah** Public Service Commission, Case No. 87-035-18. Oral testimony delivered July 8, 1987.

"Cogeneration: Small Power Production," **Federal Energy Regulatory Commission**, Docket No. RM87-12-000. Statement on behalf of State of Utah delivered March 27, 1987, in San Francisco.

"In the Matter of the Investigation of Rates for Backup, Maintenance, Supplementary, and Standby Power for Utah Power and Light Company," **Utah** Public Service Commission, Case No. 86-035-13. Direct testimony submitted January 5, 1987. Case settled by stipulation approved August 1987.

"In the Matter of the Application of Sunnyside Cogeneration Associates for Approval of the Cogeneration Power Purchase Agreement," **Utah** Public Service Commission, Case No. 86-2018-01. Rebuttal testimony submitted July 16, 1986. Cross examined July 17, 1986.

"In the Matter of the Investigation of Demand-Side Alternatives to Capacity Expansion for Electric Utilities," **Utah** Public Service Commission, Case No. 84-999-20. Direct testimony submitted June 17, 1985. Rebuttal testimony submitted July 29, 1985. Cross examined August 19, 1985.

"In the Matter of the Implementation of Rules Governing Cogeneration and Small Power Production in Utah," **Utah** Public Service Commission, Case No. 80-999-06, pp. 1293-1318. Direct testimony submitted January 13, 1984 (avoided costs), May 9, 1986 (security for levelized contracts) and November 17, 1986 (avoided costs). Cross-examined February 29, 1984 (avoided costs), April 11, 1985 (standard form contracts), May 22-23, 1986 (security for levelized contracts) and December 16-17, 1986 (avoided costs).

OTHER RELATED ACTIVITY

Participant, Oregon Direct Access Task Force (UM 1081), May 2003 to November 2003.

Participant, Michigan Stranded Cost Collaborative, March 2003 to March 2004.

Member, Arizona Electric Competition Advisory Group, December 2002 to present.

Board of Directors, ex-officio, Desert STAR RTO, September 1999 to February 2002.

Member, Advisory Committee, Desert STAR RTO, September 1999 to February 2002. Acting Chairman, October 2000 to February 2002.

Board of Directors, Arizona Independent Scheduling Administrator Association, October 1998 to present.

Acting Chairman, Operating Committee, Arizona Independent Scheduling Administrator Association, October 1998 to June 1999.

Member, Desert Star ISO Investigation Working Groups: Operations, Pricing, and Governance, April 1997 to present. Legal & Negotiating Committee, April 1999 to December 1999.

Participant, Independent System Operator and Spot Market Working Group, Arizona Corporation Commission, April 1997 to September 1997.

Participant, Unbundled Services and Standard Offer Working Group, Arizona Corporation Commission, April 1997 to October 1997.

Participant, Customer Selection Working Group, Arizona Corporation Commission, March 1997 to September 1997.

Member, Stranded Cost Working Group, Arizona Corporation Commission, March 1997 to September 1997.

Member, Electric System Reliability & Safety Working Group, Arizona Corporation Commission, November 1996 to September 1998.

Chairman, Salt Palace Renovation and Expansion Committee, Salt Lake County/State of Utah/Salt Lake City, multi-government entity responsible for implementation of planning, design, finance, and construction of an $85 million renovation of the Salt Palace Convention Center, Salt Lake City, Utah, May 1991 to December 1994.

State of Utah Representative, Committee on Regional Electric Power Cooperation, a joint effort of the Western Interstate Energy Board and the Western Conference of Public Service Commissioners, January 1987 to December 1990.

Member, Utah Governor's Economic Coordinating Committee, January 1987 to December 1990.

Chairman, Standard Contract Task Force, established by Utah Public Service Commission to address contractual problems relating to qualifying facility sales under PURPA, March 1986 to December 1990.

Chairman, Load Management and Energy Conservation Task Force, Utah Public Service Commission, August 1985 to December 1990.

Alternate Delegate for Utah, Western Interstate Energy Board, Denver, Colorado, August 1985 to December 1990.

Articles Editor, Economic Forum, September 1980 to August 1981.

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AECC Adjustments to PWEC O&M and A&G Expenses

Total Company
(Thousands of Dollars)

Line No.	Description	(a) APS Amount in Filing	(b) AECC Recommended Amount	(c) = (b) - (a) AECC Adjustment
1	REVENUES:			
2	Operating Revenue			
3	Fuel and Purchased Power Expense			
4	Operating Revenue less Fuel and Purchased Power Expenses			
5	EXPENSES:			
6	Other Operating Expense			
7	Operations Excluding Fuel & Purchased Power Expenses	26,204 /1	21,353 /2	(4,851)
8	Maintenance (Overhaul)	10,000 /1	11,238 /2	1,238
9	O&M Subtotal	36,204	32,591	(3,613)
10	Depreciation and Amortization			
11	Amortization of Gain			
12	Administrative and General	20,415 /1	8,797 /2	(11,618)
13	Other Taxes			
14	Total	56,619	41,388	(15,231)
15	OPERATING INCOME (before imcome tax)	(56,619)	(41,388)	15,231
16	Interest Expense			
17	Taxable Income	(56,619)	(41,388)	15,231
18	Income Tax @ 39.05%	(22,110)	(16,162)	5,948
19	OPERATING INCOME AFTER TAX	(34,509)	(25,226)	9,283

Data Sources:
Note 1 - APS Workpaper LLR_WP13, pp. 2 & 3 of 11.
Note 2 - APS Schedule DGR-8RB, p. 3 of 4 in ACC Docket E-01345A-03-0437.

AECC Adjustments to PWEC O&M and A&G Expenses

(Thousands of Dollars)

Line No.	Description	(a) Total Company Adjustment	(b) ACC Jurisdictional Adjustment
1	REVENUES:		
2	Operating Revenue	0	0
3	Fuel and Purchased Power Expense	0	0
4	Operating Revenue less Fuel and Purchased Power Expenses	0	0
5	EXPENSES:		
6	Other Operating Expense		
7	Operations Excluding Fuel & Purchased Power	(4,851)	(4,795)
8	Maintenance (Overhaul)	1,238	1,224
9	O&M Subtotal	(3,613)	(3,571)
10	Depreciation and Amortization	0	0
11	Amortization of Gain	0	0
12	Administrative and General	(11,618)	(11,484)
13	Other Taxes	0	0
14	Total	(15,231)	(15,056)
15	OPERATING INCOME (before imcome tax)	15,231	15,056
16	Interest Expense	0	0
17	Taxable Income	15,231	15,056
18	Income Tax @ 39.05%	5,948	5,879
19	OPERATING INCOME AFTER TAX	9,283	9,176
20	Gross Revenue Conversion Factor		1.640703
21	Impact on Revenue Requirement (-Ln 19 x Ln 20)		(15,056)

AECC Adjustments to Pension Expense

Total Company
(Thousands of Dollars)

Line No.	Description	(a) APS Amount in Filing	(b) AECC Recommended Amount	(c) = (b) - (a) AECC Adjustment
1	REVENUES:			
2	Operating Revenue			
3	Fuel and Purchased Power Expense			
4	Operating Revenue less Fuel and Purchased Power Expenses			
5	EXPENSES:			
6	Other Operating Expense			
7	Operations Excluding Fuel & Purchased Power Expenses	43,695 /1	0	(43,695)
8	Maintenance (Overhaul)			
9	O&M Subtotal	43,695	0	(43,695)
10	Depreciation and Amortization			
11	Amortization of Gain			
12	Administrative and General			
13	Other Taxes			
14	Total	43,695	0	(43,695)
15	OPERATING INCOME (before imcome tax)	(43,695)	0	43,695
16	Interest Expense			
17	Taxable Income	(43,695)	0	43,695
18	Income Tax @ 39.05%	(17,063)	0	17,063
19	OPERATING INCOME AFTER TAX	(26,632)	0	26,632

Data Sources:
Note 1 - APS Workpaper LLR_WP22, pp. 2 of 2.

AECC Adjustments to Pension Expense

(Thousands of Dollars)

Line No.	Description	(a) Total Company Adjustment	(b) ACC Jurisdictional Adjustment
1	REVENUES:		
2	Operating Revenue	0	0
3	Fuel and Purchased Power Expense	0	0
4	Operating Revenue less Fuel and Purchased Power Expenses	0	0
5	EXPENSES:		
6	Other Operating Expense		
7	Operations Excluding Fuel & Purchased Power	(43,695)	(41,166)
8	Maintenance (Overhaul)	0	0
9	O&M Subtotal	(43,695)	(41,166)
10	Depreciation and Amortization	0	0
11	Amortization of Gain	0	0
12	Administrative and General	0	0
13	Other Taxes	0	0
14	Total	(43,695)	(41,166)
15	OPERATING INCOME (before imcome tax)	43,695	41,166
16	Interest Expense	0	0
17	Taxable Income	43,695	41,166
18	Income Tax @ 39.05%	17,063	16,075
19	OPERATING INCOME AFTER TAX	26,632	25,091
20	Gross Revenue Conversion Factor		1.640703
21	Impact on Revenue Requirement (-Ln 19 x Ln 20)		(41,166)

EXHIBIT
PDMC 1
AECC-5
Admitted

BEFORE THE ARIZONA CORPORATION COMMISSION

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND TO AMEND DECISION NO. 67744	)	**Docket No. E-01345A-05-0816**

Direct Testimony of Kevin C. Higgins

on behalf of

Phelps Dodge Mining Company and

Arizonans for Electric Choice and Competition

Cost-of-Service / Rate Spread / Rate Design

September 1, 2006

TABLE OF CONTENTS

Table of Contents.....i

Introduction.....1

Use of the 4-CP Method for Allocating Fixed Production and Transmission Costs.....3

APS Proposed Rate Spread.....4

Allocation of Hourly Energy Costs.....8

AECC Proposed Rate Spread.....15

Rate Design.....18

ATTACHMENTS

KCH-4.....Summary of APS's Cost-of-Service Results

KCH-5.....APS Cost-of-Service Results Adjusted to Reflect Hourly Fuel and Purchased Power Costs

KCH-6.....AECC Proposed Rate Spread at APS Requested Revenue Increase

KCH- 7 .....Derivation of Transmission Demand Charges

KCH-8.....Comparison of APS's Generation Cost Components with APS's Proposed Generation Revenue Components

DIRECT TESTIMONY OF KEVIN C. HIGGINS

I. Introduction

Q. Please state your name and business address.

A. Kevin C. Higgins, 215 South State Street, Suite 200, Salt Lake City, Utah, 84111.

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

A. I am a Principal in the firm of Energy Strategies, LLC. Energy Strategies is a private consulting firm specializing in economic and policy analysis applicable to energy production, transportation, and consumption.

Q. On whose behalf are you testifying in this proceeding?

A. My testimony is being sponsored by Phelps Dodge Mining Company ("Phelps Dodge") and Arizonans for Electric Choice and Competition ("AECC"). AECC is a business coalition that advocates on behalf of retail electric customers in Arizona.

Q. Are you the same Kevin C. Higgins who submitted direct testimony on behalf of Phelps Dodge and AECC with respect to Revenue Requirements?

A. Yes, I am.

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

A. My testimony addresses cost-of-service, rate spread, and rate design issues pertaining to the general rate case filed by Arizona Public Service Company ("APS").

Q. What are your conclusions and recommendations with respect to these topics?

A. I offer the following conclusions and recommendations:

- APS's use of the 4-CP method for allocating fixed production cost is appropriate given the Company's system load characteristics and should be accepted by the Commission.

- APS's proposed rate spread continues the current practice of requiring General Service customers to subsidize Residential rates. According to APS's cost-of-service study, General Service rates would have to increase 14.88 percent and Residential rates would have to increase 27.05 percent for the Company to recover its requested revenue requirement (excluding the proposed Environmental Improvement Charge). Instead, APS has proposed a 21.6 percent increase for General Service rates and a 21.14 percent increase for Residential rates.

- APS's fuel and purchased power costs vary considerably throughout the year, as well as during the course of each day. Generally, these costs are higher in summer, and for any given day, higher during the peak hours of the afternoon and evening. Yet, the Company's allocation of its energy costs across customer classes does not take into consideration the variation in class usage across seasons or time-of-day. The Company's approach simply allocates fuel and purchased power cost based on the system average cost throughout the year. Such an approach understates the energy cost responsibility for those customer classes whose usage is more heavily weighted toward the more expensive summer and daily on-peak periods. In turn, this practice overstates the cost responsibility for the remaining classes. To better align the allocation of APS's energy cost with cost causation, I have added a step to APS's cost-of-service analysis in which the Company's hourly fuel and purchased power costs are allocated based on each class's actual usage for each of the 8,760 hours of the test year. I recommend that rate spread be guided by the results of this modified version of the APS cost-of-service study, to reflect the hourly allocation of fuel and purchased power costs.

- With respect to rate spread, I recommend the following approach:

  (1) Set Residential rates midway between system average percentage increase and Residential cost-of-service, as modified to include an hourly energy allocation.
  (2) Set the percentage increase for Street Lighting equal to Residential.
  (3) Set Rates E-34 and E-35 equal to cost-of-service, as modified to include an hourly energy allocation.

(4) Set the percentage increase for Rate E-32, Water Pumping, and Dusk-to-Dawn equal to the respective cost-of-service for each, as modified to include an hourly energy allocation, plus the same percentage point increase necessary to fund the Residential rate mitigation.

- For all customers with demand meters (e.g., Rates E-32 [> 20 kW], E-34, E-35), except partial requirements customers, the transmission revenue requirement should be recovered exclusively through a demand charge instead of an energy charge.

- The generation rate increases that APS has proposed for Rates E-32, E-34, and E-35 are heavily weighted on the energy charge, with much smaller increases falling on the demand-related charges. As a result, APS's proposed generation demand-related charges for these rate schedules under-collect generation-related demand costs, while the Company's proposed generation energy charges over-collect energy-related costs. This bias unfairly impacts higher-load-factor customers and is unreasonable. Instead, any APS generation rate increase for these rate schedules should be implemented by increasing demand-related revenues and energy-related revenues by an equal percentage.

II. Use of the 4-CP Method for Allocating Fixed Production and Transmission Costs

Q. Do you agree with the Company's use of the 4-CP method for allocating fixed production and transmission costs?

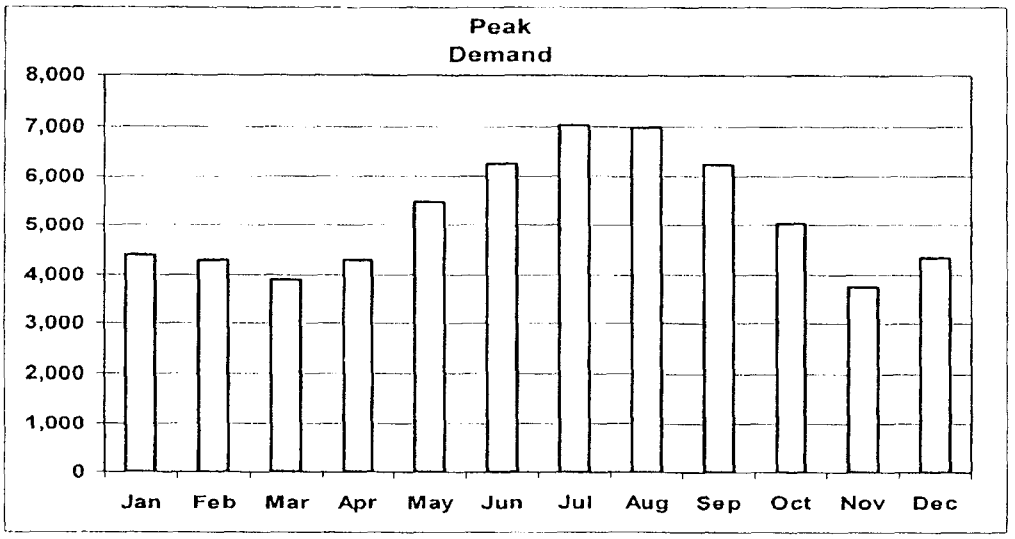
A. Yes, I do.

Q. Please explain the basis for your agreement with APS on this point.

A. APS's retail demands are driven by summer usage, as shown in Figure KCH-1, below. As indicated by that graph, APS's summer peak requirements are quite pronounced. In fact, the Company's average peak of 6,629 MW in the four summer months is 50 percent greater than its average peak of 4,423 MW in the non-summer months.

Figure KCH-1[1]

APS Monthly Peak Demands



The 4-CP method allocates fixed production and transmission costs based on the average of system peak demands in the four summer months, which is when APS's production and transmission capacity requirements are determined. Such an approach properly aligns the allocation of the Company's fixed costs with cost causation. Both this Commission and the FERC have previously recognized the merit of applying the 4-CP method to APS, given the Company's system load characteristics. I recommend approval of APS's continued use of this method in this proceeding.

III. <u>APS proposed rate spread</u>

Q. What general guidelines should be employed in spreading any change in rates?

[1] Source: APS Workpaper PWE WP-11.

A. In determining rate spread, it is important to align rates with cost causation, to the greatest extent practicable. Properly aligning rates with the costs caused by each customer class is essential for ensuring fairness, as it minimizes cross subsidies among customers. It also sends proper price signals, which improves efficiency in resource utilization.

At the same time, it can be appropriate to mitigate the impact of moving immediately to cost-based rates for classes that would experience significant rate increases from doing so. This principle of ratemaking is known as "gradualism." When employing this principle, it is important to adopt a long-term strategy of moving in the direction of cost causation, and to avoid schemes that result in permanent cross-subsidies from other customers.

Q. What rate spread does APS propose and how does it relate to APS's cost-of-service results?

A. Table KCH-1 provides a comparison of APS's proposed rate spread, at APS's proposed revenue requirement, and the rate increases that would apply if each customer class were charged cost-based rates, as determined by APS's cost-of-service study. A more detailed summary of APS's cost-of-service results is shown in Attachment KCH-4.

Note that all proposed rate increases in my testimony are expressed in terms of changes in base rates, exclusive of PSA-related charges. That is, the rate changes are *not* expressed as incremental to the 7-mill-per-kWh Interim PSA Adjustor that was approved in Decision No. 68685, but refer to total changes in rates relative to base rate levels prior to the adoption of the Interim PSA Adjustor.

This approach is necessary in order to maintain consistency between my analysis and APS's filing. (Upon adoption of new base rates pursuant to this proceeding, the Interim PSA Adjustor will be terminated. Thus, as experienced by customers, the incremental rate change resulting from this rate case proceeding will be less than the total rate changes presented here, by the amount of 7-mills-per-kWh.)

Table KCH-1[2]

Comparison of APS Cost-of-Service Results to APS Proposed Rate Change

Class	Rate Change Based on APS COS	APS Proposed Rate Change	Relative Rates of Return Current	Relative Rates of Return APS Proposal
Residential	27.05%	21.14%	0.58	0.82
General Service	14.88%	21.60%	1.51	1.25
E-32	13.40%	21.19%	1.37	1.28
E-34	24.61%	24.61%	0.03	1.00
E-35	24.85%	24.85%	(1.07)	1.00
Water Pumping	(1.15)%	0.14%	3.59	1.07
Street Lighting	42.10%	24.11%	0.79	0.67
Dusk-to-Dawn	17.78%	10.50%	2.23	0.86
Total	21.14%	21.14%	1.00	1.00

As Table KCH-1 shows, APS's cost-of-service study indicates that Residential rates would have to increase 27.05 percent to fund that class's share of the Company's requested $450 million base rate increase, if rates were set at Residential cost-of-service (as calculated by APS). Instead, however, APS proposes that Residential rates increase 21.14 percent, which is exactly the system average.

[2] Source: Attachment KCH-4.

To fund the resulting revenue shortfall, APS proposes that General Service rates increase to a level significantly higher than the cost to serve that customer class. Specifically, the APS cost-of-service study indicates that General Service rates would have to increase 14.88 percent to be priced at cost, but instead APS proposes an increase for this class of 21.60 percent, which is even slightly higher than the Residential class. Within the General Service class, the industrial customer rates of E-34 and E-35 are proposed to be increased by nearly 25 percent, placing these rate schedules exactly on cost-of-service, as calculated by APS.

Under APS's proposal, the bulk of the subsidization burden falls to Rate E-32, which warrants a cost-based increase of 13.4 percent, but is proposed to receive an increase of 21.19 percent.

Q. What is your assessment of the Company's rate spread proposal?

A. In my view, APS's proposal to set the Residential increase at the system average – and to set E-32 rates almost 8 percent above cost in order to make this possible – is not equitable. Gradualism provides for mitigation of rate impacts – but rate increases for classes that are below cost-of-service should generally be set above the system average in order to move them more reasonably toward cost-based rates.

I note here that APS makes no attempt to mitigate the rate impact of its proposed 25 percent increase for the industrial Rates E-34 and E-35, making it difficult to justify on principled grounds that another customer class warranting a 27 percent increase needs somehow to be limited to 21 percent.

Q. What rate spread do you recommend?

A. I present my rate spread recommendation in a later section of my testimony following my discussion of the allocation of energy costs. To properly determine cost-of-service used for rate spread, APS's cost-of-service results should be adjusted to reflect an allocation of the Company's fuel and purchased power costs based on hourly costs. I recommend that the final approved rate spread be guided by the results of this modified version of the APS cost-of-service study reflecting such an hourly cost allocation. I discuss this proposal in the next section of my testimony.

IV. Allocation of Hourly Energy Costs

Q. How are fuel and purchased power costs allocated to customer classes in APS's cost-of-service study?

A. Currently, in APS's cost-of-service study, fuel and purchased power costs ("energy costs") are allocated based on the number of kilowatt-hours each customer class consumes. It makes no difference whether those kilowatt-hours are concentrated in high-cost, summer on-peak periods, or lower-cost, off-peak periods: each kilowatt-hour is assigned exactly the same weight.

Q. But aren't APS's rates characterized by seasonal and time-of-use pricing features?

A. Yes. That is how the costs that are allocated to the classes are *collected* from customers. That is a matter of rate design, but rate design should not be confused with cost allocation. Under present practice, the amounts *to be collected*

from each respective class are determined without regard to energy price differences during the course of the year or time of day. Put another way, APS's seasonal and time-of-use rates are designed based on class revenue requirements that are determined based on system average kWh costs throughout the year. These average kWh costs are then "shaped" into seasonal and time-of-use rates as part of the design of each class's rate schedule(s). But no seasonal or time-of-use information is used in determining the allocation of APS energy costs to the customer classes in the first instance.

Q. In your opinion, should seasonal and time-of-use information be used in determining the allocation of energy costs to customer classes?

A. Yes, definitely. Such a step would better align cost responsibility with cost causation, improving fairness and encouraging efficiency in resource utilization through better price signals. While these objectives are often addressed in ratemaking with respect to fixed costs, they are frequently overlooked with respect to energy-related costs. But with the increasing sensitivity of energy costs to seasonality and time-of-use, and with the widespread availability of powerful software packages that can be applied to large data bases to perform the necessary calculations, the time has come to start using seasonal and time-of-use information in determining the allocation of energy costs to customer classes.

Q. Is the need to include seasonal and time-of-use information in determining the class allocation of energy costs particularly important in Arizona?

A. Yes, in Arizona the need is acute. The Commission is well aware that the rapid load growth in the APS service territory is causing great pressure on APS's

costs, with much of the new load requirements occurring in summer when energy costs are most expensive. As the strong summer growth pushes up the system average cost of energy, all customers are negatively impacted – but the greatest percentage rate increases are occurring in the industrial sector.

As part of the record of the Interim proceeding, APS indicated that if its rate increase proposal in this proceeding was approved, the Company's industrial customer rates would rise cumulatively in excess of 40 percent between mid-2003 and early 2007. In my view, this is a matter of very serious concern for Arizona economic development and sustainability. APS's industrial rates are already 52 percent higher than in neighboring Utah, 28 higher than in Colorado, and 5 percent higher than in New Mexico.[3]

The pressure on industrial customer rates in Arizona is exacerbated by the lack of an hourly energy cost allocation in APS's cost-of-service study. While it is fair for industrial customers to pay their share of summer energy costs based on industrial summer usage, it is not fair for the cost of expensive summer usage of other customers to be transferred to industrial customers via the averaging of annual energy costs in the cost-of-service study. And currently, that is what happens. As I explain below, the use of annual average energy cost in assigning class energy cost responsibility is causing the rates for E-34 customers to be inflated by 3 percent, and is causing the rates for E-35 customers to be inflated by over 6 percent.

[3] All comparisons are for a 10 MW, 75% load factor customer. APS rates are for Rate E-34. Utah rates are calculated for PacifiCorp Rate 9, Colorado rates are calculated for Public Service of Colorado Rate Schedule PG, and New Mexico rates are calculated for Public Service Company of New Mexico Large Primary Voltage Rate.

Q. Can you provide a simple example of how this transfer of cost responsibility occurs?

A. Yes, let's assume we have two customer classes, Cooling and Manufacturing. Assume further that we have two pricing periods, Winter and Summer, and that the price of energy is $20/MW in Winter and $50/MWh in Summer. Further, assume that the load for Cooling is 10 MWH in Winter and 40 MWH in Summer, whereas for Manufacturing it is 20 MWH in each period. These assumptions are listed in Table KCH-2, below.

Table KCH-2

Average Energy Cost Allocation – Simple Example

Class	Winter P = $20	Summer P = $50	Annual Totals
Cooling Manufacturing System MWH	10 MWH 20 MWH 30 MWH	40 MWH 20 MWH 60 MWH	50 MWH 40 MWH 90 MWH
System Cost Average Energy Cost	$600 $20	$3,000 $50	$3,600 $40
Cost caused by Cooling Cost allocated to Cooling	$200	$2,000	$2,200 $2,000
Cost caused by Manuf. Cost allocated to Manuf.	$400	$1000	$1,400 $1,600

As shown in Table KCH-2, the Winter cost attributable to the Cooling class is $200 ($20 x 10 MWH) and the Summer cost attributable to this class is $2,000 ($50 x 40 MWH) for a total of $2,200. However, the use of average annual energy cost for cost allocation assigns only $2,000 of cost to this class

($40/MWH x 50 MWH). The difference, of course, is picked up by Manufacturing, which causes $1,400 in energy costs, but is allocated $1,600. Essentially, the higher system costs driven by Cooling's strong summer usage is being transferred, in part, to Manufacturing's Winter usage. This simple example illustrates the transfer of cost responsibility that occurs if seasonal and time-of-use considerations are not incorporated into the allocation of energy costs across classes.

Q. Using this simple example, how would your recommended method allocate energy cost responsibility?

A. My approach would identify that the Cooling class is responsible for causing $200 in energy costs in Winter and $2,000 in Summer, and allocate $2,200 in energy costs to this class. Similarly, it would identify that the Manufacturing class is responsible for $400 in energy costs in Winter and $1,000 in Summer, and allocate $1,400 to that class.

A convenient means to implement these adjustments is to apply an energy cost multiplier of 1.10 to Cooling's average annual cost of $2,000 and to apply an energy cost multiplier of 0.875 to Manufacturing's average annual cost of $1,600.

Q. How do you apply this principle to the APS system?

A. Instead of two classes, there are several, and instead of two periods, there are 8,760 hours, corresponding to each hour in the test period.

Q. How did you calculate the hourly energy cost allocator for the APS system?

A. In response to data requests, APS provided me with its average hourly energy cost for the test period. The Company also provided its load research data

and formulas for computing hourly loads by customer class. I used this information to compute each customer class's energy cost responsibility for each hour of the test period, and then aggregated these results for the test year. I then translated this information into scalars (or energy cost multipliers) which I applied to the energy costs that APS had allocated to each customer class in its cost-of-service study.

A summary of the scalars, or energy cost multipliers, calculated for each class is presented in Table KCH-3, below.

Table KCH-3

Energy Cost Multipliers Applied to APS Energy Cost Allocations to Reflect Hourly Energy Cost Differences between Classes

Class	Energy Cost Multiplier
Residential	1.0323
General Service	
E-32	0.9780
E-34	0.9625
E-35	0.9339
Water Pumping	0.9762
Street Lighting	0.8278
Dusk-to-Dawn	0.8353
Total	1.0000

Q. After you re-calculated each class's energy cost allocation, what step did you take next?

A. I used this new information to recalculate APS's cost-of-service results, changing only the allocation of fuel and purchased power costs to each class. This calculation is presented in Attachment KCH-5 and is summarized in Table KCH-4, below.

Table KCH-4

Comparison of APS and AECC Cost-of-Service Results
Impact of Using Hourly Energy Allocator

Class	Rate Change Based on APS COS	Rate Change Based on AECC COS
Residential	27.05%	28.74%
General Service	14.88%	13.19%
E-32	13.40%	12.14%
E-34	24.61%	21.60%
E-35	24.85%	18.72%
Water Pumping	(1.15)%	(2.82)%
Street Lighting	42.10%	35.16%
Dusk-to-Dawn	17.78%	14.53%
Total	21.14%	21.14%

Q. What do the results of the re-calculated cost-of-service study show?

A. The net impact on the Residential class of including an hourly energy allocator is relatively modest: the overall cost responsibility for Residential customers increases by 1.69 percent. When rate spread mitigation is taken into account, the net impact on Residential rates is even less. However, the beneficial impact on industrial rate schedules more significant: the cost responsibility for Rate E-34 declines 3.01 percent and that of Rate E-35 declines by 6.13 percent.

This is an important result. It demonstrates that increasing the accuracy of energy cost allocation has a significant beneficial impact for Arizona industry, while having a modest impact on Residential customers. This result is especially important in light of the fact that APS is proposing to set rates for industrial customers exactly at cost-of-service. It is essential, then, that these costs are calculated as accurately as possible.

1 **Q. Other than modifying the allocation of energy costs, did you make any other**
2 **changes to APS's cost-of-service study?**
3 A. No. Modifying the allocation of fuel and purchased power to reflect hourly
4 cost and class usage was the only change I made to the study.
5 **Q. Cost-of-service studies frequently apply energy allocators to cost items other**
6 **than fuel and purchased power. Does your modification change any energy**
7 **allocators that are applied to cost items other than fuel and purchased**
8 **power?**
9 A. No. The logical basis for the modification I made is tied to the variation in
10 the cost of fuel and purchased power over the course of the year. There was no
11 reason to modify the energy allocators applied to other cost items in the study.
12 **Q. What is your recommendation to the Commission on this issue?**
13 A. I strongly recommend that the Commission approve the utilization of an
14 hourly energy cost allocator in APS's cost-of-service study. I have made this
15 single modification to APS's cost-of-service study, and urge the adoption of that
16 study, as modified.
17
18 **V. <u>AECC Proposed Rate Spread</u>**
19 **Q. What is your recommended rate spread?**
20 A. As a first step, I recommend setting Residential rates midway between
21 system average percentage increase and Residential cost-of-service. The basis for
22 determining cost-of-service for this purpose should be the re-calculated APS cost-
23 of-service study that incorporates my recommended hourly energy cost allocation,

as shown in Attachment KCH-5. Further, within the General Service customer class, Rates E-34 and E-35 should be set exactly at cost-of-service. These results are presented in Attachment KCH-6 and summarized in Table KCH-5, below.

Table KCH-5

Comparison of APS and AECC Recommended Rate Spread Calculated at APS's Requested Revenue Requirement

Class	APS Proposed Rate Change	AECC Proposed Rate Change
Residential	21.14%	24.94%
General Service	21.60%	17.34%
E-32	21.19%	16.97%
E-34	24.61%	21.60%
E-35	24.85%	18.72%
Water Pumping	0.14%	2.01%
Street Lighting	24.11%	24.94%
Dusk-to-Dawn	10.50%	19.36%
Total	21.14%	21.14%

Q. What are you recommending for the Water Pumping and Dusk-to-Dawn classes?

A. The cost-of-service results indicate that these two relatively-small rate classes warrant rate increases that are less than system average. APS proposes a miniscule increase of 0.14 percent for Water Pumping and an increase of about half the system average for Dusk-to-Dawn of 10.50 percent.

In my opinion, assigning less-than-average increases for these two rate classes is appropriate. But at the same time, Rate E-32 should not be expected to shoulder the full cost burden of mitigating the Residential rate increase. It would be more equitable for Rate E-32, Water Pumping, and Dusk-to-Dawn to each pay

the same percentage above their respective costs-of-service to mitigate the Residential rate increase. My proposed rate spread for the Water Pumping and Dusk-to-Dawn customer classes reflects this principle.

Q. What are you recommending for the Street Lighting class?

A. The cost-of-service study indicates that Street Lighting is below cost-of-service. APS had recommended the system average increase for this class. I recommend basing the Street Lighting rate increase on its cost-of-service, but capping the increase at the same level assigned to Residential. My proposed rate spread for Street Lighting reflects this result.

Q. Do you have any other rate spread recommendations for specific rate schedules?

A. Yes. In the last rate proceeding, Rate E-32-TOU was created as an option for E-32 customers to move to time-of-use rates. In this proceeding, APS's proposed rate increase for Rate E-32-TOU is 34.72 percent – more than 50 percent higher than the Company's recommended increase for Rate E-32. I believe this dramatic differential would strongly discourage E-32 customers from switching to time-of-use rates. Instead, the rate increase for Rate E-32-TOU should be set equal to the rate increase for Rate E-32, to retain the same relationship between these two rate schedules that was established in the last proceeding.

Q. What approach to rate spread should be adopted if the Company's requested revenue requirement is reduced by the Commission?

A. If the Company's requested rate increase is reduced by the Commission, then the rate increase necessary for each customer class to have its rates set at cost-of-service will be reduced. In this case, these new cost-based rate changes should be re-calculated or estimated by APS in a compliance filing, using the energy cost multipliers developed in my analysis to reflect hourly energy cost responsibility. Then, the same basic formulation I recommended above should be applied:

(1) Set Residential rates midway between system average percentage increase and Residential cost-of-service.

(2) Set the percentage increase for Street Lighting equal to Residential.

(3) Set Rates E-34 and E-35 equal to cost-of-service.

(4) Set the percentage increase for Rate E-32, Water Pumping, and Dusk-to-Dawn equal to the respective cost-of-service for each, plus the same percentage point increase necessary to fund the Residential mitigation.

VI. Rate Design

A. Transmission Rate Design

Q. What has APS proposed with respect to transmission rate design?

A. APS has proposed to levy a flat 4.76 mills-per-kWh unbundled transmission charge for all customers. This is the same rate design that was adopted in the previous general rate case.

Q. Do you agree with this rate design?

A. No. This rate design was acceptable as part of a settlement package in the prior rate case, but as transmission charges are 100 percent demand-related, these charges should be billed to customers who have demand meters through a demand charge. The one exception to this rule should be customers with distributed generation who take partial requirements service, as the service needs for these customers are unique.

Q. What rate design do you recommend instead?

A. I am not recommending any change in the transmission rate design for Residential customers, partial requirements customers, or non-residential customers without demand meters. But for all other customers with demand meters (e.g., Rates E-32 [> 20 kW], E-34, E-35), I am recommending that the transmission revenue requirement be recovered exclusively through a demand charge instead of an energy charge.

Q. Have you determined what this charge should be?

A. Yes. For E-32 customers with billings demands greater than 20 kW, APS's proposed 4.76 mills-per-kWh charge can be replaced with a demand charge of $1.826 per kW-month. For E-34 customers, the equivalent transmission demand charge is $2.474 per kW-month, and for E-35 customers, it is $2.853 per kW-month. These calculations are shown in Attachment KCH-7.

Alternatively, a single transmission demand charge for all demand-billed General Service customers could be implemented.

1 B. Generation Rate Design

2 **Q. What are your observations regarding APS's proposed generation rate**

3 **design for Rates E-32, E-34, and E-35?**

4 A. The generation rate increases that APS has proposed for Rates E-32, E-34,

5 and E-35 are heavily weighted on the energy charge, with a much smaller increase

6 falling on the demand-related charges, as summarized in Table KCH-6, below.[4]

7 The net effect of APS's proposed generation rate design is that higher-load-factor

8 customers would experience a much greater rate increase than lower-load-factor

9 customers. This impact is demonstrated in the Company's Schedule H-4, which

10 shows the customer bill impacts resulting from the Company's proposed rate

11 changes.

12 **Table KCH-6**

13

14 **APS Proposed Generation Rate Increases by Rate Component**

15

Rate Schedule	APS Proposed Rev. Increase from Demand-Related Charges	APS Proposed Rev. Increase from Energy Charges
E-32 >20 kW	2%	53%
E-34	11%	53%
E-35	12%	48%

Q. In your opinion, is it appropriate for APS to recover such a large proportion

of its proposed generation rate increase on the energy charge of these rate

schedules?

A. No. Attachment KCH-8 compares the Company's proposed unbundled

generation *revenues* to the Company's energy and demand *costs* in its cost-of-

[4] Note that for Rate E-32, APS's generation-related demand costs are not collected through a demand charge, but are collected as part of the first energy block, which is collected on a "first 200 kWh per kW basis."

service study. For each of these rate schedules, APS's proposed generation demand charge (or demand-related charge) under-collects the rate schedule's generation-related demand costs. At the same time, the Company's proposed generation energy charge over-collects the rate schedule's energy-related costs. This information demonstrates that the strong bias in APS's proposed rate increase toward increasing the generation energy charge is unwarranted. This bias unfairly impacts higher-load-factor customers and is unreasonable.

Q. From a customer's perspective, why should it matter if APS proposes a demand charge that does not fully recover its demand-related costs?

A. If a utility proposes a demand charge that is below the cost of demand, then the utility is going to seek to recover the revenue requirement for that rate schedule by over-recovering its costs in another area, most typically through levying an energy charge that is above unit energy costs, which is the case here. For a given rate schedule, when demand charges are set below cost, and energy charges are set above cost, those customers with relatively higher load factors end up subsidizing the costs of the lower-load-factor customers within the rate class.

Q. Why is it important for rate design to be representative of underlying cost causation?

A. Aligning rate design with underlying cost causation improves efficiency because it sends proper price signals. For example, setting a demand charge below the cost of demand understates the economic cost of demand-related assets, which in turn distorts consumption decisions, and calls forth a greater level of investment in fixed assets than is economically desirable.

At the same time, aligning rate design with underlying cost causation is important for ensuring equity among customers, because properly aligning with costs minimizes cross-subsidies among customers. As I stated above, if demand costs are understated in utility rates, the costs are made up elsewhere – typically in energy rates. When this happens, higher-load-factor customers (who use fixed assets relatively efficiently through relatively constant energy usage) are forced to pay the demand-related costs of lower-load-factor customers. This amounts to a cross-subsidy that is fundamentally inequitable.

Q. What generation rate design approach do you recommend?

A. For Rate E-34, any generation rate increase should be implemented as an equal percentage increase on both the demand and the energy charge. This approach will produce a better alignment of demand charges with demand costs, and energy charges with energy costs, relative to the Company's approach. It will have the additional advantage of removing any load-factor bias in the generation rate increase. That is, the generation rate increase would impact high- and low-load-factor customers on a proportionate basis.

For Rate E-32 customers with billing demands greater than 20 kW, any generation rate increase should be implemented as an equal percentage increase on the first energy block (i.e., the first 200 kWh/kW block) and the second energy block. As is the case for Rates E-34, this approach will produce a better alignment of demand charges with demand costs, and energy charges with energy costs, relative to the Company's approach. It will also have the additional advantage of removing any load-factor bias in the generation rate increase. That is, the

generation rate increase would impact high- and low-load-factor customers on a proportionate basis.

For Rate E-35, any generation rate increase should be implemented as an equal percentage increase on the energy charges and on "demand charge revenues in the aggregate." For Rate E-35, demand charge revenues need to be treated on an aggregate basis due to APS's proposed change in the definition of the off-peak demand charge for this rate schedule. As is the case for Rates E-32 and E-34, this approach will produce a better alignment of demand charges with demand costs, and energy charges with energy costs, relative to the Company's approach. It will also have the additional advantage of removing any load-factor bias in the generation rate increase.

