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Transcript Exhibit(s)

Docket #(s): E-01345A-06-0009

Exhibit # : S-1, S-2, S-3, S-4, S-5, S-6, S-7, S-8, S-9, S-10

APS / Interim Rates E-01345A-06-0009
March 20 through 29, 2006
Volumes I through VIII

STAFF EXHIBITS

1 through 10

EXHIBIT
S-1
ADMITTED

BEFORE THE ARIZONA CORPORATION COMMISSION

JEFF HATCH-MILLER
Chairman
WILLIAM A. MUNDELL
Commissioner
MARC SPITZER
Commissioner
MIKE GLEASON
Commissioner
KRISTIN K. MAYES
Commissioner

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.	)))))	DOCKET NO. E-01345A-06-0009

DIRECT

TESTIMONY

OF

J. RANDALL WOOLRIDGE

ON BEHALF OF

THE ARIZONA CORPORATION COMMISSION,

UTILITIES DIVISION STAFF

FEBRUARY 28, 2006

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EXECUTIVE SUMMARY
ARIZONA PUBLIC SERVICE COMPANY
EMERGENCY INTERIM RATE INCREASE
DOCKET NO. E-01345A-06-0009

My testimony addresses the following issues:

(1) the impact of the recent bond rating downgrading on APS' financial condition, cost of capital, ability to raise capital, and the Company's customers;

(2) an assessment of whether the downgrade constitutes a financial "Emergency" in the sense that the Company's solvency is in question and/or the Company's ability to maintain service is in serious doubt, and

(3) an evaluation of the likelihood of additional downgrades of APS' debt both with and without the relief requested by APS, and

(4) the impact of such an additional downgrade, if it were to occur, on the Company's cost of capital, ability to raise capital, and the Company's customers.

There are three primary conclusions to my testimony:

(1) The evidence does not indicate that a "financial emergency" exists with respect to APS and the collection of deferred power supply costs. A review of the statements and overall assessments of rating agencies and investment firms do not support such a categorization. In this regard, APS has overstated its current financial condition with reference to the situation in its filing for emergency rate relief. Nonetheless, some improvement on the Company's ability to collect deferred power supply costs through rates would no doubt improve its financial condition.

(2) APS has used the financial ratios used by rating agencies 'as proof' that the Company's bonds may be downgraded to 'junk' status. In this regard, the Company has misconstrued how rating agencies interpret and use these ratios. In short, these ratios do not represent standards that must be met to achieve a particular bond rating.

(3) Based on an analysis of yield spreads, it appears that the S&P downgrading from BBB to BBB- has had a slight increase in the cost of capital for APS.

I. INTRODUCTION

Q. Please state your full name, address, and occupation.

A. My name is J. Randall Woolridge and my business address is 120 Haymaker Circle, State College, PA 16801. I am a Professor of Finance and the Goldman, Sachs & Co. and Frank P. Smeal Endowed University Fellow in Business Administration at the University Park Campus of the Pennsylvania State University. I am also the Director of the Smeal College Trading Room and the President of the Nittany Lion Fund, LLC. A summary of my educational background, research, and related business experience is provided in Attachment JRW-1.

II. DISCUSSION OF ISSUES

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

A. The purpose of my testimony is to examine a number of issues related to bond ratings of the Company. These issues include (1) the impact of the recent bond rating downgrading on APS' financial condition, cost of capital, ability to raise capital, and the Company's customers; (2) an assessment of whether the downgrade constitutes a financial "Emergency" in the sense that the Company's solvency is in question and/or the Company's ability to maintain service is in serious doubt, and (3) an evaluation of the likelihood of additional downgrades of APS' debt both with and without the relief requested by APS, and (4) the impact of such an additional downgrade, if it were to occur, on the Company's cost of capital, ability to raise capital, and the Company's customers.

Q. Mr. Brandt emphasizes the impact of the recent bond downgrade and the prospect for a further downgrade to 'junk' status.' please discuss the company's bond rating.

A. The Company's current bond ratings are:[1]

[1] See APS response to STF 4.19.

S&P	Moody's	Fitch
BBB-	Baa1	BBB

As shown, the only rating agency that has the Company rated one notch above a 'junk' rating is S&P. Nonetheless, the recent trends in APS' bond ratings have been in a negative direction, and the primary reason given for this negative direction of the ratings is the issue involving the collection of deferred power supply charges.

It is important to recognize that these bond ratings are for the Company's unsecured debt. The table below shows the bond ratings for the Company's mortgage bonds, as taken from Bloomberg. As shown, APS' secured debt is rated BBB by Standard and Poor's.

Arizona Public Services
Outstanding Bonds

Corporate Securities — Page 1/1

PNW (9 Found) Cpn Typ All Mty Typ All Exclude Matured/called/MTN

Issuer	Coupon	Maturity	Series	Rtg	Mty Type	Announce	Curr	Ask Px	PCS
1)PINNACLE WST CAP	6.400	04/01/06		BBB-	CALLABLE	03/21/01	USD	100.0000	TRAC
2)ARIZONA PUB SERV	6.750	11/15/06		BBB	CALLABLE	11/19/96	USD	100.9700	TRAC
3)ARIZONA PUB SERV	6.375	10/15/11		BBB	CALLABLE	10/02/01	USD	103.9640	TRAC
4)ARIZONA PUB SERV	6.500	03/01/12		BBB	CALLABLE	02/26/02	USD	103.2210	TRAC
5)ARIZONA PUB SERV	5.800	06/30/14		BBB	CALLABLE	06/24/04	USD	100.9140	TRAC
6)ARIZONA PUB SERV	4.650	05/15/15		BBB	BULLET	05/07/03	USD	93.5180	TRAC
7)PVNGS II FUNDING	8.000	12/30/15		BBB	SINKABLE	03/10/93	USD	110.8181	BFV
8)ARIZONA PUB SERV	5.625	05/15/33		BBB	BULLET	05/07/03	USD	93.4680	TRAC
9)ARIZONA PUB SERV	5.500	09/01/35		BBB	CALLABLE	08/17/05	USD	91.6140	TRAC

Data Source: Bloomberg, February 23, 2006

Q. In your opinion, what is the impact of the recent bond rating downgrade on the Company's financial condition?

A. The downgrading of the Company's bonds certainly is not a positive for the Company. Nonetheless, recent reports from rating agencies and investment firms suggest that recent actions of the Arizona Corporation Commission ("ACC") appear to have stabilized the situation. Specifically, rating agencies and investment firms reacted positively to the January 25th ACC decision to lift the cap on deferred fuel acquisition costs as well as to advance the collection of deferred costs (under the terms of the power supply adjuster ("PSA")). According to a February 2, 2006, report on APS' parent, Pinnacle West Capital Corporation ("PNW"), APS' PSA should provide at least $110M in cash recovery in 2006 of previously incurred fuel costs. In assessing the January 25th decision by ACC, Citigroup indicated that the regulatory risk profile of the Company 'modestly improved.' Likewise, in response to the decision, Standard and Poor's affirmed APS' corporate credit rating of BBB- and termed the decisions 'generally constructive.'

Q. In your opinion does the downgrading of the bonds and the Company's current financial condition constitute an 'emergency' situation?

A. No. Mr. Donald Brandt, the Company's Chief Financial Officer, indicates in his testimony that the current situation facing the Company regarding fuel and purchased power costs constitutes a financial 'emergency.' Based on my review of reports by rating agencies and investment firms, I believe that this overstates the Company's current financial situation.

To illustrate this point, the most recent *Value Line Investment Survey* for PNW, dated February 10, 2006, is attached as Exhibit (JRW-2). In the discussion section of the report, it is noted that PNW has filed for a general rate increase of $409M for 2007. In addition to a summary of the components of the rate request, the report notes the ACC decision of January 25, 2006 to lift the cap on deferred fuel acquisition costs and to advance the collection of deferred costs. There is no mention of, or any indication of, a 'financial emergency' or a 'liquidity crisis.' In fact, Value Line gives PNW its highest 'Safety Rating' – 1 out of 5 – and ranks its 'Financial Strength' an 'A'. Furthermore, with reference to the investment prospects of PNW's stock, *Value Line* makes the following observation: "Those of a conservative bent might also note PNW's strong finances."

A similar observation is made by Standard & Poor's in a stock report on PNW dated February 18, 2006. S&P gives PNW's stock three stars (***), which rates it a 'hold.' More importantly, in S&P's assessment of PNW's peer group of midsized electric utilities, PNW's 'Quality Rating' of 'A-' is the highest of the peer group.[2]

Q. Staff Witness Smith believes that APS has over-stated the direness of its financial situation. Do you agree?

A. Yes. As noted by Mr. Smith, APS has claimed that it is in a "financial crisis" due to the "escalating PSA balances"[3] and "is facing an operational cash flow emergency."[4] These statements are not consistent with the views of rating agencies, investment firms, or APS. The rating agencies have consistently noted that the Company's liquidity position – as indicated by its cash on hand and lines of credit, are 'adequate.' The opinions of investment firms are similar. For example, a Citigroup report on PNW made the following observation:[5]

"We believe that for the near-term undercoveries are manageable through adjustor/surcharge recoveries, cash on hand, and pending equity infusion of over $200M of Silverhawk asset sale proceeds, which closed 1/10/06."

[2] Standard & Poor's Stock Report, Pinnacle West Capital, February 18, 2006. The other electric utilities in the S&P peer group are Duquense Light, Great Plains Energy, Hawaiian Electric Holdings, Pepco Holdings, UIL Holdings, and Westar Energy.
[3] See, e.g., APS Application, page 2, footnote 4.
[4] See, APS application at page 18.
[5] Citigroup, Pinnacle West Capital Corporation, February 2, 2006, p. 3.

Even APS appears not to believe that the 'financial crisis' story that it once proclaimed. In response to Commissioner Mayes, the Company's President Mr. Davis makes the following comment:

> And the credit rating agencies have not expressed concern over APS' current liquidity situation. As a matter of fact, APS currently has cash on hand of about $80 million. But again, current liquidity is not the issue at hand.

Q. APS points to the financial ratios used by rating agencies as evidence that a financial emergency exists. Please respond.

A. Mr. Brandt not only suggests that the Company's situation constitutes a financial emergency, he also indicates that if the Commission does not provide the emergency rate relief proposed by the Company that APS' credit ratings would likely be downgraded by rating agencies to below investment grade even with the approval of the PSA surcharge and the implementation of the annual PSA adjustment. He supports his argument by reference to the financial ratios used by the rating agencies. Likewise, in response to Commissioner Mayes, APS President Mr. Davis references the financial ratios to support the case for emergency relief:

> The continuing imbalance between fuel costs and cost recovery has weakened the Company's key credit strength indicator (the ratio of Funds from Operations to Debt, known as FFO Debt) to the point where APS has been downgraded by one major rating agency (S&P) to the lowest investment-grade rating and put on negative watch for a downgrade by the other two (Moody's and Fitch).

Q. Given these arguments by APS, please discuss the role of financial ratios in the ratings process.

A. The rating agencies consider many factors in their ratings process. These factors include many business risk indicators such as the economic conditions of the service territory, competitive environment, regulatory climate, customers, and exposure to unregulated businesses. Ratio analysis is also part of the credit risk analysis performed by rating agencies. Rating agencies do publish guidelines for key financial ratios. Standard and Poor's lists guidelines for three ratios: Funds from Operations/Interest ("FFO/INT"), Funds from Operations/Total Debt ("FFO/TD"), and Total Debt/Total Capital ("TD/TC").

Initially, it is important to highlight the fact that the ratios published by rating agencies for different bond ratings are not strict standards which must be met to achieve a particular bond rating. For example, with reference to the three ratios listed above, S&P states:[6]

> It is important to emphasize that these metrics are only guidelines associated with expectations for various rating levels. Although credit ratio analysis is an important part of the rating process, these three statistics are by no means the only critical financial measures that Standard & Poor's uses in its analytical process. We also analyze a wide array of financial ratios that do not have published guidelines for each rating category.

And S&P goes on to further emphasize this point:

> Again, ratings analysis is not driven solely by these financial ratios, nor has it ever been. In fact, the new financial guidelines that Standard & Poor's is incorporating for the specified rating categories reinforce the analytical framework whereby other factors can outweigh the achievement of otherwise acceptable financial ratios. These factors include:
>
> Effectiveness of liability and liquidity management;
> Analysis of internal funding sources;
> Return on invested capital;
> The record of execution of stated business strategies;
> Accuracy of projected performance versus actual results, as well as the trend;
> Assessment of management's financial policies and attitude toward credit; and

[6] Standard & Poor's, "New Business Profile Scores Assigned for U.S. Utility and Power Companies: Financial Guidelines revised," June 2, 2004, p. 3.

> Corporate governance practices."

Furthermore, S&P has warned against using ratios to conclude appropriate bond ratings:[7]

> The key ratio medians for U.S. corporations by rating category and their definitions are displayed below. The ratio medians are purely statistical, and are not intended as a guide to achieving a given rating level. They are not hurdles or prerequisites that should be achieved to attain a specific debt rating.

Moody's appears to be even more qualitative in their rating approach. Moody's explains their approach in the following fashion:[8]

> Because it involves a look into the future, credit rating is by nature subjective. Moreover, because long-term credit judgments involve so many factors unique to particular industries, issuers, and countries, we believe that any attempt to reduce credit rating to a formulaic methodology would be misleading and would lead to serious mistakes.
>
> That is why Moody's uses a multidisciplinary or "universal" approach to risk analysis, which aims to bring an understanding of *all* relevant risk factors and viewpoints to every rating analysis. We then rely on the judgment of a diverse group of credit risk professionals to weigh those factors in light of a variety of plausible scenarios for the issuer and thus come to a conclusion on what the rating should be.

Q. What other observations do you have on the use of financial ratios in credit analysis?

A. Not only are the ratios not strict standards to meet different rating categories, these guidelines have broad ranges. The table below shows the ranges for the three ratios for a BBB rating and a business profile of 6.[9]

---

7 Standard & Poor's, " Corporate Ratings Criteria," June 9, 2005, p. 42.

8 http://www.moodys.com/moodys/cust/AboutMoodys/AboutMoodys.aspx?%20topic=rapproach

9 Standard & Poor's, "New Business Profile Scores Assigned for U.S. Utility and Power Companies: Financial Guidelines Revised," June 2, 2004.

S&P Ratio Ranges
BBB Rating – Business Profile of 6

Ratio	High	Low
FFO/INT	4.2	3.0
FFO/TD	28%	15%
TD/TC	48%	58%

Furthermore, Moody's financial ratio guidelines for Baa rated utilities are even broader than those published by S&P, as shown below: profile of 3.[10]

Moody's Ratio Ranges
Baa Rating – Low Business Risk

Ratio	High	Low
FFO/INT	4.0	2.0
FFO/TD	13%	5%
TD/TC	75%	60%

Q. Given this discussion, what are APS' FFO/INT, FFO/TD, and TD/TC ratios?

A. Whereas Mr. Brandt and Mr. Davis emphasize the FFO/TD ratio, S&P does publish guidelines on all three ratios discussed above. For APS, these ratios as of 2005 are:[11]

Arizona Public Service
2005

Ratio	2005
FFO/INT	3.3
FFO/TD	14.8%
TD/TC	50.1%

As shown, the only ratio that violates S&P's guidelines for the BBB rating is FFO/TD. The other ratios fall within the range specified by S&P for a BBB rating.

[10] Moody's Rating Methodology: Global Regulated Electric Utilities, March 2005, page 9.
[11] As computed by APS in Attachment APS07015. Calculation presumes present rates PSA deferrals, but no PSA increase.

Q. Do you believe that the bond downgrading has restricted the Company's access to capital?

A. No. And the Company has presented no evidence that the downgrading has restricted the Company's access to capital.

Q. If the Company were to be downgraded to 'junk' status, do you believe that such an event would restrict the Company's access to capital?

A. Yes, I do believe that such an event would restrict the Company's access to capital.

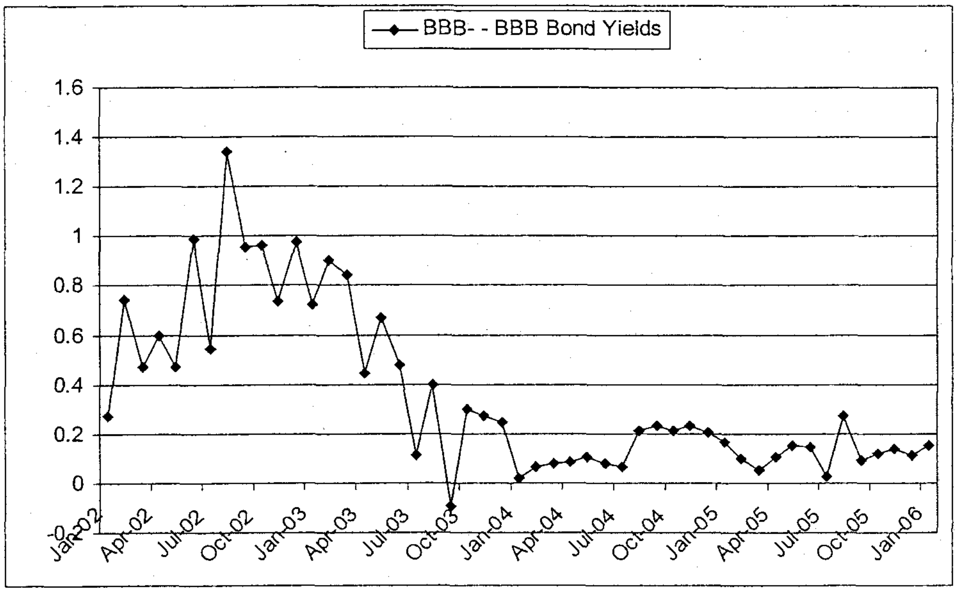
Q. Has the Company presented any evidence that its bonds are about to be downgraded to 'junk' status?

A. No, and as discussed by Staff witness Smith, the rating status of the bonds by S&P, the only agency that has the Company's bond rating one notch above 'junk' status, is stable.

Q. Finally, please comment on the impact of the S&P downgrading on the Company's cost of capital.

A. The downgrading of the Company's bonds to BBB- by S&P has had a slight increase in the Company's overall cost of capital. The graph below shows the yield differential between long-term public utility bonds rated 'BBB' and 'BBB-.' The graph shows that as of January, 2006, was 15 basis points.

Yield Differential
Long-Term Public Utility Bonds
BBB- - BBB Yields



Data Source: Bloomberg

III. SUMMARY OF FINDINGS AND RECOMMENDATIONS

Q. Please summarize your findings and recommendations.

A. There are three primary conclusions to my testimony:

(1) The evidence does not indicate that a "financial emergency" exists with respect to APS and the collection of deferred power supply costs. A review of the statements and overall assessments of rating agencies and investment firms do not support such a categorization. In this regard, APS has overstated its current financial condition with reference to the situation in its filing for emergency rate relief. Nonetheless, some improvement on the Company's ability to collect deferred power supply costs through rates would no doubt improve its financial condition.

(2) APS has used the financial ratios used by rating agencies 'as proof' that the Company's bonds may be downgraded to 'junk' status. In this regard, the Company has misconstrued

how rating agencies interpret and use these ratios. In short, these ratios do not represent standards that must be met to achieve a particular bond rating.

(3) Based on an analysis of yield spreads, it appears that the S&P downgrading from BBB to BBB- has had a slight increase in the cost of capital for APS.

Q. Does this conclude your testimony?

A. Yes it does.

APPENDIX A

EDUCATIONAL BACKGROUND, RESEARCH, AND RELATED BUSINESS EXPERIENCE J. RANDALL WOOLRIDGE

J. Randall Woolridge is a Professor of Finance and the Goldman, Sachs & Co. and Frank P. Smeal Endowed Faculty Fellow in Business Administration in the College of Business Administration of the Pennsylvania State University in University Park, PA. In addition, Professor Woolridge is Director of the Smeal College Trading Room and President and CEO of the Nittany Lion Fund, LLC. He is also a Vice President of the Columbia Group, a public utility consulting firm based in Georgetown, CT, and serves on the Investment Committee of ARIS Corporation, an asset management firm based in State College, PA.

Professor Woolridge received a Bachelor of Arts degree in Economics from the University of North Carolina, a Master of Business Administration degree from the Pennsylvania State University, and a Doctor of Philosophy degree in Business Administration (major area-finance, minor area-statistics) from the University of Iowa. At Iowa he received a Graduate Fellowship and was awarded membership in Beta Gamma Sigma, a national business honorary society. He has taught Finance courses at the University of Iowa, Cornell College, and the University of Pittsburgh, as well as the Pennsylvania State University. These courses include corporation finance, commercial and investment banking, and investments at the undergraduate, graduate, and executive MBA levels.

Professor Woolridge's research has centered on the theoretical and empirical foundations of corporation finance and financial markets and institutions. He has published over 25 articles in the best academic and professional journals in the field, including the *Journal of Finance,* the *Journal of Financial Economics,* and the *Harvard Business Review.* His research has been cited extensively in the business press. His work has been featured in the *New York Times*, *Forbes, Fortune, The Economist*, *Financial World*, *Barron's*, *Wall Street Journal*, *Business Week*, *Washington Post*, *Investors' Business Daily*, *Worth Magazine*, *USA Today*, and other publications. In addition, Dr. Woolridge has appeared as a guest on CNN's *Money Line* and CNBC's *Morning Call* and *Business Today*.

The second edition of Professor Woolridge's popular stock valuation book, *The StreetSmart Guide to Valuing a Stock* (McGraw-Hill, 2003), was recently released. He has also co-authored *Spinoffs and Equity Carve-Outs: Achieving Faster Growth and Better Performance* (Financial Executives Research Foundation, 1999) as well as a new textbook entitled *Modern Corporate Finance, Capital Markets, and Valuation* (Kendall Hunt, 2003). Dr. Woolridge is a founder and a managing director of www.valuepro.net - a stock valuation website.

Professor Woolridge has also consulted with and prepared research reports for major corporations, financial institutions, and investment banking firms, and government agencies. In addition, he has directed and participated in over 500 university- and company- sponsored professional development programs for executives in 25 countries in North and South America, Europe, Asia, and Africa.

Dr. Woolridge has prepared testimony and/or provided consultation services in the following cases:

Pennsylvania: Dr. Woolridge has prepared testimony on behalf of the Pennsylvania Office of Consumer Advocate in the following cases before the Pennsylvania Public Utility Commission:
Bell Telephone Company (R-811819), Peoples Natural Gas Company (R-832315), Pennsylvania Power Company (R-832409), Western Pennsylvania Water Company (R-832381), Pennsylvania Power Company (R-842740), Pennsylvania Gas and Water Company (R-850178), Metropolitan Edison Company (R-860384), Pennsylvania Electric Company (R-860413), North Penn Gas Company (R-860535), Philadelphia Electric Company (R-870629), Western Pennsylvania Water Company (R-870825), York Water Company (R-870749), Pennsylvania-American Water Company (R-880916), Equitable Gas Company (R-880971), the Bloomsburg Water Co. (R-891494), Columbia Gas of Pennsylvania, Inc. (R-891468), Pennsylvania-American Water Company (R-90562), Breezewood Telephone Company (R-901666), York Water Company (R-901813), Columbia Gas of Pennsylvania, Inc. (R-901873), National Fuel Electric

utility Company (R-911912), Pennsylvania-American Water Company (R-911909), Borough of Media Water Fund (R-912150), UGI Utilities, Inc. - Electric Utility Division (R-922195), Dauphin Consolidated Water Supply Company - General Waterworks of Pennsylvania, Inc, (R-932604), National Fuel Electric utility Company (R-932548), Commonwealth Telephone Company (I-920020), Conestoga Telephone and Telegraph Company (I-920015), Peoples Natural Gas Company (R-932866), Blue Mountain Consolidated Water Company (R-932873), National Fuel Gas Company (R-942991), UGI - Gas Division (R-953297), UGI - Electric Division (R-953534), Pennsylvania-American Water Company (R-973944), Pennsylvania-American Water Company (R-994638), Philadelphia Suburban Water Company (R-994868;R-994877;R-994878; R-9948790), Philadelphia Suburban Water Company (R-994868), Wellsboro Electric Company (R-00016356), Philadelphia Suburban Water Company (R-00016750), National Fuel Electric utility Company (R-00038168), Pennsylvania-American Water Company (R-00038304), York Water Company (R-00049165), Valley Energy Company (R-00049345), Wellsboro Electric Company (R-00049313), and National Fuel Electric utility Corporation (R-00049656).

New Jersey: Dr. Woolridge prepared testimony for the New Jersey Department of the Public Advocate, Division of Rate Counsel: New Jersey-American Water Company (R-91081399J), New Jersey-American Water Company (R-92090908J), and Environmental Disposal Corp (R-94070319).

Hawaii: Dr. Woolridge prepared testimony for the Hawaii Office of the Consumer Advocate: East Honolulu Community Services, Inc. (Docket No. 7718).

Delaware: Dr. Woolridge prepared testimony for the Delaware Division of Public Advocate: Artesian Water Company (R-00-649).

Ohio: Dr. Woolridge prepared testimony for the Ohio Office of Consumers' Council: SBC Ohio (Case No. 02-1280-TP-UNC R-00-649).

New York: Dr. Woolridge prepared testimony for the County of Nassau in New York State: Long Island Lighting Company (PSC Case No. 942354).

Connecticut: Dr. Woolridge prepared testimony for the Office of Consumer Counsel in Connecticut: United Illuminating (Docket No. 96-03-29) and Yankee Gas Company (Docket No. 04-06-01).

Kentucky: Dr. Woolridge prepared testimony for the Office of Attorney General in Kentucky: Kentucky-American Water Company (Case No. 2004-00103).

Washington, D.C.: Dr. Woolridge prepared testimony for the Office of the People's Counsel in the District of Columbia: Potomac Electric Power Company (Formal Case No. 939).

Washington: Dr. Woolridge consulted with trial staff of the Washington Utilities and Transportation Commission on the following cases: Puget Energy Corp. (Docket Nos. UE-011570 and UG-011571); and Avista Corporation (Docket No. UE-011514).

Kansas: Dr. Woolridge prepared testimony on behalf of the Kansas Citizens' Utility Ratepayer Board Utilities in the following cases: Western Resources Inc. (Docket No. 01-WSRE-949-GIE) and UtiliCorp (Docket No. 02-UTCG701-CIG).

FERC: Dr. Woolridge has prepared testimony on behalf of the Pennsylvania Office of Consumer Advocate in the following cases before the Federal Energy Regulatory Commission: National Fuel Gas Supply Corporation (RP-92-73-000) and Columbia Gulf Transmission Company (RP97-52-000).

Vermont: Dr. Woolridge prepared testimony for the Department of Public Service in the Central Vermont Public Service Case (Docket No. 6988).

PINNACLE WEST NYSE-PNW

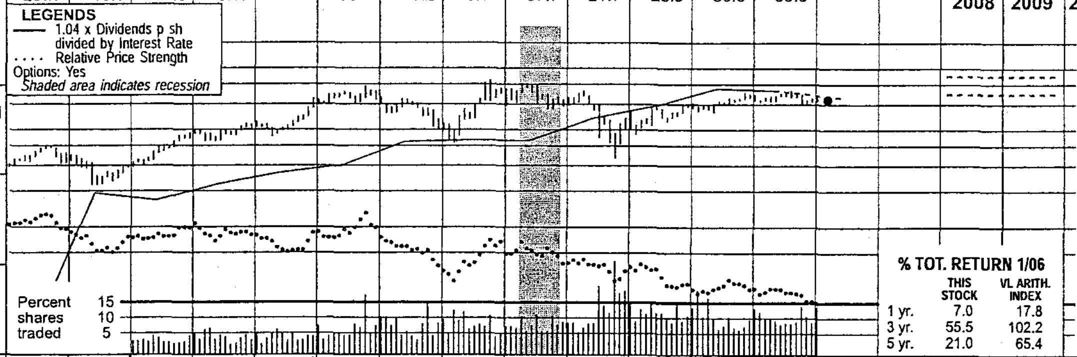
RECENT PRICE **42.33** | P/E RATIO **12.6** (Trailing: 12.9 / Median: 12.0) | RELATIVE P/E RATIO **0.65** | DIV'D YLD **4.8%** | **VALUE LINE**

TIMELINESS 3 Raised 8/5/05
SAFETY 1 Raised 5/16/03
TECHNICAL 4 Lowered 2/3/06
BETA .90 (1.00 = Market)

	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
High:	22.8	28.9	32.3	42.8	49.3	43.4	52.7	50.7	46.7	40.5	45.8	46.7	
Low:	16.0	19.6	26.3	27.6	39.4	30.2	25.7	37.7	21.7	28.3	36.3	39.8	

Target Price Range: 2008 | 2009 | 2010

LEGENDS
— 1.04 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



2008-10 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	55	(+30%)	10%
Low	45	(-5%)	6%

Insider Decisions

	M	A	M	J	J	A	S	O	N
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	1	8	0	0	0
to Sell	0	0	0	0	1	8	0	0	0

Institutional Decisions

	1Q2005	2Q2005	3Q2005
to Buy	129	162	147
to Sell	90	76	106
Hld's(000)	67222	71481	72697

% TOT. RETURN 1/06

	THIS STOCK	VL ARITH. INDEX
1 yr.	7.0	17.8
3 yr.	55.5	102.2
5 yr.	21.0	65.4

1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	© VALUE LINE PUB., INC.	08-10
17.39	18.38	16.95	19.39	19.66	19.28	19.08	20.77	23.52	25.12	28.57	43.50	53.66	28.90	30.87	31.59	30.15	32.50	Revenues per sh	36.00
3.45	3.27	d1.39	4.70	5.25	5.09	5.16	5.90	7.12	7.34	7.73	7.99	8.72	7.01	7.33	6.93	7.60	8.10	"Cash Flow" per sh	9.60
1.44	.81	d3.90	1.73	1.95	1.99	2.22	2.47	2.76	2.85	3.18	3.35	3.68	2.53	2.52	2.58	3.26	3.25	Earnings per sh A	3.55
.80	--	--	--	.20	.83	.93	1.03	1.13	1.23	1.33	1.43	1.53	1.63	1.73	1.83	1.93	2.03	Div'd Decl'd per sh B■†	2.33
3.46	2.98	2.10	2.57	2.69	2.92	3.38	2.95	3.63	3.76	4.05	7.76	12.27	9.81	7.60	5.86	9.35	8.90	Cap'l Spending per sh	8.05
16.31	17.40	15.23	17.00	18.87	20.32	21.49	22.51	23.90	25.50	26.00	28.09	29.46	29.44	31.00	32.14	33.65	34.90	Book Value per sh C	38.75
86.72	86.87	87.01	87.16	87.42	87.43	87.52	87.52	84.83	84.83	84.83	84.83	84.83	91.26	91.29	91.79	99.10	99.10	Common Shs Outst'g D	99.10
8.7	16.3	--	10.8	11.5	9.6	10.8	11.8	11.8	15.2	11.9	11.3	12.0	14.4	14.0	15.8	13.2		Avg Ann'l P/E Ratio	14.5
.66	1.21	--	.66	.68	.63	.72	.74	.68	.79	.68	.73	.61	.79	.80	.84	.70		Relative P/E Ratio	.95
6.4%	--	--	--	.9%	4.3%	3.9%	3.5%	3.5%	2.8%	3.5%	3.8%	3.5%	4.5%	4.9%	4.5%	4.5%		Avg Ann'l Div'd Yield	5.2%

CAPITAL STRUCTURE as of 9/30/05
Total Debt $2811.6 mill. **Due in 5 Yrs** $1439.4 mill.
LT Debt $2569.4 mill. **LT Interest** $153.0 mill.
(LT interest earned: 4.2x)

Pension Assets-12/04 $982.3 mill. **Oblig.** $1.45 bill.

Pfd Stock None

Common Stock 99,000,520 shs. as of 11/7/05
MARKET CAP: $4.1 billion (Mid Cap)

1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006		08-10
1669.8	1817.8	1995.0	2130.6	2423.4	3690.2	4551.4	2637.3	2817.9	2899.7	2988.0	3220	Revenues ($mill) F	3570
194.4	198.3	248.7	252.6	270.8	283.6	312.2	215.2	230.6	235.2	314.9	320	Net Profit ($mill)	350
39.7%	39.3%	37.7%	39.5%	38.3%	44.1%	40.6%	39.1%	31.4%	35.4%	35.0%	35.0%	Income Tax Rate	35.0%
7.2%	7.4%	6.5%	7.4%	4.3%	7.6%	15.3%	20.5%	6.2%	6.9%	2.0%	2.0%	AFUDC % to Net Profit	2.0%
53.9%	52.0%	50.5%	47.6%	50.0%	45.1%	51.7%	51.8%	50.6%	46.7%	44.0%	44.5%	Long-Term Debt Ratio	47.0%
40.4%	43.2%	45.6%	50.2%	50.0%	54.9%	48.3%	48.2%	49.4%	53.3%	56.0%	55.5%	Common Equity Ratio	53.0%
4660.4	4561.1	4442.9	4307.6	4411.8	4337.8	5172.4	5567.9	5727.5	5535.2	5935	6260	Total Capital ($mill)	7240
4647.1	4655.1	4677.6	4730.6	4778.5	5133.2	5907.3	6479.4	7480.1	7535.5	8025	8425	Net Plant ($mill)	9260
6.4%	6.2%	7.4%	7.6%	7.9%	8.1%	7.6%	5.4%	5.5%	5.6%	6.5%	6.5%	Return on Total Cap'l	6.5%
9.0%	9.1%	11.3%	11.2%	12.3%	11.9%	12.5%	8.0%	8.1%	8.0%	9.5%	9.5%	Return on Shr. Equity	9.0%
9.3%	9.2%	11.6%	11.2%	12.2%	11.9%	12.5%	8.0%	8.1%	8.0%	9.5%	9.5%	Return on Com Equity E	9.0%
5.0%	4.6%	6.9%	6.4%	7.1%	6.8%	7.3%	2.9%	2.6%	2.3%	4.0%	3.5%	Retained to Com Eq	3.0%
51%	54%	44%	45%	42%	43%	41%	64%	68%	71%	59%	62%	All Div'ds to Net Prof	66%

ELECTRIC OPERATING STATISTICS

	2002	2003	2004
% Change Retail Sales (KWH)	-.2	+5.1	+3.2
Avg. Indust. Use (MWH)	660	695	707
Avg. Indust. Revs. per KWH (¢)	5.57	5.62	5.57
Capacity at Peak (Mw)	6490	7935	7758
Peak Load, Summer (Mw)	5803	6332	6402
Annual Load Factor (%)	52.6	50.9	52.2
% Change Customers (yr-end)	+3.1	+3.3	+3.7
Fixed Charge Cov. (%)	274	250	261

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '02-'04 to '08-'10
Revenues	4.5%	3.5%	3.0%
"Cash Flow"	3.5%	-1.0%	5.0%
Earnings	3.0%	-3.0%	6.0%
Dividends	17.5%	7.0%	5.0%
Book Value	5.0%	4.0%	4.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2002	501.5	618.4	873.0	644.4	2637.3
2003	552.7	683.3	847.7	734.2	2817.9
2004	566.3	711.9	886.8	734.7	2899.7
2005	615.1	755.8	955.6	691.6	2988.0
2006	645	785	985	805	3220

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2002	.63	.89	1.19	d.18	2.53
2003	.22	.60	1.20	.50	2.52
2004	.34	.78	1.14	.32	2.58
2005	.27	.87	1.89	.23	3.26
2006	.35	.90	1.75	.25	3.25

Cal-endar	QUARTERLY DIVIDENDS PAID B■† Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2002	.40	.40	.40	.425	1.63
2003	.425	.425	.425	.45	1.73
2004	.45	.45	.45	.475	1.83
2005	.475	.475	.475	.50	1.93
2006					

BUSINESS: Pinnacle West Capital Corporation (parent of Arizona Public Service) supplies electricity to approx. 1,780,000 people in 11 of 15 Arizona counties. Electric revenue sources: residential, 50%; commercial, industrial, and other, 50%. Power costs: 38% of electric revenues; labor costs: 13% of total revenues. The mining industry is the largest industrial customer. Energy sources: coal, 21%; nuclear, 14%; gas & other, 8%; purch. power, 57%. Has 7,200 employees; 34,248 stockholders. Reported '04 depreciation rate: 3.4%. Est'd plant age: 8 years. Chairman & CEO: William J. Post. Pres.: Jack E. Davis. Inc.: Arizona. Address: 400 E. Van Buren St., Suite 700, P.O. Box 52132, Phoenix, AZ 85072-2132. Tel.: 602-379-2568. Internet: www.pinnaclewest.com.

Pinnacle West has filed its general rate case for 2007. It seeks an increase of $409 million, based on an 11.50% allowed return on common equity, up from the current 10.25%. About $247 million, or 60% of the total, is for recovery of the high cost of fuel and purchased power. The application also asks for a $42.5 million boost in the rate base for the May, 2005 purchase of the 450-megawatt gas-fired Sundance plant. Another $41.2 million is sought to defray rising pension expenses. Management plans to accelerate the funding of this underfunded account over five years. Lastly, the proposal calls for timely cost recovery of environmental upgrades through a $4.4 million surcharge to annual rates. A regulatory order on the petition is due by yearend. Separately, the commission modified the power supply adjustor that limited fuel cost recovery above an annual $776.2 million cap. This will allow recoupment of $112 million of deferred costs over the next 12 months.

The company has sold its Silverhawk gas-fired plant. This 75%-owned, 570-megawatt unit was Pinnacle's only merchant facility. Because of a difficult wholesale market, the plant was never profitable. Though the company provides no breakdown, we think the plant's operation resulted in a loss between $0.20 and $0.25 a share last year. As a result, the unit was sold in early 2006 to Nevada Power for $208 million. PNW booked a $55 million aftertax loss on the sale, which we've excluded from our estimates because of its nonrecurring nature.

We look for only flat earnings in 2006. Retail energy sales will probably rise by 4%-5% again this year. But the gain will be *offset by increased operating and* maintenance expense related to customer service and benefit costs. For now, we estimate 2006 earnings of $3.25 a share. If the regulators authorize a reasonable increase on the aforementioned rate request, earnings would move substantially higher in 2007.

Dividend growth prospects exceed those of the group. Projected earnings gains after 2006 and a low payout ratio point to above-average dividend growth to 2008-2010. Those of a conservative bent might also note PNW's strong finances.

Arthur H. Medalie *February 10, 2006*

(A) Diluted egs. Excl. nonrecur.: '91, ($4.68); '93, 22¢; '94, 31¢; '95, net 6¢; '99, ($1.20); '02, (77¢); excl. discont.: '89, ($7.80); '90, 31¢; '91, $1.76; '92, 7¢; '99, ($1.97); '00, 22¢; '05, (36¢). Next egs. rpt. due late Apr. (B) Div'ds historically paid in early Mar., early June, early Sept., and early Dec. ■ Reinvest. plan avail. † Shareholder investment plan avail. (C) Incl. def. chgs. In '04: $2.64/sh. (D) In mill. (E) Rate base: Fair value. Rate all'd on com. eq. in '05: 10.25%; earn. on avg. com. eq. in '04: 8.1%. Regul. Clim.: Avg.

Company's Financial Strength	A
Stock's Price Stability	80
Price Growth Persistence	55
Earnings Predictability	65

EXHIBIT

S-2

admitted

BEFORE THE ARIZONA CORPORATION COMMISSION

JEFF HATCH-MILLER
Chairman
WILLIAM A. MUNDELL
Commissioner
MARC SPITZER
Commissioner
MIKE GLEASON
Commissioner
KRISTIN K. MAYES
Commissioner

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.

DOCKET NO. E-01345A-06-0009

DIRECT

TESTIMONY

OF

RALPH C. SMITH

ON BEHALF OF

THE ARIZONA CORPORATION COMMISSION,

UTILITIES DIVISION STAFF

FEBRUARY 28, 2006

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ATTACHMENTS:

Attach-ment No.	Description	Number of Pages	APS Marked "Confidential"
RCS-1	Resume and Qualifications	8	No
RCS-2	STF 1-11, APS projection of native load fuel and purchased power costs for 2006	1	No
RCS-3	Standard & Poors report dated January 26, 2006, affirmed the corporate credit rating of APS and its parent, Pinnacle West Capital Corp.	2	No
RCS-4	Fitch Ratings January 30, 2006 report, which lowered PNW's long- and short-term ratings, and lowered APS's long-term ratings, while affirming its commercial paper rating.	2	No
RCS-5	Standard & Poors discussion of its outlook and expectations for APS's emergency interim filing in a report issued January 24, 2006	3	No
RCS-6	APS's response to STF 4-48, financial results assuming present rates, PSA deferrals, but no PSA increase	1	No
RCS-7	APS's response to STF 1-6 identifies approximately $1 million of increased cost associated with S&P's rating downgrade to BBB-	1	No
RCS-8	APS's response to STF 1-14 explained why APS believed it was experiencing an "emergency."	3	No
RCS-9	APS's response to STF 4.7 listing provisions in APS's indentures that address minimum financial ratios and default conditions.	1	No
RCS-10	APS's response to STF 4.8 listing provisions in APS's indentures and credit arrangements that address minimum financial ratios and default conditions.	1	No
	TOTAL	23	

I. INTRODUCTION

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

A. Ralph C. Smith. I am a Senior Regulatory Consultant at Larkin & Associates, PLLC, 15728 Farmington Road, Livonia, Michigan 48154.

Q. Please describe Larkin & Associates.

A. Larkin & Associates is a Certified Public Accounting and Regulatory Consulting firm. The firm performs independent regulatory consulting primarily for public service/utility commission staffs and consumer interest groups (public counsels, public advocates, consumer counsels, attorneys general, etc.). Larkin & Associates has extensive experience in the utility regulatory field as expert witnesses in over 400 regulatory proceedings including numerous telephone, water and sewer, gas, and electric matters.

Q. Mr. Smith, please summarize your educational background.

A. I received a Bachelor of Science degree in Business Administration (Accounting Major) with distinction from the University of Michigan - Dearborn, in April 1979. I passed all parts of the C.P.A. examination in my first sitting in 1979, received my CPA license in 1981, and received a certified financial planning certificate in 1983. I also have a Master of Science in Taxation from Walsh College, 1981, and a law degree (J.D.) cum laude from Wayne State University, 1986. In addition, I have attended a variety of continuing education courses in conjunction with maintaining my accountancy license. I am a licensed Certified Public Accountant and attorney in the State of Michigan. I am also a Certified Financial Planner™ professional and a Certified Rate of Return Analyst (CRRA). Since 1981, I have been a member of the Michigan Association of Certified Public Accountants. I am also a member of the Michigan Bar Association and the Society of Utility and Regulatory Financial Analysts (SURFA). I have also been a member of the

American Bar Association ("ABA"), and the ABA sections on Public Utility Law and Taxation.

Q. Please summarize your professional experience.

A. Subsequent to graduation from the University of Michigan, and after a short period of installing a computerized accounting system for a Southfield, Michigan realty management firm, I accepted a position as an auditor with the predecessor CPA firm to Larkin & Associates in July 1979. Before becoming involved in utility regulation where the majority of my time for the past 26 years has been spent, I performed audit, accounting, and tax work for a wide variety of businesses that were clients of the firm.

During my service in the regulatory section of our firm, I have been involved in rate cases and other regulatory matters concerning numerous electric, gas, telephone, water, and sewer utility companies. My present work consists primarily of analyzing rate case and regulatory filings of public utility companies before various regulatory commissions, and, where appropriate, preparing testimony and schedules relating to the issues for presentation before these regulatory agencies.

I have performed work in the field of utility regulation on behalf of industry, state attorney generals, consumer groups, municipalities, and public service commission staffs concerning regulatory matters before regulatory agencies in Alabama, Alaska, Arizona, Arkansas, California, Connecticut, Delaware, Florida, Georgia, Hawaii, Illinois, Kentucky, Louisiana, Maine, Michigan, Minnesota, Mississippi, Missouri, New Jersey, New Mexico, New York, Nevada, North Dakota, Ohio, Pennsylvania, South Carolina, South Dakota, Texas, Utah, Vermont, Washington, Washington D.C., and Canada as well as the Federal Energy Regulatory Commission and various state and federal courts of law.

Q. **Have you prepared an attachment summarizing your educational background and regulatory experience?**

A. Yes. Attachment RCS-1 provides details concerning my experience and qualifications.

Q. **Have you previously submitted testimony and/or testified before other state regulatory commissions on issues involving the review of electric utility fuel and purchased power?**

A. Yes. I have submitted testimony and/or testified in several proceedings involving the review of electric utility fuel and purchased power issues. Recent examples include the following:

Docket No.	Utility	Description	Client
05-806-EL-UNC	Cincinnati Gas & Electric Company	Financial and Management/Performance Audit of the Fuel and Purchased Power Rider	Energy Ventures Analysis, Inc./ Public Utility Commission of Ohio
21229-U	Savannah Electric & Power Company	FCR Fuel Case	Georgia Public Service Commission Staff
A.96-10-038	Pacific Enterprises and Enova Corporation d/b/a as Sempra Energy	Management Audit and Market Power Mitigation Analysis of the Merged Gas System of Pacific Enterprises and Enova Corporation	California Public Utilities Commission - Energy Division
19142-U	Georgia Power Company	FCR Fuel Case	Georgia Public Service Commission Staff
19042-U	Savannah Electric & Power Company	FCR Fuel Case	Georgia Public Service Commission Staff
ER 02060363	Rockland Electric Company	Audit of Deferred Balances, Phase I and II	New Jersey Board of Public

			Utilities
Non-Docketed	Georgia Power Company & Savannah Electric & Power Company	Fuel Procurement Review	Georgia Public Service Commission Staff
13711-U	Georgia Power Company	FCR Fuel Case	Georgia Public Service Commission Staff
13605-U	Savannah Electric & Power Company	FCR Fuel Case	Georgia Public Service Commission Staff
13196-U	Savannah Electric & Power Company	Natural Gas Procurement and Risk Management Hedging Proposal	Georgia Public Service Commission Staff
U-12604	Upper Peninsula Power Company	Power Supply Cost Recovery Plan	Michigan Attorney General
U-12613	Wisconsin Public Service Corporation	Power Supply Cost Recovery Plan	Michigan Attorney General

Q. On whose behalf are you appearing?

A. I am appearing on behalf of the Arizona Corporation Commission ("ACC" or "Commission") Utilities Division Staff ("Staff").

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

A. Yes. I have testified before the Commission previously on a number of occasions.

Q. What is the purpose of the testimony you are presenting?

A. The purpose of my testimony is to address the application for an emergency interim rate increase filed by Arizona Public Service Company ("APS" or "Company") for accelerated recovery of $299 million of estimated under-recovered fuel and purchased power costs.

Q. Have you prepared any exhibits to be filed with your testimony?

A. Yes. Attachments RCS-2 through RCS-10 contain copies of selected APS responses to discovery and other documents that are referenced in my testimony.

Q. Please briefly describe the information you reviewed in preparation for your testimony.

A. The information I reviewed included APS's application and testimony, APS's responses to data requests of Staff and other parties, information provided to me by Staff, and other publicly available information.

Q. Please provide some background for the request that APS has made in the current proceeding.

A. APS is an Arizona utility providing electricity to more than 1 million customers in 11 of Arizona's 15 counties. With its headquarters in Phoenix, APS is the largest subsidiary of Pinnacle West Capital Corporation ("PWC" or "PNW"[1]).

APS' current rates became effective April 1, 2005, pursuant to Decision No. 67744, dated April 2, 2005, which adopted a Settlement Agreement among Staff, the Company and numerous intervenors. The Agreement resulted in a total revenue requirement increase of $75.5 million or approximately 4.3 percent over test year revenues. The approved Settlement Agreement also implemented a Power Supply Adjustor ("PSA") which provides for the recovery of both fuel and purchased power costs through an adjustor and possible surcharge.

[1] PNW is the stock symbol for Pinnacle West Capital and rating agency and investment reports therefore use "PNW." In this testimony, both abbreviations, PWC and PNW, are used interchangeably.

On July 22, 2005, APS filed with the Commission an application for approval to institute a surcharge to recover $100 million in deferred fuel and purchased power costs. The request was subsequently reduced to $80 million. Hearings were held on the matter in October 2005. An Administrative Law Judge issued a Recommended Opinion and Order ("ROO") on January 4, 2006, which found the application for surcharge to be premature and, therefore, denied. The Commission's January 25, 2006, Decision No. 68437 reached the same conclusion, and ruled that APS's application for that surcharge was premature and therefore denied. However, that decision also accelerated the reset of the adjustor rate from April 1, 2006, to February 1, 2006.

On November 4, 2005, the Company filed a general rate application[2] with the Commission and proposes that the new rates become effective no later than December 31, 2006. The request was for a revenue increase of $409 million, a 20.0 percent increase over the revenues of the 2004 calendar year Test Year. The Company indicated that approximately $246 million of the proposed revenue increase was attributable to higher fuel and purchased power costs. On December 5, 2005, Staff filed a letter in the docket documenting an understanding between Staff and APS that APS would update financial schedules, testimony and other data in the November 4th filing and will complete the revisions by January 31, 2006.

On January 31, 2006, APS filed its update, using a test year ended September 30, 2005. As a result of the updated filing, APS is requesting a 21.3%, or $453.9 million, increase in its annual retail electricity revenues effective no later than December 31, 2006. The $453.9 million increase that APS has requested includes $299 million for increased fuel and purchased power cost.

[2] Docket No. E-01345A-05-0816.

On January 6, 2006, in the instant proceeding, Docket No. E-01345A-06-0009, APS filed the application at issue which is an application for an emergency rate increase of $299 million, or $14%, to be effective April 1, 2006 and subject to refund. As noted above, the $299 million is the amount of increased fuel and purchased power cost contained in the Company's January 31, 2006 updated rate case filing, Docket No. E-01345A-05-0816. The Company's Securities and Exchange Commission ("SEC") Form 8-K dated January 6, 2006 stated that:

> "**<u>The purpose of the emergency interim rate increase is solely to address APS' under-collection of higher annual fuel and purchased power costs</u>**. The increase would **<u>accelerate</u>** recovery of the fuel and purchased power component of APS' general rate case and is not an additional increase and would be subject to refund."

(Emphasis supplied.)

On January 25, 2006, the Commission issued Decision No. 68437 in Docket No. E-01345A-03-0437 et al, which I have already referred to on page 6. In that decision, the Commission approved a 4 mill increase in APS's PSA rate effective February 1, 2006 and has allowed APS to defer fuel and purchased power costs in excess of the $776.2 million annual power supply cost limit referenced in Decision No. 67744 until this issue has been further examined in the current docket.

On February 2, 2006, APS filed an application for two PSA surcharges totaling $59 million.[3]

II. DISCUSSION OF ISSUES

Q. What issues are addressed in your testimony?

A. My testimony addresses the following issues:

[3] Docket No. E-01345-06-0063.

- The $776.2 million cap on APS' recovery of fuel and purchased power expenses
- Whether APS is experiencing a financial "emergency"
- Whether the emergency rate relief requested by APS should be granted
- Whether any requirements should be placed on the Company as conditions for approval of all or part of its Emergency request.
- Whether it would be appropriate for APS to post a bond if the relief they are requesting is approved.
- The operation of the PSA as it relates to APS's request for an emergency rate increase

A. The $776.2 Million Cap

Q. Please discuss the $776.2 million cap and how it originated.

A. The $776.2 million cap originated in APS's last base rate case, Docket No. E-01345A-03-0437. The Settlement Agreement in that case provided that a Power Supply Adjustor ("PSA") be implemented and remain in effect for a minimum of five years, with reviews available during APS's next rate case or upon APS's filing its report on the PSA four years after rates are implemented in that case. The $776.2 million cap was not incorporated into the Settlement Agreement, but was added by the Commission to "help to lessen the detrimental impact to ratepayers of this change to an adjustor mechanism." In this regard, Decision No. 67744 (4/7/2005), at pages 17-18, states as follows:

> "Further, we will limit the amount of 'annual net fuel and purchased power costs' ... that can be used to calculate the annual PSA to no more than $776,200,000. Any fuel or purchased power costs above that level will not be recovered from ratepayers. We believe that this 'cap' on fuel and purchased power costs will further encourage APS to manage its costs, and will help to prevent large account balances from occurring in one year. Because the PSA actually adjusts for growth, putting a 'cap' on recovery of these costs will help insure that APS will file a rate case application when necessary. Since there is no moratorium on filing a rate case, APS can file a rate case to reset base rates if it deems it necessary because the cap is reached. Further, although the Settlement Agreement provides that the PSA will be in effect for 5 years, if APS files a rate case prior to the expiration of that 5 year term or if we find that APS has not complied with the terms of the PSA, we believe that the Commission should be able to eliminate the PSA if appropriate. Finally, we will not allow any fuel costs from 2005 that were incurred prior to the effective date of this Decision to be included in the calculation of the PSA

> implemented in 2006. We believe that these additional provisions to the PSA will help to lessen the detrimental impact to ratepayers of this change to any adjustor mechanism."

The operation of the cap subsequently received considerable attention from the Commission in Docket No. E-03145A-03-0437 et al where the Commission considered a Revised Plan of Administration that was filed pursuant to the Commission's Decision No. 67744.

Q. Did the $776.2 million cap affect APS's operations in 2005?

A. No. The $776.2 million cap did not affect APS's operations in 2005. In 2005, APS's fuel and purchased power costs were below the cap.

Q. Does the Company project that its fuel and purchased power expenses will exceed $776.2 million in 2006?

A. Yes. APS's projections, which were provided in the response to STF 1-11, indicate that the Company anticipates incurring $901.5 million in fuel and purchase power costs in 2006, before off-system margin.[4] Consequently, APS has projected that it will exceed the $776.2 million cap by the end of 2006.

Q. Does one of the Commission's recent orders impact how the $776.2 million cap will affect APS's operations in 2006?

A. Yes. The Commission's recent Decision No. 68437 (1/26/06) in Docket No. E-01345A-03-0437 et al, at page 26, ordered that APS:

> "may continue to defer fuel and purchased power costs in excess of the $776.2 million 'cap' referenced in Decision No. 67744 until this issue has been further examined in Docket No. E-01345A-06-0009."

[4] See Attachment RCS-2, which reproduces the non-confidential portion of APS's response to STF 1-11.

Q. How will the $776.2 million cap affect APS's operations in 2006?

A. The answer to this would appear to be dependent upon whether or not the cap is reinstated after further examination in the current docket. As long as APS is allowed to continue to defer fuel and purchased power costs above that "cap," there should be no impact on APS's operations in 2006.

Q. Was the "cap" intended to deny APS recovery of prudently incurred fuel and purchased power costs?

A. My understanding from reading various materials, including Decision No. 68437, is that the $776.2 million "cap" was not intended to deny APS recovery of prudently incurred fuel and purchased power costs.

Q. Did having the $776.2 million cap in place during 2005 achieve some of the desired objectives?

A. Yes, it did. One objective of instituting the cap was identified by the Commission in Decision No. 67744, at page 17, specifically: "putting a 'cap' on recovery of these costs will help insure that APS will file a rate case application when necessary." That page of the Decision also states: "APS can file a rate case to reset base rates if it deems it necessary because that cap is reached." APS forecasts that the cap will be exceeded in 2006 and has filed a rate case application, so that objective of having the cap has been fulfilled.

A second impact of the cap identified by the Commission at page 17 of that Decision was that having "this 'cap' on fuel and purchased power costs will further encourage APS to manage its costs." APS has taken at least some proactive steps to manage its exposure to upside price volatility in natural gas and purchased power costs, including implementing what appears to be a fairly aggressive hedging program.[5]

Q. Does the $776.2 million cap currently constitute a "financial emergency" for APS?

A. No, for two reasons: (1) APS has not yet incurred fuel and purchased power costs in excess of the cap, and (2) the Commission's January 25, 2006 Decision No. 68437 has allowed APS to defer fuel and purchased power costs in excess of the cap. Because APS has been allowed to defer fuel and purchased power costs in excess of the cap, as provided in that Decision, the $776.2 million cap does not constitute a "financial emergency" for APS.

Q. What have the credit rating agencies stated about the $776.2 million cap and the Commission's January 25, 2006 Decision No. 68437?

A. Standard & Poor's published a report dated January 26, 2006, that affirmed the corporate credit rating of APS and its parent, PWC. That report is provided for ease of reference in Attachment RCS-3 to my testimony. In that report, S&P stated that these ratings were affirmed and the outlook was stable:

> "...following the generally constructive decisions made by the Arizona Corporation Commission (ACC) on Jan. 25. The commission lifted a cap that limited APS' opportunity to recover fuel and purchase power costs and modestly advanced the collection of deferred costs that APS was incurring under the terms of its power supply adjuster (PSA). However, the ACC also restricted APS' ability to file for a surcharge, which raises certain credit concerns. The outlook is stable.
>
> "The ACC vote to remove the $776 million cap on annual fuel and purchase power costs is favorable because it allows APS to defer any costs

[5] See, e.g., Docket No. E-01345A-05-0816, Direct Testimony of Peter Ewen (1/31/06), page 5: "By the end of August 2005, the Company had hedged 85% of its 2006 gas and power requirements. The vast majority of these contracts are at prices significantly below recent market prices and, valued at November 30, 2005, will save the Company and its customers almost $2.50/MMBtu on the effective gas price incurred in 2006."

> that exceed this level, which is in fact expected to occur in late 2006. APS' current deferral level is about $170 million, which will likely increase by approximately $250 million this year. The ACC adopted an amendment to advance the commencement of recovery of these costs by two months to Feb. 1 from April 1. While the impact is small, providing APS only about $14 million of incremental recovery in 2006, the vote is an important indicator that the ACC acknowledges that timely action is necessary to limit cash flow pressure on the company."

Fitch Ratings, in a January 30, 2006 report, lowered PWC's long- and short-term ratings, and lowered APS's long-term ratings, while affirming its commercial paper rating.[6] Fitch removed the securities of PWC and APS from Rating Watch Negative, where they were placed January 6, 2006. Fitch indicates that its Rating Outlook for these is Stable. Concerning the Commission's January 25, 2006 Decision, the Fitch report stated that:

> "The ACC decision in the PSA proceedings, issued on Jan 25, 2006, has positive and negative implications for PNW and APS' creditworthiness. The commission's decision to accelerate the effective date of the PSA rate to Feb. 1 from April 1, along with the removal of the $776 million annual power supply cost limit, were constructive developments in Fitch's view."

Notably, the outlook for APS and its parent company, PNW, in both the S&P and Fitch credit agency reports is listed as "stable."

Q. What was APS's concern regarding the $776.2 million cap?

A. APS's primary concern regarding the cap was that, without an interim lifting of the cap, APS would be unable to defer some $65 million in estimated 2006 fuel costs, thus potentially affecting its ability to ever recover such sums. Page 18 of APS's application claims that:

[6] See Attachment RCS-4 for a copy of the Fitch report.

> "The lack of any reasonable prospect for resolution of Docket No. E-01345A-05-0816 prior to the Company reaching the $776.2 million 'cap' means the potential for tens of millions of prudently-incurred costs becoming unrecoverable by any means during the fourth quarter of this year. "

Q. Did the Commission's January 25, 2006 Decision address and alleviate that concern?

A. Yes. The Commission's January 25, 2006 Decision No. 68437 to permit APS to defer fuel and purchased power costs in excess of $776.2 million has effectively remedied this concern.

