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BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

JEFF HATCH-MILLER, Chairman
WILLIAM A. MUNDELL
MIKE GLEASON
MARC SPITZER
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 TO AMEND DECISION NO. 67744	DOCKET NO. E-01345A-05-0816 **AMENDED APPLICATION**

Pursuant to A.R.S. §§40-250, 40-251 and 40-252; and also A.A.C. R14-2-103, Arizona Public Service Company ("APS" or "Company") hereby amends its Application of November 4, 2005 to request a permanent base rate increase of $449.6 million on annualized test year sales, or 21.1% on average, for its jurisdictional electric operations, to become effective no later than December 31, 2006.[1] This increase is based on a test year consisting of the twelve months ending September 30, 2005, which is the test period requested by Commission Staff.[2] APS also requests that the Commission permanently modify or eliminate the $776.2 million "cap" placed on total annual net fuel and purchased power costs by Decision No. 67744 (April 7, 2005) and make such other changes to the Power Supply Adjustment ("PSA") mechanism as are set forth herein.

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[1] These figures do not include the Environmental Improvement Charge, which when added to the base rate request would increase the total to $453.9 million, or 21.3%.

[2] APS had originally filed its Application on November 4, 2005 based on a calendar year 2004 test year.

APS is also requesting adoption of an Environmental Improvement Charge ("EIC") to recover on a timely basis the costs of Commission-approved environmental improvements at the Company's fossil generating plants. The EIC initially would be set at $.000152 per KWh, or a .2% increase. This would increase revenues by an additional $4.3 million based on adjusted test period sales.

On January 6, 2006, APS filed an Application for an emergency interim rate increase that would raise the base fuel rate from $.020743 per kWh to $.031904 per kWh. To the extent granted by the Commission, this increase, which amounts to $299 million or approximately 14%, would reduce the current asking by a similar amount. Thus, APS asks that any such interim relief be made permanent in this proceeding and any refund obligation associated with that interim relief be discharged.

APS' current rates and charges do not produce a reasonable return on the fair value of its property devoted to public service and are therefore not just and reasonable. The rate increase sought is required to enable the Company to maintain its credit ratings and attract new capital on reasonable terms, recover its costs of service, and permit APS to earn a fair rate of return on the fair value of its assets devoted to public service, which return will recover the Company's capital costs necessarily and prudently incurred in rendering adequate utility service to customers. The requested increase is necessary for APS to continue as the type of financially strong utility that can ensure APS customers continued reliable service, on demand, and at reasonable prices into the future.

APS is requesting that the Arizona Corporation Commission ("Commission") recognize the higher fuel and purchased power expenses that are being incurred by the Company; allow APS to include in rates at cost of service the Sundance generation assets; authorize a return of fair value rate base that includes an 11.5% return on equity; approve certain changes to the Company's Power Supply Adjustment ("PSA") mechanism; and grant such other relief as is set forth in the testimony and exhibits filed as part of this

Application. APS specifically notes that 2005 Palo Verde unplanned outage costs are not included in its base rate request.

In addition, APS requests that the Commission approve the depreciation and amortization rates and classifications for certain of the Company's tangible and intangible property. The latter are the same adopted in Decision No. 67744, while the former represent merely a technical update of the depreciation rates adopted by that same Decision.

In support of this Application, the Company respectfully states as follows:

I.

The Company is a corporation duly organized, existing and in good standing under the laws of the State of Arizona. Its principal place of business is 400 North Fifth Street, Phoenix, Arizona, 85004, and its post office address is P.O. Box 53999, Phoenix, Arizona 85072-3999.

II.

The Company is a public service corporation principally engaged in the generation, transmission and distribution of electricity for sale in Arizona. In conducting such business, the Company operates an interconnected and integrated electric utility system.

III.

All communications and correspondence concerning this Application, as well as communications and pleadings with respect thereto filed by other parties, should be served upon the following:

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IV.