Q. Does this conclude your direct testimony?

A. Yes, it does.

Summary of APS's Cost of Service Results

Revenue Increase Required to Move each Customer Class to Cost of Service using APS' Cost of Service Results

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
Line No.	Rate Class	Current Retail Revenues	Rate Base	Current Return	APS Current Rate of Return	APS Current Relative Rate of Return	APS Required Return @ Equal ROR of 8.73%	Req'd Rev. Increase w/o EIC @ Conversion Factor of 1.6407	Percent Change @ Equal ROR
1	Residential	$1,089,551,030	$2,489,739,663	$37,745,444	1.52%	0.58	$217,354,273	$294,684,796	27.05%
2	General Service								
3	E-20	$3,586,700	$7,360,472	$623,406	8.47%	3.26	$642,569	$31,441	0.88%
4	E-32	$859,172,589	$1,664,603,376	$75,138,666	4.51%	1.74	$145,319,875	$115,146,540	13.40%
5	E-34	$66,719,281	$115,618,777	$86,584	0.07%	0.03	$10,093,519	$16,418,412	24.61%
6	E35	$67,661,237	$88,981,169	($2,480,075)	-2.79%	(1.07)	$7,768,056	$16,814,142	24.85%
7	General Service Total	$997,139,807	$1,876,563,794	$73,368,581	3.91%	1.51	$163,824,019	$148,410,535	14.88%
8	Water Pumping (E-38, E-221)	$20,864,101	$25,474,477	$2,370,299	9.30%	3.59	$2,223,922	($240,161)	-1.15%
9	Street Lighting	$13,344,265	$51,298,120	$1,053,936	2.05%	0.79	$4,478,326	$5,618,408	42.10%
10	Dusk to Dawn	$6,422,696	$23,620,450	$1,366,217	5.78%	2.23	$2,062,065	$1,141,681	17.78%
11	ACC Total	$2,127,321,899	$4,466,696,504	$115,904,477	2.59%	1.00	$389,942,605	$449,615,257	21.14%

Data Source: APS Workpaper DJR_WP1

APS Proposed Revenue Increase without EIC for each Customer Class using APS' Cost of Service Results

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
Line No.	Rate Class	Current Retail Revenues	Rate Base	Proposed Return	APS Proposed Rate of Return	APS Proposed Relative Rate of Return	Change from Current Return	Rev. Increase w/o EIC @ Conversion Factor 1.6407	APS Proposed Percent Change
12	Residential	$1,089,551,030	$2,489,739,663	$178,138,344	7.15%	0.82	$140,392,900	$230,343,093	21.14%
13	General Service								
14	E-20	$3,586,700	$7,360,472	$642,641	8.73%	1.00	$19,235	$31,558	0.88%
15	E-32	$859,172,589	$1,664,603,376	$186,118,703	11.18%	1.28	$110,980,037	$182,085,312	21.19%
16	E-34	$66,719,281	$115,618,777	$10,094,296	8.73%	1.00	$10,007,712	$16,419,686	24.61%
17	E35	$67,661,237	$88,981,169	$7,767,902	8.73%	1.00	$10,247,977	$16,813,890	24.85%
18	General Service Total	$997,139,807	$1,876,563,794	$204,623,542	10.90%	1.25	$131,254,961	$215,350,445	21.60%
19	Water Pumping (E-38, E-221)	$20,864,101	$25,474,477	$2,388,379	9.38%	1.07	$18,080	$29,663	0.14%
20	Street Lighting	$13,344,265	$51,298,120	$3,014,967	5.88%	0.67	$1,961,031	$3,217,471	24.11%
21	Dusk to Dawn	$6,422,696	$23,620,450	$1,777,373	7.52%	0.86	$411,156	$674,584	10.50%
22	ACC Total	$2,127,321,899	$4,466,696,504	$389,942,605	8.73%	1.00	$274,038,128	$449,615,257	21.14%

APS's Cost of Service Results Adjusted to Reflect Hourly Fuel and Purchased Power Costs

Revenue Increase Required to Move each Customer Class to Cost of Service using AECC's Proposed Hourly Energy Cost Allocation Method

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
Line No.	Rate Class	Current Retail Revenues	Rate Base	Return Req'd Return @ Equal ROR	Equalized Rate of Return	Equalized Relative Rate of Return	Required Revenue Increase w/o EIC	Required Revenue Increase	Req'd Percent Change
1	Residential	$1,089,551,030	$2,489,739,663	$217,354,273	8.73%	1.00	$1,402,634,119	$313,083,089	28.74%
2	General Service								
3	E-20	$3,586,700	$7,360,472	$642,569	8.73%	1.00	$3,685,034	$98,334	2.74%
4	E-32	$859,172,589	$1,664,603,376	$145,319,875	8.73%	1.00	$963,502,314	$104,329,725	12.14%
5	E-34	$66,719,281	$115,618,777	$10,093,519	8.73%	1.00	$81,129,877	$14,410,596	21.60%
6	E35	$67,661,237	$88,981,169	$7,768,056	8.73%	1.00	$80,329,232	$12,667,995	18.72%
7	General Service Total	$997,139,807	$1,876,563,794	$163,824,019	8.73%	1.00	$1,128,646,457	$131,506,650	13.19%
8	Water Pumping (E-38, E-221)	$20,864,101	$25,474,477	$2,223,922	8.73%	1.00	$20,276,356	($587,745)	-2.82%
9	Street Lighting	$13,344,265	$51,298,120	$4,478,326	8.73%	1.00	$18,036,625	$4,692,360	35.16%
10	Dusk to Dawn	$6,422,696	$23,620,450	$2,062,065	8.73%	1.00	$7,356,001	$933,305	14.53%
11	ACC Total	$2,127,321,899	$4,466,696,504	$389,942,605	8.73%	1.00	$2,576,949,558	$449,627,659	21.14%

Summary of Energy Cost Multipliers (Relecting Hourly Energy Cost Differences)

	Residential					
	E-10	E-12	EC-1	ET-1	ECT-1R	Residential Total
Overall Retail Energy Cost (¢/kWh)	3.1904	3.1904	3.1904	3.1904	3.1904	3.1904
Class Cost Ratio (Step 3)	1.0179	1.0275	1.0244	1.0398	1.0241	1.0323
Class Energy Rate (¢/kWh)	3.2475	3.2781	3.2684	3.3175	3.2674	3.2936
Energy Use @ Generation (MWh)	852,812	4,001,457	504,571	6,373,509	1,478,487	13,210,836
Energy Use @ Meter (MWh)	793,929	3,725,172	469,732	5,933,443	1,376,403	12,298,679
Energy Revenue ($)	$25,783,227	$122,115,055	$15,352,556	$196,840,323	$44,972,271	$405,063,432

	General Service								
	Church Rate E-20	0 - 20 kW E-21, E-23, E-30 E-32 & E-32 TOU	21 - 100 kW E-22, E-32 & E-32 TOU	101-400 kW E-32 & E-32 TOU	401-999 kW E-24, E-32 & E-32 TOU	1000 + kW E-32 & E-32 TOU	E-32 Total	E-34	E-35
Overall Retail Energy Cost (¢/kWh)	3.1904	3.1904	3.1904	3.1904	3.1904	3.1904	3.1904	3.1904	3.1904
Class Cost Ratio (Step 3)	1.0402	0.9805	0.9818	0.9813	0.9744	0.9685	0.9780	0.9625	0.9339
Class Energy Rate (¢/kWh)	3.3186	3.1282	3.1324	3.1308	3.1088	3.0898	3.1203	3.0707	2.9796
Energy Use @ Generation (MWh)	38,650	1,404,282	2,696,965	3,314,293	2,310,169	1,714,920	11,440,629	1,242,014	1,455,999
Energy Use @ Meter (MWh)	36,618	1,307,541	2,511,175	3,140,255	2,188,928	1,626,501	10,774,400	1,178,438	1,397,289
Energy Revenue ($)	$1,215,190	$40,901,867	$78,661,029	$98,314,070	$68,049,629	$50,255,946	$336,190,235	$36,186,552	$41,633,187

	Water Pumping E-38/E-221	Streetlights	Dusk to Dawn	ACC Total
Overall Retail Energy Cost (¢/kWh)	3.1904	3.1904	3.1904	3.1904
Class Cost Ratio (Step 3)	0.9762	0.8278	0.8353	1.0000
Class Energy Rate (¢/kWh)	3.1146	2.6410	2.6651	3.1904
Energy Use @ Generation (MWh)	339,389	124,808	29,370	27,881,695
Energy Use @ Meter (MWh)	321,550	114,924	27,044	36,923,342
Energy Revenue ($)	$10,014,931	$3,035,197	$720,749	$1,178,002,303

(Note: Hourly load data based on 12 months ending Sept. 30, 2005)
(Note: Overall energy cost of 3.1904 ¢/kWh based on 12 months ending Dec. 31, 2006)

AECC's Adjusted Cost of Service Study Using Energy Scalars
for Fuel and Purchased Power Costs
for the 12 Months ending Sep. 30, 2005
(5)

Line No.	1 Description	2 Allocation Factor	3 Electric Total	4 ACC Jurisdiction	5 All Other	6 Total Residential	7 E-10 Residential	8 E-12 Residential	9 EC-1 Residential	10 ET-1 Residential	11 ECT-1 Residential	12 Total General Service	13 E-20 Church Rate
	SUMMARY OF RESULTS												
16	TOTAL RATE BASE		$5,327,833,192	$4,466,696,504	$861,136,688	$2,489,739,663	$148,234,534	$795,627,566	$79,691,088	$1,227,004,375	$239,182,100	$1,876,563,794	$7,360,472
17													
18	DEVELOPMENT OF RETURN												
19	Revenues from Rates		$2,103,857,729	$2,066,144,726	$37,713,003	$1,058,729,739	$70,337,587	$360,585,198	$36,686,029	$490,471,664	$100,649,261	$967,398,538	$3,344,799
20	Proforma to Revenues from Rates		$68,953,295	$61,177,173	($223,878)	$30,821,291	($2,224,915)	$11,853,176	($1,254,829)	$20,328,518	$2,119,341	$29,741,269	$241,901
21	Other Electric Revenues		$1,344,909,372	$1,313,268,573	$31,640,799	$624,903,158	$40,280,141	$189,690,778	$23,754,957	$301,576,795	$69,600,487	$662,981,780	$1,836,772
22	TOTAL OPERATING REVENUES		$3,509,720,396	$3,440,590,472	$69,129,924	$1,714,454,188	$108,392,813	$562,129,152	$59,186,157	$812,376,977	$172,369,089	$1,660,121,587	$5,423,472
23	Revenue Increase Required to Achieve Equalized ROR		$449,627,659	$449,627,659	$0	$313,083,089	$18,438,156	$77,192,927	$11,369,627	$170,049,197	$36,033,182	$131,506,650	$98,334
24	TOTAL OPERATING REVENUES WITH REVENUE INCREASE		$3,959,348,055	$3,890,218,131	$69,129,924	$2,027,537,277	$126,830,969	$639,322,079	$70,555,784	$982,426,174	$208,402,271	$1,791,628,237	$5,521,806
25	Percent Increase		20.77%	21.14%	0.00%	28.74%	27.07%	20.73%	32.09%	33.29%	35.06%	13.19%	2.74%
24													
25	OPERATING EXPENSES												
26													
27	O&M Energy Related												
28	Energy Production	Energy1	$74,369,000	$73,170,843	$1,198,157	$34,692,327	$2,239,528	$10,508,029	$1,325,029	$16,737,158	$3,882,582	$37,182,385	$101,497
29	Energy Production - Related Fuel (M&T)	Energy2	$842,735,000	$829,157,722	$13,577,278	$393,126,677	$25,377,890	$119,074,939	$15,014,971	$189,662,215	$43,996,662	$421,343,530	$1,150,143
30	Energy Production - Related Fuel	Energy100	$885,397,911	$871,149,260	$14,248,651	$426,382,540	$27,140,225	$128,542,154	$16,160,595	$207,200,327	$47,339,237	$430,410,906	$1,256,908
31	Total Energy Related		$1,802,501,911	$1,773,477,826	$29,024,085	$854,201,543	$54,757,643	$258,125,123	$32,500,595	$413,599,700	$95,218,481	$888,936,821	$2,508,548
32	O&M Non-Energy Related		$443,510,785	$528,986,908	($85,476,123)	$301,820,410	$19,684,036	$102,391,452	$9,791,173	$142,143,302	$27,810,447	$216,936,518	$643,832
33	Operation & Maintenance		$2,246,012,696	$2,302,464,734	($56,452,038)	$1,156,021,953	$74,441,680	$360,516,575	$42,291,768	$555,743,002	$123,028,928	$1,105,873,339	$3,152,380
34	Administrative & General		$141,768,184	$132,687,129	$9,081,055	$81,444,413	$5,435,590	$28,926,720	$2,483,640	$37,721,841	$6,876,622	$48,487,581	$168,558
35	Depreciation & Amortization Expense		$321,526,002	$285,758,992	$35,767,010	$159,732,184	$9,911,645	$51,449,950	$5,249,433	$77,904,622	$15,216,534	$119,779,815	$441,855
36	Amortization on Gain		($6,613,637)	($6,528,054)	($85,583)	($3,299,367)	($196,177)	($991,655)	($116,349)	($1,649,307)	($354,879)	($3,172,586)	($7,702)
37	Regulatory Assets		($2,203,511)	($2,203,511)	$0	($1,144,246)	($65,676)	($342,833)	($38,994)	($575,685)	($121,058)	($1,049,237)	($2,397)
38	Pro-Forma Energy Related - Jurisdictional	Energy100'	$61,052,503	$60,070,266	$982,237	$29,401,291	$1,871,459	$8,863,649	$1,114,357	$14,287,539	$3,264,286	$29,679,067	$86,670
39	Pro-Forma Energy Related - ACC	Energy100'	$269,376,144	$269,376,144	$0	$131,845,700	$8,392,281	$39,747,712	$4,997,168	$64,070,335	$14,638,205	$133,091,349	$388,660
40	Pro-Forma Energy Related - ACC(Weather & Cust)	Assigned	$18,114,000	$18,114,000	$0	$9,044,540	($677,719)	$3,428,524	($350,866)	$5,867,427	$777,174	$9,157,238	$56,452
41	Pro-Forma Non-Energy Related		$485,465,130	$477,680,531	$7,784,599	$80,661,617	$4,686,627	$26,134,252	$2,515,995	$39,350,626	$7,974,117	$66,749,536	$154,603
42	Proforma Adjustments		$504,561,367	$495,794,531	$8,766,836	$250,953,148	$14,272,648	$78,174,137	$8,276,654	$123,575,927	$26,653,782	$238,677,190	$686,386
43	Taxes Other than Income		$139,970,769	$116,332,656	$23,638,113	$65,666,582	$4,071,767	$21,173,025	$2,145,953	$32,890,164	$6,185,673	$47,839,519	$190,638
44	Income Tax		$185,532,148	$175,969,050	$9,563,098	$100,808,337	$6,018,617	$30,957,874	$3,306,647	$50,489,128	$10,036,071	$71,368,597	$249,519
45	TOTAL OPERATING EXPENSES		$3,530,554,018	$3,500,275,527	$30,278,491	$1,810,183,004	$113,890,094	$569,863,793	$63,598,752	$875,308,692	$187,521,673	$1,627,804,218	$4,879,237
46													
47	OPERATING INCOME		$428,794,038	$389,942,605	$38,851,433	$217,354,273	$12,940,875	$69,458,287	$6,957,032	$107,117,482	$20,880,597	$163,824,019	$642,569
48													
49	RETURN		$428,794,038	$389,942,605	$38,851,433	$217,354,273	$12,940,875	$69,458,287	$6,957,032	$107,117,482	$20,880,597	$163,824,019	$642,569
50													
51	RATE OF RETURN (EQUALIZED)		8.05%	8.73%	4.51%	8.73%	8.73%	8.73%	8.73%	8.73%	8.73%	8.73%	8.73%
52													
53	INDEX RATE OF RETURN		1.00	1.08	0.56	1.08	1.08	1.08	1.08	1.08	1.08	1.08	1.08
54													
55	ACC JURISDICTION INDEX RATE OF RETURN			1.00		1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
	Tax Calculation:		843593			858							
	Operating Revenues		815224	28369	27511								
	Operating Expenses Before Income Taxes		$3,959,348,055	$3,890,218,131	$69,129,924	$2,027,537,277	$126,830,969	$639,322,079	$70,555,784	$982,426,174	$208,402,271	$1,791,628,237	$5,521,806
	Operating Income Before Interest and Income Taxes		$3,345,021,870	$3,324,306,477	$20,715,393	$1,709,374,667	$107,871,477	$538,905,919	$60,292,105	$824,819,564	$177,485,605	$1,556,435,621	$4,629,717
			$614,326,185	$565,911,654	$48,414,531	$318,162,609	$18,959,491	$100,416,160	$10,263,679	$157,606,610	$30,916,668	$235,192,616	$892,089
	Interest Expense:												
	Rate Base		$5,327,833,192	$4,466,696,504	$861,136,688	$2,489,739,663	$148,234,534	$795,627,566	$79,691,088	$1,227,004,375	$239,182,100	$1,876,563,794	$7,360,472
	Long Term Debt Rate		2.46%	2.46%	2.46%	2.46%	2.46%	2.46%	2.46%	2.46%	2.46%	2.46%	2.46%
	Interest Expense (RB x LTD)		$131,147,279	$109,949,968	$21,197,310	$61,286,187	$3,648,867	$19,584,770	$1,961,636	$30,203,326	$5,887,587	$46,192,556	$181,182
	State Taxable Income		$483,178,907	$455,961,686	$27,217,221	$256,876,422	$15,310,624	$80,831,390	$8,302,043	$127,403,284	$25,029,081	$189,000,060	$710,907
	State Income Tax Rate		6.23%	6.23%	6.23%	6.23%	6.23%	6.23%	6.23%	6.23%	6.23%	6.23%	6.23%
	State Income Taxes		$30,106,048	$28,410,190	$1,695,858	$16,005,529	$953,979	$5,036,465	$517,286	$7,938,280	$1,559,519	$11,776,269	$44,295
	Federal Taxable Income		$453,072,858	$427,551,496	$25,521,362	$240,870,893	$14,356,646	$75,794,925	$7,784,757	$119,465,004	$23,469,562	$177,223,791	$666,612
	Federal Income Tax Rate		35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%
	Federal Income Taxes		$158,575,500	$149,643,024	$8,932,477	$84,304,813	$5,024,826	$26,528,224	$2,724,665	$41,812,751	$8,214,347	$62,028,327	$233,314
	Total State and Federal Income Taxes		$188,681,549	$178,053,214	$10,628,335	$100,310,342	$5,978,805	$31,564,689	$3,241,951	$49,751,031	$9,773,866	$73,804,596	$277,609
	Proforma Production Income Tax Adjustment - Demand		($1,784,029)	($1,763,462)	($20,567)	($915,736)	($52,560)	($274,368)	($31,207)	($460,719)	($96,882)	($839,701)	($1,918)
	Proforma Production Income Tax Adjustment - Energy		($78,374)	($77,111)	($1,263)	($36,561)	($2,360)	($11,074)	($1,396)	($17,639)	($4,092)	($39,185)	($107)
	Proforma Production Income Tax Adjustment		($1,286,998)	($243,591)	($1,043,407)	$1,450,292	$94,732	($321,373)	$97,299	$1,216,455	$363,179	($1,557,113)	($26,065)
	Total Income Taxes		$185,532,148	$175,969,050	$9,563,098	$100,808,337	$6,018,617	$30,957,874	$3,306,647	$50,489,128	$10,036,071	$71,368,597	$249,519

AECC's Adjusted Cost of Service Study Using Energy Scalars
for Fuel and Purchased Power Costs
for the 12 Months ending Sep. 30, 2005
($)

Line No.	1 Description	2 Allocation Factor	E-30, E-32 Total	14 E-30, E-32 (0 - 20 kW)	15 E-32 (21 - 100 kW)	16 E-32 (101 - 400 kW)	17 E-32 (401 - 999 kW)	18 E-32 (1,000 + kW)	19 E-34	20 E-35	21 E-38, 221 Water Pumping	22 Street Lighting	23 Dusk to Dawn
	SUMMARY OF RESULTS												
16	TOTAL RATE BASE		$1,664,603,376	$378,234,736	$469,359,372	$410,940,132	$228,078,549	$177,990,587	$115,618,777	$88,981,169	$25,474,477	$51,298,120	$23,620,450
17													
18	DEVELOPMENT OF RETURN												
19	Revenues from Rates		$830,331,951	$142,275,889	$218,138,380	$129,640,445	$146,123,538	$94,153,699	$66,695,622	$67,026,166	$20,966,540	$12,913,853	$6,136,856
20	Proforma to Revenues from Rates		$28,840,638	$9,060,700	$3,862,319	$13,851,012	$1,053,159	$1,013,448	$23,659	$635,071	($102,439)	$431,212	$285,840
21	Other Electric Revenues		$535,912,322	$67,075,107	$127,027,116	$155,000,606	$107,242,574	$79,566,919	$57,813,897	$67,418,789	$15,739,104	$8,074,267	$1,570,264
22	TOTAL OPERATING REVENUES		$1,395,084,911	$218,411,696	$349,027,815	$398,492,063	$254,419,271	$174,734,066	$124,533,178	$135,080,026	$36,603,205	$21,418,532	$7,992,960
23	Revenue Increase Required to Achieve Equalized ROR		$104,329,725	$30,894,780	$27,549,990	$14,900,922	$7,219,198	$23,764,834	$14,410,596	$12,667,995	($587,744.7)	$4,692,360	$933,305
24	TOTAL OPERATING REVENUES WITH REVENUE INCREASE		$1,499,414,636	$249,306,476	$376,577,805	$413,392,985	$261,638,469	$198,498,900	$138,943,774	$147,748,021	$36,015,460	$26,110,892	$8,926,265
25	Percent Increase		12.34%	20.41%	12.41%	6.12%	4.91%	24.97%	21.60%	18.72%	-2.82%	35.16%	14.53%
26													
27	OPERATING EXPENSES												
28													
29	O&M Energy Related												
30	Energy Production	Energy1	$29,995,769	$3,687,388	$7,082,367	$8,703,502	$6,038,893	$4,483,619	$3,261,592	$3,823,527	$891,253	$327,752	$77,127
31	Energy Production - Related Fuel (M&T)	Energy2	$339,906,198	$41,784,757	$80,256,003	$98,626,385	$68,431,554	$50,807,500	$36,959,723	$43,327,466	$10,099,502	$3,714,023	$873,989
32	Energy Production - Related Fuel	Energy100	$349,267,098	$43,043,545	$82,787,067	$101,682,496	$70,057,238	$51,696,753	$37,374,165	$42,512,734	$10,358,616	$3,230,153	$767,046
33	Total Energy Related		$719,169,065	$88,515,690	$170,125,436	$209,012,382	$144,527,685	$106,987,872	$77,595,480	$89,663,727	$21,349,371	$7,271,928	$1,718,163
34	O&M Non-Energy Related		$186,519,760	$39,935,977	$49,240,450	$47,241,310	$28,103,553	$21,998,470	$15,082,655	$14,690,272	$3,635,216	$5,209,795	$1,384,969
35	Operation & Maintenance		$905,688,826	$128,451,666	$219,365,886	$256,253,693	$172,631,238	$128,986,343	$92,678,134	$104,353,999	$24,984,587	$12,481,723	$3,103,132
36	Administrative & General		$42,560,789	$10,453,288	$11,676,787	$10,128,362	$5,827,742	$4,474,610	$3,006,658	$2,751,576	$880,883	$1,303,165	$571,087
37	Depreciation & Amortization Expense		$105,486,858	$23,085,668	$29,369,824	$26,524,854	$15,018,891	$11,487,621	$7,583,550	$6,267,552	$1,842,301	$3,034,821	$1,369,871
38	Amortization on Gain		($2,680,293)	($476,581)	($702,487)	($718,845)	($430,995)	($351,385)	($241,284)	($243,367)	($45,007)	($8,981)	($2,113)
39	Regulatory Assets		($905,344)	($182,950)	($247,693)	($234,916)	($129,353)	($111,332)	($74,806)	($67,490)	($10,028)	$0	$0
40	Pro-Forma Energy Related - Jurisdictional	Energy100'	$24,083,780	$2,968,076	$5,708,598	$7,011,536	$4,830,810	$3,564,760	$2,577,143	$2,931,474	$714,280	$222,736	$52,892
41	Pro-Forma Energy Related - ACC	Energy100'	$108,008,119	$13,309,894	$25,599,357	$31,442,188	$21,663,048	$15,985,633	$11,556,812	$13,145,757	$3,203,084	$998,825	$237,186
42	Pro-Forma Energy Related - ACC(Weather & Cust)	Assigned	$9,679,725	$2,669,378	$500,908	$6,436,947	$40,808	$31,684	($578,939)	$0	($125,097)	$37,319	$0
43	Pro-Forma Non-Energy Related		$57,260,104	$11,831,089	$14,879,773	$15,349,113	$8,287,116	$6,993,013	$4,637,795	$4,697,034	$767,202	$50,580	$5,186
44	Proforma Adjustments		$199,023,729	$30,778,437	$46,688,636	$60,239,784	$34,741,783	$26,575,089	$18,192,811	$20,774,265	$4,559,469	$1,309,460	$295,263
45	Taxes Other than Income		$42,553,612	$9,622,639	$12,021,204	$10,585,525	$5,888,989	$4,435,255	$2,889,635	$2,285,634	$739,434	$1,432,424	$654,697
46	Income Tax		$62,366,584	$14,554,417	$17,430,575	$14,738,555	$8,178,917	$7,464,121	$4,814,757	$3,937,736	$839,900	$2,079,954	$872,263
47	TOTAL OPERATING EXPENSES		$1,354,094,761	$216,286,584	$335,602,732	$377,517,912	$241,727,212	$182,960,322	$128,850,255	$139,979,965	$33,791,538	$21,632,566	$6,864,200
48													
49	OPERATING INCOME		$145,319,875	$33,019,892	$40,975,073	$35,875,074	$19,911,257	$15,538,578	$10,093,519	$7,768,056	$2,223,922	$4,478,326	$2,062,065
50													
51	RETURN		$145,319,875	$33,019,892	$40,975,073	$35,875,074	$19,911,257	$15,538,578	$10,093,519	$7,768,056	$2,223,922	$4,478,326	$2,062,065
52													
53	RATE OF RETURN (EQUALIZED)		8.73%	8.73%	8.73%	8.73%	8.73%	8.73%	8.73%	8.73%	8.73%	8.73%	8.73%
54													
55	INDEX RATE OF RETURN		1.08	1.08	1.08	1.08	1.08	1.08	1.08	1.08	1.08	1.08	1.08
	ACC JURISDICTION INDEX RATE OF RETURN		1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
	Tax Calculation:												
	Operating Revenues		$1,499,414,636	$249,306,476	$376,577,805	$413,392,985	$261,638,469	$198,498,900	$138,943,774	$147,748,021	$36,015,460	$26,110,892	$8,926,265
	Operating Expenses Before Income Taxes		$1,291,728,177	$201,732,167	$318,172,157	$362,779,357	$233,548,295	$175,496,201	$124,035,498	$136,042,229	$32,951,639	$19,552,612	$5,991,937
	Operating Income Before Interest and Income Taxes		$207,686,459	$47,574,309	$58,405,648	$50,613,628	$28,090,175	$23,002,699	$14,908,276	$11,705,792	$3,063,821	$6,558,279	$2,934,328
	Interest Expense:												
	Rate Base		$1,664,603,376	$378,234,736	$469,359,372	$410,940,132	$228,078,549	$177,990,587	$115,618,777	$88,981,169	$25,474,477	$51,298,120	$23,620,450
	Long Term Debt Rate		2.46%	2.46%	2.46%	2.46%	2.46%	2.46%	2.46%	2.46%	2.46%	2.46%	2.46%
	Interest Expense (RB x LTD)		$40,975,045	$9,310,437	$11,553,516	$10,115,497	$5,614,268	$4,381,327	$2,846,014	$2,190,316	$627,067	$1,262,729	$581,429
	State Taxable Income		$166,711,415	$38,263,872	$46,852,132	$40,498,132	$22,475,907	$18,621,372	$12,062,262	$9,515,476	$2,436,754	$5,295,551	$2,352,899
	State Income Tax Rate		6.23%	6.23%	6.23%	6.23%	6.23%	6.23%	6.23%	6.23%	6.23%	6.23%	6.23%
	State Income Taxes		$10,387,502	$2,384,156	$2,919,276	$2,523,369	$1,400,435	$1,160,266	$751,579	$592,893	$151,830	$329,957	$146,605
	Federal Taxable Income		$156,323,912	$35,879,716	$43,932,856	$37,974,763	$21,075,472	$17,461,106	$11,310,683	$8,922,583	$2,284,924	$4,965,594	$2,206,294
	Federal Income Tax Rate		35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%
	Federal Income Taxes		$54,713,369	$12,557,901	$15,376,500	$13,291,167	$7,376,415	$6,111,387	$3,958,739	$3,122,904	$799,724	$1,737,958	$772,203
	Total State and Federal Income Taxes		$65,100,871	$14,942,057	$18,295,776	$15,814,536	$8,776,850	$7,271,653	$4,710,318	$3,715,797	$951,554	$2,067,915	$918,808
	Proforma Production Income Tax Adjustment - Demand		($724,544)	($146,415)	($198,228)	($187,282)	($103,521)	($89,098)	($59,227)	($54,012)	($8,025)	$0	$0
	Proforma Production Income Tax Adjustment - Energy		($31,611)	($3,886)	($7,464)	($9,172)	($6,364)	($4,725)	($3,437)	($4,030)	($939)	($345)	($81)
	Proforma Production Income Tax Adjustment		($1,978,132)	($237,339)	($659,509)	($879,527)	($488,048)	$286,291	$167,103	$279,981	($102,690)	$12,384	($46,464)
	Total Income Taxes		$62,366,584	$14,554,417	$17,430,575	$14,738,555	$8,178,917	$7,464,121	$4,814,757	$3,937,736	$839,900	$2,079,954	$872,263

Allocation Factor Name	Electric Total	ACC Jurisdiction	All Other	Total Residential	E-10 Residential	E-12 Residential	EC-1 Residential	ET-1 Residential	ECT-1 Residential
Energy1	100.00%	98.39%	1.61%	46.65%	3.01%	14.13%	1.78%	22.51%	5.22%
Energy2	100.00%	98.39%	1.61%	46.65%	3.01%	14.13%	1.78%	22.51%	5.22%
Energy2'		100.00%		47.41%	3.06%	14.36%	1.81%	22.87%	5.31%
Energy100	100.00%	98.39%	1.61%	48.16%	3.07%	14.52%	1.83%	23.40%	5.35%
Energy100'		100.00%		48.94%	3.12%	14.76%	1.86%	23.78%	5.43%

Energy Data Input:

	Electric Total	ACC Jurisdiction	All Other	Total Residential	E-10 Residential	E-12 Residential	EC-1 Residential	ET-1 Residential	ECT-1 Residential
DJR_WP5 Totals	28,319,711	27,863,453	456,258	13,210,836	852,812	4,001,457	504,571	6,373,509	1,478,487
Data Source: DJR WP5.									
AECC Energy Wtg					1.0179	1.0275	1.0244	1.0398	1.0241
Wtd. Energy	28,319,711	27,863,964	455,747	13,637,970	868,088	4,111,458	516,901	6,627,363	1,514,159

AECC Development of
Energy Related
Allocation Factors

Allocation Factor Name	Total General Service	E-20 Church Rate	E-30, E-32 (0 - 20 kW)	E-32 (21 - 100 kW)	E-32 (101 - 400 kW)	E-32 (401 - 999 kW)	E-32 (1,000 + kW)	E-34	E-35	E-38, 221 Water Pumping	Street Lighting	Dusk to Dawn
Energy1	50.00%	0.14%	4.96%	9.52%	11.70%	8.12%	6.03%	4.39%	5.14%	1.20%	0.44%	0.10%
Energy2	50.00%	0.14%	4.96%	9.52%	11.70%	8.12%	6.03%	4.39%	5.14%	1.20%	0.44%	0.10%
Energy2'	50.82%	0.14%	5.04%	9.68%	11.89%	8.25%	6.13%	4.46%	5.23%	1.22%	0.45%	0.11%
Energy100	48.61%	0.14%	4.86%	9.35%	11.48%	7.91%	5.84%	4.22%	4.80%	1.17%	0.36%	0.09%
Energy100'	49.41%	0.14%	4.94%	9.50%	11.67%	8.04%	5.93%	4.29%	4.88%	1.19%	0.37%	0.09%

Energy Data Input:

	Total General Service	General Service								E-38, 221 Water Pumping	Street Lighting	Dusk to Dawn
		E-20 Church Rate	E-30, E-32 (0 - 20 kW)	E-32 (21 - 100 kW)	E-32 (101 - 400 kW)	E-32 (401 - 999 kW)	E-32 (1,000 + kW)	E-34	E-35			
DJR_WP5 Totals	14,159,050	38,650	1,404,157	2,696,965	3,314,293	2,299,610	1,707,362	1,242,014	1,455,999	339,389	124,808	29,370
Data Source: DJR_WP5.												
AECC Energy Wtg		1.0402	0.9805	0.9818	0.9813	0.9744	0.9685	0.9625	0.9339	0.9762	0.8278	0.8353
Wtd. Energy	13,766,819	40,203	1,376,760	2,647,969	3,252,344	2,240,801	1,653,536	1,195,424	1,359,782	331,323	103,317	24,534

AECC Proposed Rate Spread at APS Requested Revenue Increase

AECC Proposed Revenue Increase for each Customer Class based on AECC's Proposed Hourly Energy Cost Allocation Method

E-32, Water Pumping & Dusk to Dawn Adder Above Cost = 4.824%

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
Line No.	Rate Class	Current Retail Revenues	Rate Base	Return Req'd Return @ Equal ROR	Equalized Rate of Return	Equalized Relative Rate of Return	Required Revenue Increase w/o EIC	Req'd Percent Change	AECC Proposed Revenue Increase w/o EIC	AECC Percent Change
1	Residential	$1,089,551,030	$2,489,739,663	$217,354,273	8.73%	1.00	$313,083,089	28.74%	$271,684,504	24.94%
2	General Service									
3	E-20	$3,586,700	$7,360,472	$642,569	8.73%	1.00	$98,334	2.74%	$98,334	2.74%
4	E-32	$859,172,589	$1,664,603,376	$145,319,875	8.73%	1.00	$104,329,725	12.14%	$145,776,879	16.97%
5	E-34	$66,719,281	$115,618,777	$10,093,519	8.73%	1.00	$14,410,596	21.60%	$14,410,596	21.60%
6	E35	$67,661,237	$88,981,169	$7,768,056	8.73%	1.00	$12,667,995	18.72%	$12,667,995	18.72%
7	General Service Total	$997,139,807	$1,876,563,794	$163,824,019	8.73%	1.00	$131,506,650	13.19%	$172,953,805	17.34%
8	Water Pumping (E-38, E-221)	$20,864,101	$25,474,477	$2,223,922	8.73%	1.00	($587,745)	-2.82%	$418,756	2.01%
9	Street Lighting	$13,344,265	$51,298,120	$4,478,326	8.73%	1.00	$4,692,360	35.16%	$3,327,453	24.94%
10	Dusk to Dawn	$6,422,696	$23,620,450	$2,062,065	8.73%	1.00	$933,305	14.53%	$1,243,141	19.36%
11	ACC Total	$2,127,321,899	$4,466,696,504	$389,942,605	8.73%	1.00	$449,627,659	21.14%	$449,627,659	21.14%

Derivation of Transmission Demand Charges

E-32 General Service	Demand Units (Over 20 kW) [1]	Transmission Revenues (Over 20 kW)[1]	Proposed Transmission Charge
Total	24,696,457	$45,092,740	$1.826

E-34	Demand Units[1]	Transmission Revenues[1]	Proposed Transmission Charge
Total	2,327,022	$5,757,046	$2.474

E-35	Demand Units[1]	Transmission Revenues[1]	Proposed Transmission Charge
Total	2,310,533	$6,592,489	$2.853

1. Source DJR_WP9

Comparison of APS's Generation Cost Components with APS's Proposed Generation Revenue Components

E-32 General Service	Generation Demand Costs (Over 20 kW)[1]	Demand Generation Revenue E-21-24 (Over 20 kW)[2]	Demand Generation Revenue E-32 (1st 200kWh/kW)[3]	Total Demand Generation Revenue
Total	$273,642,337	$3,709,768	$182,147,286	$185,857,054
		Generation Demand Cost Under Collection		($87,785,283)
E-32 General Service	Generation Energy Costs (Over 20 kW)[1]	Energy Generation Revenue E-21-24 (Over 20 kW)[2]	Energy Generation Revenue E-32 (1st 200kWh/kW & All Addt.)[3]	Total Energy Generation Revenue
Total	$315,557,749	$8,086,307	$422,771,992	$430,858,299
		Generation Energy Cost Over Collection		$115,300,550

E-34	Generation Demand Costs[1]		Total Demand Generation Revenue[2]
Total	$28,359,773		$19,923,962
		Generation Demand Cost Under Collection	($8,435,811)
E-34	Generation Energy Costs[1]		Total Energy Generation Revenue[2]
Total	$37,684,591		$46,201,502
		Generation Energy Cost Over Collection	$8,516,911

E-35	Generation Demand Costs[1]		Total Demand Generation Revenue[2]
Total	$26,046,173		$20,968,904
		Generation Demand Cost Under Collection	($5,077,269)
E-35	Generation Energy Costs[1]		Total Energy Generation Revenue[2]
Total	$44,903,360		$47,600,181
		Generation Energy Cost Over Collection	$2,696,821

1. Source DJR_WP3
2. Source DJR_WP9
3. See KCH-8 pg. 2 Line 7

Comparison of APS's Generation Cost Components with APS's Proposed Generation Revenue Components

Derivation of E-32 Demand-Related & Energy-Related Revenues

Line	(a) Summer	(b) Units	(c) Rate	(d) Line 1 - Line 2	(e) Demand Related Revenue[1]	(f) Energy Related Revenue	(g) Source
1	Gen. - 1st 200kWh/kW	2,642,829,245	$0.09085	$0.03855	$101,881,067	$138,219,970	= Row ((b) x (c)) - (e)
2	Gen. - All Addit. kWh	2,595,455,920	$0.05230			$135,742,345	= Row (b) x (c)
3				Total Summer	$101,881,067	$273,962,314	
	Winter	Units	Rate	Line 4 - Line 5	Demand Related Revenue[1]	Energy Related Revenue[2]	
4	Gen. - 1st 200kWh/kW	2,082,132,784	$0.07555	$0.03855	$80,266,219	$77,038,913	= Row ((b) x (c)) - (e)
5	Gen. - All Addit. kWh	1,939,750,391	$0.0370			$71,770,764	= Row (b) x (c)
6				Total Winter	$80,266,219	$148,809,677	
7				Total Revenue	$182,147,286	$422,771,992	

1. Row (d) x (b)

EXHIBIT
PDMC 1
AECC - 6
Admitted

BEFORE THE ARIZONA CORPORATION COMMISSION

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND TO AMEND DECISION NO. 67744	)	**Docket No. E-01345A-05-0816**

Surrebuttal Testimony of Kevin C. Higgins

on behalf of

Phelps Dodge Mining Company and

Arizonans for Electric Choice and Competition

September 27, 2006

TABLE OF CONTENTS

Table of Contents.....i

Introduction.....1

Transmission Cost Allocation and Rate Design.....3

Production Cost-of-Service Methodology.....6

General Service Rate Design.....10

Environmental Portfolio Surcharge.....15

Fuel Expense.....15

PWEC-Related Costs.....17

Prospective PSA Adjustor.....19

Corrections.....20

ATTACHMENTS

KCH-1SR.....Derivation of Transmission Charges for Major Rate Schedules

KCH-2SR..... APS COS Results Adjusted for Hourly Energy and 4-CP Transmission

KCH-3SR.....AECC Recommended Rate Spread

KCH-4SR.....COS Results Using Average and Excess Demand Method

REVISED ATTACHMENTS

KCH-5, page 2 (Revised).....Summary of Energy Cost Multipliers

KCH-7 (Revised).....Derivation of Transmission Demand Charges

1 SURREBUTTAL TESTIMONY OF KEVIN C. HIGGINS

2

3 I. Introduction

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

5 A. Kevin C. Higgins, 215 South State Street, Suite 200, Salt Lake City, Utah,

6 84111.

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

8 A. I am a Principal in the firm of Energy Strategies, LLC. Energy Strategies

9 is a private consulting firm specializing in economic and policy analysis

10 applicable to energy production, transportation, and consumption.

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

12 A. My testimony is being sponsored by Phelps Dodge Mining Company

13 ("Phelps Dodge") and Arizonans for Electric Choice and Competition ("AECC").

14 AECC is a business coalition that advocates on behalf of retail electric customers

15 in Arizona.

16 **Q. Are you the same Kevin C. Higgins who submitted direct testimony on behalf**

17 **of Phelps Dodge and AECC with respect to Revenue Requirements and Cost-**

18 **of-Service / Rate Spread / Rate Design?**

19 A. Yes, I am.

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

21 A. My surrebuttal testimony responds to issues raised by parties in direct

22 testimony filed on September 1, 2006 addressing non-revenue-requirements

23 issues, and to issues raised in APS's rebuttal testimony filed on September 15,

2006. With respect to the later, I do not respond here to each instance in which APS has disagreed with my direct testimony, in order to avoid restating my direct testimony. Consequently, absence of a surrebuttal response here should not be taken as acceptance of the Company's rebuttal argument; to the contrary, it should be taken as an indication that I continue to adhere to the positions expressed in my direct testimony.

In addition, I present corrections to three numbers that appear in attachments filed with my direct testimony. These corrections do not affect the conclusions or recommendations in my direct testimony.

Q. What conclusions and recommendations do you offer as part of your surrebuttal testimony?

A. I offer the following conclusions and recommendations:

(1) Witness Stephen J. Baron for The Kroger Co. ("Kroger") is correct in asserting that APS over-allocated transmission costs to General Service customers, because the Company unreasonably allocated transmission costs based on energy. In response to Mr. Baron's point, I have revised the cost-of-service, rate spread, and transmission rate design results presented in my direct testimony to more appropriately reflect the allocation of transmission costs on a 4-CP basis.

(2) I recommend against adoption of the Peak and Average production cost allocation method proposed by Staff, and support the continued application of the 4-CP approach proposed by APS. However, if the Commission orders that an energy-weighted method be used to allocate fixed production costs, then I recommend that the Average and Excess Demand method be used instead of the Peak and Average approach, because the former avoids the analytical shortcomings of the latter.

(3) With respect to General Service rate design:

(a) I continue to urge rejection of APS's proposed weighting of demand-related charges and energy charges, which is strongly biased to the disadvantage of higher-load-factor customers;

(b) I support adoption of Mr. Baron's proposal for Rate E-32 in which the "first 100 kW" and "all additional kW" of delivery charge would receive the same percentage increase; and

(c) I support adoption of the proposal by Federal Executive Agencies ("FEA") witness Dennis W. Goins to increase the Rate E-34 voltage discounts to more fully reflect cost-of-service differences between primary and secondary service.

(4) I support adoption of the proportionate increase in the Environmental Portfolio Surcharge rates and caps recommended by Staff witness Barbara Keene.

(5) After review of APS's rebuttal testimony, I continue to support the adjustments to revenue requirements offered in my direct testimony.

(6) Staff's proposal for a prospective PSA Adjustor creates some serious concerns, and I recommend that the Commission be very cautious in considering Staff's proposed change to the PSA mechanism.

II. Transmission Cost Allocation and Rate Design

Q. In his direct testimony, Kroger witness Stephen J. Baron testifies that APS over-allocated transmission costs to General Service customers. What is your assessment of Mr. Baron's statement?

A. Mr. Baron is correct. Although APS had described its transmission allocation as being based on a 4-CP method, upon closer inspection of the allocation formulas, it is clear that the Company actually allocated transmission costs to customer classes based on energy. In my opinion, this approach is not reasonable. Transmission costs are largely, if not entirely, demand-related, and thus, are more properly allocated on a demand basis. Consequently, APS's transmission costs are not properly allocated to the customer classes.

In my direct testimony, I recommended that for most customers with demand meters (e.g., Rates E-32 [> 20 kW], E-34, E-35), the transmission

revenue requirement should be recovered exclusively through a demand charge instead of an energy charge. Also, as part of my direct testimony, I calculated demand charges for Rates E-32, E-34 , and E-35 based on APS's allocation of transmission costs, which I presented in Attachment KCH-7.[1] However, because, as Mr. Baron points out, APS over-allocated transmission costs to General Service customers, it is necessary for me to revise the calculations in Attachment KCH-7 to correct for this problem. This revision is presented in Attachment KCH-1SR.

For the same reason, it is also necessary for me to revise the cost-of-service and rate spread results presented in my direct testimony to reflect the allocation of transmission costs on a 4-CP basis. These cost-of-service and rate spread revisions are presented in Attachments KCH-2SR and KCH-3SR, respectively, and are summarized in Tables KCH-1SR and KCH-2SR, below. For ease of exposition, the tables below include a side-by-side comparison of the cost-of-service results and rate spread recommendations from my direct testimony, which reflects APS's allocation of transmission costs on an energy basis.

[1] I note that the kW-billing determinant for E-32 in Attachment KCH-7 contains a transcription error. This also causes an error in the E-32 kW charge in that attachment. These corrections are addressed at the end of this surrebuttal testimony.

Table KCH-1SR

AECC Cost-of-Service Results
Transmission Allocated on an Energy Basis vs 4-CP Basis

Class	Rate Change Based on AECC COS [2] Transmission allocated using Energy	Rate Change Based on AECC COS [3] Transmission allocated using 4-CP
Residential	28.74%	29.23%
General Service	13.19%	12.80%
E-32	12.14%	12.11%
E-34	21.60%	19.98%
E-35	18.72%	15.11%
Water Pumping	(2.82)%	(6.94)%
Street Lighting	35.16%	31.17%
Dusk-to-Dawn	14.53%	12.60%
Total	21.14%	21.14%

[2] Source: AECC Attachment KCH-5.
[3] Source: AECC Attachment KCH-2SR.

Table KCH-2SR

AECC Recommended Rate Spread
Transmission Allocated on an Energy Basis vs 4-CP Basis
Calculated at APS's Requested Revenue Requirement

Class	AECC Proposed Rate Change[4] Transmission allocated using Energy	AECC Proposed Rate Change [5] Transmission allocated using 4-CP
Residential	24.94%	25.18%
General Service	17.34%	17.13%
E-32	16.97%	17.13%
E-34	21.60%	19.98%
E-35	18.72%	15.11%
Water Pumping	2.01%	0.00%[6]
Street Lighting	24.94%	25.18%
Dusk-to-Dawn	19.36%	17.62%
Total	21.14%	21.14%

As can be seen in the preceding tables, properly allocating transmission costs on a 4-CP basis results in a small increase in cost responsibility for Residential customers,[7] and a more substantial relative decrease in cost responsibility for Rates E-34, E-35, as well as those customer classes that primarily use the system during off-peak periods.

III. Production Cost-of-Service Methodology

Q. What method has Staff recommended for production cost-of-service?

[4] Source: AECC Attachment KCH-6.
[5] Source: AECC Attachment KCH-3SR.
[6] I have added a constraint to my rate spread proposal that precludes providing a rate decrease to any customer class in this proceeding. Thus, Water Pumping would receive a 0% rate change, instead of a rate reduction.
[7] The Residential Transmission Charge would increase from 4.76 mills/kWh to 5.07 mills/kWh, but the net increase to Residential would be half that amount due to rate spread mitigation.

1 A. As described in the direct testimony of Staff witness Michael L. Brosch,
2 Staff is recommending adoption of the "Peak and Average" methodology to
3 allocate fixed production cost to customer classes.

4 **Q. What is the "Peak and Average" method?**

5 A. The Peak and Average method is classified in the NARUC Cost
6 Allocation Manual as a "Judgmental Energy Weighting" approach. According to
7 this method, fixed production cost is allocated based on a combination of each
8 class's share of coincident peak demand, as well as each class's share of energy
9 usage. In applying this method, class energy consumption is typically expressed
10 as "average demand," which gives rise to the term "Peak and Average." (Average
11 demand is simply annual energy divided by the number of hours in the year.)

12 **Q. How does the Peak and Average method differ from the approach used by**
13 **APS?**

14 A. APS uses the Four Coincident Peak ("4-CP") method to allocate fixed
15 production cost. According to this method, fixed production costs are allocated on
16 the basis of each class's share of coincident peak demand during the four greatest
17 peak-demand months, which in the case of APS are June through September. In
18 contrast, the Peak and Average method combines a CP allocation with an energy
19 (or "average demand") allocation. In the specific case of Staff's proposal, fixed
20 production costs are allocated using a combination of 4-CP and average demand.