Q. What do you recommend concerning the $776.2 million cap?

A. APS should be allowed to defer fuel and purchased power costs in excess of the cap in 2006. The actual costs incurred by APS should be reviewed for whether they have been prudently incurred.

B. The Emergency Relief Requested by APS and whether APS is experiencing a "Financial Emergency"

Q. Please summarize your understanding of the Emergency Rate Relief that has been requested by APS in this proceeding.

A. The Company's application indicates that APS is seeking an emergency rate increase of $299 million, or $14%, to be effective April 1, 2006, and subject to refund. Page 18 of APS's application claims that:

> "The Company is facing an operating cash flow emergency under any reasonable definition of that term. It is facing an imminent down grade to 'junk bond' status, which will make it unable to secure financing or transact business on reasonable terms and without very significant additional costs to APS customers. .... Clearly, now is the time for decisive and positive action to rectify the underlying cause of both these problems, namely the imbalance between base fuel revenues and current fuel and purchased power costs."

The basis for the amount of the emergency increase requested by APS is the Company's projected higher annual fuel and purchased power costs the Company expects to incur in 2006.

Q. Have any of the rating agencies discussed their outlook for APS's emergency interim filing?

A. Yes. S&P discussed its outlook and expectations for APS's emergency interim filing in a report issued January 24, 2006. See Attachment RCS-5. On the second page of that report, S&P stated that:

"What is the status with APS' emergency interim filing?

> On Jan. 6, 2006, APS filed a $299 million request for emergency fuel and purchased power-related rate relief. Any amounts, if granted, would be subject to future prudency review. As part of a procedural conference on Jan.12, four of the five commissioners questioned the definition of an emergency and whether relief is justified. Based on the strong views expressed, it appears unlikely that the filing has support. On Jan. 19, a procedural schedule was set that should allow for a decision in April 2006. Standard & Poor's forecast estimates do not assume emergency relief is granted."

S&P's January 24, 2006 report has stated that it appears unlikely that APS's emergency interim filing has support at the Commission, and S&P's forecast estimates do not assume emergency relief is granted. As noted above, a subsequent S&P report dated January 30, 2006 (see Attachment RCS-6), has nevertheless stated that the agency's outlook for APS and PNW is "stable."

Q. Does that S&P report also discuss the size and expectations for APS's deferrals of fuel and purchased power cost?

A. Yes. S&P's January 24, 2006 report discusses the estimated level of APS's deferred fuel and purchased power costs of approximately $165 million at January 31, 2006, and S&P's estimate that APS would likely incur an additional $250 million in fuel and purchased power costs in 2006 that are not recoverable in base electric rates. S&P states that:

> "The sum of balances to date of $165 million plus the expected incremental deferrals of $250 million total $415 million; however, because APS has the potential to collect some of its 2005 balances through a power supply adjustor (PSA) beginning April 1, year-end 2006 deferrals on the utility's balance sheet will not reach that level."

The S&P report also addresses ways in which S&P anticipates the fuel and purchased power deferrals accumulating at APS could be recovered. Notably, as mentioned above, S&P does not assume that the emergency rate relief requested by APS is granted, and S&P states that "it appears unlikely that the [APS emergency rate increase] filing has support."

Q. Does S&P's January 24, 2006, report discuss how APS's rating of BBB- relates to certain financial performance metrics?

A. Yes. This is discussed by S&P on the second page of its January 24, 2006 report.[7] APS's filing and testimony suggest that one particular financial metric, funds from operation as a percent of total debt ("FFO/Debt"), would cause the rating agencies to downgrade its credit standing to "junk" status.[8] However, while FFO/Debt is an important metric, this one measure by itself is not determinative of a bond rating. The January 24, 2006, S&P report explains that:

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[7] See Attachment RCS-5.
[8] See, e.g., APS's Application at pages 11-12.

> "FFO to total debt is an important metric for Standard & Poor's, and at a business profile of '6' (on a 10-point scale where '1' is excellent and '10' vulnerable), it reflects a below-investment-grade performance. For the 12 months ending Sept. 30, 2005, FFO interest coverage was 3.3x, which is reasonable for the current rating. Adjusted total debt to total capitalization was 53.1% and is solid for the current rating."

Thus, S&P reviews a number of financial metrics in the analytical process of establishing its ratings, and APS's other ratios, such as FFO interest coverage and debt to total capitalization, are reasonable or strong for the current rating. Staff witness Woolridge presents additional discussion regarding credit rating agency use of financial metrics in his prefiled direct testimony.

Q. Would the emergency rate relief that APS has requested necessarily prevent future downgrades of the Company's debt ratings?

A. No. There are at least two reasons why the emergency rate relief that APS has requested would not necessarily prevent future downgrades of the Company's debt ratings. First, any "emergency" rate increases granted in this proceeding would be subject to refund. Temporary refundable rate relief would thus only tend to postpone, and not prevent, further bond downgrades. Second, other factors, such as a sustained, unscheduled outage at the Palo Verde nuclear plant or one of APS's coal-fired generating facilities during a peak demand period could result in a downgrading. Fitch's January 30, 2006 report (provided in Attachment RCS-4), for example, mentions the operational risk and asset concentration of the Palo Verde nuclear plant as a concern and states that: "The facility has experienced intermittent operating problems over the past year and a sustained, unscheduled outage at the plant could lead to further negative rating actions."

Q. Has APS provided proof that granting its requested emergency rate relief would result in a bond rating upgrade?

A. No. APS has provided no proof that granting its requested emergency rate relief would result in a bond rating upgrade. STF 4.25 asked APS to: "Provide all quantitative analysis that APS has concerning the amount of additional annual revenues it would take to raise its bond rating up by one step." APS's response states:

> "No such specific analysis has been prepared. However, as stated at p. 13 of the Application the full amount of rate relief in addition to the annual PSA adjustments and an $80 million PSA Surcharge is need (sic) to bring the APS FFO to Debt ratio to 21%, which is in the lower half of the BBB ratings."

As explained elsewhere in my testimony and in additional detail in the testimony of Staff witness Woolridge, a particular FFO to Debt ratio does not, of itself, dictate a bond rating. Moreover, as shown in Attachment RCS-5, Standard & Poor's does not expect APS to be granted the emergency rate relief that APS has requested, but, as shown in Attachment RCS-6, lists the outlook for APS as "stable."

Q. Has APS's debt been downgraded to "junk" status?

A. No. APS's debt is still investment grade.

Q. What are APS's current bond ratings?

A. APS's response to STF 4.26 shows that APS's current long term debt ratings are:

S&P: BBB-

Moody's: Baa1

Fitch: BBB

Q. Has APS provided an estimate of how much its borrowing costs would increase if its long-term debt were to be downgraded to "junk" status?

A. Yes. APS's response to STF 1-14 explained why APS believed it was experiencing an "emergency." See Attachment RCS-8. As part of that response, APS states that:

> "A further downgrade of APS to 'junk bond' status will cost between $10-15 million in higher interest and other financing costs in 2006 with an escalating impact in future years such that the total cost increase to customers will be some $1 billion, if not more, over the next 10 years."

The testimony of Staff witness Woolridge addresses impacts on the Company's cost of capital associated with bond rating changes.

Q. Would a downgrading of APS's debt to "junk" status be a desirable outcome?

A. No, it would not. In addition to resulting in increased borrowing cost, such a downgrade could also impede the Company's access to credit.

Q. Does it appear imminent or probable that APS's debt will be downgraded to "junk" status if the $299 million emergency rate increase requested by APS is not granted?

A. No, it does not. After recent downgrades by investment rating agencies such as Standard & Poor's and Fitch, APS's debt is still investment grade and those agencies have listed their outlook for APS and PNW as "stable." See Attachments RCS-4 and RCS-6. Standard & Poor's has even stated that it does not expect APS's request for emergency rate relief to be granted and it is not reflected in S&P's estimates. See Attachment RCS-5.

Q. Has APS identified how its financing costs have increased as the result of S&P's rating downgrade to BBB-?

A. Yes. APS's response to STF 1-6 has identified approximately $1.027 million of increased annual interest cost associated with S&P's rating downgrade to BBB-. See Attachment RCS-7. Approximately $527,000 relates to increased costs of bank facilities and insurance, and $500,000 relates to a 25 basis point increase in borrowing cost on $200 million of commercial paper.

Q. How are a utility's interest costs charged to ratepayers?

A. In general, a utility's financing costs for debt are reflected in the weighted cost of debt in the capital structure. The debt cost is multiplied by the jurisdictional rate base and ratepayers pay for the interest cost as one of the components of the utility's cost of capital. Depending on how the utility accounts for them, some borrowing costs, such as bank fees, may be included in operating expenses.

The PSA that has been established for APS also includes a provision for financing cost.

Q. If APS's annual borrowing costs increase by $1 million, would that necessarily result in $1 million of additional annual financing costs to ratepayers?

A. No. However, if a utility's borrowing costs increase, eventually ratepayers may be required to pay for some portion of the increased costs when they are recognized in a rate case.

Q. Has APS provided proof that granting its requested emergency rate relief of $299 million would result in a cost savings to ratepayers?

A. No.

Q. Has APS defaulted on any bond indenture or credit arrangements?

A. It appears not. APS's responses to STF 4.7 and 4.8 list provisions in APS's indentures and credit arrangements that address minimum financial ratios and default conditions. See Attachments RCS-9 and RCS-10. The response to STF 4.7 states that "There are no provisions in any APS' indentures that address minimum financial ratios." That response also lists events of default. Notably, APS' application or testimony does not claim that a default has occurred. Nor do APS's responses to Staff data requests or the APS SEC filings that I have reviewed indicate that a default has occurred. A default would tend to be a "significant event" and would thus require reporting by APS and its parent company on SEC filings.

APS's response to STF 4.8 states that there are two provisions in APS's credit arrangement that address minimum financial ratios. The first one is that APS maintain Interest Coverage of at least two times. The second one is that APS's amount of debt does not exceed 65% of total capitalization. Calculations of coverage ratios provided in response to STF 4.48 show that with present rates, PSA deferrals but no PSA increase, APS is meeting both of these requirements.

Q. Is APS currently experiencing a "financial crisis" or "cash flow emergency"?

A. No. APS has claimed that it is in a "financial crisis"[9] and "is facing an operational cash flow emergency."[10] As explained in my and Staff witness Woolridge's testimony, APS is not currently experiencing a financial crisis and is not facing a cash flow emergency. Moreover, the Commission's action on January 25, 2006 in Decision No. 68437 to allow APS to defer 2006 fuel costs in excess of the $776.2 million cap and to implement a 4 mill

[9] See, e.g., APS Application, page 2, footnote 4.
[10] See, APS application at page 18.

PSA effective February 1, 2006 have already addressed some of APS's concerns regarding the build-up of a deferred PSA balance in 2006.

Q. Has APS proved that a $299 million emergency rate increase is needed?

A. No. APS has not demonstrated that its requested emergency rate relief would:

- prevent future downgrades of APS' debt ratings
- result in an upgrade of APS's debt ratings
- result in lower long-term costs for their customers, or
- be appropriate under the circumstances.

Q. Should the $299 million of emergency relief requested by APS be granted?

A. No. After the Commission's actions in Decision No. 68437, APS does not require a $299 million emergency rate increase at this time.

Q. If an emergency rate increase is not granted, how should APS's accumulation of deferred fuel costs be addressed?

A. Rather than grant APS emergency rate relief that is not needed, Staff recommends that the Commission should establish a means to address any deferred fuel balances that may be experienced by APS, as discussed later in my testimony.

C. Whether requirements should be placed on the Company as conditions for approval of all or part of its Emergency request.

Q. If any refundable emergency rate relief is granted in response to APS's current request, what safeguards are required?

A. I am not recommending that emergency rate relief be granted to APS in this proceeding. However, if the Commission were inclined to grant APS some amount of "emergency" rate relief, I have been advised by Staff counsel that current Arizona law would require posting of a bond by the utility as a legal requirement. Thus, granting emergency rate relief would result in an additional cost to APS and its ratepayers related to the cost of the surety bond.

Q. Has APS estimated what the cost of a surety bond would be?

A. Yes. In response to STF 4-41, APS estimates that the cost of a surety bond would be between .75 percent and 1 percent of the bond's value.

Q. Is there a way to avoid the extra cost of a surety bond to APS and its ratepayers?

A. Yes. Such cost could be avoided by denying APS's request for an emergency interim rate increase.

Q. If it were not for the legal requirement, would a surety bond appear to be necessary to assure that APS would have the ability financially to make refunds, or something you would recommend incurring an extra cost for?

A. No. I have not seen evidence in the instant proceeding or in APS's January 31, 2006 base rate case filing which suggests that APS is on the verge of bankruptcy, with or without its requested emergency relief. APS's current financial situation appears to be fairly healthy in many respects. Consequently, incurring additional cost for a surety bond does not appear necessary, given such circumstances.

Q. Whether or not any emergency rate increase is granted in this proceeding, should some reporting safeguards be imposed on APS?

A. Yes. Whether or not any emergency rate increase is granted in this proceeding, I recommend that the Commission temporarily impose some additional reporting safeguards on APS in order to monitor any deterioration in APS's financial condition. I recommend that the Commission require APS to file a monthly report on APS's and PWC's cash position and financial ratios, and their cash flow projections for the upcoming 12 months, and to notify the Commission immediately if any event occurs, or is projected by APS to occur within the next 12 months, which would constitute a default condition, such as those listed in APS's responses to STF 4-7 and 4-8.[11] By doing this, the Commission will have an additional means of keeping apprised of deterioration in APS's cash and financial situation.

D. Operation of the PSA as it Relates to APS's Request for an Emergency Rate Increase

Q. Please discuss how APS's request for $299 million of "emergency" rate relief relates to the recovery of fuel and purchase power costs through the base rates and PSA that was established by the Commission for APS in the utility's last rate case.

A. APS's request for $299 million of "emergency" rate relief appears to me to essentially be an attempt by the Company to supplement provisions in the PSA that were established by the Commission for APS in the utility's last rate case. APS's proposed emergency rate increase is essentially an <u>alternative</u> method of collecting for fuel and purchased power costs.

A press release from APS dated January 6, 2006, for example, states: **"The sole issue in this emergency rate filing is fuel and fuel alone."** A Securities and Exchange

[11] See Attachments RCS-9 and RCS-10.

Commission (SEC) combined Form 8-K dated January 6, 2006, filed by APS and its parent company, similarly described the reasons for APS's emergency interim rate increase of $299 million, or 14%, as being solely to address and accelerate the collection of fuel and purchased power costs:

> "**The purpose of the emergency interim rate increase is solely to address APS' under-collection of higher annual fuel and purchased power costs.** The increase would **accelerate** recovery of the fuel and purchased power component of APS' general rate case and is not an additional increase and would be subject to refund. The request for an emergency interim rate increase would not affect, and would be in addition to, APS' pending $80 million surcharge request and the annual PSA adjustment in April 2006."

(Emphasis supplied.)

Q. What significant features to the collection of fuel and purchased power costs does APS's emergency rate increase present?

A. In contrast with the method provided for collection of prudently incurred fuel and purchased power costs that the Commission has implemented for APS in Decision Nos. 67744 and 68437, the APS emergency rate increase:

(1) is based on increasing rates to accelerate collection of forecast estimates of fuel cost under-collections,

(2) would likely require incurring additional cost for a surety bond, and

(3) is based upon a claim that APS is currently experiencing a financial emergency and cash flow crisis.

Q. Among the various ways that the Commission could provide for APS to collect fuel and purchase power costs, is granting the Company's $299 million emergency rate increase request a preferred alternative?

A. No. Granting APS's requested emergency rate increase request for $299 million is not a preferred alternative because:

(1) it is based on increasing rates to accelerate collection of forecast estimates of fuel cost under-collections, rather than upon collection of actual costs already incurred;

(2) it would likely require incurring additional cost for a surety bond;

(3) APS has not proven that it is currently experiencing a financial emergency or cash flow crisis; and

(4) there is no assurance that increasing APS's rates by $299 million subject to refund would result in a bond rating upgrade or prevent a bond rating downgrade.

Q. What are some other alternatives for addressing APS's recovery of fuel and purchase power costs?

A. Alternatives for addressing APS's recovery of fuel and purchase power costs include: (1) allowing APS to address the build-up of deferred balances and the financial strain on APS that could be caused by carrying large deferred balances, or (2) allowing the existing fuel and purchased power cost recovery mechanism, including the PSA and the surcharge request process, to function as currently ordered by the Commission. The second alternative would essentially be a continuation of the current status quo.

Q. Which of these two alternatives is preferable?

A. In my opinion, the first alternative is preferable to the second because it provides for a means, other than another emergency rate increase request filing, for addressing recovery of APS's actual fuel and purchased power costs in a manner that is more likely to alleviate or prevent a financial crisis situation from developing later in 2006. The primary concern with the status quo is that it provides no interim means for addressing a large build-up in the annual tracking account before a decision in the rate case or before February 1, 2007. The mechanism recommended in the preferred alternative is more likely to avert the possibility of an emergency rate filing by APS later this year. By establishing a mechanism that would allow for earlier treatment of accumulated balances in the tracking account, the Commission would be positioned to act expeditiously if necessary. By providing a means of addressing such build-ups on a more timely basis, the preferred alternative may help to avert a financial crisis or additional credit downgrading later this year.

Q. Has APS demonstrated that its proposed $299 million emergency rate increase is a reasonable way of supplementing the existing PSA?

A. No. The PSA established by the Commission does not need to be supplemented at this time with a $299 million emergency rate increase for APS that would accelerate the collection of estimated future costs.

Q. Please discuss how the current PSA provides for the timing of when APS can file a request for a PSA surcharge?

A. The PSA <u>requires</u> APS to file a surcharge request under specified circumstances, such as within 45 days of the paragraph 19(d) additional recoverable or refundable balancing account exceeding plus or minus $50 million.[12] I have been advised that Decision No. 68437 effectively precludes APS from applying for a PSA surcharge for 2006 additional recoverable amounts recorded in the annual tracking account prior to February 1, 2007. It is Staff's understanding that, per Decision No. 68437, the Commission would view a surcharge request filed by APS prior to February 1, 2007 for 2006 amounts recorded in the annual tracking account as premature, but if APS filed for such a surcharge request after February 1, 2007, it would not be viewed as premature.

Q. Did APS file for a PSA surcharge in 2005?

A. Yes. As noted in Decision No. 68437, on July 22, 2005, APS filed an application for a PSA surcharge of $0.001770 per kWh. APS subsequently modified this request for recovery of $80 million over 24 months, with a surcharge of $0.001416 per kWh.

Q. What was Staff's recommendation concerning APS's request for a surcharge of $0.001416 per kWh?

A. Staff recommended that the surcharge of $0.001416 per kWh requested by APS be approved. Given the state of the natural gas market, Staff advised the Commission that the under-collected balance was likely to grow over the near term and denying or delaying the surcharge request would result in future surcharge requests of even greater magnitude. Staff also indicated that the approval of the surcharge would not impair the Commission's ability to consider whether the costs were imprudent or otherwise subject to disallowance and true-up or refund in a later rate case or other proceeding.

[12] A more detailed description of the requirement to file a surcharge is provided for in the PSA Plan of Administration. The Plan is currently being revised by the parties pursuant to the guidance provided in Decision No. 68437.

Q. Did the Commission appear to agree in principle that APS's under-collection of actual fuel costs should be addressed as soon as possible, rather than later?

A. Yes. Page 20 of Decision No. 68437 states:

> "Fuel and purchased power costs incurred by APS during the latter part of 2005 have escalated faster than the company anticipated. As a result, APS has accrued a significant undercollection for its fuel and purchase power costs. It is generally accepted that these costs will continue to mount in 2006. Under the circumstances and or at least the near future, the Commission agrees with Staff that APS' undercollection should be addressed as soon as possible instead of later. The most expeditious way to begin recovery is to change the timing of the reset for the adjustor. Therefore, we will allow APS to implement the annual Adjustor Rate on February 1 of each year."

Q. Does Staff continue to support the concept that addressing APS's under-collection as soon as possible rather than later is preferable?

A. Yes. Staff believes that prompt action on PSA surcharge requests is a better and more appropriate way to address the Company's growing deferred fuel balance than is the Company's request for emergency rate relief.

Q. Has APS recently filed for additional PSA surcharges?

A. Yes. On February 2, 2006, APS filed an application for two separate surcharges to recover a balance of $59.9 million in retail fuel and purchased power costs deferred by APS in 2005 under the PSA. The first surcharge would recover approximately $15.3 million over a 12-month period. The second surcharge requested by APS would recover approximately $44.6 million, also over a 12-month period. The $44.6 million represents PSA deferrals for replacement power cost associated with unplanned outages at Palo Verde from April 1, 2005 (the effective date of the PSA) through December 31, 2005.

Q. Did Standard & Poor's recent credit research on APS mention an expectation for a PSA surcharge request relating to the $59 million?

A. Yes. As shown in Attachment RCS-3, Standard & Poor's January 26, 2006 report addressed this and stated that:

> "The remaining $59 million will be addressed through a surcharge filing, which may be made only after Feb. 1, but for which the collection timeline and approval date are uncertain."

Q. Has concern been expressed regarding the timing of the Commission's action on PSA surcharge requests from APS?

A. Yes. As one example, as shown in Attachment RCS-3, Standard & Poor's January 26, 2006 report stated that:

> "While a technicality, the surcharge vote removes potential critical flexibility for timely recovery of prudently incurred fuel and purchased power costs. The PSA has a very narrow 4 mill per kilowatt-hour lifetime cap, and the ACC is not bound to act on a surcharge filing by any specific date. As a result, the ACC's decision could cause uncertainty over the timing and disposition of future, expected deferrals."

That S&P report notes further that the "very weak PSA" structure and the 4 mill lifetime cap results in transferring "any deferred balances to a surcharge process" which in turn "is open-ended, with no concrete timeline for resolution."

Q. Would prompt approval of some portion of the PSA surcharges filed by APS on February 2 be one means by which the Commission could address concerns regarding APS's deferred fuel costs?

A. Yes.

Q. Should the first surcharge requested in APS's February 2, 2006 application be promptly addressed?

A. Yes. The PSA surcharge application process is preferable to an emergency rate request as a means of addressing growing deferred fuel and purchased power costs. Prompt processing of this surcharge request could be viewed as a positive development by the credit rating agencies and investment community.

Q. What about the second component of APS's February 2, 2006 PSA surcharge request?

A. The second requested surcharge is for $0.001611 per kWh to recover $44.6 million for costs related to the 2005 unscheduled outages at Palo Verde that are being investigated in Docket No. E-01345A-05-0826. Questions remain regarding whether the unscheduled outages were prudent. Consequently, the Commission should reserve judgment regarding that PSA surcharge request until a determination is made whether the unscheduled Palo Verde outages were prudent and the resultant additional power costs resulting from those unscheduled outages were prudent and reasonable.

Q. Should the functioning of the current PSA be reexamined in the current APS rate case?

A. Yes. The PSA was implemented to apply to fuel and purchased power costs incurred on or after April 1, 2005. It is a relatively new adjustor and has not yet been operational for a full year. Some features of the PSA have been identified during the course of review in this proceeding which appear to deserve further review and discussion for potential improvement. I therefore recommend that the functioning of the PSA be reviewed in the current APS rate case and the PSA be revised if necessary in that case when the additional operating experience in 2006 can be taken into consideration.

Q. What does Staff recommend in the interim?

A. In order to address the potential for growing fuel cost under-collections that APS anticipates for 2006 when and if they are actually incurred and as a preferable alternative to an emergency rate increase, I recommend that the Commission allow APS to file for PSA surcharge requests in 2006 on a quarterly basis if necessary (i.e., that the Commission allow APS to file quarterly surcharge requests to amortize under- or over-recovered balances in the Annual Tracking Account).

I have been informed by Commission Staff that it is willing to expedite the processing of these surcharge requests. Staff envisions filing its recommendation no later than 30 days after APS' filing. Staff's ability to expedite its processing of APS' surcharge requests, however, depends upon APS' filing of a suitable application that at least addresses the items set forth subsequently in my testimony.

Q. When should APS be permitted to file the quarterly PSA surcharge requests?

A. APS should be permitted to file PSA surcharge requests in order to amortize its Annual Tracking Account not more frequently than quarterly. Staff is not recommending that the Commission **require** APS to file these quarterly surcharge requests; instead, Staff recommends that the Commission **permit** APS to do so in order to afford both the Company and the Commission the opportunity to address under-recovered balances before the 2007 reset. The first surcharge request should not be filed before June 30, 2006, and subsequent requests should not be filed before the end of each subsequent calendar quarter. APS should be permitted to file these quarterly surcharge requests until the Commission has issued a final order in APS' pending rate case. If APS elects to file a surcharge request, it should inform Staff of its intent to do so ten days before its filing.

Q. What information should be included in the quarterly PSA surcharge requests?

A. Any quarterly surcharge requests should include at a minimum the following information:

(1) the amount expected to be collected and how it relates to the most current month-end balance in the annual tracking account;

(2) the Company's proposed amortization period, including starting and ending dates, and the proposed surcharge rates expressed as a per-kWh charge;

(3) clear identification of how much of the proposed balance relates to replacement power costs for unscheduled plant outages.

(4) whether interest is requested;

(5) the impact upon customer bills;

(6) monthly forecasts of the Annual Tracking Account balance for the ensuing year; and

(7) a reconciliation of any differences between APS' monthly reports and the surcharge application.

Q. Please explain why you believe that this recommendation is appropriate at this time.

A. Providing for timely recovery of prudently incurred fuel and purchased power costs through a PSA surcharge process would be preferable to addressing fuel cost under-collections through emergency rate increases. APS's current request for a $299 million emergency rate increase should be rejected for the reasons described in my testimony. There is not a present financial crisis or cash flow emergency as suggested by APS. The Commission's January 25, 2007 Decision No. 68437 helped alleviate a financial crisis from developing at APS for the time being. However, a concern continues to exist regarding the build-up of deferred fuel balances in 2006 and the uncertain time frame for recovery of prudently incurred fuel and purchased power costs. This concern presents the possibility that APS may face circumstances that could implicate a financial crisis sometime in 2006. Allowing APS to make quarterly PSA surcharge filings, if necessary, in 2006 could thus function as a "safety valve" against financial pressure from carrying large deferred balances building to an emergency situation. It could thus help in avoiding an emergency situation from occurring later this year and could provide both the Commission and the Company with a ready means to address and prevent a potentially serious situation.

Commission Staff's willingness to file its recommendation regarding APS's surcharge requests within a specified time table would be an appropriate response to the presently existing lack of certainty about the time frame for consideration of such requests. This would be a simple step to address the lingering concern regarding timing. I also believe that setting such parameters would be viewed as a positive development by the rating agencies.

Q. Does this conclude your testimony?

A. Yes, it does.

Attachment RCS-1
QUALIFICATIONS OF RALPH C. SMITH

Accomplishments

Mr. Smith's professional credentials include being a Certified Financial Planner™ professional, a licensed Certified Public Accountant and attorney. He functions as project manager on consulting projects involving utility regulation, regulatory policy and ratemaking and utility management. His involvement in public utility regulation has included project management and in-depth analyses of numerous issues involving telephone, electric, gas, and water and sewer utilities.

Mr. Smith has performed work in the field of utility regulation on behalf of industry, PSC staffs, state attorney generals, municipalities, and consumer groups concerning regulatory matters before regulatory agencies in Alabama, Alaska, Arizona, California, Connecticut, Delaware, Florida, Georgia, Hawaii, Illinois, Kentucky, Louisiana, Maine, Michigan, Minnesota, Mississippi, Missouri, New Jersey, New York, Nevada, North Carolina, Ohio, Pennsylvania, South Carolina, South Dakota, Texas, Canada, Federal Energy Regulatory Commission and various state and federal courts of law. He has presented expert testimony in regulatory hearings on behalf of utility commission staffs and intervenors on several occasions.

Project manager in Larkin & Associates' review, on behalf of the Georgia Commission Staff, of the budget and planning activities of Georgia Power Company; supervised 13 professionals; coordinated over 200 interviews with Company budget center managers and executives; organized and edited voluminous audit report; presented testimony before the Commission. Functional areas covered included fossil plant O&M, headquarters and district operations, internal audit, legal, affiliated transactions, and responsibility reporting. All of our findings and recommendations were accepted by the Commission.

Key team member in the firm's management audit of the Anchorage Water and Wastewater Utility on behalf of the Alaska Commission Staff, which assessed the effectiveness of the Utility's operations in several areas; responsible for in-depth investigation and report writing in areas involving information systems, finance and accounting, affiliated relationships and transactions, and use of outside contractors. Testified before the Alaska Commission concerning certain areas of the audit report. AWWU concurred with each of Mr. Smith's 40 plus recommendations for improvement.

Co-consultant in the analysis of the issues surrounding gas transportation performed for the law firm of Cravath, Swaine & Moore in conjunction with the case of Reynolds Metals Co. vs. the Columbia Gas System, Inc.; drafted in-depth report concerning the regulatory treatment at both state and federal levels of issues such as flexible pricing and mandatory gas transportation.

Lead consultant and expert witness in the analysis of the rate increase request of the City of Austin - Electric Utility on behalf of the residential consumers. Among the numerous ratemaking issues addressed was the economies of the Utility's employment of outside services; provided both written and oral testimony outlining recommendations and their bases. Most of Mr. Smith's recommendations were adopted by the City Council and Utility in a settlement.

Key team member performing an analysis of the rate stabilization plan submitted by the Southern Bell Telephone & Telegraph Company to the Florida PSC; performed comprehensive analysis of the Company's projections and budgets which were used as the basis for establishing rates.

Lead consultant in analyzing Southwestern Bell Telephone separations in Missouri; sponsored the complex technical analysis and calculations upon which the firm's testimony in that case was based. He has also assisted in analyzing changes in depreciation methodology for setting telephone rates.

Lead consultant in the review of gas cost recovery reconciliation applications of Michigan Gas Utilities Company, Michigan Consolidated Gas Company, and Consumers Power Company. Drafted recommendations regarding the appropriate rate of interest to be applied to any over or under collections and the proper procedures and allocation methodology to be used to distribute any refunds to customer classes.

Lead consultant in the review of Consumers Power Company's gas cost recovery refund plan. Addressed appropriate interest rate and compounding procedures and proper allocation methodology.

Project manager in the review of the request by Central Maine Power Company for an increase in rates. The major area addressed was the propriety of the Company's ratemaking attrition adjustment in relation to its corporate budgets and projections.

Project manager in an engagement designed to address the impacts of the Tax Reform Act of 1986 on gas distribution utility operations of the Northern States Power Company. Analyzed the reduction in the corporate tax rate, uncollectibles reserve, ACRS, unbilled revenues, customer advances, CIAC, and timing of TRA-related impacts associated with the Company's tax liability.

Project manager and expert witness in the determination of the impacts of the Tax Reform Act of 1986 on the operations of Connecticut Natural Gas Company on behalf of the Connecticut Department of Public Utility Control - Prosecutorial Division, Connecticut Attorney General, and Connecticut Department of Consumer Counsel.

Lead Consultant for The Minnesota Department of Public Service ("DPS") to review the Minnesota Incentive Plan ("Incentive Plan") proposal presented by Northwestern Bell Telephone Company ("NWB") doing business as U S West Communications ("USWC"). Objective was to express an opinion as to whether current rates addressed by the plan were appropriate from a Minnesota intrastate revenue requirements and accounting perspective, and to assist in developing recommended modifications to NWB's proposed Plan.

Performed a variety of analytical and review tasks related to our work effort on this project. Obtained and reviewed data and performed other procedures as necessary (1) to obtain an understanding of the Company's Incentive Plan filing package as it relates to rate base, operating income, revenue requirements, and plan operation, and (2) to formulate an opinion concerning the reasonableness of current rates and of amounts included within the Company's Incentive Plan filing. These procedures included requesting and reviewing extensive discovery, visiting the Company's offices to review data, issuing follow-up information requests in many instances, telephone and on-site discussions with Company representatives, and frequent discussions with counsel and DPS Staff assigned to the project.

Lead Consultant in the regulatory analysis of Jersey Central Power & Light Company for the Department of the Public Advocate, Division of Rate Counsel. Tasks performed included on-site review and audit of Company, identification and analysis of specific issues, preparation of data requests, testimony, and cross examination questions. Testified in Hearings.

Assisted the NARUC Committee on Management Analysis with drafting the Consultant Standards for Management Audits.

Presented training seminars covering public utility accounting, tax reform, ratemaking, affiliated transaction auditing, rate case management, and regulatory policy in Maine, Georgia, Kentucky, and Pennsylvania. Seminars were presented to commission staffs and consumer interest groups.

Previous Positions

With Larkin, Chapski and Co., the predecessor firm to Larkin & Associates, was involved primarily in utility regulatory consulting, and also in tax planning and tax research for businesses and individuals, tax return preparation and review, and independent audit, review and preparation of financial statements.

Installed computerized accounting system for a realty management firm.

Education

Bachelor of Science in Administration in Accounting, with distinction, University of Michigan, Dearborn, 1979.

Master of Science in Taxation, Walsh College, Michigan, 1981. Master's thesis dealt with investment tax credit and property tax on various assets.

Juris Doctor, cum laude, Wayne State University Law School, Detroit, Michigan, 1986. Recipient of American Jurisprudence Award for academic excellence.

Continuing education required to maintain CPA license and CFP certificate.

Passed all parts of CPA examination in first sitting, 1979. Received CPA certificate in 1981 and Certified Financial Planning certificate in 1983. Admitted to Michigan and Federal bars in 1986.

Michigan Bar Association.

American Bar Association, sections on public utility law and taxation.

Partial list of utility cases participated in:

79-228-EL-FAC	Cincinnati Gas & Electric Company (Ohio PUC)
79-231-EL-FAC	Cleveland Electric Illuminating Company (Ohio PUC)
79-535-EL-AIR	East Ohio Gas Company (Ohio PUC)
80-235-EL-FAC	Ohio Edison Company (Ohio PUC)
80-240-EL-FAC	Cleveland Electric Illuminating Company (Ohio PUC)
U-1933*	Tucson Electric Power Company (Arizona Corp. Commission)
U-6794	Michigan Consolidated Gas Co. --16 Refunds (Michigan PSC)
81-0035TP	Southern Bell Telephone Company (Florida PSC)
81-0095TP	General Telephone Company of Florida (Florida PSC)
81-308-EL-EFC	Dayton Power & Light Co.- Fuel Adjustment Clause (Ohio PUC)
810136-EU	Gulf Power Company (Florida PSC)
GR-81-342	Northern States Power Co. -- E-002/Minnesota (Minnesota PUC)
Tr-81-208	Southwestern Bell Telephone Company (Missouri PSC))
U-6949	Detroit Edison Company (Michigan PSC)
8400	East Kentucky Power Cooperative, Inc. (Kentucky PSC)
18328	Alabama Gas Corporation (Alabama PSC)
18416	Alabama Power Company (Alabama PSC)
820100-EU	Florida Power Corporation (Florida PSC)
8624	Kentucky Utilities (Kentucky PSC)
8648	East Kentucky Power Cooperative, Inc. (Kentucky PSC)
U-7236	Detroit Edison - Burlington Northern Refund (Michigan PSC)
U6633-R	Detroit Edison - MRCS Program (Michigan PSC)
U-6797-R	Consumers Power Company -MRCS Program (Michigan PSC)

U-5510-R	Consumers Power Company - Energy conservation Finance Program (Michigan PSC)
82-240E	South Carolina Electric & Gas Company (South Carolina PSC)
7350	Generic Working Capital Hearing (Michigan PSC)
RH-1-83	Westcoast Transmission Co., (National Energy Board of Canada)
820294-TP	Southern Bell Telephone & Telegraph Co. (Florida PSC)
82-165-EL-EFC (Subfile A)	Toledo Edison Company(Ohio PUC)
82-168-EL-EFC	Cleveland Electric Illuminating Company (Ohio PUC)
830012-EU	Tampa Electric Company (Florida PSC)
U-7065	The Detroit Edison Company - Fermi II (Michigan PSC)
8738	Columbia Gas of Kentucky, Inc. (Kentucky PSC)
ER-83-206	Arkansas Power & Light Company (Missouri PSC)
U-4758	The Detroit Edison Company – Refunds (Michigan PSC)
8836	Kentucky American Water Company (Kentucky PSC)
8839	Western Kentucky Gas Company (Kentucky PSC)
83-07-15	Connecticut Light & Power Co. (Connecticut DPU)
81-0485-WS	Palm Coast Utility Corporation (Florida PSC)
U-7650	Consumers Power Co. - Partial and Immediate (Michigan PSC)
83-662	Continental Telephone Company of California, (Nevada PSC)
U-7650	Consumers Power Company – Final (Michigan PSC)
U-6488-R	Detroit Edison Co., FAC & PIPAC Reconciliation (Michigan PSC)
U-15684	Louisiana Power & Light Company (Louisiana PSC)
7395 & U-7397	Campaign Ballot Proposals (Michigan PSC)
820013-WS	Seacoast Utilities (Florida PSC)
U-7660	Detroit Edison Company (Michigan PSC)
83-1039	CP National Corporation (Nevada PSC)
U-7802	Michigan Gas Utilities Company (Michigan PSC)
83-1226	Sierra Pacific Power Company (Nevada PSC)
830465-EI	Florida Power & Light Company (Florida PSC)
U-7777	Michigan Consolidated Gas Company (Michigan PSC)
U-7779	Consumers Power Company (Michigan PSC)
U-7480-R	Michigan Consolidated Gas Company (Michigan PSC)
U-7488-R	Consumers Power Company – Gas (Michigan PSC)
U-7484-R	Michigan Gas Utilities Company (Michigan PSC)
U-7550-R	Detroit Edison Company (Michigan PSC)
U-7477-R**	Indiana & Michigan Electric Company (Michigan PSC)
18978	Continental Telephone Co. of the South Alabama (Alabama PSC)
R-842583	Duquesne Light Company (Pennsylvania PUC)
R-842740	Pennsylvania Power Company (Pennsylvania PUC)
850050-EI	Tampa Electric Company (Florida PSC)
16091	Louisiana Power & Light Company (Louisiana PSC)
19297	Continental Telephone Co. of the South Alabama (Alabama PSC)
76-18788AA &76-18793AA	Detroit Edison - Refund - Appeal of U-4807 (Ingham County, Michigan Circuit Court)
85-53476AA & 85-534785AA	Detroit Edison Refund - Appeal of U-4758 (Ingham County, Michigan Circuit Court)
U-8091/U-8239	Consumers Power Company - Gas Refunds (Michigan PSC)
TR-85-179**	United Telephone Company of Missouri (Missouri PSC)
85-212	Central Maine Power Company (Maine PSC)
ER-85646001 & ER-85647001	New England Power Company (FERC)
850782-EI & 850783-EI	Florida Power & Light Company (Florida PSC)
R-860378	Duquesne Light Company (Pennsylvania PUC)

R-850267	Pennsylvania Power Company (Pennsylvania PUC)
851007-WU & 840419-SU	Florida Cities Water Company (Florida PSC)
G-002/GR-86-160	Northern States Power Company (Minnesota PSC)
7195 (Interim)	Gulf States Utilities Company (Texas PUC)
87-01-03	Connecticut Natural Gas Company (Connecticut PUC))
87-01-02	Southern New England Telephone Company (Connecticut Department of Public Utility Control)
R-860378	Duquesne Light Company Surrebuttal (Pennsylvania PUC)
3673-	Georgia Power Company (Georgia PSC)
29484	Long Island Lighting Co. (New York Dept. of Public Service)
U-8924	Consumers Power Company – Gas (Michigan PSC)
Docket No. 1	Austin Electric Utility (City of Austin, Texas)
Docket E-2, Sub 527	Carolina Power & Light Company (North Carolina PUC)
870853	Pennsylvania Gas and Water Company (Pennsylvania PUC)
880069**	Southern Bell Telephone Company (Florida PSC)
U-1954-88-102 T E-1032-88-102	Citizens Utilities Rural Company, Inc. & Citizens Utilities Company, Kingman Telephone Division (Arizona CC)
89-0033	Illinois Bell Telephone Company (Illinois CC)
U-89-2688-T	Puget Sound Power & Light Company (Washington UTC))
R-891364	Philadelphia Electric Company (Pennsylvania PUC)
F.C. 889	Potomac Electric Power Company (District of Columbia PSC)
Case No. 88/546*	Niagara Mohawk Power Corporation, et al Plaintiffs, v. Gulf+Western, Inc. et al, defendants (Supreme Court County of Onondaga, State of New York)
87-11628*	Duquesne Light Company, et al, plaintiffs, against Gulf+ Western, Inc. et al, defendants (Court of the Common Pleas of Allegheny County, Pennsylvania Civil Division)
890319-EI	Florida Power & Light Company (Florida PSC)
891345-EI	Gulf Power Company (Florida PSC)
ER 8811 0912J	Jersey Central Power & Light Company (BPU)
6531	Hawaiian Electric Company (Hawaii PUCs)
R0901595	Equitable Gas Company (Pennsylvania Consumer Counsel)
90-10	Artesian Water Company (Delaware PSC)
89-12-05	Southern New England Telephone Company (Connecticut PUC)
900329-WS	Southern States Utilities, Inc. (Florida PSC)
90-12-018	Southern California Edison Company (California PUC)
90-E-1185	Long Island Lighting Company (New York DPS)
R-911966	Pennsylvania Gas & Water Company (Pennsylvania PUC)
I.90-07-037, Phase II	(Investigation of OPEBs) Department of the Navy and all Other Federal Executive Agencies (California PUC)
U-1551-90-322	Southwest Gas Corporation (Arizona CC)
U-1656-91-134	Sun City Water Company (Arizona RUCO)
U-2013-91-133	Havasu Water Company (Arizona RUCO)
91-174***	Central Maine Power Company (Department of the Navy and all Other Federal Executive Agencies)
U-1551-89-102 & U-1551-89-103	Southwest Gas Corporation - Rebuttal and PGA Audit (Arizona Corporation Commission)
Docket No. 6998	Hawaiian Electric Company (Hawaii PUC)
TC-91-040A and TC-91-040B	Intrastate Access Charge Methodology, Pool and Rates Local Exchange Carriers Association and South Dakota Independent Telephone Coalition
9911030-WS & 911-67-WS	General Development Utilities - Port Malabar and West Coast Divisions (Florida PSC)
922180	The Peoples Natural Gas Company (Pennsylvania PUC)
7233 and 7243	Hawaiian Nonpension Postretirement Benefits (Hawaiian PUC)

R-00922314 & M-920313C006	Metropolitan Edison Company (Pennsylvania PUC)
R00922428	Pennsylvania American Water Company (Pennsylvania PUC)
E-1032-92-083 & U-1656-92-183	Citizens Utilities Company, Agua Fria Water Division (Arizona Corporation Commission)
92-09-19	Southern New England Telephone Company (Connecticut PUC)
E-1032-92-073	Citizens Utilities Company (Electric Division), (Arizona CC)
UE-92-1262	Puget Sound Power and Light Company (Washington UTC))
92-345	Central Maine Power Company (Maine PUC)
R-932667	Pennsylvania Gas & Water Company (Pennsylvania PUC)
U-93-60**	Matanuska Telephone Association, Inc. (Alaska PUC)
U-93-50**	Anchorage Telephone Utility (Alaska PUC)
U-93-64	PTI Communications (Alaska PUC)
7700	Hawaiian Electric Company, Inc. (Hawaii PUC)
E-1032-93-111 & U-1032-93-193	Citizens Utilities Company - Gas Division (Arizona Corporation Commission
R-00932670	Pennsylvania American Water Company (Pennsylvania PUC)
U-1514-93-169/ E-1032-93-169	Sale of Assets CC&N from Contel of the West, Inc. to Citizens Utilities Company (Arizona Corporation Commission)
7766	Hawaiian Electric Company, Inc. (Hawaii PUC)
93-2006- GA-AIR*	The East Ohio Gas Company (Ohio PUC)
94-E-0334	Consolidated Edison Company (New York DPS)
94-0270	Inter-State Water Company (Illinois Commerce Commission)
94-0097	Citizens Utilities Company, Kauai Electric Division (Hawaii PUC)
PU-314-94-688	Application for Transfer of Local Exchanges (North Dakota PSC)
94-12-005-Phase I	Pacific Gas & Electric Company (California PUC)
R-953297	UGI Utilities, Inc. - Gas Division (Pennsylvania PUC)
95-03-01	Southern New England Telephone Company (Connecticut PUC)
95-0342	Consumer Illinois Water, Kankakee Water District (Illinois CC)
94-996-EL-AIR	Ohio Power Company (Ohio PUC)
95-1000-E	South Carolina Electric & Gas Company (South Carolina PSC)
Non-Docketed Staff Investigation	Citizens Utility Company - Arizona Telephone Operations (Arizona Corporation Commission)
E-1032-95-473	Citizens Utility Co. - Northern Arizona Gas Division (Arizona CC)
E-1032-95-433	Citizens Utility Co. - Arizona Electric Division (Arizona CC)
	Collaborative Ratemaking Process Columbia Gas of Pennsylvania (Pennsylvania PUC)
GR-96-285	Missouri Gas Energy (Missouri PSC)
94-10-45	Southern New England Telephone Company (Connecticut PUC)
A.96-08-001 et al.	California Utilities' Applications to Identify Sunk Costs of Non-Nuclear Generation Assets, & Transition Costs for Electric Utility Restructuring, & Consolidated Proceedings (California PUC)
96-324	Bell Atlantic - Delaware, Inc. (Delaware PSC)
96-08-070, et al.	Pacific Gas & Electric Co., Southern California Edison Co. and San Diego Gas & Electric Company (California PUC)
97-05-12	Connecticut Light & Power (Connecticut PUC)
R-00973953	Application of PECO Energy Company for Approval of its Restructuring Plan Under Section 2806 of the Public Utility Code (Pennsylvania PUC)
97-65	Application of Delmarva Power &Light Co. for Application of a Cost Accounting Manual and a Code of Conduct (Delaware PSC)
16705	Entergy Gulf States, Inc. (Cities Steering Committee)
E-1072-97-067	Southwestern Telephone Co. (Arizona Corporation Commission)
Non-Docketed Staff Investigation	Delaware - Estimate Impact of Universal Services Issues (Delaware PSC)

PU-314-97-12	US West Communications, Inc. Cost Studies (North Dakota PSC)
97-0351	Consumer Illinois Water Company (Illinois CC)
97-8001	Investigation of Issues to be Considered as a Result of Restructuring of Electric Industry (Nevada PSC)
U-0000-94-165	Generic Docket to Consider Competition in the Provision of Retail Electric Service (Arizona Corporation Commission)
98-05-006-Phase I	San Diego Gas & Electric Co., Section 386 costs (California PUC)
9355-U	Georgia Power Company Rate Case (Georgia PUC)
97-12-020 - Phase I	Pacific Gas & Electric Company (California PUC)
U-98-56, U-98-60, U-98-65, U-98-67	Investigation of 1998 Intrastate Access charge filings (Alaska PUC)
(U-99-66, U-99-65, U-99-56, U-99-52)	Investigation of 1999 Intrastate Access Charge filing (Alaska PUC)
Phase II of 97-SCCC-149-GIT	Southwestern Bell Telephone Company Cost Studies (Kansas CC)
PU-314-97-465	US West Universal Service Cost Model (North Dakota PSC)
Non-docketed Assistance	Bell Atlantic - Delaware, Inc., Review of New Telecomm. and Tariff Filings (Delaware PSC)
Contract Dispute	City of Zeeland, MI - Water Contract with the City of Holland, MI (Before an arbitration panel)
Non-docketed Project	City of Danville, IL - Valuation of Water System (Danville, IL)
Non-docketed Project	Village of University Park, IL - Valuation of Water and Sewer System (Village of University Park, Illinois)
E-1032-95-417	Citizens Utility Co., Maricopa Water/Wastewater Companies et al. (Arizona Corporation Commission)
T-1051B-99-0497	Proposed Merger of the Parent Corporation of Qwest Communications Corporation, LCI International Telecom Corp., and US West Communications, Inc. (Arizona CC)
T-01051B-99-0105	US West Communications, Inc. Rate Case (Arizona CC)
A00-07-043	Pacific Gas & Electric - 2001 Attrition (California PUC)
T-01051B-99-0499	US West/Quest Broadband Asset Transfer (Arizona CC)
99-419/420	US West, Inc. Toll and Access Rebalancing (North Dakota PSC)
PU314-99-119	US West, Inc. Residential Rate Increase and Cost Study Review (North Dakota PSC
98-0252	Ameritech - Illinois, Review of Alternative Regulation Plan (Illinois CUB)
00-108	Delmarva Billing System Investigation (Delaware PSC)
U-00-28	Matanuska Telephone Association (Alaska PUC)
Non-Docketed	Management Audit and Market Power Mitigation Analysis of the Merged Gas System Operation of Pacific Enterprises and Enova Corporation (California PUC)
00-11-038	Southern California Edison (California PUC)
00-11-056	Pacific Gas & Electric (California PUC)
00-10-028	The Utility Reform Network for Modification of Resolution E-3527 (California PUC)
98-479	Delmarva Power & Light Application for Approval of its Electric and Fuel Adjustments Costs (Delaware PSC)
99-457	Delaware Electric Cooperative Restructuring Filing (Delaware PSC)
99-582	Delmarva Power & Light dba Conectiv Power Delivery Analysis of Code of Conduct and Cost Accounting Manual (Delaware PSC)
99-03-04	United Illuminating Company Recovery of Stranded Costs (Connecticut OCC)
99-03-36	Connecticut Light & Power (Connecticut OCC)
Civil Action No. 98-1117	West Penn Power Company vs. PA PUC (Pennsylvania PSC)

Case No. 12604	Upper Peninsula Power Company (Michigan AG)
Case No. 12613	Wisconsin Public Service Commission (Michigan AG)
41651	Northern Indiana Public Service Co Overearnings investigation (Indiana UCC)
13605-U	Savannah Electric & Power Company – FCR (Georgia PSC)
14000-U	Georgia Power Company Rate Case/M&S Review (Georgia PSC)
13196-U	Savannah Electric & Power Company Natural Gas Procurement and Risk Management/Hedging Proposal, Docket No. 13196-U (Georgia PSC)
Non-Docketed	Georgia Power Company & Savannah Electric & Power FPR Company Fuel Procurement Audit (Georgia PSC)
Non-Docketed	Transition Costs of Nevada Vertically Integrated Utilities (US Department of Navy)
Application No. 99-01-016, Phase I	Post-Transition Ratemaking Mechanisms for the Electric Industry Restructuring (US Department of Navy)
99-02-05	Connecticut Light & Power (Connecticut OCC)
01-05-19-RE03	Yankee Gas Service Application for a Rate Increase, Phase I-2002-IERM (Connecticut OCC)
G-01551A-00-0309	Southwest Gas Corporation, Application to amend its rate Schedules (Arizona CC)
00-07-043	Pacific Gas & Electric Company Attrition & Application for a rate increase (California PUC)
97-12-020 Phase II	Pacific Gas & Electric Company Rate Case (California PUC)
01-10-10	United Illuminating Company (Connecticut OCC)
13711-U	Georgia Power FCR (Georgia PSC)
02-001	Verizon Delaware § 271(Delaware DPA)
02-BLVT-377-AUD	Blue Valley Telephone Company Audit/General Rate Investigation (Kansas CC)
02-S&TT-390-AUD	S&T Telephone Cooperative Audit/General Rate Investigation (Kansas CC)
01-SFLT-879-AUD	Sunflower Telephone Company Inc., Audit/General Rate Investigation (Kansas CC)
01-BSTT-878-AUD	Bluestem Telephone Company, Inc. Audit/General Rate Investigation (Kansas CC)
P404, 407, 520, 413 426, 427, 430, 421/ CI-00-712	Sherburne County Rural Telephone Company, dba as Connections, Etc. (Minnesota DOC)
U-01-85	ACS of Alaska, dba as Alaska Communications Systems (ACS), Rate Case (Alaska Regulatory Commission PAS)
U-01-34	ACS of Anchorage, dba as Alaska Communications Systems (ACS), Rate Case (Alaska Regulatory Commission PAS)
U-01-83	ACS of Fairbanks, dba as Alaska Communications Systems (ACS), Rate Case (Alaska Regulatory Commission PAS)
U-01-87	ACS of the Northland, dba as Alaska Communications Systems (ACS), Rate Case (Alaska Regulatory Commission PAS)
96-324, Phase II	Verizon Delaware, Inc. UNE Rate Filing (Delaware PSC)
03-WHST-503-AUD	Wheat State Telephone Company (Kansas CC)
04-GNBT-130-AUD	Golden Belt Telephone Association (Kansas CC)
Docket 6914	Shoreham Telephone Company, Inc. (Vermont BPU)

ARIZONA CORPORATION COMMISSION STAFF'S
FIRST SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY
RE: DOCKET NO. E-01345A-06-0009
JANUARY 11, 2006

STF 1-11 On page 3 line 12 of the application you state that the $776.2 million cap is likely to be exceeded in the fourth quarter of 2006. Please provide work papers that support this projection. Please include a list of all assumptions and forecasts of fuel and purchase power costs by month

Response:

The forecast of fuel and purchased power is based on the Company's 2006 Fuel Budget, with fuel and purchased power prices and hedge value updates as of the November 30th market. Details of this fuel and purchased power forecast are provided in attachment STF 1-11b as APS07170 which are confidential and being provided pursuant to a Protective Agreement

APS' projected native load fuel and purchased power costs in 2006 total $901,509,000 before off-system margin of $8,298,000. After netting these numbers, adjusting for the Sundance fuel savings deferral, removing ISFSI costs and FAS133 mark to market adjustments, the costs are allocated between retail and wholesale customers. The Retail Net Fuel and Purchased Power Cost on line 21 of attachment STF 1-11a as APS07169 which are confidential and being provided pursuant to a Protective Agreement shows the monthly cumulative fuel and purchased power cost for 2006, which reaches $804,600,000 by the end of November, and is projected to be $848,960,000 by the end of 2006.

Please note that this number is different from the figure in 1.9 because the former does not reflect the normalizations and annualizations customarily done in rate cases, including the Company's last rate proceeding.

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RESEARCH

Research Update: APS, PWCC's 'BBB-' Corporate Credit Ratings Affirmed On ACC Vote But Challenges Continue

Publication date: 26-Jan-2006
Primary Credit Analyst: Anne Selting, San Francisco (1) 415-371-5009; anne_selting@standardandpoors.com

Credit Rating: BBB-/Stable/A-3

Rationale

Standard & Poor's Ratings Services affirmed its 'BBB-' corporate credit ratings on Arizona Public Service (APS) and its parent, Pinnacle West Capital Corp. (PWCC), following the generally constructive decisions made by the Arizona Corporation Commission (ACC) on Jan. 25. The commission lifted a cap that limited APS' opportunity to recover fuel and purchased power costs and modestly advanced the collection of deferred costs that APS was incurring under the terms of its power supply adjuster (PSA). However, the ACC also restricted APS' ability to file for a surcharge, which raises certain credit concerns. The outlook is stable.

The ACC vote to remove the $776 million cap on annual fuel and purchased power costs is favorable because it allows APS to defer any costs that exceed this level, which is in fact expected to occur in late 2006. APS' current deferral level is about $170 million, which will likely increase by approximately $250 million this year. The ACC adopted an amendment to advance the commencement of recovery of these costs by two months to Feb. 1 from April 1. While the impact is small, providing APS only about $14 million of incremental recovery in 2006, the vote is an important indicator that the ACC acknowledges that timely action is necessary to limit cash flow pressure on the company. (Note: As a result of staff and company testimony, some of the numbers Standard & Poor's cited in its Jan. 25 credit FAQ have been updated here.)

However, the ACC also voted to prohibit APS from requesting surcharges before the annual PSA adjustor is implemented. Heretofore, Standard & Poor's understood that APS would be permitted to file for surcharge relief any time that deferrals reached $100 million, as appeared to be implied by the settlement in its last rate case, as amended by the ACC in March 2005. With respect to the $170 million of deferrals that have accumulated as of year-end 2005, the recently enacted PSA adjuster will generate only about $111 million over the next 12 months. The remaining $59 million will be addressed through a surcharge filing, which may be made only after Feb. 1, but for which the collection timeline and approval date are uncertain.

While a technicality, the surcharge vote removes potentially critical flexibility for timely recovery of prudently incurred fuel and purchased power costs. The PSA has a very narrow 4 mill per kilowatt-hour lifetime cap, and the ACC is not bound to act on a surcharge filing by any specific date. As a result, the ACC's decision could cause uncertainty over the timing and disposition of future, expected deferrals.

Standard & Poor's current expectation is that high fuel and purchased power costs will result in a 2006 deferral problem that is larger than that of 2005. The ACC's vote to limit the flexibility of the timing of the surcharge elevates the importance of APS' request for $299 million in interim emergency rate relief, which is expected to be ruled on in April. That is, a limited PSA with a backstop surcharge that can be filed according to a specified timeline places incremental pressure on other processes that could support credit quality through 2006, especially when permanent rate relief via a general rate case ruling is not expected to occur within the next year.

Much of these issues stem from the very weak PSA, which is triggered based on a date and not on a threshold level of deferrals and which limits any adjustment to a narrow cap. This structure transfers any deferred balances to a surcharge process. In turn, the surcharge process is open-ended, with no concrete timeline for resolution. At the same time, APS has a significant reliance on natural gas. And this dependence is expected to grow in the coming years. Given the volatility of this fuel and expectations that at least in the near-term prices will remain high relative to historic levels--certainly relative to 2003 levels on which current retail rates are based--a critical underpinning of credit quality is the timing of recovery. This emphasis is particularly important in Arizona, where there is little precedent to support the conclusion that general rate cases can be processed quickly.

However, despite the emphasis that Standard & Poor's places on power supply adjustment mechanisms, it is possible that if the ACC establishes a track record of being supportive and timely toward emergency rate relief requests, that this vehicle could compensate for the current limitations of APS' PSA.

Outlook

The stable outlook is premised on the ACC providing sustained regulatory support that adequately addresses building deferrals. Negative rating actions could result if regulatory support does not continue, or if market forces or operational issues lead to significant increases in the expected 2006 deferral level.

Ratings List

Pinnacle West Capital Corp.	
Corp credit rating	BBB-/Stable/A-3
Senior unsecured debt	BB+
Commercial paper	A-3
Arizona Public Service Co.	
Corp credit rating	BBB-/Stable/A-3
Senior unsecured debt	BBB-
PVNGS II funding Corp Inc.	BBB-
Commercial paper	A-3

Complete ratings information is available to subscribers of RatingsDirect, Standard & Poor's Web-based credit analysis system, at www.ratingsdirect.com. All ratings affected by this rating action can be found on Standard & Poor's public Web site at www.standardandpoors.com; under Credit Ratings in the left navigation bar, select Find a Rating, then Credit Ratings Search.