This Commission has jurisdiction to conduct public hearings to determine the fair value of the property of a public service corporation, to fix a just and reasonable rate of return thereon, and thereafter, to approve rate schedules designed to develop such return. Further, the Commission has jurisdiction to establish the practices and procedures to govern the conduct of such hearing, including, but not limited to, such matters as notice, intervention, filing, service, exhibits, discovery and other prehearing and hearing matters.

V.

Accompanying this Application are the relevant standard filing requirements ("SFRs") and rate design schedules described in A.A.C. R14-2-103[3] and the direct testimony and attachments of the following witnesses:

- Dr. William Avera
- Fred Balluff
- Stephen Bischoff
- Donald Brandt
- Gregory DeLizio

[3] This Application does not include SFR Schedule E-6 because such schedule applies only to a "combination utility" within the meaning of A.A.C. R14-2-103(A)(3)(q), which does not include APS.

- Patrick Dinkel
- Peter Ewen
- Stephen Fetter
- Edward Fox
- Chris Froggatt
- Donald Robinson
- Laura Rockenberger
- David Rumolo
- Steven Wheeler
- Dr. Ronald White

VI.

As part of this general rate proceeding, this Commission also has jurisdiction to modify its previous rate decisions, including Decision No. 67744 under appropriate circumstances.

VII.

The Company respectfully requests that this Commission set a date for a hearing on this Application such that new rates for the Company will become effective December 31, 2006. At the hearing conducted pursuant to this rate request, APS will establish and hereby alleges that:

(1) its current rates and charges do not permit the Company to earn a fair return on the fair value of its assets devoted to public service and are therefore no longer just and reasonable;

(2) the requested increase is the minimum amount necessary to allow the Company an opportunity to earn a fair return on the fair value of its assets devoted to public service, for preservation of the Company's financial

integrity and for the attraction of new capital investment on reasonable terms;

(3) the Company requires additional permanent base revenue of at least $449.6 million based on annualized test period sales in order to continue to provide adequate and reliable electric service to its customers as required by law;

(4) the Sundance units were prudently acquired and are used and useful;

(5) the PSA approved by Decision No. 67744 should be retained but modified as set forth below and in the Company's testimony and exhibits:

a. the total fuel cost cap of $776.2 million should be raised to $1.5 billion or eliminated;

b. the four mill cumulative "lifetime" cap on the April adjustments to the annual PSA charge should be changed to an annual cap of plus or minus four mills per kWh;

c. the 90/10 cost sharing mechanism provided for in the PSA should not apply to renewable resources or to the demand component of purchased power agreements acquired from the competitive wholesale market;

d. the mandatory obligation to seek a PSA surcharge before the PSA bank balance reaches $100 million should be eliminated; and,

e. 10% of realized hedging gains and losses should be excluded from the determination of PSA charges, with the remaining 90% of such gains and losses subject to the 90/10 sharing provision of the PSA.

(6) an EIC should be approved at an initial level of $.000152 per kWh ($4.3 million) to allow for the timely recovery of Commission-approved environmental upgrades at the Company's fossil generating plants.

VIII.

In addition to setting a hearing date, APS asks that the Commission issue a procedural order setting forth the prescribed notice for the Application, establishing procedures for intervention, and providing for appropriate discovery. In this last regard, APS requests that to expedite such discovery, the Company be authorized to serve all discovery requests, answers and objections electronically. Hard copy service would remain available to parties upon request or when the confidential nature of the information makes the use of electronic service impractical.

* * *

WHEREFORE, THE COMPANY RESPECTFULLY REQUESTS that the Commission:

A. issue a procedural order establishing a date for hearing evidence concerning the Application and prescribing the time and form of notice to APS customers;

B. issue a final order granting the Company the permanent rate increase sought herein on or before December 31, 2006;

C. issue a final order confirming and making permanent any interim rate relief granted in Docket No. E-01345A-06-0009 and discharging any refund obligation imposed in such docket;

D. issue a final order approving the requested EIC;

E. issue a final order approving the new or modified rate and service schedules included with the Company's Application with an effective date no later than December 31, 2006;

F. issue a final order authorizing APS' depreciation and amortization rates and classifications;

G. issue a final order modifying the PSA approved by Decision No. 67744 as requested herein; and

H. grant the Company such other relief as the Commission deems just and proper.

RESPECTFULLY SUBMITTED this 31st day of January, 2006.