21 **Q. What rationale is offered by Mr. Brosch in proposing this method?**

22 A. Although Mr. Brosch states that the 4-CP allocations performed by APS
23 were generally reasonable and are comparable to the allocation methodologies

1 previously employed in APS general rate case proceedings, he goes on to state
2 that Staff believes the Company's cost-of-service study should utilize an energy-
3 weighted allocation approach in order to reflect the use of production facilities
4 throughout the year. The Peak and Average study prepared by Mr. Brosch is
5 Staff's attempt to incorporate an energy-weighting into the allocation of fixed
6 production costs.

7 **Q. In your direct testimony, do you address APS's use of the 4-CP method?**

8 A. Yes, given APS's load characteristics, I support APS's use of the 4-CP
9 method for allocating fixed production costs.

10 **Q. Do the witnesses sponsored by other intervening parties address APS's use of**
11 **the 4-CP method?**

12 A. Yes. Both Mr. Baron for Kroger and Dr. Goins for the FEA testified in
13 support of the 4-CP method.

14 **Q. Do you agree with Staff's proposal to use a Peak and Average approach**
15 **instead of the 4-CP method?**

16 A. No, I do not. The average peak demand during APS's four summer peak
17 months is over 50 percent higher than the average peak demand in the remaining
18 eight months, and the new capacity being added to APS's system is driven by
19 APS's growing summer demands. The Peak and Average method attempts to shift
20 cost responsibility for these capacity requirements by allocating fixed production
21 costs on an energy basis, placing more of the cost burden on higher-load factor
22 customers who use energy at a relatively constant level throughout the year, rather

than those classes whose summer usage is driving the Company's need for production capacity.

Moreover, if the intention of Staff is to allocate a portion of fixed production costs on an energy basis, then there are approaches that are conceptually superior to the Peak and Average method.

Q. Please elaborate on this latter point.

A. The Peak and Average method is conceptually flawed in that average demand is already included in peak demand and is thus counted twice in the allocation of costs. This double-counting contributes to the bias against higher-load-factor customers inherent in this method.

In contrast, an analytically-superior methodology that incorporates an energy weighting in the allocation of fixed production costs is the "Average and Excess Demand" method. This method is described at length in the NARUC Cost Allocation Manual and is used by both Salt River Project and Public Service Company of Colorado. The "Average and Excess Demand" method avoids double-counting by allocating costs based on a combination of average demand and the *excess* of class non-coincident peak over average demand. This method meets Staff's stated objectives of using an energy weighting and allocates a share of fixed production costs to the classes using the system solely during off-peak periods.

Q. Have you prepared a cost-of-service analysis using the Average and Excess Demand approach?

A. Yes, I have. The results are presented in Attachment KCH-4SR. These results also include the hourly allocation of fuel and purchased power costs described in my direct testimony and the allocation of transmission costs on a 4-CP basis as described above.

Q. Are you recommending the use of the Average and Excess Demand method in lieu of the 4-CP method for allocating fixed production costs?

A. No, I am not. However, if the Commission orders that an energy-weighted method be used to allocate fixed production costs, then I recommend that the Average and Excess Demand method be used instead of the Peak and Average approach.

Q. If an energy-weighted approach is adopted by the Commission for the allocation of fixed production costs, should the Commission also adopt the recommendation in your direct testimony to allocate fuel and purchased power costs using hourly cost information?

A. Yes, absolutely. The reasons presented in my direct testimony for using an hourly allocation of fuel and purchased power costs remain just as compelling if an energy-weighted approach to fixed-production costs is adopted by the Commission.

IV. General Service Rate Design

Q. Do you have any comments on the testimony addressing General Service rate design that was filed by other parties?

A. Yes. In our respective direct testimonies, both Mr. Baron and I pointed out that APS's proposed rate design would negatively impact high-load-factor customers. This negative impact would result from APS's proposal to levy a much greater proportion of its requested generation rate increase on the energy charge relative to the demand-related charges. For example, APS proposes that the generation demand charge for Rate E-34 be increased 11 percent and that the generation energy charge be increased by 53 percent. The negative impact of the Company's proposed design on higher-load-factor customers is evident in APS's Schedule H-4, excerpts of which are reproduced in Table KCH-3SR, below.

Table KCH-3SR

Impact of APS Proposed Rate Design on General Service Customers Differentiated by Load Factor

Rate	Customer Size	Load Factor	APS Proposed Rate Change
E-32	200 kW	15%	15.1% (W) 18.0% (S)
E-32	200 kW	45%	20.0% (W) 24.1% (S)
E-32	200 kW	75%	24.1% (W) 28.6% (S)
E-34	5000 kW	20%	17.6%
E-34	5000 kW	40%	22.7%
E-34	5000 kW	75%	27.8%
E-35	5000 kW	20%	21.1%
E-35	5000 kW	40%	24.1%
E-35	5000 kW	75%	27.3%

Table KCH-3SR shows that APS's proposed rate design would raise rates for higher load-factor customers by as much as 10 percentage points higher than lower-load-factor customers of the same size. The proposal I advanced, as well as the ones advanced by Mr. Baron, would remedy this bias. Mr. Baron's

recommendation is limited to Rate E-32. My recommendation is applicable to the generation rate for Rates E-32, E-34, and E-35. The thrust of our recommendations is similar: remove the bias against high-load-factor customers in APS's proposal because such a bias is not supported by the Company's own cost-of-service analysis.

In the Company's rebuttal testimony, the rate design proposals made by Mr. Baron and myself are characterized as being adverse to low-load-factor customers. A better characterization of our proposals is that they would *neutralize* the negative impact on higher-load-factor customers in the Company's proposal. Equally weighting demand and energy rate components, as I am recommending, is clearly neutral with respect to load factor.

Q. On page 17 of her direct testimony, Staff witness Erinn Andreasen recommends that the demand rates for Rate E-32 not be increased significantly beyond the levels proposed by APS in this proceeding. Do you wish to respond?

A. Yes. Subject to one exception and two qualifications, I do not object to Ms. Andreasen's recommendation. The exception is that the transmission charge for all demand-billed general service customers (except partial requirements) should be converted from an energy charge to a demand charge, as discussed in my direct testimony. Because of the need to correctly design the transmission charge, the limitation on the Rate E-32 demand charge proposed by Staff should not apply to the transmission portion of the rate.

1 **Q. Please address the qualifications that accompany your support for Staff's**
2 **recommendations for the design of Rate E-32.**
3 A. The first qualification regarding my support for Staff's recommendation
4 pertains to the design of the delivery charge. As Mr. Baron correctly notes, the
5 Rate E-32 Delivery Charge increase proposed by APS for the first 100 kW of
6 demand is, inexplicably, lower than the proposed increase for all additional kW.
7 Mr. Baron proposes that the "first 100 kW" and "all additional kW" receive the
8 same percentage increase. I support this modification. Mr. Baron's proposal does
9 not change the total demand charge to Rate E-32 – it just spreads the demand
10 charge increase on a more even and equitable basis. Presumably this adjustment
11 would not violate Staff's recommendation.
12 The second qualification pertains to my recommendation to increase, on
13 an equal-percentage-basis, the first energy block and the energy tailblock in the
14 Rate E-32 generation rate. My proposal affects the demand-related charges in the
15 first energy block (i.e., the portion of the first energy block intended to recover
16 demand-related costs), but does not impact the Rate E-32 demand charge itself.
17 To the extent that Staff's recommendation is directed to the Rate E-32 demand
18 charge, my proposal with respect to Rate E-32 generation rates is consistent with
19 Staff's recommendation.
20 **Q. Do you have any other observations with respect to General Service rate**
21 **design issues?**
22 A. Yes. On pages 16 through 17 of his direct testimony, FEA witness Dennis
23 W. Goins addresses the fact that APS's proposed voltage discounts for Rate E-34

is not fully reflective of costs. Dr. Goins recommends that the Rate E-34 voltage discounts should be increased to more fully reflect cost-of-service differences between primary and secondary service. I concur with Dr. Goins' assessment and support his recommendation.

Q. Have you reviewed the rate design testimony of DEAA witness William J. Murphy?

A. Yes, I have.

Q. Do you have any response to Mr. Murphy's testimony?

A. Yes. Mr. Murphy's testimony is directed primarily to Rate 32-R, which is applicable to Partial Requirements service, i.e., customers with on-site generation. I do not disagree with designing rates for partial requirements service in a manner that takes into account the special characteristics of partial requirements customers. In fact, I have proposed an exception for partial requirements service in my recommended transmission charge design. To the extent that Mr. Murphy's rate design objectives are limited to partial requirements rate schedules I do not offer any objections to them. However, I would strongly object if Mr. Murphy's rate design preferences were applied to Rate 32, which is applicable to the large majority of General Service customers. Shifting cost responsibility from the demand-related charges to the energy charges for Rate E-32 customers would result in an increased subsidy from higher-load-factor customers to lower-load-factor customers. Such an increased subsidy would be inequitable and unreasonable.

1 V. **Environmental Portfolio Surcharge ("EPS")**

2 Q. **Have you reviewed the proposal by Staff witness Barbara Keene to increase**
3 **the EPS adjustor rate and caps to allow for more funding of the EPS Credit**
4 **Purchase Program?**

5 A. Yes, I have. Staff is recommending that the EPS surcharge rate and caps
6 be increased proportionately to fund the additional $4.25 million EPS revenue
7 requirement approved for APS in Decision No. 68668.

8 Q. **What is your assessment of Staff's recommendation?**

9 A. Staff's recommendation for a proportional increase in the surcharge rates
10 and caps is consistent with the terms of the settlement agreement approved in
11 Decision No. 67744 and I support its adoption.

12

13 VI. **Fuel Expense**

14 Q. **In his rebuttal testimony, APS witness Peter Ewen objects to your**
15 **recommendation to reduce APS's fuel expense by $67 million. Do you wish to**
16 **respond?**

17 A. Yes. In the Company's rebuttal testimony filed in the Interim proceeding,
18 APS acknowledged that fuel and purchased power costs had declined by about
19 one-third relative to the November 30, 2005 forward prices that are the basis for
20 the fuel expense used by APS in its direct case in this general rate proceeding. In
21 his rebuttal testimony filed in the Interim docket on March 13, 2006, Company
22 witness Peter Ewen stated that the Company's fuel-related expense in the general
23 rate case filing would decline by $67 million if February 28, 2006 prices held. In

my direct testimony in this proceeding, I testified that as these prices have generally held during the subsequent months (citing prices as of June 30, 2006) the $67 million reduction in fuel expense should be adopted.

In his rebuttal testimony in this proceeding, Mr. Ewen has reversed his stated expectation that a $67 million fuel expense reduction would be forthcoming based on February 28 prices, and instead is recommending a $32 million *increase* in fuel expense relative to the Company's initial filing. Mr. Ewen objects to my recommendation to adopt the $67 million reduction indicated in the Interim proceeding, asserting that the price of natural gas had risen by more than $1.00 by July 31, 2006 relative to the mid-year forward price on June 30, 2006, cited in my testimony. He takes the position that fuel expense should be based on more recent forward prices.

In that regard, I note that the most recent forward prices – those available on September 25, 2006 – indicate that forward gas prices have, in fact, *fallen* significantly relative to the June 30, 2006 prices cited in my testimony. This information is presented in Table KCH-4SR, below.

Table KCH-4R
12-Month Forward Price of Natural Gas
S/MMBtu

Date	Term	NYMEX	San Juan	Permian Basin
11-30-05	Jan 06 - Dec 06	$11.066	$9.522	$9.787
2-28-06	Apr 06 - Mar 07	$ 8.312	$6.538	$6.943
6-30-06	Aug 06 - Jul 07	$ 8.451	$6.967	$7.285
9-25-06	Oct 06 - Sep 08	$ 6.958	$5.928	$6.156

On September 25, the twelve-month forward price for Permian Basin gas stood at $6.156/mmbtu, 11 percent lower than the twelve-month forward price on February 28, and 37 percent lower than the price on November 30, 2005. Comparable reductions have occurred with respect to San Juan gas prices. Yet APS is attempting to increase the fuel expense relative to its November 30, 2005 calculation.

As the most recent fuel prices are significantly below the February 28 levels that formed the basis for APS's prior indications that fuel expense would be reduced from its initial filing, and consequently, are even further below the November 30, 2005 levels upon which APS based its initial fuel expense projections, I see no reason to change my recommendation to reduce APS's fuel expense by $67 million.

VII. PWEC-Related Costs

Q. In her rebuttal testimony, APS witness Laura Rockenberger reduces PWEC-related expense by $5.1 million, but objects to your recommendation to reduce A&G expenses associated with PWEC units by $11.7 million, which is

to the level of A&G expense indicated in the prior rate case. Do you wish to respond?

A. Yes. I continue to recommend that for the purpose of this proceeding, the A&G and O&M expense allowed for the PWEC units should be based on the levels represented to the parties to the 2004 Settlement Agreement and the Commission when the benefits of including the PWEC units in rate base was being advanced by APS. This adjustment is not "arbitrary", as Ms. Rockenberger states. To the contrary, it is sound policy and follow-through to insist that the benefits to customers not be eroded in this proceeding by escalating the allowed A&G and O&M costs above the levels depicted by APS when APS was persuading the parties and the Commission that the PWEC units should be included in rate base.

As I indicated in my direct testimony, maintaining consistency between the PWEC costs depicted in the prior proceeding and those allowed in this proceeding does not mean that PWEC-related costs should be permanently capped at these levels. This rate proceeding is following relatively close in time to the decision that allowed the PWEC units into rate base. It is reasonable, at this time, to limit the O&M and A&G expense for these units at the amounts indicated by APS in the prior rate proceeding.

1 **VIII. <u>Prospective PSA Adjustor</u>**

2 **Q. Have you reviewed the proposal for a prospective PSA Adjustor**
3 **recommended by Staff witness John Antonuk on pages 33 through 42 of his**
4 **direct testimony?**

5 A. Yes, I have.

6 **Q. What is your assessment of that proposal?**

7 A. The specifics of the proposal are not entirely clear to me. However, on
8 pages 8 through 9 of his rebuttal testimony, APS witness Donald G. Robinson has
9 attempted to elaborate on how Staff's proposal would work. Based on my review
10 of Mr. Antonuk's testimony and Mr. Robinson's discussion of it, I have two
11 serious concerns with the proposal and recommend that the Commission proceed
12 cautiously with respect to it.

13 **Q. Please describe your concerns with the Prospective PSA Adjustor proposal.**

14 A. First, I agree with Mr. Robinson's statement that Staff's proposal is a
15 dramatic change to the current form of the PSA Adjustor.[8] As the current PSA
16 was negotiated as a package, and was intended to be in place for at least five
17 years, I have serious concerns with making changes to the design of the
18 mechanism before the five-year implementation period has run its course.

19 My second concern is that changing the mechanism from a retrospective
20 calculation to a prospective calculation appears to require a "doubling up" of the
21 adjustor in the coming year. That is, customers would be asked to pay both the
22 original adjustor and the prospective adjustor simultaneously, as described on

[8] Rebuttal testimony of Donald G. Robinson, p. 3, lines 3-4.

page 9 of Mr. Robinson's rebuttal testimony (see items 2 and 3 in Mr. Robinson's testimony). The rate impact on customers resulting from this overlapping payment should be considered before action is taken on this proposal.

Corrections

Q. Please describe the corrections to exhibits to your direct testimony.

A. It is necessary for me to correct three numbers that appeared in exhibits in my direct testimony. These corrections do not affect the conclusions or recommendations in my direct testimony.

The first corrections are in Attachment KCH-7. Due to a transcription error, I entered an incorrect billing determinant for Rate E-32 billing demand of 24,696,457 kW. The correct billing demand is 25,196,428 kW. This, in turn, impacted the calculation of the Proposed Transmission Charge for Rate E-32 in that attachment. Instead of $1.826 per kW-month, the correct charge should have read $1.790 per kW-month. I note, however, that in this surrebuttal testimony I have re-calculated the appropriate transmission charge for Rate E-32 using a 4-CP cost allocation for transmission service. Consequently, I view the proposed transmission charges in Attachment KCH-7 to be superseded by the proposed charges in Attachment KCH-1SR. Nevertheless, I wish to make these corrections to Attachment KCH-7 to ensure an accurate record. The corrected attachment is designated as Attachment KCH-7 (Revised).

The other correction applies to Attachment KCH-5, page 2. Due to a formula error that double-counted the megawatts-hours for Rate E-32 in the

summary, the ACC Total Energy Use at the Meter is incorrectly shown as 36,923,342 MWH. The correct amount is 26,148,942 MWH. This value was presented for summary purposes only, and consequently, did not affect any of the calculations in my attachments or workpapers. The corrected page is designated as Attachment KCH-5, page 2 (Revised).

Q. Does this conclude your surrebuttal testimony?

A. Yes, it does.

1839218.1/23040.041

Derivation of Transmission Charges for Major Rate Schedules
Based on 4-CP Allocation of APS Trasmission Costs

Residential	kWh Units	Transmission Revenue Requirement	Proposed Transmission Charge
Total	12,362,652,000	$62,703,331	$0.00507

E-32 General Service	Demand Units (Over 20 kW)[1]	Transmission Revenues (Over 20 kW)[2]	Proposed Transmission Charge
Total	25,196,428	$39,586,312	$1.571

E-34	Demand Units[1]	Transmission Revenues[2]	Proposed Transmission Charge
	2,327,022	$4,055,471	$1.743

E-35	Demand Units[1]	Transmission Revenues[2]	Proposed Transmission Charge
	2,310,533	$3,698,384	$1.601

1. Source: DJR_WP9
2. Source: Attachment KCH - 2 SR, pp. 2-3, Lines 32 & 43

APS's Cost of Service Results Adjusted to Reflect Hourly Fuel and Purchased Power Costs and Allocation of Transmission Expenses Using APS's 4-CP Demand Allocator

Revenue Increase Required to Move each Customer Class to Cost of Service using AECC's Proposed Cost of Service Study Results

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
Line No.	Rate Class	Current Retail Revenues	Rate Base	Return Req'd Return @ Equal ROR	Equalized Rate of Return	Equalized Relative Rate of Return	Required Revenue Increase w/o EIC	Required Revenue Increase	Req'd Percent Change
1	Residential	$1,089,551,030	$2,489,739,663	$217,354,273	8.73%	1.00	$1,408,005,912	$318,454,882	29.23%
2	General Service								
3	E-20	$3,586,700	$7,360,472	$642,569	8.73%	1.00	$3,643,363	$56,663	1.58%
4	E-32	$859,172,589	$1,664,603,376	$145,319,875	8.73%	1.00	$963,215,325	$104,042,736	12.11%
5	E-34	$66,719,281	$115,618,777	$10,093,519	8.73%	1.00	$80,047,975	$13,328,694	19.98%
6	E35	$67,661,237	$88,981,169	$7,768,056	8.73%	1.00	$77,885,179	$10,223,942	15.11%
7	General Service Total	$997,139,807	$1,876,563,794	$163,824,019	8.73%	1.00	$1,124,791,842	$127,652,035	12.80%
8	Water Pumping (E-38, E-221)	$20,864,101	$25,474,477	$2,223,922	8.73%	1.00	$19,416,207	($1,447,894)	-6.94%
9	Street Lighting	$13,344,265	$51,298,120	$4,478,326	8.73%	1.00	$17,503,500	$4,159,235	31.17%
10	Dusk to Dawn	$6,422,696	$23,620,450	$2,062,065	8.73%	1.00	$7,232,097	$809,401	12.60%
11	ACC Total	$2,127,321,899	$4,466,696,504	$389,942,605	8.73%	1.00	$2,576,949,559	$449,627,660	21.14%

AECC's Adjusted Cost of Service Study Using Energy Scalars
for Fuel and Purchased Power Costs and 4-CP
for Transmission Expenses
for the 12 Months ending Sep. 30, 2005
($)

	1	2	3	4	5	6	7	8	9	10	11
Line No.	Description	Allocation Factor	Electric Total	ACC Jurisdiction	All Other	Total Residential	E-10 Residential	E-12 Residential	EC-1 Residential	ET-1 Residential	ECT-1 Residential
	SUMMARY OF RESULTS										
16	TOTAL RATE BASE		$5,327,833,192	$4,466,696,504	$861,136,688	$2,489,739,663	$148,234,534	$795,627,566	$79,691,088	$1,227,004,375	$239,182,100
17											
18	DEVELOPMENT OF RETURN										
19	Revenues from Rates		$2,103,857,729	$2,066,144,726	$37,713,003	$1,058,729,739	$70,337,587	$360,585,198	$36,686,029	$490,471,664	$100,649,261
20	Proforma to Revenues from Rates		$60,953,295	$61,177,173	($223,878)	$30,821,291	($2,224,915)	$11,853,176	($1,254,829)	$20,328,518	$2,119,341
21	Other Electric Revenues		$1,344,909,372	$1,313,268,573	$31,640,799	$624,903,158	$40,280,141	$189,690,778	$23,754,957	$301,576,795	$69,600,487
22	TOTAL OPERATING REVENUES		$3,509,720,396	$3,440,590,472	$69,129,924	$1,714,454,188	$108,392,813	$562,129,152	$59,186,157	$812,376,977	$172,369,089
23	Revenue Increase Required to Achieve Equalized ROR		$449,627,660	$449,627,660	$0	$318,454,882	$18,559,116	$78,492,739	$11,439,813	$173,670,901	$36,292,314
24	TOTAL OPERATING REVENUES WITH REVENUE INCREASE		$3,959,348,056	$3,890,218,132	$69,129,924	$2,032,909,070	$126,951,929	$640,621,891	$70,625,970	$986,047,878	$208,661,403
25	Percent Increase		20.77%	21.14%	0.00%	29.23%	27.25%	21.08%	32.29%	34.00%	35.31%
24											
25	OPERATING EXPENSES										
26											
27	O&M Energy Related										
28	Energy Production	Energy1	$74,369,000	$73,170,843	$1,198,157	$34,692,327	$2,239,528	$10,508,029	$1,325,029	$16,737,158	$3,882,582
29	Energy Production - Related Fuel (M&T)	Energy2	$842,735,000	$829,157,722	$13,577,278	$393,126,677	$25,377,890	$119,074,939	$15,014,971	$189,662,215	$43,996,662
30	Energy Production - Related Fuel	Energy100	$885,397,911	$871,149,260	$14,248,651	$426,382,540	$27,140,225	$128,542,154	$16,160,595	$207,200,327	$47,339,237
31	Total Energy Related		$1,802,501,911	$1,773,477,826	$29,024,085	$854,201,543	$54,757,643	$258,125,123	$32,500,595	$413,599,700	$95,218,481
32	OATT Transmission Expense	4-CP Trans.	$0	$117,547,846	($117,547,846)	$61,040,586	$3,503,525	$18,288,673	$2,080,159	$30,710,312	$6,457,917
33	Other O&M Enon-Energy Expenses		$443,510,786	$411,439,063	$32,071,723	$246,087,716	$16,086,269	$85,510,463	$7,662,534	$115,255,312	$21,573,138
34	Total O&M Non-Energy Related		$443,510,786	$528,986,909	($85,476,123)	$307,128,302	$19,589,794	$103,799,136	$9,742,693	$145,965,624	$28,031,055
35	Operation & Maintenance		$2,246,012,697	$2,302,464,735	($56,452,038)	$1,161,329,845	$74,347,438	$361,924,259	$42,243,288	$559,565,324	$123,249,536
36	Administrative & General		$141,768,184	$132,687,129	$9,081,055	$81,444,413	$5,435,590	$28,926,720	$2,483,640	$37,721,841	$6,876,622
37	Depreciation & Amortization Expense		$321,526,002	$285,758,992	$35,767,010	$159,732,184	$9,911,645	$51,449,950	$5,249,433	$77,904,622	$15,216,534
38	Amortization on Gain		($6,613,637)	($6,528,054)	($85,583)	($3,299,367)	($196,177)	($991,655)	($116,349)	($1,640,307)	($354,879)
39	Regulatory Assets		($2,203,511)	($2,203,511)	$0	($1,144,246)	($65,676)	($342,833)	($38,994)	($575,685)	($121,058)
40	Pro-Forma Energy Related - Jurisdictional	Energy100'	$61,052,503	$60,070,266	$982,237	$29,401,291	$1,871,459	$8,863,649	$1,114,357	$14,287,539	$3,264,286
41	Pro-Forma Energy Related - ACC	Energy100'	$269,376,144	$269,376,144	$0	$131,845,700	$8,392,281	$39,747,712	$4,997,168	$64,070,335	$14,638,205
42	Pro-Forma Energy Related - ACC(Weather & Cust)	Assigned	$18,114,000	$18,114,000	$0	$9,044,540	($677,719)	$3,428,524	($350,866)	$5,867,427	$777,174
43	Pro-Forma OATT Transmission Expense	4-CP Trans.	$3,202,002	$3,202,002	$0	$1,662,745	$95,436	$498,183	$56,664	$836,549	$175,914
44	Other Pro-Forma Expenses		$152,816,718	$145,032,119	$7,784,599	$79,062,774	$4,806,393	$25,528,196	$2,577,998	$38,313,459	$7,836,728
45	Pro-Forma Non-Energy Related		$485,465,130	$477,680,531	$7,784,599	$80,725,519	$4,901,829	$26,026,379	$2,634,662	$39,150,008	$8,012,642
46	Proforma Adjustments		$504,561,367	$495,794,531	$8,766,836	$251,017,050	$14,487,850	$78,066,264	$8,395,320	$123,375,308	$26,692,307
47	Taxes Other than Income		$139,970,769	$116,332,656	$23,638,113	$65,666,582	$4,071,767	$21,173,025	$2,145,953	$32,090,164	$6,185,673
48	Income Tax		$185,532,148	$175,969,050	$9,563,098	$100,808,337	$6,018,617	$30,957,874	$3,306,647	$50,489,128	$10,036,071
49	TOTAL OPERATING EXPENSES		$3,530,554,019	$3,500,275,528	$30,278,491	$1,815,554,798	$114,011,054	$571,163,604	$63,668,938	$878,930,396	$187,780,805
50											
51	OPERATING INCOME		$428,794,038	$389,942,605	$38,851,433	$217,354,273	$12,940,875	$69,458,287	$6,957,032	$107,117,482	$20,880,597
52											
53	RETURN		$428,794,038	$389,942,605	$38,851,433	$217,354,273	$12,940,875	$69,458,287	$6,957,032	$107,117,482	$20,880,597
54											
55	RATE OF RETURN (EQUALIZED)		8.05%	8.73%	4.51%	8.73%	8.73%	8.73%	8.73%	8.73%	8.73%
56											
57	INDEX RATE OF RETURN		1.00	1.08	0.56	1.08	1.08	1.08	1.08	1.08	1.08
58											
59	ACC JURISDICTION INDEX RATE OF RETURN			1.00		1.00	1.00	1.00	1.00	1.00	1.00

AECC's Adjusted Cost of Service Study Using Energy Scalars
for Fuel and Purchased Power Costs and 4-CP
for Transmission Expenses
for the 12 Months ending Sep. 30, 2005
($)

Line No.	1 Description	2 Allocation Factor	12 Total General Service	13 E-20 Church Rate	E-30, E-32 Total	14 E-30, E-32 (0 - 20 kW)	15 E-32 (21 - 100 kW)	16 E-32 (101 - 400 kW)	17 E-32 (401 - 999 kW)	18 E-32 (1,000 + kW)
	SUMMARY OF RESULTS									
16	TOTAL RATE BASE		$1,876,563,794	$7,360,472	$1,664,603,376	$378,234,736	$469,359,372	$410,940,132	$228,078,549	$177,990,587
17										
18	DEVELOPMENT OF RETURN									
19	Revenues from Rates		$967,398,538	$3,344,799	$830,331,951	$142,275,889	$218,138,380	$229,640,445	$146,123,538	$94,153,699
20	Proforma to Revenues from Rates		$29,741,269	$241,901	$28,840,638	$9,060,700	$3,862,319	$13,851,012	$1,053,159	$1,013,448
21	Other Electric Revenues		$662,981,780	$1,836,772	$535,912,322	$67,075,107	$127,027,116	$155,000,606	$107,242,574	$79,566,919
22	TOTAL OPERATING REVENUES		$1,660,121,587	$5,423,472	$1,395,084,911	$218,411,696	$349,027,815	$398,492,063	$254,419,271	$174,734,066
23	Revenue Increase Required to Achieve Equalized ROR		$127,652,035	$56,663	$104,042,736	$34,524,136	$29,657,534	$12,604,856	$4,598,998	$22,657,212
24	TOTAL OPERATING REVENUES WITH REVENUE INCREASE		$1,787,773,622	$5,480,135	$1,499,127,647	$252,935,832	$378,685,349	$411,096,919	$259,018,269	$197,391,278
25	Percent Increase		12.80%	1.58%	12.11%	22.81%	13.36%	5.18%	3.12%	23.81%
24										
25	OPERATING EXPENSES									
26										
27	O&M Energy Related									
28	Energy Production	Energy1	$37,182,385	$101,497	$29,995,769	$3,687,388	$7,082,367	$8,703,502	$6,038,893	$4,483,619
29	Energy Production - Related Fuel (M&T)	Energy2	$421,343,530	$1,150,143	$339,906,198	$41,784,757	$80,256,003	$98,626,385	$68,431,554	$50,807,500
30	Energy Production - Related Fuel	Energy100	$430,410,906	$1,256,908	$349,267,098	$43,043,545	$82,787,067	$101,682,496	$70,057,238	$51,696,753
31	Total Energy Related		$888,936,821	$2,508,548	$719,169,065	$88,515,690	$170,125,436	$209,012,382	$144,527,685	$106,987,872
32	OATT Transmission Expense	4-CP Trans.	$55,972,307	$127,881	$48,296,185	$9,759,609	$13,213,344	$12,483,728	$6,900,440	$5,939,065
33	Other O&M Enon-Energy Expenses		$157,203,584	$480,779	$138,332,015	$34,011,718	$37,863,262	$33,259,267	$18,402,164	$14,795,604
34	Total O&M Non-Energy Related		$213,175,891	$608,660	$186,628,200	$43,771,326	$51,076,606	$45,742,995	$25,302,604	$20,734,669
35	Operation & Maintenance		$1,102,112,712	$3,117,207	$905,797,266	$132,287,016	$221,202,042	$254,755,377	$169,830,288	$127,722,542
36	Administrative & General		$48,487,581	$168,558	$42,560,789	$10,453,288	$11,676,787	$10,128,362	$5,827,742	$4,474,610
37	Depreciation & Amortization Expense		$119,779,815	$441,855	$105,486,858	$23,085,668	$29,369,824	$26,524,854	$15,018,891	$11,487,621
38	Amortization on Gain		($3,172,586)	($7,702)	($2,680,293)	($476,581)	($702,487)	($718,845)	($430,995)	($351,385)
39	Regulatory Assets		($1,049,237)	($2,397)	($905,344)	($182,950)	($247,693)	($234,016)	($129,353)	($111,332)
40	Pro-Forma Energy Related - Jurisdictional	Energy100'	$29,679,067	$86,670	$24,083,780	$2,968,076	$5,708,598	$7,011,536	$4,830,810	$3,564,760
41	Pro-Forma Energy Related - ACC	Energy100'	$133,091,349	$388,660	$108,000,119	$13,309,894	$25,599,357	$31,442,188	$21,663,048	$15,985,633
42	Pro-Forma Energy Related - ACC(Weather & Cust)	Assigned	$9,157,238	$56,452	$9,679,725	$2,669,378	$500,908	$6,436,947	$40,808	$31,684
43	Pro-Forma OATT Transmission Expense	4-CP Trans.	$1,524,685	$3,483	$1,315,588	$265,852	$359,931	$340,057	$187,968	$161,780
44	Other Pro-Forma Expenses		$65,130,863	$144,621	$55,549,088	$11,359,143	$14,791,130	$14,211,306	$8,199,897	$6,987,412
45	Pro-Forma Non-Energy Related		$66,655,548	$148,104	$56,864,676	$11,625,095	$15,151,161	$14,551,363	$8,387,865	$7,149,192
46	Proforma Adjustments		$238,583,202	$679,887	$198,628,300	$30,572,442	$46,960,024	$59,442,034	$34,922,532	$26,731,268
47	Taxes Other than Income		$47,839,519	$190,638	$42,553,612	$9,622,639	$12,021,204	$10,585,525	$5,888,989	$4,435,255
48	Income Tax		$71,368,597	$249,519	$62,366,584	$14,554,417	$17,430,575	$14,738,555	$8,178,917	$7,464,121
49	TOTAL OPERATING EXPENSES		$1,623,949,603	$4,837,566	$1,353,807,772	$219,915,939	$337,710,276	$375,221,846	$239,107,012	$181,852,700
50										
51	OPERATING INCOME		$163,824,019	$642,569	$145,319,875	$33,019,892	$40,975,073	$35,875,074	$19,911,257	$15,538,578
52										
53	RETURN		$163,824,019	$642,569	$145,319,875	$33,019,892	$40,975,073	$35,875,074	$19,911,257	$15,538,578
54										
55	RATE OF RETURN (EQUALIZED)		8.73%	8.73%	8.73%	8.73%	8.73%	8.73%	8.73%	8.73%
56										
57	INDEX RATE OF RETURN		1.08	1.08	1.08	1.08	1.08	1.08	1.08	1.08
58										
59	ACC JURISDICTION INDEX RATE OF RETURN		1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00

AECC's Adjusted Cost of Service Study Using Energy Scalars
for Fuel and Purchased Power Costs and 4-CP
for Transmission Expenses
for the 12 Months ending Sep. 30, 2005
($)

Line No.	1 Description	2 Allocation Factor	19 E-34	20 E-35	21 E-38, 221 Water Pumping	22 Street Lighting	23 Dusk to Dawn
	SUMMARY OF RESULTS						
16	TOTAL RATE BASE		$115,618,777	$88,981,169	$25,474,477	$51,298,120	$23,620,450
17							
18	DEVELOPMENT OF RETURN						
19	Revenues from Rates		$66,695,622	$67,026,166	$20,966,540	$12,913,053	$6,136,856
20	Proforma to Revenues from Rates		$23,659	$635,071	($102,439)	$431,212	$285,840
21	Other Electric Revenues		$57,813,897	$67,418,789	$15,739,104	$8,074,267	$1,570,264
22	TOTAL OPERATING REVENUES		$124,533,178	$135,080,026	$36,603,205	$21,418,532	$7,992,960
23	Revenue Increase Required to Achieve Equalized ROR		$13,328,694	$10,223,942	($1,447,893.6)	$4,159,235	$809,401
24	TOTAL OPERATING REVENUES WITH REVENUE INCREASE		$137,861,872	$145,303,968	$35,155,311	$25,577,767	$8,802,361
25	Percent Increase		19.98%	15.11%	-6.94%	31.17%	12.60%
24							
25	OPERATING EXPENSES						
26							
27	O&M Energy Related						
28	Energy Production	Energy1	$3,261,592	$3,823,527	$891,253	$327,752	$77,127
29	Energy Production - Related Fuel (M&T)	Energy2	$36,959,723	$43,327,466	$10,099,502	$3,714,023	$873,989
30	Energy Production - Related Fuel	Energy100	$37,374,165	$42,512,734	$10,358,616	$3,230,153	$767,046
31	Total Energy Related		$77,595,480	$89,663,727	$21,349,371	$7,271,928	$1,718,163
32	OATT Transmission Expense	4-CP Trans.	$3,947,929	$3,600,312	$534,953	$0	$0
33	Other O&M Enon-Energy Expenses		$9,842,957	$8,547,834	$2,203,432	$4,683,266	$1,261,065
34	Total O&M Non-Energy Related		$13,790,886	$12,148,146	$2,738,385	$4,683,266	$1,261,065
35	Operation & Maintenance		$91,386,366	$101,811,873	$24,087,756	$11,955,194	$2,979,228
36	Administrative & General		$3,006,658	$2,751,576	$880,883	$1,303,165	$571,087
37	Depreciation & Amortization Expense		$7,583,550	$6,267,552	$1,842,301	$3,034,821	$1,369,871
38	Amortization on Gain		($241,284)	($243,307)	($45,007)	($8,981)	($2,113)
39	Regulatory Assets		($74,006)	($67,490)	($10,028)	$0	$0
40	Pro-Forma Energy Related - Jurisdictional	Energy100'	$2,577,143	$2,931,474	$714,280	$222,736	$52,892
41	Pro-Forma Energy Related - ACC	Energy100'	$11,556,812	$13,145,757	$3,203,084	$998,825	$237,186
42	Pro-Forma Energy Related - ACC(Weather & Cust)	Assigned	($578,939)	$0	($125,097)	$37,319	$0
43	Pro-Forma OATT Transmission Expense	4-CP Trans.	$107,542	$98,072	$14,572	$0	$0
44	Other Pro-Forma Expenses		$4,740,120	$4,697,034	$789,312	$43,984	$5,186
45	Pro-Forma Non-Energy Related		$4,847,662	$4,795,106	$803,884	$43,984	$5,186
46	Proforma Adjustments		$18,402,678	$20,872,337	$4,596,151	$1,302,864	$295,263
47	Taxes Other than Income		$2,889,635	$2,205,634	$739,434	$1,432,424	$654,697
48	Income Tax		$4,814,757	$3,937,736	$839,900	$2,079,954	$872,263
49	TOTAL OPERATING EXPENSES		$127,768,353	$137,535,911	$32,931,390	$21,099,441	$6,740,296
50							
51	OPERATING INCOME		$10,093,519	$7,768,056	$2,223,922	$4,478,326	$2,062,065
52							
53	RETURN		$10,093,519	$7,768,056	$2,223,922	$4,478,326	$2,062,065
54							
55	RATE OF RETURN (EQUALIZED)		8.73%	8.73%	8.73%	8.73%	8.73%
56							
57	INDEX RATE OF RETURN		1.08	1.08	1.08	1.08	1.08
58							
59	ACC JURISDICTION INDEX RATE OF RETURN		1.00	1.00	1.00	1.00	1.00

AECC Proposed Rate Spread at APS Requested Revenue Increase

AECC Proposed Revenue Increase for each Customer Class based on AECC's Proposed Cost of Service Study Reflecting Hourly Fuel and Purchased Power Costs and Allocation of Transmission Expenses Using APS's 4-CP Demand Allocator

E-32, Water Pumping & Dusk to Dawn Adder Above Cost (if Change > 0%) = 5.018%

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
Line No.	Rate Class	Current Retail Revenues	Rate Base	Return Req'd Return @ Equal ROR	Equalized Rate of Return	Equalized Relative Rate of Return	Required Revenue Increase w/o EIC	Req'd Percent Change	AECC Proposed Revenue Increase w/o EIC	AECC Percent Change
1	Residential	$1,089,551,030	$2,489,739,663	$217,354,273	8.73%	1.00	$318,454,882	29.23%	$274,370,401	25.18%
2	General Service									
3	E-20	$3,586,700	$7,360,472	$642,569	8.73%	1.00	$56,663	1.58%	$56,663	1.58%
4	E-32	$859,172,589	$1,664,603,376	$145,319,875	8.73%	1.00	$104,042,736	12.11%	$147,155,919	17.13%
5	E-34	$66,719,281	$115,618,777	$10,093,519	8.73%	1.00	$13,328,694	19.98%	$13,328,694	19.98%
6	E35	$67,661,237	$88,981,169	$7,768,056	8.73%	1.00	$10,223,942	15.11%	$10,223,942	15.11%
7	General Service Total	$997,139,807	$1,876,563,794	$163,824,019	8.73%	1.00	$127,652,035	12.80%	$170,765,219	17.13%
8	Water Pumping (E-38, E-221)	$20,864,101	$25,474,477	$2,223,922	8.73%	1.00	($1,447,894)	-6.94%	$0	0.00%
9	Street Lighting	$13,344,265	$51,298,120	$4,478,326	8.73%	1.00	$4,159,235	31.17%	$3,360,349	25.18%
10	Dusk to Dawn	$6,422,696	$23,620,450	$2,062,065	8.73%	1.00	$809,401	12.60%	$1,131,692	17.62%
11	ACC Total	$2,127,321,899	$4,466,696,504	$389,942,605	8.73%	1.00	$449,627,660	21.14%	$449,627,660	21.14%

APS's Cost of Service Results Adjusted to Reflect Hourly Fuel and Purchased Power Costs, Allocation of Transmission Expenses Using APS's 4-CP Demand Allocator and Use of Average and Excess Demand Allocator

Revenue Increase Required to Move each Customer Class to Cost of Service using AECC's Proposed Cost of Service Study Results

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
Line No.	Rate Class	Current Retail Revenues	Rate Base	Return Req'd Return @ Equal ROR	Equalized Rate of Return	Equalized Relative Rate of Return	Required Revenue Increase w/o EIC	Required Revenue Increase	Req'd Percent Change
1	Residential	$1,089,551,030	$2,580,945,496	$225,316,542	8.73%	1.00	$1,443,666,166	$354,115,136	32.50%
2	General Service								
3	E-20	$3,586,700	$10,488,903	$915,681	8.73%	1.00	$4,866,297	$1,279,597	35.68%
4	E-32	$859,172,589	$1,540,595,739	$134,494,008	8.73%	1.00	$914,733,051	$55,560,462	6.47%
5	E-34	$66,719,281	$109,636,156	$9,571,236	8.73%	1.00	$77,708,554	$10,989,273	16.47%
6	E35	$67,661,237	$89,723,138	$7,832,830	8.73%	1.00	$78,174,574	$10,513,337	15.54%
7	General Service Total	$997,139,807	$1,750,443,936	$152,813,756	8.73%	1.00	$1,075,482,476	$78,342,669	7.86%
8	Water Pumping (E-38, E-221)	$20,864,101	$46,494,343	$4,058,956	8.73%	1.00	$27,633,087	$6,768,986	32.44%
9	Street Lighting	$13,344,265	$62,924,087	$5,493,273	8.73%	1.00	$22,048,805	$8,704,540	65.23%
10	Dusk to Dawn	$6,422,696	$25,888,643	$2,260,078	8.73%	1.00	$8,119,024	$1,696,328	26.41%
11	ACC Total	$2,127,321,899	$4,466,696,504	$389,942,605	8.73%	1.00	$2,576,949,558	$449,627,659	21.14%

Development of Average and Excess Demand Factor

A&E Factor = Avg Demand Component + Excess Demand Component

Where: Avg Demand Component = Class Avg. Demand + Jurisdictional Peak Demand
Excess Demand Component = (((Class NCP - Class Avg Demand) + (Juris. NCP Total - Juris. Avg Demand)) x (Juris. Peak Demand - Juris. Avg Demand)) + Juris. Peak Demand

			Source
Jurisdictional Maximum (Peak) Demand @ Generation- (MW):	6,245	=j	= JP
Sum of Individual Class Maximum Demand @ Gneration (MW):	7,203	=k	= Σ Ln 1 for each class
Total Energy @ Generation (MWh):	27,881,695	=l	Source: APS Data Response to AECC 3.1
Ln 6 [Total] = Jurisdiction Peak Demand [6245 MW] - Jurisdictional Average Demand [3183 MW]:	3,062	=m	= JP - Ln 4 [Total]

Residential

Ln #	Description	E-10	E-12	EC-1	ET-1	ECT-1R	Residential Total	Source
1	*Annual NCP* Peak Demand@ Generator (MW)	238	1,254	153	2,060	428	4,129	APS Data Response to AECC 3.1
2	Annual Energy @ Input (MWh)	852,812	4,001,457	504,571	6,373,509	1,478,487	13,210,836	APS Data Response to AECC 3.1
3	Calculated Annual Load Factor (%)	40.88%	36.42%	37.61%	35.31%	39.41%	36.53%	= Ln 2 ÷ (Ln 1 x 8760)
4	Average Demand (MW)	97	457	58	728	169	1,508	= Ln 2 ÷ 8760
5	Individual Excess Demand (MW)	141	797	96	1,333	259	2,621	= Ln 1 - Ln 4
6	Allocated Jurisdictional Excess Demand (MW)	107	607	73	1,015	198	1,996	= Ln 6 (Total) x (Ln 5 ÷ Ln 5(Total))
7	Average and Alloc. Juris. Excess Demand (MW)	205	1,064	130	1,743	366	3,504	= Ln 4 + Ln 6
8	Avg Demand Factor Component	1.56%	7.31%	0.92%	11.65%	2.70%	24.15%	= Ln 4 ÷ ln 7 [Total]
9	Excess Demand Factor Component	1.72%	9.73%	1.17%	16.25%	3.16%	31.96%	= ((Ln 5 ÷ Ln 5 [Total]) x (Ln 6 [Total]) ÷ Ln 5 [Total]
10	Avg & Excess Demand Factor	3.28%	17.04%	2.09%	27.91%	5.87%	56.11%	= Ln 8 + Ln 9