Fitch Lowers PNW & APS' Sr. Unsecured Ratings to 'BBB-' & 'BBB', Respectively; Outlook Stable

Ratings
30 Jan 2006 4:23 PM (EST)

Fitch Ratings-New York-30 January 2006: Fitch Ratings has lowered Pinnacle West Capital's (PNW) long- and short-term ratings. At the same time, Fitch has lowered Arizona Public Service Company's (APS) long-term ratings, while affirming its commercial paper rating. The securities of PNW and APS have been removed from Rating Watch Negative, where they were placed Jan. 6, 2006. The Rating Outlook is Stable. The following actions are effective immediately:

Pinnacle West Capital:

--Issuer default rating (IDR) downgraded to 'BBB-' from 'BBB';
--Senior unsecured debt downgraded to 'BBB-' from 'BBB';
--Commercial Paper downgraded to 'F3' from 'F2'.

The Rating Outlook is Stable.

Arizona Public Service Co.

--IDR downgraded to 'BBB-' from 'BBB';
--Senior unsecured debt downgraded to 'BBB' from 'BBB+';
--Commercial Paper affirmed at 'F2'.

The Rating Outlook is Stable.

Approximately $3.8 billion of debt is affected by the rating actions.

The rating actions and Stable Rating Outlook reflect the resolution of APS' power supply adjustor (PSA) proceedings by the Arizona Corporation Commission (ACC) and the utility's significant exposure to high and rising natural gas commodity costs. The commodity exposure is a function of a generating capacity mix, about half of which is natural gas fired, and rapid service territory load growth, which is likely to be met predominantly by natural gas-fired resources. The revised ratings also consider the operational risk and asset concentration of the Palo Verde nuclear plant. The facility has experienced intermittent operating problems over the past year and a sustained, unscheduled outage at the plant could lead to further negative rating actions.

The ACC decision in the PSA proceedings, issued on Jan. 25, 2006, has positive and negative implications for PNW and APS' creditworthiness. The commission's decision to accelerate the effective date of the PSA rate to Feb. 1 from April 1, along with the removal of the $776 million annual power supply cost limit, were constructive developments in Fitch's view. However, the ACC bench order rejecting APS's $80 million surcharge request on procedural grounds and restriction of PSA adjustments to an annual reset is less favorable than Fitch had anticipated in its previous ratings and is a significant source of concern for PNW and APS fixed-income investors. The fact that there is no vehicle within the PSA protocol to recover supply costs more frequently than annually during periods of sustained high and rising energy costs subjects APS to significant cash flow volatility and working capital requirements. Such costs would be exacerbated in a meaningful way by an extended outage of a base load nuclear- or coal-fired generating facility during periods of peak demand. The only option to recover fuel and purchase power costs above amounts determined annually in the PSA would be an emergency rate filing, in which the timing and amount of rate relief would be uncertain.

It is Fitch's understanding that energy cost deferrals in a particular year of up to four mills per kilowatt hour (approximately $110 million-$115 million on an annual run rate) will be recovered through an annual PSA rate adjustment that will recover those costs over the following 12 months. The surcharge is expected to facilitate recovery of costs in excess of the four mills per kilowatt hour limit over a time horizon to be determined by the commission.

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Fitch's rating definitions and the terms of use of such ratings are available on the agency's public site, 'www.fitchratings.com'. Published ratings, criteria and methodologies are available from this site, at all times. Fitch's code of conduct, confidentiality, conflicts of interest, affiliate firewall, compliance and other relevant policies and procedures are also available from the 'Code of Conduct' section of this site.

STANDARD & POOR'S | RATINGSDIRECT

RESEARCH

Credit FAQ: Credit Issues Expected To Continue For Pinnacle West Capital Corp. And Arizona Public Service Co.

Publication date: 24-Jan-2006
Primary Credit Analyst: Anne Selting, San Francisco (1) 415-371-5009; anne_selting@standardandpoors.com

On Dec. 21, 2005, Standard & Poor's Ratings Services lowered the corporate credit ratings on Arizona Public Service Co. (APS) and its parent, Pinnacle West Capital Corp. (PWCC) by one notch to 'BBB-'. This action reflected three factors: growing fuel and purchased power deferrals, which are weakening financial performance in 2005 and 2006, the lack of action by the Arizona Corporation Commission (ACC) in 2005 to address a portion of these deferrals through a special surcharge, and the likelihood of delays in the completion of APS' recent general rate case (GRC) filing, which suggest that financial weakening may extend into 2007.

Standard & Poor's stated at the time that any adverse regulatory developments or continued delays in resolving the pending surcharge request could trigger another rating action, which could include a revision of the stable rating outlook to negative, placing the company's debt rating on CreditWatch with negative implications, or lowering the rating to non-investment grade.

Frequently Asked Questions

How large are APS' deferrals of fuel and purchased power?
At Jan. 31, 2006, APS' estimated fuel and purchased power deferrals are expected to be about $165 million. These deferrals are accumulating because APS' base electric rates are set to reflect 2003 costs, and power and natural gas costs have far exceeded these rates. APS collects 2.0473 cents per kilowatt-hour (kWh) in rates for these costs, but for the 12 months ended September 2005, its actual cost averaged 2.701 cents per kWh. Because these rates will not be updated until the completion of APS' recently filed GRC or the emergency interim request, deferrals will likely continue to accumulate in 2006 and into 2007.

The amount by which 2006 actual fuel and purchased power costs will exceed the authorized expenditures will be a function of retail sales growth, commodity costs, the operational performance of APS' generation assets, and the fuel-in-base factor. Standard & Poor's has estimated that, at year-end 2006, the utility will likely incur an additional $250 million in fuel and purchased power costs that are not recoverable in base electric rates. The sum of balances to date of $165 million plus the expected incremental deferrals of $250 million total $415 million; however, because APS has the potential to collect some of its 2005 balances through a power supply adjuster (PSA) beginning April 1, year-end 2006 deferrals on the utility's balance sheet will not reach that level.

What are the ways that APS could recover its expected deferrals?

Under the terms of a settlement reached in APS' 2003 rate case approved by the ACC in April 2005, the PSA may be increased as much as four mills per kWh (a cap over the life of the PSA) on April 1, 2006. Using 2005 retail sales, and assuming a 4.5% growth rate (which is consistent with recent results), the four mills should yield about $125 million in rate relief on an annualized basis, or about $83 million for the eight months of 2006. Thus, as a rough approximation, APS' deferred balance would be about $330 million at year-end 2006.

On Jan. 17, the chairman of the ACC introduced a proposal to accelerate the PSA adjustment to Feb. 1. If this were approved by the ACC, an additional two months of the PSA would provide about $20 million in incremental revenues (e.g., roughly $125 million multiplied by two-twelfths of the year) in 2006. Thus, if the Hatch-Miller amendment moves forward, year-end 2006 deferred balances will be closer to about $310 million. The amendment is expected to be discussed on Jan. 24.

Additional relief could be provided if the ACC grants APS' request to recover $80 million by means of a two-year special surcharge that would increase retail rates by about 2%. On Jan. 4, an administrative law judge issued a decision indicating that APS' surcharge application is premature until the company's first power supply adjustment occurs in April. An ACC vote is scheduled for Jan. 24. Standard & Poor's current assumption is that the surcharge will be approved by the ACC, but will be delayed until July 1, 2006. A surcharge implemented at this time would provide roughly an additional $20 million to the company in 2006. If it were implemented sooner, the impact on deferrals would be relatively small, providing about $3 million in each month it is in place during 2006. If the Hatch-Miller amendment were approved and a surcharge was implemented and approved for Feb. 1, the two measures collectively would bring between $50 million-$57 million in relief. Accordingly, relative to the year-end expected balances, an accelerated surcharge and PSA, if granted, will reduce deferrals but only by about 20% in the best-case scenario.

What is the status with APS' emergency interim filing?
On Jan. 6, 2006, APS filed a $299 million request for emergency fuel and purchased power-related rate relief. Any amounts, if granted, would be subject to future prudency review. As part of a procedural conference on Jan. 12, four of the five commissioners questioned the definition an emergency and whether relief is justified. Based on the strong views expressed, it appears unlikely that the filing has support. On Jan. 19, a procedural schedule was set that should allow for a decision in April 2006. Standard & Poor's forecast estimates do not assume emergency relief is granted.

Are there credit concerns related to APS' rate cap?
Balancing these potential sources of rate relief are additional adverse financial effects that could occur for APS if its "hard cap" of $776 million is not lifted. The cap is part of APS' 2004 settlement, approved by the ACC in April 2005, which restricts the total amount of annual fuel and purchased power costs that can be collected in retail rates. APS expects that its fuel and purchased power costs will exceed the cap in the fourth quarter of 2006, and has indicated publicly that its estimated fuel costs will exceed $800 million. As part of its emergency interim filing, APS has requested that the cap be removed. If the cap is not lifted, any amounts above $776 million would be unrecoverable, putting further pressure on cash flows.

What assumptions does Standard & Poor's make about the performance of APS' generation assets in estimating deferred balances?
Standard & Poor's estimates assume normal operational performance of APS' generation fleet. Forced outages could increase deferred balances. Palo Verde unit 1 is in the process of exiting an outage that occurred last week due to pipe vibrations within the emergency cooling system. APS took the unit offline last week to install clamps in an effort to stop the excess vibrations. From late December until Jan. 17, unit 1 has operated at about 30% capacity while crews have tried to fix the problem, which followed the completion of the unit's exit from a refueling and maintenance outage begun in the fall of 2005. The plant is expected to maintain approximately this level of reduced capacity while additional repairs are considered. Replacement power costs have been incurred in association with this last outage, and could build, depending on the timeline for a solution to be implemented. These and any future costs are not part of Standard & Poor's deferred estimates.

How are these estimated deferrals expected to affect 2005 and 2006 financial performance, especially in the context of the credit benchmarks at the 'BBB-' rating?
Year-end results for 2005 are not yet available, but Standard & Poor's expects that 2005 and 2006 results will be on par with the 12 months ending Sept. 30, 2005, when consolidated adjusted funds from operations (FFO) to total debt was 14.8%. FFO to total debt is an important metric for Standard & Poor's, and at a business profile of '6' (on a 10-point scale where '1' is excellent and '10' vulnerable), it reflects a below-investment-grade performance. For the 12 months ending Sept. 30, 2005, FFO interest coverage was 3.3x, which is reasonable for the current rating. Adjusted total debt to total capitalization was 53.1%, and is solid for the current rating.

Performance in 2007 will be heavily dependent on when the GRC is resolved. APS filed on Nov. 4, 2005, for a $409.1 million (or 19.9%) rate increase, the majority of which is related to fuel and purchased power costs. Typically, the ACC certifies the application as complete within 30 days, and the case commences. But in early December 2005, the ACC requested that the company re-file its application using a test year ending Sept. 30, 2005, rather than the Dec. 31, 2004 data that APS used. The updated application is expected to be re-submitted to the ACC on Jan. 31, 2005.

As a result, the case will not begin until early March 2006, suggesting that an outcome will be delayed roughly three months from the original schedule, which envisions a ruling by early 2007. Recent public statements by the ACC indicate that spring 2007 may be the earliest a decision could be expected. But there is little precedent in Arizona that would suggest a year-long rate case is likely. A more conservative estimate would assume mid-2007. This could be a credit concern because if permanent rate relief is not in place prior to the peak summer season, financial recovery could also be stalled in 2007.

How is the company's liquidity?

Unaudited consolidated cash and investments stood at roughly $150 million as of Dec. 31, 2005. PWCC and APS also maintain a total of $700 million in revolving credit facilities, which had approximately $15 million of usage at year-end 2005 for miscellaneous letters of credit. Standard & Poor's preliminary assessment is that the company's credit lines should be sufficient to support working capital needs, purchases of gas and power, as well as fund margining and collateral requirements for trading operations. As of Dec. 31, 2005, PWCC and APS comfortably met their loan covenant requirements.

PWCC has a $300 million dollar maturity on April 1, which it plans to refinance. Adverse regulatory actions could affect the costs of borrowing or even access to the capital markets, although this is not currently seen as a significant threat.

APS' reliance on purchases and gas-fired peaking capacity during the winter is low; however, this is seasonal. Fuel and purchased power expenses are anticipated to be accrued faster in July 2006 through September 2006. Standard & Poor's is conducting a more detailed liquidity assessment, which will be completed once more clarity is provided on how the ACC is expected to address interim rate relief requests. APS has a significant hedging program and 85% of its 2006 power and gas requirements are hedged. APS and PWCC are currently holding counterparties' collateral as a result of their in-the-money hedged positions.

Could cost saving measures, or the sale of nonregulated assets by PWCC assist in restoring credit quality?

The ACC has requested that the company explain what cost reductions it is making to compensate for the fact that its retail rates are not aligned with production costs. In response, the company cancelled bonuses for its corporate officers, and is certain to investigate additional cost-savings measures. While these actions may address other public policy issues of concern to the ACC, from a credit standpoint cost cutting measures are unlikely to materially alleviate APS' sagging financial performance.

The deferred balances stem from fuel and purchased power costs that the utility incurred to serve retail loads. APS earns no margin on these expenses; they are simply passed straight through to customers. Similar to the circumstances that other western utilities have faced in recent years, APS' fuel and purchased costs substantially exceed the amount currently recoverable in rates. The company may be able to temporarily subsidize the cost of serving retail loads by reducing expenses in other parts of the company, selling other PWCC assets, or issuing debt, but such a strategy is not sustainable, and could very well result in longer-term adverse consequences for the company.

ARIZONA CORPORATION COMMISSION STAFF'S
FOURTH SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY
DOCKET NO. E-01345A-06-0009
FEBRUARY 7, 2006

STF 4.48 Please provide all analysis conducted in preparation for the Emergency Rate Case by the company or its contractors/consultants of the Company's financial condition that have not been previously provided to the Commission.

Response:

See the attachments APS07014 files for financial results assuming the Company received the 14% interim rate increase effective April 1,2006, and attachments APS07015 for financial results assuming the Company received present base rates and no PSA revenues in 2006, but PSA deferrals continued.

Also, see attachment APS07016 file for calculation of the percentage of capital expenditures covered by net cash flow for the past 10 years, as well as the 2006 through 2009 period, that leads to the over $1 billion financing need for 2006-2009.

ARIZONA CORPORATION COMMISSION STAFF'S
FIRST SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY
RE: DOCKET NO. E-01345A-06-0009
JANUARY 11, 2006

STF 1-6: At page 5 lines 24-25 Mr. Brandt states that APS' borrowing costs have increased $1 million per year as a result of S& P's downgrade. Please show how that $1 million figure was developed.

Response:

S&P Downgrade Impacts

Increased Annual Costs of Bank Facilities/Insurance:

APS – Sr. Unsecured
Old Rating BBB/Baa1
New Rating BBB-/Baa1

Facility	Amount ($M)	Old Pricing (bp)	New Pricing (bp)	Additional Annual Cost ($)
Citibank Revolver	395.2	9.0	11.0	79,040
Letters of Credit under Revolver	4.8	40.0	50.0	4,800
Sale Leaseback Letter of Credit	93.1	60.0	70.0	46,538
Sale Leaseback Letter of Credit	90.8	60.0	70.0	45,382
Farmington 1994A-C Letter of Credit	149.6	50.0	50.0	0
Coconino 1994A & 1998 Letter of Credit	50.5	60.0	60.0	0
Maricopa 2002A Insurance	90.0	0.0	0.0	0
Coconino 2004A Insurance	12.9	22.5	32.5	12,850
Navajo 2004A-E Insurance	166.2	22.5	32.5	166,150
Maricopa 2005A-E Insurance	164.0	16.0	26.5	172,174
			Total	**$526,934**

Average Commercial Paper Outstanding	$200M
Additional Interest Due to Downgrade	25bp
Additional Annual Interest	**$500K**

The sum of the additional bank facility/insurance costs and the additional interest on commercial paper is $1,026,934.

ARIZONA CORPORATION COMMISSION STAFF'S
FIRST SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY
RE: DOCKET NO. E-01345A-06-0009
JANUARY 11, 2006

STF 1-14: Please describe the nature of the "emergency." That is, explain what factor(s) caused APS to characterize their January 6 application as an Application for Emergency Interim Rates ... Please be specific.

Response:

Whether an "emergency" exists is a conclusion to be drawn from the specific facts before the Commission. Indeed the Attorney General stated In Op. Atty. Gen. 71-17 that the "only valid generalization on this subject' [of what constitutes an emergency] is that a mere allegation of a low rate of return, standing alone, is not an "emergency. . ." The Attorney General's opinion further references the need "to avoid serious damage" is the fundamental basis for emergency relief. With this background, the facts are as follows:

(1) APS has experienced a dramatic increase in its fuel and purchased power costs since the establishment of the base fuel rate in Decision No. 67744 and will continue to face continued and significant further increases in those costs during 2006.

(2) Because these increases are not reflected in either base rates or in PSA rates, APS' cost deferrals have reached some $170 million by the end of 2005 and will continue to increase in 2006 even if the annual adjustment to the PSA is implemented on April 1, 2006 and even if the pending PSA surcharge is approved – reaching an estimated $285 million by December 31, 2006.

(3) The continued imbalance between fuel costs and cost recovery has weakened the Company's key financial indicators to the point where APS has been down-rated by one major rating agency (S&P) to the lowest investment-grade rating and put on negative watch for a downgrade by the other two (Moody's and Fitch). All three have threatened further downgrades if the Commission does not address fuel cost recovery in a manner that reverses the downward trend in the Company's financial indicators.

(4) A further downgrade of APS to "junk bond" status will cost between $10-15 million in higher interest and other financing costs in 2006

with an escalating impact in future years such that the total cost increase to customers will be some $1 billion, if not more, over the next 10 years. It will also impede the Company's ability to attract the new capital it will need to meet growth and continue to provide customers with reliable service at a reasonable cost.

(5) Credit limitations imposed on APS as a result of a further downgrading will increase the cost of acquiring the fuel and purchased power needed to serve customers, thus additionally burdening APS customers with costs that could be avoided by timely Commission action to prevent the downgrade. They also consume already scarce cash resources needed to fund infrastructure improvement and expansion. These limitations range from higher collateral requirements, to reduced liquidity as certain venders drop out of the market available to APS, to prepayment requirements for power, gas, gas transportation, and coal.

(6) Once downgraded, it will take years and sustained positive regulatory action to reverse the situation, but the much of the higher cost alluded to above will continue on until such time as the debt incurred during the interim period of years can be repaid or refinanced.

(7) Without an interim raising of the $776.2 million "cap," APS will be unable to defer some $65 million in 2006 fuel costs, thus potentially affecting its ability to ever recover such sums.

(8) The pending APS general rate case will not be decided within a reasonable time, by which the Company means, within time to prevent the above circumstances from happening. And even a 100% favorable outcome from that proceeding likely would not be sufficient to result in an upgrade of APS or undue the loss to APS during 2006 resulting from the $776.2 million "cap."

These facts, if not addressed by the Commission in this interim filing, constitute "serious damage" to APS and its customers just as, if not more so, the inability of APS to timely complete Palo Verde was found to be in 1984 or the prospective loss by Arizona Water Company of tax benefits was found to be in 1982.

ARIZONA CORPORATION COMMISSION STAFF'S
FIRST SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY
RE: DOCKET NO. E-01345A-06-0009
JANUARY 11, 2006

On the other hand, APS customers are only being asked to pay for the fuel costs necessary to serve them both since April 2005 and in 2006 – costs for which they will be responsible whether paid in the form of interim rates, PSA charges and/or higher base rates resulting from Docket No. E-01345A-05-0816. To the extent the Commission later finds that any portion of such costs was imprudently incurred, customers will receive a refund or other appropriate adjustment.

In sum, customers are fully protected from a grant of interim relief that is later found to be in even the smallest degree unwarranted by closer examination of the prudence of the Company's actions. Their only protection from the higher costs attributable to the Company's slide into "junk bond" status is action by this Commission. As was again noted by the Attorney General in his opinion, the goal of emergency relief is to prevent the emergency from happening and not to wait until all that can be done is to attempt to repair the damage.

ARIZONA CORPORATION COMMISSION STAFF'S
FOURTH SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY
DOCKET NO. E-01345A-06-0009
FEBRUARY 7, 2006

STF 4.7 Provide a description of all provisions in all APS bond indentures that address minimum financial ratios and/or default conditions

Response:

There are no provisions in any APS' indentures that address minimum financial ratios.

Events of default are:

- Non-payment of principal, interest or fees;
- Non-compliance with covenants;
- Bankruptcy and insolvency events.

See also response to STF 4.8.

ARIZONA CORPORATION COMMISSION STAFF'S
FOURTH SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY
DOCKET NO. E-01345A-06-0009
FEBRUARY 7, 2006

STF 4.8 Provide a description of all provisions in all APS credit arrangements that address minimum financial ratios and/or default conditions

Response:

There are two provisions that address minimum financial ratios. The first one is the requirement that APS maintain Interest Coverage of at least two times, and the second one requires that the amount of debt does not exceed 65% of total capitalization.

Events of default are:

- Non-payment of principal, interest or fees;
- Material misrepresentations;
- Non-compliance with covenants;
- Non-payment under significant operating leases;
- Bankruptcy and insolvency events;
- Judgments against APS significantly exceeding insurance coverage;
- Change in control of PWCC or APS;

ERISA violations.

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
JEFF HATCH-MILLER, Chairman
WILLIAM A. MUNDELL
MARC SPITZER
MIKE GLEASON
KRISTIN K. MAYES

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	DOCKET NO. E-01345A-06-0009 **STAFF'S SECOND NOTICE OF ERRATA**

NOTICE IS HEREBY GIVEN by Staff of the Arizona Corporation Commission that the testimony of its witness Ralph C. Smith incorrectly identified the attachment at page 14, lines 25-26. Lines 25-27 should read as follows:

> As noted above, a subsequent S&P report dated January 26, 2006 (see Attachment RCS-3), has nevertheless stated that the agency's outlook for APS and PNW is "stable."

The correction is being provided in both red-lined and final versions.

RESPECTFULLY SUBMITTED this 8th day of March 2006.

Janet Wagner

Christopher C. Kempley, Chief Counsel
Janet Wagner, Senior Staff Counsel
Jason Gellman, Senior Staff Counsel
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The basis for the amount of the emergency increase requested by APS is the Company's projected higher annual fuel and purchased power costs the Company expects to incur in 2006.

Q. Have any of the rating agencies discussed their outlook for APS's emergency interim filing?

A. Yes. S&P discussed its outlook and expectations for APS's emergency interim filing in a report issued January 24, 2006. See Attachment RCS-5. On the second page of that report, S&P stated that:

> **"What is the status with APS' emergency interim filing?**
>
> On Jan. 6, 2006, APS filed a $299 million request for emergency fuel and purchased power-related rate relief. Any amounts, if granted, would be subject to future prudency review. As part of a procedural conference on Jan.12, four of the five commissioners questioned the definition of an emergency and whether relief is justified. Based on the strong views expressed, it appears unlikely that the filing has support. On Jan. 19, a procedural schedule was set that should allow for a decision in April 2006. Standard & Poor's forecast estimates do not assume emergency relief is granted."

S&P's January 24, 2006 report has stated that it appears unlikely that APS's emergency interim filing has support at the Commission, and S&P's forecast estimates do not assume emergency relief is granted. As noted above, a subsequent S&P report dated January ~~30~~ 26, 2006 (see Attachment ~~RCS-6~~ RCS-3), has nevertheless stated that the agency's outlook for APS and PNW is "stable."

The basis for the amount of the emergency increase requested by APS is the Company's projected higher annual fuel and purchased power costs the Company expects to incur in 2006.

Q. Have any of the rating agencies discussed their outlook for APS's emergency interim filing?

A. Yes. S&P discussed its outlook and expectations for APS's emergency interim filing in a report issued January 24, 2006. See Attachment RCS-5. On the second page of that report, S&P stated that:

> **"What is the status with APS' emergency interim filing?**
>
> On Jan. 6, 2006, APS filed a $299 million request for emergency fuel and purchased power-related rate relief. Any amounts, if granted, would be subject to future prudency review. As part of a procedural conference on Jan.12, four of the five commissioners questioned the definition of an emergency and whether relief is justified. Based on the strong views expressed, it appears unlikely that the filing has support. On Jan. 19, a procedural schedule was set that should allow for a decision in April 2006. Standard & Poor's forecast estimates do not assume emergency relief is granted."

S&P's January 24, 2006 report has stated that it appears unlikely that APS's emergency interim filing has support at the Commission, and S&P's forecast estimates do not assume emergency relief is granted. As noted above, a subsequent S&P report dated January 26, 2006 (see Attachment RCS-3), has nevertheless stated that the agency's outlook for APS and PNW is "stable."

EXHIBIT
ALL-STATE LEGAL®
S-4
admitted

BEFORE THE ARIZONA CORPORATION COMMISSION

JEFF HATCH-MILLER
Chairman
WILLIAM A. MUNDELL
Commissioner
MARC SPITZER
Commissioner
MIKE GLEASON
Commissioner
KRISTIN K. MAYES
Commissioner

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	DOCKET NO. E-01345A-06-0009

DIRECT

TESTIMONY

OF

WILLIAM GEHLEN

PUBLIC UTILITIES ANALYST V

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

FEBRUARY 28, 2006

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EXECUTIVE SUMMARY
ARIZONA PUBLIC SERVICE COMPANY
DOCKET NO. E-01345A-06-0009

On January 6, 2006, Arizona Public Service ("APS" or "Company") filed with the Commission an application for an emergency interim rate increase and for an interim amendment to Decision No. 67744. The interim rate increase of $299 million in additional annual revenues, or approximately a 14 percent increase, was requested to have an April 1, 2006 implementation date.

The result of Staff's analysis indicates that the APS production cost simulation model provides a reasonable assessment of projected uncollected fuel and purchased power expenses through 2006. The volatility of projections is minimized because APS has hedged 85 percent of its natural gas and purchased power costs for 2006. Barring a significant change in the actual load, or a loss of a base generating unit, the projected uncollected fuel and purchase power expenses are predictable.

INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is William Gehlen. I am a Public Utilities Analyst V employed by the Arizona Corporation Commission ("ACC" or "Commission") in the Utilities Division ("Staff"). My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. Briefly describe your responsibilities as a Public Utility Analyst V.

A. In my capacity as a Public Utilities Analyst V, I provide recommendations to the Commission on energy-related issues.

Q. Please describe your educational background and professional experience.

A. I earned a BS degree in Business Administration from Aquinas College, and an MBA from Western Michigan University. My background includes 26 years of utility experience with 16 years in investor-owned utilities. In the fuels area, I have been responsible for the planning, procurement and transportation of multiple fuel categories (natural gas, gasoline, coal, oil and nuclear). In addition, I have been responsible for the procurement of land, equipment, services, consulting and construction contracts, and purchased power (short-, medium- and long-term). Management positions also included responsibility for integrated resource planning, long-range forecasting, transmission planning, environmental affairs and strategic planning. My most recent 10 years experience includes one year with Office of Consumer Advocate for the State of Nevada as a regulatory analyst, and nine years in the development and marketing of energy trading platforms, origination of purchased power agreements, real time energy trading, and support of merchant generators in gathering market intelligence on regulatory, fuel and product issues to aid in understanding inter and intra regional market design issues and solutions.

Q. What is the scope of your testimony in this case?

A. I will address the Arizona Public Service Company ("APS" or "Company") request for an emergency interim rate increase of $299 million in annual revenue, and for an interim amendment to Decision No. 67744. I will evaluate the APS load forecast and hedging assumptions to determine the reasonableness of the projected uncollected fuel and purchased power expenses.

KEY COMPONENTS AND PROJECTIONS

Q. Describe the key components in the calculation of projected uncollected fuel and purchased power expenses.

A. The key planning component in determining fuel and purchased power costs is the load forecast. Modeling assumptions in the APS production cost simulation model are keyed to the load forecast. The projected usage of fuel and purchased power are calculated in the modeling process as their demand is determined by dispatching APS generating units on an economic basis.

Q. Describe the Company's production cost simulation model.

A. The APS production cost simulation model simulates the dispatch of generation units on an hourly and daily basis. The variables included in the simulation are load shape, fuel prices (including wholesale market prices for power) and characteristics of APS-owned generating plants (heat rates, overhaul cycles, unplanned outage rates, start-up costs and ramp rates), along with commitments for purchases and sales of power. In addition, the model simulates market purchases when load exceeds generating capacity, and conversely simulates market sales when the generating units are not fully utilized. As the production cost simulation model dispatches units in merit order sequence, the fuel cost associated with each unit is utilized. The average costs of coal and nuclear power are fairly predictable while the costs of gas and purchased power have been hedged to lock in a known cost for 85 percent of APS' predicted requirement.

Q. Describe the Company's fuel and purchased power hedges for 2006.

A. The Company has developed a hedge implementation strategy. The intent of the strategy is to manage price risk that has arisen from increased volatility in the natural gas and purchased power markets. At present, the Company has hedged 85 percent of its 2006 natural gas and purchased power requirements. The 2006 hedges were entered into over a two year period (25 percent hedged by November 8, 2004; 50 percent hedged by April 13, 2005; and 85 percent hedged by August 29, 2005). As such, the prices associated with 85 percent of the natural gas and purchased power for 2006 are known. Assuming an accurate load forecast, the 15 percent that is not hedged will be obtained at market prices which may be higher, or lower, than the hedged amounts.

Q. **If fuel and purchased power costs are lower in 2006, will there be a significant impact on the projected uncollected fuel and purchased power expenses?**

A. No. With 85 percent of the 2006 natural gas and purchased power costs known values, the projected uncollected fuel and purchased power cost changes, both up or down, are limited. Uncollected fuel and purchased power expenses are as much influenced by actual load as fuel and purchased power prices. The actual load incurred versus forecasted load will determine the actual need for fuel and purchased power. Natural gas and purchased power prices have recently been dropping but the impact, if any, of these recent prices is hard to determine. The projected load forecast may be low, and gas and purchased power prices may increase with increased demand during the peak usage months of June through September, or not. Both the load forecast and fuel and purchased power prices can, and will, vary but neither variable will result in a significant impact on uncollected fuel and purchased power expenses as long as the other forecast variables are held constant.

Q. What would have the greatest impact on projected uncollected fuel and purchased power expenses?

A. With hedging of natural gas and purchased power, the greatest impact on fuel and purchased power expenses would be the loss of a nuclear, or coal, base unit resource during the peak June through September period. To cover the loss of a base generating unit, APS would become even more reliant on its gas generating units as well as the purchased power market which is indexed to the price of natural gas. This would result in a dramatic increase in gas and purchased power costs. An example of this is the $44.6 million APS spent to cover power replacement cost for Palo Verde associated outages in 2005 (Docket No. E-01345A-06-0063).

CONCLUSION

Q. Are the APS projections for uncollected fuel and purchased power expenses reasonable?

A. Yes. Staff evaluated the assumptions utilized in calculating the various projections for uncollected fuel and purchased power expenses for 2006. The software utilized and assumptions on load growth, outage rates, fuel costs and characteristics of APS generating plants are consistent with projections developed for Docket No. E-01345A-05-0526 (Application of APS for Approval of a Power Supply Adjustor Surcharge). The projected uncollected balances proved reliable utilizing a hedging percentage of 75 percent. The 85 percent hedging of fuel and purchased costs for 2006 in this docket remove even more volatility from projections, which should provide more reliable projections than those for 2005.

Q. Does this conclude your direct testimony?

A. Yes, it does.

EXHIBIT
S-5
admitted

BEFORE THE ARIZONA CORPORATION COMMISSIC

JEFF HATCH-MILLER
Chairman
WILLIAM A. MUNDELL
Commissioner
MARC SPITZER
Commissioner
MIKE GLEASON
Commissioner
KRISTIN K. MAYES
Commissioner

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.)	DOCKET NO. E-01345A-06-0009

DIRECT

TESTIMONY

OF

BARBARA KEENE

PUBLIC UTILITIES ANALYST MANAGER

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

~~FEBRUARY 28~~MARCH 1, 2006

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APPENDICES

EXECUTIVE SUMMARY
ARIZONA PUBLIC SERVICE COMPANY
EMERGENCY INTERIM RATE INCREASE
DOCKET NO. E-01345A-06-0009

This testimony estimates the impact of Arizona Public Service Company's proposed emergency interim rate increase on the bills of its residential customers. The testimony also responds to the February 9, 2006, letter by Commissioner Mayes for estimates of the impact on bills of the rate increase approved in April 2005; the February 1, 2006, adjustor reset; APS' proposed surcharges; and the proposed general 2006 rate case.

INTRODUCTION

Q. Please state your name and business address.

A. My name is Barbara Keene. My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

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

A. I am employed by the Utilities Division of the Arizona Corporation Commission as a Public Utilities Analyst Manager. My duties include supervising the energy portion of the Telecommunications and Energy Section. A copy of my résumé is provided in Appendix 1.

Q. As part of your employment responsibilities, were you assigned to review matters contained in Docket No. E-01345A-06-0009?

A. Yes.

Q. What is the subject matter of your testimony?

A. Staff's testimony estimates the impact of Arizona Public Service Company's ("APS") proposed emergency interim rate increase on the bills of its residential customers. The testimony also responds to the February 9, 2006, letter by Commissioner Mayes for estimates of the impact on bills of the rate increase approved in April 2005; the February 1, 2006, adjustor reset; APS' proposed surcharges; and the proposed general 2006 rate case.

IMPACT OF APS' PROPOSED EMERGENCY INTERIM RATE INCREASE

Q. What did APS propose in its application for an emergency interim rate increase?

A. In its application, APS proposed that the base cost of fuel and purchased power be reset to $0.031904 per kWh. In April 2005, Decision No. 67744 set the base cost at $0.020743 per kWh. Therefore, the difference between the two base costs would be $0.011161 per kWh.

Q. What is the effect of changing the base cost?

A. There are actually two effects of APS' proposal. The first effect is that customer rates would go up by $0.011161 per kWh. The second effect is that future amounts being deferred for recovery through APS' Power Supply Adjustor ("PSA") would be reduced because of the higher base cost of fuel and purchased power.

Impact on Customer Bills of APS' Proposal

Q. What would be the impact on customer bills of APS' proposed emergency interim rate increase?

A. As proposed by APS, rates would be increased by $0.011161 per kWh. Although APS requested the increase to be effective on April 1, 2006, the current procedural schedule contemplates a Commission Decision in May 2006. As a result of the increase, the average summer bill for a residential customer on E-12 (using 1,047 kWh) would increase by $11.69 or 9.97 percent over current rates.

Table 1
Impact of APS-Proposed Emergency Interim Rate Increase on Residential Customer Bills

	E-12 Bill Under Current Rates	E-12 Bill With Emergency Interim Rate Increase	Dollar Increase	Percent Increase
Summer (July)				
Average Usage (1047 kWh)	$117.26	$128.94	$11.69	9.97%
Median Usage (818 kWh)	$87.66	$96.79	$9.13	10.41%
Winter (December)				
Average Usage (677 kWh)	$61.80	$69.35	$7.56	12.23%
Median Usage (531 kWh)	$50.26	$56.19	$5.93	11.79%

Impact on the PSA of APS' Proposal

Q. Please describe the impact of APS' proposed emergency interim rate increase on the PSA.

A. APS' proposal would raise the base cost of fuel and purchased power from $0.020743 per kWh to $0.031904 per kWh. In the PSA Tracking Account, actual costs are compared to base costs. The annual adjustor rate calculation uses the difference between the actual costs and the base costs in the determination of the new adjustor rate. If base costs are closer to actual costs, the amount flowing into the adjustor rate calculation is smaller.

Using APS' forecasts of sales and fuel and purchased power costs for 2006, the Tracking Account balance at the end of the year would be about $244.9 million if the base cost remains at $0.020743 per kWh. The February 2007 adjustor rate calculation would result in the Adjustor Rate remaining at $0.004 and about $197.2 million going into the Paragraph 19(d) Balancing Account. This calculation assumes that no surcharges to collect 2005 costs were approved. (See Appendix 2 for the PSA schedules.)

If the base cost is raised to $0.031904 per kWh in May 2006, the Tracking Account balance at the end of the year would be about $39 million. The February 2007 adjustor rate calculation would result in the Adjustor Rate being reduced to $0.003689 and nothing going into the Paragraph 19(d) Balancing Account.

Table 2
Impact of Change in Base Cost on Power Supply Adjustor

Base Cost	End of 2006 Tracking Account Balance	February 2007 Adjustor Rate	Carried Forward to Paragraph 19(d) Balancing Account
$0.020743 per kWh	$244.9 million	$0.004000 per kWh	$197.2 million
raised to $0.031904 per kWh in May 2006	$39.0 million	$0.003689 per kWh	$0

BILL IMPACTS OF OTHER RATE INCREASES

Q. Please describe the impacts on customer bills of other approved or proposed rate increases, as requested by the February 9, 2006, letter of Commissioner Mayes.

A. The first rate increase to be discussed is the rate case increase approved by the Commission in April 2005 (Decision No. 67744). Before that rate increase, the average summer bill for a residential customer on E-12 (using 1,047 kWh in July) was $108.10. After the rate increase, the bill increased by $4.97 or 4.60 percent. The average winter bill for a residential customer on E-12 (using 677 kWh in December) was $57.91 before the rate increase. After the rate increase, the bill increased by $1.18 or 2.04 percent.

Table 3
Impact of April 2005 Rate Case Decision on Residential Customer Bills

	E-12 Bill Before 4/05 Rate Case Increase	E-12 Bill After 4/05 Rate Case Increase	Dollar Increase	Percent Increase
Summer (July)				
Average Usage (1,047 kWh)	$108.10	$113.07	$4.97	4.60%
Median Usage (818 kWh)	$80.64	$84.39	$3.75	4.65%
Winter (December)				
Average Usage (677 kWh)	$57.91	$59.09	$1.18	2.04%
Median Usage (531 kWh)	$47.11	$48.14	$1.03	2.19%

Q. As other rate impacts are discussed, how will the impact over time be described?

A. For each rate change, the impact on the rates current at that time will be discussed and the cumulative impact of all the rate changes that had occurred by that time will be described. The cumulative rate impacts represent the change from rates that were in effect before the April 2005 rate case decision and are listed under the heading "Cumulative Percent Increase Over pre-April 05 Rates" in the tables.

Q. Can the individual rate percent increases be added together to total a cumulative percent increase?

A. No. The rate impacts are compounded. Here is an example.

step 1. A customer bill is $10.

step 2. A 5 percent increase makes the bill $10.50 (5 % of $10 = $0.50).

step 3. Then a 4 percent increase makes the bill $10.92 (4% of $10.50 = $0.42).

step 4. Compare the bill in step 3 ($10.92) to the bill in step 1 ($10): $10.92 is 9.2 percent higher than $10. This is different than simply adding 5 percent and 4 percent to total 9 percent. It is because the 4 percent is applied to $10.50, not to $10.

Q. Please describe the next rate impact on APS' residential customers.

A. The next rate impact was the resetting of the PSA adjustor rate on February 1, 2006. The PSA was increased by $0.004 per kWh. As a result, the average winter bill for a residential customer on E-12 (using 677 kWh) increased by $2.71 or 4.58 percent. The cumulative percent increase including the April 2005 rate case decision was 6.71 percent for winter bills and 8.47 percent for summer bills.

Table 4
Impact of February 2006 PSA Adjustor Rate Reset on Residential Customer Bills

	E-12 Bill After 4/05 Rate Case Increase	E-12 Bill After 2/06 PSA Adjustor Rate Reset	Dollar Increase	Percent Increase	Cumulative Percent Increase Over pre-April 05 Rates
Summer (July)					
Average Usage (1047 kWh)	$113.07	$117.26	$4.19	3.70%	8.47%
Median Usage (818 kWh)	$84.39	$87.66	$3.27	3.88%	8.71%
Winter (December)					
Average Usage (677 kWh)	$59.09	$61.80	$2.71	4.58%	6.71%
Median Usage (531 kWh)	$48.14	$50.26	$2.12	4.41%	6.69%

Q. Please describe the rate impact associated with APS' proposed emergency interim rate request.

A. As proposed by APS, rates would be increased by $0.011161 per kWh. As a result of the increase, the average summer bill for a residential customer on E-12 (using 1,047 kWh) would increase by $11.69 or 9.97 percent. The cumulative percent increase, including the April 2005 rate case decision and the resetting of the PSA adjustor rate, would be 19.28 percent for summer bills and 19.76 percent for winter bills.

Table 5
Impact of APS-Proposed May 2006 Emergency Interim Rate Increase on Residential Customer Bills

	E-12 Bill After 2/06 PSA Adjustor Rate Reset	E-12 Bill After 5/06 Emergency Interim Rate Increase	Dollar Increase	Percent Increase	Cumulative Percent Increase Over pre-April 05 Rates
Summer (July)					
Average Usage (1047 kWh)	$117.26	$128.94	$11.69	9.97%	19.28%
Median Usage (818 kWh)	$87.66	$96.79	$9.13	10.41%	20.03%
Winter (December)					
Average Usage (677 kWh)	$61.80	$69.35	$7.56	12.23%	19.76%
Median Usage (531 kWh)	$50.26	$56.19	$5.93	11.79%	19.28%

Q. **Please describe the rate impact associated with the two surcharges proposed by APS in its February 2, 2006, filing.**

A. The purpose of these surcharges is to recover the $59.9 million of 2005 fuel and purchased power costs that fell outside of the $0.004 bandwidth of the PSA and carried forward to the Paragraph 19(d) Balancing Account. As proposed by APS, the first surcharge of $0.000554 per kWh, designed to collect $15.3 million over 12 months, would become effective concurrent with the emergency interim rate increase that APS has requested to begin in April 2006, but would more likely begin in May 2006 if approved by the Commission.

As a result of the first surcharge, the average summer bill for a residential customer on E-12 (using 1,047 kWh) would increase by $0.58 or 0.45 percent. The cumulative percent increase (including the April 2005 rate case decision, the resetting of the PSA adjustor rate, and the emergency interim rate increase) would be 19.82 percent for summer bills and 20.41 percent for winter bills.

Table 6
Impact of APS-Proposed May 2006 PSA Surcharge on Residential Customer Bills

	E-12 Bill After 5/06 Emergency Interim Rate Increase	E-12 Bill After 5/06 PSA Surcharge	Dollar Increase	Percent Increase	Cumulative Percent Increase Over pre-April 05 Rates
Summer (July)					
Average Usage (1047 kWh)	$128.94	$129.52	$0.58	0.45%	19.82%
Median Usage (818 kWh)	$96.79	$97.24	$0.45	0.47%	20.59%
Winter (December)					
Average Usage (677 kWh)	$69.35	$69.73	$0.38	0.54%	20.41%
Median Usage (531 kWh)	$56.19	$56.48	$0.29	0.52%	19.90%

As proposed by APS, a second surcharge of $0.001611 per kWh, designed to collect $44.6 million over 12 months, would become effective upon completion of the Commission's inquiry into the unplanned 2005 outages at the Palo Verde Nuclear Generating Station. For this analysis, Staff assumes that the inquiry would be completed in July 2006.

As a result of the second surcharge, the average summer bill for a residential customer on E-12 (using 1,047 kWh) would increase by $1.69 or 1.30 percent. The cumulative percent increase (including the April 2005 rate case decision, the resetting of the PSA adjustor rate, the emergency interim rate increase, and the May 2006 PSA surcharge) would be 21.38 percent for summer bills and 22.29 percent for winter bills.

Table 7
Impact of Second APS-Proposed 2006 PSA Surcharge on Residential Customer Bills

	E-12 Bill After 5/06 PSA Surcharge	E-12 Bill After 2nd 2006 PSA Surcharge	Dollar Increase	Percent Increase	Cumulative Percent Increase Over pre-April 05 Rates
Summer (July)					
Average Usage (1047 kWh)	$129.52	$131.21	$1.69	1.30%	21.38%
Median Usage (818 kWh)	$97.24	$98.56	$1.32	1.36%	22.23%
Winter (December)					
Average Usage (677 kWh)	$69.73	$70.82	$1.09	1.56%	22.29%
Median Usage (531 kWh)	$56.48	$57.34	$0.86	1.51%	21.72%

Q. Please describe the potential rate impact associated with APS' proposal in its general rate case.

A. This analysis assumes that APS would receive all the revenue it requested and that the E-12 rate schedule is designed as APS proposed. For this analysis, Staff assumes that rates from the rate case would become effective in January 2007. At that time, the emergency interim rate increase would cease because it is included in the general rate case, but the PSA adjustor rate and the two PSA surcharges would remain in effect.

As a result of APS-proposed rates in the general rate case, the average winter bill for a residential customer on E-12 (using 677 kWh) would increase by $1.20 or 1.69 percent over rates that include the emergency interim rate increase. The cumulative percent increase (including the April 2005 rate case decision, the resetting of the PSA adjustor rate, the May 2006 PSA surcharge, and the second 2006 surcharge) would be 24.37 percent for winter bills and 29.48 percent for summer bills.

Table 8
Impact of 2006 General Rate Case on Residential Customer Bills

	E-12 Bill After 2nd 2006 PSA Surcharge	E-12 Bill After 2006 General Rate Case	Dollar Increase	Percent Increase	Cumulative Percent Increase Over pre-April 05 Rates
Summer (July)					
Average Usage (1047 kWh)	$131.21	$139.96	$8.75	6.67%	29.48%
Median Usage (818 kWh)	$98.56	$103.69	$5.13	5.20%	28.59%
Winter (December)					
Average Usage (677 kWh)	$70.82	$72.02	$1.20	1.69%	24.37%
Median Usage (531 kWh)	$57.34	$58.28	$0.94	1.64%	23.71%

Q. Does this conclude Staff's testimony?

A. Yes, it does.

RESUME

BARBARA KEENE

Education

B.S.	Political Science, Arizona State University (1976)
M.P.A.	Public Administration, Arizona State University (1982)
A.A.	Economics, Glendale Community College (1993)

Additional Training

Management Development Program - State of Arizona, 1986-1987
UPLAN Training - LCG Consulting, 1989, 1990, 1991
various seminars, workshops, and conferences on ratemaking, energy efficiency, rate design, computer skills, labor market information, training trainers, and Census products

Employment History

Arizona Corporation Commission, Utilities Division, Phoenix, Arizona: Public Utilities Analyst Manager (May 2005-present). Supervise the energy portion of the Telecommunications and Energy Section. Conduct economic and policy analyses of public utilities. Coordinate working groups of stakeholders on various issues. Prepare Staff recommendations and present testimony on electric resource planning, rate design, special contracts, energy efficiency programs, and other matters. Responsible for maintaining and operating UPLAN, a computer model of electricity supply and production costs.

Arizona Corporation Commission, Utilities Division, Phoenix, Arizona: Public Utilities Analyst V (October 2001-present), Senior Economist (July 1990-October 2001), Economist II (December 1989-July 1990), Economist I (August 1989-December 1989). Conduct economic and policy analyses of public utilities. Coordinate working groups of stakeholders on various issues. Prepare Staff recommendations and present testimony on electric resource planning, rate design, special contracts, energy efficiency programs, and other matters. Responsible for maintaining and operating UPLAN, a computer model of electricity supply and production costs.

Arizona Department of Economic Security, Research Administration, Economic Analysis Unit: Labor Market Information Supervisor (September 1985-August 1989), Research and Statistical Analyst (September 1984-September 1985), Administrative Assistant (September 1983-September 1984). Supervised professional staff engaged in economic research and analysis. Responsible for occupational employment forecasts, wage surveys, economic development studies, and over 50 publications. Edited the monthly **Arizona Labor Market Information Newsletter**, which was distributed to about 4,000 companies and individuals.

Testimony

Resource Planning for Electric Utilities (Docket No. U-0000-90-088), Arizona Corporation Commission, 1990; testimony on production costs and system reliability.

Trico Electric Cooperative Rate Case (Docket No. U-1461-91-254), Arizona Corporation Commission, 1992; testimony on demand-side management and time-of-use and interruptible power rates.

Navopache Electric Cooperative Rate Case (Docket No. U-1787-91-280), Arizona Corporation Commission, 1992; testimony on demand-side management and economic development rates.

Arizona Electric Power Cooperative Rate Case (Docket No. U-1773-92-214), Arizona Corporation Commission, 1993; testimony on demand-side management, interruptible power, and rate design.

Tucson Electric Power Company Rate Case (Docket Nos. U-1933-93-006 and U-1933-93-066) Arizona Corporation Commission, 1993; testimony on demand-side management and a cogeneration agreement.

Resource Planning for Electric Utilities (Docket No. U-0000-93-052), Arizona Corporation Commission, 1993; testimony on production costs, system reliability, and demand-side management.

Duncan Valley Electric Cooperative Rate Case (Docket No. E-01703A-98-0431), Arizona Corporation Commission, 1999; testimony on demand-side management and renewable energy.

Tucson Electric Power Company vs. Cyprus Sierrita Corporation, Inc. (Docket No. E-0000I-99-0243), Arizona Corporation Commission, 1999; testimony on analysis of special contracts.

Arizona Public Service Company's Request for Variance (Docket No. E-01345A-01-0822), Arizona Corporation Commission, 2002; testimony on competitive bidding.

Generic Proceeding Concerning Electric Restructuring Issues (Docket No. E-00000A-02-0051), Arizona Corporation Commission, 2002; testimony on affiliate relationships and codes of conduct.

Tucson Electric Power Company's Application for Approval of New Partial Requirements Service Tariffs, Modification of Existing Partial Requirements Service Tariff 101, and Elimination of Qualifying Facility Tariffs (Docket No. E-01933A-02-0345) and Application for Approval of its Stranded Cost Recovery (Docket No. E-01933A-98-0471), Arizona Corporation Commission, 2002, testimony on proposals to eliminate, modify, or introduce tariffs and testimony on the modification of the Market Generation Credit.

Arizona Public Service Company's Application for Approval of Adjustment Mechanisms (Docket No. E-01345A-02-0403), Arizona Corporation Commission, 2003, testimony on the proposed Power Supply Adjustment and the proposed Competition Rules Compliance Charge.

Generic Proceeding Concerning Electric Restructuring Issues, et al (Docket No. E-00000A-02-0051, et al), Arizona Corporation Commission, 2003-2005; Staff Report and testimony on Code of Conduct.

Arizona Public Service Company Rate Case (Docket No. E-01345A-03-0437), Arizona Corporation Commission, 2004; testimony on demand-side management, system benefits, renewable energy, the Returning Customer Direct Assignment Charge, and service schedules.

Arizona Electric Power Cooperative Rate Case (Docket No. E-01773A-04-0528), Arizona Corporation Commission, 2005; testimony on a fuel and purchased power cost adjustor, demand-side management, and rate design.

Trico Electric Cooperative Rate Case (Docket No. E-01461A-04-0607), Arizona Corporation Commission, 2005; testimony on the Environmental Portfolio Standard; demand-side management; special charges; and Rules, Regulations, and Line Extension Policies.

Arizona Public Service Company (Docket Nos. E-01345A-03-0437 and E-01345A-05-0526), Arizona Corporation Commission, 2005; testimony on the Plan of Administration of the Power Supply Adjustor.

Publications

Author of the following articles published in the *Arizona Labor Market Information Newsletter*:

"1982 Mining Employees - Where are They Now?" - September 1984
"The Cost of Hiring" and "Arizona's Growing Industries" - January 1985
"Union Membership - Declining or Shifting?" - December 1985
"Growing Industries in Arizona" - April 1986
"Women's Work?" - July 1986
"1987 SIC Revision" - December 1986
"Growing and Declining Industries" - June 1987
"1986 DOT Supplement" and "Consumer Expenditure Survey" - July 1987
"The Consumer Price Index: Changing With the Times" - August 1987
"Average Annual Pay" - November 1987
"Annual Pay in Metropolitan Areas" - January 1988
"The Growing Temporary Help Industry" - February 1988
"Update on the Consumer Expenditure Survey" - April 1988
"Employee Leasing" - August 1988
"Metropolitan Counties Benefit from State's Growing Industries" - November 1988
"Arizona Network Gives Small Firms Helping Hand" - June 1989

Major contributor to the following books published by the Arizona Department of Economic Security:

Annual Planning Information - editions from 1984 to 1989
Hispanics in Transition - 1987

(with David Berry) "Contracting for Power," *Business Economics*, October 1995.

(with Robert Gray) "Customer Selection Issues," *NRRI Quarterly Bulletin*, Spring 1998.

Reports

(with Task Force) *Report of the Task Force on the Feasibility of Implementing Sliding Scale Hookup Fees*. Arizona Corporation Commission, 1992.

Customer Repayment of Utility DSM Costs, Arizona Corporation Commission, 1995.

(with Working Group) *Report of the Participants in Workshops on Customer Selection Issues*," Arizona Corporation Commission, 1997.

"DSM Workshop Progress Report," Arizona Corporation Commission, 2004.

(with Erin Casper) "Staff Report on Demand Side Management Policy," Arizona Corporation Commission, 2005.

ARIZONA PUBLIC SERVICE COMPANY
Schedule 1
Annual Tracking Account
Projected Year 2006 (no emergency increase)

Line No.	Month	(a) Retail[1] Energy Sales (kWh)	(b) Wholesale[2] Native Load Energy Sales (kWh)	(c) Total Native Load Energy Sales (kWh)	(d) System [3] Book Fuel and Purchased Power Costs	(e) System Book [4] Off-System Sales Revenue	(f) Net Native Load Power Supply Costs	(g) Retail[5] Power Supply Costs	(h) Base Rate[7] Power Supply Revenue	(i) Pre-90/10 Sharing (Over)/Under Collection	(j) Post-90/10 Sharing (Over)/Under Collection	(k) Interest	(l) Tracking Account Balance
				(a + b)			(d - e)	(a/c * f)	(a * base cost)	(g - h)	(i * 0.9)	(l*rate/12)	(j+k+l)
1	Jan.	2,089,640,472	73,263,396	2,162,903,868			$ 43,952,820	$ 42,464,019	$ 43,345,412	$ (881,393)	$ (793,254)		$ (793,254)
2	Feb.	1,787,127,818	56,462,611	1,843,590,429			$ 44,258,686	$ 42,903,200	$ 37,070,392	$ 5,832,808	$ 5,249,527	$ (2,895)	$ 4,453,378
3	Mar.	1,853,941,184	74,143,473	1,928,084,657			$ 43,674,902	$ 41,995,407	$ 38,456,302	$ 3,539,105	$ 3,185,195	$ 16,255	$ 7,654,828
4	Apr.	1,879,071,188	64,757,510	1,943,828,698			$ 51,519,024	$ 49,802,698	$ 38,977,574	$ 10,825,124	$ 9,742,612	$ 27,940	$ 17,425,380
5	May	2,362,657,190	78,278,437	2,440,935,627			$ 67,090,288	$ 64,938,768	$ 49,008,598	$ 15,930,170	$ 14,337,153	$ 63,603	$ 31,826,136
6	Jun.	2,731,973,935	81,579,064	2,813,552,999			$ 97,401,606	$ 94,577,443	$ 56,669,335	$ 37,908,108	$ 34,117,297	$ 116,165	$ 66,059,598
7	Jul.	3,185,558,761	94,759,550	3,280,318,311			$ 143,430,340	$ 139,287,024	$ 66,078,045	$ 73,208,979	$ 65,888,081	$ 241,118	$ 132,188,797
8	Aug.	3,143,508,084	79,189,639	3,222,697,723			$ 138,745,688	$ 135,336,364	$ 65,205,788	$ 70,130,576	$ 63,117,518	$ 482,489	$ 195,788,804
9	Sep.	2,603,844,092	69,795,736	2,673,639,828			$ 96,137,011	$ 93,627,341	$ 54,011,538	$ 39,615,803	$ 35,654,223	$ 714,629	$ 232,157,656
10	Oct.	2,128,551,695	63,607,186	2,192,158,881			$ 62,906,850	$ 61,081,559	$ 44,152,548	$ 16,929,011	$ 15,236,110	$ 847,375	$ 248,241,141
11	Nov.	1,895,523,759	79,817,225	1,975,340,984			$ 36,270,956	$ 34,805,362	$ 39,318,849	$ (4,513,487)	$ (4,062,138)	$ 906,080	$ 245,085,083
12	Dec.	2,171,928,096	64,165,636	2,236,093,732			$ 45,157,769	$ 43,861,948	$ 45,052,304	$ (1,190,356)	$ (1,071,320)	$ 894,561	$ 244,908,324
13	Total	27,833,326,274	879,819,463	28,713,145,737			$ 870,545,940	$ 844,681,133	$ 577,346,685	$ 267,334,448	$ 240,601,004	$ 4,307,320	$ 244,908,324
14		interest rate[6] =	4.38%										

[1] Retail energy sales under rate schedule E-36 were excluded.
[2] Includes traditional sales-for-resale and Pacificorp supplemental sales.
[3] Includes native load and off-system fuel and purchased power costs less those costs associated with E-36, the non-fuel Bridge PPA, ISFSI and mark-to-market accounting adjustments. Excludes net savings associated with the Sundance units and broker fees.
[4] Includes off-system revenue less mark-to-market accounting adjustments.
[5] The maximum annual amount that can be used for the PSA calculation is $776,200,000. However, Decision No. 68437 allows deferral of costs in excess of the cap until this issue has been further examined in Docket No. E-01345A-06-0009.
[6] Based on one-year Nominal Treasury Constant Maturities rate contained in the Federal Reserve Statistical Release, H-15.
[7] The base cost was $0.020743 per kWh.