PINNACLE WEST CAPITAL CORP.
Law Department

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ORIGINAL AND 15 COPIES OF THE FOREGOING
filed this 31st day of January, 2006, with:

Docket Control
Arizona Corporation Commission
1200 West Washington
PHOENIX, AZ 85007

And copies of the foregoing mailed, faxed or transmitted electronically this 31st day of January, 2006 to:

All Parties of Record

Birdie Cobb

STEVEN M. WHEELER

DIRECT TESTIMONY OF STEVEN M. WHEELER

On Behalf of Arizona Public Service Company

Docket No. E-01345A-05-0816

January 31, 2006

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DIRECT TESTIMONY OF STEVEN M. WHEELER
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-05-0816)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, ADDRESS AND OCCUPATION.

A. My name is Steven M. Wheeler. I am Executive Vice President, Customer Service and Regulation for Arizona Public Service Company ("APS" or "Company"). In that role, I am responsible for the planning, construction, maintenance and operation of the APS transmission and distribution systems. I am also responsible for customer service, rate, and regulatory matters affecting the Company before the Arizona Corporation Commission ("Commission") and the Federal Energy Regulatory Commission ("FERC").

Q. WHAT IS YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND?

A. I received a Bachelors degree from Princeton University in 1971. I graduated from Cornell University School of Law in 1974. From 1974 until 2001, I was an attorney with Snell & Wilmer LLP in Phoenix, Arizona, involved in general business, real estate, environmental and public utility issues. During my over 27 years at the firm, I represented APS and other public utilities in numerous state and FERC proceedings involving utility rate and service matters, generation and transmission siting, electric industry restructuring, resource planning, and prudence reviews. In 2001, I joined APS as Senior Vice President. I assumed my present responsibilities with the Company in 2004.

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

My testimony will summarize the central issues that required the Company to initially file this rate request some seven months after Commission approval of the 2004 APS Rate Settlement Agreement ("2004 Settlement"). In this testimony, I address the key issues facing the Company, of which the increasing cost of fuel and purchase power is the most significant. In this regard, I will sponsor Standard Filing Requirement ("SFR") Schedule A-1 of the Company's rate application.

Q. HAS APS SUBMITTED DIRECT TESTIMONY IN SUPPORT OF ITS APPLICATION?

A. Yes. In addition to my testimony, APS has filed testimony by the following witnesses in the following areas:

<u>Revenue Requirements</u>

Dr. William Avera:	Cost of Equity
Mr. Donald Brandt:	Financial Results, Capital Structure, and Requested Return on Equity, Revenue Requirements
Mr. Fred Balluff:	Cash Working Capital
Mr. Stephen Bischoff:	Bark Beetle Remediation
Mr. Patrick Dinkel:	Sundance Assets
Mr. Peter Ewen:	Pro Forma Fuel and Purchased Power Adjustments (net), Customer and Sales Annualization, Weather Normalization and Power Plant Maintenance.
Mr. Steven Fetter:	Quality of Regulation
Mr. Chris Froggatt:	Actual Test Year Results, Cost of Debt, Pro Forma Rate Base and Operating Income Adjustments

Mr. Edward Fox:	Environmental Improvement Charge, Green Power Tariffs
Mr. Donald Robinson:	Power Supply Adjustment Mechanism and Associated Financial Results
Ms. Laura Rockenberger:	Pro Forma Rate Base and Operating Income Adjustments, Depreciation, Calculation of Reconstruction Cost New Less Depreciation, Accounting Issues and Total Working Capital Requirements
Dr. Ronald White:	Depreciation

Allocations, Rate Design and Service Schedules

Mr. Gregory DeLizio:	Service Schedules 1 and 4; Environmental Improvement Charge, Net Metering, Green Power Tariffs
Mr. David Rumolo:	Cost of Service Study, Rate Design and Service Schedule 3