General Service

Ln #	Description	Church Rate E-20	0 - 20 kW E-21, E-23, E-30 E-32 & E-32 TOU	21 - 100 kW E-22, E-32 & E-32 TOU	101-400 kW E-32 & E-32 TOU	401-999 kW E-24, E-32 & E-32 TOU	1000 + kW E-32 & E-32 TOU	E-32 Total	E-34	E-35	Source
1	*Annual NCP* Peak Demand@ Generator (MW)	19	354	589	718	502	324	2,467	208	202	APS Data Response to AECC 3.1
2	Annual Energy @ Input (MWh)	38,650	1,404,282	2,696,965	3,314,293	2,310,169	1,714,920	11,440,629	1,242,014	1,455,999	APS Data Response to AECC 3.1
3	Calculated Annual Load Factor (%)	22.64%	45.26%	52.26%	52.72%	52.55%	60.47%	52.93%	68.11%	82.30%	= Ln 2 ÷ (Ln 1 x 8760)
4	Average Demand (MW)	4	160	308	378	264	196	1,306	142	166	= Ln 2 ÷ 8760
5	Individual Excess Demand (MW)	15	194	281	339	238	128	1,161	66	36	= Ln 1 - Ln 4
6	Allocated Jurisdictional Excess Demand (MW)	11	148	214	258	181	97	885	51	27	= Ln 6 (Total) x (Ln 5 ÷ Ln 5(Total))
7	Average and Alloc. Juris. Excess Demand (MW)	16	308	522	637	445	293	2,191	192	193	= Ln 4 + Ln 6
8	Avg Demand Factor Component	0.07%	2.57%	4.93%	6.06%	4.22%	3.13%	20.91%	2.27%	2.66%	= Ln 4 ÷ ln 7 [Total]
9	Excess Demand Factor Component	0.18%	2.36%	3.43%	4.14%	2.90%	1.56%	14.16%	0.81%	0.44%	= ((Ln 5 ÷ Ln 5 [Total]) x (Ln 6 [Total]) ÷ Ln 5 [Total]
10	Avg & Excess Demand Factor	0.25%	4.93%	8.36%	10.20%	7.13%	4.70%	35.08%	3.08%	3.10%	= Ln 8 + Ln 9

Ln #	Description	Water Pumping E-38/E-221	Streetlights	Dusk to Dawn	ACC Total		Source
1	*Annual NCP* Peak Demand@ Generator (MW)	105	40	8	7,203	=k	APS Data Response to AECC 3.1
2	Annual Energy @ Input (MWh)	339,389	124,808	29,370	27,881,695	=l	APS Data Response to AECC 3.1
3	Calculated Annual Load Factor (%)	36.74%	35.67%	44.04%	44.19%		= Ln 2 ÷ (Ln 1 x 8760)
4	Average Demand (MW)	39	14	3	3,183		= Ln 2 ÷ 8760
5	Individual Excess Demand (MW)	67	26	4	4,020		= Ln 1 - Ln 4
6	Allocated Jurisdictional Excess Demand (MW)	51	20	3	3,062	=m	= Ln 6 (Total) x (Ln 5 ÷ Ln 5(Total))
7	Average and Alloc. Juris. Excess Demand (MW)	90	34	7	6,245	=j	= Ln 4 + Ln 6
8	Avg Demand Factor Component	0.62%	0.23%	0.05%	50.97%		= Ln 4 ÷ ln 7 [Total]
9	Excess Demand Factor Component	0.81%	0.31%	0.05%	49.03%		= ((Ln 5 ÷ Ln 5 [Total]) x (Ln 6 [Total]) ÷ Ln 5 [Total]
10	Avg & Excess Demand Factor	1.43%	0.54%	0.11%	100.00%		= Ln 8 + Ln 9

AECC's Adjusted Cost of Service Study Using Energy Scalars
for Fuel and Purchased Power Costs, 4-CP for Transmission
Expenses and Avg and Excess Demand Allocator
for the 12 Months ending Sep. 30, 2005
($)

Line No.	1 Description	2 Allocation Factor	3 Electric Total	4 ACC Jurisdiction	5 All Other	6 Total Residential	7 E-10 Residential	8 E-12 Residential	9 EC-1 Residential	10 ET-1 Residential	11 ECT-1 Residential
	SUMMARY OF RESULTS										
16	Rate Base - Production Demand Related Related		$2,172,189,724	$2,147,019,278	$25,170,446	$1,206,116,221	$70,335,410	$365,864,854	$44,818,693	$599,129,401	$125,967,864
17	Rate Base - Non-Production Demand Related		$3,155,643,468	$2,319,677,226	$835,966,242	$1,374,829,274	$84,242,416	$461,583,726	$41,696,842	$666,078,469	$121,227,821
18	TOTAL RATE BASE		$5,327,833,192	$4,466,696,504	$861,136,688	$2,580,945,496	$154,577,826	$827,448,580	$86,515,535	$1,265,207,870	$247,195,685
19											
20	DEVELOPMENT OF RETURN										
21	Revenues from Rates		$2,103,857,729	$2,066,144,726	$37,713,003	$1,058,729,739	$70,337,587	$360,585,198	$36,686,029	$490,471,664	$100,649,261
22	Proforma to Revenues from Rates		$60,953,295	$61,177,173	($223,878)	$30,821,291	($2,224,915)	$11,853,176	($1,254,829)	$20,328,518	$2,119,341
23	Other Electric Rev. - DEMPROD1 Related	Dem-A&E	$4,714,348	$4,659,999	$54,349	$2,617,816	$152,660	$794,092	$97,277	$1,300,381	$273,407
24	Other Electric Rev. - Non-DEMPROD1 Demand		$1,340,195,024	$1,308,608,574	$31,586,450	$622,483,300	$40,141,249	$188,965,752	$23,672,492	$300,359,333	$69,344,473
25	Other Electric Revenues		$1,344,909,372	$1,313,268,573	$31,640,799	$625,101,116	$40,293,909	$189,759,844	$23,769,769	$301,659,714	$69,617,880
26	TOTAL OPERATING REVENUES		$3,509,720,396	$3,440,590,472	$69,129,924	$1,714,652,146	$108,406,581	$562,198,218	$59,200,969	$812,459,896	$172,386,482
27	Revenue Increase Required to Achieve Equalized ROR		$449,627,659	$449,627,659	$0	$354,115,136	$21,039,581	$90,936,624	$14,107,604	$188,606,658	$39,424,669
28	TOTAL OPERATING REVENUES WITH REVENUE INCREASE		$3,959,348,055	$3,890,218,131	$69,129,924	$2,068,767,282	$129,446,162	$653,134,842	$73,308,573	$1,001,066,554	$211,811,151
29	Percent Increase		20.77%	21.14%	0.00%	32.50%	30.89%	24.42%	39.82%	36.91%	38.36%
30											
31	OPERATING EXPENSES										
32											
33	O&M Energy Related										
34	Energy Production	Energy1	$74,369,000	$73,170,843	$1,198,157	$34,692,327	$2,239,528	$10,508,029	$1,325,029	$16,737,158	$3,882,582
35	Energy Production - Related Fuel (M&T)	Energy2	$842,735,000	$829,157,722	$13,577,278	$393,126,677	$25,377,890	$119,074,939	$15,014,971	$189,662,215	$43,996,662
36	Energy Production - Related Fuel	Energy100	$885,397,911	$871,149,260	$14,248,651	$426,382,540	$27,140,225	$128,542,154	$16,160,595	$207,200,327	$47,339,237
37	Total O&M Energy Related		$1,802,501,911	$1,773,477,826	$29,024,085	$854,201,543	$54,757,643	$258,125,123	$32,500,595	$413,599,700	$95,218,481
38	OATT Transmission Expense	4-CP Trans.	$0	$117,547,846	($117,547,846)	$61,040,586	$3,503,525	$18,288,673	$2,080,159	$30,710,312	$6,457,917
39	O&M - DEMPROD1 Related	Dem-A&E	$238,634,716	$235,883,642	$2,751,074	$132,510,728	$7,727,445	$40,195,975	$4,924,034	$65,823,734	$13,839,540
40	Other O&M		$204,876,070	$175,555,421	$29,320,649	$123,597,376	$9,055,735	$48,810,523	$3,488,272	$53,628,830	$8,614,016
41	Total O&M Non-Energy Related		$443,510,786	$528,986,909	($85,476,123)	$317,148,689	$20,286,704	$107,295,172	$10,492,465	$150,162,875	$28,911,473
42	Operation & Maintenance		$2,246,012,697	$2,302,464,735	($56,452,038)	$1,171,350,232	$75,044,348	$365,420,295	$42,993,060	$563,762,576	$124,129,954
43	A&G - DEMPROD1 Related	Dem-A&E	$47,709,445	$47,159,432	$550,013	$26,492,429	$1,544,922	$8,036,248	$984,446	$13,159,920	$2,766,893
44	A&G - Non-DEMPROD1 Demand		$94,058,739	$85,527,697	$8,531,042	$56,955,327	$4,029,999	$21,589,423	$1,649,094	$25,401,063	$4,285,748
45	Administrative & General		$141,768,184	$132,687,129	$9,081,055	$83,447,756	$5,574,921	$29,625,671	$2,633,539	$38,560,984	$7,052,641
46	Depr. & Amort. - DEMPROD1 Related	Dem-A&E	$131,357,492	$129,843,152	$1,514,340	$72,941,092	$4,253,605	$22,126,045	$2,710,456	$36,232,953	$7,618,033
47	Depr. & Amort. - Non-DEMPROD1 Demand		$190,168,510	$155,915,840	$34,252,670	$92,306,856	$6,041,657	$31,248,313	$2,951,693	$43,982,063	$8,083,130
48	Depreciation & Amortization Expense		$321,526,002	$285,758,992	$35,767,010	$165,247,949	$10,295,262	$53,374,358	$5,662,148	$80,215,017	$15,701,164
49	Amort. of Gain - DEMPROD1 Related	Dem-A&E	($4,575,723)	($4,522,972)	($52,751)	($2,540,839)	($148,171)	($770,741)	($94,416)	($1,262,143)	($265,368)
50	Amort. of Gain - Non-DEMPROD1 Demand		($2,037,914)	($2,005,082)	($32,832)	($950,665)	($61,369)	($287,949)	($36,309)	($458,644)	($106,393)
51	Amortization on Gain		($6,613,637)	($6,528,054)	($85,583)	($3,491,504)	($209,540)	($1,058,690)	($130,726)	($1,720,788)	($371,761)
52	Regulatory Assets		($2,203,511)	($2,203,511)	$0	($1,144,246)	($65,676)	($342,833)	($38,994)	($575,685)	($121,058)
53	Pro-Forma Energy Related - Jurisdictional	Energy100'	$61,052,503	$60,070,266	$982,237	$29,401,291	$1,871,459	$8,863,649	$1,114,357	$14,287,539	$3,264,286
54	Pro-Forma Energy Related - ACC	Energy100'	$269,376,144	$269,376,144	$0	$131,845,700	$8,392,281	$39,747,712	$4,997,168	$64,070,335	$14,638,205
55	Pro-Forma Energy Related - ACC(Weather & Cust)	Assigned	$18,114,000	$18,114,000	$0	$9,044,540	($677,719)	$3,428,524	($350,866)	$5,867,427	$777,174
56	Pro-Forma OATT Transmission Expense	4-CP Trans.	$3,202,002	$3,202,002	$0	$1,662,745	$95,436	$498,183	$56,664	$836,549	$175,914
57	Pro-Forma - DEMPROD1 Related	Dem-A&E	$116,501,191	$115,144,635	$1,356,556	$64,684,008	$3,772,088	$19,621,331	$2,403,626	$32,131,307	$6,755,656
58	Other Pro-Forma Expenses		$36,315,529	$29,887,486	$6,428,043	$19,277,356	$1,375,322	$7,618,243	$540,430	$8,232,734	$1,510,627
59	Total Pro-Forma Non-Energy Related		$485,465,132	$477,680,533	$7,784,599	$85,624,109	$5,242,846	$27,737,757	$3,000,720	$41,200,590	$8,442,197
60	Proforma Adjustments		$504,561,369	$495,794,533	$8,766,836	$255,915,640	$14,828,867	$79,777,642	$8,761,378	$125,425,891	$27,121,862
61	Taxes Other than Income - DEMPROD1 Related	Dem-A&E	$50,248,418	$49,669,135	$579,283	$27,902,288	$1,627,139	$8,463,916	$1,036,835	$13,860,257	$2,914,140
62	Taxes Other than Income - Non-DEMPROD1 Demand		$89,722,351	$66,663,521	$23,058,830	$39,874,250	$2,591,374	$13,445,256	$1,266,994	$19,113,706	$3,456,919
63	Taxes Other than Income		$139,970,769	$116,332,656	$23,638,113	$67,776,537	$4,218,513	$21,909,172	$2,303,830	$32,973,963	$6,371,059
64	Income Tax		$185,532,145	$175,969,046	$9,563,098	$104,348,376	$6,264,823	$32,192,966	$3,571,530	$51,971,949	$10,347,108
65	TOTAL OPERATING EXPENSES		$3,530,554,018	$3,500,275,526	$30,278,491	$1,843,450,740	$115,951,518	$580,898,581	$65,755,767	$890,613,907	$190,230,968
66											
67	OPERATING INCOME		$428,794,038	$389,942,605	$38,851,433	$225,316,542	$13,494,644	$72,236,261	$7,552,806	$110,452,647	$21,580,183
68											
69	RETURN		$428,794,038	$389,942,605	$38,851,433	$225,316,542	$13,494,644	$72,236,261	$7,552,806	$110,452,647	$21,580,183
70											
71	RATE OF RETURN (EQUALIZED)		8.05%	8.73%	4.51%	8.73%	8.73%	8.73%	8.73%	8.73%	8.73%
72											
73	INDEX RATE OF RETURN		1.00	1.08	0.56	1.08	1.08	1.08	1.08	1.08	1.08
74											
75	ACC JURISDICTION INDEX RATE OF RETURN			1.00		1.00	1.00	1.00	1.00	1.00	1.00

AECC's Adjusted Cost of Service Study Using Energy Scalars
for Fuel and Purchased Power Costs, 4-CP for Transmission
Expenses and Avg and Excess Demand Allocator
for the 12 Months ending Sep. 30, 2005
($)

Line No.	1 Description	2 Allocation Factor	12 Total General Service	13 E-20 Church Rate	E-30, E-32 Total	14 E-30, E-32 (0 - 20 kW)	15 E-32 (21 - 100 kW)	16 E-32 (101 - 400 kW)	17 E-32 (401 - 999 kW)	18 E-32 (1,000 + kW)
	SUMMARY OF RESULTS									
16	Rate Base - Production Demand Related Related		$896,218,080	$5,464,184	$758,125,412	$105,885,022	$179,496,608	$218,919,573	$153,012,872	$100,811,337
17	Rate Base - Non-Production Demand Related		$854,225,856	$5,024,719	$782,470,326	$199,974,819	$228,016,761	$182,914,012	$102,041,558	$69,513,166
18	TOTAL RATE BASE		$1,750,443,936	$10,488,903	$1,540,595,739	$305,859,852	$407,513,370	$401,843,584	$255,054,430	$170,324,503
19										
20	DEVELOPMENT OF RETURN									
21	Revenues from Rates		$967,398,538	$3,344,799	$830,331,951	$142,275,889	$218,138,380	$229,640,445	$146,123,538	$94,153,699
22	Proforma to Revenues from Rates		$29,741,269	$241,901	$28,840,638	$9,060,700	$3,862,319	$13,851,012	$1,053,159	$1,013,448
23	Other Electric Rev. - DEMPROD1 Related	Dem-A&E	$1,945,197	$11,860	$1,645,474	$229,818	$389,589	$475,154	$332,107	$218,806
24	Other Electric Rev. - Non-DEMPROD1 Demand		$660,762,846	$1,831,702	$533,997,696	$66,688,203	$126,503,294	$154,505,708	$106,969,017	$79,331,474
25	Other Electric Revenues		$662,708,043	$1,843,562	$535,643,170	$66,918,021	$126,892,882	$154,980,862	$107,301,114	$79,550,280
26	TOTAL OPERATING REVENUES		$1,659,847,850	$5,430,262	$1,394,815,759	$218,254,610	$348,893,581	$398,472,319	$254,477,821	$174,717,427
27	Revenue Increase Required to Achieve Equalized ROR		$78,342,669	$1,279,597	$55,560,462	$6,231,970	$5,479,599	$9,046,662	$15,142,943	$19,659,288
28	TOTAL OPERATING REVENUES WITH REVENUE INCREASE		$1,738,190,519	$6,709,859	$1,450,376,221	$224,486,580	$354,373,180	$407,518,982	$269,620,764	$194,376,715
29	Percent Increase		7.86%	35.68%	6.47%	4.12%	2.47%	3.72%	10.29%	20.66%
30										
31	OPERATING EXPENSES									
32										
33	O&M Energy Related									
34	Energy Production	Energy1	$37,182,385	$101,497	$29,995,769	$3,687,388	$7,082,367	$8,703,502	$6,038,893	$4,483,619
35	Energy Production - Related Fuel (M&T)	Energy2	$421,343,530	$1,150,143	$339,906,198	$41,784,757	$80,256,003	$98,626,385	$68,431,554	$50,807,500
36	Energy Production - Related Fuel	Energy100	$430,410,906	$1,256,908	$349,267,098	$43,043,545	$82,787,067	$101,682,496	$70,057,238	$51,696,753
37	Total O&M Energy Related		$888,936,821	$2,508,548	$719,169,065	$88,515,690	$170,125,436	$209,012,382	$144,527,685	$106,987,872
38	OATT Transmission Expense	4-CP Trans.	$55,972,307	$127,881	$48,296,185	$9,759,609	$13,213,344	$12,483,728	$6,900,440	$5,939,065
39	O&M - DEMPROD1 Related	Dem-A&E	$98,463,571	$600,326	$83,291,932	$11,633,126	$19,720,509	$24,051,738	$16,810,857	$11,075,702
40	Other O&M		$44,883,775	$224,160	$41,415,905	$14,427,079	$11,348,002	$8,208,131	$4,555,030	$2,877,663
41	Total O&M Non-Energy Related		$199,319,653	$952,367	$173,004,022	$35,819,814	$44,281,855	$44,743,597	$28,266,326	$19,892,430
42	Operation & Maintenance		$1,088,256,473	$3,460,915	$892,173,087	$124,335,503	$214,407,292	$253,755,979	$172,794,011	$126,880,302
43	A&G - DEMPROD1 Related	Dem-A&E	$19,685,494	$120,021	$16,652,279	$2,325,772	$3,942,656	$4,808,584	$3,360,939	$2,214,328
44	A&G - Non-DEMPROD1 Demand		$26,031,855	$117,253	$23,184,673	$6,537,796	$6,375,679	$5,119,972	$3,059,330	$2,091,896
45	Administrative & General		$45,717,349	$237,274	$39,836,952	$8,863,568	$10,318,335	$9,928,556	$6,420,269	$4,306,224
46	Depr. & Amort. - DEMPROD1 Related	Dem-A&E	$54,199,690	$330,452	$45,848,397	$6,403,503	$10,855,238	$13,239,381	$9,253,607	$6,096,667
47	Depr. & Amort. - Non-DEMPROD1 Demand		$57,952,899	$300,598	$52,138,974	$12,305,221	$14,774,387	$12,735,350	$7,396,677	$4,927,340
48	Depreciation & Amortization Expense		$112,152,590	$631,050	$97,987,371	$18,708,724	$25,629,625	$25,974,731	$16,650,285	$11,024,007
49	Amort. of Gain - DEMPROD1 Related	Dem-A&E	($1,887,999)	($11,511)	($1,597,089)	($223,060)	($378,133)	($461,182)	($322,341)	($212,372)
50	Amort. of Gain - Non-DEMPROD1 Demand		($1,018,900)	($2,781)	($821,966)	($101,054)	($194,068)	($238,500)	($165,482)	($122,863)
51	Amortization on Gain		($2,906,898)	($14,292)	($2,419,055)	($324,114)	($572,200)	($699,682)	($487,823)	($335,235)
52	Regulatory Assets		($1,049,237)	($2,397)	($905,344)	($182,950)	($247,693)	($234,016)	($129,353)	($111,332)
53	Pro-Forma Energy Related - Jurisdictional	Energy100'	$29,679,067	$86,670	$24,083,780	$2,968,076	$5,708,598	$7,011,536	$4,830,810	$3,564,760
54	Pro-Forma Energy Related - ACC	Energy100'	$133,091,349	$388,660	$108,000,119	$13,309,894	$25,599,357	$31,442,188	$21,663,048	$15,985,633
55	Pro-Forma Energy Related - ACC(Weather & Cust)	Assigned	$9,157,238	$56,452	$9,679,725	$2,669,378	$500,908	$6,436,947	$40,808	$31,684
56	Pro-Forma OATT Transmission Expense	4-CP Trans.	$1,524,685	$3,483	$1,315,588	$265,852	$359,931	$340,057	$187,968	$161,780
57	Pro-Forma - DEMPROD1 Related	Dem-A&E	$48,064,172	$293,044	$40,658,263	$5,678,613	$9,626,402	$11,740,656	$8,206,080	$5,406,512
58	Other Pro-Forma Expenses		$10,294,702	$19,362	$8,233,523	$1,798,875	$1,846,150	$1,980,516	$1,439,408	$1,168,574
59	Total Pro-Forma Non-Energy Related		$59,883,559	$315,890	$50,207,373	$7,743,340	$11,832,484	$14,061,228	$9,833,456	$6,736,866
60	Proforma Adjustments		$231,811,213	$847,672	$191,970,998	$26,690,688	$43,641,347	$58,951,899	$36,368,122	$26,318,942
61	Taxes Other than Income - DEMPROD1 Related	Dem-A&E	$20,733,105	$126,408	$17,538,470	$2,449,544	$4,152,474	$5,064,484	$3,539,799	$2,332,169
62	Taxes Other than Income - Non-DEMPROD1 Demand		$24,188,757	$136,603	$22,146,350	$5,498,775	$6,437,985	$5,310,601	$2,973,250	$1,925,739
63	Taxes Other than Income		$44,921,863	$263,011	$39,684,820	$7,948,319	$10,590,459	$10,375,086	$6,513,049	$4,257,908
64	Income Tax		$66,473,411	$370,945	$57,553,383	$11,745,277	$15,030,099	$14,385,484	$9,225,952	$7,166,571
65	TOTAL OPERATING EXPENSES		$1,585,376,764	$5,794,178	$1,315,882,213	$197,785,015	$318,797,263	$372,438,037	$247,354,512	$179,507,386
66										
67	OPERATING INCOME		$152,813,756	$915,681	$134,494,008	$26,701,565	$35,575,917	$35,080,945	$22,266,252	$14,869,329
68										
69	RETURN		$152,813,756	$915,681	$134,494,008	$26,701,565	$35,575,917	$35,080,945	$22,266,252	$14,869,329
70										
71	RATE OF RETURN (EQUALIZED)		8.73%	8.73%	8.73%	8.73%	8.73%	8.73%	8.73%	8.73%
72										
73	INDEX RATE OF RETURN		1.08	1.08	1.08	1.08	1.08	1.08	1.08	1.08
74										
75	ACC JURISDICTION INDEX RATE OF RETURN		1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00

AECC's Adjusted Cost of Service Study Using Energy Scalars
for Fuel and Purchased Power Costs, 4-CP for Transmission
Expenses and Avg and Excess Demand Allocator
for the 12 Months ending Sep. 30, 2005
($)

Line No.	1 Description	2 Allocation Factor	19 E-34	20 E-35	21 E-38, 221 Water Pumping	22 Street Lighting	23 Dusk to Dawn
	SUMMARY OF RESULTS						
16	Rate Base - Production Demand Related Related		$66,126,575	$66,501,909	$30,790,817	$11,625,967	$2,268,193
17	Rate Base - Non-Production Demand Related		$43,509,581	$23,221,229	$15,703,526	$51,298,120	$23,620,450
18	TOTAL RATE BASE		$109,636,156	$89,723,138	$46,494,343	$62,924,087	$25,888,643
19							
20	DEVELOPMENT OF RETURN		$66,695,622	$67,026,166	$20,966,540	$12,913,053	$6,136,856
21	Revenues from Rates		$23,659	$635,071	($102,439)	$431,212	$285,840
22	Proforma to Revenues from Rates		$143,524	$144,339	$66,830	$25,234	$4,923
23	Other Electric Rev. - DEMPROD1 Related	Dem-A&E	$57,657,388	$67,276,060	$15,717,897	$8,074,267	$1,570,264
24	Other Electric Rev. - Non-DEMPROD1 Demand		$57,800,912	$67,420,399	$15,784,727	$8,099,501	$1,575,187
25	Other Electric Revenues		$124,520,193	$135,081,636	$36,648,828	$21,443,766	$7,997,883
26	TOTAL OPERATING REVENUES		$10,989,273	$10,513,337	$6,768,986.5	$8,704,540	$1,696,328
27	Revenue Increase Required to Achieve Equalized ROR		$135,509,466	$145,594,973	$43,417,814	$30,148,306	$9,694,211
28	TOTAL OPERATING REVENUES WITH REVENUE INCREASE		16.47%	15.54%	32.44%	65.23%	26.41%
29	Percent Increase						
30							
31	OPERATING EXPENSES						
32							
33	O&M Energy Related		$3,261,592	$3,823,527	$891,253	$327,752	$77,127
34	Energy Production	Energy1	$36,959,723	$43,327,466	$10,099,502	$3,714,023	$873,989
35	Energy Production - Related Fuel (M&T)	Energy2	$37,374,165	$42,512,734	$10,358,616	$3,230,153	$767,046
36	Energy Production - Related Fuel	Energy100	$77,595,480	$89,663,727	$21,349,371	$7,271,928	$1,718,163
37	Total O&M Energy Related		$3,947,929	$3,600,312	$534,953	$0	$0
38	OATT Transmission Expense	4-CP Trans.	$7,265,038	$7,306,275	$3,382,853	$1,277,294	$249,196
39	O&M - DEMPROD1 Related	Dem-A&E	$1,920,634	$1,323,076	$1,129,940	$4,683,266	$1,261,065
40	Other O&M		$13,133,602	$12,229,663	$5,047,746	$5,960,560	$1,510,261
41	Total O&M Non-Energy Related		$90,729,081	$101,893,390	$26,397,117	$13,232,488	$3,228,424
42	Operation & Maintenance		$1,452,475	$1,460,719	$676,323	$255,365	$49,821
43	A&G - DEMPROD1 Related	Dem-A&E	$1,422,774	$1,307,154	$666,263	$1,303,165	$571,087
44	A&G - Non-DEMPROD1 Demand		$2,875,249	$2,767,873	$1,342,586	$1,558,530	$620,908
45	Administrative & General		$3,999,071	$4,021,770	$1,862,106	$703,092	$137,171
46	Depr. & Amort. - DEMPROD1 Related	Dem-A&E	$3,222,674	$2,290,653	$1,251,393	$3,034,821	$1,369,871
47	Depr. & Amort. - Non-DEMPROD1 Demand		$7,221,745	$6,312,423	$3,113,499	$3,737,913	$1,507,042
48	Depreciation & Amortization Expense		($139,304)	($140,095)	($64,865)	($24,492)	($4,778)
49	Amort. of Gain - DEMPROD1 Related	Dem-A&E	($89,377)	($104,775)	($24,423)	($8,981)	($2,113)
50	Amort. of Gain - Non-DEMPROD1 Demand		($228,681)	($244,870)	($89,288)	($33,473)	($6,891)
51	Amortization on Gain		($74,006)	($67,490)	($10,028)	$0	$0
52	Regulatory Assets		$2,577,143	$2,931,474	$714,280	$222,736	$52,892
53	Pro-Forma Energy Related - Jurisdictional	Energy100'	$11,556,812	$13,145,757	$3,203,084	$998,815	$237,186
54	Pro-Forma Energy Related - ACC	Energy100'	($578,939)	$0	($125,097)	$37,319	$0
55	Pro-Forma Energy Related - ACC(Weather & Cust)	Assigned	$107,542	$98,072	$14,572	$0	$0
56	Pro-Forma OATT Transmission Expense	4-CP Trans.	$3,546,368	$3,566,497	$1,651,311	$623,501	$121,643
57	Pro-Forma - DEMPROD1 Related	Dem-A&E	$872,134	$1,169,683	$265,356	$44,613	$5,459
58	Other Pro-Forma Expenses		$4,516,043	$4,834,253	$1,931,240	$668,114	$127,102
59	Total Pro-Forma Non-Energy Related		$18,081,060	$20,911,483	$5,723,507	$1,926,994	$417,180
60	Proforma Adjustments		$1,529,772	$1,538,455	$712,315	$268,955	$52,472
61	Taxes Other than Income - DEMPROD1 Related	Dem-A&E	$1,221,461	$684,344	$513,393	$1,432,424	$654,697
62	Taxes Other than Income - Non-DEMPROD1 Demand		$2,751,233	$2,222,799	$1,225,707	$1,701,379	$707,169
63	Taxes Other than Income		$4,582,549	$3,966,534	$1,655,759	$2,531,201	$960,300
64	Income Tax		$125,938,230	$137,762,143	$39,358,858	$24,655,033	$7,434,132
65	TOTAL OPERATING EXPENSES						
66			$9,571,236	$7,832,830	$4,058,956	$5,493,273	$2,260,078
67	OPERATING INCOME						
68			$9,571,236	$7,832,830	$4,058,956	$5,493,273	$2,260,078
69	RETURN						
70			8.73%	8.73%	8.73%	8.73%	8.73%
71	RATE OF RETURN (EQUALIZED)						
72			1.08	1.08	1.08	1.08	1.08
73	INDEX RATE OF RETURN						
74			1.00	1.00	1.00	1.00	1.00
75	ACC JURISDICTION INDEX RATE OF RETURN						

Summary of Energy Cost Multipliers (Relecting Hourly Energy Cost Differences)

	Residential					
	E-10	E-12	EC-1	ET-1	ECT-1R	Residential Total
Overall Retail Energy Cost (¢/kWh)	3.1904	3.1904	3.1904	3.1904	3.1904	3.1904
Class Cost Ratio (Step 3)	1.0179	1.0275	1.0244	1.0398	1.0241	1.0323
Class Energy Rate (¢/kWh)	3.2475	3.2781	3.2684	3.3175	3.2674	3.2936
Energy Use @ Generation (MWh)	852,812	4,001,457	504,571	6,373,509	1,478,487	13,210,836
Energy Use @ Meter (MWh)	793,929	3,725,172	469,732	5,933,443	1,376,403	12,298,679
Energy Revenue ($)	$25,783,227	$122,115,055	$15,352,556	$196,840,323	$44,972,271	$405,063,432

	General Service								
	Church Rate E-20	0 - 20 kW E-21, E-23, E-30 E-32 & E-32 TOU	21 - 100 kW E-22, E-32 & E-32 TOU	101-400 kW E-32 & E-32 TOU	401-999 kW E-24, E-32 & E-32 TOU	1000 + kW E-32 & E-32 TOU	E-32 Total	E-34	E-35
Overall Retail Energy Cost (¢/kWh)	3.1904	3.1904	3.1904	3.1904	3.1904	3.1904	3.1904	3.1904	3.1904
Class Cost Ratio (Step 3)	1.0402	0.9805	0.9818	0.9813	0.9744	0.9685	0.9780	0.9625	0.9339
Class Energy Rate (¢/kWh)	3.3186	3.1282	3.1324	3.1308	3.1088	3.0898	3.1203	3.0707	2.9796
Energy Use @ Generation (MWh)	38,650	1,404,282	2,696,965	3,314,293	2,310,169	1,714,920	11,440,629	1,242,014	1,455,999
Energy Use @ Meter (MWh)	36,618	1,307,541	2,511,175	3,140,255	2,188,928	1,626,501	10,774,400	1,178,438	1,397,289
Energy Revenue ($)	$1,215,190	$40,901,867	$78,661,029	$98,314,070	$68,049,629	$50,255,946	$336,190,235	$36,186,552	$41,633,187

	Water Pumping E-38/E-221	Streetlights	Dusk to Dawn	ACC Total
Overall Retail Energy Cost (¢/kWh)	3.1904	3.1904	3.1904	3.1904
Class Cost Ratio (Step 3)	0.9762	0.8278	0.8353	1.0000
Class Energy Rate (¢/kWh)	3.1146	2.6410	2.6651	3.1904
Energy Use @ Generation (MWh)	339,389	124,808	29,370	27,881,695
Energy Use @ Meter (MWh)	321,550	114,924	27,044	26,148,942
Energy Revenue ($)	$10,014,931	$3,035,197	$720,749	$834,255,846

(Note: Hourly load data based on 12 months ending Sept. 30, 2005)
(Note: Overall energy cost of 3.1904 ¢/kWh based on 12 months ending Dec. 31, 2006)

Derivation of Transmission Demand Charges

E-32 General Service	Demand Units (Over 20 kW) [1]	Transmission Revenues (Over 20 kW)[1]	Proposed Transmission Charge
Total	25,196,428	$45,092,740	$1.790

E-34	Demand Units[1]	Transmission Revenues[1]	Proposed Transmission Charge
Total	2,327,022	$5,757,046	$2.474

E-35	Demand Units[1]	Transmission Revenues[1]	Proposed Transmission Charge
Total	2,310,533	$6,592,489	$2.853

1. Source DJR_WP9

EXHIBIT
Mundell-1
admitted

PINNACLE WEST
CAPITAL CORPORATION

INVESTOR FACTS

1st Quarter 2006 NYSE: PNW

ABOUT PINNACLE WEST

Pinnacle West Capital Corporation (PNW) is a Phoenix-based company with consolidated assets of about $11 billion and consolidated revenues of $3 billion. Through our subsidiaries, we generate, sell and deliver electricity and sell energy-related products and services to retail and wholesale customers in the western United States. We also develop residential, commercial and industrial real estate projects.

Strategic Objectives:

- Focus on superior long-term total returns for shareholders
- Provide Arizona electricity customers with outstanding service and reliable energy at fair prices
- Actively manage our costs and business risks
- Work with regulators to achieve positive regulatory outcomes that benefit both customers and shareholders
- Maximize the long-term value of our assets
- Capture growth opportunities in our electricity markets
- Increase our resource portfolio consistent with our native load, environmental factors, cash flow and market conditions
- Maintain a disciplined focus on our long-term goals while remaining agile

KEY INVESTMENT CONCEPTS

- Ranked first in dividend growth for 1996-2005 among U.S. electric utilities with average annual dividend growth rate of 7.2%
- Customer growth about three times U.S. electric utility average
- Profitability and operational excellence emphasized
- $2.00 per share indicated annual dividend
- 12 consecutive annual dividend increases

FINANCIAL HIGHLIGHTS

HIGHLIGHTS

(in millions, except per share data, unaudited)

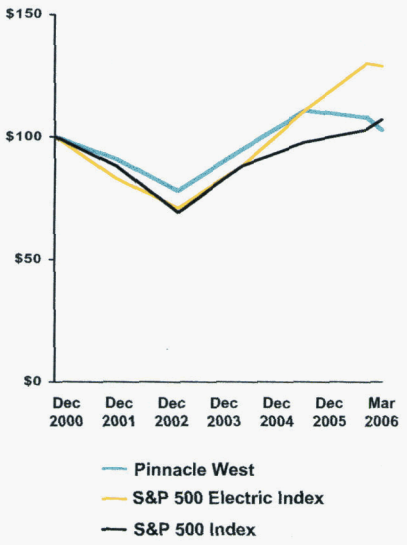
	12 Months Ended 3/31/06	Year Ended December 31, 2005	2004	2003
INCOME				
Operating Revenues	**$ 3,073**	$ 2,988	$ 2,829	$ 2,759
Income From Continuing Operations*	**$ 205**	$ 223	$ 247	$ 225
BALANCE SHEET				
Total Assets	**$10,756**	$11,323	$ 9,897	$ 9,519
Common Stock Equity	**$ 3,211**	$ 3,425	$ 2,950	$ 2,830
PER SHARE				
Earnings Per Share – Diluted:				
Continuing Operations*	**$ 2.08**	$ 2.31	$ 2.69	$ 2.47
Net Income*	**$ 1.67**	$ 1.82	$ 2.66	$ 2.63
Indicated Annual Dividend Rate – End of Period	**$ 2.00**	$ 2.00	$ 1.90	$ 1.80
Book Value – End of Period	**$ 32.37**	$ 34.58	$ 32.14	$ 30.97
STOCK PERFORMANCE				
Stock Price Per Share – End of Period	**$ 39.10**	$ 41.35	$ 44.41	$ 40.02
Market Capitalization – End of Period	**$ 3,879**	$ 4,097	$ 4,077	$ 3,657
ANNUAL GROWTH RATES				
Earnings Per Share From Continuing Operations – Diluted	**(22.4)%**	(14.1)%	8.9 %	(11.2)%
Dividends Per Share - Indicated	**5.3 %**	5.3 %	5.6 %	5.9 %
Operating Revenues	**7.8 %**	5.6 %	2.5 %	14.7 %
Electric Sales in Kilowatt-Hours	**(10.3)%**	(6.3)%	7.3 %	11.4 %
Electric Customers – Average	**4.4 %**	4.3 %	3.7 %	3.3 %

* Includes non-recurring items.
Certain prior-year amounts have been reclassified to conform to current-period presentation.

STOCK PERFORMANCE COMPARISON

TOTAL RETURN

Value of $100 Invested at December 31, 2000
With Dividends Reinvested

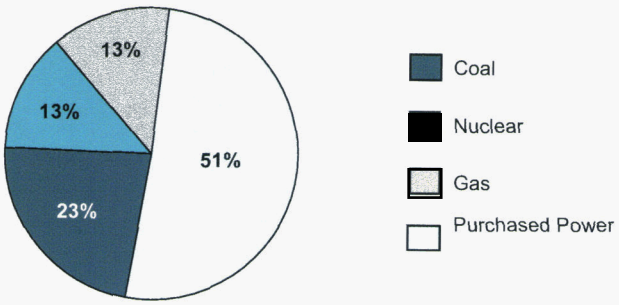


OPERATING HIGHLIGHTS

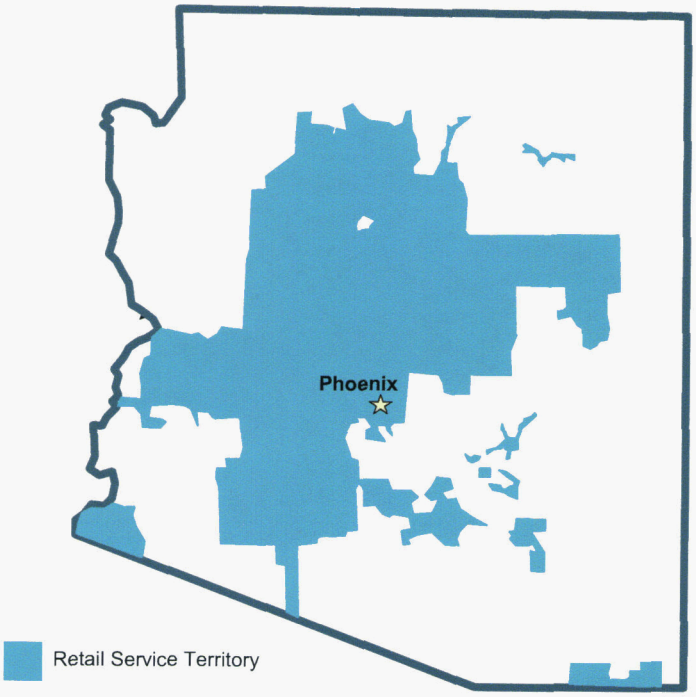
	12 Months Ended 3/31/06	Year Ended December 31, 2005	2004	2003
ELECTRIC SALES (GWH)*				
Retail Sales	**26,685**	26,477	25,353	24,562
Other	**5,621**	5,196	3,441	1,594
Total Regulated	**32,306**	31,673	28,794	26,156
Marketing and Trading	**21,403**	23,572	30,178	28,803
Total Electric Sales	**53,709**	55,245	58,972	54,959
CUSTOMERS				
Average	**1,018,868**	1,007,718	966,265	931,528
End of Period	**1,048,497**	1,033,500	989,580	953,317

* A gigawatt-hour equals one million kilowatt-hours

2005 CONSOLIDATED ENERGY FUEL MIX



RETAIL SERVICE TERRITORY



ANALYST COVERAGE (EQUITY)

Argus Research

Bank of America Securities

Citigroup

Credit Suisse

Harris Nesbitt

J. P. Morgan Securities

Lehman Brothers

Merrill Lynch

Regulatory Research Associates

Standard & Poor's Corporation

UBS Securities

Value Line

CONTACT INFORMATION

Street Address
400 North 5th Street
Phoenix, Arizona 85004

Mailing Address
P.O. Box 53999
Phoenix, Arizona 85072-3999

Main Telephone Number
(602) 250-1000

Corporate Web Site
http://www.pinnaclewest.com

Investor Relations
Rebecca Hickman, Director
(602) 250-5668
Lisa Malagon, Manager
(602) 250-5671

Investors Advantage Plan
(direct stock purchase and
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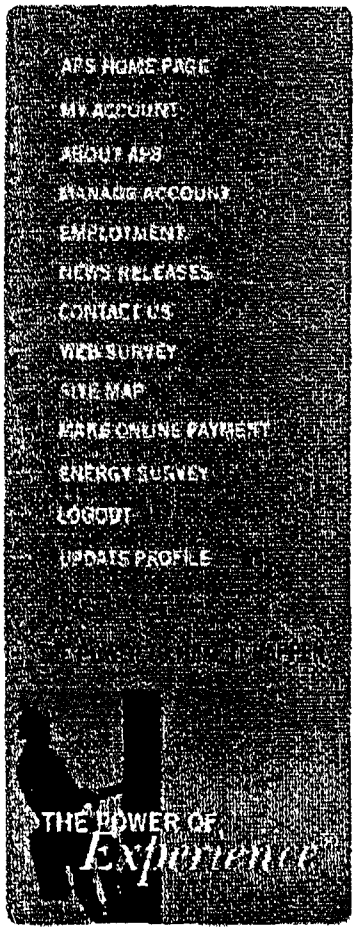
Transfer Agent & Registrar
Bank of New York
1-800-457-2983 (toll free)

Arizona Utility Investors Association
P.O. Box 34805
Phoenix, Arizona 85067

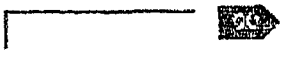
Media Relations
Alan Bunnell
(602) 250-3376

MY ACCOUNT
Rate Comparison

MY ACCOUNT MY COMMUNITY



SEARCH



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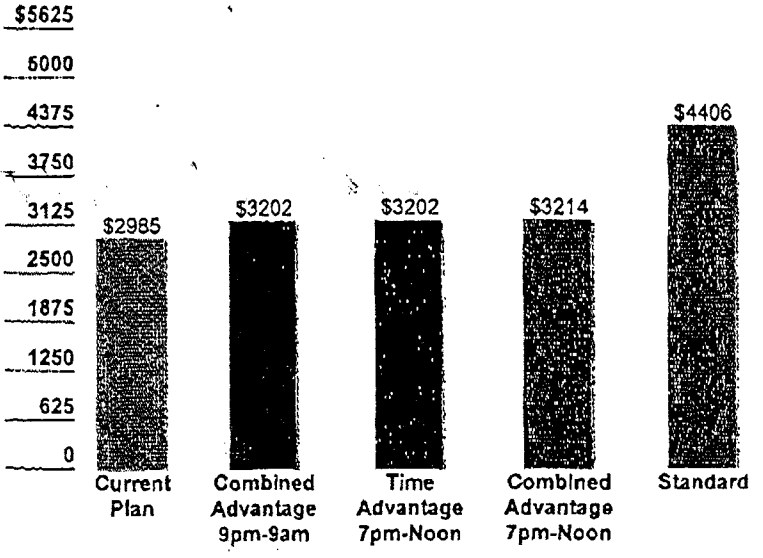
Rate Comparison

APS Account #:

This graph is based on 12 months of actual usage history. The orange bar shows the amount you paid while on your current Rate Plan. The blue bars show what you would have paid on a different APS Rate Plan. **The shortest bar reflects the rate with the lowest dollar amount** during the 12 month period. If your current Rate Plan does not reflect the lowest dollar amount, you may want to complete a Rate Plan change.