ARIZONA PUBLIC SERVICE COMPANY
Schedule 1
Annual Tracking Account
Projected Year 2006 (with emergency increase)

Line No.	Month	(a) Retail[1] Energy Sales (kWh)	(b) Wholesale[2] Native Load Energy Sales (kWh)	(c) Total Native Load Energy Sales (kWh)	(d) System [3] Book Fuel and Purchased Power Costs	(e) System Book [4] Off-System Sales Revenue	(f) Net Native Load Power Supply Costs	(g) Retail[5] Power Supply Costs	(h) Base Rate[7] Power Supply Revenue	(i) Pre-90/10 Sharing (Over)/Under Collection	(j) Post-90/10 Sharing (Over)/Under Collection	(k) Interest	(l) Tracking Account Balance
				(a + b)			(d - e)	(a/c * f)	(a * base cost)	(g - h)	(i * 0.9)	(l*rate/12)	(j+k+l)
1	Jan.	2,089,640,472	73,263,396	2,162,903,868			$ 43,952,820	$ 42,464,019	$ 43,345,412	$ (881,393)	$ (793,254)		$ (793,254)
2	Feb.	1,787,127,818	56,462,611	1,843,590,429			$ 44,258,686	$ 42,903,200	$ 37,070,392	$ 5,832,808	$ 5,249,527	$ (2,895)	$ 4,453,378
3	Mar.	1,853,941,184	74,143,473	1,928,084,657			$ 43,674,902	$ 41,995,407	$ 38,456,302	$ 3,539,105	$ 3,185,195	$ 16,255	$ 7,654,828
4	Apr.	1,879,071,188	64,757,510	1,943,828,698			$ 51,519,024	$ 49,802,698	$ 38,977,574	$ 10,825,124	$ 9,742,612	$ 27,940	$ 17,425,380
5	May	2,362,657,190	78,278,437	2,440,935,627			$ 67,090,288	$ 64,938,768	$ 75,378,215	$ (10,439,447)	$ (9,395,502)	$ 63,603	$ 8,093,481
6	Jun.	2,731,973,935	81,579,064	2,813,552,999			$ 97,401,606	$ 94,577,443	$ 87,160,896	$ 7,416,547	$ 6,674,892	$ 29,541	$ 14,797,914
7	Jul.	3,185,558,761	94,759,550	3,280,318,311			$ 143,430,340	$ 139,287,024	$ 101,632,067	$ 37,654,957	$ 33,889,461	$ 54,012	$ 48,741,387
8	Aug.	3,143,508,084	79,189,639	3,222,697,723			$ 138,745,688	$ 135,336,364	$ 100,290,482	$ 35,045,882	$ 31,541,294	$ 177,906	$ 80,460,587
9	Sep.	2,603,844,092	69,795,736	2,673,639,828			$ 96,137,011	$ 93,627,341	$ 83,073,042	$ 10,554,299	$ 9,498,869	$ 293,681	$ 90,253,137
10	Oct.	2,128,551,695	63,607,186	2,192,158,881			$ 62,906,850	$ 61,081,559	$ 67,909,313	$ (6,827,754)	$ (6,144,979)	$ 329,424	$ 84,437,582
11	Nov.	1,895,523,759	79,817,225	1,975,340,984			$ 36,270,956	$ 34,805,362	$ 60,474,790	$ (25,669,428)	$ (23,102,485)	$ 308,197	$ 61,643,294
12	Dec.	2,171,928,096	64,165,636	2,236,093,732			$ 45,157,769	$ 43,861,948	$ 69,293,194	$ (25,431,246)	$ (22,888,121)	$ 224,998	$ 38,980,171
13	Total	27,833,326,274	879,819,463	28,713,145,737			$ 870,545,940	$ 844,681,133	$ 803,061,679	$ 41,619,454	$ 37,457,509	$ 1,522,662	$ 38,980,171
14	interest rate[6] =		4.38%										

[1] Retail energy sales under rate schedule E-36 were excluded.
[2] *Includes traditional sales-for-resale and Pacificorp supplemental sales.*
[3] Includes native load and off-system fuel and purchased power costs less those costs associated with E-36, the non-fuel Bridge PPA, ISFSI and mark-to-market accounting adjustments. Excludes net savings associated with the Sundance units and broker fees.
[4] Includes off-system revenue less mark-to-market accounting adjustments.
[5] The maximum annual amount that can be used for the PSA calculation is $776,200,000. However, Decision No. 68437 allows deferral of costs in excess of the cap until this issue has been further examined in Docket No. E-01345A-06-0009.
[6] Based on one-year Nominal Treasury Constant Maturities rate contained in the Federal Reserve Statistical Release, H-15.
[7] **The base cost was $0.020743 per kWh from January through April and $0.031904 per kWh from May through December..**

ARIZONA PUBLIC SERVICE COMPANY
Schedule 2
2007 PSA Adjustor Rate Calculation (with emergency increase, no surcharges)

Line No.	PSA Adjustor Rate Calculation			
1	Tracking Account Balance (from Schedule 1)		$ 38,980,171	
2	Annual Adjustor Account Balance (from Schedule 3)		$ 2,291,081	
3	Paragraph 19(d) Balancing Account Balance (from Schedule 4)		$ 62,533,253	
4	Total (Credit)/Charge Amount (Line 1 + Line 2 + Line 3)			**$ 103,804,505**
5	Projected Energy Sales without E-3, E-4 and E-36 (kWh)	28,137,808,000		
6	Computed Adjustor Rate per kWh (Line 4/ Line 5)		$ 0.003689	
7	Current Adjustor Rate per kWh	$0.004000		
8	Diff. between Current Adj. Rate and Computed Adj. Rate (line 6 - line 7)	-$0.000311		
	Adjustor Rate Bandwidth			
9	Adjustor Rate Bandwidth Upper Limit		$ 0.004000	
10	Adjustor Rate Bandwidth Lower Limit		$ (0.004000)	
11	Applicable Adjustor Rate per kWh for February 1, 2007			**$ 0.003689**
12	Amount Carried Forward to Annual Adjustor Account (Line 5 * Line 11)			**$ 103,804,505**
13	Amount Carried Forward to Paragraph 19(d) Balancing Account (Line 4 - Line 12)			**$ -**

ARIZONA PUBLIC SERVICE COMPANY
Schedule 2
2007 PSA Adjustor Rate Calculation (no emergency increase, no surcharges)

Line No.	PSA Adjustor Rate Calculation			
1	Tracking Account Balance (from Schedule 1)		$ 244,908,324	
2	Annual Adjustor Account Balance (from Schedule 3)		$ 2,291,081	
3	Paragraph 19(d) Balancing Account Balance (from Schedule 4)		$ 62,533,253	
4	Total (Credit)/Charge Amount (Line 1 + Line 2 + Line 3)			**$ 309,732,658**
5	Projected Energy Sales without E-3, E-4 and E-36 (kWh)	28,137,808,000		
6	Computed Adjustor Rate per kWh (Line 4/ Line 5)		$ 0.011008	
7	Current Adjustor Rate per kWh	$0.004000		
8	Diff. between Current Adj. Rate and Computed Adj. Rate (line 6 - line 7)	$0.007008		
	Adjustor Rate Bandwidth			
9	Adjustor Rate Bandwidth Upper Limit		$ 0.004000	
10	Adjustor Rate Bandwidth Lower Limit		$ (0.004000)	
11	Applicable Adjustor Rate per kWh for February 1, 2007			**$ 0.004000**
12	Amount Carried Forward to Annual Adjustor Account (Line 5 * Line 11)			**$ 112,551,232**
13	Amount Carried Forward to Paragraph 19(d) Balancing Account (Line 4 - Line 12)			**$ 197,181,426**

ARIZONA PUBLIC SERVICE COMPANY
Schedule 3
Annual Adjustor Account
Projected Year February 2006 - January 2007

Line No.		February	March	April	May	June	July	August	September	October	November	December	January
1	PSA Adjustor Rate	$ 0.004000	$ 0.004000	$ 0.004000	$ 0.004000	$ 0.004000	$ 0.004000	$ 0.004000	$ 0.004000	$ 0.004000	$ 0.004000	$ 0.004000	$ 0.004000
2	Beginning Balance	$ 109,723,888	$ 103,028,346	$ 96,029,322	$ 88,900,505	$ 79,809,229	$ 69,234,496	$ 56,836,001	$ 44,566,481	$ 34,415,123	$ 26,098,849	$ 18,666,289	$ 10,109,225
3	Retail Energy Sales[1] (kWh)	1,767,557,000	1,837,064,000	1,863,031,000	2,345,380,000	2,706,630,000	3,151,298,000	3,107,899,000	2,569,129,000	2,102,797,000	1,875,111,000	2,148,457,000	1,956,619,000
4	Less: Revenue from Adjustor Rate (line 1 * line 3)	$ 7,070,228	$ 7,348,256	$ 7,452,124	$ 9,381,520	$ 10,826,520	$ 12,605,192	$ 12,431,596	$ 10,276,516	$ 8,411,188	$ 7,500,444	$ 8,593,828	$ 7,826,476
5	Balance before Interest (line 2 - line 4)	$ 102,653,660	$ 95,680,090	$ 88,577,198	$ 79,518,985	$ 68,982,709	$ 56,629,304	$ 44,404,405	$ 34,289,965	$ 26,003,935	$ 18,598,405	$ 10,072,461	$ 2,282,749
6	Monthly Interest (line 5 * (4.38%/12)[2]	$ 374,686	$ 349,232	$ 323,307	$ 290,244	$ 251,787	$ 206,697	$ 162,076	$ 125,158	$ 94,914	$ 67,884	$ 36,764	$ 8,332
7	Ending Balance with Interest (line 5 + line 6)	$ 103,028,346	$ 96,029,322	$ 88,900,505	$ 79,809,229	$ 69,234,496	$ 56,836,001	$ 44,566,481	$ 34,415,123	$ 26,098,849	$ 18,666,289	$ 10,109,225	$ 2,291,081

[1] Excludes sales from E-36, E-3, and E-4 rate schedules.
[2] Based on one-year Nominal Treasury Constant Maturities rate contained in the *Federal Reserve Statistical Release*, H-15.

ARIZONA PUBLIC SERVICE COMPANY
Schedule 4
Paragraph 19(d) Balancing Account
Projected Year February 2006 - January 2007

Line No.		February	March	April	May	June	July	August	September	October	November	December	January
1	Beginning Balance	$ 59,858,187	$ 60,076,669	$ 60,295,949	$ 60,516,029	$ 60,736,913	$ 60,958,603	$ 61,181,102	$ 61,404,413	$ 61,628,539	$ 61,853,483	$ 62,079,248	$ 62,305,837
2	Less: Approved Balance for Surcharge (if any)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	Balance Less Amort. Surcharge (line 1 - line 2)	$ 59,858,187	$ 60,076,669	$ 60,295,949	$ 60,516,029	$ 60,736,913	$ 60,958,603	$ 61,181,102	$ 61,404,413	$ 61,628,539	$ 61,853,483	$ 62,079,248	$ 62,305,837
4	Monthly Interest (line 3 * (4.38%/12)[1]	$ 218,482	$ 219,280	$ 220,080	$ 220,884	$ 221,690	$ 222,499	$ 223,311	$ 224,126	$ 224,944	$ 225,765	$ 226,589	$ 227,416
5	Ending Balance with Interest (line 3 + line 4)	$ 60,076,669	$ 60,295,949	$ 60,516,029	$ 60,736,913	$ 60,958,603	$ 61,181,102	$ 61,404,413	$ 61,628,539	$ 61,853,483	$ 62,079,248	$ 62,305,837	$ 62,533,253

[1] Based on one-year Nominal Treasury Constant Maturities rate contained in the Federal Reserve Statistical Release, H-15.

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
JEFF HATCH-MILLER, Chairman
WILLIAM A. MUNDELL
MARC SPITZER
MIKE GLEASON
KRISTIN K. MAYES

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

DOCKET NO. E-01345A-06-0009

STAFF'S NOTICE OF ERRATA

NOTICE IS HEREBY GIVEN that Staff of the Arizona Corporation Commission is filing a revised version of the Direct Testimony of Barbara Keene which was filed on February 28, 2006. This filing includes the insertion of Table 2 which was inadvertently omitted as well as corrections to the page headers, and other formatting corrections. The testimony is being provided in both red-lined and final versions.

RESPECTFULLY SUBMITTED this 1st day of March, 2006.

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EXHIBIT
S-D
admitted

Staff's Response to Request of Commissioner Mayes

Impact of Per kWh Surcharges on E-12 Bills

	kWh	Current Bill	One-year Amortizations: August 2006 Bill With Surcharge $33 Million $0.001182/kWh	Percent Increase Over Current	November 2006 Bill With Combined Surcharge $33 & $144 Million $0.006277/kWh	Percent Increase Over 1st Surcharge	Two-year Amortizations: August 2006 Bill With Surcharge $33 Million $0.000579/kWh	Percent Increase Over Current	November 2006 Bill With Combined Surcharge $33 & $144 Million $0.003077/kWh	Percent Increase Over 1st Surcharge
summer										
median	818	$87.71	$88.69	1.12%	$92.92	4.77%	$88.19	0.55%	$90.26	2.35%
average	1047	$117.32	$118.58	1.07%	$123.99	4.56%	$117.93	0.52%	$120.59	2.26%
winter										
median	531	$50.30	$50.93	1.25%	$53.68	5.40%	$50.61	0.62%	$51.95	2.65%
average	677	$61.84	$62.65	1.31%	$66.15	5.59%	$62.24	0.65%	$63.95	2.75%

Impact of Equal Percentages on E-12 Bills

	kWh	Current Bill	One-year Amortizations: August 2006 Bill With Equal % $33 Million 1.45%	Percent Increase Over Current	November 2006 Bill With Combined Equal % $33 & $144 Million 7.69%	Percent Increase Over 1st %	Two-year Amortizations: August 2006 Bill With Equal % $33 Million 0.71%	Percent Increase Over Current	November 2006 Bill With Combined Equal % $33 & $144 Million 3.77%	Percent Increase Over 1st %
summer										
median	818	$87.71	$88.93	1.39%	$94.20	5.93%	$88.31	0.68%	$90.89	2.92%
average	1047	$117.32	$118.96	1.40%	$126.02	5.93%	$118.12	0.68%	$121.58	2.93%
winter										
median	531	$50.30	$51.00	1.39%	$54.00	5.88%	$50.64	0.68%	$52.11	2.90%
average	677	$61.84	$62.70	1.39%	$66.39	5.89%	$62.26	0.68%	$64.07	2.91%

Calculation of Surcharge Rates

	2006 kWh	2007 kWh	2008 kWh
Jan		2,133,624,000	2,218,968,960
Feb	1,936,737,000	2,014,206,480	2,094,774,739
Mar	1,836,348,000	1,909,801,920	1,986,193,997
Apr	1,788,435,000	1,859,972,400	1,934,371,296
May	1,985,474,000	2,064,892,960	2,147,488,678
Jun	2,490,130,000	2,589,735,200	2,693,324,608
Jul	2,994,552,000	3,114,334,080	3,238,907,443
Aug	3,003,268,000	3,123,398,720	3,248,334,669
Sep	2,897,508,000	3,013,408,320	3,133,944,653
Oct	2,359,096,000	2,453,459,840	2,551,598,234
Nov	1,965,969,000	2,044,607,760	2,126,392,070
Dec	2,017,608,000	2,098,312,320	2,182,244,813

kWh excludes E-3 and E-4
assume 4% growth

	revenue	rate with 1-yr amortization	rate with 2-yr amortization
surcharge starts 8/1	$33,000,000	$0.001182	$0.000579
surcharge starts 11/1	$144,000,000	$0.005095	$0.002498
combined surcharge		$0.006277	$0.003077

E-12 Residential

Summer (July 2005 cunsumption)

				median	average
				818	1047
basic service charge	$0.253	per day	31 days	$7.84	$7.84
energy charge					
1st 400 kWh	0.07570	per kWh		30.28	30.28
next 400 kWh	0.10556	per kWh		42.22	42.22
all additional kWh	0.12314	per kWh		2.22	30.42
CRCC	0.000338	per kWh		0.28	0.35
EPS ($0.35 cap)	0.000875	per kWh		0.35	0.35
PSA adjustor rate	$0.004	per kWh		3.27	4.19
proposed surcharge	0	per kWh		0.00	0.00
			subtotal	86.46	115.65
franchise fee	1.44%			1.25	1.67
			Total Bill	**$87.71**	**$117.32**

Winter (December 2004 consumption)

				median	average
				531	677
basic service charge	$0.253	per day	31 days	$7.84	$7.84
energy charge	0.07361	per kWh		39.09	49.83
CRCC	0.000338	per kWh		0.18	0.23
EPS ($0.35 cap)	0.000875	per kWh		0.35	0.35
PSA adjustor rate	$0.004	per kWh		2.12	2.71
proposed surcharge	0	per kWh		0.00	0.00
			subtotal	49.58	60.96
franchise fee	1.44%			0.71	0.88
			Total Bill	**$50.30**	**$61.84**

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Surcharge Impacts

E-12 Residential

Summer (July 2005 cunsumption)

					median	**average**
					818	1047
basic service charge		$0.253	per day	31 days	$7.84	$7.84
energy charge						
	1st 400 kWh	0.07570	per kWh		30.28	30.28
	next 400 kWh	0.10556	per kWh		42.22	42.22
	all additional kWh	0.12314	per kWh		2.22	30.42
CRCC		0.000338	per kWh		0.28	0.35
EPS	($0.35 cap)	0.000875	per kWh		0.35	0.35
PSA adjustor rate		$0.004	per kWh		3.27	4.19
proposed surcharge		0.001182	per kWh		0.97	1.24
				subtotal	87.43	116.89
franchise fee		1.44%			1.26	1.68
				Total Bill	**$88.69**	**$118.58**

Winter (December 2004 consumption)

					median	**average**
					531	677
basic service charge		$0.253	per day	31 days	$7.84	$7.84
energy charge		0.07361	per kWh		39.09	49.83
CRCC		0.000338	per kWh		0.18	0.23
EPS	($0.35 cap)	0.000875	per kWh		0.35	0.35
PSA adjustor rate		$0.004	per kWh		2.12	2.71
proposed surcharge		0.001182	per kWh		0.63	0.80
				subtotal	50.21	61.76
franchise fee		1.44%			0.72	0.89
				Total Bill	**$50.93**	**$62.65**

E-12 Residential

Summer (July 2005 cunsumption)					median	average
					818	1047
basic service charge		$0.253	per day	31 days	$7.84	$7.84
energy charge						
	1st 400 kWh	0.07570	per kWh		30.28	30.28
	next 400 kWh	0.10556	per kWh		42.22	42.22
	all additional kWh	0.12314	per kWh		2.22	30.42
CRCC		0.000338	per kWh		0.28	0.35
EPS	($0.35 cap)	0.000875	per kWh		0.35	0.35
PSA adjustor rate		$0.004	per kWh		3.27	4.19
proposed surcharge		0.006277	per kWh		5.13	6.57
				subtotal	91.60	122.23
franchise fee		1.44%			1.32	1.76
				Total Bill	**$92.92**	**$123.99**

Winter (December 2004 consumption)					median	average
					531	677
basic service charge		$0.253	per day	31 days	$7.84	$7.84
energy charge		0.07361	per kWh		39.09	49.83
CRCC		0.000338	per kWh		0.18	0.23
EPS	($0.35 cap)	0.000875	per kWh		0.35	0.35
PSA adjustor rate		$0.004	per kWh		2.12	2.71
proposed surcharge		0.006277	per kWh		3.33	4.25
				subtotal	52.92	65.21
franchise fee		1.44%			0.76	0.94
				Total Bill	**$53.68**	**$66.15**

Surcharge Impacts

E-12 Residential

Summer (July 2005 cunsumption)

				median	average
				818	1047
basic service charge	$0.253	per day	31 days	$7.84	$7.84
energy charge					
1st 400 kWh	0.07570	per kWh		30.28	30.28
next 400 kWh	0.10556	per kWh		42.22	42.22
all additional kWh	0.12314	per kWh		2.22	30.42
CRCC	0.000338	per kWh		0.28	0.35
EPS ($0.35 cap)	0.000875	per kWh		0.35	0.35
PSA adjustor rate	$0.004	per kWh		3.27	4.19
proposed surcharge	0.000579	per kWh		0.47	0.61
			subtotal	86.94	116.26
franchise fee	1.44%			1.25	1.67
			Total Bill	**$88.19**	**$117.93**

Winter (December 2004 consumption)

				median	average
				531	677
basic service charge	$0.253	per day	31 days	$7.84	$7.84
energy charge	0.07361	per kWh		39.09	49.83
CRCC	0.000338	per kWh		0.18	0.23
EPS ($0.35 cap)	0.000875	per kWh		0.35	0.35
PSA adjustor rate	$0.004	per kWh		2.12	2.71
proposed surcharge	0.000579	per kWh		0.31	0.39
			subtotal	49.89	61.36
franchise fee	1.44%			0.72	0.88
			Total Bill	**$50.61**	**$62.24**

E-12 Residential

Summer (July 2005 cunsumption)

					median	**average**
					818	1047
basic service charge		$0.253	per day	31 days	$7.84	$7.84
energy charge						
	1st 400 kWh	0.07570	per kWh		30.28	30.28
	next 400 kWh	0.10556	per kWh		42.22	42.22
	all additional kWh	0.12314	per kWh		2.22	30.42
CRCC		0.000338	per kWh		0.28	0.35
EPS	($0.35 cap)	0.000875	per kWh		0.35	0.35
PSA adjustor rate		$0.004	per kWh		3.27	4.19
proposed surcharge		0.003077	per kWh		2.52	3.22
				subtotal	88.98	118.88
franchise fee		1.44%			1.28	1.71
				Total Bill	**$90.26**	**$120.59**

Winter (December 2004 consumption)

					median	**average**
					531	677
basic service charge		$0.253	per day	31 days	$7.84	$7.84
energy charge		0.07361	per kWh		39.09	49.83
CRCC		0.000338	per kWh		0.18	0.23
EPS	($0.35 cap)	0.000875	per kWh		0.35	0.35
PSA adjustor rate		$0.004	per kWh		2.12	2.71
proposed surcharge		0.003077	per kWh		1.63	2.08
				subtotal	51.22	63.05
franchise fee		1.44%			0.74	0.91
				Total Bill	**$51.95**	**$63.95**

Calculation of Equal Percentage Rates

	2006 Revenue	2007 Revenue	2008 Revenue
Jan	161,734,000	168,203,360	174,931,494
Feb	139,949,000	145,546,960	151,368,838
Mar	145,372,000	151,186,880	157,234,355
Apr	153,003,000	159,123,120	165,488,045
May	195,458,000	203,276,320	211,407,373
Jun	221,339,000	230,192,560	239,400,262
Jul	258,823,000	269,175,920	279,942,957
Aug	255,015,000	265,215,600	275,824,224
Sep	214,894,000	223,489,760	232,429,350
Oct	169,499,000	176,278,960	183,330,118
Nov	147,059,000	152,941,360	159,059,014
Dec	167,914,000	174,630,560	181,615,782

assume 4% growth

	increase in revenue	1-year base revenue	% increase 1-year amortization	2-year base revenue	% increase 2-year amortization
percentage starts 8/1	$33,000,000	$2,281,086,120	1.45%	$4,653,415,685	0.71%
percentage starts 11/1	$144,000,000	$2,306,662,440	6.24%	$4,705,591,378	3.06%
	combined percentage		7.69%		3.77%

E-12 Residential

Summer (July 2005 cunsumption)

					median	**average**
					818	1047
basic service charge		$0.253	per day	31 days	$7.84	$7.84
energy charge						
	1st 400 kWh	0.07570	per kWh		30.28	30.28
	next 400 kWh	0.10556	per kWh		42.22	42.22
	all additional kWh	0.12314	per kWh		2.22	30.42
CRCC		0.000338	per kWh		0.28	0.35
EPS	($0.35 cap)	0.000875	per kWh		0.35	0.35
				subtotal	83.19	111.47
proposed percentage		1.45%			1.21	1.62
PSA adjustor rate		$0.004	per kWh		3.27	4.19
				subtotal	87.67	117.27
franchise fee		1.44%			1.26	1.69
				Total Bill	**$88.93**	**$118.96**

Winter (December 2004 consumption)

					median	**average**
					531	677
basic service charge		$0.253	per day	31 days	$7.84	$7.84
energy charge		0.07361	per kWh		39.09	49.83
CRCC		0.000338	per kWh		0.18	0.23
EPS	($0.35 cap)	0.000875	per kWh		0.35	0.35
				subtotal	47.46	58.26
proposed percentage		1.45%			0.69	0.84
PSA adjustor rate		$0.004	per kWh		2.12	2.71
				subtotal	50.27	61.81
franchise fee		1.44%			0.72	0.89
				Total Bill	**$51.00**	**$62.70**

E-12 Residential

Summer (July 2005 cunsumption)

					median	average
					818	1047
basic service charge		$0.253	per day	31 days	$7.84	$7.84
energy charge						
	1st 400 kWh	0.07570	per kWh		30.28	30.28
	next 400 kWh	0.10556	per kWh		42.22	42.22
	all additional kWh	0.12314	per kWh		2.22	30.42
CRCC		0.000338	per kWh		0.28	0.35
EPS	($0.35 cap)	0.000875	per kWh		0.35	0.35
				subtotal	83.19	111.47
proposed percentage		7.69%			6.40	8.57
PSA adjustor rate		$0.004	per kWh		3.27	4.19
				subtotal	92.86	124.23
franchise fee		1.44%			1.34	1.79
				Total Bill	**$94.20**	**$126.02**

Winter (December 2004 consumption)

					median	average
					531	677
basic service charge		$0.253	per day	31 days	$7.84	$7.84
energy charge		0.07361	per kWh		39.09	49.83
CRCC		0.000338	per kWh		0.18	0.23
EPS	($0.35 cap)	0.000875	per kWh		0.35	0.35
				subtotal	47.46	58.26
proposed percentage		7.69%			3.65	4.48
PSA adjustor rate		$0.004	per kWh		2.12	2.71
				subtotal	53.23	65.44
franchise fee		1.44%			0.77	0.94
				Total Bill	**$54.00**	**$66.39**

E-12 Residential

Summer (July 2005 cunsumption)

					median	average
					818	1047
basic service charge		$0.253	per day	31 days	$7.84	$7.84
energy charge						
	1st 400 kWh	0.07570	per kWh		30.28	30.28
	next 400 kWh	0.10556	per kWh		42.22	42.22
	all additional kWh	0.12314	per kWh		2.22	30.42
CRCC		0.000338	per kWh		0.28	0.35
EPS	($0.35 cap)	0.000875	per kWh		0.35	0.35
				subtotal	83.19	111.47
proposed percentage		0.71%			0.59	0.79
PSA adjustor rate		$0.004	per kWh		3.27	4.19
				subtotal	87.05	116.45
franchise fee		1.44%			1.25	1.68
				Total Bill	**$88.31**	**$118.12**

Winter (December 2004 consumption)

					median	average
					531	677
basic service charge		$0.253	per day	31 days	$7.84	$7.84
energy charge		0.07361	per kWh		39.09	49.83
CRCC		0.000338	per kWh		0.18	0.23
EPS	($0.35 cap)	0.000875	per kWh		0.35	0.35
				subtotal	47.46	58.26
proposed percentage		0.71%			0.34	0.41
PSA adjustor rate		$0.004	per kWh		2.12	2.71
				subtotal	49.92	61.38
franchise fee		1.44%			0.72	0.88
				Total Bill	**$50.64**	**$62.26**

E-12 Residential

Summer (July 2005 cunsumption)					median	average
					818	1047
basic service charge		$0.253	per day	31 days	$7.84	$7.84
energy charge						
	1st 400 kWh	0.07570	per kWh		30.28	30.28
	next 400 kWh	0.10556	per kWh		42.22	42.22
	all additional kWh	0.12314	per kWh		2.22	30.42
CRCC		0.000338	per kWh		0.28	0.35
EPS	($0.35 cap)	0.000875	per kWh		0.35	0.35
				subtotal	83.19	111.47
proposed percentage		3.77%			3.14	4.20
PSA adjustor rate		$0.004	per kWh		3.27	4.19
				subtotal	89.60	119.86
franchise fee		1.44%			1.29	1.73
				Total Bill	**$90.89**	**$121.58**

Winter (December 2004 consumption)					median	average
					531	677
basic service charge		$0.253	per day	31 days	$7.84	$7.84
energy charge		0.07361	per kWh		39.09	49.83
CRCC		0.000338	per kWh		0.18	0.23
EPS	($0.35 cap)	0.000875	per kWh		0.35	0.35
				subtotal	47.46	58.26
proposed percentage		3.77%			1.79	2.20
PSA adjustor rate		$0.004	per kWh		2.12	2.71
				subtotal	51.37	63.16
franchise fee		1.44%			0.74	0.91
				Total Bill	**$52.11**	**$64.07**

EXHIBIT
S-8
admitted

Staff's Response to March 23, 2006, letter from Chairman Hatch-Miller

Decrease in 2006 year-end balance for under-collected fuel and purchased power expenses:

	Bandwidths (changed in May 2006)						
Dec. 31, 2006 Balance	0.004	0.005	0.006	0.007	0.008	0.009	0.010
Annual Tracking Account	$247,558,521	$247,558,521	$247,558,521	$247,558,521	$247,558,521	$247,558,521	$247,558,521
Annual Adjustor Account	$11,319,274	-$8,656,063	-$28,631,403	-$48,606,740	-$68,582,077	-$88,557,416	-$130,265,140
Paragraph 19(d) Balancing Account	$62,305,837	$62,305,837	$62,305,837	$62,305,837	$62,305,837	$62,305,837	$62,305,837
Total Dec. 2006 under-collected amount	$321,183,632	$301,208,295	$281,232,955	$261,257,618	$241,282,281	$221,306,942	$179,599,218

Increase in 2006 revenues for fuel and purchased power expense recovery:

	Bandwidths (changed in May 2006)						
	0.004	0.005	0.006	0.007	0.008	0.009	0.010
Dec. '06 Balance in Annual Adjustor Account	$11,319,274	-$8,656,063	-$28,631,403	-$48,606,740	-$68,582,077	-$88,557,416	-$130,265,140
Decrease in Balance compared to "0.004" (increase in revenues)	$0	$19,975,337	$39,950,677	$59,926,014	$79,901,351	$99,876,690	$141,584,414

Improvement in the Funds from Operation (FFO) to Debt ratio:

	Bandwidths (changed in May 2006)						
	0.004	0.005	0.006	0.007	0.008	0.009	0.010
Funds from Operations	$520,552,000	$540,527,337	$560,502,677	$580,478,014	$600,453,351	$620,428,690	$662,136,414
Debt	$3,259,115,000	$3,259,115,000	$3,259,115,000	$3,259,115,000	$3,259,115,000	$3,259,115,000	$3,259,115,000
Ratio	16.0%	16.6%	17.2%	17.8%	18.4%	19.0%	20.3%

Improvement in internal cash flow to fund APS' CAPEX progrm in 2006:

	Bandwidths (changed in May 2006)						
	0.004	0.005	0.006	0.007	0.008	0.009	0.010
Funds from Operations	$520,552,000	$540,527,337	$560,502,677	$580,478,014	$600,453,351	$620,428,690	$662,136,414
less Common Dividends	$170,000,000	$170,000,000	$170,000,000	$170,000,000	$170,000,000	$170,000,000	$170,000,000
Net Cash Flow	$350,552,000	$370,527,337	$390,502,677	$410,478,014	$430,453,351	$450,428,690	$492,136,414

ARIZONA PUBLIC SERVICE COMPANY
Schedule 1
Annual Tracking Account
Year 2006

Line No.	Month	(a) Retail[1] Energy Sales (kWh)	(b) Wholesale[2] Native Load Energy Sales (kWh)	(c) Total Native Load Energy Sales (kWh)	(d) System[3] Book Fuel and Purchased Power Costs	(e) System Book[4] Off-System Sales Revenue	(f) Net Native Load Power Supply Costs	(g) Retail[5] Power Supply Costs	(h) Base Rate Power Supply Revenue	(i) Pre-90/10 Sharing (Over)/Under Collection	(j) Post-90/10 Sharing (Over)/Under Collection	(k) Interest	(l) Tracking Account Balance
				(a + b)			(d - e)	(a/c * f)	(a * 0.020743)	(g - h)	(i * 0.9)	(l*rate/12)	(j+k+l)
1	Jan.	1,973,106,000	59,892,000	2,032,998,000	$ 50,733,000	$ 5,474,000	$ 45,259,000	$ 43,925,673	$ 40,928,138	$ 2,997,535	$ 2,697,782		$ 2,697,782
2	Feb.	1,717,598,000	64,909,000	1,782,507,000	$ 45,695,000	$ 4,245,000	$ 41,450,000	$ 39,940,621	$ 35,628,135	$ 4,312,486	$ 3,881,237	$ 9,847	$ 6,588,866
3	Mar.	1,853,941,184	74,143,473	1,928,084,657	$ -	$ -	$ 49,832,000	$ 47,915,737	$ 38,456,302	$ 9,459,435	$ 8,513,492	$ 24,049	$ 15,126,407
4	Apr.	1,879,071,188	64,757,510	1,943,828,698	$ -	$ -	$ 57,034,000	$ 55,133,946	$ 38,977,574	$ 16,156,372	$ 14,540,735	$ 55,211	$ 29,722,354
5	May	2,362,657,190	78,278,437	2,440,935,627	$ -	$ -	$ 71,065,000	$ 68,786,014	$ 49,008,598	$ 19,777,416	$ 17,799,674	$ 108,487	$ 47,630,514
6	Jun.	2,731,973,935	81,579,064	2,813,552,999	$ -	$ -	$ 101,288,000	$ 98,351,151	$ 56,669,335	$ 41,681,816	$ 37,513,634	$ 173,851	$ 85,318,000
7	Jul.	3,185,558,761	94,759,550	3,280,318,311	$ -	$ -	$ 134,546,000	$ 130,659,329	$ 66,078,045	$ 64,581,284	$ 58,123,156	$ 311,411	$ 143,752,566
8	Aug.	3,143,508,084	79,189,639	3,222,697,723	$ -	$ -	$ 132,076,000	$ 128,830,567	$ 65,205,788	$ 63,624,779	$ 57,262,301	$ 524,697	$ 201,539,564
9	Sep.	2,603,844,092	69,795,736	2,673,639,828	$ -	$ -	$ 91,499,000	$ 89,110,406	$ 54,011,538	$ 35,098,868	$ 31,588,981	$ 735,619	$ 233,864,165
10	Oct.	2,128,551,695	63,607,186	2,192,158,881	$ -	$ -	$ 59,213,000	$ 57,494,889	$ 44,152,548	$ 13,342,341	$ 12,008,107	$ 853,604	$ 246,725,876
11	Nov.	1,895,523,759	79,817,225	1,975,340,984	$ -	$ -	$ 38,337,000	$ 36,787,924	$ 39,318,849	$ (2,530,925)	$ (2,277,833)	$ 900,549	$ 245,348,592
12	Dec.	2,171,928,096	64,165,636	2,236,093,732	$ -	$ -	$ 46,857,000	$ 45,512,419	$ 45,052,304	$ 460,115	$ 414,104	$ 895,522	$ 246,658,219
12.5												$ 900,302	
13	Total	27,647,261,984	874,894,456	28,522,156,440	$ 96,428,000	$ 9,719,000	$ 868,456,000	$ 842,448,676	$ 573,487,154	$ 268,961,522	$ 242,065,370	$ 5,493,151	$ 247,558,521
14	interest rate[6] =		4.38%										

[1] Retail energy sales under rate schedule E-36 were excluded.

[2] Includes traditional sales-for-resale and Pacificorp supplemental sales.

[3] Includes native load and off-system fuel and purchased power costs less those costs associated with E-36, ISFSI and mark-to-market accounting adjustments. Excludes net savings associated with the Sundance units and broker fees.

[4] Includes off-system revenue less mark-to-market accounting adjustments.

[5] The maximum annual amount that can be used for the PSA calculation is $776,200,000. However, Decision No. 68437 allows deferral of costs in excess of the cap until this issue has been further examined in Docket No. E-01345A-06-0009.

[6] Based on one-year Nominal Treasury Constant Maturities rate contained in the Federal Reserve Statistical Release, H-15.

ARIZONA PUBLIC SERVICE COMPANY
Schedule 4
Paragraph 19(d) Balancing Account
Year February 2006 - January 2007

Line No.		February	March	April	May	June	July	August	September	October	November	December	January
1	Beginning Balance	$ 59,858,187	$ 60,076,669	$ 60,295,949	$ 60,516,029	$ 60,736,913	$ 60,958,603	$ 61,181,102	$ 61,404,413	$ 61,628,539	$ 61,853,483	$ 62,079,248	$ 62,305,837
2	Less: Approved Balance for Surcharge (if any)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	Monthly Interest (line 1 * (4.38%/12)[1]	$ 218,482	$ 219,280	$ 220,080	$ 220,884	$ 221,690	$ 222,499	$ 223,311	$ 224,126	$ 224,944	$ 225,765	$ 226,589	$ 227,416
4	Ending Balance with Interest (line 1 - line 2 + line 3)	$ 60,076,669	$ 60,295,949	$ 60,516,029	$ 60,736,913	$ 60,958,603	$ 61,181,102	$ 61,404,413	$ 61,628,539	$ 61,853,483	$ 62,079,248	$ 62,305,837	$ 62,533,253

[1] Based on one-year Nominal Treasury Constant Maturities rate contained in the Federal Reserve Statistical Release, H-15.

ARIZONA PUBLIC SERVICE COMPANY
Schedule 3
Annual Adjustor Account
Year February 2006 - January 2007

Line No.		February	March	April	May	June	July	August	September	October	November	December	January
1	PSA Adjustor Rate	$ 0.004000	$ 0.004000	$ 0.004000	$ 0.004000	$ 0.004000	$ 0.004000	$ 0.004000	$ 0.004000	$ 0.004000	$ 0.004000	$ 0.004000	$ 0.004000
2	Retail Energy Sales[1] (kWh)	1,936,737,000	1,836,348,000	1,788,435,000	1,985,474,000	2,490,130,000	2,994,552,000	3,003,268,000	2,897,508,000	2,359,096,000	1,965,969,000	2,017,608,000	2,133,624,000
3	Beginning Balance	$ 109,723,888	$ 102,377,432	$ 95,405,718	$ 88,600,209	$ 80,981,704	$ 71,316,767	$ 59,598,865	$ 47,803,329	$ 36,387,779	$ 27,084,210	$ 19,319,191	$ 11,319,274
3.5	Revenue True-up from January Estimate[2]	$ -											
4	Less: Revenue from Adjustor Rate (line 1 * line 2)	$ 7,746,948	$ 7,345,392	$ 7,153,740	$ 7,941,896	$ 9,960,520	$ 11,978,208	$ 12,013,072	$ 11,590,032	$ 9,436,384	$ 7,863,876	$ 8,070,432	$ 8,534,496
5	Monthly Interest (line 3 ± line 3.5)* (4.38%/12)[3]	$ 400,492	$ 373,678	$ 348,231	$ 323,391	$ 295,583	$ 260,306	$ 217,536	$ 174,482	$ 132,815	$ 98,857	$ 70,515	$ 41,315
6	Ending Balance with Interest (line 3 - line 4 + line 5	$ 102,377,432	$ 95,405,718	$ 88,600,209	$ 80,981,704	$ 71,316,767	$ 59,598,865	$ 47,803,329	$ 36,387,779	$ 27,084,210	$ 19,319,191	$ 11,319,274	$ 2,826,093

[1] Excludes sales from E-36, E-3, and E-4 rate schedules.
[2] True-up is the result of using estimated revenue for January in the annual PSA Adjustor Rate Calculation because the actual amount was not available at the time of filing that schedule.
[3] Based on one-year Nominal Treasury Constant Maturities rate contained in the Federal Reserve Statistical Release, H-15.

ARIZONA PUBLIC SERVICE COMPANY
Schedule 3
Annual Adjustor Account
Year February 2006 - January 2007

Line No.		February	March	April	May	June	July	August	September	October	November	December	January
1	PSA Adjustor Rate	$ 0.004000	$ 0.004000	$ 0.004000	$ 0.005000	$ 0.005000	$ 0.005000	$ 0.005000	$ 0.005000	$ 0.005000	$ 0.005000	$ 0.005000	$ 0.005000
2	Retail Energy Sales[1] (kWh)	1,936,737,000	1,836,348,000	1,788,435,000	1,985,474,000	2,490,130,000	2,994,552,000	3,003,268,000	2,897,508,000	2,359,096,000	1,965,969,000	2,017,608,000	2,133,624,000
3	Beginning Balance	$ 109,723,888	$ 102,377,432	$ 95,405,718	$ 88,600,209	$ 78,996,230	$ 66,833,916	$ 52,105,100	$ 37,278,944	$ 22,927,472	$ 11,215,677	$ 1,426,769	$ (8,656,063)
3.5	Revenue True-up from January Estimate[2]	$ -											
4	Less: Revenue from Adjustor Rate (line 1 * line 2)	$ 7,746,948	$ 7,345,392	$ 7,153,740	$ 9,927,370	$ 12,450,650	$ 14,972,760	$ 15,016,340	$ 14,487,540	$ 11,795,480	$ 9,829,845	$ 10,088,040	$ 10,668,120
5	Monthly Interest (line 3 ± line 3.5)* (4.38%/12)[3]	$ 400,492	$ 373,678	$ 348,231	$ 323,391	$ 288,336	$ 243,944	$ 190,184	$ 136,068	$ 83,685	$ 40,937	$ 5,208	$ (31,595)
6	Ending Balance with Interest (line 3 - line 4 + line 5	$ 102,377,432	$ 95,405,718	$ 88,600,209	$ 78,996,230	$ 66,833,916	$ 52,105,100	$ 37,278,944	$ 22,927,472	$ 11,215,677	$ 1,426,769	$ (8,656,063)	$ (19,355,778)

[1] Excludes sales from E-36, E-3, and E-4 rate schedules.

[2] True-up is the result of using estimated revenue for January in the annual PSA Adjustor Rate Calculation because the actual amount was not available at the time of filing that schedule.

[3] *Based on one-year Nominal Treasury Constant Maturities rate contained in the Federal Reserve Statistical Release, H-15.*

ARIZONA PUBLIC SERVICE COMPANY
Schedule 3
Annual Adjustor Account
Year February 2006 - January 2007

Line No.		February	March	April	May	June	July	August	September	October	November	December	January
1	PSA Adjustor Rate	$ 0.004000	$ 0.004000	$ 0.004000	$ 0.006000	$ 0.006000	$ 0.006000	$ 0.006000	$ 0.006000	$ 0.006000	$ 0.006000	$ 0.006000	$ 0.006000
2	Retail Energy Sales[1] (kWh)	1,936,737,000	1,836,348,000	1,788,435,000	1,985,474,000	2,490,130,000	2,994,552,000	3,003,268,000	2,897,508,000	2,359,096,000	1,965,969,000	2,017,608,000	2,133,624,000
3	Beginning Balance	$ 109,723,888	$ 102,377,432	$ 95,405,718	$ 88,600,209	$ 77,010,756	$ 62,351,065	$ 44,611,334	$ 26,754,557	$ 9,467,163	$ (4,652,858)	$ (16,465,655)	$ (28,631,403)
3.5	Revenue True-up from January Estimate[2]	$ -											
4	Less: Revenue from Adjustor Rate (line 1 * line 2)	$ 7,746,948	$ 7,345,392	$ 7,153,740	$ 11,912,844	$ 14,940,780	$ 17,967,312	$ 18,019,608	$ 17,385,048	$ 14,154,576	$ 11,795,814	$ 12,105,648	$ 12,801,744
5	Monthly Interest (line 3 ± line 3.5)* (4.38%/12)[3]	$ 400,492	$ 373,678	$ 348,231	$ 323,391	$ 281,089	$ 227,581	$ 162,831	$ 97,654	$ 34,555	$ (16,983)	$ (60,100)	$ (104,505)
6	Ending Balance with Interest (line 3 - line 4 + line 5	$ 102,377,432	$ 95,405,718	$ 88,600,209	$ 77,010,756	$ 62,351,065	$ 44,611,334	$ 26,754,557	$ 9,467,163	$ (4,652,858)	$ (16,465,655)	$ (28,631,403)	$ (41,537,652)

[1] Excludes sales from E-36, E-3, and E-4 rate schedules.
[2] True-up is the result of using estimated revenue for January in the annual PSA Adjustor Rate Calculation because the actual amount was not available at the time of filing that schedule.
[3] Based on one-year Nominal Treasury Constant Maturities rate contained in the Federal Reserve Statistical Release, H-15.

ARIZONA PUBLIC SERVICE COMPANY
Schedule 3
Annual Adjustor Account
Year February 2006 - January 2007

Line No.		February	March	April	May	June	July	August	September	October	November	December	January
1	PSA Adjustor Rate	$ 0.004000	$ 0.004000	$ 0.004000	$ 0.007000	$ 0.007000	$ 0.007000	$ 0.007000	$ 0.007000	$ 0.007000	$ 0.007000	$ 0.007000	$ 0.007000
2	Retail Energy Sales[1] (kWh)	1,936,737,000	1,836,348,000	1,788,435,000	1,985,474,000	2,490,130,000	2,994,552,000	3,003,268,000	2,897,508,000	2,359,096,000	1,965,969,000	2,017,608,000	2,133,624,000
3	Beginning Balance	$ 109,723,888	$ 102,377,432	$ 95,405,718	$ 88,600,209	$ 75,025,282	$ 57,868,214	$ 37,117,569	$ 16,230,172	$ (3,993,144)	$ (20,521,391)	$ (34,358,077)	$ (48,606,740)
3.5	Revenue True-up from January Estimate[2]	$ -											
4	Less: Revenue from Adjustor Rate (line 1 * line 2)	$ 7,746,948	$ 7,345,392	$ 7,153,740	$ 13,898,318	$ 17,430,910	$ 20,961,864	$ 21,022,876	$ 20,282,556	$ 16,513,672	$ 13,761,783	$ 14,123,256	$ 14,935,368
5	Monthly Interest (line 3 ± line 3.5)* (4.38%/12)[3]	$ 400,492	$ 373,678	$ 348,231	$ 323,391	$ 273,842	$ 211,219	$ 135,479	$ 59,240	$ (14,575)	$ (74,903)	$ (125,407)	$ (177,415)
6	Ending Balance with Interest (line 3 - line 4 + line 5	$ 102,377,432	$ 95,405,718	$ 88,600,209	$ 75,025,282	$ 57,868,214	$ 37,117,569	$ 16,230,172	$ (3,993,144)	$ (20,521,391)	$ (34,358,077)	$ (48,606,740)	$ (63,719,523)

[1] Excludes sales from E-36, E-3, and E-4 rate schedules.
[2] True-up is the result of using estimated revenue for January in the annual PSA Adjustor Rate Calculation because the actual amount was not available at the time of filing that schedule.
[3] Based on one-year Nominal Treasury Constant Maturities rate contained in the Federal Reserve Statistical Release, H-15.

ARIZONA PUBLIC SERVICE COMPANY
Schedule 3
Annual Adjustor Account
Year February 2006 - January 2007

Line No.		February	March	April	May	June	July	August	September	October	November	December	January
1	PSA Adjustor Rate	$ 0.004000	$ 0.004000	$ 0.004000	$ 0.008000	$ 0.008000	$ 0.008000	$ 0.008000	$ 0.008000	$ 0.008000	$ 0.008000	$ 0.008000	$ 0.008000
2	Retail Energy Sales[1] (kWh)	1,936,737,000	1,836,348,000	1,788,435,000	1,985,474,000	2,490,130,000	2,994,552,000	3,003,268,000	2,897,508,000	2,359,096,000	1,965,969,000	2,017,608,000	2,133,624,000
3	Beginning Balance	$ 109,723,888	$ 102,377,432	$ 95,405,718	$ 88,600,209	$ 73,039,808	$ 53,385,363	$ 29,623,804	$ 5,705,787	$ (17,453,451)	$ (36,389,924)	$ (52,250,499)	$ (68,582,077)
3.5	Revenue True-up from January Estimate[2]	$ -											
4	Less: Revenue from Adjustor Rate (line 1 * line 2)	$ 7,746,948	$ 7,345,392	$ 7,153,740	$ 15,883,792	$ 19,921,040	$ 23,956,416	$ 24,026,144	$ 23,180,064	$ 18,872,768	$ 15,727,752	$ 16,140,864	$ 17,068,992
5	Monthly Interest (line 3 ± line 3.5)* (4.38%/12)[3]	$ 400,492	$ 373,678	$ 348,231	$ 323,391	$ 266,595	$ 194,857	$ 108,127	$ 20,826	$ (63,705)	$ (132,823)	$ (190,714)	$ (250,325)
6	Ending Balance with Interest (line 3 - line 4 + line 5	$ 102,377,432	$ 95,405,718	$ 88,600,209	$ 73,039,808	$ 53,385,363	$ 29,623,804	$ 5,705,787	$ (17,453,451)	$ (36,389,924)	$ (52,250,499)	$ (68,582,077)	$ (85,901,394)

[1] Excludes sales from E-36, E-3, and E-4 rate schedules.
[2] True-up is the result of using estimated revenue for January in the annual PSA Adjustor Rate Calculation because the actual amount was not available at the time of filing that schedule.
[3] Based on one-year Nominal Treasury Constant Maturities rate contained in the Federal Reserve Statistical Release, H-15.

ARIZONA PUBLIC SERVICE COMPANY
Schedule 3
Annual Adjustor Account
Year February 2006 - January 2007

Line No.		February	March	April	May	June	July	August	September	October	November	December	January
1	PSA Adjustor Rate	$ 0.004000	$ 0.004000	$ 0.004000	$ 0.009000	$ 0.009000	$ 0.009000	$ 0.009000	$ 0.009000	$ 0.009000	$ 0.009000	$ 0.009000	$ 0.009000
2	Retail Energy Sales[1] (kWh)	1,936,737,000	1,836,348,000	1,788,435,000	1,985,474,000	2,490,130,000	2,994,552,000	3,003,268,000	2,897,508,000	2,359,096,000	1,965,969,000	2,017,608,000	2,133,624,000
3	Beginning Balance	$ 109,723,888	$ 102,377,432	$ 95,405,718	$ 88,600,209	$ 71,054,334	$ 48,902,512	$ 22,130,038	$ (4,818,599)	$ (30,913,759)	$ (52,258,458)	$ (70,142,922)	$ (88,557,416)
3.5	Revenue True-up from January Estimate[2]	$ -											
4	Less: Revenue from Adjustor Rate (line 1 * line 2)	$ 7,746,948	$ 7,345,392	$ 7,153,740	$ 17,869,266	$ 22,411,170	$ 26,950,968	$ 27,029,412	$ 26,077,572	$ 21,231,864	$ 17,693,721	$ 18,158,472	$ 19,202,616
5	Monthly Interest (line 3 ± line 3.5)* (4.38%/12)[3]	$ 400,492	$ 373,678	$ 348,231	$ 323,391	$ 259,348	$ 178,494	$ 80,775	$ (17,588)	$ (112,835)	$ (190,743)	$ (256,022)	$ (323,235)
6	Ending Balance with Interest (line 3 - line 4 + line 5	$ 102,377,432	$ 95,405,718	$ 88,600,209	$ 71,054,334	$ 48,902,512	$ 22,130,038	$ (4,818,599)	$ (30,913,759)	$ (52,258,458)	$ (70,142,922)	$ (88,557,416)	$ (108,083,267)

[1] Excludes sales from E-36, E-3, and E-4 rate schedules.
[2] True-up is the result of using estimated revenue for January in the annual PSA Adjustor Rate Calculation because the actual amount was not available at the time of filing that schedule.
[3] Based on one-year Nominal Treasury Constant Maturities rate contained in the Federal Reserve Statistical Release, H-15.

ARIZONA PUBLIC SERVICE COMPANY
Schedule 3
Annual Adjustor Account
Year February 2006 - January 2007

Line No.		February	March	April	May	June	July	August	September	October	November	December	January
1	PSA Adjustor Rate	$ 0.004000	$ 0.004000	$ 0.004000	$ 0.010000	$ 0.010000	$ 0.010000	$ 0.010000	$ 0.010000	$ 0.010000	$ 0.010000	$ 0.010000	$ 0.010000
2	Retail Energy Sales[1] (kWh)	1,936,737,000	1,836,348,000	1,788,435,000	1,985,474,000	2,490,130,000	2,994,552,000	3,003,268,000	2,897,508,000	2,359,096,000	1,965,969,000	2,017,608,000	2,133,624,000
3	Beginning Balance	$ 109,723,888	$ 102,377,432	$ 95,405,718	$ 88,600,209	$ 69,068,860	$ 44,419,661	$ 14,636,273	$ (15,342,985)	$ (44,374,067)	$ (68,126,992)	$ (88,035,346)	$ (108,532,755)
3.5	Revenue True-up from January Estimate[2]	$ -											
4	Less: Revenue from Adjustor Rate (line 1 * line 2)	$ 7,746,948	$ 7,345,392	$ 7,153,740	$ 19,854,740	$ 24,901,300	$ 29,945,520	$ 30,032,680	$ 28,975,080	$ 23,590,960	$ 19,659,690	$ 20,176,080	$ 21,336,240
5	Monthly Interest (line 3 ± line 3.5)* (4.38%/12)[3]	$ 400,492	$ 373,678	$ 348,231	$ 323,391	$ 252,101	$ 162,132	$ 53,422	$ (56,002)	$ (161,965)	$ (248,664)	$ (321,329)	$ (396,145)
6	Ending Balance with Interest (line 3 - line 4 + line 5	$ 102,377,432	$ 95,405,718	$ 88,600,209	$ 69,068,860	$ 44,419,661	$ 14,636,273	$ (15,342,985)	$ (44,374,067)	$ (68,126,992)	$ (88,035,346)	$ (108,532,755)	$ (130,265,140)

[1] Excludes sales from E-36, E-3, and E-4 rate schedules.
[2] True-up is the result of using estimated revenue for January in the annual PSA Adjustor Rate Calculation because the actual amount was not available at the time of filing that schedule.
[3] Based on one-year Nominal Treasury Constant Maturities rate contained in the Federal Reserve Statistical Release, H-15.

Staff's Response to Request of Commissioner Gleason

Impact on E-12 Bills of Different Adjustor Rates:

E-12 Monthly Bills

Adjustor Rate	0.004	0.005	0.006	0.007	0.008	0.009	0.01
summer							
median	$87.71	$88.54	$89.37	$90.20	$91.03	$91.86	$92.69
average	$117.32	$118.38	$119.44	$120.51	$121.57	$122.63	$123.69
winter							
median	$50.30	$50.84	$51.37	$51.91	$52.45	$52.99	$53.53
average	$61.84	$62.53	$63.22	$63.90	$64.59	$65.28	$65.96

Attached are copies of Schedule 2, PSA Adjustor Rate Calculation, with various changes in bandwidth, assuming that the bandwidth was changed in May 2006.

EXHIBIT
S-9
admitted

filename=ResidentialBillImpacts.xls

Impact on E-12 Residential Customer Bills

Adjustor Rate = 0.004 per kWh

Summer (July 2005 cunsumption)

				median	average
				818	1047
basic service charge	$0.253	per day	31 days	$7.84	$7.84
energy charge					
1st 400 kWh	0.07570	per kWh		30.28	30.28
next 400 kWh	0.10556	per kWh		42.22	42.22
all additional kWh	0.12314	per kWh		2.22	30.42
CRCC	0.000338	per kWh		0.28	0.35
EPS ($0.35 cap)	0.000875	per kWh		0.35	0.35
PSA adjustor rate	$0.004	per kWh		3.27	4.19
			subtotal	86.46	115.65
franchise fee (Phx)	1.44%			1.25	1.67
			Total Bill	**$87.71**	**$117.32**

Winter (December 2004 consumption)

				median	average
				531	677
basic service charge	$0.253	per day	31 days	$7.84	$7.84
energy charge	0.07361	per kWh		39.09	49.83
CRCC	0.000338	per kWh		0.18	0.23
EPS ($0.35 cap)	0.000875	per kWh		0.35	0.35
PSA adjustor rate	$0.004	per kWh		2.12	2.71
			subtotal	49.58	60.96
franchise fee (Phx)	1.44%			0.71	0.88
			Total Bill	**$50.30**	**$61.84**

filename=ResidentialBillImpacts.xls

Impact on E-12 Residential Customer Bills

Adjustor Rate = 0.005 per kWh

Summer (July 2005 cunsumption)

				median	average
				818	1047
basic service charge	$0.253	per day	31 days	$7.84	$7.84
energy charge					
1st 400 kWh	0.07570	per kWh		30.28	30.28
next 400 kWh	0.10556	per kWh		42.22	42.22
all additional kWh	0.12314	per kWh		2.22	30.42
CRCC	0.000338	per kWh		0.28	0.35
EPS ($0.35 cap)	0.000875	per kWh		0.35	0.35
PSA adjustor rate	$0.005	per kWh		4.09	5.24
			subtotal	87.28	116.70
franchise fee (Phx)	1.44%			1.26	1.68
			Total Bill	**$88.54**	**$118.38**

Winter (December 2004 consumption)

				median	average
				531	677
basic service charge	$0.253	per day	31 days	$7.84	$7.84
energy charge	0.07361	per kWh		39.09	49.83
CRCC	0.000338	per kWh		0.18	0.23
EPS ($0.35 cap)	0.000875	per kWh		0.35	0.35
PSA adjustor rate	$0.005	per kWh		2.66	3.39
			subtotal	50.11	61.64
franchise fee (Phx)	1.44%			0.72	0.89
			Total Bill	**$50.84**	**$62.53**

filename=ResidentialBillImpacts.xls

Impact on E-12 Residential Customer Bills

Adjustor Rate = 0.006 per kWh

Summer (July 2005 cunsumption)

				median	average
				818	1047
basic service charge	$0.253	per day	31 days	$7.84	$7.84
energy charge					
1st 400 kWh	0.07570	per kWh		30.28	30.28
next 400 kWh	0.10556	per kWh		42.22	42.22
all additional kWh	0.12314	per kWh		2.22	30.42
CRCC	0.000338	per kWh		0.28	0.35
EPS ($0.35 cap)	0.000875	per kWh		0.35	0.35
PSA adjustor rate	$0.006	per kWh		4.91	6.28
			subtotal	88.10	117.75
franchise fee (Phx)	1.44%			1.27	1.70
			Total Bill	**$89.37**	**$119.44**

Winter (December 2004 consumption)

				median	average
				531	677
basic service charge	$0.253	per day	31 days	$7.84	$7.84
energy charge	0.07361	per kWh		39.09	49.83
CRCC	0.000338	per kWh		0.18	0.23
EPS ($0.35 cap)	0.000875	per kWh		0.35	0.35
PSA adjustor rate	$0.006	per kWh		3.19	4.06
			subtotal	50.65	62.32
franchise fee (Phx)	1.44%			0.73	0.90
			Total Bill	**$51.37**	**$63.22**

filename=ResidentialBillImpacts.xls

Impact on E-12 Residential Customer Bills

Adjustor Rate = 0.007 per kWh

Summer (July 2005 cunsumption)

				median	average
				818	1047
basic service charge	$0.253	per day	31 days	$7.84	$7.84
energy charge					
1st 400 kWh	0.07570	per kWh		30.28	30.28
next 400 kWh	0.10556	per kWh		42.22	42.22
all additional kWh	0.12314	per kWh		2.22	30.42
CRCC	0.000338	per kWh		0.28	0.35
EPS ($0.35 cap)	0.000875	per kWh		0.35	0.35
PSA adjustor rate	$0.007	per kWh		5.73	7.33
			subtotal	88.92	118.80
franchise fee (Phx)	1.44%			1.28	1.71
			Total Bill	**$90.20**	**$120.51**

Winter (December 2004 consumption)

				median	average
				531	677
basic service charge	$0.253	per day	31 days	$7.84	$7.84
energy charge	0.07361	per kWh		39.09	49.83
CRCC	0.000338	per kWh		0.18	0.23
EPS ($0.35 cap)	0.000875	per kWh		0.35	0.35
PSA adjustor rate	$0.007	per kWh		3.72	4.74
			subtotal	51.18	62.99
franchise fee (Phx)	1.44%			0.74	0.91
			Total Bill	**$51.91**	**$63.90**

filename=ResidentialBillImpacts.xls

Impact on E-12 Residential Customer Bills

Adjustor Rate = 0.008 per kWh

Summer (July 2005 cunsumption)

				median	average
				818	1047
basic service charge	$0.253	per day	31 days	$7.84	$7.84
energy charge					
1st 400 kWh	0.07570	per kWh		30.28	30.28
next 400 kWh	0.10556	per kWh		42.22	42.22
all additional kWh	0.12314	per kWh		2.22	30.42
CRCC	0.000338	per kWh		0.28	0.35
EPS ($0.35 cap)	0.000875	per kWh		0.35	0.35
PSA adjustor rate	$0.008	per kWh		6.54	8.38
			subtotal	89.73	119.84
franchise fee (Phx)	1.44%			1.29	1.73
			Total Bill	**$91.03**	**$121.57**

Winter (December 2004 consumption)

				median	average
				531	677
basic service charge	$0.253	per day	31 days	$7.84	$7.84
energy charge	0.07361	per kWh		39.09	49.83
CRCC	0.000338	per kWh		0.18	0.23
EPS ($0.35 cap)	0.000875	per kWh		0.35	0.35
PSA adjustor rate	$0.008	per kWh		4.25	5.42
			subtotal	51.71	63.67
franchise fee (Phx)	1.44%			0.74	0.92
			Total Bill	**$52.45**	**$64.59**

filename=ResidentialBillImpacts.xls

Impact on E-12 Residential Customer Bills

Adjustor Rate = 0.009 per kWh

Summer (July 2005 cunsumption)

				median	average
				818	1047
basic service charge	$0.253	per day	31 days	$7.84	$7.84
energy charge					
1st 400 kWh	0.07570	per kWh		30.28	30.28
next 400 kWh	0.10556	per kWh		42.22	42.22
all additional kWh	0.12314	per kWh		2.22	30.42
CRCC	0.000338	per kWh		0.28	0.35
EPS ($0.35 cap)	0.000875	per kWh		0.35	0.35
PSA adjustor rate	$0.009	per kWh		7.36	9.42
			subtotal	90.55	120.89
franchise fee (Phx)	1.44%			1.30	1.74
			Total Bill	**$91.86**	**$122.63**

Winter (December 2004 consumption)

				median	average
				531	677
basic service charge	$0.253	per day	31 days	$7.84	$7.84
energy charge	0.07361	per kWh		39.09	49.83
CRCC	0.000338	per kWh		0.18	0.23
EPS ($0.35 cap)	0.000875	per kWh		0.35	0.35
PSA adjustor rate	$0.009	per kWh		4.78	6.09
			subtotal	52.24	64.35
franchise fee (Phx)	1.44%			0.75	0.93
			Total Bill	**$52.99**	**$65.28**

filename=ResidentialBillImpacts.xls

Impact on E-12 Residential Customer Bills

Adjustor Rate = 0.01 per kWh

Summer (July 2005 cunsumption)

				median	average
				818	1047
basic service charge	$0.253	per day	31 days	$7.84	$7.84
energy charge					
1st 400 kWh	0.07570	per kWh		30.28	30.28
next 400 kWh	0.10556	per kWh		42.22	42.22
all additional kWh	0.12314	per kWh		2.22	30.42
CRCC	0.000338	per kWh		0.28	0.35
EPS ($0.35 cap)	0.000875	per kWh		0.35	0.35
PSA adjustor rate	$0.010	per kWh		8.18	10.47
			subtotal	91.37	121.94
franchise fee (Phx)	1.44%			1.32	1.76
			Total Bill	**$92.69**	**$123.69**

Winter (December 2004 consumption)

				median	average
				531	677
basic service charge	$0.253	per day	31 days	$7.84	$7.84
energy charge	0.07361	per kWh		39.09	49.83
CRCC	0.000338	per kWh		0.18	0.23
EPS ($0.35 cap)	0.000875	per kWh		0.35	0.35
PSA adjustor rate	$0.010	per kWh		5.31	6.77
			subtotal	52.77	65.03
franchise fee (Phx)	1.44%			0.76	0.94
			Total Bill	**$53.53**	**$65.96**

ARIZONA PUBLIC SERVICE COMPANY
Schedule 2
PSA Adjustor Rate Calculation
February 2007

Line No.	**PSA Adjustor Rate Calculation**			
1	Tracking Account Balance (from Schedule 1)		$ 247,558,521	
2	Annual Adjustor Account Balance (from Schedule 3)		$ 2,826,093	
3	Surcharge Account Balance after surcharge termination (from Schedule 5)*		$ -	
4	Paragraph 19(d) Balancing Account Balance (from Schedule 4)*		$ 62,533,253	
5	Total (Credit)/Charge Amount (Line 1 + Line 2 + Line 3 + Line 4)			**$ 312,917,867**
6	Projected Energy Sales without E-3, E-4 and E-36 (kWh)	28,505,098,960		
7	Computed Adjustor Rate per kWh (Line 5/ Line 6)		$ 0.010978	
8	*Current Adjustor Rate per kWh*	*0.004*		
9	Difference between Current Adj. Rate and Computed Adj. Rate (line 7 - line 8)	0.007		
	Adjustor Rate Bandwidth			
10	Adjustor Rate Bandwidth Upper Limit		**$ 0.004000**	
11	Adjustor Rate Bandwidth Lower Limit		$ (0.004000)	
12	Applicable Adjustor Rate per kWh for February 1, 20XX			**$ 0.004000**
13	Amount Carried Forward to Annual Adjustor Account (Line 6 * Line 12)			**$ 114,020,396**
14	Amount Carried Forward to Paragraph 19(d) Balancing Account (Line 5 - Line 13)			**$ 198,897,471**

* Includes interest for January.