II. SUMMARY

Q. WOULD YOU PLEASE SUMMARIZE YOUR DIRECT TESTIMONY?

A. After more than a decade of rate reductions totaling some $1.74 billion, APS received a 4.21% general rate increase (approximately $75.5 million) effective April 1, 2005. *See* Decision No. 67744 (April 7, 2005). The Company had requested a 9.8% increase (approximately $175 million) effective July 1, 2004. Of the $75.5 million granted by Decision No. 67744, some $8 million represented a temporary surcharge to recover the prior costs of implementing retail electric competition in Arizona. Another $9 million represented base rate funding for a portion of the additional Demand Side Management ("DSM") spending mandated by Decision No. 67744. Neither of the latter two amounts provided any additional earnings to the Company. At the Special Open Meeting to consider the 2004 Settlement, which served as the basis for Decision No.

67744, APS stated that because of escalating fuel costs, the Company would have to seek additional rate relief in the near future.

The increased cost of fuel and purchased power is the most significant reason why the Company has filed this request for rate relief. In this proceeding, APS is requesting a 21.34% base rate increase, or approximately $450 million. Of this amount, approximately $299 million (which is approximately 70% of the total requested relief), is attributable to higher fuel and purchased power costs. Due to the normalization of power plant performance, as described in Mr. Ewen's testimony, none of the proposed increase is related to the increase in unplanned Palo Verde outages during 2005. This request also is approximately $169 million or approximately eight percentage points (based on November 30, 2005 market prices) less than it otherwise would have been had the Company not mitigated its fuel costs through its hedging program.

The requested increase is necessary if APS is to continue as the type of viable utility that can ensure APS customers continued reliable service, on demand, and at reasonable prices into the future. Furthermore, I must emphasize that it is crucial that the Company maintain an investment grade credit rating so that it can attract the necessary capital to provide such service. Finally, as discussed in Mr. Robinson's testimony, the Company is also seeking certain modifications of the Power Supply Adjustment ("PSA") mechanism.

APS has serious concerns about its ability to continue to obtain capital at reasonable rates. On December 21, 2005, Standard and Poors downgraded the Company to a BBB- credit rating, which is one level above non-investment grade. The investment community has indicated that further down-grading may

be forthcoming if there are delays in resolving outstanding issues related to the cost recovery of fuel expenses. For these reasons, on January 6, 2006, the Company filed for emergency interim rate relief and requested that emergency rates be effective by April 1, 2006, subject to refund. To the extent that such emergency relief is granted, the Company's request for permanent rate relief would be incrementally reduced.

APS has based its revenue requirement on an adjusted historical test period, specifically the twelve months ended September 30, 2005 ("Test Year"), and a cost of common equity of 11.50%. The use of such a non-calendar test year was required by Commission Staff. The cost of equity ("COE") is the midpoint of the range found reasonable by Dr. Avera, the Company's return on equity expert. For APS to recover its cost-of-capital, it must receive a fair rate of return of 6.37% on a fair value rate base of $6,120,755,000.

APS has made various adjustments, both up and down, to the Test Year. These adjustments will make the historical test period both more representative of a "typical" year and of the period (2007) in which the new rates authorized by the Commission will likely be in full effect. In large part, the pro forma adjustments to the Test Year represent the implementation of the Commission's decision in the Company's last rate case (Decision No. 67744).

Perhaps the most significant of the Company's pro forma adjustments is the reflection of the very substantial increases APS has experienced in the cost of fuel, especially natural gas, and purchased power from other utilities and unregulated merchant power entities. These two categories of cost have been increasing at an annual rate of 23% percent since 2003, which was the basis for

the fuel and purchased power portion of the 2004 Settlement and Decision No. 67744. Even though the costs reflected in the 2004 Settlement were partially updated to reflect some 2003 prices, it is estimated that overall per kWh fuel and purchase power costs will have increased by at least 54% by the end of 2006, which is when the rates requested in this proceeding are proposed to take effect.