Current Plan
Time Advantage 9pm-9am

Total Energy Dollars
(past 12 months)



Congratulations! Based on your energy use patterns, you are already on the Rate Plan best suited to you. Please check back next year to re-evaluate your Rate Plan selection.

If you would still like to change to either the Time Advantage 7 p.m. - Noon Rate Plan or the Combined Advantage 7 p.m. - Noon Rate Plan, you may change your rate.

Take our Survey

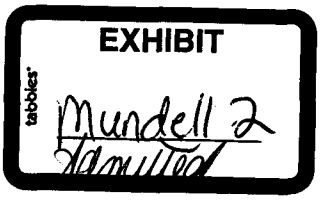
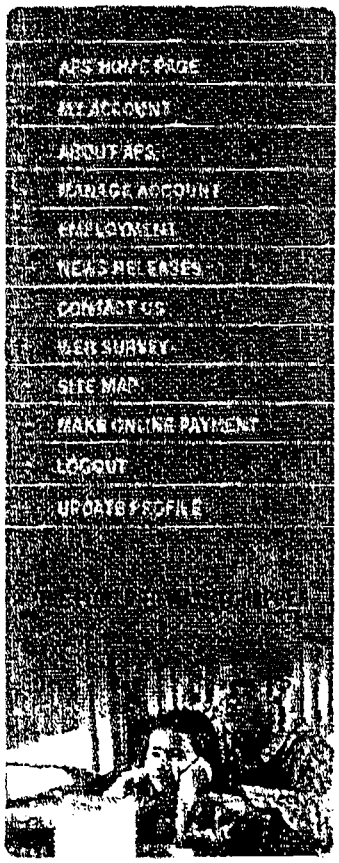


EXHIBIT
Mundell 3
Admitted

APS

RESIDENTIAL SERVICE
Rate Plans & Tariffs

MY ACCOUNT MY COMMUNITY



SEARCH

GO

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Rate Pricing and Other Details

Summer (May-October)

Rate Plan	Demand Based	Time Based	Off-peak hours	Service charge per day	Cost per kWh on-peak	Cost per kWh off-Peak	Cost per kW on-Peak	Best for homes per sq foot
Standard*	No	No	N/A*	$ 0.253	N/A*	N/A*	N/A	<1,100
Time Advantage 9 p.m. - 9 a.m.	No	Yes	9 p.m. - 9 a.m.	$0.493	$0.13310	$0.04299	N/A	>1,100
Time Advantage 7 p.m. - Noon	No	Yes	7 p.m. - noon	$0.493	$0.18200	$0.04519	N/A	>1,100
Combined Advantage 9 p.m. - 9 a.m.	Yes	Yes	9 p.m. - 9 a.m.	$0.493	$0.04765	$0.02672	$11.81	>1,100
Combined Advantage 7 p.m. - Noon	Yes	Yes	7 p.m. - noon	$0.493	$0.05890	$0.02792	$11.81	>1,100

Winter (November-April)

Rate Plan	Demand Based	Time Based	Off-peak hours	Service charge per day	Cost per kWh on-peak	Cost per kWh off-Peak	Cost per kW on-Peak	Best for homes per sq foot
Standard*	No	No	N/A*	$0.253	N/A*	N/A*	N/A	<1,100
Time Advantage 9 p.m. - 9 a.m.	No	Yes	9 p.m. - 9 a.m.	$0.493	$0.10918	$0.04167	N/A	>1,100
Time Advantage 7 p.m. - Noon	No	Yes	7 p.m. - noon	$0.493	$0.08703	$0.05783	N/A	>1,100
Combined Advantage 9 p.m. - 9 a.m.	Yes	Yes	9 p.m. - 9 a.m.	$0.493	$0.03641	$0.02570	$8.11	>1,100
Combined Advantage 7 p.m. - Noon	Yes	Yes	7 p.m. - noon	$0.493	$0.03730	$0.02733	$8.11	>1,100

***The Standard Plan** pricing is as follows: **May-October** 0.07570 per kWh for first 400kWh, 0.10556 per kWh next 400 kWh and 0.12314 per kWh all additional kWh; **November-April** 0.07394 per kWh for all usage.

If you have had service with APS for more than six months, you can do a Rate Comparison using your actual usage data. Log in to aps.com and see what you might have paid on a different plan.

Innovest Strategic Value Advisors

EXHIBIT
Solar - 1
Admitted

Intangible Value Assessment

Feb-04

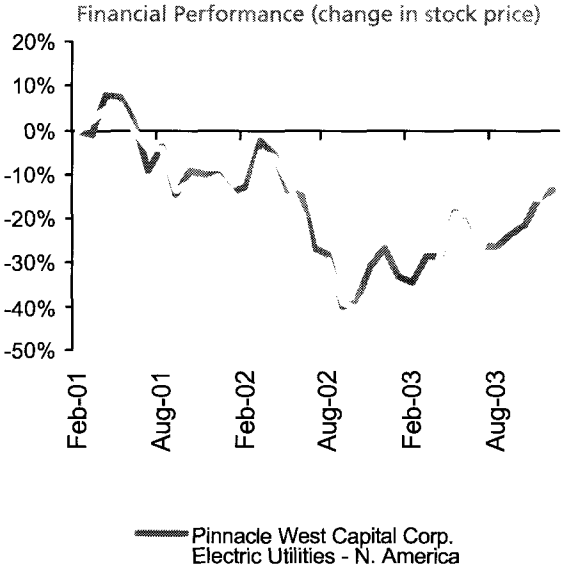
Pinnacle West Capital Corp.

Country:	United States
Ticker Symbol:	PNW
Industrial Sector:	Electric Utilities - N. America
Rating:	AAA
Rank:	1
Analyst:	Carla Tabossi

Intangible value comprises a growing percentage of market capitalization. Innovest's IVA ™ ratings analyze relative corporate performance on intangible value drivers related to sustainability. By assessing differentials typically not identified by traditional equity analysis, IVA ™ ratings uncover hidden value potential for investors.

COMPANY OVERVIEW

Pinnacle West Capital (PWCC) regulated electric transmission and delivery subsidiary is Arizona Public Service (APS), which serves about 900,000 wholesale and retail customers (98% of annual revenues) with about 4,100 MW of generating capacity. After the California energy crisis, deregulation was delayed in Arizona. As a result, PWCC cancelled its plans of transferring APS generation assets to its unregulated subsidiary Pinnacle West Energy (PWEC) and APS remains an integrated utility. Subsidiary SunCor is a real estate development company in Phoenix. Subsidiary El Dorado is a diversified venture capital firm which invests in energy-related companies in addition to owning 22% of the NBA's Phoenix Suns and an interest in the Arizona Diamondbacks. The company has approximately 6,500 employees.



KEY ISSUES FOR STRATEGIC INVESTORS

Investment in Renewable Energies Enhances Competitive Positioning: PWCC outperforms most of its competitors in its strategy to develop new technologies to generate and distribute electricity, particularly solar power. PWCC's on-going efforts are likely to see increasing value as environmental regulations continue to tilt the competitive playing field in the direction of cleaner, more efficient generation assets (See Products and Services).

Relatively More Proactive Strategies With Labor Unions: PWCC formally recognizes the right of employees to organize and bargain collectively through the representatives they choose. The company has also formalized and discloses the rules managing corporate relations with unions. Senior management states that this strategy has facilitated the company's relationship with unions and agreements (See Strategy with Labor Unions).

INDUSTRY DRIVING FORCES

Several factors are prompting companies in the U.S. electric power industry to assume fuller responsibility for their negative impacts. These include a movement away from cost-plus rate-making driven by restructuring in many states in the U.S.; a growing number of customers with the right to choose their electricity supplier; increasing availability of alternative power sources; fuel mix disclosure and renewable power standards; rapidly expanding information on corporate impacts; growing market demands for more socially

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responsible products and services; and a higher awareness among stakeholders of the potential financial impact that environmental and social factors may have on corporate stock performance in the form of hidden liabilities. As a result, companies increasingly incorporate environmental considerations into their risk management strategies.

Environmental Risk Profiles: Under restructuring, it is necessary to distinguish between power producers and T&D companies. The main environmental impacts are associated with power producers. Deregulated markets will also require increased levels of investment in transmissions to accommodate greater volumes of electricity. Siting problems persist in many areas and uncertainty about future environmental regulations complicates further long term investment planning The owner, operator and generator are increasingly distinct, which complicates the allocations of responsibilities and network planning.

Public Concerns/Nuclear: While nuclear generation does not cause greenhouse gas emissions, various stakeholders have objections to nuclear operations due to safety concerns. There is strong public sentiment against nuclear power in many parts of the world, based on concerns about plant safety, radioactive waste disposal, and the proliferation of nuclear weapons. Potential nuclear accidents or mishaps pose an additional general risk. Risks of new nuclear plants are also expected to increase under deregulation given increased consumer choice and the likely limited ability to recover capital costs. This will represent potential high risks for investors in nuclear plants.

Risk Exposure Being Shifted From Ratepayers to Investors: On-going restructuring in some states in the U.S. increase competition and shift the burden of compliance costs from ratepayers to investors. Under the historic utility model of monopoly and vertical integration, the financial expenditures required to comply, for example, with environmental regulations would simply be dealt with through regulated cost-based rates. Under restructuring, however, the ability of companies to recoup compliance costs through regulated rates will be increasingly limited. Therefore, complying with increasing environmental regulations could require additional expenditures by the industry with the potential of eroding future earnings and resulting in stranded assets.

Increasing Pressures To Improve CSR: These include increasing regulations to increase disclosure and accountability of management to stakeholders (i.e. Sarbanes-Oxley Act of 2002); ethical and governance scandals that have eroded investor confidence; more effective activist campaigns; shareholder activism; and a growing influence of socially responsible investment. Industry leaders report that improving governance practices helps them enhance reputation; attract and retain talented employees; manage and mitigate risk; ensure license to operate; as well as develop alliances with stakeholders that enhance business development.

Greater Investor Attention To CSR Performance: A study released by McKinsey & Co. found that institutional investors are willing to pay a 14 percent premium, on average, for shares of well-governed U.S. companies. In 2003, Russell Reynolds Associates interviewed about 400 institutional investors in the U.S, U.K., France, Germany, Japan and China, with the aim of finding out how they are making their investment decisions. In the U.S., 53 percent of investors reported that CEOs should practice social responsibility and 47 percent reported that CEOs should focus on returns only; the importance of corporate governance as a decision factor has increased to 71 percent (2003) from 53 percent (2000); and the quality of a company's board of directors has nearly doubled in importance to 45 percent (2003) from 25 percent (1997). These factors are among several driving rapid growth in the SRI market. SRI assets have grown 40% faster than all other assets under professional management in the U.S. since 1995 (to 2.2 trillion dollars).

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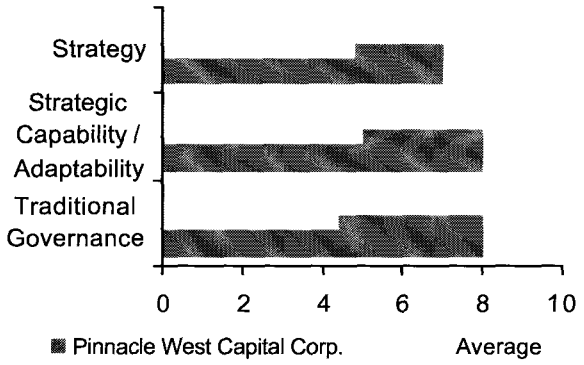
INTANGIBLE VALUE DRIVERS

SUSTAINABLE GOVERNANCE



Strategy: PWCC's commitments to environmental and social leadership are integrated into its overall business strategy. Corporate best practices are driven by APS. APS' proactive environmental programs, partnerships and corporate giving enhance corporate image and facilitate businesses. The company's Ethics Policy provides guidelines for employees to conduct business in line with corporate values of integrity, fairness, accountability, and social caring with the goal of earning the public's trust as a good community citizen. Employees commit, in writing, to abide by these standards and are held accountable accordingly.

Strategic Capability/ Responsiveness: PWCC has developed programs to ensure employee accountability, customer satisfaction and fair employment that sometimes go beyond regulatory compliance, particularly in the areas of health, safety and the environment.

Programs include policies on Ethics, Workplace Principles, Sexual Harassment, Fire Prevention, Public Safety, Environmental Protection and Nuclear Safety. In addition, the company has an Accident Manual, the Palo Verde Occupational Health and Safety Program, an Environmental Health and Safety Management Plan and an Employee Concerns Program.

PWCC has also designated formal positions to implement these programs. Instrumental departments include Environmental Health & Safety, Governmental Affairs, Health Services, Human Resources, Benefits, and the Law Department. Armando Flores is the head of corporate services which consolidates human resources, community affairs, suppliers, customer relations and diversity. This strengthens cross functions and improves implementation. There is one person formally appointed as responsible for diversity issues across the organization. The Communications and Health & Safety departments annually present to the board, which includes an environmental committee. Overall CSR reporting is limited to APS, which publishes an annual environmental report annually based on CERES and GRI guidelines.

CSR leaders report that progress towards CSR helps them gain better access to capital markets, attracts talented employees contributing to overall productivity, facilitates relationships with external stakeholders, and forges innovation which increases their overall competitive advantage.

Traditional Governance Factors: PWCC's was among the few in the sector willing to discuss corporate governance related issues more extensively. Unlike many of it industry peers, the company has developed a management structure to address corporate governance issues and ensure compliance in line with the New York Stock Exchange. The company has established a Corporate Governance Committee composed of non-management directors each of whom is independent under New York Exchange rules, and has developed Corporate Governance Guidelines. PWCC's Board of Directors consists of thirteen members, including three women and one Hispanic. The top 50 paid employees include seven minorities and one woman. The company, however, does not have a policy of separating the functions of the CEO and the Chairman of the Board as other leaders in this area do with the goal of strengthening accountability of management.

Pinnacle has some exposure to criticism of several groups over the corrupting influence that the growing amount of money donated by corporations to political parties is having on the political process.

Based on data provided by the Federal Election Commission and distributed by the Center for Responsive Politics, the electric utility sector donated $21 million during the 2002 election cycle ranking 16th in total campaign giving as compared to 80 other industries. Pinnacle ranked the 20th largest contributor to political campaigns, accounting for 1% of total contributions made by twenty companies in the sector. This may increase the company's overall exposure to corporate governance risks as the McCain-Feingold legislation bans unlimited "soft money" contributions

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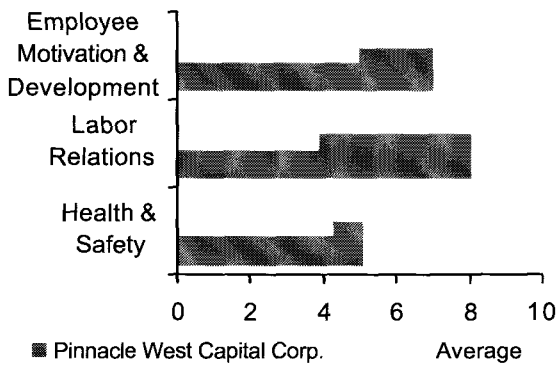
that individuals, labor unions and corporations can give political parties. Critics of the current campaign finance system argue that the growing amount of money donated to political parties is having a corrupting influence on the political process. These concerns have given rise to several campaign finance bills. In December 2003, the U.S. Supreme Court upheld the core provisions of McCain-Feingold, including the ban on soft money for national and state parties when used for federal elections. The company reports that much of its giving is through an independent political action committee voluntarily composed of employees and shareholder contributions.

Despite this, the company has taken some measures that partially mitigating the risks mentioned above. With the goal of supporting the political process, senior management at Pinnacle reports that the company has committed to not attempt to influence public officials by offering gifts, gratuities or other promises of reward or benefit; offer or accept a bribe in connection with an election; make a campaign contribution or expenditure in the name of the company or on its behalf; reimburse anyone who makes a contribution to the company's PAC. Pinnacle designed the Business Practices Department as responsible to assist employees in complying with these commitments. Through the Department of Government and Federal Affairs, APS participates in the law-making process, and the formation of global air policy at the regional and global level.

HUMAN CAPITAL



Employee Motivation & Development: The company pursues a progressive strategy in this area focusing on training, empowering and rewarding employees with the goals of developing and retaining a good workforce. Reported programs include school-to-work and scholarship opportunities as well as extensive internship programs and specific programs targeting finance, accounting, engineering, and mathematics skills. In addition to internal environmental, health and safety training, the company encourages employees to continue education through external course offerings with tuition reimbursement, and internal Pinnacle West University, which uses e-learning and has a library of more than 750 self-paced courses covering popular business topics.

Senior management reports that the company rewards employees for outstanding performance and seeks to engage them in decision-making processes through an open-door policy. In April 2003, the company completed a survey to apply for the Fortune Magazine's Award on Best Companies For Minorities.

APS offers all emp loyees, regardless of its association with unions, 401(k) plans. In 2003, APS switched to an account balance pension plan whose reported benefits include greater flexibility for automatic vesting rights, portability in case of changing jobs. The company matches 75% up to the first 6% of annual compensation. All 401(k) matching is in PNW stock. Other companies, however, avoid matching policies based on stocks with the goal of protecting savings under 401(k) after the Enron case.

The company monitors satisfaction through external surveys, conducted by Gallup, on employees' engagement levels. The company reports that voluntary employee turnover has been less than 3% over the last several years (1.2% in 2003), which is low relative to peers. Senior management reports that employees and officers own a total of 4.84% of the company stock. (Employees-3.7% and officers/directors-1.14%).

Industry leaders pursue best industry practices to ensure a good working atmosphere and develop employees' skills. These companies' commitments involve seeking to help employees balance their work and home lives by implementing "Balanced Living Programs." These include flexible work schedule to meet family requirements, paternity leave, employee assistance program, domestic partner leave quality child care, summer camp, elderly care, college scholarships and financial aid, selecting college counseling and support groups, adoption assistance. Many companies implement centralized training programs to promote career development (e.g. formal mentoring programs, rotational assignments, and online intranet courses), regularly monitor employee satisfaction levels and

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reward them for innovative ideas. Leading companies in this area report that best practices positively impact productivity and turnover rates.

Labor Relations: PWCC outperforms most of its peers in this area. Under its Standards of Business Practices, PWCC formally recognizes the right of employees to organize and bargain collectively through the representatives they choose. The company has formalized and discloses the rules governing corporate relations with unions. Senior management states that the company is committed to avoiding punitive actions against employees that report suspected illegal activity by the company or a fellow employee.

One-third of the comp any's employees are represented by the International Brotherhood of Electrical Worker (IBEW) with which the company's senior management reports to have a positive and productive relationship. Through successful negotiation between APS and IBEW, members of the union's Local 387 now participate in the company's benefits and incentives programs.

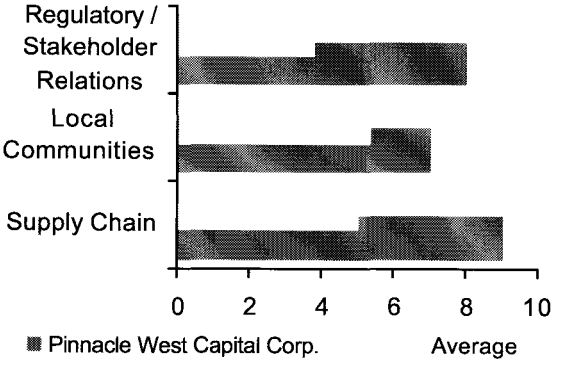
The company implemented cost-containment measures that involved layoffs. To reduce them, the company offered voluntary resignations. For example, within the company's management hierarchy, seven Pinnacle West officers chose to take a voluntary severance option.

Health & Safety: Overall corporate strategy in health and safety focuses on empowerment, training and accountability of employees. The Internal Communications Department works with the Safety and Health Advisory Team in promoting health and safety programs and practices through internal news publications, a daily electronic newsletter, general safety meetings, job-specific safety meetings, training and safety interventions.

Partially prompted by safety problems, senior management adopted an aggressive awareness campaign and implemented new information tools to address safety problems in 2000. As a result of these measures, senior management reports the accident rate decreased by 18% in 2001. The 2002 safety campaign was titled "My Safety, My Choice" with the goal of encouraging employees to choose safe work practices. The campaign resulted in a second consecutive year of improved safety performance. In 2002, the company's safety goal was to have zero preventable recordable injuries per week (achieved in fossil, 28 weeks; nuclear, 42 weeks; and energy delivery and sales, 26 weeks). While the total number of recordable injuries remained flat, lost days and severity improved.

The company is not as proactive as most of its peers in implementing health and safety programs to achieve beyond regulatory compliance and does not disclose quantitative performance indicators (e.g. employee turnover, illness, accident, injury, rates). For example, most companies in the sector develop safety targets, track performance through regular reporting, and communicate performance and corrective actions to stakeholders. The most proactive companies also integrate safety and environmental regulatory compliance data into their risk management strategy and their corporate procedures and contract management policies. Some of them also pursue certification under the "Star Status", which reflects beyond-compliance heath and safety performance, under the Voluntary Protection Program (VPP) developed by OSHA. For example, six of PPL facilities have obtained the star status. OSHA reports that VPP participant sites typically experience about 60% fewer lost workday injuries relative to the industry average site of the same size.

STAKEHOLDER CAPITAL



Regulatory/ Stakeholder Relations: PWCC pursues proactive relationships with regulatory agencies, industry groups and NGOs. These organizations include the Western Regional Air Partnership groups, the Edison Electric Institute and the Electric Power Research Institute. By actively supporting industry efforts, APS aims to help develop technology that can make a mainstream impact in the future. For example, it partners with Arizona State University and Northern Arizona University to collect performance data from our solar generating facilities.

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Communities: Senior management states that PWCC pursues community participation and accountability as part of its long term business strategy. The company works with governments and other groups with the goal of creating responsible regulations and standards to safeguard the community, workplace and environment. Its commitments include sharing with local communities data performance in the environmental, health and safety areas.

Since APS operates in a rapidly growing area that will need further developments to meet power needs, it engages community stakeholders in line sitting and construction of new power plants. To address community concerns in these areas, the company sponsors public meetings, advisory boards, outreach events, newsletters, and monthly billing inserts and notices.

In 2003, PWCC sponsored the employees' contribution of 75,000 hours to engage in 300 community-based projects. APS matches 50 cents for every employee dollar donated, increasing 2003 donations to United Way charities to $2.2 million. Pinnacle West and APS provide support to many civic and community organizations in support of human services, environment and culture. Through a variety of partnerships, APS also contributed $1.7 million to health initiatives and $1 million to education.

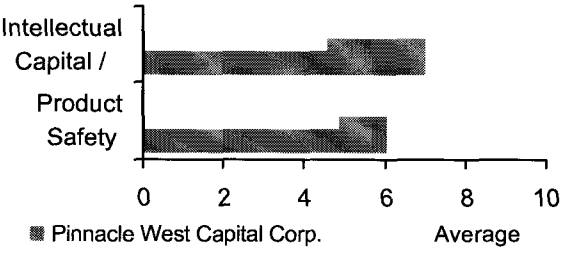
Despite these initiatives, other CSR leaders are relatively more proactive in allocating resources, including managerial functions and financial contributions, and in reporting progress to external stakeholders with the goal of developing formal mechanisms to strengthening their relationships with communities and enhancing transparency of reporting to stakeholders. Improvements along these lines would maximize the company's overall efforts in this area.

Supply Chain: Pinnacle pursues a leading supply chain policy. It pursues environmental performance policies with suppliers and has initiated programs to improve social screening throughout its supply chain.

Pinnacle's Supplier Diversity & Development Team is committed to facilitating competitive business opportunities for Minority- and Women-Owned Businesses primarily in Arizona and the Southwest. In 2002, APS purchased more than $54.5 million worth of goods and services from minority-and women-owned businesses — exceeding its goal of $43.2 million. Pinnacle founded the Academy for the Advancement of Minority and Women-owned Enterprises in 1997 to teach these groups business skills (e.g. strategic planning, finance, management/operations and marketing.) The academy is free to those accepted. In 2002, eight companies graduated from the Academy. These practices will likely encourage job creation, enable purchasing power and build stakeholder relationships.

Among industry leaders, PEG was the only company in the sector that has additionally established a 2nd Tier Diversity Plan to encourage the use of minority- and women-owned firms beyond primary suppliers. To implement this, the company requests that its primary suppliers establish procurement strategies and goals to promote the products and services supplied by minority- and women-owned firms.

PRODUCTS/SERVICES



Intellectual Capital/ Product Development: Major opportunities to develop intellectual capital in this sector are related to technological developments of alternative energy and clean power generation.

PWCC outperforms most of its competitors in this area. The company has engaged in testing renewable power applications, mainly solar power. Its long-term generation strategy away from fossil fuels and mandatory renewable power standards are the main drivers. In 2002, the company's main subsidiary, APS, began operating the first phase of its Prescott Airport Solar Power Plant with a projected 5 MW of capacity on the APS grid, making it the largest solar photovoltaic power plant in the world. While APS continues to increase the distributed power capacity on its system (2,469 KWh of solar power in 2003), it does not provide yet net metering services. The company plans to add 1 MW of solar per year representing 1% of capacity by 2007. In 2002, its facility in Phoenix began offering hydrogen, and a compressed natural gas-hydrogen blend

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hydrogen. It also research clean coal generation technologies.

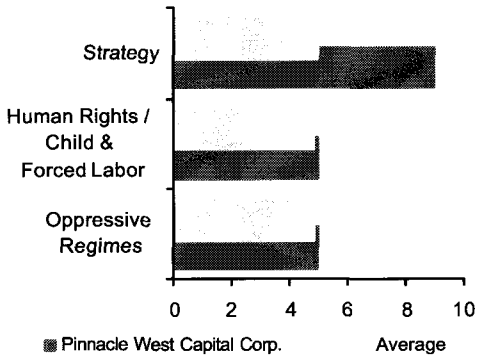
PWCC's on-going efforts are likely to see increasing value as environmental regulations continue to tilt the competitive playing field in the direction of cleaner, more efficient generation assets. On balance, the firm is well positioned to capitalize on medium-term demand for relatively cleaner power generation and decentralized power sources.

Product Safety: APS has below average exposure to increasing air regulations due to its relatively diversified energy mix (coal 40%, nuclear 30%, gas 5% and purchase power 25%) and above average emissions rate performance, particularly of SO2. PWEC is introducing 2,800 MW of gas-fired capacity (mostly combined-cyle) scheduled for 2004.

While the company has relatively lower exposure to risks associated with nuclear power, including long term waste disposal and radiation, its nuclear operations are expected to face increasing public opposition due a public perception of safety risk. Partially to address this, the Palo Verde plant annually provides neighbors with information regarding plant operations, emergency planning zone maps, emergency classifications, important telephone numbers, procedures, locations of care centers and suggested protective actions. Palo Verde also conducts joint emergency planning drills with local, state and federal emergency response agencies at least twice per year.

To monitor customer satisfaction, the company conducts third-party customer surveys and its own surveys. For the Customer Satisfaction Tracking survey, residential and small-to-mid size business customers are surveyed twice each year regarding their level of satisfaction with APS' performance. Participants are randomly selected regardless of whether they have had any recent company contact. Large commercial and industrial customers participate in the survey once per year.

EMERGING MARKETS



Strategy: The company is not involved in developing countries.

Human Rights/ Child & Forced Labor: No evidence in our research suggests that the company has been implicated in human rights abuses or the use of child/forced labor. Firms in this industry face a lower risk of incidents in these areas than companies in other sectors due to the nature of its physical assets. Please refer to the Emerging Markets Strategy.

Oppressive Regimes: Please refer to the Emerging Markets Strategy

ENVIRONMENT

The company's environmental performance has been comprehensively analyzed using Innovest's EcoValue '21 assessment methodology. The company's EcoValue '21 rating and related analysis are available in a separate report. Information about this report is available at www.innovestgroup.com.

STRATEGIC PROFIT OPPORTUNITIES

Socially responsible products and services that protect public health and economic development may include maximizing low air emissions generation technologies, minimizing nuclear related safety impacts as well as pursuing proactive relationships with stakeholders. For example, natural gas generation technology holds an advantageous position as the cleanest and most efficient of the fossil fuels. Modern natural gas facilities produce less emissions (90 percent) and are 40 percent more fuel-efficient than older fossil plants. Because this

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technology is preferable to that of older facilities, it has earned the support of health, safety, environmental and consumer groups. Climate change related challenges also stimulate demand for renewable sources of energy and natural gas as a means to reduce current air emissions while also providing a "transition" fuel towards a carbon-free economy. Recent events in the Middle East may exacerbate this trend given that reducing energy dependency is paramount. Such a scenario may lead to increasing support from regulatory bodies and public opinion thereby contributing to rapid growth (See Products and Services Section).

SRI NEGATIVE SCREENING INFORMATION

The following information is provided for investors who for various ethical or social reasons may wish to avoid investments in companies involved in the following business areas. Innovest's IVA product uses a positive screening approach to identify superior management. Beyond assessing potential market risks, involvement in the following businesses does not impact IVA ratings. Please contact Innovest for screening on other issues which do not appear below.

SCREEN

Alcohol:	N/A
Animal Testing:	N/A
Gambling:	N/A
GMO:	N/A
Nuclear Power:	34%
Pornography:	N/A
Tobacco:	N/A
Weapons Production:	N/A

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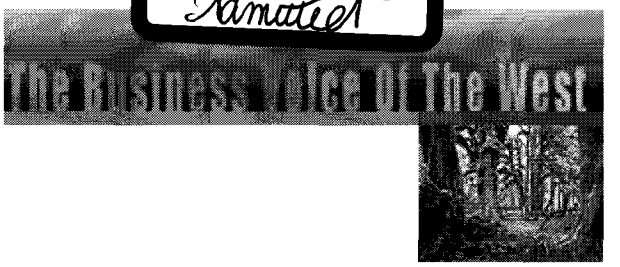
EXHIBIT
Solar 3
Admitted



Success Stories

Pinnacle West Again Receives 'AAA' Rating From Innovest

PHOENIX - Pinnacle West Capital Corporation (NYSE: PNW) has been recognized as one of nation's top two utilities in demonstrating superior environmental and social performance characteristics by an international investment advisory firm.

Innovest Strategic Value Advisors Inc., of New York (www.innovestgroup.com), assigned Pinnacle West its top rating (AAA), and ranked the Company second out of 28 electric companies listed on the Standard & Poor's 500 for environmental performance. Pinnacle West also earned the AAA rating and a number-three ranking from Innovest's initial study in 2000.

"Pinnacle West has demonstrated strong leadership in the environmental area," said Frank Dixon, Managing Director of Research and Development for Innovest. "In the face of increasing regulations and consumer concerns about the environment, environmental leadership helps companies build a competitive advantage. In addition, environmental leadership is a strong indicator of superior overall management, which is the primary determinant of stock market returns. As a result, it is likely Pinnacle West will outperform the market going forward."

Innovest develops industry sector annual reports to help investors identify companies with excellent environmental performance records. The research firm has found a positive correlation between stock price and environmental performance mainly because environmental performance turns out to be an excellent proxy for management quality, the primary determinant of stock returns. Innovest's environmental ratings (ranging from AAA to CCC) identify environmental risks, management quality and profit opportunity differentials typically not identified by traditional financial analysts.

These ratings are based on a number of environmental risk factors including site liabilities, spills and releases, regulatory compliance and emissions. Pinnacle West received top ratings for 14 of the study's 22 performance indicators. The indicators include environmental management, performance improvement and opportunity factors. This included a "Best in Class" designation of the Environmental Training & Development category.

Innovest cited several examples where Pinnacle West subsidiary Arizona Public Service, the largest and longest-serving electric utility in Arizona, reduced costs through aggressive pollution prevention and waste minimization programs. Among those APS efforts:

· The implementation of integrated waste management programs, which led to about $2.5 million in savings in 2000;

· Employees sharing surplus materials more efficiently through an intranet-based Materials Exchange Program, which saved $90,000 in 2000 and $300,000 in 1999; and

· The Materials Safety Program, which has reduced the use of hazardous products by 14 percent while reducing overall procurement costs.

"As an independent, third party, Innovest's review of our environmental risk and exposure found that our performance merited its highest ranking, and that means a lot to us," said Ed Fox, Pinnacle West Vice President of Communications, Environment and Safety. "We take our environmental performance seriously. To have a third party without a vested interest in our organization tell us we're performing at such a high level is important because it indicates we are doing right by the communities in which we work and live, our employees and our shareholders.

"We're proud that Innovest has so positively acknowledged our environmental efforts. At the same time, we will continue our pursuit of environmental excellence."

In 1994, Pinnacle West's subsidiary Arizona Public Service became the first electric utility in the world to endorse the 10-point Code of Conduct adopted by the Coalition for Environmentally Responsible Economies (CERES). These CERES principles require public reporting of specific environmental achievements and goals.

Pinnacle West (NYSE: PNW) is a Phoenix-based company with consolidated assets of approximately $8 billion. Through its subsidiaries, the company generates, sells and delivers electricity and sells electricity and energy-related products and services to retail and wholesale customers in the western United States. It also develops residential, commercial, and industrial real estate projects.

Western Business Roundtable
350 Indiana Street, Suite 640, Golden, CO 80401
122 C Street, N.W., Suite 500, Washington, D.C. 20005
303-216-WBRT | f: 720-294-9901 | info@westernroundtable.com

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EXHIBIT
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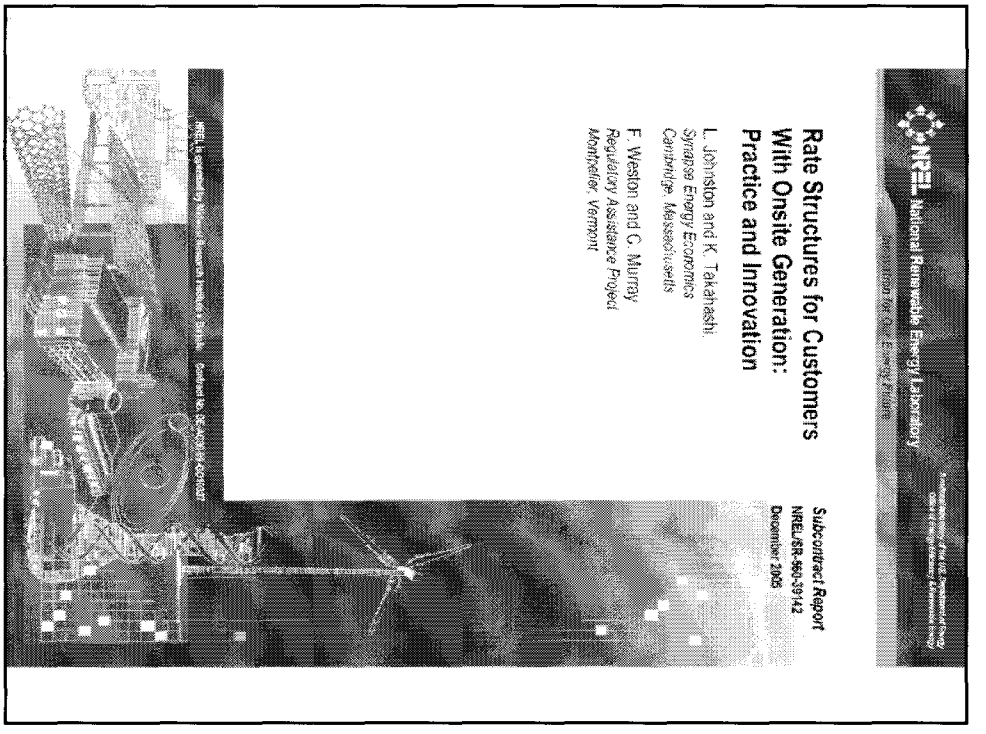
EPACT 2005

SEC. 1251. NET METERING AND ADDITIONAL STANDARDS.

NET METERING.—Each electric utility shall make available upon request net metering service to any electric consumer that the electric utility serves. For purposes of this paragraph, the term 'net metering service' means service to an electric consumer under which electric energy generated by that electric consumer from an eligible on-site generating facility and delivered to the local distribution facilities may be used to offset electric energy provided by the electric utility to the electric consumer during the applicable billing period.

Note implication that net metering might be limited to total customer load for 1251 purposes.



Seminal Findings of Rate Structures for Customers With On-Site Generation: Practice and Innovation

- "Interestingly, we have found little detailed analysis has been performed on the nature and types of costs imposed on the grid for stand-by service, or on the benefits that DG bestows in return. In fact, the lack of specific cost analysis of the impacts of DG installations on distribution systems is emerging as one of the stumbling blocks in the design of DG-specific cost-based standby tariffs."

pages 9-10

EXHIBIT
Solar 5
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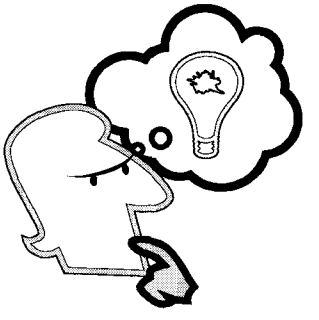
Seminal Findings (continued)

- The determination of whether particular facilities are dedicated or shared and, if shared, **the appropriate allocations of the costs** of the facilities among customers, **are critical to the setting of rates** for both full and partial requirements customer. The allocations could, conceivably, vary from circuit to circuit. Although these are demand-related costs, they are not related to system demand and, consequently, customer class non-coincident peaks and individual customer maximum demands are typically used to allocate them.

--page 12

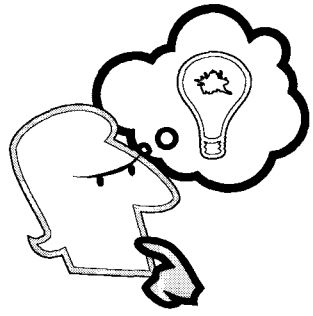
Hypothesis

- The generally accepted method of allocating distribution costs—both investment in assets and operating costs—is based on a "rule of thumb" that may no longer be justified.
- Such techniques were required when information regarding time of use, local peaks, were either simply unavailable, or much too expensive



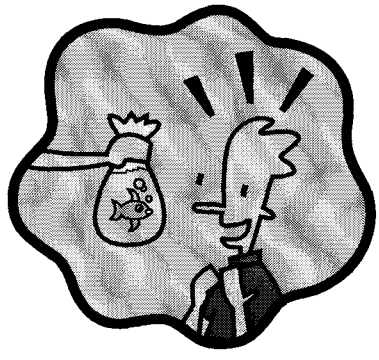
Hypothesis (cont.)

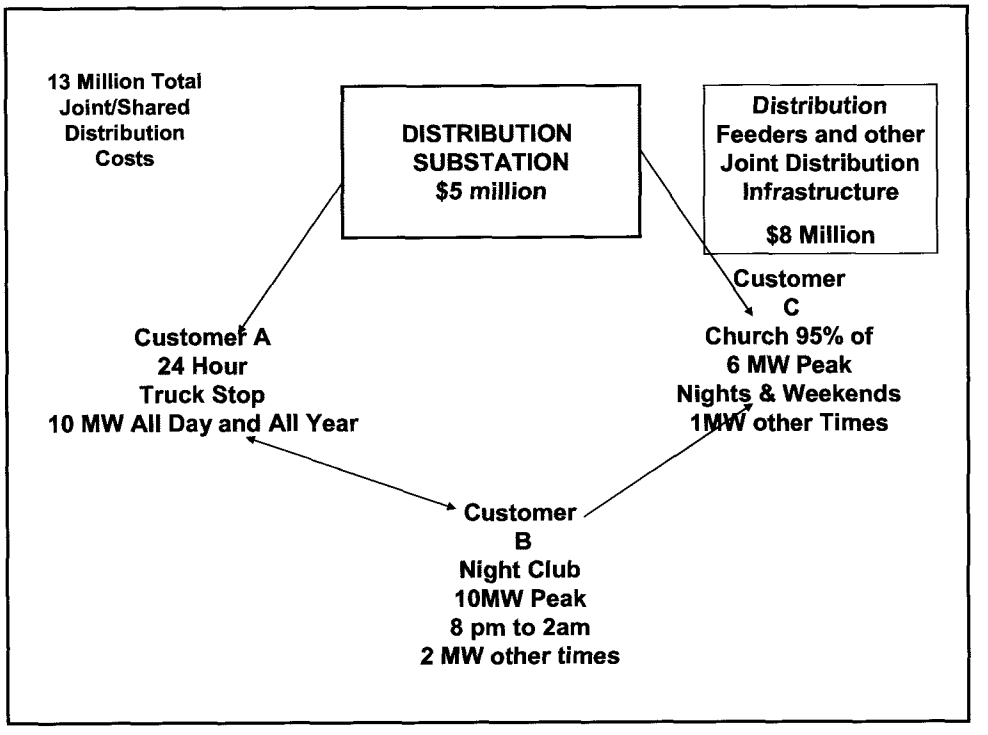
- Distributions costs typically allocated by customer class's share of NonCoincident Peak—or Individual Customer's Maximum Demand
- This "rule of thumb," operating far under most regulator's radar, unintentionally but powerfully ignores one of the most important benefits brought to the electric system by distributed generation and smart grid technology---the ability to control individual customer peaks in time, shape and magnitude.



Essential Hypothesis (cont.)

- Reexamination of the historical basis and modern alternatives to the allocation of distribution costs largely based on NonCoincident peaks of customer classes, or maximum demands, **is likely to reduce the costs otherwise allocable to DG and other customers willing and able to modify their peak demand**--with no policy change required other than rationalizing cost allocation methods based on newly available data.





What Might Arizona Do?

- Examine The Cost Allocations Inherent In Current Standby Rates For Bias Against Publicly Beneficial Ability To Shift, Reduce, And Shape Load. Use real cost data to consider innovative rate approaches—recognizing benefits of Onsite Generation
- Consider Tools Used by Other States:
  - Exemptions
  - Prohibition of charges where "physical assurance"
  - Charge for only "normal" reliability margin
  - More reasonable and statewide tariff, simple maintenance tariff procedures

III.A. Development of the Distribution Demand Allocators

There are several factors to consider when allocating the demand components of distribution plant. Distribution facilities, from a design and operational perspective are installed primarily to meet localized area loads. Distribution substations are designed to meet the maximum load from the distribution feeders emanating from the substation. Similarly, when designing primary and secondary distribution feeders, the distribution engineer ensures that sufficient conductor and transformer capacity is available to meet the customer's loads at the primary-and secondary-distribution service levels. Local area loads are the major factors in sizing distribution equipment. Consequently, customer – class non-coincident demands (NCPs) and individual customer maximum demands are the load characteristics normally used to allocate the demand component of distribution facilities. The customer –class load characteristic use to allocate the demand component of distribution plant (whether customer class NCPs or the summation of individual customer maximum demands) depends on the load diversity that is present at the equipment to be allocated. The load diversity at distribution substations and primary feeders is usually high. For this reason, customer –class peaks are normally used for the allocation of these facilities. The facilities nearer the customer, such as secondary feeders and line transformers, have much lower load diversity. They are normally allocated according to the individual customer's maximum demands. Although these are the methods normally used for the allocation of distribution demand costs, some exceptions exist.