ARIZONA PUBLIC SERVICE COMPANY
Schedule 2
PSA Adjustor Rate Calculation
February 2007

Line No.	**PSA Adjustor Rate Calculation**			
1	Tracking Account Balance (from Schedule 1)		$ 247,558,521	
2	Annual Adjustor Account Balance (from Schedule 3)		$ (19,355,778)	
3	Surcharge Account Balance after surcharge termination (from Schedule 5)*		$ -	
4	Paragraph 19(d) Balancing Account Balance (from Schedule 4)*		$ 62,533,253	
5	Total (Credit)/Charge Amount (Line 1 + Line 2 + Line 3 + Line 4)			**$ 290,735,996**
6	Projected Energy Sales without E-3, E-4 and E-36 (kWh)	28,505,098,960		
7	Computed Adjustor Rate per kWh (Line 5/ Line 6)		$ 0.010199	
8	Current Adjustor Rate per kWh	0.004		
9	Difference between Current Adj. Rate and Computed Adj. Rate (line 7 - line 8)	0.006		
	Adjustor Rate Bandwidth			
10	Adjustor Rate Bandwidth Upper Limit		**$ 0.005000**	
11	Adjustor Rate Bandwidth Lower Limit		$ (0.004000)	
12	Applicable Adjustor Rate per kWh for February 1, 20XX			**$ 0.005000**
13	Amount Carried Forward to Annual Adjustor Account (Line 6 * Line 12)			**$ 142,525,495**
14	Amount Carried Forward to Paragraph 19(d) Balancing Account (Line 5 - Line 13)			**$ 148,210,501**

* Includes interest for January.

ARIZONA PUBLIC SERVICE COMPANY
Schedule 2
PSA Adjustor Rate Calculation
February 2007

Line No.	PSA Adjustor Rate Calculation			
1	Tracking Account Balance (from Schedule 1)		$ 247,558,521	
2	Annual Adjustor Account Balance (from Schedule 3)		$ (41,537,652)	
3	Surcharge Account Balance after surcharge termination (from Schedule 5)*		$ -	
4	Paragraph 19(d) Balancing Account Balance (from Schedule 4)*		$ 62,533,253	
5	Total *(Credit)/Charge Amount* (Line 1 + Line 2 + Line 3 + Line 4)			**$ 268,554,122**
6	Projected Energy Sales without E-3, E-4 and E-36 (kWh)	28,505,098,960		
7	Computed Adjustor Rate per kWh (Line 5/ Line 6)		$ 0.009421	
8	Current Adjustor Rate per kWh	0.004		
9	Difference between Current Adj. Rate and Computed Adj. Rate (line 7 - line 8)	0.005		
	Adjustor Rate Bandwidth			
10	Adjustor Rate Bandwidth Upper Limit		**$ 0.006000**	
11	Adjustor Rate Bandwidth Lower Limit		$ (0.004000)	
12	Applicable Adjustor Rate per kWh for February 1, 20XX			**$ 0.006000**
13	Amount Carried Forward to Annual Adjustor Account (Line 6 * Line 12)			**$ 171,030,594**
14	Amount Carried Forward to Paragraph 19(d) Balancing Account (Line 5 - Line 13)			**$ 97,523,528**

* Includes interest for January.

ARIZONA PUBLIC SERVICE COMPANY
Schedule 2
PSA Adjustor Rate Calculation
February 2007

Line No.	PSA Adjustor Rate Calculation			
1	Tracking Account Balance (from Schedule 1)		$ 247,558,521	
2	Annual Adjustor Account Balance (from Schedule 3)		$ (63,719,523)	
3	Surcharge Account Balance after surcharge termination (from Schedule 5)*		$ -	
4	Paragraph 19(d) Balancing Account Balance (from Schedule 4)*		$ 62,533,253	
5	Total (Credit)/Charge Amount (Line 1 + Line 2 + Line 3 + Line 4)			**$ 246,372,251**
6	Projected Energy Sales without E-3, E-4 and E-36 (kWh)	28,505,098,960		
7	Computed Adjustor Rate per kWh (Line 5/ Line 6)		$ 0.008643	
8	Current Adjustor Rate per kWh	0.004		
9	Difference between Current Adj. Rate and Computed Adj. Rate (line 7 - line 8)	0.005		
	Adjustor Rate Bandwidth			
10	Adjustor Rate Bandwidth Upper Limit		**$ 0.007000**	
11	Adjustor Rate Bandwidth Lower Limit		$ (0.004000)	
12	Applicable Adjustor Rate per kWh for February 1, 20XX			**$ 0.007000**
13	Amount Carried Forward to Annual Adjustor Account (Line 6 * Line 12)			**$ 199,535,693**
14	Amount Carried Forward to Paragraph 19(d) Balancing Account (Line 5 - Line 13)			**$ 46,836,558**

* Includes interest for January.

ARIZONA PUBLIC SERVICE COMPANY
Schedule 2
PSA Adjustor Rate Calculation
February 2007

Line No.	PSA Adjustor Rate Calculation			
1	Tracking Account Balance (from Schedule 1)		$ 247,558,521	
2	Annual Adjustor Account Balance (from Schedule 3)		$ (85,901,394)	
3	*Surcharge Account Balance after surcharge termination (from Schedule 5)**		$ -	
4	Paragraph 19(d) Balancing Account Balance (from Schedule 4)*		$ 62,533,253	
5	Total (Credit)/Charge Amount (Line 1 + Line 2 + Line 3 + Line 4)			**$ 224,190,380**
6	Projected Energy Sales without E-3, E-4 and E-36 (kWh)	28,505,098,960		
7	Computed Adjustor Rate per kWh (Line 5/ Line 6)		$ 0.007865	
8	*Current Adjustor Rate per kWh*	0.004		
9	Difference between Current Adj. Rate and Computed Adj. Rate (line 7 - line 8)	0.004		
	Adjustor Rate Bandwidth			
10	Adjustor Rate Bandwidth Upper Limit		**$ 0.008000**	
11	Adjustor Rate Bandwidth Lower Limit		$ (0.004000)	
12	Applicable Adjustor Rate per kWh for February 1, 20XX			**$ 0.007865**
13	Amount Carried Forward to Annual Adjustor Account (Line 6 * Line 12)			**$ 224,190,380**
14	Amount Carried Forward to Paragraph 19(d) Balancing Account (Line 5 - Line 13)			**$ -**

* Includes interest for January.

ARIZONA PUBLIC SERVICE COMPANY
Schedule 2
PSA Adjustor Rate Calculation
February 2007

Line No.	PSA Adjustor Rate Calculation			
1	Tracking Account Balance (from Schedule 1)		$ 247,558,521	
2	Annual Adjustor Account Balance (from Schedule 3)		$(108,083,267)	
3	Surcharge Account Balance after surcharge termination (from Schedule 5)*		$ -	
4	Paragraph 19(d) Balancing Account Balance (from Schedule 4)*		$ 62,533,253	
5	Total (Credit)/Charge Amount (Line 1 + Line 2 + Line 3 + Line 4)			**$ 202,008,507**
6	Projected Energy Sales without E-3, E-4 and E-36 (kWh)	28,505,098,960		
7	Computed Adjustor Rate per kWh (Line 5/ Line 6)		$ 0.007087	
8	Current Adjustor Rate per kWh	0.004		
9	Difference between Current Adj. Rate and Computed Adj. Rate (line 7 - line 8)	0.003		
	Adjustor Rate Bandwidth			
10	Adjustor Rate Bandwidth Upper Limit		**$ 0.009000**	
11	Adjustor Rate Bandwidth Lower Limit		$ (0.004000)	
12	Applicable Adjustor Rate per kWh for February 1, 20XX			**$ 0.007087**
13	Amount Carried Forward to Annual Adjustor Account (Line 6 * Line 12)			**$ 202,008,507**
14	Amount Carried Forward to Paragraph 19(d) Balancing Account (Line 5 - Line 13)			**$ -**

* Includes interest for January.

ARIZONA PUBLIC SERVICE COMPANY
Schedule 2
PSA Adjustor Rate Calculation
February 2007

Line No.	PSA Adjustor Rate Calculation			
1	Tracking Account Balance (from Schedule 1)		$ 247,558,521	
2	Annual Adjustor Account Balance (from Schedule 3)		$(130,265,140)	
3	Surcharge Account Balance after surcharge termination (from Schedule 5)*		$ -	
4	Paragraph 19(d) Balancing Account Balance (from Schedule 4)*		$ 62,533,253	
5	Total (Credit)/Charge Amount (Line 1 + Line 2 + Line 3 + Line 4)			**$ 179,826,634**
6	Projected Energy Sales without E-3, E-4 and E-36 (kWh)	28,505,098,960		
7	Computed Adjustor Rate per kWh (Line 5/ Line 6)		$ 0.006309	
8	Current Adjustor Rate per kWh	0.004		
9	Difference between Current Adj. Rate and Computed Adj. Rate (line 7 - line 8)	0.002		
	Adjustor Rate Bandwidth			
10	Adjustor Rate Bandwidth Upper Limit		$ 0.010000	
11	Adjustor Rate Bandwidth Lower Limit		$ (0.004000)	
12	Applicable Adjustor Rate per kWh for February 1, 20XX			**$ 0.006309**
13	Amount Carried Forward to Annual Adjustor Account (Line 6 * Line 12)			**$ 179,826,634**
14	Amount Carried Forward to Paragraph 19(d) Balancing Account (Line 5 - Line 13)			**$ -**

* Includes interest for January.

Monthly Bills

Adjustor Rate	0.004	0.005	0.006	0.007	0.008	0.009	0.01
E-32							
summer							
median	$165.23	$166.64	$168.05	$169.47	$170.88	$172.29	$173.71
average	$699.41	$709.25	$719.09	$728.93	$738.78	$748.62	$758.46
winter							
median	$119.38	$120.47	$121.55	$122.63	$123.71	$124.80	$125.88
average	$494.22	$502.02	$509.82	$517.62	$525.43	$533.23	$541.03
E-34							
median	$118,503.47	$120,465.62	$122,427.78	$124,389.93	$126,352.08	$128,314.24	$130,276.39
average	$151,560.84	$154,078.34	$156,595.84	$159,113.35	$161,630.85	$164,148.35	$166,665.86

Bills on E-35 are not yet available because it is a time-of-use rate and we need to obtain information on the on-peak/off-peak usage.

EXHIBIT
tabbies
S-10
admitted

filename=CommercialBillImpacts.xls

Impact on Commercial Customer Bills

Adjustor Rate = 0.004 per kWh

E-32 General Service

Summer

				median	average
			kWh	1393	9702
			kW	7	27
basic service charge	$0.575	per day	31 days	$17.83	$17.83
energy charge (secondary service, demands < 20 kW)					
1st 5,000 kWh	0.09892	per kWh		137.80	
all additional kWh	0.04711	per kWh		0.00	
energy charge (demands > 20 kW)					
1st 200 kWh	0.07938	per kWh			15.88
all additional kWh	0.04175	per kWh			396.71
demand charge (demands > 20 kW)					
1st 100 kW	7.722	per kW			208.49
all additional kW	3.497	per kW			0.00
CRCC	0.000338	per kWh		0.47	3.28
EPS ($13 cap)	0.000875	per kWh		1.22	8.49
February 2006 PSA Adjustor Rate				5.57	38.81
			subtotal	162.88	689.48
franchise fee (Phx)	1.44%			2.35	9.93
			Total Bill	**$165.23**	**$699.41**

Winter

				median	average
			kWh	1067	7691
			kW	6	23
basic service charge	$0.575	per day	30 days	$17.25	$17.25
energy charge (secondary service, demands < 20 kW)					
1st 5,000 kWh	0.08892	per kWh		94.88	
all additional kWh	0.03711	per kWh		0.00	
energy charge (demands > 20 kW)					
1st 200 kWh	0.06945	per kWh			13.89
all additional kWh	0.03182	per kWh			238.36
demand charge (demands > 20 kW)					
1st 100 kW	7.722	per kW			177.61
all additional kW	3.497	per kW			0.00
CRCC	0.000338	per kWh		0.36	2.60
EPS ($13 cap)	0.000875	per kWh		0.93	6.73
February 2006 PSA Adjustor Rate				4.27	30.76
			subtotal	117.69	487.20
franchise fee (Phx)	1.44%			1.69	7.02
			Total Bill	**$119.38**	**$494.22**

E-34 Extra Large General Service

				median	average
			kWh	1934300	2481766
			kW	3792	4828
basic service charge	$0.575	per day	31 days	$17.83	$17.83
energy charge	0.03183	per kWh		61568.77	78994.61
demand charge (secondary)	12.343	per kW		46804.66	59592.00
CRCC	0.000338	per kWh		653.79	838.84
EPS ($39 cap)	0.000875	per kWh		39.00	39.00
February 2006 PSA Adjustor Rate				7737.20	9927.06
			subtotal	116821.24	149409.34
franchise fee (Phx)	1.44%			1682.23	2151.49
			Total Bill	**$118,503.47**	**$151,560.84**

filename=CommercialBillImpacts.xls

Impact on Commercial Customer Bills

Adjustor Rate = 0.005 per kWh

E-32 General Service

Summer

				median	average
			kWh	1393	9702
			kW	7	27
basic service charge	$0.575	per day	31 days	$17.83	$17.83
energy charge (secondary service, demands < 20 kW)					
1st 5,000 kWh	0.09892	per kWh		137.80	
all additional kWh	0.04711	per kWh		0.00	
energy charge (demands > 20 kW)					
1st 200 kWh	0.07938	per kWh			15.88
all additional kWh	0.04175	per kWh			396.71
demand charge (demands > 20 kW)					
1st 100 kW	7.722	per kW			208.49
all additional kW	3.497	per kW			0.00
CRCC	0.000338	per kWh		0.47	3.28
EPS ($13 cap)	0.000875	per kWh		1.22	8.49
February 2006 PSA Adjustor Rate				6.97	48.51
			subtotal	164.28	699.18
franchise fee (Phx)	1.44%			2.37	10.07
			Total Bill	**$166.64**	**$709.25**

Winter

				median	average
			kWh	1067	7691
			kW	6	23
basic service charge	$0.575	per day	30 days	$17.25	$17.25
energy charge (secondary service, demands < 20 kW)					
1st 5,000 kWh	0.08892	per kWh		94.88	
all additional kWh	0.03711	per kWh		0.00	
energy charge (demands > 20 kW)					
1st 200 kWh	0.06945	per kWh			13.89
all additional kWh	0.03182	per kWh			238.36
demand charge (demands > 20 kW)					
1st 100 kW	7.722	per kW			177.61
all additional kW	3.497	per kW			0.00
CRCC	0.000338	per kWh		0.36	2.60
EPS ($13 cap)	0.000875	per kWh		0.93	6.73
February 2006 PSA Adjustor Rate				5.34	38.46
			subtotal	118.76	494.89
franchise fee (Phx)	1.44%			1.71	7.13
			Total Bill	**$120.47**	**$502.02**

E-34 Extra Large General Service

				median	average
			kWh	1934300	2481766
			kW	3792	4828
basic service charge	$0.575	per day	31 days	$17.83	$17.83
energy charge	0.03183	per kWh		61568.77	78994.61
demand charge (secondary)	12.343	per kW		46804.66	59592.00
CRCC	0.000338	per kWh		653.79	838.84
EPS ($39 cap)	0.000875	per kWh		39.00	39.00
February 2006 PSA Adjustor Rate				9671.50	12408.83
			subtotal	118755.54	151891.11
franchise fee (Phx)	1.44%			1710.08	2187.23
			Total Bill	**$120,465.62**	**$154,078.34**

filename=CommercialBillImpacts.xls

Impact on Commercial Customer Bills

Adjustor Rate = 0.006 per kWh

E-32 General Service

Summer

			median	average
		kWh	1393	9702
		kW	7	27
basic service charge	$0.575 per day	31 days	$17.83	$17.83
energy charge (secondary service, demands < 20 kW)				
1st 5,000 kWh	0.09892 per kWh		137.80	
all additional kWh	0.04711 per kWh		0.00	
energy charge (demands > 20 kW)				
1st 200 kWh	0.07938 per kWh			15.88
all additional kWh	0.04175 per kWh			396.71
demand charge (demands > 20 kW)				
1st 100 kW	7.722 per kW			208.49
all additional kW	3.497 per kW			0.00
CRCC	0.000338 per kWh		0.47	3.28
EPS ($13 cap)	0.000875 per kWh		1.22	8.49
February 2006 PSA Adjustor Rate			8.36	58.21
		subtotal	165.67	708.88
franchise fee (Phx)	1.44%		2.39	10.21
		Total Bill	**$168.05**	**$719.09**

Winter

			median	average
		kWh	1067	7691
		kW	6	23
basic service charge	$0.575 per day	30 days	$17.25	$17.25
energy charge (secondary service, demands < 20 kW)				
1st 5,000 kWh	0.08892 per kWh		94.88	
all additional kWh	0.03711 per kWh		0.00	
energy charge (demands > 20 kW)				
1st 200 kWh	0.06945 per kWh			13.89
all additional kWh	0.03182 per kWh			238.36
demand charge (demands > 20 kW)				
1st 100 kW	7.722 per kW			177.61
all additional kW	3.497 per kW			0.00
CRCC	0.000338 per kWh		0.36	2.60
EPS ($13 cap)	0.000875 per kWh		0.93	6.73
February 2006 PSA Adjustor Rate			6.40	46.15
		subtotal	119.82	502.58
franchise fee (Phx)	1.44%		1.73	7.24
		Total Bill	**$121.55**	**$509.82**

E-34 Extra Large General Service

				median	average
			kWh	1934300	2481766
			kW	3792	4828
basic service charge	$0.575	per day	31 days	$17.83	$17.83
energy charge	0.03183	per kWh		61568.77	78994.61
demand charge (secondary)	12.343	per kW		46804.66	59592.00
CRCC	0.000338	per kWh		653.79	838.84
EPS ($39 cap)	0.000875	per kWh		39.00	39.00
February 2006 PSA Adjustor Rate				11605.80	14890.60
			subtotal	120689.84	154372.87
franchise fee (Phx)	1.44%			1737.93	2222.97
			Total Bill	**$122,427.78**	**$156,595.84**

filename=CommercialBillImpacts.xls

Impact on Commercial Customer Bills

Adjustor Rate = **0.007 per kWh**

E-32 General Service

Summer

			median	average
		kWh	1393	9702
		kW	7	27
basic service charge	$0.575 per day	31 days	$17.83	$17.83
energy charge (secondary service, demands < 20 kW)				
1st 5,000 kWh	0.09892 per kWh		137.80	
all additional kWh	0.04711 per kWh		0.00	
energy charge (demands > 20 kW)				
1st 200 kWh	0.07938 per kWh			15.88
all additional kWh	0.04175 per kWh			396.71
demand charge (demands > 20 kW)				
1st 100 kW	7.722 per kW			208.49
all additional kW	3.497 per kW			0.00
CRCC	0.000338 per kWh		0.47	3.28
EPS ($13 cap)	0.000875 per kWh		1.22	8.49
February 2006 PSA Adjustor Rate			9.75	67.91
		subtotal	167.06	718.59
franchise fee (Phx)	1.44%		2.41	10.35
		Total Bill	**$169.47**	**$728.93**

Winter

			median	average
		kWh	1067	7691
		kW	6	23
basic service charge	$0.575 per day	30 days	$17.25	$17.25
energy charge (secondary service, demands < 20 kW)				
1st 5,000 kWh	0.08892 per kWh		94.88	
all additional kWh	0.03711 per kWh		0.00	
energy charge (demands > 20 kW)				
1st 200 kWh	0.06945 per kWh			13.89
all additional kWh	0.03182 per kWh			238.36
demand charge (demands > 20 kW)				
1st 100 kW	7.722 per kW			177.61
all additional kW	3.497 per kW			0.00
CRCC	0.000338 per kWh		0.36	2.60
EPS ($13 cap)	0.000875 per kWh		0.93	6.73
February 2006 PSA Adjustor Rate			7.47	53.84
		subtotal	120.89	510.28
franchise fee (Phx)	1.44%		1.74	7.35
		Total Bill	**$122.63**	**$517.62**

E-34 Extra Large General Service

				median	average
			kWh	1934300	2481766
			kW	3792	4828
basic service charge	$0.575	per day	31 days	$17.83	$17.83
energy charge	0.03183	per kWh		61568.77	78994.61
demand charge (secondary)	12.343	per kW		46804.66	59592.00
CRCC	0.000338	per kWh		653.79	838.84
EPS ($39 cap)	0.000875	per kWh		39.00	39.00
February 2006 PSA Adjustor Rate				13540.10	17372.36
			subtotal	122624.14	156854.64
franchise fee (Phx)	1.44%			1765.79	2258.71
			Total Bill	**$124,389.93**	**$159,113.35**

filename=CommercialBillImpacts.xls

Impact on Commercial Customer Bills

Adjustor Rate = **0.008 per kWh**

E-32 General Service

Summer

				median	average
			kWh	1393	9702
			kW	7	27
basic service charge	$0.575	per day	31 days	$17.83	$17.83
energy charge (secondary service, demands < 20 kW)					
1st 5,000 kWh	0.09892	per kWh		137.80	
all additional kWh	0.04711	per kWh		0.00	
energy charge (demands > 20 kW)					
1st 200 kWh	0.07938	per kWh			15.88
all additional kWh	0.04175	per kWh			396.71
demand charge (demands > 20 kW)					
1st 100 kW	7.722	per kW			208.49
all additional kW	3.497	per kW			0.00
CRCC	0.000338	per kWh		0.47	3.28
EPS ($13 cap)	0.000875	per kWh		1.22	8.49
February 2006 PSA Adjustor Rate				11.14	77.62
			subtotal	168.45	728.29
franchise fee (Phx)	1.44%			2.43	10.49
			Total Bill	**$170.88**	**$738.78**

Winter

				median	average
			kWh	1067	7691
			kW	6	23
basic service charge	$0.575	per day	30 days	$17.25	$17.25
energy charge (secondary service, demands < 20 kW)					
1st 5,000 kWh	0.08892	per kWh		94.88	
all additional kWh	0.03711	per kWh		0.00	
energy charge (demands > 20 kW)					
1st 200 kWh	0.06945	per kWh			13.89
all additional kWh	0.03182	per kWh			238.36
demand charge (demands > 20 kW)					
1st 100 kW	7.722	per kW			177.61
all additional kW	3.497	per kW			0.00
CRCC	0.000338	per kWh		0.36	2.60
EPS ($13 cap)	0.000875	per kWh		0.93	6.73
February 2006 PSA Adjustor Rate				8.54	61.53
			subtotal	121.96	517.97
franchise fee (Phx)	1.44%			1.76	7.46
			Total Bill	**$123.71**	**$525.43**

E-34 Extra Large General Service

				median	average
			kWh	1934300	2481766
			kW	3792	4828
basic service charge	$0.575	per day	31 days	$17.83	$17.83
energy charge	0.03183	per kWh		61568.77	78994.61
demand charge (secondary)	12.343	per kW		46804.66	59592.00
CRCC	0.000338	per kWh		653.79	838.84
EPS ($39 cap)	0.000875	per kWh		39.00	39.00
February 2006 PSA Adjustor Rate				15474.40	19854.13
			subtotal	124558.44	159336.41
franchise fee (Phx)	1.44%			1793.64	2294.44
			Total Bill	**$126,352.08**	**$161,630.85**

filename=CommercialBillImpacts.xls

Impact on Commercial Customer Bills

Adjustor Rate = **0.009 per kWh**

E-32 General Service

Summer

			median	average
		kWh	1393	9702
		kW	7	27
basic service charge	$0.575 per day	31 days	$17.83	$17.83
energy charge (secondary service, demands < 20 kW)				
1st 5,000 kWh	0.09892 per kWh		137.80	
all additional kWh	0.04711 per kWh		0.00	
energy charge (demands > 20 kW)				
1st 200 kWh	0.07938 per kWh			15.88
all additional kWh	0.04175 per kWh			396.71
demand charge (demands > 20 kW)				
1st 100 kW	7.722 per kW			208.49
all additional kW	3.497 per kW			0.00
CRCC	0.000338 per kWh		0.47	3.28
EPS ($13 cap)	0.000875 per kWh		1.22	8.49
February 2006 PSA Adjustor Rate			12.54	87.32
		subtotal	169.85	737.99
franchise fee (Phx)	1.44%		2.45	10.63
		Total Bill	**$172.29**	**$748.62**

Winter

			median	average
		kWh	1067	7691
		kW	6	23
basic service charge	$0.575 per day	30 days	$17.25	$17.25
energy charge (secondary service, demands < 20 kW)				
1st 5,000 kWh	0.08892 per kWh		94.88	
all additional kWh	0.03711 per kWh		0.00	
energy charge (demands > 20 kW)				
1st 200 kWh	0.06945 per kWh			13.89
all additional kWh	0.03182 per kWh			238.36
demand charge (demands > 20 kW)				
1st 100 kW	7.722 per kW			177.61
all additional kW	3.497 per kW			0.00
CRCC	0.000338 per kWh		0.36	2.60
EPS ($13 cap)	0.000875 per kWh		0.93	6.73
February 2006 PSA Adjustor Rate			9.60	69.22
		subtotal	123.02	525.66
franchise fee (Phx)	1.44%		1.77	7.57
		Total Bill	**$124.80**	**$533.23**

E-34 Extra Large General Service

				median	average
			kWh	1934300	2481766
			kW	3792	4828
basic service charge	$0.575	per day	31 days	$17.83	$17.83
energy charge	0.03183	per kWh		61568.77	78994.61
demand charge (secondary)	12.343	per kW		46804.66	59592.00
CRCC	0.000338	per kWh		653.79	838.84
EPS ($39 cap)	0.000875	per kWh		39.00	39.00
February 2006 PSA Adjustor Rate				17408.70	22335.89
			subtotal	126492.74	161818.17
franchise fee (Phx)	1.44%			1821.50	2330.18
			Total Bill	**$128,314.24**	**$164,148.35**

filename=CommercialBillImpacts.xls

Impact on Commercial Customer Bills

Adjustor Rate = **0.01 per kWh**

E-32 General Service

Summer

				median	average
			kWh	1393	9702
			kW	7	27
basic service charge	$0.575	per day	31 days	$17.83	$17.83
energy charge (secondary service, demands < 20 kW)					
1st 5,000 kWh	0.09892	per kWh		137.80	
all additional kWh	0.04711	per kWh		0.00	
energy charge (demands > 20 kW)					
1st 200 kWh	0.07938	per kWh			15.88
all additional kWh	0.04175	per kWh			396.71
demand charge (demands > 20 kW)					
1st 100 kW	7.722	per kW			208.49
all additional kW	3.497	per kW			0.00
CRCC	0.000338	per kWh		0.47	3.28
EPS ($13 cap)	0.000875	per kWh		1.22	8.49
February 2006 PSA Adjustor Rate				13.93	97.02
			subtotal	171.24	747.69
franchise fee (Phx)	1.44%			2.47	10.77
			Total Bill	**$173.71**	**$758.46**

Winter

				median	average
			kWh	1067	7691
			kW	6	23
basic service charge	$0.575	per day	30 days	$17.25	$17.25
energy charge (secondary service, demands < 20 kW)					
1st 5,000 kWh	0.08892	per kWh		94.88	
all additional kWh	0.03711	per kWh		0.00	
energy charge (demands > 20 kW)					
1st 200 kWh	0.06945	per kWh			13.89
all additional kWh	0.03182	per kWh			238.36
demand charge (demands > 20 kW)					
1st 100 kW	7.722	per kW			177.61
all additional kW	3.497	per kW			0.00
CRCC	0.000338	per kWh		0.36	2.60
EPS ($13 cap)	0.000875	per kWh		0.93	6.73
February 2006 PSA Adjustor Rate				10.67	76.91
			subtotal	124.09	533.35
franchise fee (Phx)	1.44%			1.79	7.68
			Total Bill	**$125.88**	**$541.03**

E-34 Extra Large General Service

					median	average
				kWh	1934300	2481766
				kW	3792	4828
basic service charge	$0.575	per day	31 days		$17.83	$17.83
energy charge	0.03183	per kWh			61568.77	78994.61
demand charge (secondary)	12.343	per kW			46804.66	59592.00
CRCC	0.000338	per kWh			653.79	838.84
EPS ($39 cap)	0.000875	per kWh			39.00	39.00
February 2006 PSA Adjustor Rate					19343.00	24817.66
			subtotal		128427.04	164299.94
franchise fee (Phx)	1.44%				1849.35	2365.92
				Total Bill	**$130,276.39**	**$166,665.86**

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AZ CORP COMMISSION
DOCUMENT CONTROL

Transcript Exhibit(s)

Docket #(s): E-0134A-06-0009

Exhibit # : R-1, R-2, R-3, R-4, R-5, R-6, R-7,
R-8

APS / Interim Rates E-01345A-06-0009

March 20 through 29, 2006

Volumes I through VIII

RUCO EXHIBITS

1 through 8

BEFORE THE ARIZONA CORPORATION COMMISSION

Arizona Corporation Commission
DOCKETED

APR - 7 2005

DOCKETED BY ML

EXHIBIT
RUCO-1
ADMITTED

COMMISSIONERS

JEFF HATCH-MILLER Chairman
WILLIAM A. MUNDELL
MARC SPITZER
MIKE GLEASON
KRISTIN K. MAYES

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.	DOCKET NO. E-01345A-03-0437 DECISION NO. 67744 **OPINION AND ORDER**

DATES OF PROCEDURAL CONFERENCES: August 13, 2003, January 6, February 18, April 7, 15, 28 May 26, June 14, August 18, and October 27, 2004

DATES OF HEARING: November 8, 9, 10, 29, 30, December 1, 2, and 3, 2004

PLACE OF HEARING: Phoenix, Arizona

ADMINISTRATIVE LAW JUDGE: Lyn Farmer

IN ATTENDANCE:
Marc Spitzer, Chairman
William A. Mundell, Commissioner
Jeff Hatch-Miller, Commissioner
Mike Gleason, Commissioner
Kristin K. Mayes, Commissioner

APPEARANCES:

Mr. Thomas L. Mumaw and Ms. Karilee S. Ramaley, PINNACLE WEST CAPITAL CORPORATION; Mr. Jeffrey B. Guldner and Ms. Kimberly Grouse, SNELL & WILMER, L.L.P., on behalf of Arizona Public Service Company;

Mr. C. Webb Crockett, FENNEMORE CRAIG, P.C., on behalf of AECC and Phelps Dodge;

Mr. Patrick J. Black, FENNEMORE CRAIG, P.C., on behalf of Panda Gila River;

Mr. S. David Childers, LOW & CHILDERS, P.C., Mr. James M. Van Nostrand, and Ms. Katherine McDowell STOEL RIVES, L.L.P., on behalf of Arizona Competitive Power Alliance;

Mr. Lawrence V. Robertson, Jr., MUNGER

the existing rate structure, the company's shareholders feel the impact. Likewise, if the costs decrease, the shareholders benefit. Under a PSA, the shareholders are insulated from the change in costs, because now the ratepayers are obligated to pay the additional costs. Further, the testimony was clear that costs are going to be increasing, not only because natural gas prices will increase, but also because APS' "mix" of fuel will change as growth occurs.[15] That mix will include an increasing amount of natural gas to supply the new generation. When compared to APS' other fuel sources such as nuclear or coal, natural gas is a substantially higher cost fuel. So here, the PSA will not only be collecting additional revenues due to fuel price increases, but also increases due to growth that is met with generation from a high cost fuel.[16]

Although the Settlement Agreement provides that APS will increase its demand side management and renewables, and we agree that those resources are increasingly important, they will not likely have a significant ameliorating cost impact in the near future. We disagree with the parties that a 90/10 sharing is sufficient incentive for APS to continue to effectively hedge its natural gas costs. Going from a 100 percent at-risk position to 10 percent at-risk almost seems like a "free pass," especially when a revenue increase is added. Although the Settlement Agreement provides that all costs will be subject to review for prudency before they can be recovered, prudency reviews, especially transactions in the wholesale market, can be difficult to conduct after the fact. Although we have confidence in our Staff's ability to conduct prudency reviews, we do not believe they provide as much incentive to APS on the front end to hedge costs as exists today without a PSA. The band-width limit will help limit drastic increases, but ultimately, APS will be able to recover all the costs from ratepayers.[17]

Accordingly, for these reasons, we believe that provisions of the PSA need to be modified to protect the ratepayers. We agree that the use of an adjustor when fuel costs are volatile prevents a

---

[15] As growth occurs, the per unit cost of fuel will increase. Tr. p. 1238. Currently, nuclear is 32 percent of sales and represents 7.4 percent of the costs of generation; coal is 45 percent of sales and 29.7 percent of generation costs; natural gas is 18 percent of sales and 47.4 percent of generation costs; and purchased power is 5 percent of sales and 15.5 percent of generation costs. Tr. p. 1257. In five years, natural gas is expected to be 29-30 percent of sales. TR. p. 1258.

[16] See discussion Tr. p. 1259, PSA will always be increasing.

[17] Staff's late-filed exhibit S-35 filed December 14, 2004 in response to a request from Commissioner Mundell to extrapolate the effects of the PSA over several years, contained an error and on March 9, 2005, Staff filed a corrected exhibit.

III. Cost of Capital

16. The Parties agree that a capital structure of 55% long-term debt and 45% common equity shall be adopted for ratemaking purposes.

17. The Parties agree that a return on common equity of 10.25% is appropriate.

18. The Parties agree that an embedded cost of long-term debt of 5.8% is appropriate.

IV. Power Supply Adjustor

19. A Power Supply Adjustor ("PSA") shall be adopted with the following characteristics.

a. The PSA shall include both fuel and purchased power.

b. The adjustor rate, initially set at zero, will be reset on April 1, 2006 and thereafter on April 1st of each subsequent year. APS will submit a publicly available report that shows the calculation of the new rate on March 1, 2006 and thereafter on March 1st of each subsequent year. The adjustor rate shall become effective with the first billing cycle in April unless suspended by the Commission.

c. There shall be an incentive mechanism where APS and its customers shall share in the costs or savings. The percentage of sharing shall be ninety (90) percent for the customers and ten (10) percent for APS with no maximum sharing amount.

d. There shall be a bandwidth which shall limit the change in the adjustor rate to plus or minus $0.004 per kilowatt hour ("kWh") per year. Any additional recoverable or refundable amounts shall be recorded in a balancing account and shall carry over to the subsequent year or years. The carryover amount shall not be subject to further sharing as described above in Paragraph 19.c in the subsequent year or years.

e. When the size of the balancing account reaches either plus or minus $50 million, APS will have forty-five days to file for Commission approval of a surcharge to amortize the over-recovered/under-recovered balance and to reset the balancing account to zero. If APS does not want to reset the balance to zero, it shall file a report explaining why. Commission action shall be required to establish or revise a surcharge created pursuant to this provision.

f. Subject to paragraphs 19.c and 19.d, ratepayers shall receive the benefits of all off-system sales margins through a credit to the PSA balance.

g. The PSA is the appropriate mechanism for recovery of the prudent direct costs of contracts used for hedging fuel and purchased power costs.

DECISION NO. 67744

Arizona Public Service Company
Retail PSA Balance
11/30/05 Market Prices
Updated for Decision 68437
thousands of $

	No Interim Rates	Interim Rates
2005 Ending Balance (Tracking Account)	169,583	169,583
2006 Projection		
Retail Net Fuel Cost	844,681	844,681
Base Fuel Collections [1]	(577,347)	(803,062)
Retail Fuel Undercollection	267,334	41,619
10% Sharing	(26,733)	(4,162)
Subtotal Fuel Undercollection	240,601	37,457
Interest	9,305	6,520
Uncollected 2006 PSA Costs (Tracking Account)	249,906	43,977
Annual Adjustor Collections [1]	(101,897)	(101,897)
Revenue from Surcharge(s) [1]	(35,176)	(35,176)
2006 Activity	112,833	(93,096)
2006 PSA Ending Balance (Total of Tracking Account, uncollected Annual Adjustor, and unrecovered Surcharge Account)	282,416	76,487
Remaining Surcharge Balance(s)	(24,724)	(24,724)
Remaining 2006 Annual Adjustor Balance	(7,824)	(7,824)
2006 PSA Balance to go to 19d Balancing Account used to determine 2/1/07 Annual Adjustor	249,868	43,939

[1] Calculation details on STF 3-5b. Includes only the 11 months in 2006.

EXHIBIT
RUCO-2
ADMITTED

RESEARCH

Arizona Public Service's Proposed Rate Settlement Is Reasonably Constructive

Publication date: 20-Aug-2004
Credit Analyst: Richard W Cortright, Jr. , New York (1) 212-438-7665; Anne Selting, San Francisco (1) 415-371-5009

EXHIBIT
RUCO-3
ADMITTED

NEW YORK (Standard & Poor's) Aug. 20, 2004--Standard & Poor's said today that the settlement agreement that Arizona Public Service Co. (APS; BBB/Negative/A-2) reached with 21 parties related to its electric rate case is constructive from a business risk perspective, but does little to strengthen the utility's financial profile.

The agreement limits the base rate increase to $75.5 million (including a five-year surcharge of about $7.9 million), or 4.21%, compared with the $175 million, or 9.8%, increase that the company had requested in its initial filing in June 2003. In February 2004, the staff of the Arizona Corporation Commission (ACC) recommended an 8% rate reduction. APS will not seek recovery of a $234 million write-off related to compliance with initial ACC restructuring rules.

The 10.25% return on equity incorporated in the settlement does compare favorably with returns authorized in other jurisdictions; however, the rate increase will not likely inject sufficient incremental revenue into the company to shore up a financial condition that is somewhat pressured at the current rating level. Approval by the ACC is expected by year end or early 2005.

From a business risk perspective, however, the settlement would resolve a significant degree of uncertainty that has hovered over APS and its parent Pinnacle West Capital Corp. (PWCC; BBB/Negative/A-2) since the state of Arizona began restructuring the electric industry in the late 1990s, reversing itself subsequently as a result of the Western power crisis. The agreement, most significantly, would allow the utility to rate-base 1,790 MW of merchant capacity at a value of $700 million, net of a $148 million disallowance, owned by unregulated affiliate Pinnacle West Energy Corp.

Pinnacle West Energy constructed the plants specifically to serve APS' load, but its merchant strategy has elevated the risk profile of the consolidated enterprise. The transfer would require the approval of the Federal Energy Regulatory Commission. Also, very significantly, the settlement calls for the establishment of a fuel adjustment mechanism, which would include a sharing mechanism with ratepayers and be reset annually to track future fuel and purchased power expenses for subsequent recovery.

The negative outlook reflects APS' pressured financial profile that the settlement agreement does not appear to address to any meaningful degree. However, the support that the settlement, if approved largely as proposed, lends to the risk profile of PWCC's overall operations may compensate for this weakness sufficiently for Standard & Poor's to consider less stringent financial ratios as appropriate benchmarks for the ratings.

EXHIBIT
RUCO-4
ADMITTED

APS

A subsidiary of Pinnacle West Capital Corporation

Jack Davis
President and Chief Executive Officer

Tel 602/250-3529
Fax 602/250-3002

Mail Station 9080
P.O. Box 53999
Phoenix, AZ 85072-3999

February 17, 2006

Commissioner Kristin K. Mayes
ARIZONA CORPORATION COMMISSION
1200 W. Washington
Phoenix, AZ 85007

RE: Response to letter dated February 1, 2006
Docket No. E-01345A-06-0009

Dear Commissioner Mayes:

The purpose of this letter is to provide additional information regarding APS' cost containment efforts in response to your February 1st letter.[1]

By way of introduction, I wish to again emphasize that APS' cost management practices have not caused APS' deteriorating financial position. In fact, since 1995, the Company's cost management efforts have led to a decline in our non-fuel unit costs of 12% (31% adjusted for inflation)[2].

The cause of the Company's precarious position is that APS' actual fuel and purchased power expenditures far exceed the amount of such costs it is currently recovering in rates from customers. The continuing imbalance between fuel costs and cost recovery has weakened the Company's key credit strength indicator (the ratio of Funds from Operations to Debt, known as FFO/Debt) to the point where APS has been downgraded by one major rating agency (S&P) to the lowest investment-grade rating and put on negative watch for a downgrade by the other two (Moody's and Fitch). Absent interim rate relief to address the growing undercollection of fuel costs, APS will likely suffer further downgrading by S&P and the other rating agencies to non-investment grade or "junk bond" status for the first time in its over 100-year history of service to the public in Arizona. As such, APS would rank among the least creditworthy, non-bankrupt utilities in the United States. Most significantly, a junk bond rating would impose an unnecessary additional $1 billion cost burden on our customers over the next 10 years.

The FFO/Debt ratio measures the sufficiency of APS' operating cash flow to service both debt service components: interest and principal repayment – **over time**. This ratio is

[1] The Company has also provided information on this subject in my letter to you, dated January 23, 2006, and in Steven Wheeler's letter to the Commissioners, dated January 31, 2006 [Docket No. E-01345A-05-0816].
[2] These results were detailed in the Company's January 31st letter to the Commissioners.

currently in the BB "junk" range. The FFO/Debt ratio is not a measure of a company's current liquidity (cash on hand to pay bills). And the credit rating agencies have not expressed concern over APS' current liquidity situation. As a matter of fact, APS currently has cash on hand of about $80 million. But again, current liquidity is not the issue at hand. The credit rating agencies are concerned that the imbalance between fuel costs and fuel cost recovery will continue to erode APS' future liquidity. And without interim rate relief to address the imbalance, the rating agencies are prepared to downgrade APS' credit rating.

You have implied that the reduction in certain expenses could offset some need for future rate increases. Therefore, I need to clarify that the Company has already excluded certain costs from its pending rate request, including (1) officer performance incentive pay;[3] (2) officer base salary increases in 2005; (3) more than six million dollars in APS advertising,[4] including its sports sponsorships; (4) charitable donations; (5) certain public affairs and community relations costs; and (6) certain economic development costs. These costs, which in total amount to over $21 million, were excluded because they either represent costs that the Company has never charged to customers, or were reductions specifically made in our pending filing to reduce the overall impact of the rate request on our customers. As a result, shareholders will bear these costs.[5] The Company's rate filing concentrates on the increasing fuel costs that are driving the Company's need for rate relief.

Finally, I want to again emphasize that the Company is and will continue to be committed to excellence in every facet of our operations, including operating performance, managing risk and costs, and providing reliable service to our customers at reasonable prices. Our cost management practices have not come at the expense of customer service and satisfaction. APS is among the highest ranked investor-owned electric utilities in the country (and number one in the West) in terms of customer satisfaction, as evidenced by a recent JD Power survey.

With the above introduction, the answers to your specific questions are presented below:

1. *Please provide a summary of the Company's advertising budget for 2005 and projected for 2006, itemized by purchase. For instance, if the Company advertised on television, please specify the media outlet and the amount spent, along with a brief*

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[3] In your letter you have commented that I made statements to the press that cutbacks such as the suspension of officer performance incentive pay were a means of providing additional cash flow to the Company. Let me be more specific. While I agreed that there is an operating cash flow issue and that we have suspended officers' performance incentive pay, neither that suspension nor the other items included in your letter alleviate the cash-flow issues that threaten the Company's credit ratings.

[4] The Company has not asked for more than $3 million in advertising costs in its rate filing, as you state in your letter. APS is seeking recovery of less than $700,000 for advertising.

[5] Another reason the Company has excluded the otherwise reasonable costs is to avoid the delay associated with litigation over these matters. However, this concession should not be viewed as an invitation to remove other legitimate costs of providing service.

description of what the advertisement was for. Please indicate whether the advertisement was believed to be related to company branding, or a conservation or safety message.

Please note that (1) in its rate application, the Company is requesting recovery of less than $700,000, which consists of advertising expenses of $400,000 related to customer communications, including customer safety and information on bill payment and rate options, and $200,000 related to energy efficiency programs; and (2) the projected advertising budget for 2006 has been reduced by more than $600,000. As shown on Schedule A, which is being provided to Commission Staff pursuant to a protective agreement dated January 19, 2006, in accordance with previously accepted practice, about half of the 2005 advertising costs and 2006 budget consist of contractual commitments that were made in prior years. Please see this schedule for the itemized purchases in 2005 and a summary of the 2006 budget.

2. *Please provide an itemization of the Company's travel budget, including all out-of-state travel by company employees for 2005 and 2006.*

Please see attached Schedule B for an itemization of our 2005 operating travel costs and 2006 budget. As described therein, the broad category of "travel" does not easily differentiate between out-of-state travel and in-state travel for such items as travel costs for crews working out of their home area, business trips between various Company locations around the state, and other activities not related to out-of-state travel. We estimate that out-of-state travel costs are approximately $2 million to $3 million, which is approximately 0.1% of the Company's total cost of service and are included in our rate filing. These out-of-state travel costs include representation before FERC, NRC, INPO and other critical government and industry agencies; participation in regional planning, research and operating organizations, such as EPRI and WECC; necessary travel to our Four Corners coal plant; and training and education in the many technical and operational matters in our industry, all of which are essential to the performance of our mission. I should also note that out-of-state travel requires the approval of the appropriate Company officer.

3. *Please itemize the Company's non-charitable contributions to all outside organizations in 2005 and 2006.*

APS did not make non-charitable contributions in 2005 and has not budgeted to do so in 2006.

However, to address your question more broadly, the Company does sponsor many organizations. We are committed to the communities we serve, because the health of the communities we serve and the health of the Company have always been intrinsically linked, and remain so. Therefore, the Company has sponsored

Chambers of Commerce, service and civic associations, and many other organizations including the Arizona-Mexico Commission, Arizona Community Foundation, Valley Forward, Make-A-Wish Foundation, Arizona Town Hall, the McDowell-Sonoran Land Trust, and the Central Arizona Land Trust. We are proud to support the various organizations that grow our service territory and make it a good place to work and live. The costs of these sponsorships are not included in our rate application.

4. *Please itemize the Company's sponsorships of sporting events, including but not limited to, sponsorships at stadiums or sporting venues, and Company-owned tickets or luxury boxes at local sporting venues in 2005 and 2006.*

Half of the 2005 advertising costs represent long term contracts with professional sport teams. The investments in professional sports were made a number of years ago and for a variety of business reasons including community support and to encourage downtown redevelopment. The Diamondback investment also encompassed a unique opportunity to partner on a downtown cooling project which has shown great potential to reduce peak electricity demand. The advertising and signage that came with these ventures was always a secondary element of the investment.

Schedule A includes an itemization of the various sport sponsorships and the tickets associated with those sponsorships, the costs of which are not part of our rate application. These sport sponsorships are also another means of community outreach for the Company. They include youth sports programs, building community baseball fields and basketball courts, and sponsoring the Arizona Interscholastic Association tournaments. They also include public service announcements and charitable programs, as well as encourage environmental and renewable program participation. Regarding the tickets associated with these sponsorships, in large measure, the Company donates these tickets to schools and community organizations.

In addition, APS has Company-owned season tickets for the Phoenix Suns and sporting events at Arizona State University, Northern Arizona University, the Fiesta Bowl, the FBR Open and the Insight Bowl. The costs of these Company-owned tickets are not part of our rate application.

APS does not own any suites except for NASCAR (which is described in Schedule A) and the Fiesta Bowl, the costs of which are not included in our rate filing. Pinnacle West Capital Corporation owns suites at Chase Field, US Airways Center and Arizona State University, of which approximately $200,000 in 2005 was charged to APS.

You have also asked whether the Company has considered cutting its dividend. The Company has rejected this idea as contrary to the best interests of our customers. The reasons are simple: a reduction in the APS dividend would not improve the Company's financial metrics that are of interest to the rating agencies, and such action would heighten the equity market's negative perception of APS and Pinnacle West. It should be remembered that ten months ago, $250 million of new equity was sold in the market and invested into APS. It is doubtful that Pinnacle West would have been able to raise the $250 million of new equity had it or APS been cutting dividends. Moreover, it is not likely that a prudent investor would invest in an electric utility company with significant and growing unrecovered costs, sub par returns and declining dividends. Most importantly, a reduction in the APS dividend would not resolve the operating cash flow deficiency caused by the failure to timely recover fuel costs, nor would it provide the financial community with any greater assurance as to the timely recovery of those fuel and purchased power costs. Because the calculation of the FFO/Debt ratio is not directly impacted by dividends that the Company pays, even if dividends were dramatically reduced, this Company ratio would not improve.

I understand that the Commission wants to examine options to alleviate the emergency situation that Company faces. The fact is that our emergency is caused by the inability to timely recover our fuel costs and the rating agencies comments which have caused the financial markets to believe that they are prepared to downgrade us to "junk" status. The only thing that will remedy this situation is the prompt recovery of fuel costs.

I hope this letter is responsive to your inquiries.

Very truly yours,

Jack Davis

Jack E. Davis
President & CEO
Arizona Public Service Company

cc. Chairman Jeff Hatch-Miller
Commissioner William A. Mundell
Commissioner Marc Spitzer
Commissioner Mike Gleason
Janet Wagner
Ernest Johnson
Heather Murphy
Docket Control

Schedule B

Operating Travel Costs, 2005 Actual Expenditures & 2006 Budget

Note:
The table below identifies by functional area the types of operating travel costs incurred and for which the Company is seeking recovery in its rate case. The table excludes approx. $300,000 of travel costs for public affairs, community relations, and economic development that are not a part of our current rate request.

Company accounting records do not distinguish between out-of-state travel costs and local travel costs such as per diem costs of lodging and meals for crews working away from their home area, trips between various Company locations, local business meals, mileage reimbursement, etc. The Company routinely incurs these kinds of local travel costs as part of serving a service territory of some 50,000 square miles.

2005 Actual Expenditures ($000)

	Airfare	Lodging	Auto Rentals	Meals - Travel, Business & Overtime	Per Diem	Training & Other	Total
Delivery	205	426	56	515	745	373	2,320
Nuclear Generation (APS' share)	114	131	32	66	-	45	388
Fossil Generation	120	162	58	225	11	177	753
Shared Services & Other	378	517	62	734	21	596	2,308
Total	**817**	**1,236**	**208**	**1,540**	**777**	**1,191**	**5,769**

2006 Travel Budget

The Company budget does not distinguish between these sub-categories. The 2006 annual operating travel budget is approximately $5.6Million, less than the actual 2005 costs of $5.8 Million.

Estimated Out-of-State Travel

APS estimates out-of-state travel costs as being most of the airfare and auto rentals, and a portion of the lodging and meal costs, totaling $2M to $3M in 2005.

EXHIBIT
RUCO-5
admitted

ARIZONA PUBLIC SERVICE COMPANY

DOCKET NO. E-01345A-06-0009

DIRECT TESTIMONY

OF

MARYLEE DIAZ CORTEZ, CPA

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

February 28, 2006

INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is Marylee Diaz Cortez. I am a Certified Public Accountant. I am the Chief of Accounting and Rates for the Residential Utility Consumer Office (RUCO) located at 1110 W. Washington, Suite 220, Phoenix, Arizona 85007.

Q. Please state your educational background and qualifications in the field of utility regulation.

A. Appendix I, which is attached to this testimony, describes my educational background and includes a list of the rate case and regulatory matters in which I have participated.

Q. Please state the purpose of your testimony.

A. The purpose of my testimony is to respond to Arizona Public Service Company's (APS or Company) request for an emergency interim rate increase and provide RUCO's recommendations.

APS' Emergency Interim Rate Request

Q. Why is APS requesting an emergency rate increase?

A. APS' fuel and purchased power costs have significantly increased such that APS wants to increase its base rates to include the current cost of these commodities. The Company estimates a $299 million increase is required to make it whole for its fuel and purchased power costs. According to the Company's application, this situation purportedly constitutes an operating cash flow emergency, and a downgrade from financial rating agencies is represented as imminent in the absence of emergency relief.

Q. To what does APS attribute its perceived state of emergency?

A. APS attributes the emergency to the Commission's failure to address its increased fuel costs, and the resultant threat of further financial downgrade to junk bond status by the Standard & Poor's (S&P) rating agency in December 2005.

Q. Didn't APS have a "growing fuel and purchased-power deferral" prior to Standard and Poor's December 2005 downgrade?

A. Yes. Pursuant to the Power Supply Adjustor (PSA) adopted in Decision No. 67744, APS had been deferring the difference between the cost of fuel and purchased power included in base rates and the cost APS was actually paying for these commodities. Thus, cost deferrals have been accruing since April 2005, when the rates set in Decision No. 67744 went into effect.

Q. If the lack of cash flow and the growing deferral are such a problem, as claimed by APS, why did the rating agency wait until December 2005 to downgrade APS?

A. S&P waited to act because the problem actually was not the lack of cash flow and the growing deferral, as represented by APS. If this had been a major concern, the rating agency would have downgraded APS back in August 2005 when, according to APS, the deferrals were already $100 million. What caused S&P's action in December 2005 was its *perception* that the ACC was not going to deal with the growing deferrals in a timely manner.

Q. How do you know that the rating agency's action in December 2005 was attributable to timing concerns?

A. S&P has stated as much in its rating reports. For example, it stated in its June 24, 2005 report that "APS' near-term challenges are largely related to regulatory lag." (see Exhibit 1) On October 4, 2005 S&P stated that "timely near-term cost collection will be the key driver of credit quality" and that "Standard & Poor's is becoming increasingly concerned with the utility's ability to achieve this." (see Exhibit 2) In the same report S&P noted that APS had filed an application for a PSA surcharge and stated that "Both the pace and the disposition of this proceeding will be critical to credit quality." (Id.) On December 21, 2005 S&P stated that it had lowered APS' credit ratings to BBB- and that "This action is based on increased regulatory and operating risk at APS. Specifically, Standard & Poor's is concerned that the Arizona Corporation Commission (ACC) is not expeditiously addressing APS' growing fuel and purchased-power cost deferrals". (see Exhibit 3)

Q. APS' testimony seems to attribute the rating agency's recent action not so much to the regulatory lag issue but to APS' Funds from Operations to Debt ratio (FFO/Debt). Please comment.

A. The FFO/Debt ratio measures the sufficiency of a company's cash flow to service its debt, and is one of three metrics used by S&P in its credit ratings. Further, metrics are not the only measures used by S&P in determining its credit ratings. S&P stated the following regarding its credit rating guidelines in its June 2, 2004 report: (see Exhibit 4)

> It is important to emphasize that these metrics are only guidelines associated with the expectations for various rating levels. Although credit ratio analysis is an important part of the ratings process, these three statistics are by no means the only critical financial measure that Standard & Poor's uses in its analytical process.

Q. What other indications do you have the FFO/Debt ratio is not the lynchpin criteria upon which the rating agency relies for its credit ratings?