From "Electric Utility Cost Allocation Manual" NARUC, January 1992 at pages 96-7

Cost of Service Studies Not A Glamour Area Of Regulation—but The Foundation Of Traditional Regulation

- NARUC "Electric Utility Cost Allocation Manual" first done in 1969 (the Green Book) and updated in a project begun in 1985, finally published in 1992
- Cost Allocation and the resulting "cost-based rates" are a fundamental pillar of traditional regulation
- Cost Allocation is not an exact science--like many accounting procedures, judgment is applied

Traditional Cost Allocation based on NonCoincident Peak demand

- Critical passage from NARUC Cost Allocation Manual:

  "Local area loads are the major factors in sizing distribution equipment. **Consequently, customer–class non-coincident demands (NCPs) and individual customer maximum demands are the load characteristics normally used to allocate the demand component of distribution facilities."**

Solar-6

TESTIMONY OF SURREBUTTAL WITNESS ROBERT ANNAN
ON BEHALF OF THE SOLAR ADVOCATES
TO THE ARIZONA CORPORATION COMMISSION
Docket No. E-01345A-05-0816

EXHIBIT
Solar-6
admitted

Q. Please state your name and address.

A. My name is Robert "Bud" Annan. I live at 6605 Evening Glow Drive, Scottsdale, AZ.

Q. What is the purpose of your testimony?

A. I am a surrebuttal witness appearing to respond to the rebuttal testimony of Barbara Lockwood and Gregory A. DeLizio representing Arizona Public Service regarding the new issue raised in APS's rebuttal testimony proposing a new total solar schedule.

Q. What is your background as it relates to your testimony?

A. I have participated in the Commission's efforts to adopt a solar/renewable energy portfolio rule since 1996. Following adoption of the current 1.1% EPS Standard under Commissioner Mundell's leadership in 2001, I worked with APS, other utilities, and Advocates' to develop realistic programs that meet the requirements of the Commission's Order. With APS, I was a member of the Cost Evaluation Working Group that completed a Commission mandated study that led to the draft rules expanding the EPS to 15% by 2025. Most recently I worked with APS representatives and others in helping structure the Arizona Dept of Commerce Solar Road Map effort that uses ACC policy as the foundation for developing a strong, focused, statewide solar energy program. My resume is attached as Exhibit 1 to my testimony.

Q, According to Ms Lockwood's and Mr. DeLizio testimony, APS plans to offer its customers the opportunity to support solar energy by purchasing ASP-generated solar energy at a proposed rate of $0.39 per kilowatt hour. What is your assessment of this proposal?

A. There are many other less expensive alternatives APS customers can already choose to support solar energy including the existing APS buydown program under the ACC EPS. It is unlikely that APS will have many customers sign up for a program that has a cost that is unreasonably high. Moreover, the proposal is a complete surprise and until this rebuttal testimony, APS has never expressed the need for a separate utility-scale project program such as they are proposing.

Q, What is your basis for stating that the $0.39 per kilowatt hour is unreasonable?

A. There are three specific credible sources of current costs for large-scale utility solar energy projects that relate directly to Arizona: One is information from solar energy developers quoting on long term power purchase agreement bid requests. The second is from current government estimates for solar energy systems installed in 2005. The third

is specific Arizona experience from the Tucson Electric Power large-scale utility at Springerville. All these sources demonstrate conclusively that a more reasonable rate for the new APS program would be in the $0.16-$.025 per kilowatt hour - significantly below the proposed APS $0.39 kilowatt hour rate.

Q. Why is the APS rate so high?

A. Ms. Lockwood's testimony states that the $0.39 kilowatt hour price is based on a single-axis photovoltaic system with an installed cost of $7,000 per kilowatt, an average production of 2,400 kilowatt hours per kilowatt, a 25 year systems life and APS' "requested cost of capital". Although the system life and production output are consistent with industry experience, the $7,000 per kilowatt installed cost exceeds the $5,500 cost per kilowatt incurred in the construction of APS' solar plant at Prescott using the same technology. APS's requested cost of capital indicates the company is using conventional, financing together with traditional equity and debt rates of recovery as if the funds were borrowed from large East coast investment bankers. These financing mechanisms will more than double the cost of energy for a solar project that has no future fuel cost. These financing mechanisms have traditionally been used by utilities for projects that have a 25 year liability for future fuel costs. However, if the new APS solar program is approved in a tariff, these funds would be collected from customer bills at virtually no risk to APS. The financing choice ends up making the cost of solar look extremely high because of the arbitrary cost of capital and lack of more appropriate financial structuring, while benefiting APS shareholders when APS ratepayers are making the investment.

It is also unclear from the testimony of the APS witnesses whether APS intends to utilize the federal Investment tax credit available for solar energy projects. This tax credit by operation of law is not available to electric utilities. Were APS to find a private third party owner for the solar energy system, the tax credit of 30% would significantly reduce the costs of the system. By neglecting that credit, APS is pursuing a plant that raises a serious question on both the prudence and legitimacy of this solar proposal.

Thus, we believe that the proposed rate is likely to be extremely misleading to the citizens of Arizona, and that it does not sufficiently reflect more creative approaches to financing the projects that would fully benefit the citizens of Arizona in taking advantage of such current opportunities as the 30% federal tax credit not available to APS, but fully available to other investors who could pass on much of that benefit to Arizona's ratepayers.

Further, we urge the Commission to review very carefully the details of how APS has performed it's cost of service studies as applied to distribution investment, and to the central station solar implementation. We believe that the "legacy" methods used to allocate distribution costs to customers, based on the "actual non-coincident peak load" of individual customers or customer classes are inherently discriminatory against customers who invest their own funds in distributed generation resources, thus enabling them to reduce their co-incident peak loads which can and should be recognized both in

the initial cost allocations and in then allocating the revenue requirement amongst various customers. As pointed out in the testimony of the Executive Agencies expert witness, the obsolete cost allocation approach utilized by APS thus lays the foundation of necessarily inefficient and uneconomic rate making in Arizona—thus inhibiting the economic development that might otherwise be present.

Q. Do you believe that program will meet its goals?

A. The program appears to have no set goal for installed capacity. This fact alone should cause the ACC to reject the proposal. However, using the solar partner's program sign up of 4,400 customers as a base, I would estimate that fewer than 1,000 customers would switch to this more expensive program. At the average kilowatt-hour demand of 1,163 kilowatt hours per month and the $0.33 net solar rate, it would appear that APS contemplates collecting $13,800 each from 1,000 solar price customers or about $14,000,000 over the life of the three year pilot. This is enough to build a 2 megawatt system at $7 a watt. This is hardly an exemplary project. I conclude that without a goal, with an unjustifiable high price resulting in little or no customer sign up and no commendable project there is no rationale for the program.

Q, You indicated that there are alternative available to customers and APS that would be more successful in supporting solar energy. What are they?

A. There are several alternatives. Provided APS implements a net metering tariff to so accommodate, customers could take their $13,800 contribution and install their own solar energy system to meet 50 or 100% of their annual energy requirements. Another alternative is that APS should first be required to issue a solicitation that would purchase solar electricity using power purchase agreements from independent power producers with the purchase agreements for 25 years between $0.18 - $0.25/kWh indexed to the consumer price index. Another alternative is that if APS is allowed to build their own plant they should be required to follow the successful Tucson Electric's model that utilizes federal tax credit, accelerated cost recovery depreciation schedules, and building incrementally by using an annual expense accounting approach since the funds are provided by ratepayers at no risk or cost of capital to APS. This model has been used by TEP as part of its EPS program to build 5MW of large-scale solar projects with a delivered price of $0.10 kilowatt hour.

Q. Does this complete your testimony?

A. It does.

Robert H. Annan

Qualifications

Robert "Bud" Annan has thirty five years experience in energy research and development. From 1964 to 1975 he was a staff member for Vice Admiral H. G. Rickover at the Atomic Energy Commission. That office was responsible for developing nuclear propulsion for Navy ships. From 1975 to 1996, Mr. Annan held various positions at the U. S Department of Energy responsible for renewable energy development. From 1982-1995 he was the Director of Solar Energy Research and Development. As director he was responsible for photovoltaics, solar thermal, and biomass power technologies. In addition to directing technology research and development he designed partnerships to accelerate the commercialization of new technologies. From 1994 to 1996, he was special assistant to the Sectary of Energy responsible for all renewable energy matters. In this position he led energy trade missions to India, China, Latin America and South Africa. He retired from government service in 1996. Mr. Annan is currently consulting with high-tech-industries, Arizona State University, and national research institutions on renewable energy matters.

In 1998, Mr. Annan organized and led the 45 member Arizona Clean Energy Industries Alliance to promote the use of solar resources in Arizona electricity restructuring rules. This organization was instrumental in Arizona adopting the first solar energy regulatory policy in the nation. He was a member of the Arizona Corporation Commission's Cost Evaluation Working Group. Its report to the Commission formed the basis for expanding Arizona's Environmental Portfolio Standard. He is a member of the Governor's Solar Energy Advisory Council and has participated in a number of special study working groups investigating the role of solar energy in Arizona's energy mix.

In November 2004 he was awarded National Renewable Energy Laboratory's highest honor, the Paul Rappaport award for "conceiving and directing research programs that have produced major improvements in solar energy technologies and for encouraging public polices that are moving those technologies into the mainstream of American life".

EXHIBIT
Solar 8
admitted

TESTIMONY OF ED SMELOFF
TO THE ARIZONA CORPORATION COMMISSION
Docket No. E-01345A-05-0816

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to recommend to the Commission that Arizona Public Service adopt a net metering rate schedule that is consistent with the goals of Arizona's Environmental Portfolio Standard and Renewable Energy Standard and Tariff rulemaking, and one that more closely matches metering policies that have been adopted in other states with successful solar energy programs.

Q. What is your background and expertise with respect to net metering?

I have attached my resume, which provides my background and expertise.

Q. What is net metering?

A. Net metering is a policy that allows electric customers to generate electricity from qualifying facilities (typically solar and wind energy facilities) and to export excess energy to the interconnected electric utility. During months when net-metered customers provide excess power to the electric utility they are given credits for that power. In subsequent months when customers use more electricity than is generated from their qualifying facility they can apply these credits to their electric bill. In other words, the excess electricity a customer generates at certain times is netted against power provided to the customer by the electric utility.

Q. Why have state legislatures and utility regulatory commissions adopted net metering policies to promote the installation of grid-tied solar electric systems?

A. Net metering policies have been adopted because grid-tied solar electric systems provide multiple benefits for the electric power system and environment including reducing peak demand for electricity, lessening the consumption of natural gas in power plants, helping the electric grid operate more efficiently by reducing line losses, saving investment capital by delaying costly upgrades to the electrical transmission and distribution systems and avoiding environmental damage from power plant emissions.

Q. How do grid-tied solar electric systems help reduce peak demand?

A. In Arizona peak demand for electricity occurs on hot summer days when air conditioners are at their maximum use[1]. Properly oriented solar systems can assist

[1] According to the APS "Time-of-Use Flexibility Study" (APS Attachment DJR_9, Table 1, Page 8) peak summer demand for the top 10 days occurred on the average between 4 and 5 pm with load of over 95% of peak occurring between 1 pm and 7 pm.

utilities in meeting a significant portion of the demand created by this air conditioning load. When combined with other energy efficiency and load management measures, grid-tied solar electric systems can defer investment in gas-fired peaking power plants.

Q. How do grid-tied solar electric systems lessen the consumption of natural gas?

A. For Arizona natural gas fired power plants tend to be on the margin during much of the year. Therefore, during most hours when solar electric plants are producing electricity they will displace the use of natural gas. Natural gas prices have been very volatile over the past two years and have peaked at over $14 per million British Thermal Units. Other sources of power generation can help hedge against this volatility.

Q. How do grid-tied solar electric systems improve grid efficiency?

A. Electricity is lost as it is transmitted over power lines from power plants to end-users. Because of these losses more electricity has to be generated to meet customers' needs. Solar power is typically located at the point of use, on a customer's roof or next to the facility using electricity. By siting the power plant at the point of load, line losses are avoided.

Q. How do grid-tied solar electric systems help distribution utilities defer transmission and distribution upgrades?

A. As demand for electricity increases in specific areas of a distribution utility's service area, the utility needs to invest in new electric equipment to deliver power. Peak demand on specific distribution lines often occurs during hot summer days when air conditioning use is at its maximum. In addition, power lines tend to be less efficient under hot conditions when they are more fully loaded. Because solar power is located at the point where it is consumed it can help defer the need for upgrading electric distribution infrastructure.

Q. How do grid-tied solar electric systems avoid environmental damage?

A. The burning of fossil fuels generates pollutants like oxides of nitrogen, mercury, small particulates and carbon dioxide that threaten public health and the natural and built environment. Solar electric systems do not emit any air pollutants and therefore the electricity they generate displaces the pollutants form fossil fuel generators.

Q. Which states have successful solar energy programs?

A. California and New Jersey lead the country in grid-tied solar electric installations. According to the Interstate Renewable Energy Council (IREC) California has over 15,000 net-metered solar systems and New Jersey has over 1,000. These two states accounted for 80% of grid tied solar electric systems installed in the United States in 2005. Several other states including Colorado and Pennsylvania have recently adopted forward-looking programs promoting solar energy including net metering policies.

Q. Please explain California's net metering policy?

A. In California, state law requires all electric utilities to allow net metering to all customers (commercial, agricultural, industrial and residential) for solar and wind-energy systems up to 1 megawatt[2]. Any excess generation from solar and wind-energy systems are carried forward and credited to the customer's next electric bill for up to 12 months. Customers who take electric service on time-of-use schedules are credited for energy delivered to the utility at the retail price per kilowatt-hour in effect during that time period. Any net excess generation remaining at the end of a twelve-month period is granted to the customer's utility. The California Public Utilities Commission has ruled that net-metered generators up to one megawatt are exempt from interconnection study costs and standby fees. Current California law limits total quantity of net-metered generators to 0.5% of a utility's peak demand. However, pending legislation would raise that cap to 2.5% of each utility's peak demand[3]. This change in law would permit approximately 1,500 megawatts of net-metered systems to be connected to the grid in California.

Q. Please explain New Jersey's net metering policy?

A. In New Jersey, all electric distribution companies are required to offer net metering to commercial and residential customers for a variety of renewable energy technologies including photovoltaics. Qualifying facilities can be renewable energy systems up to 2 megawatts. A customer-generator receives credit at the electric distribution company's full retail rate for any excess electricity exported to the grid up to the total amount of electricity the customer consumes on an annual basis. If the customer has excess credits over the course of a year the electric distribution utility must compensate the customer for those credits at the company's avoided cost of wholesale power. Customers eligible for net metering retain ownership for all renewable energy credits associated with the electricity they generate. There is no cap on the number of systems that can be net-metered in New Jersey[4].

Q. Are there other states that allow net metering for systems greater than one megawatt?

A. Yes. Both Colorado and Pennsylvania allow net metering for customer-generators up to two megawatts. In Colorado, the Colorado Public Utilities Commission adopted regulations that allow solar and wind owners to net meter on a 1:1 kilowatt-hour ratio over a period of one year with any excess production at the end of the calendar year paid

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[2] The only generators that are not eligible for net metering are those located in an area served by a secondary network system.

[3] As of the filing of this testimony, the referenced legislation, Senate Bill 1, had passed out of the Legislature and moved to Governor's desk for signature. Governor Schwarzenegger is expected to sign it into law.

[4] The New Jersey Electric Discount and Energy Competition Act allows the Board of Public Utilities to authorize a utility to cease offering net metering when the total amount of net metering load reaches 0.1 percent of peak load.

at the utility's incremental cost of electricity. These rules[5] apply to all utilities in Colorado that serve more than 40,000 customers. Colorado's net metering regulation does not limit the total amount of net-metered systems in the state[6].

Q. What is the requirement in Pennsylvania?

A. Pennsylvania's Alternative Energy Portfolio Standards Act allows residential customers to net meter systems up to 50kW and other customers to net meter on-site generators up to one megawatt in size. Customers who agree to have their generators available to operate in parallel during grid emergencies, can net meter up to 2 megawatts in capacity. The law did not specify a cap on total installations[7].

Q. How does the net metering rate proposed by Arizona Public Service (APS) differ from the net metering policies in California and New Jersey?

A. There are several differences. First, APS proposes limiting net metering to facilities of 10 kW or less. Second, participation in the net metering is limited to residential customers and commercial customers with a monthly demand of 20 kW or less. Third, APS proposes to limit the total quantity of net-metered systems to 15 megawatts. Fourth, APS proposes compensating itself through the Environmental Portfolio Standard surcharge for lost revenues associated with transmission and distribution and other non-avoidable costs.

Q. Is the limitation on size of qualifying facilities reasonable?

A. No. Thirty-six other states with net metering policies have limits on system size greater than 10 kilowatts. This limitation will act as a significant constraint in achieving the goals of Commission's Environmental Portfolio Standard, which has prioritized solar power, and the Commission's Renewable Energy Standard and Tariff rulemaking, in which Commissioners are proposing a significant increase in distributed generation. A limitation on net-metered systems of less than 10 kilowatts is not consistent with this policy of promoting distributed generation.

Q. What would you recommend as the appropriate size limit for net-metered customer generators?

A. It is my opinion that the decisions of the utility regulators in New Jersey, Colorado and Pennsylvania are the appropriate ones for jurisdictions desiring to promote solar energy and the limit should, therefore, be two megawatts.

Q. Is the limitation on which customers can participate in the net metering program reasonable?

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[5] Colorado Code of Regulations 723-3-3664

[6] Colorado's Amendment 37 requires that 0.2% of renewable energy come from on-site solar generators.

[7] The Pennsylvania Public Utilities Commission is currently undertaking a rulemaking to further define net metering requirements.

A. No. There simply is no rational basis for excluding larger commercial and industrial customers from participating in the net metering program. Such a limitation as to who can participate is not consistent with a policy of promoting distributed generation as part of Arizona's Environmental Portfolio Standard and the Renewable Energy Standard and Tariff rulemaking. In fact, the proposed Renewable Energy Standard and Tariff requires that half of an affected utility's Distributed Renewable Energy Requirement come from non-residential, non-utility applications[8]. It would be counterproductive to the fulfillment of that mandate to limit net metered systems to sizes under 10 kW. In California and New Jersey numerous distributed solar projects have been placed on flat commercial roofs. In Arizona a significant opportunity exists for developing cost effective systems for larger commercial, industrial or governmental facilities. APS asserts that there are costs associated with net metering and that these costs could create subsidies between one class of customers and another. APS has not demonstrated that the costs of net metering outweigh the benefits or that net metering would create subsidies from one class to another. However, even if APS's assertion were true, it still does not logically follow that certain groups of customers should be excluded from participating in the program.

Q. Is the 15 megawatt limitation on the quantity of net-metered systems reasonable?

A. No. There is no basis in any other Arizona policy for such a limitation. Arizona aspires to have 15% of the state's electricity requirements met by renewable energy technologies by 2025. Furthermore, 30% or more of that requirement is likely to come from distributed resources located on the customer side of the electric meter. These are very laudable goals. Meeting them will require an aggressive suite of policies and incentives. Net metering is one of the most important policies in promoting distributed technologies like solar. Limiting the amount of systems that qualify for net metering to 15 megawatts would create a major obstacle to achieving the state's renewable energy goals. California is proposing a cap of 2.5% of peak load[9]. The Commission should adopt a net metering policy that is closely aligned with the distributed generation goal in Arizona's Renewable Energy Standard and Tariff rulemaking—that is, about 2,300 MW by 2025[10].

Q. Should APS be compensated through the EPS surcharge for lost revenues associated with net-metered solar electric systems?

A. No. Use of funds from the EPS surcharge for this purpose is inappropriate. Such a use would diminish the ability of the Commission to meet its renewable energy policy goals. APS has previously stated that the revenue provided by the surcharge will likely not be sufficient to support the renewable energy goals of the EPS. APS has said, "The

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[8] R14-2-1805 (D).

[9] About 1,500 MW of net metered solar systems.

[10] In APS testimony (attachment DJR_9, "APS Investigation into Rate Designs Conducive to Conservation and DSM", page 7), APS testified that 2005 retail sales were about 30,000,000,000 kWh, and annual growth is expected to be about 4.6%. Using these figures, and estimating a conservative production of 1,500 kWh per kW of solar photovoltaic panels, if APS's REST mandate were met exclusively with solar photovoltaics, about 2,300 MW of solar photovoltaics would be required.

funding necessary to support the Distributed Renewable Energy Requirement (DRER) alone will likely exceed the funding contemplated by the sample tariff after 2007. If PV continues to play a significant role in DRER, APS generally estimates cost of compliance to average between $50 million and $60 million per year…[11]"

In addition, no other state uses funds collected for the purpose of developing renewable energy resources to compensate electric utilities for revenue losses associated with net metering programs. APS's request is unprecedented.

Q. Are there other mechanisms that are used to compensate electric utilities for lost revenues associated with policies that decrease electricity consumption?

A. Yes. Electric utilities can experience diminished revenues as a result of effective energy efficiency and conservation programs. Various state regulatory commissions have developed policies that allow for adjusting revenues to account for variation in sales from the test revenue year. Rather than draining funds from the limited EPS surcharge fund the Commission should explore how to manage this issue in a more comprehensive manner.

Q. What are the key elements that should be included in a net metering policy for Arizona?

A. I will identify them in bulleted form:

- All renewable technologies eligible for credit under the Environmental Portfolio Standard promulgated by the Commission should be eligible for net metering.
- All types and classes of customers should be eligible.
- Maximum individual system capacity should be two megawatts[12].
- Any limit on aggregate capacity of all net-metered systems should be aligned with the distributed generation target set by the Commission for the Environmental Portfolio Standard.
- Net excess generation (NEG) should be credited on a 1:1 kWh basis (full retail value) and carried forward to the next monthly bill for at least one year. The customer should be paid for any remaining excess annual kilowatt hours at the utility's avoided costs.
- Simplified interconnection standards must be in place, including a standard agreement.
- There should be no application fee or metering charge to initiate net metering.
- There should be no ongoing special charges or fees.
- There should be no restriction on the customer's right or ability to retain or sell renewable-energy credits (RECs).
- There should be no additional insurance requirements.

---

[11] Testimony of APS to ACC, April 17, 2006.

[12] Interconnection standards will limit on-site generation to the size of the customer's service connection.

- Net metered customers should be treated identical to customers in same class without on-site generation.
- There should be no change in tariff for customers participating who net meter. Net metering should be a rider on the customer's existing tariff so that the rate structure does not change pre and post net metering.

Q. Is there a good model of net metering rules you would recommend?

A. Yes. the Model Net Metering Rules of the Interstate Renewable Energy Council (IREC) is a good model. It is attached as an appendix to this testimony.

Q. Does this conclude your testimony?

A. Yes.

IREC "Connecting to the Grid" Project Model Net Metering Rules[1] (June 2006)

Net Metering

1.000 Definitions

Qualifying retail utility (QRU) means any utility offering retail electric service in the State.

Service entrance capacity means the rating of the customer's electric service determined by multiplying the voltage provided to the customer by the QRU times the ampere rating of the customer's primary over current protection device (fuse or circuit breaker) times the appropriate multiplier for multi-phase service and generators.

2.000 Net metering general provisions

2.100 All qualifying retail utilities (QRUs) shall offer net metering to customers with solar, wind and other generators defined at 2.115, that generate electricity on the customer's side of the meter and are interconnected with the QRU pursuant to the interconnection rules in Section [*reference state interconnection rules here*], provided that the generating capacity of the customer-generator's facility meets both of the following criteria:

(a) The rated capacity of the generator does not exceed two megawatts (MW); and

(b) The rated capacity of the generator does not exceed the customer's service entrance capacity.

2.101 The QRU shall develop a net metering tariff that provides for customer-generators to be credited in kilowatt-hours (kWh) at a ratio of 1:1 for any excess production of their generating facility that exceeds the customer's on-site consumption of kWh in the billing period following the billing period of excess production. However, any excess kWh credits shall not reduce any fixed monthly customer charges imposed by the QRU.

2.102 The QRU shall carry over any excess kWh credits earned under 2.101 and apply those credits to subsequent billing periods to offset any customer consumption in those billing periods until all credits are used or the end of the calendar year is reached. A QRU that cycle-bills throughout the month may use the December billing month as the end of the calendar year.

2.103 At the end of each calendar year, the QRU shall either carry forward any excess kWh credits for use against consumption in future months, or compensate the customer-generator for any excess kWh credits at the QRU's average hourly incremental cost of electricity supply over the same calendar year period.

2.104 If a customer-generator terminates its service with the QRU [[*or switches electricity suppliers*]], the QRU shall compensate the customer-generator for any excess kWh credits at the QRU's average hourly incremental cost of electricity supply over the calendar year period immediately prior to termination of service.

2.105 A customer-generator facility used for net metering shall be equipped with metering equipment that can measure the flow of electricity in both directions at the same rate. For customer facilities less

[1] Available online at www.irecusa.org/connect.

than 10 kilowatts (kW), this shall be accomplished through use of a single, bi-directional electric revenue meter that has only a single register for billing purposes.

2.106 A customer-generator may choose to use an existing electric revenue meter if the following criteria are met:

(a) The meter is capable of measuring the flow of electricity both into and out of the customer-generator's facility at the same rate and ratio; and

(b) The meter is accurate to within plus or minus 5 percent when measuring electricity flowing from the customer-generator facility to the electric distribution system.

2.107 If the customer-generator's existing electric revenue meter does not meet the requirements at 2.106 above, the QRU shall install and maintain a new revenue meter for the customer-generator, at the company's expense. Any subsequent revenue meter change necessitated by the customer-generator, whether because of a decision to stop net metering or for any other reason, shall be paid for by the customer-generator.

2.108 The electric distribution company shall not require more than one meter per customer-generator. However, an additional meter may be installed under either of the following circumstances:

(a) The QRU may install an additional meter at its own expense if the customer-generator consents; or

(b) The customer-generator may request that the QRU install a meter, in addition to the revenue meter addressed in 2.106 above, at the customer-generator's expense. In such a case, the QRU shall charge the customer-generator no more than the actual cost of the meter and its installation.

2. 109 A customer-generator owns the renewable energy credits (RECs) of the electricity it generates, and may apply to the state regulatory commission or its authorized designee for issuance of solar RECs (S-RECs) or RECs as appropriate and based on actual on-site electric generation, or the calculated estimate for generators less than 10 kW in rated capacity and as further defined in Section [[*reference any state renewable portfolio standard (RPS) requirements here*]].

2.110 A QRU shall provide to net-metered customer-generators electric service at non-discriminatory rates that are identical, with respect to rate structure, retail rate components and any monthly charges, to the rates that a customer-generator would be charged if not a customer-generator.

2.111 A QRU shall not charge a customer-generator any fee or charge; or require additional equipment, insurance, or any other requirement not specifically authorized under this sub-section or the interconnection rules in Section [*reference state interconnection rules here*], unless the fee, charge or other requirement would apply to other similarly situated customers who are not customer-generators.

2.112 Each QRU shall make net metering available to eligible customer-generators in a timely manner and on a first-come, first-served basis up to 5 percent of the QRU's most recently measured annual peak load.

2.113 [[*optional*]] Each QRU shall submit an annual net metering report to the state regulatory commission. The report shall be submitted by [[*insert date*]] of each year, and shall include the following information for the previous compliance year:

(a) The total number of customer-generator facilities;

(b) The total estimated rated generating capacity of its net-metered customer-generators;

(c) The total estimated net kilowatt-hours received from customer-generators; and

(d) The total estimated amount of energy produced by the customer-generators.

2.114 [[*optional*]] Other qualifying generators [[*examples*]]

Biomass generators (but must run on-peak at 100% capacity) (and qualifies for air permit or otherwise meet criteria established by the Department of Environment)

Fuel cells using a renewable fuel

Combined heat and power (CHP) generators with efficiency greater than 2 times system average (and qualifies for air permit or otherwise meet criteria established by the Department of Environment)

3.000 General Provisions

3.001 If a net metering interconnection has been approved under the interconnection rules Section [*reference state interconnection rules here*], the QRU shall not require a customer-generator to test or perform maintenance on its facility except for any manufacturer-recommended testing or maintenance.

3.002 A QRU shall have the right to inspect a customer-generator's facility during reasonable hours and with reasonable prior notice to the customer-generator. If the QRU discovers that the customer-generator's facility is not in compliance with the requirements of the interconnection rules in Section [*reference state interconnection rules here*], the requirements of IEEE Standard 1547, and the non-compliance adversely affects the safety or reliability of the QRU's or other customers facilities, the QRU may require the customer-generator to disconnect the customer-generator facility until compliance is achieved.

EDWARD A. SMELOFF

5901 Bolsa Ave
Huntington Beach, CA 92647
714-903-4878
ed.smeloff@sharpusa.com

PROFESSIONAL OVERVIEW

Over 20 years experience in energy policy, resource planning, program development and management for solar businesses, electric utilities and non-profit energy organizations. Developed and implemented solar and energy efficiency programs and sustainable development strategies. I have senior policy and management experience with a mastery of energy policy, regulation and market delivery issues. Highlights of my experience:

- As Senior Manager for Project Sales of the Sharp Solar Energy Solutions Group I am responsible for developing commercial project business. In that capacity I work with large system integrators, independent power developers and electric utilities in planning, pricing and scheduling for the sale of solar electric equipment. I also provide technical assistance and advice to Sharp management on federal, state and local energy policy and participate in selected public proceedings. I provide support to the new product development team in assessing business opportunities and introducing new products to selected customers. I also create and maintain constructive relations with consumer, environmental, labor and business organizations interested in solar energy.

- As Assistant General Manager for Power Policy, Planning and Resource Development of the San Francisco Public Utilities Commission I managed a staff of 18 with an annual capital and operating budget of $15 million. I was responsible for developing solar and energy efficiency projects for public facilities in San Francisco, including the largest city-owned solar power plant in the United States at the Moscone Convention Center. I supervised the development and was senior author of the San Francisco Electricity Resource Plan that provides a 10-year blueprint for phasing out obsolete fossil fuel power plants in San Francisco and replacing them with a mix of cleaner energy resources. I was responsible for legislative and regulatory strategy for the City and County of San Francisco on energy policy and succeeded in passing several pieces of critically important legislation.

- As Executive Director of the Pace Law School Energy Project I provided technical assistance and advice to environmental organizations and solar and energy service companies regarding electricity restructuring legislation in New Jersey resulting in passage of law that provides for a renewable portfolio standard and significant funding for solar energy development through a systems benefit charge. I also led efforts for continuation and expansion of the systems benefit charge by the New York Public Service Commission that funds energy efficiency and renewable projects. I developed and supervised the implementation of the New York Shines project, funded by the New York State Energy Research and Development Authority that provided public information and market development for solar energy throughout New York.

- As Chairman of the Board of the Northeast Sustainable Energy Association in 1999 and 2000, I oversaw the selection of new management leading to a renewal of this organization's mission. I led in the organization of Clean Energy Expositions in Albany, New York and Trenton, New Jersey involving dozens of clean energy companies and senior officials in the administrations of Governor George Pataki and Governor Christine Whitman.

- As an elected member of the Board of Directors of the Sacramento Municipal Utility District from 1987 through 1997 I guided the transformation of that utility from dependence on a troubled nuclear power plant to leadership in the development of energy efficiency programs and clean energy technologies including the implementation of the largest solar energy program in the nation.

EDUCATION

- University of California, Davis, BA, Russian
- University of Southern California, MPA, Public Administration

PUBLICATIONS

Reinventing Electric Utilities: Competition, Citizen Action, and Clean Power, Washington, D.C., Island Press, 1997

"Utility Deregulation and Global Warming: The Coming Collision," *Natural Resources and Environment,* Volume 12, Number 4, spring 1998, Chicago, IL.

Choosing San Francisco's Energy Future: The Electricity Resource Plan, San Francisco Public Utilities Commission, December 2002.

OTHER PROFESSIONAL ACTIVITIES

Member, Steering Committee, California Apollo Alliance, *The California Apollo Alliance is a coalition of unions, environmentalists, businesses and community based organizations convened for the purpose of pursuing a statewide agenda of investment in renewable energy and energy efficiency to create good jobs, revitalize underserved communities and improve our environment.*

Member, Board of Directors, Solar Electric Power Association, Washington DC, 2003 to present. *The Solar Electric Power Association's mission is to facilitate the use and integration of solar electric power by utilities, electric service providers, and their customers.*

Member, Board of Advisors, TheVote Solar Initiative, San Francisco CA, 2002 to present. *The Vote Solar Initiative's mission is to promote a national transition to clean energy by empowering city governments to implement large-scale, cost-effective solar projects.*

Member, Board of Directors, Center for Resource Solutions, San Francisco CA, 1995 to 2001. *The Center for Resource Solutions is dedicated to promoting renewable energy and economic and environmental sustainability.*

President, Board of Directors, The Northeast Sustainable Energy Association, Greenfield MA, 1999-2000. *NESEA's goal is to bring clean electricity, green transportation, and healthy, efficient buildings into everyday use in order to strengthen the economy and improve the environment.*

Member, Technical Advisory Committee to the New York State Energy Research and Development Authority, Albany NY, 1998. Provided advice on selection of developer for first wind energy project in New York.

Member, Board of Directors, California Institute for Energy and the Environment, Berkeley CA, 1995-1997. *CIEE's objectives are to increase the security and sustainability of energy systems in California, to enhance the productivity and competitiveness of California's businesses, and to contribute to improving the environment.*

EXHIBIT
Solar 9
admitted

SURREBUTTAL TESTIMONY OF ED SMELOFF
ON BEHALF OF THE SOLAR ADVOCATES
TO THE ARIZONA CORPORATION COMMISSION
Docket No. E-01345A-05-0816

Q. Please state your name and business address.

A. My name is Ed Smeloff. My business address is 5901 Bolsa Avenue, Huntington Beach, CA 92647.

Q. Did you file direct testimony in this docket?

A. Yes.

Q. Please summarize your surrebuttal testimony.

A. My surrebuttal testimony will address APS's proposed net metering program. Specifically, the size of systems allowed to be net metered, caps on total participation, the type of meters that should be used, errors in the proposed allocation of costs and benefits of net metered systems, and APS's proposal to use EPS surcharge funds as compensation for alleged lost revenues.

Q. Have you read the Direct Testimony of Barbara Keene?

A. Yes.

Q. Can you discuss her definition of net metering?

A. Ms. Keene defines net metering as a system by which "customers receive retail prices for the electricity they generate."[1] This is incorrect. Net metering is more accurately described as an exchange of a kWh fed into the grid at one point in time for a kWh drawn from the grid at another point in time. At no point in time is a net metered customer/generator actually receiving payment at a retail price for generation. Under classic net metering, there is no buy/sell transaction. The Federal Energy Regulatory Commission has very clearly ruled to this effect. From FERC's decision in MidAmerican v. Iowa Utility Board, I quote: "In the case before us we find likewise that no sale occurs when an individual homeowner or farmer (or similar entity such as a business) installs generation and accounts for its dealings with the utility through the practice of netting."

Q. Can you comment upon Ms. Keene's testimony regarding APS's recovery of alleged 'revenue loss' through EPS funds?

A. I believe Ms. Keene's embrace of the concept that APS should be compensated for alleged revenue loss associated with net metering through the EPS is misguided for several reasons. First, it is based on a misinterpretation of net metering. Ms. Keene

[1] Barbara Keene testimony of August 18, 2006, page 4.

likens net metering to a power purchasing arrangement, testifying, "This situation is analogous to when APS contracts to buy renewable energy in the wholesale market." Ms. Keene's analogy is incorrect on several grounds. In terms of impact on utility operations and other ratepayers, net metering is actually much more analogous to energy conservation. Net metering adds no additional burden to a utility or other ratepayers (indeed, it can provide direct economic benefits), but effectively reduces the net amount of utility-provided energy required by the customer. The revenue impacts are exactly the same as investments in energy conservation.

Additionally, from a public policy point of view, an electrical system incorporating significant net-metered customer site generation has the following additional benefits not provided under the traditional central station/wholesale bulk purchase model:

1. Increased energy security based on the multiple sourced generation which is much more resilient to natural and man-made catastrophes.
2. Increased reliability based on reducing loading on the transmission and distribution system, where most outages originate.
3. The intangible but very real benefit of heightening the awareness and commitment to our nation's energy challenge in the coming decades by engaging customers directly in the solution while at the same time reducing fuel price fluctuation risk through diversity
4. The economic development benefits to the state, ranging from the creation of many additional jobs in the solar industry as homeowners and businesses install and maintain their systems, to the benefits of beginning to develop Arizona's unique solar resource—a national asset of significant and largely unrecognized national economic, environmental, and security importance.

Q. What would happen if the logic behind the premise of awarding compensation for lost revenues were applied evenly?

A. The logical extension of this argument would result in a situation where customers would pay the utility for lost revenue or lost contribution to fixed costs when they installed a more energy efficient refrigerator or permanently unplugged an extra refrigerator in the garage.

Q. Do any other states provide for the compensation of a utility's alleged loss of revenue due to net metering with funds dedicated to the support of renewable energy?

A. To the best of my knowledge, no. A survey of the 40 states that provide net metering does not reveal a single instance of compensation as described. The proposed arrangement is truly without precedent. Further, at a time when Arizona is facing extraordinary need for additional power, with APS seeking permission to invest in hundreds of millions of dollars in generation, transmission, and distribution system, it is especially illogical to focus on alleged "lost revenues."

Electric utilities do not have an inherent right to all possible "future revenue" and we recommend that the Commission explicitly state that fact in the course of this proceeding. While I agree APS is entitled to a fair chance to recover its investment and earn a reasonable rate of return thereon, at a time of unprecedented growth, we believe that the focus should be on the traditional rate making concepts of accurate determining of rate base on an expedited basis, and the allowed rate of return. With such an approach, "lost revenues" becomes irrelevant. "Lost Revenues" as a rate-making concept is only appropriate in a much more static regulated environment no longer present in Arizona. Moreover, a policy directing solar energy users (or the EPS funds) to provide compensation to APS for lost revenues when similarly situated customers who cause lost revenues do not have to provide equivalent compensation is contrary to the policy goals of promoting distributed renewable energy use.

Q. Can you summarize the Staff testimony regarding the size of systems eligible for net metering?

A. Staff witness Barbara Keene recommends 100 kW. Ms. Keene's argument is that a 100 kW size limitation "would allow larger projects to participate, while continuing to not allow a few projects to consume all the funds."[2] I believe she uses the unrealistically low proposed cap on the program to justify adding yet another limitation on the development of Arizona's indigenous and uniquely abundant solar energy resources and that this does not comport with the policy goals of promoting distributed renewable energy generation.

Q. Do you agree with Staff's arguments and recommendations on size limitations for net metered systems?

A. No. Ms. Keene's support for a 100 kW cap is based upon her belief that net metering causes compensable loss of revenues to APS, and she proposes the cap as a way to limit the State of Arizona's development of its renewable energy resources. As discussed earlier in my testimony, net metering brings benefits, and I believe that it should be the policy of the Commission to support policies that increase, not limit, the amount of renewable energy in Arizona, as a matter of good business, economic development, enhanced energy security of the nation, and environmental protection. I have not seen and do not believe Staff has undertaken any credible study to identify the proper economic valuation of the power provided by solar energy both in terms of the time of day when solar energy is produced and the value at the point where power is delivered to the grid.

Q. Can you comment on the APS rebuttal testimony regarding the size of systems eligible for net metering?

A. APS witness Gregory A. DeLizio recommends 10 kW as the size limit for the proposed net metering tariff. Mr. DeLizio points out that APS offers net billing (a system by which a customer sending electricity back into the grid is paid for that generation at APS's avoided generation rate) to customers up to 100 kW in size under Schedule EPR-

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[2] Barbara Keene testimony of August 18, 2006, page 7.

2, and for systems up to 10 kW in size under Schedule EPR-4. However, net billing is categorically different from net metering, and the argument is not relevant, and is disingenuous. It directly contradicts the provisions of the Energy Policy Act of 2005 which specifically provides, in new PURPA Net Metering Standard (16 U.S.C. 2621(d)(11)):

> (11) Net Metering. Each electric utility shall make available upon request net metering service to any electric consumer that the electric utility serves. For purposes of this paragraph, the term `net metering service' means service to an electric consumer under which electric energy generated by that electric consumer from an eligible on-site generating facility and delivered to the local distribution facilities **may be used to offset** electric energy provided by the electric utility to the electric consumer during the applicable billing period.

The emphasized phrase now in federal law, "may be used to offset" highlights the exchange aspect of net-metering, and the inherent lack of an immediate sale often advocated by "anti-solar energy" net metering opponents.

Mr. DeLizio also points out that 33 other states have net metering programs with caps on generator size at or below 100 kW. It is unclear why this is an argument for, rather than against, a 10 kW APS limit. The simple fact of the matter is that the economic impact on a utility and other ratepayers (both postively and negatively) are dictated by the total capacity interconnected, not the size of any one system. Larger systems are often cheaper as APS itself has argued previously, and prudent policymaking would suggest that any caps be set at a level that allows for the most cost-effective installations. Colorado, a distant competitor to Arizona in terms of its solar energy resource, has chosen 2 MW, and we believe that is the minimum support the development of Arizona's unique solar resource should receive. An artificially low cap on individual project size would drive up the overall cost of a distributed renewable energy program in Arizona and would needlessly make it more difficult to meet the targets established for distributed renewable generation.

Q. Can you comment on the issue of meters?

A. I support APS witness Mr. DeLizio's recommendation that a single bi-directional meter is a better option.

Q. Does this complete your testimony?

A. It does.

FEDERAL ENERGY REGULATORY COMMISSION

A S S E S S M E N T O F

Demand Response & Advanced Metering

STAFF REPORT

Docket Number: AD-

EXHIBIT

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Solar 10

Admitted

KILOWATTHOURS

AUGUST 2006

Assessment of Demand Response and Advanced Metering
Staff Report

Docket AD06-2-000
August 2006

Table of Contents

Table of Contents — *i*

Executive Summary — *v*

- **Energy Policy Act of 2005** — v
- **Commission Staff Activities** — v
- **Advanced Metering** — vi
- **Existing Demand Response Programs and Time-Based Rates** — vi
- **Demand Response in Regional Transmission Planning and Operations** — x
- **Regulatory Barriers** — xi
- **Conclusions** — xii

Chapter I. Introduction — *1*

- **Energy Policy Act of 2005** — 1
- **Commission Staff Activities** — 1
- **Demand Response and Advanced Metering Survey** — 2
- **Report Organization** — 2
- **Regional Definitions** — 3

Chapter II. Background on Demand Response — *5*

- **Definition of Demand Response** — 5
- **Types of Demand Response** — 6
- **Role of Demand Response in Retail and Wholesale Markets** — 7
- **Use of Demand Response in the United States** — 8
- **Benefits of Demand Response** — 10
  - Participant Benefits — 10
  - Market and System Benefits — 10
  - Additional Benefits Created by Demand Response — 11
- **Evidence of Customer Price-Responsiveness** — 13
- **Role of Enabling Technology** — 14

Table of Contents (Cont.)

Chapter III. Advanced Metering and Market Penetration ____ *17*

What is advanced metering? ____ **17**

Overview of Advanced Metering ____ **18**
Building Blocks of Advanced Metering ____ 19

Estimates of Advanced Metering Market Penetration from FERC Survey ____ **25**
FERC Survey ____ 25
Advanced Metering Market Penetration Estimates ____ 26
Uses of Advanced Metering ____ 31
Recent Deployments of AMI Systems ____ 32

Costs and Benefits Associated with Advanced Metering ____ **33**
Costs of Deploying Advanced Metering ____ 33
Benefits Associated with Advanced Metering ____ 35

Current Issues Associated with Advanced Metering ____ **38**
AMI specifications ____ 38
Advanced Metering and Price Responsive Demand Response Networks ____ 39
Providing Timely Information to Customers ____ 40
Interoperability and Standard Interfaces ____ 41
Security ____ 42
Costs and Benefits to Include in Business Case Analyses ____ 43

Chapter IV. Existing Demand Response Programs and Time-Based Rates ____ *45*

Incentive-Based Demand Response Programs ____ **45**
Direct Load Control ____ 46
Interruptible/Curtailable Rates ____ 47
Emergency Demand Response Programs ____ 48
Capacity-Market Programs ____ 49
Demand Bidding/Buyback Programs ____ 49
Ancillary Services ____ 51

Time-Based Rate Programs ____ **51**
Time-of-Use Rates ____ 53
Time-of-Use Rates ____ 54
Critical Peak Pricing ____ 57
Real-Time Pricing ____ 60

Demand Response Program Survey Results ____ **63**
Incentive-Based Demand Response ____ 63
Time-Based Rates ____ 65

Motivations for the Use of Demand Response and Time-Based Rates ____ **69**

Current issues/challenges ____ **71**

Demand Response Activities at the State, Regional and Federal Level ____ **75**

Table of Contents (Cont.)