A. S&P indicated in its December 21, 2005 report that APS' average FFO/Debt ratio was 14.8%. (see Exhibit 3) Under its own guidelines a BBB rating requires a ~~15%~~ 18% to ~~20%~~ 28% FFO/Debt ratio for an issuer with a Business Profile of 6 to maintain a BBB rating. (see Exhibit 4) Yet, S&P in December 2005 rated APS BBB-/Stable, clearly demonstrating that the FFO/Debt ratio was not the controlling factor behind its credit rating for APS.

Q. At the time APS filed its emergency rate request was there any merit to the Company's claim of an emergency?

A. Perhaps. At the time the Company filed its emergency application, Standard and Poor's had down-graded APS to a BBB- debt rating and announced its intention to downgrade APS to junk bond status if the Arizona Corporation Commission did not "expeditiously" address APS' growing fuel and purchased-power deferral. (see Exhibit 3) Such a downgrade to junk status would have long-term detrimental effects on the Company and its ability to serve its growing customer base. Downgrade to junk status would also have constrained APS' access to debt, which would have constrained APS' ability to finance the infrastructure needed to serve its growing customer base.

Q. What are the criteria used to determine if an emergency exists?

A. Under Attorney General Opinion 71-17, a utility must meet one of the three following criteria to merit emergency rate relief:

1) A company is insolvent;

2) A sudden change brings hardship to a company;

3) A company's condition is such that its ability to maintain service pending a formal rate determination is in serious doubt.

Q. As of today, does APS meet any of these three criteria?

A. No. While prior to the issuance of Decision No. 68437 (February 2, 2006) there might have been a case to debate whether APS met criteria #3, since the issuance of that Decision there are no grounds for a finding of an emergency.

Q. Please explain.

A. Decision No. 68437 accelerated the implementation of the PSA adjustor from April 1, 2006 to February 1, 2006. As a result, APS will recover approximately $112 million of the deferred costs over the next year.[1] The acceleration of the adjustor also had the effect of accelerating APS eligibility for a surcharge. APS has recently filed that surcharge request. Decision No. 68437 also gave permission for APS to continue to defer costs over the $776.2 cap imposed by Decision No. 67744. In Decision No. 68437 the Commission stated that it never was its intention that the cap create automatic disallowances of fuel and purchased power costs. Thus, there is no longer any basis for a *perception* by the rating agencies

[1] The recovery authorized by Decision No. 68437 actually exceeds that requested by APS, which was $80 million over 2 years.

that the ACC will not deal with the growing deferrals in a timely manner, and hence reduced threat of imminent downgrade to junk bond status.

Q. What assurance do you have that Decision No. 68437 obviates the threat of downgrade to junk bond status?

A. The assurance comes in Standard and Poor's own statement in December 2005 that its then-stable rating of BBB- for APS reflected Standard and Poor's expectation that the ACC would resolve at least a portion of APS' deferred costs in January 2006. (see Exhibit 3) If Standard and Poor's mere "expectation" that the ACC would grant some recovery of the deferral was sufficient to maintain a stable BBB- rating in December 2005, the ACC authorization of recovery of the deferrals in January 2006 certainly should be sufficient to maintain the status quo rating of BBB-. Further, since the Commission voted on what became Decision No. 68437[2], two of the rating agencies have indicated that their present investment grade ratings are stable. On January 26, S&P affirmed its current BBB-, even though two days earlier it had reported that it appeared unlikely that the Commission would grant the pending emergency application. (see Exhibits 5 & 6) In addition, while Fitch downgraded APS' rating for senior unsecured debt from BBB+ to BBB on January 30, 2006, it reported a stable ratings outlook. (see Exhibit 7) Thus, the rating agencies view the Commission's actions in Decision No.

[2] The Commission voted at its Open Meeting on January 25, 2006.

68437 as adequate to maintain APS' investment grade ratings for the time being.

Q. If there is no emergency, should interim rates be considered?

A. No. The criteria of Attorney General Opinion 71-17 must be met; otherwise, rates cannot be changed without a finding of fair value.

Q. Do you believe APS will be harmed by ACC denial of its emergency rate request?

A. No. With the threat of imminent junk bond status thwarted by: 1) the February 1, 2006 implementation of the PSA adjustor, 2) the recent APS application for a surcharge and 3) the pending rate case, there is no emergency. The appropriate action is to allow the PSA to operate as it was intended and to allow the pending rate case to look at APS' current cost of service on a comprehensive basis that considers all ratemaking elements. There is no need to implement interim rates when we have a PSA mechanism to make APS whole for any fuel and purchased power costs that exceed the Company's base cost, and a pending rate case that will allow a full vetting of the current cost of fuel and power, as well as all other elements of APS' cost of service.

Q. Did APS present any evidence that it will be unable to continue to provide electric service absent emergency interim rate relief?

A. No. In fact APS presented evidence to the contrary. On page 6 of APS' January 6, 2006 application for emergency rates the Company states:

> Indeed, some 20% of the Company's meager 2006 return on equity of 6.6% will be comprised of nothing other than the Commission's assurance that these IOUs will be honored through actual cash recovery in APS rates.

Thus, by APS' own admission the deferrals have only constrained 20% of its equity returns, which will not jeopardize the Company's ability to continue to provide service in the immediate future. The pending rate case can deal with these issues for the longer-term future.

Q. Are there any other reasons why APS should not and need not receive an emergency interim rate increase?

A. Yes. Granting an emergency interim rate increase at this juncture would substantively change the terms of the settlement agreement and Decision No. 67744.

Q. Please explain.

A. Decision No. 67744 required that any fuel and purchased power under- or over-recoveries were to be shared 90%/10% between stockholders and ratepayers. That Decision specifically stated that this sharing provision was designed to be an "incentive".[3] The emergency interim rate request, if authorized, would circumvent this sharing mechanism and result in 100% of the under-recovered fuel and purchased power costs being borne by ratepayers. Granting the emergency rates would, in essence, change the terms of the settlement agreement and Decision No. 67744, and harm ratepayers. Any revisiting of this sharing provision should take place in the pending full rate case, where it can be considered in the broader context of APS' overall rates.

Q. Does this conclude your direct testimony?

A. Yes.

[3] Decision No. 67744 at page 13, line 13

APPENDIX I

APPENDIX I

Qualifications of Marylee Diaz Cortez

EDUCATION: University of Michigan, Dearborn
B.S.A., Accounting 1989

CERTIFICATION: Certified Public Accountant - Michigan
Certified Public Accountant - Arizona

EXPERIENCE: Audit Manager
Residential Utility Consumer Office
Phoenix, Arizona 85007
July 1994 - Present

Responsibilities include the audit, review and analysis of public utility companies. Prepare written testimony, schedules, financial statements and spreadsheet models and analyses. Testify and stand cross-examination before Arizona Corporation Commission. Advise and work with outside consultants. Work with attorneys to achieve a coordination between technical issues and policy and legal concerns. Supervise, teach, provide guidance and review the work of subordinate accounting staff.

Senior Rate Analyst
Residential Utility Consumer Office
Phoenix, Arizona 85004
October 1992 - June 1994

Responsibilities included the audit, review and analysis of public utility companies. Prepare written testimony and exhibits. Testify and stand cross-examination before Arizona Corporation Commission. Extensive use of Lotus 123, spreadsheet modeling and financial statement analysis.

Auditor/Regulatory Analyst
Larkin & Associates - Certified Public Accountants
Livonia, Michigan
August 1989 - October 1992

Performed on-site audits and regulatory reviews of public utility companies including gas, electric, telephone, water and sewer throughout the continental United States. Prepared integrated proforma financial statements and rate models for some of the largest public utilities in the United States. Rate models consisted of anywhere from twenty to one hundred fully integrated schedules. Analyzed financial statements, accounting detail, and identified and developed rate case issues based on this analysis. Prepared written testimony, reports, and briefs. Worked closely with outside legal counsel to achieve coordination of technical accounting issues with policy, procedural and legal concerns. Provided technical assistance to legal counsel at hearings and depositions. Served in a teaching and supervisory capacity to junior members of the firm.

RESUME OF RATE CASE AND REGULATORY PARTICIPATION

Utility Company	Docket No.	Client
Potomac Electric Power Co.	Formal Case No. 889	Peoples Counsel of District of Columbia
Puget Sound Power & Light Co.	Cause No. U-89-2688-T	U.S. Department of Defense - Navy
Northwestern Bell-Minnesota	P-421/EI-89-860	Minnesota Department of Public Service
Florida Power & Light Co.	890319-EI	Florida Office of Public Counsel
Gulf Power Company	890324-EI	Florida Office of Public Counsel
Consumers Power Company	Case No. U-9372	Michigan Coalition Against Unfair Utility Practices
Equitable Gas Company	R-911966	Pennsylvania Public Utilities Commission
Gulf Power Company	891345-EI	Florida Office of Public Counsel

Jersey Central Power & Light	ER881109RJ	New Jersey Department of Public Advocate Division of Rate Counsel
Green Mountain Power Corp.	5428	Vermont Department of Public Service
Systems Energy Resources	ER89-678-000 & EL90-16-000	Mississippi Public Service Commission
El Paso Electric Company	9165	City of El Paso
Long Island Lighting Co.	90-E-1185	New York Consumer Protection Board
Pennsylvania Gas & Water Co.	R-911966	Pennsylvania Office of Consumer Advocate
Southern States Utilities	900329-WS	Florida Office of Public Counsel
Central Vermont Public Service Co.	5491	Vermont Department of Public Service
Detroit Edison Company	Case No. U-9499	City of Novi
Systems Energy Resources	FA-89-28-000	Mississippi Public Service Commission
Green Mountain Power Corp.	5532	Vermont Department of Public Service
United Cities Gas Company	176-717-U	Kansas Corporation Commission

General Development Utilities	911030-WS & 911067-WS	Florida Office of Public Counsel
Hawaiian Electric Company	6998	U.S. Department of Defense - Navy
Indiana Gas Company	Cause No. 39353	Indiana Office of Consumer Counselor
Pennsylvania American Water Co.	R-00922428	Pennsylvania Office of Consumer Advocate
Wheeling Power Co.	Case No. 90-243-E-42T	West Virginia Public Service Commission Consumer Advocate Division
Jersey Central Power & Light Co.	EM89110888	New Jersey Department of Public Advocate Division of Rate Counsel
Golden Shores Water Co.	U-1815-92-200	Residential Utility Consumer Office
Consolidated Water Utilities	E-1009-92-135	Residential Utility Consumer Office
Sulphur Springs Valley Electric Cooperative	U-1575-92-220	Residential Utility Consumer Office
North Mohave Valley Corporation	U-2259-92-318	Residential Utility Consumer Office
Graham County Electric Cooperative	U-1749-92-298	Residential Utility Consumer Office

Graham County Utilities	U-2527-92-303	Residential Utility Consumer Office
Consolidated Water Utilities	E-1009-93-110	Residential Utility Consumer Office
Litchfield Park Service Co.	U-1427-93-156 & U-1428-93-156	Residential Utility Consumer Office
Pima Utility Company	U-2199-93-221 & U-2199-93-222	Residential Utility Consumer Office
Arizona Public Service Co.	U-1345-94-306	Residential Utility Consumer Office
Paradise Valley Water	U-1303-94-182	Residential Utility Consumer Office
Paradise Valley Water	U-1303-94-310 & U-1303-94-401	Residential Utility Consumer Office
Pima Utility Company	U-2199-94-439	Residential Utility Consumer Office
SaddleBrooke Development Co.	U-2492-94-448	Residential Utility Consumer Office
Boulders Carefree Sewer Corp.	U-2361-95-007	Residential Utility Consumer Office
Rio Rico Utilities	U-2676-95-262	Residential Utility Consumer Office
Rancho Vistoso Water	U-2342-95-334	Residential Utility Consumer Office
Arizona Public Service Co.	U-1345-95-491	Residential Utility Consumer Office
Citizens Utilities Co.	E-1032-95-473	Residential Utility Consumer Office
Citizens Utilities Co.	E-1032-95-417 et al.	Residential Utility Consumer Office

Paradise Valley Water	U-1303-96-283 & U-1303-95-493	Residential Utility Consumer Office
Far West Water	U-2073-96-531	Residential Utility Consumer Office
Southwest Gas Corporation	U-1551-96-596	Residential Utility Consumer Office
Arizona Telephone Company	T-2063A-97-329	Residential Utility Consumer Office
Far West Water Rehearing	W-0273A-96-0531	Residential Utility Consumer Office
SaddleBrooke Utility Company	W-02849A-97-0383	Residential Utility Consumer Office
Vail Water Company	W-01651A-97-0539 & W-01651B-97-0676	Residential Utility Consumer Office
Black Mountain Gas Company Northern States Power Company	G-01970A-98-0017 G-03493A-98-0017	Residential Utility Consumer Office
Paradise Valley Water Company Mummy Mountain Water Company	W-01303A-98-0678 W-01342A-98-0678	Residential Utility Consumer Office
Bermuda Water Company	W-01812A-98-0390	Residential Utility Consumer Office
Bella Vista Water Company Nicksville Water Company	W-02465A-98-0458 W-01602A-98-0458	Residential Utility Consumer Office
Paradise Valley Water Company	W-01303A-98-0507	Residential Utility Consumer Office
Pima Utility Company	SW-02199A-98-0578	Residential Utility Consumer Office
Far West Water & Sewer Company	WS-03478A-99-0144 Interim Rates	Residential Utility Consumer Office

Vail Water Company	W-01651B-99-0355 Interim Rates	Residential Utility Consumer Office
Far West Water & Sewer Company	WS-03478A-99-0144	Residential Utility Consumer Office
Sun City Water and Sun City West	W-01656A-98-0577 & SW-02334A-98-0577	Residential Utility Consumer Office
Southwest Gas Corporation ONEOK, Inc.	G-01551A-99-0112 G-03713A-99-0112	Residential Utility Consumer Office
Table Top Telephone	T-02724A-99-0595	Residential Utility Consumer Office
U S West Communications Citizens Utilities Company	T-01051B-99-0737 T-01954B-99-0737	Residential Utility Consumer Office
Citizens Utilities Company	E-01032C-98-0474	Residential Utility Consumer Office
Southwest Gas Corporation	G-01551A-00-0309 & G-01551A-00-0127	Residential Utility Consumer Office
Southwestern Telephone Company	T-01072B-00-0379	Residential Utility Consumer Office
Arizona Water Company	W-01445A-00-0962	Residential Utility Consumer Office
Litchfield Park Service Company	W-01427A-01-0487 & SW-01428A-01-0487	Residential Utility Consumer Office
Bella Vista Water Co., Inc.	W-02465A-01-0776	Residential Utility Consumer Office
Generic Proceedings Concerning Electric Restructuring Issues	E-00000A-02-0051	Residential Utility Consumer Office
Arizona Public Service Company	E-01345A-02-0707	Residential Utility Consumer Office
Qwest Corporation	RT-00000F-02-0271	Residential Utility Consumer Office

Arizona Public Service Company	E-01345A-02-0403	Residential Utility Consumer Office
Citizens/UniSource	G-01032A-02-0598 E-01032C-00-0751 E-01933A-02-0914 E-01302C-02-0914 G-01302C-02-0914	Residential Utility Consumer Office
Arizona-American Water Company	WS-01303A-02-0867	Residential Utility Consumer Office
Arizona Public Service Company	E-01345A-03-0437	Residential Utility Consumer Office
UniSource	E-04230A-03-0933	Residential Utility Consumer Office
Arizona Public Service Company	E-01345A-04-0407	Residential Utility Consumer Office
Qwest Corporation	T-01051B-03-0454 & T-00000D-00-0672	Residential Utility Consumer Office
Tucson Electric Power Company	E-01933A-04-0408	Residential Utility Consumer Office
Arizona-American Water Company	W-1303A-05-0280	Residential Utility Consumer Office
Southwest Gas Corporation	G-01551A-04-0876	Residential Utility Consumer Office
Arizona-American Water Company	W-1303A-05-0405	Residential Utility Consumer Office
Arizona-American Water Company	W-1303A-05-0718	Residential Utility Consumer Office

EXHIBITS

1.	Standard & Poor's	June 24, 2005
2.	Standard & Poor's	October 4, 2005
3.	Standard & Poor's	December 21, 2005
4.	Standard & Poor's	June 2, 2004
5.	Standard & Poor's	January 26, 2006
6.	Standard & Poor's	January 24, 2006
7.	Fitch	January 30, 2006

EXHIBIT 1

Standard & Poor's
June 24, 2005

RESEARCH

Summary: Arizona Public Service Co.

Publication date: 24-Jun-2005
Primary Credit Analyst: Anne Selting, San Francisco (1) 415-371-5009; anne_selting@standardandpoors.com

Credit Rating: BBB/Stable/A-2

Rationale

Arizona Public Service Co. (APS) is a wholly owned subsidiary of Pinnacle West Capital Corp. (PWCC), and by far the most important company within the PWCC family. The ratings on APS and PWCC are based on the consolidated credit assessment method, resulting in the same corporate credit rating for the holding company and APS.

APS' business profile is satisfactory, a '5' on Standard & Poor's Ratings Services' 10-point scale (where '1' is excellent). Strengths specific to the utility include a Phoenix service territory that is the second-fastest growing region in the U.S. (behind Las Vegas), a diversified power supply portfolio, and the recent approval by the Arizona Corporation Commission (ACC) of a settlement in APS' rate case, which, through a 4.21% increase in retail rates and the addition of a fuel and purchased power costs adjuster, should modestly shore up a financial performance that has been weakening over the past several years.

APS' near-term challenges are largely related to regulatory lag. Timely recovery of costs incurred in the rate base will remain challenging for the utility, despite the recent completion of a major rate case. APS filed its recently completed rate case in June 2003, and the process that culminated in the settlement allowed a modest rate increase that took effect in April 2005, nearly two years later. Because these rates are based on a December 2002 test year, the utility will need to file a new rate case soon to reflect its significant capital expenditures and to keep current on its generation costs that are gradually becoming more concentrated in natural gas. While the fuel and purchased power adjuster is expected to provide some rate relief to the utility, the adjuster is capped at a level that will likely need to be revisited well before its expiration in five years. And, because load growth in APS' service territory is projected to grow about 4% per year over the next five years, APS will still need an additional 1,200 MW by the summer of 2007 to fill the gap between power supply and demand. APS recently issued a request for proposals to meet 1,000 MW of this demand.

PWCC's business profile of '5' reflects the most significant benefit of the APS settlement, which is the authorization that the utility received from the ACC to rate-base 1,790 MW of generation that is currently owned by Pinnacle West Energy Corp (PWEC), PWCC's non-regulated wholesale generation subsidiary. The transfer received Federal Energy Regulatory Commission (FERC) approval on June 15, 2005, and should be completed by August 2005. PWCC announced June 21, 2005, that it has reached an agreement to sell its 425 MW interest in Silverhawk to Nevada Power Co. (NPC; B+/Negative/NR) for $208 million. PWCC expects it will recognize an after-tax loss of about $55 million with the sale. The elimination of merchant operations from PWCC's consolidated operations, combined with the scaling back of activities of its three other unregulated subsidiaries--SunCor, El Dorado, and APS Energy Services--has improved consolidated business risks and should help to achieve improved financial metrics, which have been weakening since 2002 as a function of APS' need for rate adjustments and PWEC's merchant operations.

Consolidated financial metrics remained largely in line with the rating, but in part due to a change in how Standard & Poor's approaches operating leases (see Standard & Poor's article, "Corporate Ratings Criteria--Operating Lease Analytics," published June 9, 2005, on RatingsDirect, Standard & Poor's Web-based credit analysis system, at www.ratingsdirect.com), 2004 consolidated adjusted funds from operations to total debt (FFO/TD) was weak at 14.1%. Additionally, due to the fact that APS retail rates were not increased until April 1, first-quarter FFO/TD metrics remain below benchmarks. Also negatively impacting FFO is an anticipated tax assessment of approximately $100 million that is expected to be paid within the next year. The company's forecast expects 2005 metrics to stabilize, with expectations that FFO/TD will be approximately 17%. The cumulative impact of PWCC's $250 million in equity issued in May, the realization of higher utility revenues through the rate increase, and the receipt of proceeds from the sale of Silverhawk, if completed, should help to achieve this expectation. However, the need for continued timely processing of APS' rate applications and reasonable rate relief will be critical to producing consolidated long-term financial health.

Short-term credit factors

PWCC's short-term rating is 'A-2'. The rating is supported by the consolidated corporate credit rating, the fact that the preponderance of cash flows are produced by APS, a vertically integrated electric utility, and the expectations for diminished capital and liquidity requirements at PWEC. As of March 31, 2005, PWCC's liquidity was ample, with consolidated cash and cash equivalents at about $250 million. This very strong cash position is due largely to APS' issuance of $300 million in notes in June 2004 in order to pre-finance about $400 million in utility obligations due in January and August 2005.

Both PWCC and APS maintain CP programs. Neither program had any CP balances as of March 31, 2005. PWCC's program is for $250 million and is supported by a three-year, $300 million credit facility that PWCC put into place in October 2004. The revolver allows PWCC to use up to $100 million of the facility for letters of credit. The revolver has no material adverse change clauses pertaining to outstanding CP balances.

APS' short-term rating is also 'A-2'. The rating is supported by the stability of cash flows from regulated operations and good liquidity, although APS will need to continue to rely on borrowings to fund portions of its capital expenditure program, which is expected to be $770 million in 2005 (which includes $190 million for the purchase of the Sundance power plant), up significantly from $484 million in 2004. APS maintains a $250 million CP program. In May 2004, APS renegotiated its revolver and increased the size to $325 million. Also a three-year term, the facility supports the utility's CP program and provides an additional $75 million for other liquidity needs, including letters of credit. The supporting facility has no material adverse change clauses pertaining to outstanding CP balances.

Outlook

The stable outlook reflects Standard & Poor's expectation that PWCC will continue to focus on the regulated operations of APS, which is projected to contribute more than 85% of its funds from operations in 2005. The failure of PWCC or APS to meet expected financial results in 2005 and 2006, particularly in light of the weakening in consolidated and utility credit metrics in 2004, could lead to a downward revision of the outlook or a ratings change. Downward pressure on the ratings will occur if APS incurs significant power or fuel cost deferrals in excess of the fuel and purchased power adjuster's limitations. Any positive rating action is unlikely in the near term given the financial metrics and the longer-term risks that the limitations placed on APS' power supply adjuster present.

EXHIBIT 2

Standard & Poor's
October 4, 2005

RESEARCH

Summary: Arizona Public Service Co.

Publication date: 04-Oct-2005
Primary Credit Analyst: Anne Selting, San Francisco (1) 415-371-5009; anne_selting@standardandpoors.com

Credit Rating: BBB/Stable/A-2

Rationale

Arizona Public Service Co. (APS) is a wholly owned subsidiary of Pinnacle West Capital Corp. (PWCC), and the most significant company within the PWCC family. PWCC's satisfactory business profile (a '5' on a 10-point scale where '1' is excellent) reflects the vertically integrated utility operations of APS and the absence of significant non-regulated businesses within PWCC.

APS' credit strengths include a Phoenix service territory that is the second-fastest growing region in the U.S. (behind Las Vegas), a diversified power supply portfolio, and a 4.21% increase in retail rates that began on April 1, 2005 in conjunction with the settlement of the utility's general rate case in March 2005. This increase had been expected to modestly shore up a financial performance that has been weakening over the past several years.

However, challenges are increasing for the utility, and performance on a 12-month rolling basis ended June 30, 2005 indicates that the utility is pressured by the rising costs of purchased power and natural gas. The addition of a fuel and purchased power cost adjuster to retail rates has not assisted APS in timely receipt of cash because revisions occur only in the spring of each year, with the first opportunity arising in April 2006. The settlement provides for the use of a surcharge filing to provide the utility with an interim vehicle for recovering costs if they exceed $50 million. As anticipated, APS did accrue this level of deferrals over the summer. Through June 30, 2005, purchased power and fuel costs totaled $401 million, of which $34 million was deferred. At Aug. 31, 2005, the deferred balance had increased to $117 million. The company's estimates of total fuel and purchased power costs in 2005 are confidential, but as a basis of comparison, in 2004 the utility spent $763 million. In July 2005, APS filed an application with the Arizona Corporation Commission (ACC) requesting that it be allowed to recover $100 million through a two-year surcharge that would increase rates by about 2.2%.

Both the pace and disposition of this proceeding will be critical to credit quality. The ACC staff and at least one commissioner have questioned whether the utility should be allowed to collect $20 million of the $100 million requested, the former being the amount roughly associated with Palo Verde replacement power costs during four months from April through July 2005. (Since then, Units 1 and 2 suffered outages in late August.) In late September, the company announced that to expedite an ACC decision, it would reduce its request for surcharge recovery to $80 million and address the $20 million in deferred costs in a later proceeding. The ACC has established a schedule for the proceeding to address the $80 million, with hearings to begin Oct. 26, 2005.

For fiscal 2005, the company continues to expect it will achieve results in line with credit metrics needed to support the current rating. And in April 2006, the utility will be able to receive additional relief through the annual fuel and purchased power adjustment mechanism. But upward adjustments are limited to 4 mills/kWh over the life of the adjuster. Because existing retail rates are based on 2003 costs, reflecting gas prices of about $5.50/MMBtu, the company expects the entire 4 mill headroom will be utilized at the first reset. The utility is expected to file another rate case by the end of 2005, but its resolution could extend well into 2006. Thus, it is clear that timely near-term cost collection will be the key driver of credit quality. Standard & Poor's is becoming increasingly concerned with the utility's ability to achieve this. A relatively weak power supply adjustment mechanism, in combination with rapidly escalating and volatile gas prices, as well as the potential for a protracted surcharge proceeding, could cause deterioration in financial performance which, year to date, has been sub par for the rating.

Whether the company's consolidated targets will be met will largely be a function of APS' third-quarter results. For the 12 months ending June 30, 2005, consolidated adjusted funds from operations (FFO) to total debt was 12.7%, but this reflects a one-time deferred tax charge taken in December 2004 based on the expectation that APS may need to refund $130 million at the end of 2005. Excluding the deferral, adjusted FFO/total debt is closer to 15.5%. FFO to interest coverage was 3.0x for the 12 months ending June 30, or 3.5x when the deferred tax obligation is excluded. Adjusted debt to total capitalization was 55.7% and benefited from PWCC's April issuance of $250 million in equity.

APS' general rate case settlement allowed for the rate-basing of 1,790 MW of Arizona generation formerly owned by Pinnacle West Energy Corp (PWEC), PWCC's merchant generation subsidiary. In July 2005, PWEC transferred this generation capacity, through five plants, to APS. PWCC has also announced that it plans to sell its remaining 75% interest in Silverhawk, a 570 MW plant near Las Vegas, Nev., to Nevada Power (NPC; B+/Positive/NR) for $208 million. If Nevada regulators approve the sale, the transaction should be completed by the end of 2005 and mark the complete wind-down of PWEC operations. Consolidated credit benefited from the transfer by reducing merchant exposure in providing APS with needed supply to meet its growing loads.

Short-term credit factors

PWCC's short-term rating is 'A-2'. The rating is supported by the fact that the preponderance of cash flows is produced by APS, a vertically integrated electric utility. Near-term liquidity is adequate to support power purchase expenses that exceed rates. Because APS is heading into its shoulder season, when demand for electricity for space cooling drops significantly, the build-up of its power cost deferrals should slow. APS has hedged nearly all of its power and gas purchases through the remainder of 2005 and about 80% in 2006, thus its cost projections should be in line with realizations. Consolidated cash and investments stood at more than $900 million as of Sept. 31, 2005. However, $500 million was used on Oct. 3, 2005 to call the Pinnacle West Energy Company's floating-rate notes due April 2007. Also impacting the cash and invested position is the increased amount of collateral held under hedging contracts.

Both PWCC and APS maintain CP programs. Neither program had any CP balances as of June 30, 2005. PWCC's program is for $250 million and is supported by a three-year, $300 million credit facility that expires in October 2007. The revolver allows PWCC to use up to $100 million of the facility for letters of credit. The revolver has no material adverse change clauses pertaining to outstanding CP balances.

APS' short-term rating is also 'A-2'. The rating is supported by the stability of cash flows from regulated operations and good liquidity, although APS will need to continue to rely on borrowings to fund portions of its capital expenditure program, which is expected to be about $770 million in 2005 (and includes $190 million for the purchase of the Sundance power plant), up significantly from $484 million in 2004. APS maintains a $250 million CP program. In May 2004, APS renegotiated its revolver and increased the size to $325 million. This facility, also a three-year term, expires in May 2007, supports the utility's CP program, and provides an additional $75 million for other liquidity needs, including letters of credit. The supporting facility has no material adverse change clauses pertaining to outstanding CP balances.

Outlook

The stable outlook reflects Standard & Poor's expectation that the ACC will resolve APS' large deferred power costs through a surcharge ruling no later than year-end that supports timely recovery of the $80 million request. In addition, the outlook presumes that third-quarter consolidated financial results will reflect improvements that demonstrate modest advances in credit metrics. An adverse outcome in either of these areas will result in a negative outlook. No positive ratings changes are expected in short-term.

EXHIBIT 3

Standard & Poor's
December 21, 2005

RESEARCH

Research Update: Pinnacle West Capital's, Arizona Public Service's Ratings Lowered To 'BBB-'; Outlook Stable

Publication date: 21-Dec-2005
Primary Credit Analyst: Anne Selting, San Francisco (1) 415-371-5009; anne_selting@standardandpoors.com

Credit Rating: BBB-/Stable/A-3

Rationale

On Dec. 21, 2005, Standard & Poor's Ratings Services lowered its corporate credit ratings on Pinnacle West Capital Corp. (PWCC) and principal electric utility subsidiary Arizona Public Service Co. (APS) to 'BBB-' from 'BBB'. The outlook is stable.

This action is based on increased regulatory and operating risk at APS. Specifically, Standard & Poor's is concerned that the Arizona Corporation Commission (ACC) is not expeditiously addressing APS' growing fuel and purchased-power cost deferrals, which have grown much more rapidly than expected in 2005, particularly because of elevated gas prices and the utility's increased dependence on this fuel. In November 2005, APS filed for a nearly 20% increase in customer electric rates, but it appears unlikely that a resolution will be reached until 2007, and may be delayed to mid-2007. Combined with a year of weaker-than-expected performance at the historically reliable Palo Verde nuclear station, Standard & Poor's now views the business profile of PWCC and APS as a satisfactory '6' (on a 10-point scale where '1' is excellent) and no longer a '5'.

APS's fuel and purchased-power cost deferrals were nearly $150 million as of Sept. 30, 2005. Because the ACC has not acted on the utility's request to recover a portion of this amount in a surcharge, this entire balance, and any new additions through Dec. 31 will be carried into 2006. Standard & Poor's estimates that the utility may incur an additional $265 million in deferral balances by year-end 2006. Actual balances will be a function of how the ACC addresses existing amounts, as well as forward market prices and the company's hedged positions. To date, APS has hedged about 85% of its purchased power and natural gas fuel price risk for its retail load in 2006 and 65% in 2007.

A surcharge proceeding that would resolve $80 million of the utility's current deferrals has been before the commission for five months. The surcharge process was mandated by the ACC as part of the settlement of APS's 2003 rate case that it approved in March 2005. APS is required to notify the ACC when its fuel and purchased-power deferrals reach $50 million and to file a plan for recovery before deferrals exceed $100 million. In July 2005, the utility filed an application to recover about $100 million through a two-year surcharge, but reduced it to $80 million to exclude Palo Verde outage related costs, which will be addressed in a later proceeding. If approved, residential rates would increase about 1.6%.

Since the fall of 2005, Standard & Poor's has conditioned a stable outlook on the satisfactory resolution of this portion of deferrals before year-end. Yet, because of the sustained increase in deferrals, even if the surcharge is implemented, it will likely resolve only about one-half of the company's expected deferred balances at year-end 2005.

Beyond the surcharge, additional 2005 deferred balances can be addressed through an adjustment to the company's power supply adjuster (PSA). However, the PSA has several limitations. It allows APS to collect 90% of the difference between actual fuel, purchased power, and associated hedging costs and those reflected in retail rates. But as per the settlement, APS may not be granted an adjustment before April 2006. Until then the PSA is set at zero. This is problematic because retail rates reflect fuel and purchased-power costs based on 2003 costs when the price of natural gas averaged about $5.50 per million BTU. In addition to a certain wait of four months for PSA adjustments to be authorized, upward adjustments are capped at 4 mils per kilowatt-hours for the life of the mechanism. As a result, all or nearly all of the PSA capacity is likely to be absorbed in APS's first PSA filing, and the utility is expected to end the summer of 2006 needing another surcharge to address additional balances that will accumulate. Thus, any rate relief granted for remaining 2005 deferrals will not completely resolve the issue because the onset of the utility's summer cooling season in late April will contribute additional amounts to deferred balances.

APS's new general rate case request totals $409.1 million (19.9%) increase in annual revenues. About $247 million of the request is related to increased fuel and purchased-power costs. Recent public statements by the ACC suggest spring 2007 may be the earliest a decision could be expected. APS's last rate case took nearly 23 months to conclude, and there is therefore substantial uncertainty as to when the case will be completed.

An additional factor contributing to PWCC's weakened business profile is the performance of the Palo Verde nuclear units in 2005. The three-unit facility typically supplies 25% to 30% of the utility's energy requirements. In 2005, the combined capacity factor for the three units is expected to be about 78%, against the company's forecast of 86%. While some of the deterioration reflects the expected increase in Unit 1's refueling outage to 75 days from 33 days, enabling the replacement of the unit's steam turbine generators, the units have been beset by a series of operational problems, which include an overhang of issues first raised by the NRC in 2004. Specifically, in the summer of 2004, the company identified piping in a portion of the emergency cooling system that was dry, a situation that the NRC flagged as "yellow," the second-most serious of four categories of violations.

The yellow flag triggered onsite NRC inspections in the fall of 2005. On Oct. 11, 2005, Units 2 and 3 were taken off line after NRC officials posed questions as to how the emergency cooling systems might operate under a range of hypothetical scenarios. The plants were brought back into service 10 days later, after the company successfully demonstrated that the cooling systems would operate as designed. An NRC inspection report related to the cooling system issues is expected in December 2005. Other operational problems have also occurred. In the spring of 2005, problems with the pressurizer heating elements in Unit 3 resulted in the extension of a planned 10-day outage to 32 days. In September, APS announced that day-to-day management of Palo Verde has been reorganized.

PWCC's consolidated cash coverage metrics are expected to be largely in line with 2004 results, which were very weak due to APS's delayed rate relief. For the 12 months ending Sept. 30, adjusted funds from operations (FFO) to interest coverage was 3.3x, identical to coverage at the end of 2004. The 12-month adjusted FFO to total debt was 14.8%, and reflects about $80 million in cash flows from Suncor assets sales that will not be realized in 2006 at this level. Future cash flow metrics will depend significantly on the ACC's actions, but are generally not expected to display any significant improvement through 2006 due to a continued build up of deferrals. Performance in 2007 will be heavily predicated on how long it takes for the ACC to rule on the company's base rate increase. Due in large part to PWCC's April 2005 issuance of $250 million in common stock, adjusted debt to total capitalization remains solid at 53% . However, borrowing requirements could rise in 2006 to fund APS's additional power and fuel costs deferrals and to invest in capital expenditures.

Short-term credit factors

PWCC's short-term rating is 'A-3'. The rating is supported by the preponderance of cash flows being produced by APS, a vertically integrated electric utility. Because of APS's sizable commercial paper program, near-term liquidity should be adequate to support cash outlays for power and fuel not recoverable in rates. And, because APS is heading into its winter season, when demand for electricity for space cooling drops significantly, the build-up of its power cost deferrals should slow. APS has hedged most of its power and gas purchases remaining in 2005, 85% of 2006 requirements, and about 65% for 2007.

Consolidated cash and investments stood at more than $900 million as of Sept. 30, 2005. However, $500 million was used on Oct.

3, 2005 to call Pinnacle West Energy Corp.'s (PWEC) floating-rate notes that were due April 2007. Also affecting the cash and invested position is the increased amount of collateral held under bilateral contracts.

PWCC and APS maintain commercial paper programs. Neither program had any balances as of Dec. 20, 2005. PWCC's program is for $250 million and is supported by a five-year, $300 million credit facility that expires in December 2010. The revolver allows PWCC to use up to $100 million of the facility for letters of credit. The revolver has no material adverse change clauses.

APS's short-term rating is also 'A-3'. The rating is supported by the stability of cash flows from regulated operations and good liquidity, although APS will need to continue to rely on borrowings to fund portions of its capital expenditure program, which is expected to be about $800 million in 2005 (and includes $190 million for the purchase of the Sundance power plant), up significantly from $484 million in 2004. APS maintains a $250 million commercial paper program. APS has a five-year, $400 million revolver that expires in December 2010 that supports its commercial paper program, and also provides an additional $150 million for other liquidity needs, including $100 million for letters of credit. The supporting facility has no material adverse change clauses. Consolidated maturities are modest and consist of $384 million in 2006, of which $300 million is a note at the parent, which is due in April. Currently, there are virtually no obligations due in 2007, as PWEC called at par in early October some $500 million in notes that it issued in April 2005 to retire an intercompany loan between PWEC and APS that was associated with the PWEC assets now owned by APS.

Outlook

The stable outlook reflects Standard & Poor's expectation that the ACC will resolve at least a portion of APS's increasing deferred power costs in January 2006. In addition, the outlook presumes that progress will be made in addressing APS' general rate case and that any outcome will support the return of consolidated financial metrics to what until 2004 was a reasonable performance. The stable outlook is also dependent on improved 2006 performance at Palo Verde. Any adverse regulatory development or continued delays in resolving the pending surcharge request could result in a downward revision of the outlook or an adverse rating action. Because no meaningful improvement in the consolidated financial profile is expected in the near term, the potential for positive rating changes does not currently exist.

Ratings List

Ratings Lowered

	To	From
Pinnacle West Capital Corp.		
Corp credit rating	BBB-/Stable/A-3	BBB/Stable/A-2
Senior unsecured debt	BB+	BBB-
Commercial paper	A-3	A-2
Arizona Public Service Co.		
Corp credit rating	BBB-/Stable/A-3	BBB/Stable/A-2
Senior unsecured debt	BBB-	BBB
Commercial paper	A-3	A-2

Complete ratings information is available to subscribers of RatingsDirect, Standard & Poor's Web-based credit analysis system, at www.ratingsdirect.com. All ratings affected by this rating action can be found on Standard & Poor's public Web site at www.standardandpoors.com; under Credit Ratings in the left navigation bar, select Find a Rating, then Credit Ratings Search.

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The McGraw-Hill Companies

EXHIBIT 4

Standard & Poor's
June 2, 2004

RESEARCH

New Business Profile Scores Assigned for U.S. Utility and Power Companies; Financial Guidelines Revised

Publication date: 02-Jun-2004
Credit Analyst: Ronald M Barone, New York (1) 212-438-7662; Richard W Cortright, Jr. , New York (1) 212-438-7665; Suzanne G Smith, New York (1) 212-438-2106; John W Whitlock, New York (1) 212-438-7678; Andrew Watt, New York (1) 212-438-7868; Arthur F Simonson, New York (1) 212-438-2094

Standard & Poor's Ratings Services has assigned new business profile scores to U.S. utility and power companies to better reflect the relative business risk among companies in the sector. Standard & Poor's also has revised its published risk-adjusted financial guidelines. The new business scores and financial guidelines do not represent a change to Standard & Poor's ratings criteria or methodology, and no ratings changes are anticipated from the new business profile scores or revised financial guidelines.

New Business Profile Scores and Revised Financial Guidelines

Standard & Poor's has always monitored changes in the industry and altered its business risk assessments accordingly. This is the first time since the 10-point business profile scale for U.S. investor-owned utilities was implemented that a comprehensive assessment of the benefits and the application of the methodology has been made. The principal purpose was to determine if the methodology continues to provide meaningful differentiation of business risk. The review indicated that while business profile scoring continues to provide analytical benefits, the complete range of the 10-point scale was not being utilized to the fullest extent.

Standard & Poor's has also revised the key financial guidelines that it uses as an integral part of evaluating the credit quality of U.S. utility and power companies. These guidelines were last updated in June 1999. The financial guidelines for three principal ratios (funds from operations (FFO) interest coverage, FFO to total debt, and total debt to total capital) have been broadened so as to be more flexible. Pretax interest coverage as a key credit ratio was eliminated.

Finally, Standard & Poor's has segmented the utility and power industry into sub-sectors based on the dominant corporate strategy that a company is pursuing. Standard & Poor's has published a new U.S. utility and power company ranking list that reflects these sub-sectors.

There are numerous benefits to the reassessment. Fuller utilization of the entire 10-point scale provides a superior relative ranking of qualitative business risk. A simultaneous revision of the financial guidelines supports the goal of not causing rating changes from the recalibration of the business profiles. Classification of companies by sub-sectors will ensure greater comparability and consistency in ratings. The use of industry segmentation will also allow more in-depth statistical analysis of ratings distributions and rating changes.

The reassessment does not represent a change to Standard & Poor's criteria or methodology for determining ratings for utility and power companies. Each business profile score should be considered as the assignment of a new score; these scores do not represent improvement or deterioration in our assessment of an individual company's business risk relative to the previously assigned score. The financial guidelines continue to be risk-adjusted based on historical utility and industrial medians. Segmentation into industry sub-sectors does not imply that specific company characteristics will not weigh heavily into the assignment of a company's business profile score.

Results

Previously, 83% of U.S. utility and power business profile scores fell between '3' and '6', which clearly does not reflect the risk differentiation that exists in the utility and power industry today. Since the 10-point scale was introduced, the industry has transformed into a much less homogenous industry, where the divergence of business risk--particularly regarding management, strategy, and degree of competitive market exposure--has created a much wider spectrum of risk profiles. Yet over the same period, business profile scores actually converged more tightly around a median score of '4'. The new business profile scores, as of the date of this publication, are shown in Chart 1. The overall median business profile score is now '5'.

Chart 1

Distribution of Business Profile Scores

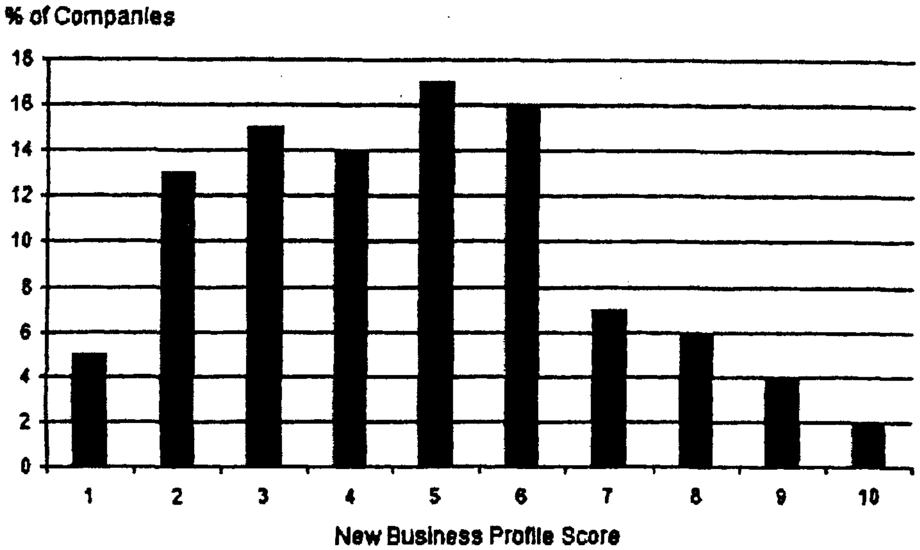


Table 1 contains the revised financial guidelines. It is important to emphasize that these metrics are only guidelines associated with expectations for various rating levels. Although credit ratio analysis is an important part of the ratings process, these three statistics are by no means the only critical financial measures that Standard & Poor's uses in its analytical process. We also analyze a wide array of financial ratios that do not have published guidelines for each rating category.

Table 1 Revised Financial Guidelines

Funds from operations/interest coverage (x)

Business Profile	AA		A		BBB		BB	
1	3	2.5	2.5	1.5	1.5	1		
2	4	3	3	2	2	1		
3	4.5	3.5	3.5	2.5	2.5	1.5	1.5	1
4	5	4.2	4.2	3.5	3.5	2.5	2.5	1.5
5	5.5	4.5	4.5	3.8	3.8	2.8	2.8	1.8
6	6	5.2	5.2	4.2	4.2	3	3	2
7	8	6.5	6.5	4.5	4.5	3.2	3.2	2.2
8	10	7.5	7.5	5.5	5.5	3.5	3.5	2.5
9			10	7	7	4	4	2.8
10			11	8	8	5	5	3

Funds from operation/total debt (%)

Business Profile	AA		A		BBB		BB	
1	20	15	15	10	10	5		
2	25	20	20	12	12	8		
3	30	25	25	15	15	10	10	5
4	35	28	28	20	20	12	12	8
5	40	30	30	22	22	15	15	10
6	45	35	35	28	28	18	18	12
7	55	45	45	30	30	20	20	15

8	70	55	55	40	40	25	25	15
9			65	45	45	30	30	20
10			70	55	55	40	40	25
Total debt/total capital (%)								
Business Profile	**AA**		**A**		**BBB**		**BB**	
1	48	55	55	60	60	70		
2	45	52	52	58	58	68		
3	42	50	50	55	55	65	65	70
4	38	45	45	52	52	62	62	68
5	35	42	42	50	50	60	60	65
6	32	40	40	48	48	58	58	62
7	30	38	38	45	45	55	55	60
8	25	35	35	42	42	52	52	58
9			32	40	40	50	50	55
10			25	35	35	48	48	52

Again, ratings analysis is not driven solely by these financial ratios, nor has it ever been. In fact, the new financial guidelines that Standard & Poor's is incorporating for the specified rating categories reinforce the analytical framework whereby other factors can outweigh the achievement of otherwise acceptable financial ratios. These factors include:

- Effectiveness of liability and liquidity management;
- Analysis of internal funding sources;
- Return on invested capital;
- The record of execution of stated business strategies;
- Accuracy of projected performance versus actual results, as well as the trend;
- Assessment of management's financial policies and attitude toward credit; and
- Corporate governance practices.

Charts 2 *through 6 show business profile* scores broken out by industry sub-sector. The five industry sub-sectors are:

- Transmission and distribution--Water, gas, and electric;
- Transmission only--Electric, gas, and other;
- Integrated electric, gas, and combination utilities;
- Diversified energy and diversified nonenergy; and
- Energy merchant/power developer/trading and marketing companies.

Chart 2

Transmission and Distribution--Water, Gas, and Electric

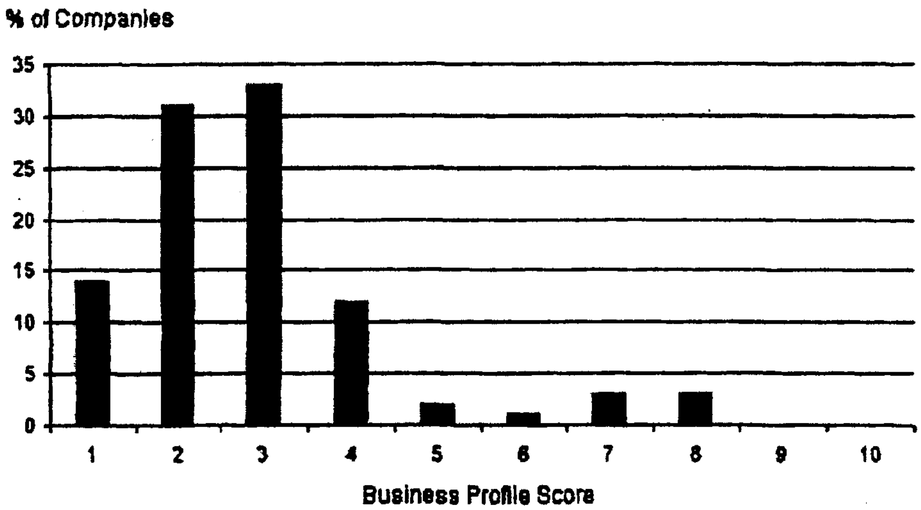


Chart 3

Transmission Only--Electric, Gas, and Other

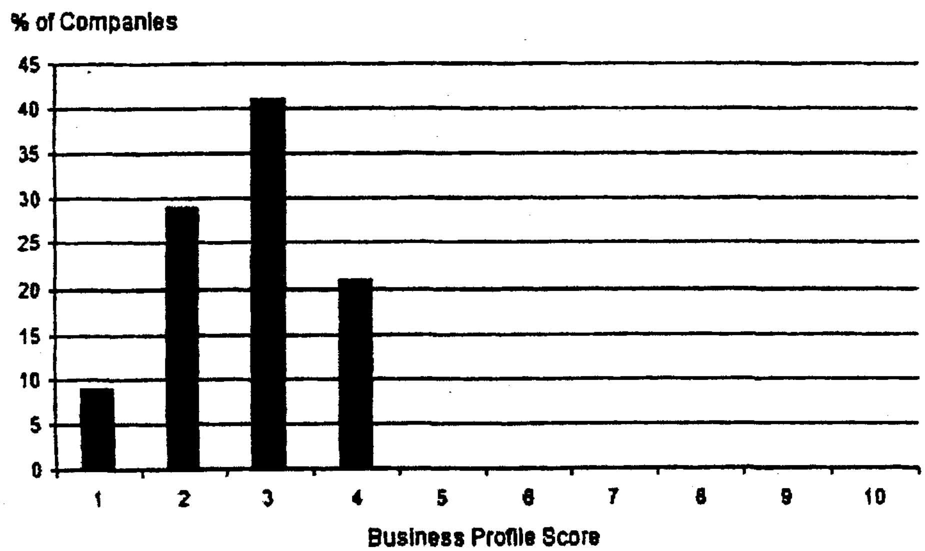


Chart 4

Integrated Electric, Gas, and Combination Utilities

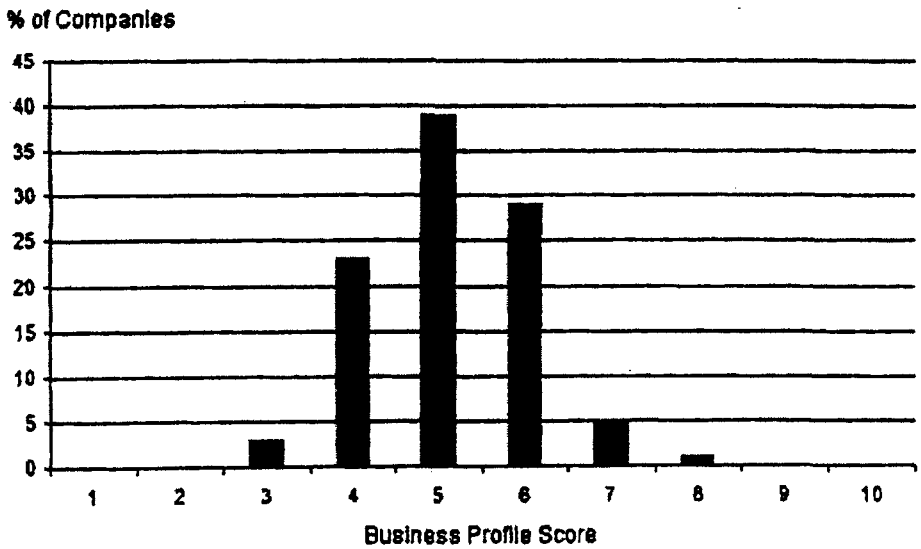


Chart 5

Diversified Energy and Diversified Non-Energy

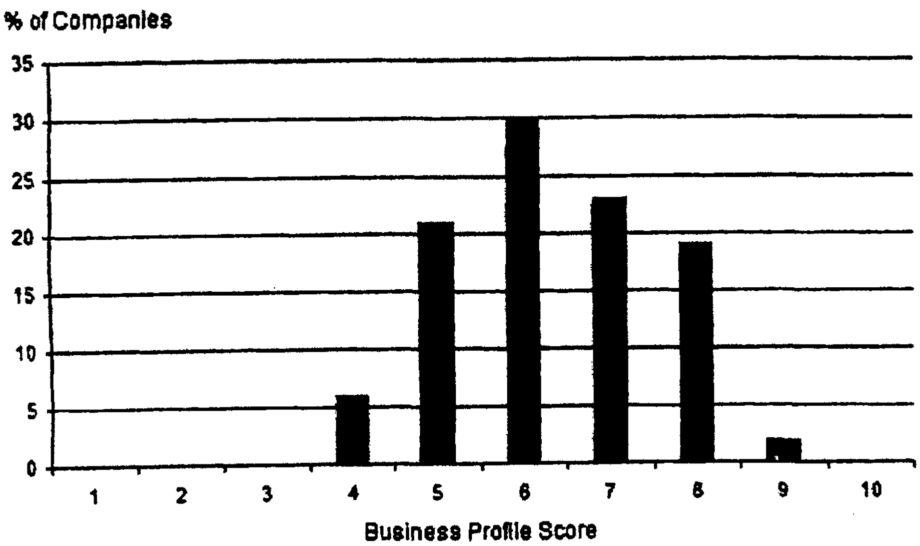
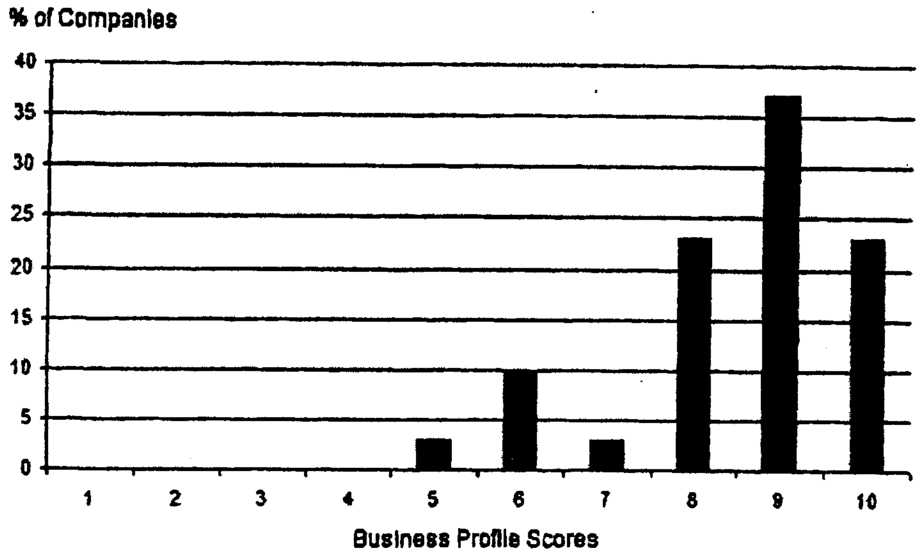


Chart 6

Energy Merchant/Developers/Trading and Marketing



The average business profile scores for transmission and distribution companies and transmission-only companies are lower on the scale than the previous averages, while the average business profile scores for integrated utilities, diversified energy, and energy merchants and developers are higher.

The Appendix provides the company list of business profile scores segmented by industry sub-sector and ranked in order of credit rating, outlook, business profile score, and relative strength.

Business Profile Score Methodology

Standard & Poor's methodology of determining corporate utility business risk is anchored in the assessment of certain specific characteristics that define the sector. We assign business profile scores to each of the rated companies in the utility and power sector on a 10-point scale, where '1' represents the lowest risk and '10' the highest risk. Business profile scores are assigned to all rated utility and power companies, whether they are holding companies, subsidiaries or stand-alone corporations. For operating subsidiaries and stand-alone companies, the score is a bottom-up assessment. Scores for families of companies are a composite of the operating subsidiaries' scores. The actual credit rating of a company is analyzed, in part, by comparing the business profile score with the risk-adjusted financial guidelines.

For most companies, business profile scores are assessed using five categories; specifically, regulation, markets, operations, competitiveness, and management. The emphasis placed on each category may be influenced by the dominant strategy of the company or other factors. For example, for a regulated transmission and distribution company, regulation may account for 30% to 40% of the business profile score because regulation can be the single-most important credit driver for this type of company. Conversely, competition, which may not exist for a transmission and distribution company, would provide a much lower proportion (e.g., 5% to 15%) of the business profile score.

For certain types of companies, such as power generators, power developers, oil and gas exploration and production companies, or nonenergy-related holdings, where these five components may not be appropriate, Standard & Poor's will use other, more appropriate methodologies. Some of these companies are assigned business profile scores that are useful only for relative ranking purposes.

As noted above, the business profile score for a parent or holding company is a composite of the business profile scores of its individual subsidiary companies. Again, Standard & Poor's does not apply rigid guidelines for determining the proportion or weighting that each subsidiary represents in the overall business profile score. Instead, it is determined based on a number of factors. Standard & Poor's will analyze each subsidiary's contribution to FFO, forecast capital expenditures, liquidity requirements, and other parameters, including the extent to which one subsidiary has higher growth. The weighting is determined case-by-case.

Appendix: U.S. Utility and Power Company Ranking List

U.S. Utility and Power Company Ranking List		
Company	**Corporate Credit Rating**	**Business Profile**
1. Regulated Transmission and Distribution - Electric, Gas, and Water		
Baton Rouge Water Works Co. (The)	AA/Stable/--	1
Nicor Gas Co.	AA/Stable/A-1+	2
Nicor Inc.	AA/Stable/A-1+	3
Washington Gas Light Co.	AA-/Stable/A-1+	2
WGL Holdings Inc.	AA-/Stable/A-1+	3
New Jersey Natural Gas Co.	A+/Stable/A-1	1
Aqua Pennsylvania	A+/Stable/--	2
KeySpan Energy Delivery Long Island	A+/Negative/--	1
KeySpan Energy Delivery New York	A+/Negative/--	1
Elizabethtown Water Co.	A+/Negative/--	2
California Water Service Co.	A+/Negative/--	3
Questar Gas Co.	A+/Negative/--	3
Southern California Gas Co.	A/Stable/A-1	1
Boston Edison Co.	A/Stable/A-1	1
Commonwealth Electric Co.	A/Stable/--	1
Cambridge Electric Light Co.	A/Stable/--	1
NSTAR	A/Stable/A-1	1
Massachusetts Electric Co.	A/Stable/A-1	1
Narragansett Electric Co.	A/Stable/A-1	1
Northwest Natural Gas Co.	A/Stable/A-1	1
Connecticut Water Service Inc.	A/Stable/ --	2
Connecticut Water Co. (The)	A/Stable/ --	2
Aquarion Co.	A/Stable/--	2
Aquarion Water Co. of Connecticut	A/Stable/--	2
NSTAR Gas Co.	A/Stable/--	2
Piedmont Natural Gas Co. Inc.	A/Stable/A-1	2
National Grid USA	A/Stable/A-1	2
Consolidated Edison Co. of New York Inc.	A/Stable/A-1	2
Orange and Rockland Utilities Inc.	A/Stable/A-1	2
Rockland Electric Co.	A/Stable/--	2
Consolidated Edison Inc.	A/Stable/A-1	2
Laclede Gas Co.	A/Stable/A-1	3
Laclede Group Inc.	A/Stable/--	3
Atlantic City Sewerage Co.	A/Stable/--	3
Niagara Mohawk Power Corp.	A/Stable/--	3
Central Hudson Gas & Electric Co.	A/Stable/--	3
American Water Capital Corp.	A/Negative/	2
Boston Gas Co.	A/Negative/--	2
Colonial Gas Co.	A/Negative/--	2
Middlesex Water Co.	A/Negative/--	3
York Water Co. (The)	A-/Stable/--	2
Alabama Gas Corp.	A-/Stable/--	2
Atlanta Gas Light Co.	A-/Stable/--	2
Public Service Co. of North Carolina Inc.	A-/Stable/A-2	2
Wisconsin Gas Co.	A-/Stable/A-2	2
North Shore Gas Co.	A-/Stable/A-2	2

Peoples Gas Light & Coke Co.	A-/Stable/A-2	2
ONEOK Inc.	A-/Stable/A-2	6
Indiana Gas Co. Inc.	A-/Negative/--	1
Southern California Water Co.	A-/Negative/--	3
American States Water Co.	A-/Negative/--	3
United Water New Jersey	A-/Negative/--	4
United Waterworks	A-/Negative/--	4
PPL Electric Utilities Corp.	A-/Negative/--	4
Commonwealth Edison Co.	A-/Negative/A-2	4
PECO Energy Co.	A-/Negative/A-2	4
Central Illinois Public Service Co.	A-/CW-Neg/--	3
Western Massachusetts Electric Co.	BBB+/Stable/--	1
Cascade Natural Gas Corp.	BBB+/Stable/--	2
South Jersey Gas Co.	BBB+/Stable/--	2
Baltimore Gas & Electric Co.	BBB+/Stable/A-2	3
Connecticut Natural Gas Corp.	BBB+/Negative/--	3
Southern Connecticut Gas Co.	BBB+/Negative/--	3
Central Maine Power Co.	BBB+/Negative/--	3
Atlantic City Electric Co.	BBB+/Negative/A-2	3
Potomac Electric Power Co.	BBB+/Negative/A-2	3
Delmarva Power & Light Co.	BBB+/Negative/A-2	3
Yankee Gas Services Co.	BBB+/Negative/--	3
Connecticut Light & Power Co.	BBB+/Negative/--	3
UGI Utilities Inc.	BBB+/Negative/--	4
Bay State Gas Co.	BBB/Stable/--	2
AEP Texas Central Co.	BBB/Stable/--	2
AEP Texas North Co.	BBB/Stable/--	2
Southwest Gas Corp.	BBB-/Stable/--	3
Columbus Southern Power Co.	BBB/Stable/--	3
Ohio Power Co.	BBB/Stable/--	3
Public Service Electric & Gas Co.	BBB/Stable/A-2	3
Oncor Electric Delivery Co.	BBB/Negative/--	2
Southern Union Co.	BBB/Negative/--	3
Centerpoint Energy Houston Electric LLC	BBB/Negative/--	3
CenterPoint Energy Resources Corp.	BBB/Negative/--	3
Duquesne Light Co.	BBB/Negative/	4
Duquesne Light Holdings Inc.	BBB/Negative/ --	5
TXU Gas Co.	BBB/CW-Dev/--	3
Jersey Central Power & Light Co.	BBB-/Stable/--	4
Metropolitan Edison Co.	BBB-/Stable/--	4
Pennsylvania Electric Co.	BBB-/Stable/--	4
Texas-New Mexico Power Co.	BB+/Stable/--	4
AmeriGas Partners L.P.	BB+/Stable/--	7
NUI Utilities Inc.	BB/CW-Dev/--	4
Suburban Propane Partners L.P.	BB-/Stable/--	8
Star Gas Partners L.P.	BB-/Stable/--	8
SEMCO Energy Inc.	BB-/Negative/--	5
Ferrellgas Partners L.P.	BB-/Negative/--	8
Potomac Edison Co.	B/Stable/--	3
West Penn Power Co.	B/Stable/--	3
Illinova Corp.	B/Negative/--	7
NorthWestern Corp.	D/NM/--	7

2. *Transmission Only - Electric, Gas, and Other*		
Questar Pipeline Co.	A+/Negative/--	3
Mid-West Independent Transmission System Operator Inc.	A/Stable/--	1
American Transmission Co.	A/Stable/A-1	1
New England Power Co.	A/Stable/A-1	1
Colonial Pipeline Co.	A/Stable/A-1	3
Dixie Pipeline Co.	--/--/A-1	3
Plantation Pipeline Co.	--/--/A-1	3
Explorer Pipeline Co.	A/Stable/A-1	4
Northern Natural Gas Co.	A-/Positive/--	2
Buckeye Partners L.P.	A-/Stable/--	4
Kern River Gas Transmission Co.	A-/Negative/--	3
Northern Border Pipeline Co.	A-/CW-Neg/--	2
Texas Gas Transmission LLC	BBB+/Stable/--	3
Iroquois Gas Transmission System L.P.	BBB+/Stable/--	3
Florida Gas Transmission Co.	BBB/Stable/--	2
International Transmission Co.	BBB/Stable	2
ITC Holding Corp.	BBB/Stable	2
Texas Eastern Transmission L.P.	BBB/Stable/--	3
PanEnergy Corp.	BBB/Stable/--	3
TE Products Pipeline Co. L.P.	BBB/Stable/--	4
TEPPCO Partners L.P.	BBB/Stable/--	4
Panhandle Eastern Pipeline LLC	BBB/Negative/--	3
Noark Pipeline Finance LLC	BBB/Negative/--	4
Southern Star Central Gas Pipeline Inc.	BB/Stable/--	3
Transwestern Pipeline Co.	BB/CW-Dev/--	4
Transcontinental Gas Pipe Line Corp.	B+/Negative/--	2
Northwest Pipeline Corp.	B+/Negative/--	2
Colorado Interstate Gas Co.	B-/Negative/--	2
Southern Natural Gas Co.	B-/Negative/--	2
ANR Pipeline Co.	B-/Negative/--	3
Tennessee Gas Pipeline Co.	B-/Negative/--	3
El Paso Tennessee Pipeline Co.	B-/Negative/--	3
El Paso Natural Gas Co.	B-/Negative/--	4
Gas Transmission-Northwest Corp.	CC/CW-Pos/--	2
3. *Integrated Electric, Gas, and Combination Utilities*		
Wisconsin Public Service Corp.	AA-/Stable/A-1+	4
Madison Gas & Electric Co.	AA/Negative/A-1+	4
Southern Co.	A/Stable/A-1	4
Georgia Power Co.	A/Stable/A-1	4
Alabama Power Co.	A/Stable/A-1	4
Mississippi Power Co.	A/Stable/A-1	4
Gulf Power Co.	A/Stable/--	4
Savannah Electric & Power Co.	A/Stable/--	4
San Diego Gas & Electric Co.	A/Stable/A-1	5
MidAmerican Energy Co.	A/Stable/A-1	5
Questar Corp.	--/--/A-1	6
Equitable Resources Inc.	A/Stable/A-1	6
Florida Power & Light Co.	A/Negative/A-1	4
South Carolina Electric & Gas Co.	A-/Stable/A-2	4
SCANA Corp.	A-/Stable/--	4

Wisconsin Electric Power Co.	A-/Stable/A-2	4
AGL Resources Inc.	A-/Stable/A-2	4
Virginia Electric & Power Co. (Dominion Virginia)	A-/Stable/A-2	5
Idaho Power Co.	A-/Stable/A-2	5
IDACORP Inc.	A-/Stable/A-2	5
Energen Corp.	A-/Stable/--	6
Vectren Utility Holdings Inc.	A-/Negative/A-2	3
Wisconsin Power & Light Co.	A-/Negative/A-2	4
Atmos Energy Corp.	A-/Negative/A-2	4
Southern Indiana Gas & Electric Co.	A-/Negative/--	5
Montana-Dakota Utilities Co.	A-/Negative/--	5
PacifiCorp	A-/Negative/A-2	5
Northern Border Partners L.P.	A-/CW-Neg/--	4
Central Illinois Light Co.	A-/CW-Neg/--	5
CILCORP	A-/CW-Neg/--	5
Union Electric Co.	A-/CW-Neg/A-2	5
Ameren Corp.	A-/CW-Neg/A-2	5
Cincinnati Gas & Electric Co.	BBB+/Stable/A2-	4
Oklahoma Gas & Electric Co.	BBB+/Stable/A-2	4
Northern States Power Wisconsin	BBB+/Stable /A-2	5
Kentucky Utilities Co.	BBB+/Stable/A-2	5
Louisville Gas & Electric Co.	BBB+/Stable/A-2	5
Allete Inc.	BBB+/Stable/A-2	5
Wisconsin Energy Corp.	BBB+/Stable/A-2	5
PSI Energy Inc.	BBB+/Stable/A-2	5
Union Light Heat & Power Co.	BBB+/Stable/--	5
Hawaiian Electric Co. Inc.	BBB+/Stable/A-2	6
Enogex Inc.	BBB+/Stable/--	6
National Fuel Gas Co.	BBB+/Stable/A-2	7
Energy East Corp.	BBB+/Negative/--A2	3
RGS Energy Group Inc.	BBB+/Negative/--	4
Rochester Gas & Electric Corp.	BBB+/Negative/--	4
Michigan Consolidated Gas Co.	BBB+/Negative/A-2	4
Interstate Power & Light Co.	BBB+/Negative/A-2	5
Public Service Co. of New Hampshire	BBB+/Negative/--	5
Kaneb Pipe Line Operating Partnership L.P.	BBB+/Negative/--	5
Consolidated Natural Gas Co.	BBB+/Negative/A-2	6
Detroit Edison Co.	BBB+/Negative/A-2	6
Questar Market Resources Inc.	BBB+/Negative/--	8
Portland General Electric Co.	BBB+/CW-Neg./A-2	5
Columbia Energy Group	BBB/Stable/--	3
NiSource Inc.	BBB/Stable/--	4
Xcel Energy Inc.	BBB/Stable/A-2	5
Public Service Co. of Colorado	BBB/Stable /A-2	5
Northern States Power Co.	BBB/Stable /A-2	5
Southwestern Public Service Co.	BBB/Stable /A-2	5
Appalachian Power Co.	BBB/Stable/--	5
Kentucky Power Co.	BBB/Stable/--	5
Public Service Co. of Oklahoma	BBB/Stable/--	5
Southwestern Electric Power Co.	BBB/Stable/--	5
Northern Indiana Public Service Co.	BBB/Stable/--	5
Entergy Arkansas Inc.	BBB/Stable/--	5

Entergy Louisiana Inc.	BBB/Stable/--	5
Progress Energy Florida	BBB/Stable/--	5
Progress Energy Carolinas Inc.	BBB/Stable/A-2	5
Kansas City Power & Light Co.	BBB/Stable/A-2	6
PNM Resources Inc.	BBB/Stable/--	6
Southern California Edison Co.	BBB/Stable/A-2	6
Empire District Electric Co.	BBB/Stable/A-2	6
Entergy Mississippi Inc.	BBB/Stable/--	6
Entergy New Orleans Inc.	BBB/Stable/--	6
Duke Energy Field Services LLC	BBB/Stable/A-2	6
Arizona Public Service Co.	BBB/Negative/A-2	5
TXU U.S. Holdings Co.	BBB/Negative/--	5
Pinnacle West Capital Corp.	BBB/Negative/A-2	6
Cleco Power LLC	BBB/Negative/A-3	6
Puget Sound Energy Inc.	BBB-/Positive/A-3	5
Puget Energy Inc.	BBB-/Positive/--	5
Green Mountain Power Corp.	BBB-/Stable/--	5
Public Service Co. of New Mexico	BBB-/Stable/A-2	6
Pacific Gas & Electric Co.	BBB-/Stable/ --	6
Cleveland Electric Illuminating Co.	BBB-/Stable/--	6
Ohio Edison Co.	BBB-/Stable/--	6
Toledo Edison Co.	BBB-/Stable/--	6
Pennsylvania Power Co.	BBB-/Stable/--	6
El Paso Electric Co.	BBB-/Stable/--	6
Central Vermont Public Service Corp.	BBB-/Stable/--	6
Entergy Gulf States Inc.	BBB-/Stable/--	6
System Energy Resources Inc.	BBB-/Stable/--	7
Tampa Electric Co.	BBB-/Negative/A-3	4
Black Hills Power Inc.	BBB-/Negative/--	6
Westar Energy Inc.	BB+/Positive/--	5
Kansas Gas & Electric Co.	BB+/Positive/--	6
Indianapolis Power & Light Co.	BB+/Stable/--	4
IPALCO Enterprises Inc.	BB+/Stable/--	4
Enterprise Products Operating L.P.	BB+/Stable/--	6
Enterprise Products Partners L.P.	BB+/Stable/--	6
GulfTerra Energy Partners L.P.	BB+/CW-Neg/--	6
Consumers Energy Co.	BB/Negative/--	6
Tucson Electric Power Co.	BB/CW-Neg/--	6
Dayton Power & Light Co.	BB-/CW-Neg/ -	7
Monongahela Power Co.	B/Stable/--	5
Nevada Power Co.	B+/Negative/--	7
Sierra Pacific Power Co.	B+/Negative/--	7
Sierra Pacific Resources	B+/Negative/--	7
4. Diversified Energy and Diversified Non-Energy		
WPS Resources Corp.	A/Stable/A-1	5
KeySpan Corp.	A/Negative/A-1	4
FPL Group Inc.	A/Negative/--	6
Peoples Energy Corp.	A-/Stable/A-2	5
Vectren Corp.	A-/Negative/--	4
PacifiCorp Holdings Inc.	A-/Negative/--	5
Exelon Corp.	A-/Negative/A-2	7

MDU Resources Group Inc.	A-/Negative/A-2	7
Centennial Energy Holdings Inc.	A-/Negative/A-2	8
Otter Tail Corp.	A-/Negative/--	8
Kinder Morgan Energy Partners L.P.	BBB+/Stable/A-2	4
Northeast Utilities	BBB+/Stable/--	5
OGE Energy Corp.	BBB+/Stable/A-2	6
LG&E Energy Corp.	BBB+/Stable/--	6
Cinergy Corp.	BBB+/Stable/A-2	6
Constellation Energy Group Inc.	BBB+/Stable/A-2	7
Sempra Energy	BBB+/Stable/A-2	7
Pepco Holdings Inc.	BBB+/Negative/A-2	5
Conectiv	BBB+/Negative/--	5
Alliant Energy Corp.	BBB+/Negative/A-2	6
DTE Energy Co.	BBB+/Negative/A-2	6
Dominion Resources Inc.	BBB+/Negative/A-2	7
Kinder Morgan Inc.	BBB/Stable/A-2	5
American Electric Power Co. Inc.	BBB/Stable/A-2	6
Entergy Corp.	BBB/Stable/--	6
Hawaiian Electric Industries Inc.	BBB/Stable/A-2	6
Progress Energy Inc.	BBB/Stable/A-2	6
PPL Corp.	BBB/Stable/--	7
Public Service Enterprise Group Inc.	BBB/Stable/A-2	7
Great Plains Energy Inc.	BBB/Stable/--	7
Duke Energy Corp.	BBB/Stable/A-2	7
Duke Capital Corp.	BBB/Stable/A-2	8
TXU Corp.	BBB/Negative/--	5
Centerpoint Energy Inc.	BBB/Negative/--	5
Cleco Corp.	BBB/Negative/A-3	6
Potomac Capital Investment Corp.	BBB/Negative/--	8
MidAmerican Energy Holdings Co.	BBB-/Positive/--	5
FirstEnergy Corp.	BBB-/Stable/--	6
TECO Energy Inc.	BBB-/Negative/A-3	5
Black Hills Corp.	BBB-/Negative/--	8
Avista Corp.	BB+/Stable/--	6
Edison International	BB+/Stable/--	6
TNP Enterprises	BB+/Stable/--	6
New York Water Service Corp.	BB/Stable	7
CMS Energy Corp.	BB/Negative/--	7
DPL Inc.	BB- /CW-Neg/--	8
Williams Companies Inc. (The)	B+/Negative/--	8
Allegheny Energy Inc.	B/Stable/--	7
Dynegy Inc.	B/Negative/--	8
Dynegy Holdings Inc.	B/Negative/--	9
El Paso CGP Corp.	B-/Negative/--	6
Aquila Inc.	B-/Negative/--	8
El Paso Corp.	B-/Negative/--	8
5. Energy Merchants/Power Developers/Trading and Marketing		
Entergy-Koch L.P.	A/Stable/--	9
KeySpan Generation LLC	A/Negative/--	5
FPL Group Capital	A/Negative/A-1	8
Exelon Generation Co.	A-/Negative/A-2	8

AmerenEnergy Generating Co.	A-/CW-Neg/--	8
Southern Power Co.	BBB+/Stable/--	6
LG&E Capital Corp.	BBB+/Stable/A-2	9
Alliant Energy Resources Inc.	BBB+/Negative/--	9
American Ref-Fuel Co. LLC	BBB/Stable/--	6
PSEG Power LLC	BBB/Stable/--	8
PPL Energy Supply LLC	BBB/Stable/--	8
TXU Energy Co. LLC	BBB/Negative/--	7
Duke Energy Trading and Marketing LLC	BBB-/Negative/--	10
Northeast Generation Company	BB+/Negative/--	9
Cogentrix Energy	BB-/Stable/--	6
PSEG Energy Holdings Inc.	BB-/Stable/--	9
AES Corp.	B+/Stable/--	9
NRG Energy Inc.	B+/Stable	9
Allegheny Energy Supply Co. LLC	B/Stable/--	8
Reliant Resources Inc.	B/Negative/--	8
Calpine Corp	B/Negative/--	9
Edison Mission Energy	B/Negative/--	9
Orion Power Holdings Inc	B/Negative/--	9
Reliant Energy Mid-Atlantic Power Holdings LLC	B/Negative/--	9
Mirant Americas Generation Inc.	D/--/--	10
Mirant Americas Energy Marketing L.P.	D/--/--	10
Mirant Corp.	D/--/--	10
NEGT Energy Trading Holdings Corp	D/--/--	10
PG&E National Energy Group	D/--/--	10
USGen New England Inc.	D/--/--	10

EXHIBIT 5

Standard & Poor's
January 26, 2006

RESEARCH

Research Update: APS, PWCC's 'BBB-' Corporate Credit Ratings Affirmed On ACC Vote But Challenges Continue

Publication date: 26-Jan-2006
Primary Credit Analyst: Anne Selting, San Francisco (1) 415-371-5009; anne_selting@standardandpoors.com

Credit Rating: BBB-/Stable/A-3

Rationale

Standard & Poor's Ratings Services affirmed its 'BBB-' corporate credit ratings on Arizona Public Service (APS) and its parent, Pinnacle West Capital Corp. (PWCC), following the generally constructive decisions made by the Arizona Corporation Commission (ACC) on Jan. 25. The commission lifted a cap that limited APS' opportunity to recover fuel and purchased power costs and modestly advanced the collection of deferred costs that APS was incurring under the terms of its power supply adjuster (PSA). However, the ACC also restricted APS' ability to file for a surcharge, which raises certain credit concerns. The outlook is stable.

The ACC vote to remove the $776 million cap on annual fuel and purchased power costs is favorable because it allows APS to defer any costs that exceed this level, which is in fact expected to occur in late 2006. APS' current deferral level is about $170 million, which will likely increase by approximately $250 million this year. The ACC adopted an amendment to advance the commencement of recovery of these costs by two months to Feb. 1 from April 1. While the impact is small, providing APS only about $14 million of incremental recovery in 2006, the vote is an important indicator that the ACC acknowledges that timely action is necessary to limit cash flow pressure on the company. (Note: As a result of staff and company testimony, some of the numbers Standard & Poor's cited in its Jan. 25 credit FAQ have been updated here.)

However, the ACC also voted to prohibit APS from requesting surcharges before the annual PSA adjustor is implemented. Heretofore, Standard & Poor's understood that APS would be permitted to file for surcharge relief any time that deferrals reached $100 million, as appeared to be implied by the settlement in its last rate case, as amended by the ACC in March 2005. With respect to the $170 million of deferrals that have accumulated as of year-end 2005, the recently enacted PSA adjuster will generate only about $111 million over the next 12 months. The remaining $59 million will be addressed through a surcharge filing, which may be made only after Feb. 1, but for which the collection timeline and approval date are uncertain.

While a technicality, the surcharge vote removes potentially critical flexibility for timely recovery of prudently incurred fuel and purchased power costs. The PSA has a very narrow 4 mill per kilowatt-hour lifetime cap, and the ACC is not bound to act on a surcharge filing by any specific date. As a result, the ACC's decision could cause uncertainty over the timing and disposition of future, expected deferrals.

Standard & Poor's current expectation is that high fuel and purchased power costs will result in a 2006 deferral problem that is larger than that of 2005. The ACC's vote to limit the flexibility of the timing of the surcharge elevates the importance of APS' request for $299 million in interim emergency rate relief, which is expected to be ruled on in April. That is, a limited PSA with a backstop surcharge that can be filed according to a specified timeline places incremental pressure on other processes that could support credit quality through 2006, especially when permanent rate relief via a general rate case ruling is not expected to occur within the next year.

Much of these issues stem from the very weak PSA, which is triggered based on a date and not on a threshold level of deferrals and which limits any adjustment to a narrow cap. This structure transfers any deferred balances to a surcharge process. In turn, the surcharge process is open-ended, with no concrete timeline for resolution. At the same time, APS has a significant reliance on natural gas. And this dependence is expected to grow in the coming years. Given the volatility of this fuel and expectations that at least in the near-term prices will remain high relative to historic levels--certainly relative to 2003 levels on which current retail rates are based--a critical underpinning of credit quality is the timing of recovery. This emphasis is particularly important in Arizona, where there is little precedent to support the conclusion that general rate cases can be processed quickly.

However, despite the emphasis that Standard & Poor's places on power supply adjustment mechanisms, it is possible that if the ACC establishes a track record of being supportive and timely toward emergency rate relief requests, that this vehicle could compensate for the current limitations of APS' PSA.

Outlook

The stable outlook is premised on the ACC providing sustained regulatory support that adequately addresses building deferrals. Negative rating actions could result if regulatory support does not continue, or if market forces or operational issues lead to significant increases in the expected 2006 deferral level.

Ratings List

Pinnacle West Capital Corp.	
Corp credit rating	BBB-/Stable/A-3
Senior unsecured debt	BB+
Commercial paper	A-3
Arizona Public Service Co.	
Corp credit rating	BBB-/Stable/A-3
Senior unsecured debt	BBB-
PVNGS II funding Corp Inc.	BBB-
Commercial paper	A-3

Complete ratings information is available to subscribers of RatingsDirect, Standard & Poor's Web-based credit analysis system, at www.ratingsdirect.com. All ratings affected by this rating action can be found on Standard & Poor's public Web site at www.standardandpoors.com; under Credit Ratings in the left navigation bar, select Find a Rating, then Credit Ratings Search.

EXHIBIT 6

Standard & Poor's
January 24, 2006

RESEARCH

Credit FAQ: Credit Issues Expected To Continue For Pinnacle West Capital Corp. And Arizona Public Service Co.

Publication date: 24-Jan-2006
Primary Credit Analyst: Anne Selting, San Francisco (1) 415-371-5009; anne_selting@standardandpoors.com

On Dec. 21, 2005, Standard & Poor's Ratings Services lowered the corporate credit ratings on Arizona Public Service Co. (APS) and its parent, Pinnacle West Capital Corp. (PWCC) by one notch to 'BBB-'. This action reflected three factors: growing fuel and purchased power deferrals, which are weakening financial performance in 2005 and 2006, the lack of action by the Arizona Corporation Commission (ACC) in 2005 to address a portion of these deferrals through a special surcharge, and the likelihood of delays in the completion of APS' recent general rate case (GRC) filing, which suggest that financial weakening may extend into 2007.

Standard & Poor's stated at the time that any adverse regulatory developments or continued delays in resolving the pending surcharge request could trigger another rating action, which could include a revision of the stable rating outlook to negative, placing the company's debt rating on CreditWatch with negative implications, or lowering the rating to non-investment grade.

Frequently Asked Questions

How large are APS' deferrals of fuel and purchased power?

At Jan. 31, 2006, APS' estimated fuel and purchased power deferrals are expected to be about $165 million. These deferrals are accumulating because APS' base electric rates are set to reflect 2003 costs, and power and natural gas costs have far exceeded these rates. APS collects 2.0473 cents per kilowatt-hour (kWh) in rates for these costs, but for the 12 months ended September 2005, its actual cost averaged 2.701 cents per kWh. Because these rates will not be updated until the completion of APS' recently filed GRC or the emergency interim request, deferrals will likely continue to accumulate in 2006 and into 2007.

The amount by which 2006 actual fuel and purchased power costs will exceed the authorized expenditures will be a function of retail sales growth, commodity costs, the operational performance of APS' generation assets, and the fuel-in-base factor. Standard & Poor's has estimated that, at year-end 2006, the utility will likely incur an additional $250 million in fuel and purchased power costs that are not recoverable in base electric rates. The sum of balances to date of $165 million plus the expected incremental deferrals of $250 million total $415 million; however, because APS has the potential to collect some of its 2005 balances through a power supply adjuster (PSA) beginning April 1, year-end 2006 deferrals on the utility's balance sheet will not reach that level.

What are the ways that APS could recover its expected deferrals?

Under the terms of a settlement reached in APS' 2003 rate case approved by the ACC in April 2005, the PSA may be increased as much as four mills per kWh (a cap over the life of the PSA) on April 1, 2006. Using 2005 retail sales, and assuming a 4.5% growth rate (which is consistent with recent results), the four mills should yield about $125 million in rate relief on an annualized basis, or about $83 million for the eight months of 2006. Thus, as a rough approximation, APS' deferred balance would be about $330 million at year-end 2006.

On Jan. 17, the chairman of the ACC introduced a proposal to accelerate the PSA adjustment to Feb. 1. If this were approved by the ACC, an additional two months of the PSA would provide about $20 million in incremental revenues (e.g., roughly $125 million multiplied by two-twelfths of the year) in 2006. Thus, if the Hatch-Miller amendment moves forward, year-end 2006 deferred balances will be closer to about $310 million. The amendment is expected to be discussed on Jan. 24.

Additional relief could be provided if the ACC grants APS' request to recover $80 million by means of a two-year special surcharge that would increase retail rates by about 2%. On Jan. 4, an administrative law judge issued a decision indicating that APS' surcharge application is premature until the company's first power supply adjustment occurs in April. An ACC vote is scheduled for Jan. 24. Standard & Poor's current assumption is that the surcharge will be approved by the ACC, but will be delayed until July 1, 2006. A surcharge implemented at this time would provide roughly an additional $20 million to the company in 2006. If it were implemented sooner, the impact on deferrals would be relatively small, providing about $3 million in each month it is in place during 2006. If the Hatch-Miller amendment were approved and a surcharge was implemented and approved for Feb. 1, the two measures collectively would bring between $50 million-$57 million in relief. Accordingly, relative to the year-end expected balances, an accelerated surcharge and PSA, if granted, will reduce deferrals but only by about 20% in the best-case scenario.

What is the status with APS' emergency interim filing?
On Jan. 6, 2006, APS filed a $299 million request for emergency fuel and purchased power-related rate relief. Any amounts, if granted, would be subject to future prudency review. As part of a procedural conference on Jan. 12, four of the five commissioners questioned the definition an emergency and whether relief is justified. Based on the strong views expressed, it appears unlikely that the filing has support. On Jan. 19, a procedural schedule was set that should allow for a decision in April 2006. Standard & Poor's forecast estimates do not assume emergency relief is granted.

Are there credit concerns related to APS' rate cap?
Balancing these potential sources of rate relief are additional adverse financial effects that could occur for APS if its "hard cap" of $776 million is not lifted. The cap is part of APS' 2004 settlement, approved by the ACC in April 2005, which restricts the total amount of annual fuel and purchased power costs that can be collected in retail rates. APS expects that its fuel and purchased power costs will exceed the cap in the fourth quarter of 2006, and has indicated publicly that its estimated fuel costs will exceed $800 million. As part of its emergency interim filing, APS has requested that the cap be removed. If the cap is not lifted, any amounts above $776 million would be unrecoverable, putting further pressure on cash flows.

What assumptions does Standard & Poor's make about the performance of APS' generation assets in estimating deferred balances?
Standard & Poor's estimates assume normal operational performance of APS' generation fleet. Forced outages could increase deferred balances. Palo Verde unit 1 is in the process of exiting an outage that occurred last week due to pipe vibrations within the emergency cooling system. APS took the unit offline last week to install clamps in an effort to stop the excess vibrations. From late December until Jan. 17, unit 1 has operated at about 30% capacity while crews have tried to fix the problem, which followed the completion of the unit's exit from a refueling and maintenance outage begun in the fall of 2005. The plant is expected to maintain approximately this level of reduced capacity while additional repairs are considered. Replacement power costs have been incurred in association with this last outage, and could build, depending on the timeline for a solution to be implemented. These and any future costs are not part of Standard & Poor's deferred estimates.

How are these estimated deferrals expected to affect 2005 and 2006 financial performance, especially in the context of the credit benchmarks at the 'BBB-' rating?
Year-end results for 2005 are not yet available, but Standard & Poor's expects that 2005 and 2006 results will be on par with the 12 months ending Sept. 30, 2005, when consolidated adjusted funds from operations (FFO) to total debt was 14.8%. FFO to total debt is an important metric for Standard & Poor's, and at a business profile of '6' (on a 10-point scale where '1' is excellent and '10' vulnerable), it reflects a below-investment-grade performance. For the 12 months ending Sept. 30, 2005, FFO interest coverage was 3.3x, which is reasonable for the current rating. Adjusted total debt to total capitalization was 53.1%, and is solid for the current rating.

Performance in 2007 will be heavily dependent on when the GRC is resolved. APS filed on Nov. 4, 2005, for a $409.1 million (or 19.9%) rate increase, the majority of which is related to fuel and purchased power costs. Typically, the ACC certifies the application as complete within 30 days, and the case commences. But in early December 2005, the ACC requested that the company re-file its application using a test year ending Sept. 30, 2005, rather than the Dec. 31, 2004 data that APS used. The updated application is expected to be re-submitted to the ACC on Jan. 31, 2005.

As a result, the case will not begin until early March 2006, suggesting that an outcome will be delayed roughly three months from the original schedule, which envisions a ruling by early 2007. Recent public statements by the ACC indicate that spring 2007 may be the earliest a decision could be expected. But there is little precedent in Arizona that would suggest a year-long rate case is likely. A more conservative estimate would assume mid-2007. This could be a credit concern because if permanent rate relief is not in place prior to the peak summer season, financial recovery could also be stalled in 2007.

How is the company's liquidity?

Unaudited consolidated cash and investments stood at roughly $150 million as of Dec. 31, 2005. PWCC and APS also maintain a total of $700 million in revolving credit facilities, which had approximately $15 million of usage at year-end 2005 for miscellaneous letters of credit. Standard & Poor's preliminary assessment is that the company's credit lines should be sufficient to support working capital needs, purchases of gas and power, as well as fund margining and collateral requirements for trading operations. As of Dec. 31, 2005, PWCC and APS comfortably met their loan covenant requirements.

PWCC has a $300 million dollar maturity on April 1, which it plans to refinance. Adverse regulatory actions could affect the costs of borrowing or even access to the capital markets, although this is not currently seen as a significant threat.

APS' reliance on purchases and gas-fired peaking capacity during the winter is low; however, this is seasonal. Fuel and purchased power expenses are anticipated to be accrued faster in July 2006 through September 2006. Standard & Poor's is conducting a more detailed liquidity assessment, which will be completed once more clarity is provided on how the ACC is expected to address interim rate relief requests. APS has a significant hedging program and 85% of its 2006 power and gas requirements are hedged. APS and PWCC are currently holding counterparties' collateral as a result of their in-the-money hedged positions.

Could cost saving measures, or the sale of nonregulated assets by PWCC assist in restoring credit quality?

The ACC has requested that the company explain what cost reductions it is making to compensate for the fact that its retail rates are not aligned with production costs. In response, the company cancelled bonuses for its corporate officers, and is certain to investigate additional cost-savings measures. While these actions may address other public policy issues of concern to the ACC, from a credit standpoint cost cutting measures are unlikely to materially alleviate APS' sagging financial performance.

The deferred balances stem from fuel and purchased power costs that the utility incurred to serve retail loads. APS earns no margin on these expenses; they are simply passed straight through to customers. Similar to the circumstances that other western utilities have faced in recent years, APS' fuel and purchased costs substantially exceed the amount currently recoverable in rates. The company may be able to temporarily subsidize the cost of serving retail loads by reducing expenses in other parts of the company, selling other PWCC assets, or issuing debt, but such a strategy is not sustainable, and could very well result in longer-term adverse consequences for the company.

EXHIBIT 7

FITCH
January 30, 2006

Fitch Lowers PNW & APS' Sr. Unsecured Ratings to 'BBB-' & 'BBB', Respectively; Outlook Stable

Ratings
30 Jan 2006 4:23 PM (EST)

Fitch Ratings-New York-30 January 2006: Fitch Ratings has lowered Pinnacle West Capital's (PNW) long- and short-term ratings. At the same time, Fitch has lowered Arizona Public Service Company's (APS) long-term ratings, while affirming its commercial paper rating. The securities of PNW and APS have been removed from Rating Watch Negative, where they were placed Jan. 6, 2006. The Rating Outlook is Stable. The following actions are effective immediately:

Pinnacle West Capital:

--Issuer default rating (IDR) downgraded to 'BBB-' from 'BBB';
--Senior unsecured debt downgraded to 'BBB-' from 'BBB';
--Commercial Paper downgraded to 'F3' from 'F2'.

The Rating Outlook is Stable.

Arizona Public Service Co.

--IDR downgraded to 'BBB-' from 'BBB';
--Senior unsecured debt downgraded to 'BBB' from 'BBB+';
--Commercial Paper affirmed at 'F2'.

The Rating Outlook is Stable.

Approximately $3.8 billion of debt is affected by the rating actions.

The rating actions and Stable Rating Outlook reflect the resolution of APS' power supply adjustor (PSA) proceedings by the Arizona Corporation Commission (ACC) and the utility's significant exposure to high and rising natural gas commodity costs. The commodity exposure is a function of a generating capacity mix, about half of which is natural gas fired, and rapid service territory load growth, which is likely to be met predominantly by natural gas-fired resources. The revised ratings also consider the operational risk and asset concentration of the Palo Verde nuclear plant. The facility has experienced intermittent operating problems over the past year and a sustained, unscheduled outage at the plant could lead to further negative rating actions.

The ACC decision in the PSA proceedings, issued on Jan. 25, 2006, has positive and negative implications for PNW and APS' creditworthiness. The commission's decision to accelerate the effective date of the PSA rate to Feb. 1 from April 1, along with the removal of the $776 million annual power supply cost limit, were constructive developments in Fitch's view. However, the ACC bench order rejecting APS's $80 million surcharge request on procedural grounds and restriction of PSA adjustments to an annual reset is less favorable than Fitch had anticipated in its previous ratings and is a significant source of concern for PNW and APS fixed-income investors. The fact that there is no vehicle within the PSA protocol to recover supply costs more frequently than annually during periods of sustained high and rising energy costs subjects APS to significant cash flow volatility and working capital requirements. Such costs would be exacerbated in a meaningful way by an extended outage of a base load nuclear- or coal-fired generating facility during periods of peak demand. The only option to recover fuel and purchase power costs above amounts determined annually in the PSA would be an emergency rate filing, in which the timing and amount of rate relief would be uncertain.

It is Fitch's understanding that energy cost deferrals in a particular year of up to four mills per kilowatt hour (approximately $110 million-$115 million on an annual run rate) will be recovered through an annual PSA rate adjustment that will recover those costs over the following 12 months. The surcharge is expected to facilitate recovery of costs in excess of the four mills per kilowatt hour limit over a time horizon to be determined by the commission.

Contact: Philip Smyth, CFA +1-212-908-0531 or Robert Hornick +1-212-908-0523, New York.

Media Relations: Brian Bertsch, New York, Tel: +1 212-908-0549.

Fitch's rating definitions and the terms of use of such ratings are available on the agency's public site, 'www.fitchratings.com'. Published ratings, criteria and methodologies are available from this site, at all times. Fitch's code of conduct, confidentiality, conflicts of interest, affiliate firewall, compliance and other relevant policies and procedures are also available from the 'Code of Conduct' section of this site.

Revised

EXHIBIT
RUCO-6
admitted

RATE IMPACT OF APS RATE REQUESTS
IN RESPONSE TO COMMISSIONER MAYE'S FEBRUARY 9, 2006 LETTER
SUBMITTED BY RUCO

LINE NO.	DESCRIPTION	SUMMER AVERAGE USAGE	INCREMENTAL % INCREASE	INCREMENTAL $ INCREASE	WINTER AVERAGE USAGE	INCREMENTAL % INCREASE	INCREMENTAL $ INCREASE
	PREVIOUS:						
1	BILL PRE-2005 RATE INCREASE	$153.39			$76.25		
	CURRENT:						
2	AVERAGE USAGE	1425			899		
3	BILL WITH 2005 RATE INCREASE	$158.19	3.13%	$4.80	$74.61	-2.16%	($1.64)
4	BILL WITH FEB 2006 ADJUSTOR	$163.89	3.60%	$5.70	$78.21	4.82%	$3.60
	REQUESTED:						
5	BILL WITH EMERGENCY 14%	$179.79	9.70%	$15.90	$88.24	12.83%	$10.03
6	BILL WITH SURCHARGE STEP 1	$180.58	0.44%	$0.79	$88.74	0.56%	$0.50
7	BILL WITH SURCHARGE STEP 2	$182.88	1.72%	$2.30	$90.19	2.21%	$1.45
8	BILL WITH 2007 RATE CASE INCREASE	$196.83 (a)	7.63%	$13.95	$91.40 (a)	1.34%	$1.21
9	TOTAL INCREASE (LINE 8-LINE 1/LINE1)		$\boxed{28.32\%}$		$\boxed{19.86\%}$		
10	TOTAL INCREASE (LINE 8-LINE 3/LINE 3)		$\boxed{24.43\%}$		$\boxed{22.50\%}$		

NOTE (a)
1) ASSUMES THAT PREVIOUS ADJUSTOR AND SURCHARGES REMAIN IN EFFECT

DATA INPUTS:	CURRENT RATES	PROPOSED RATES
MONTHLY SERVICE CHARGE	7.59	7.59
SUMMER - 1ST 400	0.0757	0.08864
2ND 400	0.10556	0.12609
OVER 800	0.12314	0.14949
WINTER - ALL USAGE	0.07361	0.08612
CRCC SURCHARGE	0.000338	0.000338
PSA ADJUSTOR (FEB 06)	0.004	0.004
EPS SURCHARGE @CURRENT	0.35	0.35
DSM SURCHARGE	0.0002121	0.0002121

EXHIBIT
RUCO-7
admitted

RATE IMPACTS OF APS SURCHARGES RESULTING FROM STAFF PROPOSAL - ON A PER KWH BASIS
IN RESPONSE TO COMMISSIONER MAYES' REQUEST
SUBMITTED BY RUCO

LINE NO.	DESCRIPTION	SUMMER AVERAGE USAGE	INCREMENTAL % INCREASE	INCREMENTAL $ INCREASE	WINTER AVERAGE USAGE	INCREMENTAL % INCREASE	INCREMENTAL $ INCREASE
	12 MONTH AMORTIZATION						
1	CURRENT BILL WITH FEB 2006 ADJUSTOR	$163.89			$78.21		
2	$33 MILLION SURCHARGE - 12 MO. AMORTIZATION	$165.66	1.08%	$1.77	$79.32	1.43%	$1.12
3	$144 MILLION SURCHARGE - 12 MO. AMORTIZATION	$173.40	4.67%	$7.74	$84.21	6.16%	$4.88

RATE IMPACTS OF APS SURCHARGES RESULTING FROM STAFF PROPOSAL - ON A PER KWH BASIS
IN RESPONSE TO COMMISSIONER MAYES' REQUEST
SUBMITTED BY RUCO

LINE NO.	DESCRIPTION	SUMMER AVERAGE USAGE	INCREMENTAL % INCREASE	INCREMENTAL $ INCREASE	WINTER AVERAGE USAGE	INCREMENTAL % INCREASE	INCREMENTAL $ INCREASE
	24 MONTH AMORTIZATION						
1	CURRENT BILL WITH FEB 2006 ADJUSTOR	$163.89			$78.21		
2	$33 MILLION SURCHARGE - 24 MO. AMORTIZATION	$164.78	0.54%	$0.89	$78.77	0.72%	$0.56
3	$144 MILLION SURCHARGE - 24 MO. AMORTIZATION	$168.65	2.35%	$3.87	$81.21	3.10%	$2.44

IMPACT OF INCREMENTAL INCREASES IN COST OF DEBT
SUBMITTED BY RUCO

APS CAPITAL STRUCTURE		CURRENT COST	WEIGHTED COST	RATE BASE	REVENUE REQUIREMENT
DEBT	45.50%	5.41%	2.46%		
EQUITY	54.50%	11.50%	6.27%		
			8.73%	$4,466,697,000	$639,709,282
50 BASIS POINT INCREASE					
DEBT	45.50%	5.91%	2.69%		
EQUITY	54.50%	11.50%	6.27%		
			8.96%	$4,466,697,000	$656,381,642
		INCREMENTAL REV. REQ. INCREASE			$16,672,360
		INCREMENTAL KWH INCREASE			$0.0006
		AVG. RESIDENTIAL SUMMER BILL INCREASE			$0.90

EXHIBIT
RUCO-8
admitted

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AZ CORP COMMISSION
DOCUMENT CONTROL

Transcript Exhibit(s)

Docket #(s): E-01345A-06-0009

Exhibit #: AECC1, AECC-2, AECC3, AECC4, AECC5, AECC-6, AECC-7

APS / Interim Rates E-01345A-06-0009

March 20 through 29, 2006

Volumes I through VIII

AECC EXHIBITS

1 through 7

EXHIBIT
AECC-1
Admitted

BEFORE THE ARIZONA CORPORATION COMMISSION

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	))))	**Docket No. E-01345A-06-0009**

Direct Testimony of Kevin C. Higgins

on behalf of

Phelps Dodge Mining Company and

Arizonans for Electric Choice & Competition

February 28, 2006

TABLE OF CONTENTS

DIRECT TESTIMONY OF KEVIN C. HIGGINS

Introduction

Q. Please state your name and business address.

A. Kevin C. Higgins, 215 South State Street, Suite 200, Salt Lake City, Utah, 84111.

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

A. I am a Principal in the firm of Energy Strategies, LLC. Energy Strategies is a private consulting firm specializing in economic and policy analysis applicable to energy production, transportation, and consumption.

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

A. My testimony is being sponsored by 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. Phelps Dodge and AECC (hereafter "AECC") are parties to the APS Settlement Agreement that was approved by the Commission, with some modification, in 2005.

Q. Were you personally involved in the negotiations that resulted in the APS Settlement Agreement?

A. Yes, I was closely involved in the negotiations on behalf of AECC.

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),[1] the hearings on the Arizona Public Service Company ("APS") Settlement Agreement (1999),[2] the hearings on the TEP Settlement Agreement (1999),[3] the AEPCO transition charge hearings (1999),[4] the Commission's Track A proceeding (2002),[5] the APS adjustment mechanism proceeding (2003),[6] the Arizona ISA proceeding (2003),[7] the APS Rate Case (2004),[8] and the Trico Rate Case (2005).[9]

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[1] Docket No. RE-00000C-94-0165.
[2] Docket Nos. RE-00000C-94-0165, E-01345A-98-0471, and E-01345A-98-0473.
[3] Docket Nos. RE-00000C-94-0165, E-01933A-97-0772, and E-01933A-97-0773.
[4] Docket No. E-01773A-98-0470.
[5] Docket Nos. E-00000A-02-0051; E-01345A-01-0822; E-00000A-01-0630; E-01933A-02-0069; E-01933A-98-0471.
[6] Docket No. E-01345A-02-0403.
[7] Docket No. E-00000A-01-0630.
[8] Docket No. E-01345A-03-0437.

Q. Have you testified before utility regulatory commissions in other states?

A. Yes. I have testified numerous times on the subjects of electric utility rates and regulatory policy before state utility regulators in Alaska, Colorado, Georgia, Idaho, Indiana, Kansas, Michigan, Nevada, New York, Ohio, Oregon, South Carolina, Utah, Washington, 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.

<u>Overview and Conclusions</u>

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

A. My testimony addresses APS's request for an emergency interim rate increase and recommends adjustments to the Company's proposal that I believe are necessary to ensure results that are just and reasonable.

Q. What conclusions have you reached in your analysis?

A. (1) In light of rising fuel and purchased power costs and the recent credit downgrade experienced by APS, some emergency rate relief is warranted; specifically, I believe it is appropriate to allow an emergency interim rate increase sufficient to permit APS to attain a FFO/Debt Ratio of 18 percent in 2006. I calculate that this ratio can be attained through an emergency and interim rate increase of $126 million in calendar-year 2006. If implemented on May 1, 2006, this incremental

[9] Docket No. E-01461A-04-0607.

revenue can be collected with an emergency and interim rate increase of approximately 7.8 percent (as measured against rates exclusive of PSA charges).

(2) I disagree with APS's proposal to establish a new base energy rate in this proceeding, as this would allow APS to avoid having to absorb its 10 percent share of the cost differential between the current base energy rate and its new proposed energy rate. Instead, the base energy rate should remain at the level established in the last general rate case, and any revenues collected from the emergency surcharge should be applied as a credit against the PSA Annual Tracking Account. In this way, the surcharge could be set to recover the 90 percent cost-share assignable to customers, with the remaining 10 percent assigned to APS per the PSA mechanism. The new base energy rate would then be established in the upcoming general rate case.

(3) The design of APS's proposed interim surcharge is not reasonable in the context of an emergency filing. Although APS advertises its proposed increase as being "14 percent", the Company's proposal would actually raise rates for many industrial customers by well over 20 percent. In my opinion, it is inappropriate in the context of an emergency rate filing – with its limited record and restricted opportunity for analysis – to levy disproportionate increases on different customer groups. If an emergency increase is granted, the only appropriate rate design would be an <u>equal percentage increase</u> for all customer groups. This can be achieved through an equal percentage surcharge on total customer bills, exclusive of PSA charges.

Need for Emergency Increase

Q. In your opinion, has APS demonstrated a need for an emergency increase?

A. Yes. In light of rising fuel and purchased power costs and the recent credit downgrade experienced by APS, some emergency rate relief is warranted. Higher utility credit costs invariably have a negative impact on customers, and I believe it is prudent to provide emergency relief to the extent that it is necessary to avoid further downgrades.

Q. What amount of emergency increase has APS requested?

APS has requested emergency and interim relief in the amount of $299 million on an annualized basis, which corresponds to a rate increase of 14 percent – although as I discuss later in this testimony the impact on many industrial customers is well over 20 percent. I note that the 14 percent increase as described by APS in its Application is based on pre-PSA Adjustor rates. With the implementation of the PSA Adjustor on February 1, 2006, the $299 million emergency request becomes a slightly smaller percentage of existing rates. To avoid confusion, when I refer to percentage rate changes hereinafter in this testimony, the reference will be to rates *exclusive* of the PSA Adjustor, and thus comparable to APS's initial representations.

Q. What criteria should be used in evaluating the emergency request?

A. APS has emphasized that the Funds-from-Operations/Debt ratio ("FFO/Debt ratio") is the key financial metric examined by the credit agencies in establishing credit ratings.[10] APS has further indicated that a FFO/Debt ratio of 18

[10] Affidavit of Donald E. Brandt, p. 4, lines 9-14.

to 28 percent is necessary for a utility with APS's risk profile to maintain a BBB credit rating from Standard & Poor's ("S&P"). I have verified this range through discussions with S&P. While I note that BBB was APS's credit rating from S&P prior to being downgraded to BBB- on December 21, 2005, my understanding of S&P's FFO/Debt ratio range is that S&P does not provide a separate range for BBB-. Based on APS's representations regarding the importance of the FFO/Debt Ratio to its credit rating, I believe it is necessary to allow an emergency interim rate increase sufficient to permit APS to attain a FFO/Debt ratio of 18 percent in 2006, in order to prevent a further credit downgrade. However, the amount of relief needed in this proceeding to accomplish this is complicated somewhat by the series of filings that APS has made in recent weeks and the extent to which rate relief provided in those other proceedings will provide partial mitigation of APS's current financial difficulties.

Q. What other rate relief has APS received recently?

A. On January 25, 2006, the Commission approved a \$.004 per KWh PSA Adjustor that took effect on February 1, 2006.

Q. What other rate relief has APS requested recently?

A. On February 2, 2006, APS requested approval of a two-part PSA Surcharge. The first part would recover \$15.3 million over 12 months and is associated with fuel and purchased power costs in the "Paragraph 19(d) Balancing Account" *not* associated with the 2005 unplanned outage at Palo Verde. I estimate that if approved to go into effect by May 1, 2006, this portion of the PSA Surcharge would collect about \$11 million over the remainder of 2006.

The second part of the requested PSA Surcharge would recover $44.6 million over 12 months, and is associated with costs associated with the unplanned outage at Palo Verde in 2005. I estimate that if this charge went into effect July 1, 2006, it would collect about $24 million over the remainder of 2006.

Q. How would recovery of these surcharge revenues impact APS's FFO/Debt ratio in 2006?

A. As each of the rate proposals has a unique starting date, it is useful in addressing this question to differentiate between the annualized revenues and the calendar-year 2006 revenues associated with the APS rate increases that have been requested and/or granted. Based on APS's 2006 retail kWh forecast, I estimate the revenues from the various rate increases under consideration as follows:

Table KCH-1
Summary of Recent APS Rate Increase Requests
($ millions)

Rate proposal	Est. start date	Rate ($/kWh)	Annualized $	$ in 2006
PSA Adjustor	2/1/06	$.004000	111.6	103.2
PSA Surcharge I	5/1/06	$.000554	15.3	11.2
PSA Surcharge II	7/1/06	$.001611	44.6	24.3
Emergency Surch.	5/1/06	$.011161	298.7	226.3

For the purpose of identifying the amount of emergency increase needed for APS to attain an FFO/Debt ratio of 18 percent in 2006, I will assume that the Step I PSA Surcharge is implemented on May 1, 2006. I note that AECC believes such an action is appropriate under the PSA mechanism. If the Step I PSA

Surcharge is not implemented at that time, then the emergency increase would need to be greater.

It appears likely that the Step II PSA Surcharge will take longer to resolve. Given the uncertainty surrounding the timing and final outcome of that surcharge request, I have excluded revenues from the Step II PSA Surcharge in formulating my emergency increase recommendation, but note that approval of the Step II PSA Surcharge would reduce the amount of the emergency increase that is needed, and respectfully suggest that the amount of the emergency increase could be adjusted upon resolution of the Step II PSA Surcharge matter.

Q. Assuming the $11 million requested Step I PSA Surcharge goes into effect on May 1, 2006, how much revenue would APS require from an emergency increase to attain a FFO/Debt ratio of 18 percent in 2006?

A. I calculate that this could be accomplished with an interim increase of $126 million in calendar-year 2006, which can be implemented through an equal percentage surcharge of approximately 7.8 percent. This figure is comparable to the 14 percent, or $226 million in calendar-year 2006 ($299 million on an annualized basis) that APS has requested. My calculations are shown in Attachment KCH-2.

Q. Why do you state that the rate increase necessary to raise $126 million in additional revenues is *approximately* 7.8 percent?

A. The calendar-year 2006 revenue increase I am recommending is 55.6 percent of the revenue that would be generated by APS's proposed increase of 14 percent, so it is accurate to state that my proposed increase is 55.6 percent of that recommended by APS – and 7.8 percent is simply 55.6 percent of APS's proposed 14 percent increase. If APS and I were recommending identical surcharge mechanisms or if the period of analysis was a full twelve months, this apportioning would result in an exact derivation of the necessary rate increase. However, APS is proposing a flat kWh charge and I am recommending a percentage-of-bill rider, and the period of analysis is eight months (May – December) – not twelve. Because APS's kWh sales and retail revenues will not move in perfect proportion on a month-to-month basis, the 7.8 percent estimate I described above will not be an exact calculation for the May to December period. This calculation can be improved significantly simply by using APS's monthly revenue projections for 2006 as the basis of the percentage increase. However, I do not have this information at the present time, although I am in the process of requesting it from APS.

Q. Please explain how you made your calculation of the additional $126 million needed by APS in 2006.

A. I started with APS workpaper DEB_WP21, which was referenced in APS Data Response STF 4.34, dated February 7, 2006. According to Data Response STF 4.34 and Workpaper DEB_21, if APS were to receive $132 million in combined PSA Adjustor/Surcharge revenues in 2006[11] and no interim increase, the Company's FFO/Debt ratio would be 16.0 percent in 2006. Using these assumptions, APS calculates that FFO in 2006 would be $520.6 million and

[11] The text of this APS data response indicates that APS assumed $133 million in PSA Adjustor/ Revenues. However, the spreadsheet attached to APS's Response to Staff Data Request No. 1-12 actually shows a combined PSA Adjustor/Surcharge revenue of $131.7 million in 2006. I use this latter figure in making my calculations rather than the $133 million that APS cites in the text of its data response.

Adjusted Average Total Debt would be $3.259 billion. These parameters are summarized below.

Table KCH-2

Key APS Assumptions and Calculations in Data Response STF 4.34 and DEB_WP21

Assumptions:	$132 million in PSA Adjustor[12]	
	No interim rate increase	
Calculations:	FFO:	$520,552,000
	Debt:	$3,259,115,000
	FFO/Debt:	16.0%

If APS were to receive an emergency increase, the Company's debt would not increase, all other things equal. (In fact, all things equal, APS debt would decline somewhat.) Therefore, for purposes of my calculation, I conservatively held APS's 2006 debt constant at $3.259 billion, and identified the FFO necessary to achieve a FFO/Debt ratio of 18 percent. This amount is $586.6 million, which is $66.1 million greater than the amount calculated by APS in DEB_WP21.

To derive the emergency increase necessary to achieve FFO of $586.6 million, it was necessary for me to adjust APS's assumption of $132 million in PSA Adjustor/Surcharge revenues to reflect adoption of the $.004 PSA Adjustor effective February 1, 2006 and to incorporate my assumption of adoption of the Step I PSA Adjustor on May 1, 2006. Under this scenario, the combined PSA Adjustor/Surcharge revenue is $114 million in 2006, $17 million less than APS had assumed in DEB__WP21.[13]

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[12] Please see my Footnote 11.
[13] $131.7 million – 114.4 million = $17.3 million.

To achieve a target FFO of $586.6 million, it was necessary for me to first replace the $17 million differential in assumed PSA revenues with emergency increase revenues, and then to derive the additional emergency increase in 2006 needed to reach the target FFO, taking account of income tax effects. I calculate that the total emergency increase needed to reach the target FFO in 2006 is $126 million, which requires an emergency increase that I estimate to be approximately 7.8 percent.

My calculation is summarized in Table KCH-3, below.

Table KCH-3

Summary of AECC Emergency Increase Calculation
($000)
All $ refer to Calendar Year 2006 Amounts

APS Projected FFO	$520,552
Target FFO	$586,641
Debt Target:	$3,259,116
FFO/Debt Target:	18.0%

Adjust APS PSA Adjustor/Surcharge Revenue:
$114,383 - $131,723 = $(17,340)
Change to FFO (w/ tax effect) $(17,430)/1.6407 = $(10,569)

Incremental FFO needed to reach target:

$586,641 - $520,552 - $10,569 = $76,658

Incremental revenue needed to reach Target FFO (w/ tax effect):

$76,658 x 1.6407 = **$125,722** = Emergency increase

Q. What is your recommendation to the Commission with respect to the amount of the emergency interim rate increase?

A. As I indicated above, I recommend targeting a FFO/Debt ratio of 18 percent in 2006. To accomplish this, I recommend that the Commission approve an emergency and interim rate increase of $126 million for calendar year 2006, to be adopted in conjunction with the first part of the PSA Surcharge, effective May 1, 2006. If the second part of the requested PSA Surcharge is later approved effective July 1, 2006, it would reduce the amount of the emergency increase that is needed. In that event, I suggest that the amount of the emergency increase could be reduced at that time.

<u>New Base Energy Rate vs. Credit to the PSA Annual Tracking Account</u>

Q. How should any emergency rate increase be treated with respect to APS's currently-approved rates and PSA mechanism?

A. I recommend a treatment that differs from APS's proposal. Currently, APS's base rate level of fuel and purchased power expenses ("base energy rate") is $.020743 per kWh, as established in the 2004 Settlement Agreement, and approved by the Commission in Decision No. 67744. In its request for an emergency rate increase, APS is requesting that a surcharge be imposed that would establish a new base energy rate of $.031904 per kWh. Currently, the PSA Annual Tracking Account is calculated based on the difference between actual costs and the base energy rate, with APS responsible for absorbing 10 percent of the cost differential and customers responsible for the remaining 90 percent. If APS's approach to establishing a new base energy rate is approved, the PSA Annual Tracking Account would be calculated, on a going-forward basis, from the Company's proposed new base energy rate of $.031904 per kWh. This would allow APS to avoid having to absorb its 10 percent share of the cost differential between the current base energy rate of $.020743 and $.031904, which the Company currently must absorb per the PSA mechanism.

In my opinion, this result would circumvent the 90/10 split in the PSA mechanism and should be rejected. While I believe that a new energy baseline should be established as part of any general rate case, "fast-forwarding" to a new base rate on an emergency basis – and sidestepping the 10 percent cost-share contained in the PSA mechanism – is not appropriate in this proceeding. Instead, the base energy rate should remain at the level established in the last general rate case, and any revenues collected from the emergency surcharge should be applied as a credit against the PSA Annual Tracking Account. In this way, customers would remain responsible for recovery of the 90 percent PSA cost-share assignable to them established in the Settlement Agreement, with the remaining 10 percent assigned to APS per the PSA mechanism. The new base energy rate would then be established in the upcoming general rate case.

Rate Design

Q. What rate design has APS proposed for its emergency increase?

A. APS has proposed a charge of 1.1161 cents per kWh on virtually all retail kWh.

Q. Do you believe the Company's proposal is a reasonable approach for an emergency rate increase?

A. No, I do not.

Q. Why do you disagree with the Company's rate design?

A. APS depicts its proposal as being a "14 percent" rate increase – which it is, on *average*; however, the Company's proposal would actually raise rates for many industrial customers by well over 20 percent. In my opinion, it is inappropriate in the context of an emergency rate filing – with its limited record and restricted opportunity for analysis – to levy disproportionate increases on different customer groups. If an emergency increase is granted, the only appropriate rate design would be an equal percentage increase for all customer groups.

Q. Please elaborate on your reasoning.

A. APS has made an emergency filing seeking approval of interim rates. In this circumstance, there is no record upon which to assign a relatively greater or lesser burden to different customer groups to bear these increased costs. Indeed, the Company's revised general rate case filing was just made on January 31, 2006, less than thirty days before pre-filed Staff and intervenor testimony is due in this proceeding. The premise under which the emergency request has been made is that the utility is currently subjected to financial hardship that requires immediate action, without the benefit of a complete analysis as to revenue requirement, cost classification, cost allocation, or rate design. The analysis pertaining to these various topics is deferred until the general rate case.