Chapter V. Demand Response as a Resource 79

FERC Survey: Demand Response Program Information 79

FERC Survey Results: Demand Response Resource Estimates 81
Potential Peak Load Reduction of Demand Response Programs and Time-Based Rates 81
Actual vs. Potential Peak Reductions of Demand Response Programs and Time-Based Rates 84

Existing Demand Response Resource Contribution 86

Chapter VI. Role of Demand Response in Regional Planning and Operations 91

Potential for Demand Response for Regional Planning 91

Transmission Planning and Operations and Demand Response 95
Transmission Planning Process 95
Demand Response in Transmission Planning 97
Provision of Ancillary Services by Demand Response 97

Regional Treatment of Demand Response 101
North American Electric Reliability Council 101
Texas Interconnection and the Electric Reliability Council of Texas 103
Western Interconnection and the Western Electric Coordinating Council 104
Eastern Interconnection 108
International Examples 114

Example Demand Response Projects 114
LIPA Edge 114
Southern California Edison Feeder Relief 115
BPA Olympic Peninsula 116
Consolidated Edison 116
Mad River Valley Project 117
The Energy Coalition 117

Concerns And Obstacles 117
Lack of Uniform Treatment of Demand Response. 117
Perceived Temporary Nature of Demand Response 118
Regulatory Treatment of Transmission and Demand Response Costs 119
Reliability of Statistical Demand Response 119
Manual Override and Voluntary Response 121
Capacity Credit 122
Co-Optimization – Response Cost Vs Duration 123

Steps that could be taken to ensure that, in regional transmission planning and operations, demand resources are provided equitable treatment 123

Table of Contents (Cont.)

Chapter VII. Regulatory Barriers ____ *125*

Regulatory Barriers ____ **125**
Disconnect Between Retail Pricing and Wholesale Markets ____ 125
Utility Disincentives Associated with Offering Demand Response ____ 126
Cost Recovery and Incentives for Enabling Technologies ____ 128
Barriers to Providing Demand-Response Services by Third Parties ____ 129
Need for Additional Research on Cost-Effectiveness and Measurement of Reductions ____ 130
Existence of Specific State-Level Barriers to Greater Demand Response ____ 131
Specific Retail and Wholesale Rules that Limit Demand Response ____ 132
Insufficient Market Transparency and Access to Data ____ 132
Better Coordination of Federal-State Jurisdiction Affecting Demand Response ____ 133

Recommendations ____ **133**

Appendices

Appendix A:
EPAct 2005 Language on Demand Response and Smart Metering

Appendix B:
Acronyms Used in the Report

Appendix C:
Glossary for the Report

Appendix D:
Bibliography for the Report

Appendix E:
The Public Process Leading to the Report

Appendix F:
The FERC Survey

Appendix G:
FERC Survey Respondents

Appendix H:
Demand Response (DR) Programs and Services at Responding Utilities

Appendix I:
Data and Sources for Figures

Appendix J: Acknowledgements

Executive Summary

Energy Policy Act of 2005

Section 1252(e)(3) of the Energy Policy Act of 2005 (EPAct 2005)[1] requires the Federal Energy Regulatory Commission (Commission) to prepare a report by appropriate region, that assesses electric demand response resources, including those available from all consumer classes. Congress directed that this report be prepared and published not later than one year after the date of enactment of the EPAct 2005, and specifically to identify and review the following for the electric power industry:

- saturation and penetration rate of advanced meters and communications technologies, devices and systems;
- existing demand response programs and time-based rate programs;
- the annual resource contribution of demand resources;
- the potential for demand response as a quantifiable, reliable resource for regional planning purposes;
- steps taken to ensure that, in regional transmission planning and operations, demand resources are provided equitable treatment as a quantifiable, reliable resource relative to the resource obligations of any load-serving entity, transmission provider, or transmitting party; and
- regulatory barriers to improved customer participation in demand response, peak reduction and critical period pricing programs.

Commission Staff Activities

In preparing this report, Commission staff undertook several activities:

- Developed and implemented a first-of-its-kind, comprehensive national survey of electric demand response and advanced metering. The FERC Demand Response and Advanced Metering Survey (FERC Survey) requested information on (a) the number and uses of advanced metering, and (b) existing demand response and time-based rate programs, including their current level of resource contribution.
- Requested and received written comments from interested persons on a draft version of the FERC Survey, and on key issues and challenges that Commission staff should examine. Thirty-one entities provided written comments to the proposed survey.
- Held a public technical conference on January 25, 2006 at Commission headquarters in Washington, D.C.; obtained comments from five panels with over 30 participants.
- Surveyed 3,365 organizations in all 50 states representing every aspect of the electric delivery industry: investor-owned utilities, municipal utilities, rural electric cooperatives, power marketers, state and federal agencies, and unregulated demand response providers. The voluntary survey had a response rate of about 55 percent.

[1] Energy Policy Act of 2005, Pub. L. No. 109-58, § 1252(e)(3), 119 Stat. 594 (2005) (EPAct section 1252(e)(3)). The full text of section 1252 is attached as Appendix A.

- Collected information on the role of demand resources in regional transmission planning and operations through review of regional transmission documents, and through interviews with regional representatives.
- Conducted a detailed review of the literature on and experience with advanced metering, demand response programs, and time-based rates.

Advanced Metering

By specifically designating saturation and penetrations rates of advanced meters and communication technologies, devices and systems as a matter to be covered in this report, Congress in section 1252 (e)(3) of EPAct 2005 recognized that the penetration of advanced metering[2] is important for the future development of electric demand responsiveness in the United States. In studying this issue, Commission staff examined the state of the technology and the market penetration of advanced metering.

One result of the FERC Survey is that advanced metering currently has a penetration of about six percent of total installed, electric meters in the United States. An analysis of market penetration by region indicates that there are differences in how much advanced metering has been adopted across the United States (see Figure ES-1). The parts of the United States associated with the ReliabilityFirst Council (RFC)[3] and Southwest Power Pool (SPP) had the highest regional overall penetration rates of 14.7 percent and 14 percent, respectively. Advanced metering penetration for the remaining regions in the United States is lower than the national average.

Commission staff also developed estimates of the penetration of advanced metering by state. These state-by-state estimates should provide a useful baseline in the state deliberations on smart metering required by EPAct 2005[4] and any future state proceedings on advanced metering. Table ES-1 displays the penetration rate of advanced metering in the ten states with the highest penetration. The remaining states reported lower penetration rates.

Market penetrations also differ by type of organization. The estimate of market penetration of advanced metering is highest among rural electric cooperatives at about 13 percent. Investor-owned utilities have the next highest penetration at close to six percent. This suggests that small, publicly-owned entities such as electric cooperatives have been actively pursuing automated and advanced meter reading.

Existing Demand Response Programs and Time-Based Rates

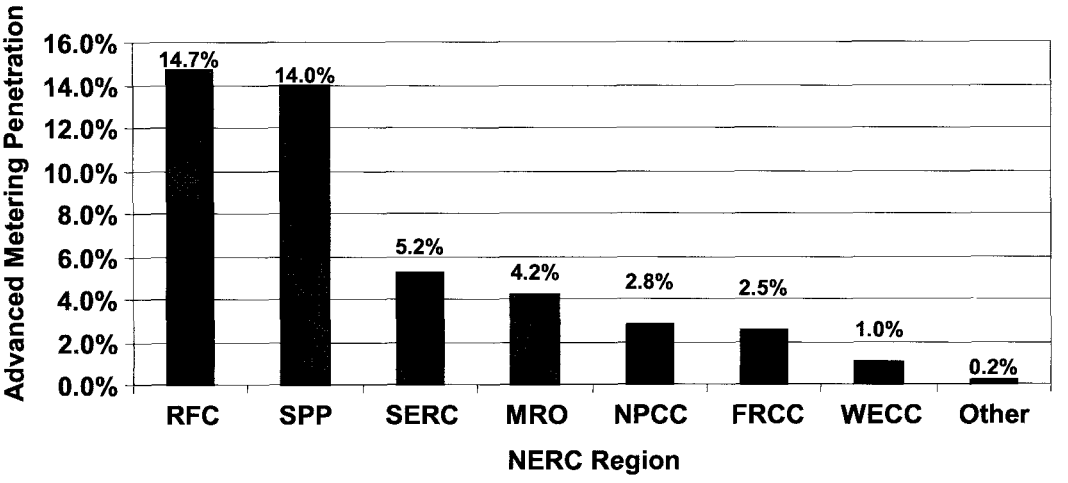
In this report, Commission staff adopted the definition of "demand response," that was used by the U.S. Department of Energy (DOE) in its February 2006 report to Congress:

[2] For purposes of this report, Commission staff defined "advanced metering" as follows: "Advanced metering is a metering system that records customer consumption [and possibly other parameters] hourly or more frequently and that provides for daily or more frequent transmittal of measurements over a communication network to a central collection point."

[3] Reliability*First* Corporation (RFC) is located in the Mid-Atlantic and in portions of the Midwest.

[4] EPAct 2005 section 1252(b)

Figure ES-1. Penetration of advanced metering by region[5]



Source: FERC Survey

Table ES-1. States with the highest penetration of advanced metering

State	Advanced Metering Penetration
Pennsylvania	52.5%
Wisconsin	40.2%
Connecticut	21.4%
Kansas	20.0%
Idaho	16.2%
Maine	14.3%
Missouri	13.4%
Arkansas	12.9%
Oklahoma	7.2%
Nebraska	6.8%

Source: FERC Survey

[5] Regional definitions used in this figure and subsequent figures are (See Chapter I for a NERC region map):

- Electric Reliability Council of Texas, Inc. (ERCOT)
- Florida Reliability Coordinating Council (FRCC)
- Midwest Reliability Organization (MRO)
- Northeast Power Coordinating Council (NPCC)
- Reliability*First* Corporation (RFC)
- SERC Reliability Corporation (SERC), which covers most of the Southeast.
- Southwest Power Pool, Inc. (SPP)
- Western Electricity Coordinating Council (WECC)
- Other (Alaska and Hawaii)

> Changes in electric usage by end-use customers from their normal consumption patterns in response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized.[6]

Demand response under this definition can be categorized into two groups: incentive-based demand response and time-based rates. Incentive-based demand response includes direct load control, interruptible/curtailable rates, demand bidding/buyback programs, emergency demand response programs, capacity market programs, and ancillary services market programs. Time-based rates include time-of-use rates, critical-peak pricing, and real-time pricing.

Based on the results of the FERC Survey, Commission staff found that the use of demand response is not widespread. Only approximately five percent of customers are on some form of time-based rates or incentive-based program. The most common demand response programs offered are direct load control, interruptible/curtailable programs, and time-of-use rates, but only about 200 entities reported that they offer these programs. Interest in time-based rates and demand response programs is growing, and results from recent programs and pilots are encouraging.

The FERC Survey also requested information on the potential peak reduction that existing demand response programs represent. Nationally, the total potential demand response resource contribution from existing programs is estimated to be about 37,500 MW. The vast majority of this resource potential is associated with incentive-based demand response. Figure ES-2 shows a breakdown of resource contribution by reliability region and by customer type. Because peak loads vary significantly among reliability regions, it is useful to characterize the existing demand response potential capability relative to each region's summer peak demand. Demand response resource potential ranges from three to seven percent in most North American Electric Reliability Council (NERC) reliability regions, with the notable exception of the MRO region (20 percent). The NERC regions of the country with the largest demand response resource contributions (as a percent of the national total) are RFC (22 percent), SERC (21 percent), and MRO (16 percent).

Demand response programs and time-based rates are offered by all forms of electric companies that serve customers. Publicly-owned utilities (electric cooperatives, political subdivisions, and municipal utilities) account for 55 percent of entities reporting that they offer time-of-use rates to residential customers. A similar distribution reported that they offered direct load control programs.

Investor-owned utility programs account for 47 percent of national demand response resource contributions, followed by Independent System Operator/Regional Transmission Organization (ISO/RTO) administered demand response programs, which contribute 19 percent of national demand response resources (see Figure ES-3).

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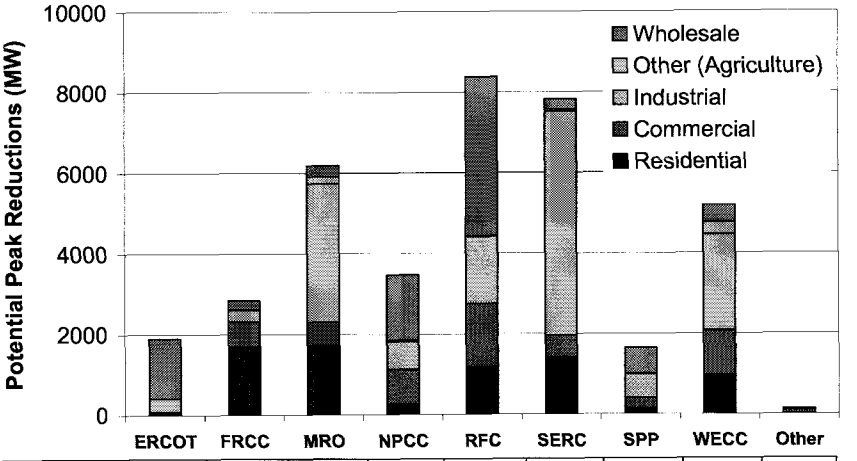
[6] U.S. Department of Energy, Benefits of Demand Response in Electricity Markets and Recommendations for Achieving Them: A Report to the United States Congress Pursuant to Section 1252 of the Energy Policy Act of 2005, February 2006 (February 2006 DOE EPAct Report).

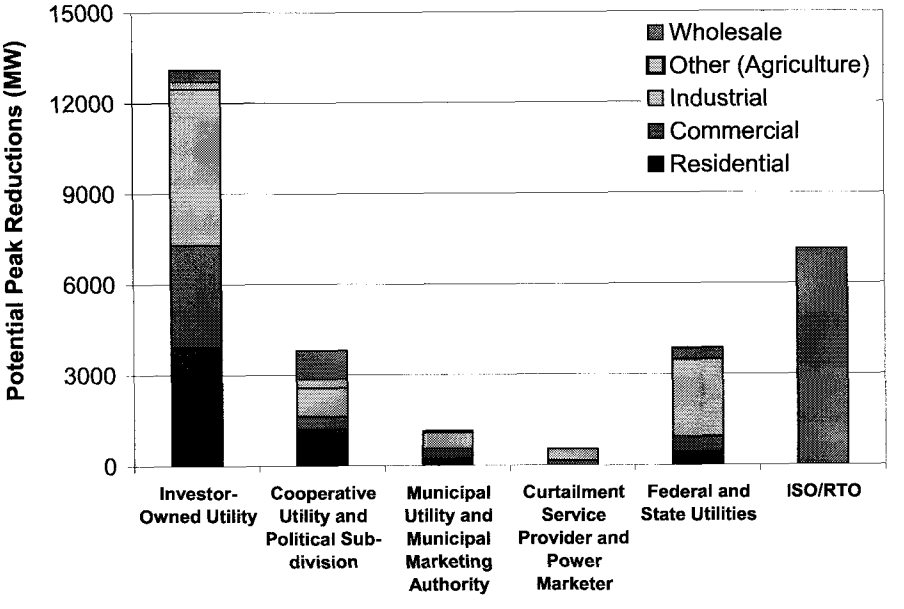
Figure ES-2. Existing demand response resource contribution by NERC region and customer type



	ERCOT	FRCC	MRO	NPCC	RFC	SERC	SPP	WECC	Other
As Percent of Projected Summer 2006 Peak Demand	3%	7%	20%	6%	4%	5%	4%	4%	N/A

Source: FERC Survey
Note: Other reliability region includes Alaska and Hawaii.

Figure ES-3. Demand response resource contributions by entity type and customer class



Source: FERC Survey

Demand Response in Regional Transmission Planning and Operations

To a degree, generation, transmission, and demand response are substitutes, depending on the location of generation or demand response. As a substitute for generation, demand response can serve as a local peaking resource and thereby assist resource adequacy. As a substitute for transmission and distribution infrastructure, demand response can reduce the need for new transmission or distribution expansion to bring generation to a local area. At minimum, demand response can provide relief for an overloaded transmission system, and can defer the need for infrastructure.[7] Time-based rates and direct-load-control can be used to target specific hours when system needs are greatest.

Demand response is not treated in transmission planning uniformly across regions, and demand response is typically not directly assessed during transmission planning. It is included only indirectly in most transmission planning. Existing or expected demand response resources are incorporated into reliability assessments either as modifications to expected load or as responsive resources. New demand response resources are typically not included as potential solutions to transmission adequacy problems. System planners do not consider demand response equally when they examine options for dealing with transmission inadequacies. If they do consider demand response, it is as a temporary solution until a permanent transmission enhancement is in place. Commission staff found that many regional transmission organizations state that their responsibility is limited to identifying transmission concerns and evaluating proposed solutions, not primarily encouraging demand response. Bonneville Power Administration, the Midwest ISO, and the PJM Interconnection were the only large entities that reported having policies to consider demand response in transmission planning; however, these have not yet resulted in demand response projects.

How to model demand response and how to measure demand response so it can be better included in electric regional planning is a challenge. In one sense, demand response is like insurance. Modeling its value correctly involves forecasting and uncertainty. A review of recent research suggests that demand response has a key role to play in regional planning. For demand response resources to be valued correctly in regional resource planning, resource plans must be made for a sufficiently long planning period. Demand response can meet peak resource needs and reduce the likelihood of low-probability, high-consequence and potentially costly events. Adding demand response resources to regional plans requires modeling that address uncertainties such as fuel prices, weather, and system factors. Modeled properly, demand response can be an important tool for risk management.

Demand response can also serve as operating reserves. Several demand response programs such as direct load control can provide the timely response necessary to provide these reserves. Load participating in these programs is continuously poised to respond but only has to reduce consumption when a reliability event occurs. Moreover, while customers providing such operating reserves do not normally reduce transmission loading, they can reduce the amount of transmission capacity that must be held in reserve to respond to contingencies. This reserve capability of demand response both reduces the need for new transmission and increases the utilization of existing transmission to provide energy from low cost generation.

[7] For example, ISO-New England obtained demand response in 2004 through the "Gap RFP" to address local reserve concerns within Southwest Connecticut.

The eligibility of demand response resources to provide operating reserves has been limited in most regions and is typically limited to providing supplemental (non-spinning) and slower reserves. Restrictions on demand response providing spinning reserve have eased recently in some areas. For example, ERCOT allows demand response as a supplier of spinning reserve. PJM allows demand response to supply synchronized reserves and regulation.

Based on comments received and Commission staff review of regional transmission planning and operations procedures, Commission staff has identified several actions and steps that could be taken to enable greater use of demand resources. The merits of taking the following steps should be considered by appropriate transmission planners and state and federal regulators:

- Assure that regions that schedule resources to meet either energy or reserve needs properly recognize the capabilities and characteristics of demand resources.
- Assure that requirements are specified in terms of functional needs rather than in terms of the technology that is expected to fill the need. This applies to ancillary services as well as to transmission enhancement.
- Accommodate the inherent characteristics of demand response resources (just as generation resource characteristics are accommodated).
- Allow appropriately designed demand response resources to provide all ancillary services including spinning reserve, regulation, and frequency response reserves.
- Allow for the consideration of demand response alternatives for all transmission enhancement proposals at both the state and ISO/RTO level. At the minimum, transmission expansion planning procedures would allow demand response resources to be proposed and considered as solutions at congested interfaces or in load pockets, along with local generation or transmission enhancements. This consideration would be done early in the process, and include a reporting and assessment of alternatives considered.
- When appropriate, treat demand response as a permanent solution, similar to transmission enhancements.
- Develop better demand response forecasting tools for system operators, to increase the usefulness and acceptability of demand response.

Regulatory Barriers

Commission staff identified several regulatory barriers to improved customer participation in demand response, peak reduction and critical peak pricing programs. These barriers are based on input received from parties in written comments, comments filed and discussion heard at the FERC Demand Response Technical Conference, a review of demand-response program experience, and through a comprehensive literature review. Key regulatory barriers include:

- **Disconnect between retail pricing and wholesale markets**. Retail rates for most customers are fixed, while wholesale prices fluctuate. Placing even a small percentage of customers on tariffs based on marginal production costs, can allocate resources more efficiently.
- **Utility disincentives associated with offering demand response**. Reductions in customer demand reduce utility revenue. Without regulatory incentives such as rate decoupling or similar incentives, electric utilities lack an incentive to use or support demand response.
- **Cost recovery and incentives for enabling technologies**. Utilities are reluctant to undertake investments in enabling technologies such as advanced metering unless the business case and regulatory support for deployment is sufficiently positive to justify the outlay. These

investments may require an increase in rates. It is uncertain whether and how would regulators allow these costs to be recovered.

- **The need for additional research on cost-effectiveness and measurement of reductions**. There are deficiencies in the measurement of demand response and assessment of its cost-effectiveness. Cost-effectiveness tests that have been used by regulators must be improved to reflect changes in the industry, especially in organized markets.
- **The existence of specific state-level barriers to greater demand response**. Policies of retail rate regulators and state statutes in several states have created barriers to implementing greater levels of demand response, especially by exposing customers to time-based rates. Several states have laws that restrict the ability of regulators to implement critical peak pricing and other forms of time-based rates.
- **Specific retail and wholesale rules that limit demand response.** Certain wholesale and retail market designs have rules and procedures that are not conducive to demand participation. For example, the standard lengthy wholesale settlement periods utilized in ISO/RTO markets delays payment to participating retail customers.
- **Barriers to providing demand response services by third parties**. Shifting regulatory rules that allow third parties to provide demand response and potential sunset of various demand response programs are a disincentive to demand response providers. Because third parties often bear the risks of programs dependent on enabling technologies, they need long-term regulatory assurance or long-term contracts to raise the capital needed to invest in enabling technologies.
- **Insufficient market transparency and access to data**. Lack of third-party access to data has been identified as a barrier to demand response. Greater transparency of unregulated retailer price offers and information on the amount of load under time-based rates or pricing would assist grid operation and planning. A related but more fundamental barrier related to data is timely access to meter data.
- **Better coordination of federal-state jurisdiction affecting demand response.** While states have primary jurisdiction over retail demand response, demand response plays a role in wholesale markets under Commission jurisdiction. Greater clarity and coordination between wholesale and state programs is needed.

Conclusions

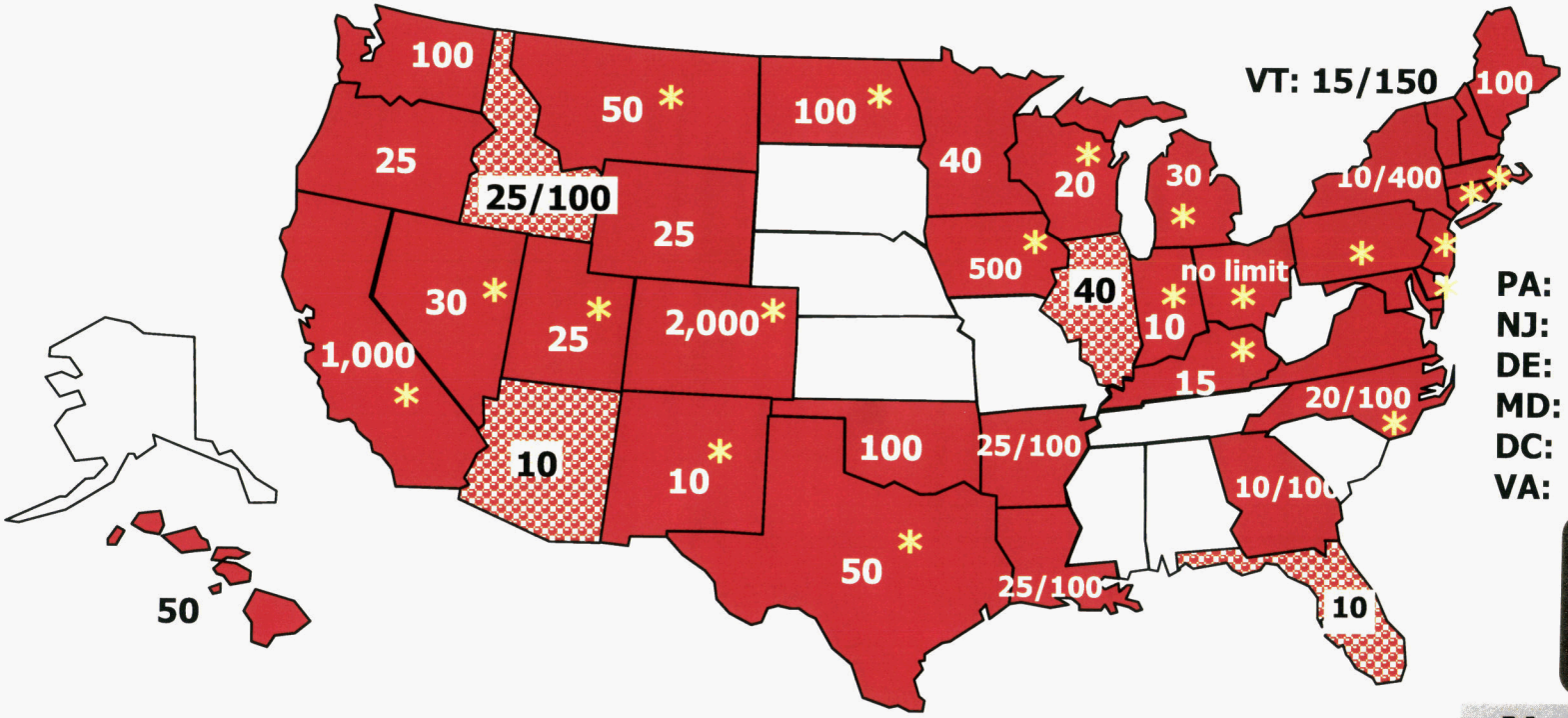
Based on the results of the FERC Survey, input from interested persons, and an extensive examination of regional and national trends in electric demand response programs policy, Commission staff concludes that demand response has an important role to play in both wholesale and retail markets. The potential immediate reduction in peak electric demand that could be achieved from existing demand response resources is between three and seven percent of peak electric demand in most regions. However, the technologies needed to support significant deployment of electric demand response resources, such as advanced metering, have little market penetration.

Demand response deserves serious attention. Staff recommends that the Commission: (1) explore how to better accommodate demand response in wholesale markets; (2) explore how to coordinate with utilities, state commissions and other interested parties on demand response in wholesale and retail markets; and (3) consider specific proposals for compatible regulatory approaches, including how to eliminate regulatory barriers to improved participation in demand response, peak reduction and critical peak pricing programs. Staff also encourages states to continue to consider ways to actively encourage demand response at the retail level. In particular, staff recommends that the Commission and states work cooperatively in finding demand response solutions.

www.dsireusa.org

September 2006

Net Metering Rules



NH: 25
MA: 60
RI: 25
CT: 100

PA: 50/1,000/2,000
NJ: 2,000
DE: 25
MD: 500
DC: 100
VA: 10/500

EXHIBIT
Solar 12
Admitted

Net metering is available in 40 states + D.C.

- State-wide net metering for all utility types
- * State-wide net metering for certain utility types (e.g., IOUs only)
- Net metering offered by one or more individual utilities

#s indicate system size limit (kW); in some cases limits are different for residential and commercial as shown

13

EXHIBIT
Solar 13
Admitted

Interstate Renewable Energy Council (IREC) "Connecting to the Grid" Project
State and Utility Net-Metering Rules and Programs
(Updated October 2006)

Program	System Size Limit / Customer Classes Eligible	Eligible Technologies	Limit on Total Capacity	Treatment of Net Excess Generation (NEG)	Interconnection Standards for Net Metering	Utilities Involved
Arizona – Salt River Project	10 kW / Residential	Photovoltaics	None	Purchased monthly by utility at average monthly market price minus a price adjustment of $0.00017/kWh	(Utility guidelines)	Salt River Project
Arizona – Tucson Electric Power	10 kW / Commercial, Residential	Photovoltaics, Wind	500 kW peak aggregate	Credited at retail rate to customer's next bill; granted to utility at end of 12-month billing cycle	(Utility guidelines)	Tucson Electric Power
Arkansas	25 kW for residential systems; 100 kW for commercial systems	Solar, Wind, Biomass, Hydro, Geothermal, Fuel Cells, Microturbines	None	Granted to utility monthly	Yes	All utilities
California	1 MW (three biogas digesters up to 10 MW per unit may net meter) / Commercial, Industrial, Residential	Photovoltaics, Landfill Gas, Wind, Anaerobic Digestion, Fuel Cells	2.5% of a utility's peak demand (separate limit of 50 MW for SDG&E)	Credited at retail rate to customer's next bill; granted to utility at end of 12-month billing cycle	Yes	All utilities[1]
Colorado	2 MW / Commercial, Industrial, Residential	Solar, Landfill Gas, Wind, Biomass, Anaerobic Digestion, Small Hydro, Fuel Cells (Renewable Fuels)	None	Credited at retail rate to customer's next bill; at end of each calendar year, customer reimbursed for NEG at utility's average hourly incremental cost for the prior 12-month period	Yes	Colorado utilities serving 40,000 or more customers
Colorado – Delta-Montrose Electric Association	May not exceed customer's measured demand / Commercial, Residential	Photovoltaics, Wind, Biomass, Hydro	1 MW	Granted to utility monthly	Yes	Delta-Montrose Electric Association
Colorado – Empire Electric Association	10 kW / Commercial, Residential, Nonprofit, Schools, Agricultural, Institutional	Photovoltaics, Wind	50 customers	Utility pays customer at a rate equal to the average cost of power from the utility's wholesale supplier for that year, excluding wholesale power sold to loads billed under the utility's SCS tariffs	Yes	Empire Electric Association
Colorado – Fort Collins Utilities	10 kW / Residential	Photovoltaics, Wind	25 customers	Credited at retail rate to customer's next bill; granted to utility at end of 12-month billing cycle	Yes	Fort Collins Utilities
Colorado – Gunnison County Electric	10 kW / Commercial, Residential	Photovoltaics, Wind	50 customers	Purchased by utility at wholesale rate	Yes	Gunnison County Electric
Colorado – Holy Cross Energy	25 kW / Commercial, Industrial, Residential	Photovoltaics, Wind, Biomass, Hydro, Geothermal	None	Credited at retail rate to customer's next bill; purchased by utility at wholesale rate at end of 12-month billing cycle	Yes	Holy Cross Energy
Colorado – La Plata Electric Association	25 kW / Commercial, Residential	Photovoltaics, Wind	1% of utility's aggregate customer peak demand	Credited at avoided-cost rate to customer's next bill; utility pays customer for any unused NEG at beginning of each calendar year	Yes	La Plata Electric Association

[1] In California, all utilities – with the exception of Los Angeles Department of Water & Power (LADWP) -- must offer net metering to customers with PV and wind-energy systems. (LADWP offers net metering voluntarily.) In addition, investor-owned utilities must offer net metering to customers with fuel cells and biomass-energy systems.

Sources: The Interstate Renewable Energy Council (IREC) and the N.C. Solar Center (NCSC). "Connecting to the Grid" Project web site, www.irecusa.org/connect; Database of State Incentives for Renewable Energy (DSIRE), www.dsireusa.org. Additional information, including statutory and regulatory source citations, is available on the projects' web sites.

Interstate Renewable Energy Council (IREC) "Connecting to the Grid" Project
State and Utility Net-Metering Rules and Programs
(Updated October 2006)

Program	System Size Limit / Customer Classes Eligible	Eligible Technologies	Limit on Total Capacity	Treatment of Net Excess Generation (NEG)	Interconnection Standards for Net Metering	Utilities Involved
Connecticut	100 kW for renewables; 50 kW for fossil fuels / Residential, Commercial	Solar, Landfill Gas, Wind, Biomass, Fuel Cells, Municipal Solid Waste, Small Hydro, Tidal Energy, Wave Energy, Ocean Thermal	None	Purchased monthly by utility at spot-market energy rate	Yes	Investor-owned utilities only
Delaware	25 kW / Commercial, Residential	Solar, Wind, Biomass, Hydro, Geothermal	None	Varies by utility	Yes	All utilities (applies to municipal utilities if they opt to compete outside their limits)
District of Columbia	100 kW / Commercial, Industrial, Residential	Solar, Wind, Biomass, Hydro, Geothermal, Tidal, Fuel Cells, CHP, Microturbines	None	Credited at retail rate to customer's next bill	Yes (*under development*)	All utilities
Florida – JEA	10 kW / Residential	Photovoltaics, Wind	None	Credited at retail rate to customer's next bill	(Utility guidelines)	JEA
Florida – New Smyrna Beach Utilities	10 kW / Commercial, Industrial, Residential	Photovoltaics	None	Credited at retail rate to customer's next bill	(Utility guidelines)	New Smyrna Beach Utilities
Georgia	100 kW for commercial systems; 10 kW for residential systems;	Photovoltaics, Wind, Fuel Cells	0.2% of a utility's annual peak demand	Credited at retail rate to customer's next bill; granted to utility at end of 12-month billing cycle	Yes	All utilities
Hawaii	50 kW / Commercial, Residential, Government	Photovoltaics, Wind, Biomass, Hydro	0.5% of a utility's annual peak demand	Credited at retail rate to customer's next bill; granted to utility at end of 12-month billing cycle	Yes	All utilities
Idaho – Idaho Power	100 kW for large commercial and agricultural; 25 kW for residential and small commercial	Photovoltaics, Wind, Biomass, Hydro, Fuel Cells	2.9 MW (0.1% of utility's 2000 peak demand)	Purchased monthly by utility at retail rate for residential and small commercial customers; purchased at 85% of Dow Jones index price for non-firm energy for large commercial and agricultural customers	(Utility guidelines)	Idaho Power
Idaho – Rocky Mountain Power	100 kW for large commercial and irrigation; 25 kW for residential and small commercial	Solar, Wind, Biomass, Hydro	714 kW (0.1% of utility's Idaho retail peak demand in 2002)	Purchased monthly by utility at retail rate for residential and small commercial customers; purchased at 85% of Dow Jones index price for non-firm energy for large commercial and agricultural customers	(Utility guidelines)	Utah Power & Light
Idaho – Avista Utilities	25 kW / Commercial, Residential, Agricultural	Solar, Wind, Biomass, Hydro, Fuel Cells	1.52 MW (0.1% of utility's 1996 peak demand)	Credited at retail rate to customer's next bill; granted to utility at end of 12-month billing cycle	(Utility guidelines)	Avista Utilities

Sources: The Interstate Renewable Energy Council (IREC) and the N.C. Solar Center (NCSC). "Connecting to the Grid" Project web site, www.irecusa.org/connect; Database of State Incentives for Renewable Energy (DSIRE), www.dsireusa.org. Additional information, including statutory and regulatory source citations, is available on the projects' web sites.

Interstate Renewable Energy Council (IREC) "Connecting to the Grid" Project
State and Utility Net-Metering Rules and Programs
(Updated October 2006)

Program	System Size Limit / Customer Classes Eligible	Eligible Technologies	Limit on Total Capacity	Treatment of Net Excess Generation (NEG)	Interconnection Standards for Net Metering	Utilities Involved
Illinois – ComEd Wind and PV Generation Program	40 kW / All retail customers	Photovoltaics, Wind	0.1% of utility's annual peak demand	Purchased monthly by utility at avoided-cost rate; customer receives an annual incentive payment for production	(Utility guidelines)	ComEd
Indiana	10 kW / Residential, Schools	Photovoltaics, Wind, Small Hydro	0.1% of a utility's most recent peak summer load	Credited at retail rate to customer's next bill	Yes	Investor-owned utilities
Iowa	500 kW / Commercial, Industrial, Residential	Photovoltaics, Wind, Biomass, Hydro, Municipal Solid Waste	None	Credited at retail rate to customer's next bill	No	Investor-owned utilities
Kentucky	15 kW Commercial, Residential, Nonprofit, Schools, Agricultural, Institutional, Government	Photovoltaics	0.1% of a utility's single-hour peak load during the previous year	Credited at retail rate to customer's next bill indefinitely	No	Investor-owned utilities, cooperatives
Louisiana	100 kW for commercial and agricultural systems; 25 kW for residential systems	Photovoltaics, Wind, Biomass, Hydro, Geothermal, Fuel Cells (Renewable Fuels), Microturbines	None	Credited at retail rate to customer's next bill indefinitely	Yes	All utilities
Maine	100 kW / Commercial, Industrial, Residential	Solar, Wind, Biomass, Hydro, Geothermal, Fuel Cells, Municipal Solid Waste, CHP, Tidal Energy	None	Credited at retail rate to customer's next bill; granted to utility at end of 12-month billing cycle	No	All utilities
Maryland	200 kW (500 kW with MD PSC permission) / Commercial, Residential, Schools, Government	Photovoltaics, Wind, Biomass	34.7 MW (0.2% of state's adjusted peak load in 1998)	Credited at retail rate to customer's next bill for up to 12 months	Yes	All utilities
Massachusetts	60 kW / Commercial, Industrial, Residential	Solar, Wind, Biomass, Hydro, CHP, Fuel Cells, Municipal Solid Waste	None	Credited at average monthly market rate to customer's next bill	Yes	Investor-owned utilities
Michigan	30 kW / Commercial, Industrial, Residential, Nonprofit, Schools, Government, Agricultural, Institutional	Solar, Wind, Biomass, Hydro, Geothermal, Municipal Solid Waste	0.1% of a utility's peak load or 100 kW (whichever is greater)	Credited at retail rate to customer's next bill; granted to utility at end of 12-month billing cycle	Yes	Various utilities (voluntary participation)
Minnesota	40 kW / Commercial, Industrial, Residential	Photovoltaics, Wind, Biomass, Hydro, Municipal Solid Waste, CHP	None	Purchased at average retail utility energy rate	Yes	All utilities
Montana	50 kW / Commercial, Industrial, Residential	Photovoltaics, Wind, Hydro	None	Credited at retail rate to customer's next bill; granted to utility at end of 12-month billing cycle	Yes	Investor-owned utilities
Montana – Montana Electric Cooperatives	10 kW / Commercial, Residential	Photovoltaics, Wind, Geothermal, Fuel Cells, Small Hydro	None	Credited at retail rate to customer's next bill; granted to utility at end of 12-month billing cycle	Yes	Most of MEC's 26 members

Sources: The Interstate Renewable Energy Council (IREC) and the N.C. Solar Center (NCSC). "Connecting to the Grid" Project web site, www.irecusa.org/connect; Database of State Incentives for Renewable Energy (DSIRE), www.dsireusa.org. Additional information, including statutory and regulatory source citations, is available on the projects' web sites.

Interstate Renewable Energy Council (IREC) "Connecting to the Grid" Project
State and Utility Net-Metering Rules and Programs
(Updated October 2006)

Program	System Size Limit / Customer Classes Eligible	Eligible Technologies	Limit on Total Capacity	Treatment of Net Excess Generation (NEG)	Interconnection Standards for Net Metering	Utilities Involved
Nevada	150 kW[2] / Commercial, Industrial, Residential	Solar, Wind, Biomass, Hydro, Geothermal	1% of a utility's peak capacity	Credited at retail rate to customer's next bill; no expiration[3]	Yes	Investor-owned utilities
New Hampshire	25 kW / Commercial, Industrial, Residential	Photovoltaics, Wind, Hydro	0.05% of a utility's peak demand	Credited at retail rate to customer's next bill	Yes	All utilities
New Jersey	2 MW / Commercial, Residential	Solar, Wind, Biomass, Hydro, Geothermal, Fuel Cells (Renewable Fuels), Tidal Energy, Wave Energy	None	Credited at retail rate to customer's next bill; purchased by utility at avoided-cost rate at end of 12-month billing cycle	Yes	Investor-owned utilities
New Mexico	10 kW / Commercial, Industrial, Residential	Solar, Wind, Biomass, Hydro, Geothermal, Fuel Cells, Municipal Solid Waste, CHP, Microturbines	None	Credited to customer's next bill or purchased by utility at avoided-cost rate	Yes	Investor-owned utilities, cooperatives
New York	10 kW for solar; 400 kW for farm waste; 125 kW for farm-based wind; 25 kW for residential wind	Photovoltaics, Biomass, Wind	Solar: 0.1% of a utility's demand in 1996; farm biogas: 0.4% of a utility's demand in 1996; wind: 0.2% of a utility's 2003 demand	Credited to customer's next bill, except NEG from wind systems over 10 kW, which is credited to customer's next bill at the utility's avoided-cost rate. All NEG purchased by utility at avoided-cost rate at end of 12-month billing cycle.	Yes	All utilities
North Carolina	20 kW for residential systems; 100 kW for non-residential systems	Photovoltaics, Wind, Biomass, Hydro	0.2% of a utility's North Carolina retail peak load for the previous year	Credited to customer's next bill at retail rate; granted to utility (annually) at beginning of each summer season	Yes	Investor-owned utilities
North Dakota	100 kW / Commercial, Industrial, Residential	Solar, Wind, Biomass, Hydro, Geothermal, Municipal Solid Waste, CHP	None	Purchased by utility at avoided-cost rate	No	Investor-owned utilities
Ohio	100 kW for microturbines; no limit for other systems / Commercial, Industrial, Residential	Solar, Wind, Biomass, Hydro, Fuel Cells, Microturbines	1% of a utility's peak demand	Credited at utility's unbundled-generation rate to customer's next monthly bill	Yes	All competitive utilities
Ohio – Yellow Springs Utilities	25 kW / Commercial, Residential	Photovoltaics, Wind	None	Not addressed	(Utility guidelines)	Yellow Springs Utilities

[2] In Nevada, utilities are permitted to require customers with systems over 30 kW in capacity to install a second meter at the customer's expense.
[3] In Nevada, it is unclear how NEG is treated for systems over 30 kW in capacity.

Sources: The Interstate Renewable Energy Council (IREC) and the N.C. Solar Center (NCSC). "Connecting to the Grid" Project web site, www.irecusa.org/connect; Database of State Incentives for Renewable Energy (DSIRE), www.dsireusa.org. Additional information, including statutory and regulatory source citations, is available on the projects' web sites.

Interstate Renewable Energy Council (IREC) "Connecting to the Grid" Project
State and Utility Net-Metering Rules and Programs
(Updated October 2006)

Program	System Size Limit / Customer Classes Eligible	Eligible Technologies	Limit on Total Capacity	Treatment of Net Excess Generation (NEG)	Interconnection Standards for Net Metering	Utilities Involved
Oklahoma	100 kW or 25,000 kWh/year (whichever is less) / Commercial, Industrial, Residential	Solar, Wind, Biomass, Hydro, Geothermal, Municipal Solid Waste, CHP	None	Granted to utility monthly or credited to customer's next bill at utility's avoided-cost rate (varies by utility)	No	Investor-owned utilities, municipal utilities
Oregon	25 kW / Commercial, Industrial, Residential	Solar, Wind, Hydro, Fuel Cells	0.5% of a utility's historic single-hour peak load	Credited at retail rate to customer's next bill or purchased by utility at avoided-cost rate	Yes	All utilities
Oregon – Ashland Electric	None / Commercial, Residential	Photovoltaics, Wind	None	Purchased by utility monthly at retail rate (1,000 kWh/month maximum)	(Utility guidelines)	Ashland Electric
Pennsylvania	50 kW for residential systems; 1 MW for nonresidential systems; 2 MW for systems connected to microgrids or available for emergencies	Solar, Wind, Biomass, Hydro, Fuel Cells, Municipal Solid Waste, CHP, Waste Coal, Other DG	None	Purchased by utility monthly at avoided-cost rate	Yes	Investor-owned utilities
Rhode Island	25 kW / Commercial, Industrial, Residential	Solar, Wind, Biomass, Hydro, Geothermal, Fuel Cells, Municipal Solid Waste, CHP	1 MW (Narragansett territory)	Credited at retail rate to customer's next bill; granted to utility at end of 12-month billing cycle	No	Narragansett Electric
Texas	50 kW / Commercial, Industrial, Residential	Solar, Wind, Biomass, Hydro, Geothermal, Fuel Cells, Tidal Energy, Wave Energy, Microturbines	None	Purchased by utility monthly at avoided-cost rate	Yes	Integrated IOUs that have not unbundled
Texas – San Antonio City Public Service	25 kW / Commercial, Residential	Photovoltaics, Wind, Biomass, Hydro, Geothermal, Tidal Energy, Wave Energy	None	Credited at retail rate to customer's next bill at utility's seasonal avoided-cost rate	(Utility guidelines)	San Antonio City Public Service
Texas – Austin Energy	20 kW / Commercial, Residential	Solar, Wind, Biomass, Hydro, Geothermal, Municipal Solid Waste	1% of utility's load	Credited to customer's next bill	(Utility guidelines)	Austin Energy
Utah	25 kW / Commercial, Industrial, Residential	Solar, Wind, Hydro, Fuel Cells	0.1% of a utility's 2001 peak demand	Credited at retail rate to customer's next bill; granted to utility at end of 12-month billing cycle	Yes	Investor-owned utilities, cooperatives
Vermont	150 kW for farm systems; 15 kW for commercial and residential / Commercial, Residential, Agricultural	All renewables	1% of a utility's 1996 peak demand or peak demand during most recent calendar year (whichever is greater)	Credited at retail rate to customer's next bill; granted to utility at end of 12-month billing cycle	Yes	All utilities
Virginia	500 kW for non-residential; 10 kW for residential / Commercial, Residential, Nonprofit, Schools, Government, Institutional	Solar, Wind, Biomass, Hydro, Geothermal, Tidal, Wave, Municipal Solid Waste	0.1% of a utility's annual peak demand	Credited at retail rate to customer's next bill; granted to utility at end of 12-month billing cycle	Yes	All utilities

Sources: The Interstate Renewable Energy Council (IREC) and the N.C. Solar Center (NCSC). "Connecting to the Grid" Project web site, www.irecusa.org/connect; Database of State Incentives for Renewable Energy (DSIRE), www.dsireusa.org. Additional information, including statutory and regulatory source citations, is available on the projects' web sites.