Yet despite the lack of opportunity to properly determine differential cost burdens, APS's approach would impose a significantly higher-than-average increase on industrial customers and high-load factor commercial customers. This impact is shown in Attachment KCH-3, and summarized in Table KCH-4, below. For example, a 75 percent load factor E-34 customer would experience a base rate increase of nearly **24 percent** under APS's proposal – nearly 70 percent higher than the 14 percent average advertised by APS.

Table KCH-4

Impact of APS Emergency Rate Design on Commercial and Industrial Customers

Rate schedule	Customer size (kW)	Load Factor	Rate Impact
E-32	100	35%	11.48%
E-32	100	55%	14.83%
E-32	100	75%	17.17%
E-32	500	35%	13.38%
E-32	500	55%	16.79%
E-32	500	75%	19.06%
E-32	1000	35%	13.66%
E-32	1000	55%	17.07%
E-32	1000	75%	19.32%
E-34	5000	55%	21.23%
E-34	5000	75%	23.69%
E-35	5000	55%	21.39%
E-35	5000	75%	24.06%

Q. Is the equal percentage approach you are recommending a typical design when base electric rates are increased on an interim basis?

A. Yes, it is very typical. In researching this issue for this proceeding, I have identified six instances in which state regulatory commissions have increased base electric rates on an interim basis during 2004-05. In four of the cases, the state regulatory commissions adopted equal percentage increases. In the fifth case (Hawaii) the Commission adopted a percentage increase approach that was differentiated by customer class. The sixth case (Wisconsin) involved a fuel cost re-opener that was triggered when actual fuel costs exceeded a previously-approved maximum. This adjustment was applied on a kWh basis. These decisions are summarized in Table KCH-5, below.

Table KCH-5

Rate Designs Adopted for Interim Rate Increases
2004-05

Date	Utility	State	Docket	Rate Design
2/20/04	Detroit Edison	Michigan	U-13808	Equal % subject to statutory caps
7/2/04	GVEA	Alaska	U-04-33(5)	Equal % on demand & energy
6/30/05	Interstate P&L	Minnesota	GRE-05-748	Equal % increase
9/27/05	Hawaiian Electric	Hawaii	04-0113	% increase by class
12/6/05	Wisconsin P&L	Wisconsin	6680-UR-114	kwh – correction to fuel $ forecast
12/30/05	Xcel Energy	Minnesota	E-002/GR-05-1428	Equal % surcharge on all bills

Q. Have you testified in other proceedings in which base rates were adjusted on an interim basis?

A. Yes, I have.

Q. What interim rate designs have been adopted in the proceedings in which you have been involved?

A. In 2003-04, I testified in a Detroit Edison interim rate proceeding in Michigan (listed above). In that case, I recommended, as did others, that any interim increase should be levied on an across-the-board equal percentage basis – the same recommendation I am making here. The equal-percentage approach was subsequently adopted by the Michigan Commission, subject to statutory rate caps for certain classes.[14]

In 2004, I participated in a rate proceeding in Alaska (also listed above), in which interim rates also were adopted. In that case, the interim increase was also collected through an equal percentage increase on all billing components, with the exception of the customer charge.[15]

Currently, I am participating in an Xcel Energy general rate proceeding in Minnesota (listed above). In that case, interim rates have been approved by the Minnesota Commission in the form of an across-the-board 7.25 percent surcharge on all customer bills.[16] The Minnesota Commission also made an interim adjustment to the energy charge which was netted against the utility's Fuel Clause Rider.

The consistency across these cases is clear: in awarding an interim rate increase, an equal percentage increase on all customers is very typical. Indeed, absent a record to properly determine that various customer groups should bear different burdens, it is the only reasonable approach to spreading an interim rate increase.

In my direct experience as an expert witness, the only material variation from this approach occurred as part of a settlement of a Puget Sound Energy

[14] "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.

[15] "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

[16] "In the Matter of the Application 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. E-002/GR-05-1428.

proceeding in 2001-02. In that case, the Washington Commission approved a multi-party stipulation that resolved numerous issues in the concurrent general rate case. That settlement incorporated an interim rate increase that increased all billing components on an equal percentage basis after first allocating costs between residential and non-residential customers.[17] However, even this variation contained many elements of the equal percentage approach.

Q. Are you personally familiar with other situations in which rate spread is determined in the absence of a record regarding class cost-of-service?

A. Yes. In Colorado, it is not unusual for general rate cases to be conducted in two phases: the first phase addresses revenue requirement and the second phase addresses cost-of-service, rate spread, and rate design. Upon determination of the first phase of the case, but prior to the resolution of the second phase, any base rate change is implemented via an equal percentage rider on all customers. Again, this approach is the most reasonable one to take in the absence of a record on cost-of-service.

Q. In this emergency proceeding, APS is claiming that the need for immediate relief is driven by increasing fuel and purchased power costs. Isn't that sufficient justification for levying any surcharge on a kWh basis?

A. No, it is not. While APS is claiming that increased fuel and purchased power costs are the driving forces behind its financial duress, the proposed emergency increase is associated with a general rate case filing, and is heavily colored by the potential cost consequences to customers with respect to APS's

[17] "2001 Puget Sound Energy Interim Rate Case," Washington Utilities and Transportation Commission, Docket Nos. UE-011570 and UE-011571.

future cost of capital if emergency relief is not provided. Thus, the emergency filing incorporates issues that have across-the-board cost implications, which is suggestive on its face of a proportionate cost burden.

Further, we cannot assume that the cost impacts that APS is experiencing translate into simplistic kWh impacts on all kWh: the proper allocation of any fuel and purchased power cost increases experienced by APS remains to be determined in the general rate case. For example, it is clear to me that APS's increased fuel and purchased power expenses are not uniform across all seasons and times-of-use. Simply allocating these costs on a kWh basis, as APS has done, assumes that a kWh consumed at 2 o'clock in the morning in April has the same cost responsibility for mitigating APS's emergency as a kWh consumed at 5 o'clock on a July afternoon. This is clearly wrong. Consequently, even if APS's financial duress is driven by rising fuel and purchased power costs, it does not follow that the most appropriate interim rate design would be a flat kWh charge levied on all kWh – particularly when significant groups of customers would experience rate impacts that are 70 percent greater than the average under such an approach.

Q. But isn't an equal percentage increase on all customer rates also simplistic?

A. Yes, it is; but an equal-percentage approach has the attribute of ensuring that customers share the cost impact in the same proportion, which in the absence of a cost-of-service record, is the most reasonable approach that can be taken.

Q. Does this conclude your direct testimony?

A. Yes, it does.

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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

"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 filed 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 and July 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 delivered March 27, 1987, on behalf of State of Utah, 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.

Estimated Emergency Increase Needed to Achieve 18% FFO/Debt in 2006

Ln No.	Funds From Operations / Adjusted Average Total Debt	As of 12/31/2006	Source
	Funds From Operations (FFO)		
1	Adjusted Net Income	200,723	See Note 1
2	Track B Disallowance	0	See Note 1
3	Depreciation and Amortization (Excl. Nuc. Fuel)	352,104	See Note 1
4	Nuclear Fuel Amortization	29,581	See Note 1
5	Cash Decommissioning Fund Contributions	(19,210)	See Note 1
6	AFUDC Equity	(10,063)	See Note 1
7	Capitalized Interest	(7,029)	See Note 1
8	Deferred Income Taxes	22,735	See Note 1
9	Deferred Income Taxes - AECC Adjustment for PSA Revenue	6,771	See Ln. 28
10	Deferred Income Taxes - AECC Adj. for Emergency Rev. Needed to Achieve Target FFO/Debt	(49,115)	See Ln. 35
11	Deferred Fuel	(48,289)	See Note 1
12	Deferred Fuel - AECC Adjustment for PSA Revenue	(17,340)	See Ln. 26
13	**Deferred Income Taxes - AECC Adj. for Emergency Rev. Needed to Achieve Target FFO/Debt**	**125,772**	See Ln. 34
14	**Adjusted Fund From Operations**	586,641	= Sum (Ln. 1: Ln. 13)
	Adjusted Average Total Debt		
15	Adjusted Total Debt (2006)	3,459,117	See Note 1
16	Adjusted Total Debt (2005)	3,059,114	See Note 1
17	2 Year Adjusted Total Debt	6,518,231	= Ln. 15 + Ln. 16
18	**Adjusted Average Total Debt**	3,259,116	= Ln 17 ÷ 2
19	*Target FFO/Adjusted Average Total Debt*	$\boxed{18.0\%}$	Target Percent = Ln. 14 ÷ Ln. 18

Note 1: Data Source - APS Response to ACC Staff Data Request No. 4-34.

KCH-2, PAGE 1 SUPPORTING CALCULATIONS:

Ln No.	IMPACT OF CHANGE IN PSA ADJUSTOR & SURCHARGE REV.	As of 12/31/2006	Source
	For 2006, APS Revenue Calculation Assumes:		
20	PSA Adjustor Revenue	88,111	See Note 2
21	PSA Surcharge Revenue	43,612	See Note 2
22	Total	131,723	
	Note 2: Data Source - APS Response to ACC Staff Data Request No. 1-12.		
	For 2006, AECC Revenue Calculation Assumes:		
23	PSA Adjustor Revenue	103,231	Attachment KCH-2, Sch. 2
24	PSA Part I Surcharge Revenue	11,151	Attachment KCH-2, Sch. 2
25	Total	114,383	
26	2006 PSA Revenue Difference	(17,340)	= Ln. 25 - Ln. 22
27	Effective Fed. & State Tax Rate	39.05%	See Note 4
28	Tax Impact of PSA Revenue Change	6,771	= -(Ln. 26 x Ln. 27)
29	Net Change to FFO from PSA Revenue Change	(10,569)	= Ln 26 + Ln. 28
	AECC PROPOSED CHANGE IN INTERIM RATE REVENUE		
30	Required Adjusted Net Income to Achieve FFO/Debt of 18%	586,641	=18% x Ln. 18
31	APS Assumed Adjusted Funds From Operation with PSA FFO Adj.	520,552	See Note 3
32	Net Change to APS FFO from PSA Revenue Change	(10,569)	= Ln. 29
33	AECC Proposed Change in Adjusted FFO	76,658	= Ln. 30 - (Ln. 31 + Ln. 29)
34	Net to Gross Conversion Factor	1.6407	See Note 4
35	Change in Deferred Fuel Balance from Interim Rate Revenue	125,772	= Ln. 33 x Ln. 34
36	Change in Deferred Tax Balance from Interim Rate Revenue	(49,115)	= -(Ln. 35 - 33)

Note 3: Data Source - APS Response to ACC Staff Data Request No. 1-4.
Note 4: Data Source - APS Nov. 2005 Rate Case Filing, Schedule C-3, p. 1 of 1, ACC Docket No. E-01345A-05-0816.

Ln No.	INTERIM PERCENT INCREASE CALCULATION	Amount	Source
37	APS Requested Annual Interim Increase Amount	298,700	APS Attachment PME-1
38	Total Annual Retail Revenue @ Current Rates	2,127,322	See Note 5
39	APS Requested Interim Increase Percent	14.0%	= Ln. 37 ÷ Ln. 38
	Note 5: Data Source - APS Nov. 2005 Rate Case Filing, Schedule H-1, p. 1 of 1, ACC Docket No. E-01345A-05-0816.		
40	AECC Proposed Interim Rate Revenue	125,772	See Ln. 35
41	APS additional revenue from interim rates (5/06 thru 12/06)	226,288	See Note 6
42	AECC Percent of APS Revenues	55.6%	= Ln. 40 ÷ Ln. 41
43	AECC Proposed Percent Increase (est.)	$\boxed{7.8\%}$	= Ln. 39 x Ln. 42

Note 6: Data Source - APS Response to ACC Staff Data Request No. 1-12.

Estimated 2006 PSA Adjustor and PSA Surcharge Revenues

Ln No.		Jan-06	Feb-06	Mar-06	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	Oct-06	Nov-06	Dec-06	Total
1	Projected Retail Sales (MWhs)[1]	2,094,795	1,791,633	1,858,076	1,883,287	2,366,570	2,737,237	3,190,865	3,148,779	2,612,605	2,135,934	1,903,190	2,179,666	27,902,637
	Annual Adjustor Collections													
2	Annual Adjustor Rate ($/kWh)	0.00000	0.00400	0.00400	0.00400	0.00400	0.00400	0.00400	0.00400	0.00400	0.00400	0.00400	0.00400	
3	Annual Adjustor Collections ($)		7,166,532	7,432,304	7,533,148	9,466,280	10,948,948	12,763,460	12,595,116	10,450,420	8,543,736	7,612,760	8,718,664	103,231,368
	Annual PSA Surcharge													
4	Part I Surcharge Rate - $15.3M/Yr ($/kWh)	0.00000	0.00000	0.00000	0.00000	0.00055	0.00055	0.00055	0.00055	0.00055	0.00055	0.00055	0.00055	
5	Annual Surcharge Colloection ($)					1,301,614	1,505,480	1,754,976	1,731,828	1,436,933	1,174,764	1,046,755	1,198,816	11,151,165
6	Total PSA Adjustor & PSA Part I Surcharge ($)	0	7,166,532	7,432,304	7,533,148	10,767,894	12,454,428	14,518,436	14,326,944	11,887,353	9,718,500	8,659,515	9,917,480	114,382,533
7	Part II Surcharge Rate - $44.6M/Yr ($/kWh)	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00160	0.00160	0.00160	0.00160	0.00160	0.00160	
8	Annual Surcharge Colloection ($)							5,105,384	5,038,046	4,180,168	3,417,494	3,045,104	3,487,466	24,273,662
9	Total PSA Adjustor & PSA Part I&II Surcharges ($)	0	7,166,532	7,432,304	7,533,148	10,767,894	12,454,428	19,623,820	19,364,991	16,067,521	13,135,994	11,704,619	13,404,946	138,656,196

Note 1: Data Source: APS Response to ACC Staff Data Request No. 1-12.

Impact of APS Proposal on Commercial and Industrial Customers

E-32 Current Rates (w/out PSA Adjustor) vs. Rates w/APS Proposed Emergency Energy Charge			
Annual % & Annual $ Increase	Demand kW		
Load Factor	100	500	1,000
35.00%	11.48%	13.38%	13.66%
	$3,422	$17,110	$34,220
55.00%	14.83%	16.79%	17.07%
	$5,377	$26,887	$53,774
75.00%	17.17%	19.06%	19.32%
	$7,333	$36,664	$73,328

Impact of APS Proposal on Commercial and Industrial Customers

E-34 Current Rates (w/out PSA Adjustor) vs. Rates w/APS Proposed Emergency Energy Charge			
Annual % & Annual $ Increase	Demand kW		
Load Factor	3,000	5,000	10,000
35.00%	17.28%	17.38%	17.46%
	$102,659	$171,098	$342,196
55.00%	21.14%	21.23%	21.31%
	$161,321	$268,868	$537,737
75.00%	23.60%	23.69%	23.75%
	$219,983	$366,639	$733,278

Impact of APS Proposal on Commercial and Industrial Customers

E-35 Current Rates (w/out PSA Adjustor) vs. Rates w/APS Proposed Emergency Energy Charge			
Annual % & Annual $ Increase	Demand kW		
Load Factor	3,000	5,000	10,000
35.00%	17.18%	17.28%	17.36%
	$102,659	$171,098	$342,196
55.00%	21.30%	21.39%	21.47%
	$161,321	$268,868	$537,737
75.00%	23.97%	24.06%	24.13%
	$219,983	$366,639	$733,278

EXHIBIT
AECC-2
Admitted

SUMMARY OF KEVIN C. HIGGINS DIRECT TESTIMONY

My testimony addresses APS's request for an emergency interim rate increase and recommends adjustments to the Company's proposal that I believe are necessary to ensure results that are just and reasonable.

In my opinion, it is appropriate to allow an emergency interim rate increase sufficient to permit APS to attain a FFO/Debt Ratio of 18 percent in 2006. I calculate that this ratio can be attained through an emergency rate increase of $126 million in calendar-year 2006, which is 55.6 percent of the emergency increase requested by APS. If implemented on May 1, 2006, this incremental revenue can be collected with an emergency rate increase of approximately 7.8 percent (as measured against rates exclusive of PSA charges). In making this calculation, I have assumed that the Step I PSA Surcharge requested by APS on February 2, 2006, is implemented on May 1, 2006, an action that I believe is appropriate under the PSA mechanism

I disagree with APS's proposal to establish a new base energy rate in this proceeding, as this would allow APS to avoid having to absorb its 10 percent share of the cost differential between the current base energy rate and its new proposed energy rate. Instead, the base energy rate should remain at the level established in the last general rate case, and any revenues collected from the emergency surcharge should be applied as a credit against the PSA Annual Tracking Account. In this way, the surcharge could be set to recover the 90 percent cost-share assignable to customers, with the remaining 10 percent assigned to APS per the PSA mechanism. The new base energy rate would then be established in the upcoming general rate case.

The flat, cents-per-kWh design of APS's proposed interim surcharge is not reasonable in the context of an emergency filing. Although APS has advertised its proposed increase as being "14 percent", the design of the Company's proposal would actually raise rates for many industrial customers by well over 20 percent. In my opinion, it is inappropriate in the context of an emergency rate filing – with its limited record and restricted opportunity for analysis – to levy disproportionate increases on different customer groups. If an emergency increase is granted, the only appropriate rate design would be an <u>equal percentage increase</u> for all customer groups, which consistent with other interim increases documented in my testimony. This can be achieved through an equal percentage surcharge on total customer bills, which is the approach I recommend here.

In summary, I believe an emergency rate increase is in the public interest, but should be modified in four important ways from what APS has proposed:

- The emergency increase should be smaller than APS has requested;

- The base energy rate should **not** be changed until the resolution of the general rate case;
- The emergency surcharge should be levied on an equal percentage basis; and
- Any revenues collected from the emergency surcharge should be applied as a credit against the PSA Annual Tracking Account.

EXHIBIT
AECC-3
Admitted

Estimated Emergency Increase Needed to Achieve 18% FFO/Debt in 2006

Update to Attachment KCH-2 to Reflect Updated Market Price Assumptions contained in APS Rebuttal Testimony filed March 10, 2006

Reflects $39 Million Reduction in APS Projected Net Power Costs for 2006
($000)

Ln No.	Funds From Operations / Adjusted Average Total Debt	As of 12/31/2006	Source
	Funds From Operations (FFO)		
1	Adjusted Net Income per APS Data Response STF 4-34	200,723	See Note 1
2	Track B Disallowance	0	See Note 1
3	Depreciation and Amortization (Excl. Nuc. Fuel)	352,104	See Note 1
4	Nuclear Fuel Amortization	29,581	See Note 1
5	Cash Decommissioning Fund Contributions	(19,210)	See Note 1
6	AFUDC Equity	(10,063)	See Note 1
7	Capitalized Interest	(7,029)	See Note 1
8	Deferred Income Taxes per APS Data Response STF 4-34	22,735	See Note 1
9	Deferred Income Taxes - AECC Adjustment for PSA Revenue Changes	6,771	See Ln. 28
9A *	Deferred Income Taxes - AECC Adjustment for APS Rebuttal Pricing Update	(15,230)	= -39.05% x Ln 12A
10 *	Deferred Income Taxes - AECC Adj. for Emergency Revenue Needed to Achieve Target FFO/Debt	(33,885)	See Ln. 35
11	Deferred Fuel per APS Data Response STF 4-34	(48,289)	See Note 1
12	Deferred Fuel - AECC Adjustment for PSA Revenue Changes	(17,340)	See Ln. 26
12A *	Deferred Fuel - AECC Adjustment for APS Rebuttal Pricing Update	39,000	= $39,000
13 *	**AECC Adj. for Emergency Revenue Needed to Achieve Target FFO/Debt**	**86,772**	See Ln. 34
14	**Adjusted Fund From Operations**	586,641	= Sum (Ln. 1: Ln. 13)
	Adjusted Average Total Debt		
15	Adjusted Total Debt (2006)	3,459,117	See Note 1
16	Adjusted Total Debt (2005)	3,059,114	See Note 1
17	2 Year Adjusted Total Debt	6,518,231	= Ln. 15 + Ln. 16
18	**Adjusted Average Total Debt**	3,259,116	= Ln 17 ÷ 2
19	*Target FFO/Adjusted Average Total Debt*	$\boxed{18.0\%}$	Target Percent = Ln. 14 ÷ Ln. 18

Note 1: Data Source - APS Response to ACC Staff Data Request No. 4-34.

*** Designates an adjustment relative to Attachment KCH-2 to reflect updated market price assumptions contained in APS' rebuttal testimony filed March 10, 2006.**

SUPPLEMENTAL ATTACHMENT KCH-4, PAGE 1 SUPPORTING CALCULATIONS:

Ln No.	IMPACT OF CHANGE IN PSA ADJUSTOR & SURCHARGE REV.	As of 12/31/2006	Source
	For 2006, APS Revenue Calculation Assumes:		
20	PSA Adjustor Revenue	88,111	See Note 2
21	PSA Surcharge Revenue	43,612	See Note 2
22	Total	131,723	
	Note 2: Data Source - APS Response to ACC Staff Data Request No. 1-12.		
	For 2006, AECC Revenue Calculation Assumes:		
23	PSA Adjustor Revenue	103,231	AECC Rev. Workpaper
24	PSA Part I Surcharge Revenue	11,151	AECC Rev. Workpaper
25	Total	114,383	
26	2006 PSA Revenue Difference	(17,340)	= Ln. 25 - Ln. 22
27	Effective Fed. & State Tax Rate	39.05%	See Note 4
28	Tax Impact of PSA Revenue Change	6,771	= -(Ln. 26 x Ln. 27)
29	Net Change to FFO from PSA Revenue Change	(10,569)	= Ln 26 + Ln. 28
	AECC PROPOSED CHANGE IN EMERGENCY RATE REVENUE		
30	Required Adjusted Net Income to Achieve FFO/Debt of 18%	586,641	=18% x Ln. 18
31	APS Assumed Adjusted Funds From Operation with PSA FFO Adj.	520,552	See Note 3
32	Net Change to APS FFO from PSA Revenue Change	(10,569)	= Ln. 29
32A *	Net Change to APS FFO for APS' Rebuttal Pricing Update	23,771	= Ln 9A + Ln.12A
33	AECC Proposed Change in Adjusted FFO	52,887	= Ln. 30 - (Ln. 31 + Ln. 32 + Ln 32A)
34	Net to Gross Conversion Factor	1.6407	See Note 4
35	Change in Deferred Fuel Balance from Emergency Rate Revenue	86,772	= Ln. 33 x Ln. 34
36	Change in Deferred Tax Balance from Emergency Rate Revenue	(33,885)	= -(Ln. 35 - Ln. 33)

Note 3: Data Source - APS Response to ACC Staff Data Request No. 1-4.
Note 4: Data Source - APS Nov. 2005 Rate Case Filing, Schedule C-3, p. 1 of 1, ACC Docket No. E-01345A-05-0816.

Ln No.	AECC EMERGENCY PERCENT INCREASE CALCULATION	Amount	Source
37	AECC Proposed Emergency Rate Revenue	86,772	= Ln. 35
38	APS Present Rate Revenue (5/06 thru 12/06)	1,630,001	See APS Response to AECC DR No. 3.1
39	AECC Proposed Percent Increase	5.3%	= Ln. 37 ÷ Ln. 38

*** Designates an adjustment relative to Attachment KCH-2 to reflect updated market price assumptions contained in APS' rebuttal testimony filed March 10, 2006.**

AECC Late-Filed Exhibit 4

Response to Commissioner Gleason:

December 31, 2006 Tracking Account Balance under AECC-Recommended Emergency Increase:

@ $85 million increase during calendar-year 2006: $160 million (same as APS estimate)

@ $126 million increase during calendar-year 2006: $119 million

Response to Chairman Hatch-Miller:

AECC generally concurs with APS's estimates of the impacts of adopting various increases in the PSA Adjustor.

EXHIBIT
tabbies
AECC-4
admitted

EXHIBIT
AECC- 5
Admitted

ARIZONA CORPORATION COMMISSION STAFF'S
FOURTH SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY
DOCKET NO. E-01345A-06-0009
FEBRUARY 7, 2006

STF 4.34 Has APS made any calculations of 2006 cash flow based on any assumed levels and timing of rate relief in 2006?

If so, please describe the sensitivity testing that APS has run, and provide the results. Include supporting workpapers. Include all Excel files and supporting calculations.

If not, explain fully why not.

Response:

See attachment APS07013 DEB_WP 21 from the January base rate filing attachment to SFT 4.6 that includes the calculation of FFO for 2006 of $520 million. These calculations assume for 2006, APS would receive $133 million of combined adjustor and surcharge revenue. If APS is granted the 14% interim base increase April 1st as requested, the $520m 2006 FFO figure would increase to approximately $665 million.

\\

Income Statement
Present Base Rates with PSA
($000)

APS	Year 2005	Year 2006	Year 2007
	Projected		
REVENUES	**$ 2,292,361**	**$ 2,533,439**	**$ 2,680,704**
Total Cost of Revenues	**697,213**	**911,809**	**1,040,116**
GROSS MARGIN	**1,595,148**	**1,621,630**	**1,640,588**
OTHER OPERATING EXPENSES			
Operations & Maintenance	596,130	654,285	726,581
Depreciation & Amortization (a)	465,574	352,104	377,099
Other Taxes	125,102	142,487	154,690
Total Other Operating Expenses	**1,186,806**	**1,148,876**	**1,258,370**
INTEREST AND OTHER EXPENSES			
Interest Expense	153,084	165,195	190,157
AFUDC Debt / Capitalized Interest	(7,780)	(7,029)	(8,010)
AFUDC Equity	(10,948)	(10,063)	(11,467)
Other (Income) Subtotal	(20,180)	(10,232)	(12,198)
Other Expense Subtotal	13,564	12,998	18,735
INCOME BEFORE INCOME TAXES	**280,603**	**321,885**	**205,001**
INCOME TAXES	103,149	121,162	73,856
NET INCOME	**$ 177,453**	**$ 200,723**	**$ 131,145**

a) $138,562 track B write-off shown on depreciation as a non-cash expense

EXHIBIT
AECC-6
admitted

FFO & Net Cash Flow Ratios
Present Base Rates with PSA
($000)

APS	Year 2005	Year 2006	Year 2007
	Projected		
FUNDS FROM OPERATIONS:			
NET INCOME	177,453	200,723	131,145
Plus:			
Depreciation & Amortization	465,574	352,104	377,099
(2005 includes $138,562 track b write-off (non-cash))			
Nuclear Fuel	28,474	29,581	30,837
Deferred Tax	(10,868)	22,735	(3,403)
Less:			
Nuc Decom Funding	17,268	19,210	19,210
Deferred Fuel	165,000	48,289	(13,788)
AFUDC Debt / Capitalized Interest	7,780	7,029	8,010
AFUDC Equity	10,948	10,063	11,467
FUNDS FROM OPERATIONS (D)	**459,637**	**520,552**	**510,779**
Common Dividends	170,000	170,000	170,000
NET CASH FLOW	**289,637**	**350,552**	**340,779**
CAPITAL EXPENDITURES:			
Construction Expenditures	804,892	644,043	710,052
Capitalized Property Taxes	5,634	4,508	4,970
Constr. Exp. + Cap. Ptax	**810,526**	**648,551**	**715,022**
ADJUSTED TOTAL DEBT:			
Long Term Debt	2,432,273	2,680,976	3,235,015
Current Maturities of Long-Term Debt	134,942	51,247	51,247
Short-term Debt		261,172	97,206
Palo Verde Lease Balance	341,899	317,722	291,747
Imputed PPA Debt on SRP T&C	150,000	148,000	148,000
Imputed PPA Debt - New			152,209
Adjusted Total Debt (E)	**3,059,114**	**3,459,117**	**3,975,423**
2 PT. Avg. Total Debt (F)	**3,114,450**	**3,259,115**	**3,717,270**
S&P BENCHMARKS			
ADJ. TOTAL DEBT / TOTAL CAPITAL (E / G)	**50.1%**	**53.3%**	**56.9%**
FFO / ADJUSTED AVG. TOTAL DEBT (D / F)	**14.8%**	**16.0%**	**13.7%**
ADJUSTED TOTAL DEBT with imputed debt	3,059,114	3,459,117	3,975,423
PREFERRED EQUITY			
COMMON EQUITY	3,052,590	3,029,313	3,005,458
ADJ. TOTAL CAPITAL (G)	6,111,704	6,488,430	6,980,881

Coverage Ratio
Present Base Rates with PSA
($000)

APS	Year 2005	Year 2006	Year 2007
	Projected		
FUNDS FROM OPERATIONS (D)	459,637	520,552	510,779
Interest Expense	153,084	165,195	190,157
PV2 S/L Imputed Interest (S&P method)	35,873	33,633	31,165
Imputed PPA Interest on SRP T&C	15,000	14,800	14,800
Imputed PPA Interest - New			15,221
ADJ. FUNDS FROM OPERATIONS (X)	**663,593**	**734,180**	**762,121**
FIXED CHARGES:			
Interest Expense	153,084	165,195	190,157
PV2 S/L Imputed Interest (S&P method)	35,873	33,633	31,165
Imputed PPA Interest on SRP T&C	15,000	14,800	14,800
Imputed PPA Interest - New			15,221
FIXED CHARGES (Z)	**203,957**	**213,628**	**251,342**
ADJ. FFO INTEREST COVERAGE (X/Z)	**3.3**	**3.4**	**3.0**
Return on Equity	**6.8%**	**6.6%**	**4.3%**

Estimated Emergency Increase Needed to Achieve 18% FFO/Debt in 2006

Update to Attachment KCH-2 to Reflect Updated Market Price Assumptions contained in APS Rebuttal Testimony filed March 10, 2006

Reflects $41 Million Reduction in APS Projected Net Power Costs for 2006 and APS $41 Million Estimated Costs for the Extended Palo Verde 2006 Outage

($000)

Ln No.	Funds From Operations / Adjusted Average Total Debt	As of 12/31/2006	Source
	Funds From Operations (FFO)		
1	Adjusted Net Income per APS Data Response STF 4-34	200,723	See Note 1
2	Track B Disallowance	0	See Note 1
3	Depreciation and Amortization (Excl. Nuc. Fuel)	352,104	See Note 1
4	Nuclear Fuel Amortization	29,581	See Note 1
5	Cash Decommissioning Fund Contributions	(19,210)	See Note 1
6	AFUDC Equity	(10,063)	See Note 1
7	Capitalized Interest	(7,029)	See Note 1
8	Deferred Income Taxes per APS Data Response STF 4-34	22,735	See Note 1
9	Deferred Income Taxes - AECC Adjustment for PSA Revenue Changes	6,771	See Ln. 28
9A *	Deferred Income Taxes - AECC Adjustment for APS Rebuttal Pricing Update	(16,011)	= -39.05% x Ln 12A
9B *	Deferred Income Taxes - AECC Adjustment for Extended Palo Verde Outage	16,011	= -39.05% x Ln 12B
10 *	Deferred Income Taxes - AECC Adj. for Emergency Revenue Needed to Achieve Target FFO/Debt	(49,115)	See Ln. 36
11	Deferred Fuel per APS Data Response STF 4-34	(48,289)	See Note 1
12	Deferred Fuel - AECC Adjustment for PSA Revenue Changes	(17,340)	See Ln. 26
12A *	Deferred Fuel - AECC Adjustment for APS Rebuttal Pricing Update	41,000	= $41,000
12B *	Deferred Fuel - AECC Adjustment for Extended Palo Verde Outage	(41,000)	APS Est. Extended Palo Verde Outage Cost
13 *	**AECC Adj. for Emergency Revenue Needed to Achieve Target FFO/Debt**	**125,772**	See Ln. 35
14	**Adjusted Fund From Operations**	586,641	= Sum (Ln. 1: Ln. 13)
	Adjusted Average Total Debt - Holding APS Debt Levels Constant (Conservative Assumption)		
15	Adjusted Total Debt (2006)	3,459,117	See Note 1
16	Adjusted Total Debt (2005)	3,059,114	See Note 1
17	2 Year Adjusted Total Debt	6,518,231	= Ln. 15 + Ln. 16
18	**Adjusted Average Total Debt**	3,259,116	= Ln 17 ÷ 2
19	*Target FFO/Adjusted Average Total Debt*	18.0%	Target Percent = Ln. 14 ÷ Ln. 18

Note 1: Data Source - APS Response to ACC Staff Data Request No. 4-34.

*** Designates an adjustment relative to Attachment KCH-2 to reflect updated market price assumptions contained in APS' rebuttal testimony filed March 10, 2006 and cost estimates for the extended Palo Verde 2006 outage.**

EXHIBIT
tabbies
AECC-7
admitted

SUPPLEMENTAL ATTACHMENT KCH-5, PAGE 1 SUPPORTING CALCULATIONS:

Ln No.	IMPACT OF CHANGE IN PSA ADJUSTOR & SURCHARGE REV.	As of 12/31/2006	Source
	For 2006, APS Revenue Calculation Assumes:		
20	PSA Adjustor Revenue	88,111	See Note 2
21	PSA Surcharge Revenue	43,612	See Note 2
22	Total	131,723	
	Note 2: Data Source - APS Response to ACC Staff Data Request No. 1-12.		
	For 2006, AECC Revenue Calculation Assumes:		
23	PSA Adjustor Revenue	103,231	AECC Rev. Workpaper
24	PSA Part I Surcharge Revenue	11,151	AECC Rev. Workpaper
25	Total	114,383	
26	2006 PSA Revenue Difference	(17,340)	= Ln. 25 - Ln. 22
27	Effective Fed. & State Tax Rate	39.05%	See Note 4
28	Tax Impact of PSA Revenue Change	6,771	= -(Ln. 26 x Ln. 27)
29	Net Change to FFO from PSA Revenue Change	(10,569)	= Ln 26 + Ln. 28
	AECC PROPOSED CHANGE IN EMERGENCY RATE REVENUE - HOLDING APS DEBT LEVELS CONSTANT		
30	Required Adjusted Net Income to Achieve FFO/Debt of 18%	586,641	=18% x Ln. 18
31	APS Assumed Adjusted Funds From Operation with PSA FFO Adj.	520,552	See Note 3
32	Net Change to APS FFO from PSA Revenue Change	(10,569)	= Ln. 29
32A *	Net Change to APS FFO for APS' Rebuttal Pricing Update	24,990	= Ln 9A + Ln.12A
32B *	Net Change to APS FFO for Extended Palo Verde 2006 Outage	(24,990)	= Ln 9B + Ln.12B
33	AECC Proposed Change in Adjusted FFO	76,658	= Ln. 30 - (Ln. 31 + Ln. 32 + Ln 32A+Ln 32B)
34	Net to Gross Conversion Factor	1.6407	See Note 4
35	Change in Deferred Fuel Balance from Emergency Rate Revenue	125,772	= Ln. 33 x Ln. 34
36	Change in Deferred Tax Balance from Emergency Rate Revenue	(49,115)	= -(Ln. 35 - Ln. 33)

Note 3: Data Source - APS Response to ACC Staff Data Request No. 1-4.
Note 4: Data Source - APS Nov. 2005 Rate Case Filing, Schedule C-3, p. 1 of 1, ACC Docket No. E-01345A-05-0816.

Ln No.	AECC EMERGENCY PERCENT INCREASE CALCULATION - HOLDING APS DEBT LEVELS CONSTANT	Amount	Source
37	AECC Proposed Emergency Rate Revenue	125,772	= Ln. 35
38	APS Present Rate Revenue (5/06 thru 12/06)	1,630,001	See APS Response to AECC DR No. 3.1
39	AECC Proposed Percent Increase	7.7%	= Ln. 37 ÷ Ln. 38

*** Designates an adjustment relative to Attachment KCH-2 to reflect updated market price assumptions contained in APS' rebuttal testimony filed March 10, 2006 and cost estimates for the extended Palo Verde 2006 outage.**

FFO/DEBT RATIOS ASSOCIATED WITH AECC RECOMMENDED
$126 MILLION EMERGENCY RATE INCREASE

Ln No.	FFO/DEBT - HOLDING APS DEBT CONSTANT	As of 12/31/2006	Source
40	**Adjusted Fund From Operations**	586,641	See KCH-5, p. 1, Ln. 14
	Adjusted Average Total Debt		
41	Adjusted Total Debt (2006)	3,459,117	See KCH-5, p. 1, Ln. 15
42	Adjusted Total Debt (2005)	3,059,114	See KCH-5, p. 1, Ln. 16
43	2 Year Adjusted Total Debt	6,518,231	= Ln. 41 + Ln. 42
44	**Adjusted Average Total Debt**	3,259,116	= Ln 43 ÷ 2
45	*FFO/Adjusted Average Total Debt*	**18.0%**	= Ln. 40 ÷ Ln. 44
	FFO/DEBT - REFLECTING EXPECTED REDUCTION IN PROJECTED APS DEBT LEVEL		
	Adjusted Average Total Debt		
46	Adjusted Total Debt (2006)	3,393,028	= Ln. 41 - (Ln. 40 - Ln. 31)
47	Adjusted Total Debt (2005)	3,059,114	= Ln. 42
48	2 Year Adjusted Total Debt	6,452,142	= Ln. 46 + Ln. 47
49	**Adjusted Average Total Debt**	3,226,071	= Ln 48 ÷ 2
50	*FFO/Adjusted Average Total Debt*	**18.2%**	= Ln. 40 ÷ Ln. 49

Estimated Emergency Increase Needed to Achieve 18% FFO/Debt in 2006

REFLECTING EXPECTED REDUCTION IN PROJECTED APS DEBT LEVELS

Update to Attachment KCH-2 to Reflect Updated Market Price Assumptions contained in APS Rebuttal Testimony filed March 10, 2006

Reflects $41 Million Reduction in APS Projected Net Power Costs for 2006 and APS $41 Million Estimated Costs for the Extended Palo Verde 2006 Outage

($000)

Ln No.	Funds From Operations / Adjusted Average Total Debt	As of 12/31/2006	Source
	Funds From Operations (FFO)		
51	Adjusted Net Income per APS Data Response STF 4-34	200,723	See Note 1
52	Track B Disallowance	0	See Note 1
53	Depreciation and Amortization (Excl. Nuc. Fuel)	352,104	See Note 1
54	Nuclear Fuel Amortization	29,581	See Note 1
55	Cash Decommissioning Fund Contributions	(19,210)	See Note 1
56	AFUDC Equity	(10,063)	See Note 1
57	Capitalized Interest	(7,029)	See Note 1
58	Deferred Income Taxes per APS Data Response STF 4-34	22,735	See Note 1
59	Deferred Income Taxes - AECC Adjustment for PSA Revenue Changes	6,771	See Ln. 28
59A *	Deferred Income Taxes - AECC Adjustment for APS Rebuttal Pricing Update	(16,011)	= -39.05% x Ln 12A
59B *	Deferred Income Taxes - AECC Adjustment for Extended Palo Verde Outage	16,011	= -39.05% x Ln 12B
60 *	Deferred Income Taxes - AECC Adj. for Emergency Revenue Needed to Achieve Target FFO/Debt	(45,618)	= -39.05% x Ln 63
61	Deferred Fuel per APS Data Response STF 4-34	(48,289)	See Note 1
62	Deferred Fuel - AECC Adjustment for PSA Revenue Changes	(17,340)	See Ln. 26
62A *	Deferred Fuel - AECC Adjustment for APS Rebuttal Pricing Update	41,000	= $41,000
62B *	Deferred Fuel - AECC Adjustment for Extended Palo Verde Outage	(41,000)	APS Est. Extended Palo Verde Outage Cost
63 *	**AECC Adj. for Emergency Revenue Needed to Achieve Target FFO/Debt**	**116,819**	AECC Emergency Rate Increase
64	**Adjusted Fund From Operations**	581,184	= Sum (Ln. 51: Ln. 63)
	Adjusted Average Total Debt - Reflecting Reduction in Projected APS Debt Levels		
65	Adjusted Total Debt (2006)	3,398,485	= Ln. 41 - (Ln. 64 - Ln. 31)
66	Adjusted Total Debt (2005)	3,059,114	See Note 1
67	2 Year Adjusted Total Debt	6,457,599	= Ln. 65 + Ln. 66
68	**Adjusted Average Total Debt**	3,228,800	= Ln 67 ÷ 2
69	*Target FFO/Adjusted Average Total Debt*	18.0%	Target Percent = Ln. 64 ÷ Ln. 68

Note 1: Data Source - APS Response to ACC Staff Data Request No. 4-34.

*** Designates an adjustment relative to Attachment KCH-2 to reflect updated market price assumptions contained in APS' rebuttal testimony filed March 10, 2006 and cost estimates for the extended Palo Verde 2006 outage.**

Ln No.	AECC EMERGENCY PERCENT INCREASE CALCULATION - REFLECTING REDUCTION IN PROJECTED APS DEBT LEVELS	Amount	Source
70	AECC Proposed Emergency Rate Revenue	116,819	= Ln. 63
71	APS Present Rate Revenue (5/06 thru 12/06)	1,630,001	See APS Response to AECC DR No. 3.1
72	AECC Proposed Percent Increase	7.2%	= Ln. 70 ÷ Ln. 71

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Transcript Exhibit(s)

Docket #(s): E-01345A-06-0009

Exhibit # : EBEW-1

APS / Interim Rates E-01345A-06-0009
March 20 through 29, 2006
Volumes I through VIII

IBEW
EXHIBIT
No. 1

Bob DeSpain's prefiled testimony

EXHIBIT IBEW-1 Admitted

Q1. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A1. Robert E. DeSpain. My business address is 5818 North 7th Street, Suite 201, Phoenix, Arizona 85014.

Q2. PLEASE DESCRIBE YOUR RECENT EMPLOYMENT.

A2. I am the Business Manager/Financial Secretary for Intervenor Local Union 387, International Brotherhood of Electrical Workers, AFL-CIO, CLC ("IBEW Local 387"). The position of Business Manager/Financial Secretary is an elected union position, and I was elected to my present position in 2004. Because all IBEW local unions have a person holding the position called "President," is common for persons outside of our organization to believe that the "President" is the principal officer of the Local. That is not the case. Article 17, §§ 4 and 8 of the Constitution of the International Brotherhood of Electrical Workers, AFL-CIO clearly states that the Business Manager/Financial Secretary is the "principal officer" of any IBEW Local Union.

Prior to my recent election, I was employed by Arizona Public Service Company ("APS") for twenty-six (26) years in a variety of bargaining unit positions, the last of which was as a Chromemoly Welder at the Cholla Power Plant. While employed at APS, I was a very active member of IBEW Local 387, including having been a member of IBEW Local 387's Executive Board for many years.

Q3. WHO IS IBEW LOCAL 387?

A3. IBEW Local 387 is a labor organization which, for the most part, represents non-managerial utility workers throughout most of the State of Arizona. For example, IBEW Local 387 is the duly elected and recognized exclusive bargaining agent for a substantial number of employees of Arizona Water Company, Graham County Electric Cooperative, Inc., Navopache Electric Cooperative, Inc., and the Santa Cruz District of UniSource Energy Corporation ("UniSource") f/k/a Citizens Communications Company. IBEW Local 387 is also the duly elected and recognized exclusive bargaining agent for approximately two-thousand (2,000) employees of APS. IBEW Local 387 and APS have entered into a long series of collective bargaining agreements dating back to 1945 concerning rates of pay, wages, hours of employment, and other terms and conditions of employment.

Q4. DO YOU BELIEVE APS IS A RESPONSIBLE CORPORATE CITIZEN?

A4. Absolutely. While by no means perfect, the relationship between IBEW Locals 387 and APS is one which is mature and stable. It is clear that this stability has enured to the benefit of APS, its employees, and customers.

In my opinion, the importance of the relationship between a public service corporation and its employees cannot be overstated. Acrimonious relations between a public service corporation and the certified representative of its employees will almost certainly hinder the company's ability to provide safe, reasonable, and adequate service. An acrimonious relationship may also impair the ability of the public service corporation to attract capital at fair and reasonable terms.

Q4. WHO IS IBEW LOCAL 640?

A4. Local Union 640, International Brotherhood of Electrical Workers, AFL-CIO, CLC ("IBEW Local 640") is a sister local of IBEW Local 387. While IBEW Local 640 represents some employees outside of the electrical/utility industry, it would be fair to say that IBEW Local 640's primary interest in this case is in its role as the supplier of highly-skilled employees to the Palo Verde Nuclear Generating Station ("Palo Verde") through an International Maintenance Agreement. This agreement was entered into between Bechtel Power Corporation ("Bechtel"), the contractor for APS's construction workers at Palo Verde, and the Building and Construction Trades Department, AFL-CIO, its constituent International Unions, and their affiliated Local Unions. Bechtel has recognized the Unions as the sole bargaining agents for all employees in the classifications covered in their respective agreements that will be working on the project.

Q5. WHO IS IBEW LOCAL 769?

A5. Like IBEW Local 640, Local Union 769, International Brotherhood of Electrical Workers, AFL-CIO, CLC ("IBEW Local 769") is another of our sister locals. IBEW Local 769 is a labor organization which represents non-managerial utility workers throughout the State of Arizona. For example, IBEW Local 769 is the duly elected and recognized exclusive bargaining agent for a substantial number of employees of the Mohave County Electric Operations of UniSource. As a union which represents a large number of employees involved in the outside line construction industry, IBEW Local 769 also represents employees of subcontractors working for APS. For example, IBEW Local 769 has recently provided outside line construction work for APS through Argent Construction, Inc., Par Electrical Contractors, Inc., Southwest Energy Solutions, Inc., and Sturgeon Construction, Inc. At any given time, IBEW Local 769 will have anywhere from five (5) to two-hundred (200) of its bargaining unit employees working for subcontractors of APS.

Q6. ARE IBEW LOCALS 387, 640, AND 769 SEPARATE LEGAL ENTITIES?

A6. Yes. In addition, it is well-settled that our International Union and its constituent local unions, including my own, are also separate legal entities. That being said, the various IBEW Local Unions in the State of Arizona meet on a regular basis to discuss issues of mutual concern and, general speaking, we are familiar with and supportive of the actions of each other.

Q7. DO IBEW LOCALS 387, 640, AND 769 HAVE A STAKE IN THIS PROCEEDING OTHER THAN IN THEIR CAPACITY AS LABOR ORGANIZATIONS?

A7. Yes. As building owners in APS's service territory, each of the Locals fall within the definition of a "small-business" customer under the E-32 Rate Plan - *i.e.*, the standard plan for APS commercial customers who have a demand of less than 3,000 kilowatts a month.

Q8. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A8. I am testifying with respect to a particular issue raised in the January 7, 2006 Arizona Republic article entitled "APS seeking 14% emergency hike in rates". According to that article, Commissioner Kristin K. Mayes believes that APS has "dug themselves into a hole, and they need to get out of it" and that in lieu of raising rates "APS [should] explore other options, including..., reduced executive salaries." IBEW Locals 387, 640 and 769 respectfully disagree with Commissioner Mayes' suggestion. In our collective opinion, the issue of executive compensation at APS is wholly unrelated to the issue presented in this particular proceeding. In particular, APS did not get into this so-called "financial jam" because of the level of compensation it pays to its employees, including its executives, nor will it solve (in whole or in part) its current problem by reducing said compensation.

Q9. DOES THIS CONCLUDE YOUR TESTIMONY?

A9. Yes.

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Transcript Exhibit(s)

Docket #(s): E-01345A-06-0009

Exhibit # : Spitzer-1

APS / Interim Rates E-01345A-06-0009
March 20 through 29, 2006
Volumes I through VIII

SPITZER EXHIBIT *No. 1*

A Busy Time for the Rating Agencies

S&P Credit Rating

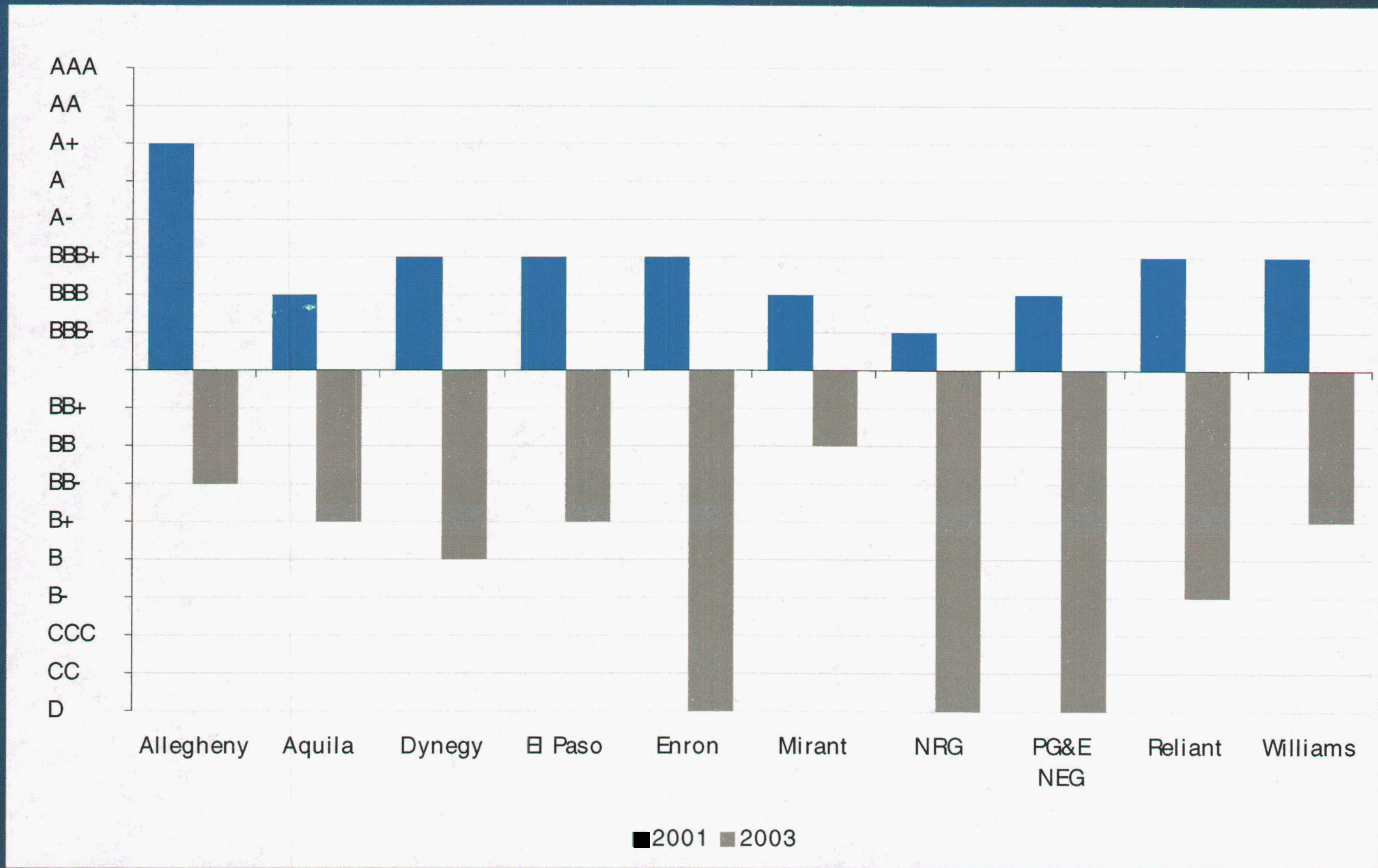

EXHIBIT
Spitzer 1
ADMITTED

Investment in power generation: A banker's perspective

Guillaume de Luze
Director, Project and Sectorial Finance
Société Générale

Paris, March 25, 2003

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Transcript Exhibit(s)

Docket #(s): E-01345A-06-0009

Exhibit # : EEA-1

APS / Interim Rates E-01345A-06-0009

March 20 through 29, 2006

Volumes I through VIII

FEA EXHIBIT

No. 1

EXHIBIT
FEA-1
Admitted

Impact of various proposed APS increases on peak winter and summer bills for Luke Air Force Base

Month	kwh	surcharge amount $/kwh	monthly increase $	surcharge type	
2006 Jan	7,845,988	0.008676	$68,072	IR-1 (interim rate adjustment)	19.01%
2005 Aug	8,350,944	0.008676	$72,453	IR-1 (interim rate adjustment)	18.15%
2006 Jan	7,845,988	0.004	$31,384	PSA 2-1-2006	8.77%
2005 Aug	8,350,944	0.004	$33,404	PSA 2-1-2006	8.37%
2006 Jan	7,845,988	0.000554	$4,347	Amort--step 1	1.21%
2005 Aug	8,350,944	0.000554	$4,626	Amort--step 1	1.16%
2006 Jan	7,845,988	0.001611	$12,640	Amort--step 2	3.53%
2005 Aug	8,350,944	0.001611	$13,453	Amort--step 2	3.37%
		total increase--Jan	$116,442		31.31%
		total increase--Aug	$123,936		31.05%

	old bill	new bill	% increase
2006 Jan	$358,012	$474,454	32.52%
2005 Aug	$399,101	$523,037	31.05%

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Transcript Exhibit(s)

Docket #(s): E-01345A-06-0009

Exhibit # : Mesquite/Bowie-1

APS / Interim Rates E-01345A-06-0009
March 20 through 29, 2006
Volumes I through VIII

Mesquite/Bowie
EXHIBIT
No. 1

EXHIBIT
MESQUITE/BOWIE
admitted #1

PREPARED TESTIMONY
OF
DAVID GETTS
ON BEHALF OF
MESQUITE POWER, L.L.C., BOWIE POWER STATION, L.L.C.
IN
DOCKET NO. E-01345A-06-0009

Q. 1 Please state your name and your business affiliation.

A. 1 My name is David Getts. I am Chief Financial Officer of Southwestern Power Group II, L.L.C.

Q. 2 Upon whose behalf are you testifying in this proceeding?

A. 2 I am testifying on behalf of Mesquite Power, L.L.C., Southwestern Power Group II, L.L.C. and Bowie Power Station, L.L.C. These three entities, together with Sempra Generation, have jointly intervened in a number of proceedings before the Commission in recent years relating to Arizona Public Service Company ("APS") which impacted the competitive wholesale electric market in Arizona.

Q. 3 What is the purpose of your testimony in this proceeding?

A. 3 I wish to express the support of Mesquite/SWPG/Bowie for that level of emergency interim rate relief that APS is able to demonstrate is necessary under applicable legal and regulatory standards to avert the financial emergency it apprehends; and I want to explain why it is important to Mesquite/SWPG/Bowie that APS be in a position where its securities and financial instruments are of investment grade quality and creditworthy.

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Q. 4 Do Mesquite/SWPG/Bowie have an opinion as to the precise amount of emergency interim rate relief to which APS may be legally entitled, or the precise level of interim rate relief necessary in order for the company to be creditworthy?

A. 4 Not at this juncture. The pre-hearing discovery process is still underway, and testimony to be elicited during the hearing in March presumably will allow for more information and insight upon these points. Moreover, Mesquite/SWPG/Bowie would not presume to tell the Commission if and when APS has met that burden of proof to be required of it, or the precise level of an interim emergency rate increase that may be warranted under the circumstances. Rather, those are matters for the Commission to resolve based upon the hearing record.

Q. 5 Why is it important to Mesquite/SWPG/Bowie that APS' securities and financial instruments be of investment grade quality, and that the company be creditworthy?

A. 5 Each of us is a competitor in the competitive wholesale electric market in Arizona. APS represents the largest potential purchaser of capacity and energy from that market on an ongoing basis. At various times during the past few years, each of us has either sold power to APS, or offered to do so as respondents to competitive power procurements conducted by APS.

From our perspective, it is of critical importance that APS be creditworthy, whether as an actual or prospective purchaser of the product(s) we have to offer. Its creditworthiness, as well as the prospective lack thereof, can have a direct effect on the

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terms and conditions we can offer to meet its power needs, not to mention our own financial circumstances when we have a power supply contract with the company.

More specifically, when APS' credit is at risk, that risk affects our own financial exposure and financial profile. In turn, those considerations affect our ability to do business with APS. APS' continued rapid growth makes it an attractive potential customer for us, subject to the assurance it will be able to make timely and complete payments for product(s) provided. That ability on the part of APS to make timely and complete payment is at the heart of the emergency relief APS has requested.

If there appears to be, or in fact there is, a financial risk associated with doing business with APS, the terms and conditions we can offer must reflect both a recognition of and provision for that increased risk. Simply stated, the price(s) we can offer will be higher, and the terms and conditions more stringent, than those we could offer if APS were creditworthy. Those increased prices reflect the increased risk that we face by doing business with APS if APS has limited or no ability to timely recover its costs for purchased power. In turn, those higher prices are ultimately passed on to APS's customers, assuming that APS satisfies the prudency test. In this regard, it is worth noting that, at page 12 of its January 6, 2006 Application for Emergency Interim Rate Increase, APS specifically states that a downgrading to the "junk" category "also has operating expense implications," which will affect its ability to purchase power for its customers, and the price it must pay.

Moreover, it is conceivable that there could be an instance where we could not transact business with APS if its creditworthiness declined to an unacceptable level under any circumstances.

In a sense, the prospect of an APS lacking in creditworthiness represents the prospect of a significant shrinkage or contraction of the competitive wholesale electric market in Arizona. In turn, in the event of an actual shrinkage or contraction of that nature, the number of wholesale electric suppliers willing to commit the resources necessary to participate in such a reduced market might also shrink or contract. We believe that such a result would not be in the best interest of the State of Arizona or its electric ratepayers as a whole.

Q. 6 Can you cite any examples of where a decline in the creditworthiness of an electric utility, due to its inability to recover purchased power costs, appears to have ultimately resulted in an increase in electric rates to its customers?

A. 6 Yes. Examples that come to mind are Pacific Gas & Electric Company and Southern California Edison Company in California. During the 2000-01 electricity crisis in California, those two utilities faced dramatic short term increases in the cost of purchased power. When the California Public Utilities Commission refused to allow emergency rate hikes in order for the utilities to recover those costs, Pacific Gas and Electric was driven into bankruptcy and Southern California Edison barely escaped bankruptcy. In recent years, Commonwealth Edison Company, Northwestern Utilities Company, and Nevada Power Company all have faced similar difficulties. Obviously,

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each of these had their individual circumstances which lead to the increases in rates, but I believe that increases in the cost of power or capital, or both, were present in each instance, as likely would be the case if APS were to experience further credit downgrades.

Q. 7 Is there an additional reason why Mesquite/SWPG/Bowie support the Commission favorably considering an emergency interim rate increase for APS?

A. 7 Yes. We believe that APS is entitled to recover purchased power and fuel expense which it prudently incurs incident to providing electric service to its customers. The recent proceedings in Docket Nos. E-01345A-03-0437 and E-01345-05-0526, involving APS's Power Supply Adjuster and its recent Surcharge proposal, underscore the importance of timely recovery of purchased power and fuel expense.

In this regard, timely recovery by APS of its purchased power and fuel expense also sends a strong signal to suppliers in the competitive wholesale power market that sales in Arizona will be backed by both a commitment to timely payment and a revenue stream to back that commitment, each of which minimizes the risk exposure of APS and ourselves.

Furthermore, given that any emergency interim rate increase which APS may receive will be subject to the prospect of a future refund, thereby affording the Commission an opportunity to fully conduct a prudency review in a permanent rate proceeding, we believe that the Commission should favorably consider and act upon that level of interim rate increase that APS can demonstrate is necessary to avert the apprehended financial emergency.

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Q. 8 Does that complete your testimony?

A. 8 Yes.

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