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State and Utility Net-Metering Rules and Programs
(Updated October 2006)

Program	System Size Limit / Customer Classes Eligible	Eligible Technologies	Limit on Total Capacity	Treatment of Net Excess Generation (NEG)	Interconnection Standards for Net Metering	Utilities Involved
Washington	100 kW / Commercial, Industrial, Residential	Solar, Wind, Hydro, Biogas, Fuel Cells, CHP	0.25% of a utility's 1996 peak load	Credited at retail rate to customer's next bill; granted to utility at end of 12-month billing cycle	Yes	All utilities
Washington – Grays Harbor PUD	25 kW / Commercial, Industrial, Residential	Solar, Wind, Hydro, Fuel Cells	0.25% of utility's 1996 peak load	Credited at retail rate to customer's next bill; purchased by utility at 50% retail rate at end of 12-month billing cycle	Yes	Grays Harbor PUD
Wisconsin	20 kW[4] / Commercial, Industrial, Residential	Solar, Wind, Biomass, Hydro, Geothermal, Municipal Solid Waste, CHP	None	Purchased by utility at retail rate (renewables) or avoided-cost rate (non-renewables)	Yes	Investor-owned utilities
Wyoming	25 kW / Commercial, Industrial, Residential	Solar, Wind, Biomass, Hydro	None	Credited at retail rate to customer's next bill; purchased by utility at avoided-cost rate at end of 12-month billing cycle	Yes	All utilities

[4] In January 2006, the Wisconsin Public Service Commission approved a proposal by We Energies (an investor-owned utility) to offer net metering to customers with wind turbines greater than 20 kW but no greater than 100 kW in capacity. This offer is available to the first 25 eligible applicants,

Sources: The Interstate Renewable Energy Council (IREC) and the N.C. Solar Center (NCSC). "Connecting to the Grid" Project web site, www.irecusa.org/connect; Database of State Incentives for Renewable Energy (DSIRE), www.dsireusa.org. Additional information, including statutory and regulatory source citations, is available on the projects' web sites.

WSJ.com THE WALL STREET JOURNAL. ONLINE

EXHIBIT
MAYES-1
admitted

COMPANY RESEARCH

STOCK CHARTING

Pinnacle West Capital Corp. (PNW)

Standard Charting | Dynamic Charting

Store Your Settings
Reset All Controls

Custom time frame: Click and drag mouse on chart to select custom time frame. Reset time frame

Trendlines:
Draw trendlines Clear

Time:	Upper Chart Controls	Lower Chart Controls
2 Years	None	Volume+
Daily	None	MACD
		DMI

Compare:	Moving Average:	Price Display:
refresh	None	OHLC
S&P 500	# of Days: refresh	Linear / Logarithmic

Chart 1: Historical Chart of PNW 10/11/04 to 10/11/06

Date: 10/10/06 Open: 45.85 High: 46.01 Low: 45.68 Close: 45.99

PNW SP500

Chart 2: Volume+ Close Up Close Down SMA (50) Volume 242,400

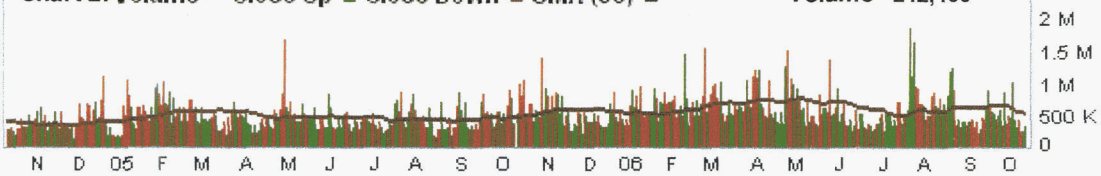
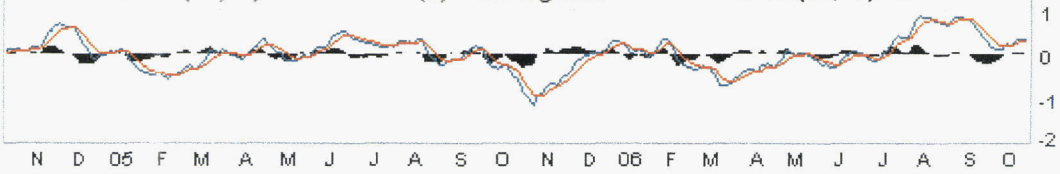


Chart 3: MACD(12,26) MACD EMA(9) Divergence MACD(12,26) .37



COMPANY RESEARCH

STOCK CHARTING

Pinnacle West Capital Corp. (PNW)

Standard Charting | Dynamic Charting

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Reset All Controls

Custom time frame: Click and drag mouse on chart to select custom time frame. Reset time frame

Trendlines:
Draw trendlines Clear

Time:	Upper Chart Controls	Lower Chart Controls
1 Year	None	Volume+
Daily	None	MACD
		DMI

Compare:	Moving Average:	Price Display:
refresh	None	OHLC
Utilities	# of Days: refresh	Linear / Logarithmic

Chart 1: Historical Chart of PNW 12/05/05 to 12/05/06

Date: 12/05/06 Open: 49.87 High: 50.12 Low: 49.65 Close: 50.03

PNW DJUA

Chart 2: Volume+ Close Up Close Down SMA (50) Volume 114,500

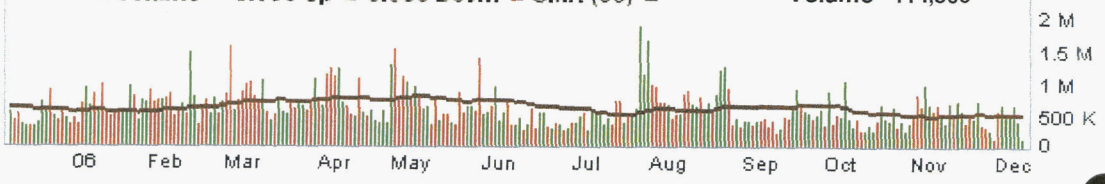
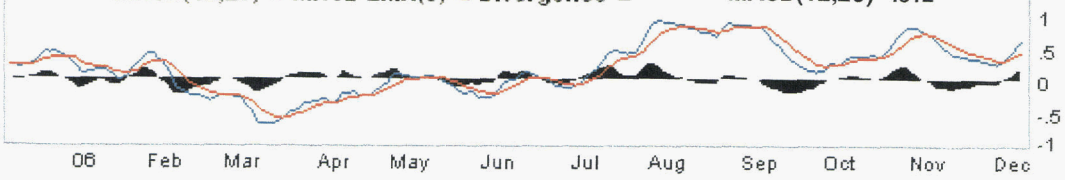
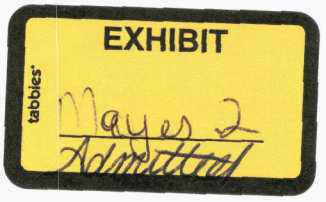
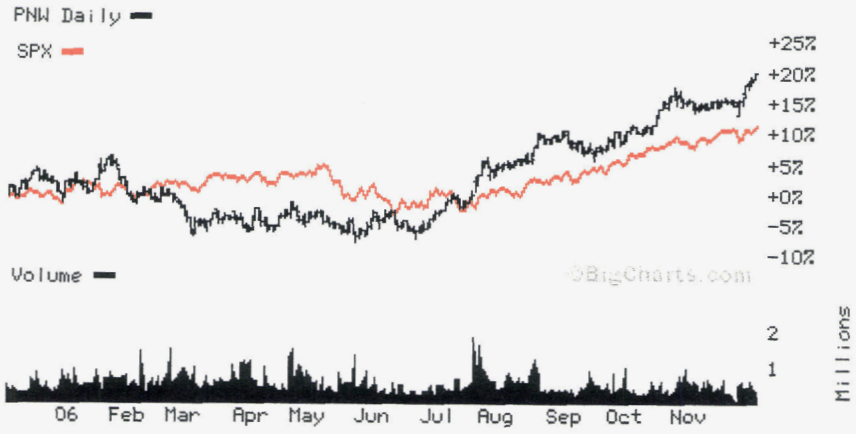


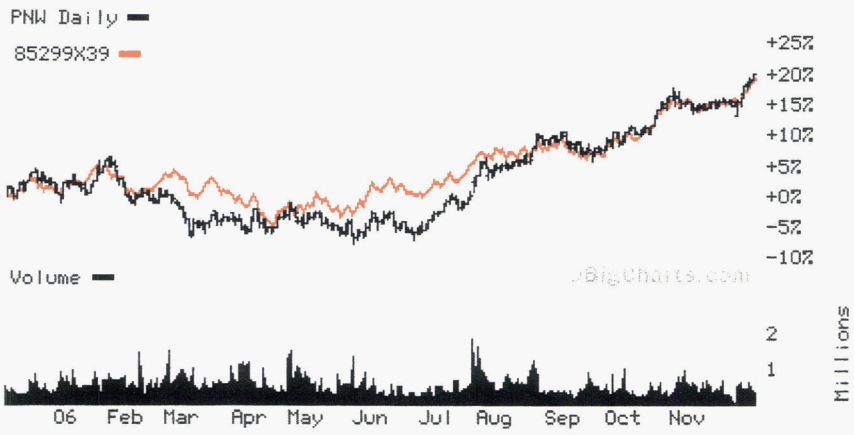
Chart 3: MACD(12,26) MACD EMA(9) Divergence MACD(12,26) .612





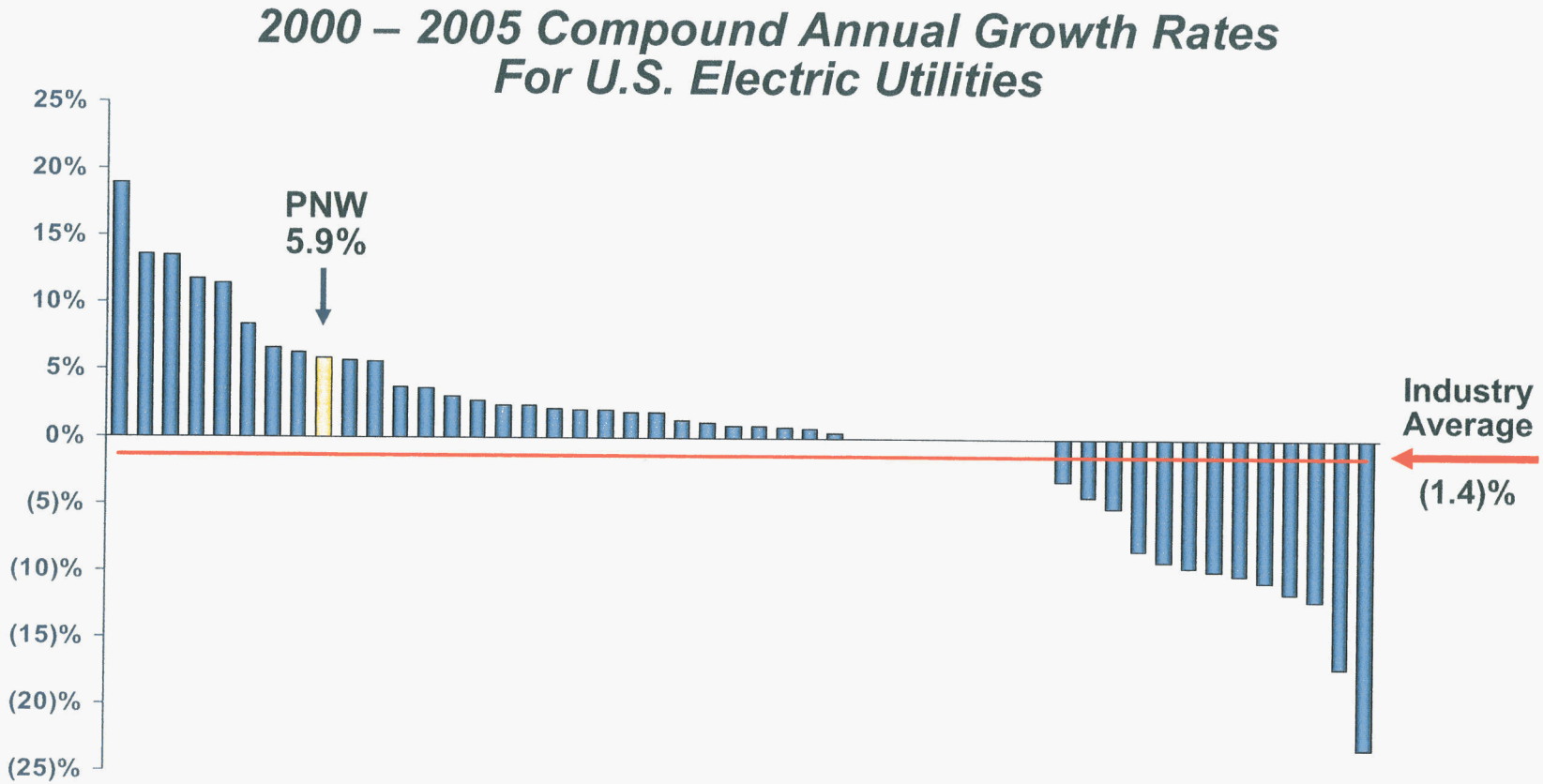


PNW
S&P 500
1-year



PNW
S&P Electric Utilities
1-year

Top Quartile Five-Year Dividend Growth



EXHIBIT
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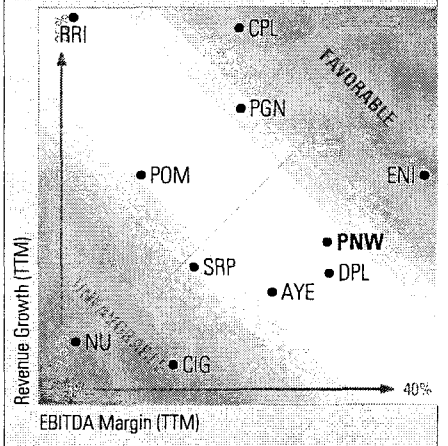
PINNACLE WEST CAPITAL CORP

Sector: Utilities | Sub-Industry: Electric Utilities | Source: GICS

Annual Dividend Rate	Annual Dividend Yield	Beta	Market Capitalization	52-Week Range	Price as of 10/4/2006
$2.00	**4.32%**	**0.81**	**$4.6 Billion**	**$38.31-$46.22**	**$46.22**

PEER GROUP ANALYSIS

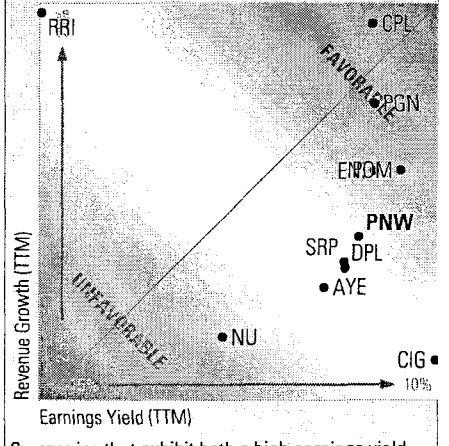
REVENUE GROWTH AND EBITDA MARGIN*



Companies with higher EBITDA margins and revenue growth rates are outperforming companies with lower EBITDA margins and revenue growth rates. Companies for this scatter plot have a market capitalization between $3.1 Billion and $11.7 Billion. Companies with NA or NM values do not appear.

*EBITDA – Earnings Before Interest, Taxes, Depreciation and Amortization.

REVENUE GROWTH AND EARNINGS YIELD



Companies that exhibit both a high earnings yield and high revenue growth are generally more attractive than companies with low revenue growth and low earnings yield. Companies for this scatter plot have revenue growth rates between 4.8% and 24.5%. Companies with NA or NM values do not appear.

INDUSTRY ANALYSIS

Stocks in the Electric industry have been under pressure as concerns of rising inflation have come into the picture. With rising inflation, it is likely that the Federal Reserve will continue to raise interest rates.

Increases in energy and purchased power costs are putting a squeeze on margins within this industry. Plus, many companies are increasingly impacted by employee benefit programs and other costs associated with the future delivery of power.

At the same time, as the economy regains its footing, there is increased demand for power. Another concern during the summer months is that it is typically the high point in demand for the year. On top of that, if temperatures reach and hold at or above historic temperatures, there is a high probability that the transmission grid will be strained.

A large drain for electric power comes from natural-gas plants. This heightened demand coupled with challenges in isolating new pipelines has caused a supply and demand imbalance for fuel. The companies that utilize nuclear and coal as a lower priced generator will thrive in meeting the excess demand.

Companies such as Exelon (EXC) have benefited from their nuclear operations as nuclear fuel prices have been quite consistent. Their success has caused many of their competitors to enter into the nuclear side of the business as a means of generating energy.

Companies like Southern Company (SO) have benefited from using coal generation for power. This advantage may be closing as the cost for coal rises to meet strong worldwide demand and delivery complications. However, coal is still fairly priced in relation to natural gas.

Individuals considering purchasing stocks in the Electric industry should evaluate companies and isolate candidates that have sound financials and good dividend growth potential.

PEER GROUP: Electric Utilities

Ticker	Company Name	Recent Price ($)	Market Cap ($M)	Price/ Earnings	Net Sales TTM ($M)	Net Income TTM ($M)
PNW	**PINNACLE WEST CAPITAL COR**	**46.22**	**4,598**	**19.84**	**3,242.49**	**249.69**
ENI	ENERSIS SA	13.62	8,894	16.61	7,028.44	528.91
AYE	ALLEGHENY ENERGY INC	40.25	6,625	35.00	3,137.09	185.49
CPL	CPFL ENERGIA SA	39.02	6,240	16.97	4,625.58	347.42
POM	PEPCO HOLDINGS INC	24.65	4,701	13.04	8,417.10	361.60
RRI	RELIANT ENERGY INC	12.56	3,863	NM	10,790.87	-523.30
CIG	CIA ENERGETICA DE MINAS	39.95	3,644	10.17	4,945.38	640.28
NU	NORTHEAST UTILITIES	23.54	3,620	NM	7,450.62	-90.37
SRP	SIERRA PACIFIC RESOURCES	14.60	3,225	24.33	3,209.18	116.04
DPL	DPL INC	27.38	3,126	24.02	1,334.50	160.30
PGN	PROGRESS ENERGY INC	46.01	11,657	16.67	10,502.00	603.00

The peer group comparison is based on Major Electric Utilities companies of comparable size.

EXHIBIT
tabbies
Hutch-Miller-1
admitted

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MARSCO $3.95 ONLINE EQUITY TRADES

PNW **Pinnacle West Capital Corp.**

Industry: **Electric Utilities** Exchange: **NYSE**

46.27
▲ **0.16 (0.35%)**

Last Trade
4:02 PM EST
10/12/2006

DISCOVER BANK Earn higher interest with Discover Bank's CD and money market account LEARN MORE

View **Ratings** for:

You are viewing the charts on this page in the "Macromedia Flash" format.
Click here to display the charts on this page in the "Java Applet" format.

Recommendations show the number of Wall Street analysts rating the stock a 'buy', a 'hold', etc.

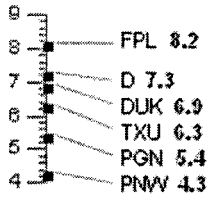
Net Change in Recommendation
From 4.29 to 4.29

Analyst Recommendations | Compare(New!)

Strong buy	
Moderate buy	
Hold	
Moderate sell	
Strong sell	1
Watch trend	○3 months ago ○2 months ago ○1 month ago ◉Current

Compare Recommendations

current



10=Strong Buy 0=Strong Sell

Earnings Estimate Trends | Compare(New!)

Quarter ending Sep 2006	$1.61
Quarter ending Dec 2006	$0.33
Fiscal Year ending Dec 2006	$3.08
Fiscal Year ending Dec 2007	$3.31
Long-Term Growth	6.75%

Watch trend
◉current
○7 days ago
○1 month ago
○2 months ago
○3 months ago

	Current	1 Mo. ago	2 Mo. ago	3 Mo. ago
Strong buy	0	0	0	0
Moderate buy	0	0	0	0
Hold	6	6	6	5
Moderate Sell	0	0	0	0
Strong Sell	1	1	1	1

	Current	7 Days ago	1 Mo. ago	2 Mo. ago	3 Mo. ago
Quarter ending **September 2006**	$ 1.61	$ 1.61	$ 1.61	$ 1.61	$ 1.55
Quarter ending **December 2006**	$ 0.33	$ 0.33	$ 0.33	$ 0.33	$ 0.44
Fiscal Year ending **December 2006**	$ 3.08	$ 3.08	$ 3.08	$ 3.07	$ 2.99
Fiscal Year ending **December 2007**	$ 3.31	$ 3.31	$ 3.31	$ 3.30	$ 3.30
Long-term growth	6.75%	6.75%	6.75%	6.75%	6.75%

Upgrades & Downgrades History

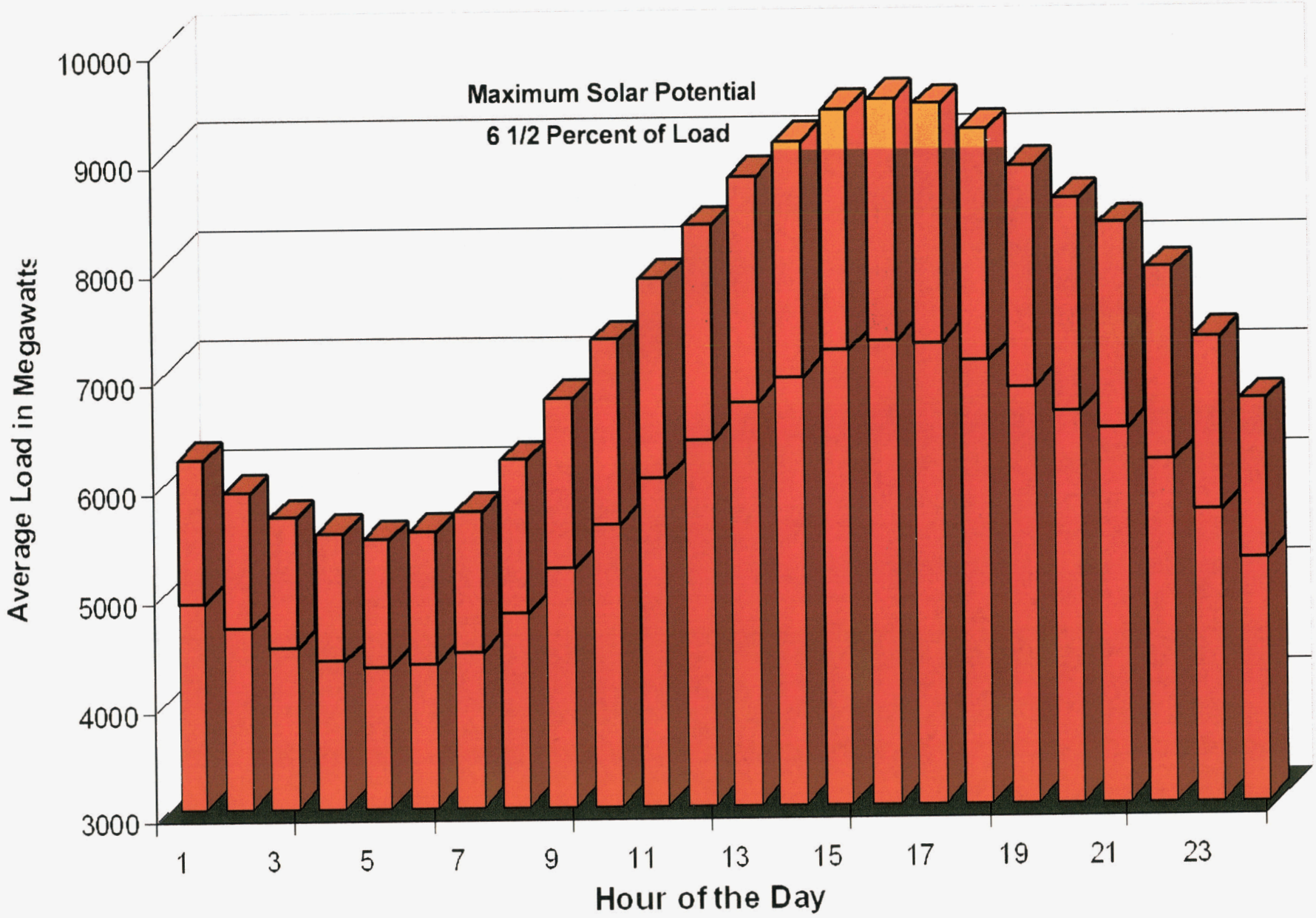
Date	Analyst	Action	From	To	Price Target

8/18/2006	Credit Suisse	Upgraded	Neutral	**Outperform**	48
6/21/2006	Deutsche Securities	Initiated		**Hold**	
9/19/2005	Morgan Stanley	Downgraded	Equal-weight	**Underweight**	
11/13/2003	Merrill Lynch	Upgrade	Neutral	**Buy**	41
4/14/2003	CSFB	Downgrade	Outperform	**Neutral**	35
3/19/2003	Salomon Smth Brny	Initiated		**In-line**	
1/24/2003	JP Morgan	Downgrade	Overweight	**Neutral**	
1/24/2003	Goldman Sachs	Downgrade	Outperform	**In-Line**	
1/21/2003	UBS Warburg	Initiated		**Neutral**	37
10/22/2002	Lehman Brothers	Upgrade	Underweight	**Equal-weight**	28

More Upgrades & Downgrades for PNW

EXHIBIT
Hatch-Miller 2
admitted

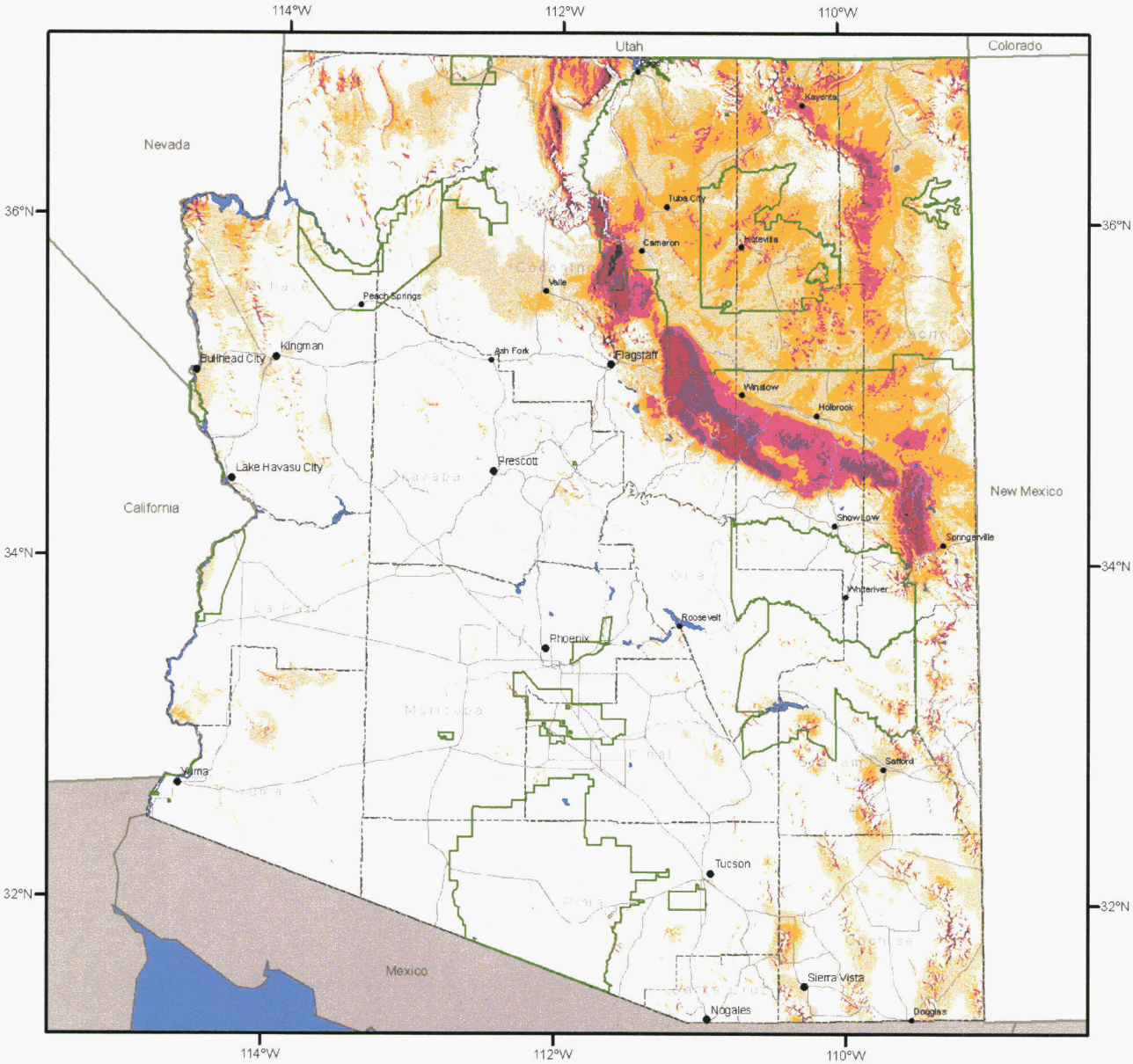
"Peak Week 2006" Power Requirements



admitted

EXHIBIT
HATCH 3
Miller

State of Arizona
April Wind Resource 164 ft (50m)



Created by: Grant Brummels
Date of Creation: 7/6/2005
For more information contact:
Dr. Earl Duque
Earl.Duque@nau.edu

Projection:
UTM, Zone 12, WGS84
Spatial Resolution of
Wind Resource Data: 200m

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ARIZONA
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Wind Power Classification

Wind Power Class	Wind Power Density (W/m^2)	Wind Speed (mph)
1 Poor	0 - 200	0.0 - 12.3
2 Marginal	200 - 300	12.3 - 14.1
3 Fair	300 - 400	14.1 - 15.7
4 Good	400 - 500	15.7 - 16.8
5 Excellent	500 - 600	16.8 - 17.9
6 Outstanding	600 - 800	17.9 - 19.7
7 Superb	> 800	> 19.7

Legend

- County Boundary
- Indian Reservation
- Rivers and Water Bodies
- Major Roads

N
W E
S

0 12.5 25 50 75 100
Miles

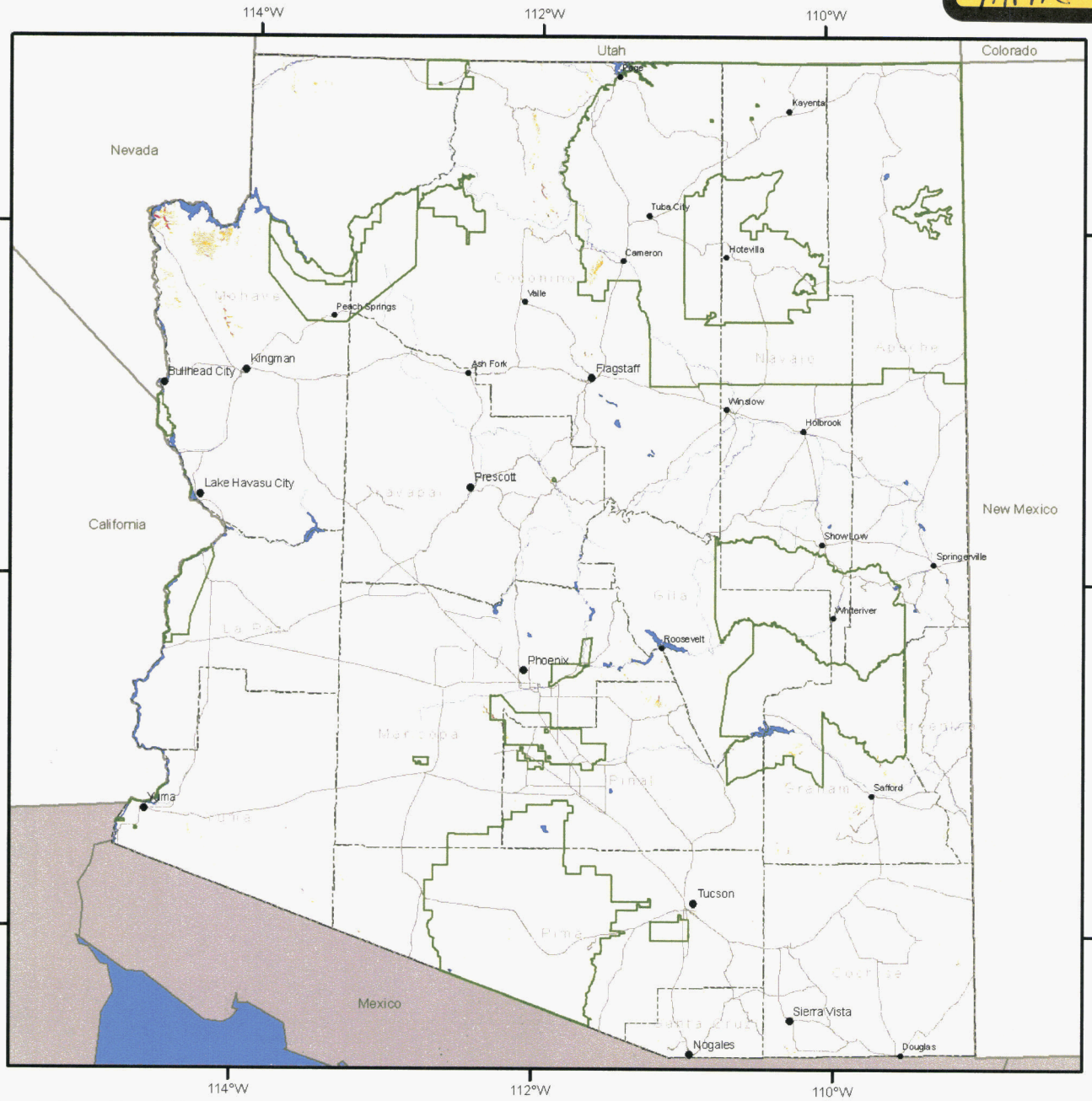
Admitted

EXHIBIT

Hatch-Miller 4

State of Arizona

August Wind Resource 164 ft (50m)



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Legend

- County Boundary
- Indian Reservation
- Rivers and Water Bodies
- Major Roads

N
W E
S

0 12.5 25 50 75 100
Miles

Admitted

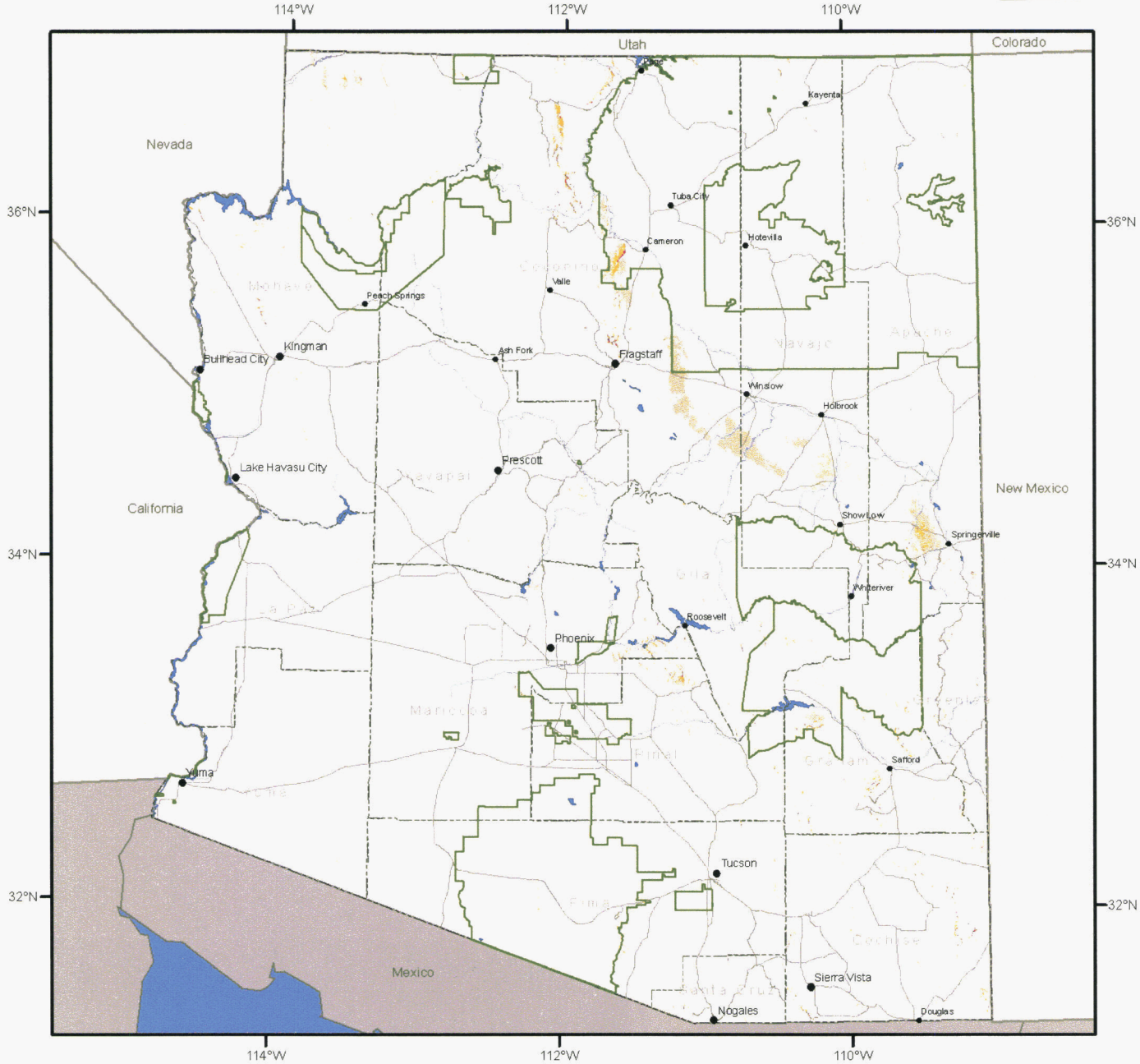
EXHIBIT

Hatch-5

Miller

State of Arizona

September Wind Resource 164 ft (50m)



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Projection:
UTM, Zone 12, WGS84
Spatial Resolution of
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Legend

- County Boundary
- Indian Reservation
- Rivers and Water Bodies
- Major Roads

N
W E
S

0 12.5 25 50 75 100
Miles

Custom Time Frame:
Click & Drag mouse on chart
to select custom time frame.

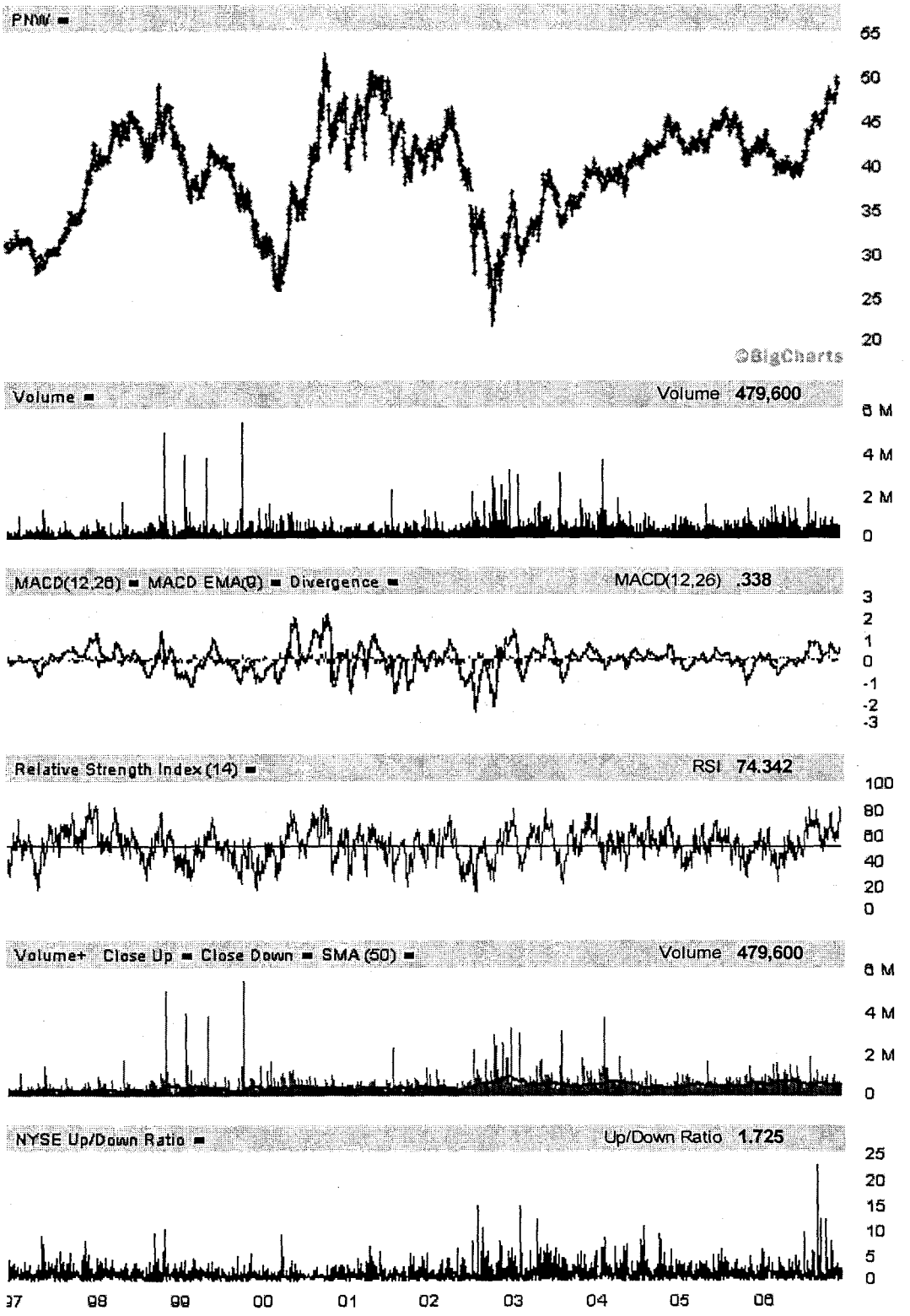
Reset Time Frame

Trendlines

Draw Trendlines

Clear

Date	Open	High	Low	Close
11/29/06	48.49	49.1	48.4	49.09



Timeframes & D

Time:
1 Decade

Frequency:
Daily

Price Display:
Linear Lo

Price Display:
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Chart Size:
Medium

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Upper Indicator

Lower Indicator

Company Event

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