These increases are offset, at least partially, by the Company's successful gas and power hedging program. In this Application, APS is proposing a program whereby APS shareholders would shoulder another 10% of the risk from hedging activities and, correspondingly, realize another 10% of any realized gain from hedging. The other 90% of either gains or losses from hedging would be reflected in the PSA calculations (and thus subject to the current 90/10 sharing mechanism), as is presently the case.

Another issue presented in this proceeding is the Company's request to include the Sundance generating assets into the APS rate base at cost-of-service, although this inclusion accounts for less than 2% of the proposed increase in base rates. The Sundance assets were prudently acquired through an open and fair competitive bidding process to serve APS customers, and these assets have been and will continue to be "used and useful" in providing service to the Company's customers in the future. Thus, they are entitled to cost-of-service rate treatment under traditional criteria previously established by this Commission.

Environmental compliance costs are another area in which APS faces increasing challenges in the future. In an attempt to get ahead of the curve, APS is asking to implement an Environmental Improvement Charge ("EIC") that will allow

recovery of the revenue requirement associated with Commission-approved environmental improvement programs on an annual basis. The EIC would add an additional $4.3 million to the Company's request, or 0.20%. *See* SFR Schedule A-1. In addition, APS is proposing to support the development and utilization of renewable resources by implementing Green Power tariffs, which would allow, but not require, customers to subscribe to specific levels of energy from a variety of renewable sources.

III. APS REQUEST

A. Nature of the Request

Q. WOULD YOU PLEASE SUMMARIZE THE COMPANY'S REVENUE REQUEST?

A. APS is seeking to increase base rates by some $450 million, or 21.34% on average, based on annualized Test Year sales. This request would have been approximately $169 million or approximately eight percentage points (based on November 30, 2005 market prices) more, had the Company not prudently hedged fuel costs through its hedging process. This rate request produces a 6.37% return on the Company's fair value rate base of $6,120,755,000. *See* SFR Schedule A-1. A 6.37% return on fair value rate base is approximately equal on a dollar basis to APS' cost of capital (expressed in terms of return on original cost rate base) of 8.73%. Consistent with Commission practice for many years, fair value rate base is simply the arithmetic average of original cost rate base and reconstruction cost new rate base. Mr. Froggatt sponsors the weighted cost of capital calculation, as reflected on SFR Schedule D-1; the fair value rate base calculation is sponsored by Ms. Rockenberger.

To promote and enhance the development and utilization of renewable resources, and to further protect Arizona's environment, the Company is submitting several new proposals. The Company is proposing adoption of an EIC that would provide for a timely recovery of the cost for the substantial capital investment necessary for adding or improving environmental controls in the Company's generation facilities. The EIC would initially be set at $0.000152 per kWh, and would increase revenues by another $4.3 million based on adjusted Test Year sales. The Company is also seeking authorization for Green Power tariffs, which would offer our customers energy from a variety of renewable resources at a more affordable price than an exclusively solar offering. In addition, APS is submitting a net metering proposal, which is a pilot program for renewable resource generation facilities with a nameplate rating of 10 kW or less, where the customer's renewable facilities and load are located at the same premise.

The revenue requirement incorporates the Company's cost of capital at September 30, 2005. That cost of capital is, in turn, premised on an 11.50% COE, which is the mid-point of Dr. Avera's recommendation. It also reflects a higher percentage of common equity capital than utilized in the Company's last rate proceeding. Increasing Pinnacle West Capital Corporation's ("Pinnacle West") equity investment in APS was necessary for the Company to address the stated concerns of ratings agencies and others over the increasingly leveraged nature of APS' capitalization. In Decision No. 68295, the Commission recognized that the increase in APS' equity by more than $450 million through investments by Pinnacle West and the retention of earnings would improve the likelihood for the Company to obtain capital on better terms.

APS is requesting that its rate request become effective no later than December 31, 2006. As I have already noted, if the Commission grants interim rate relief, the incremental amount of the rate increase sought in this docket would be reduced by that amount. The Company is further requesting certain changes to its currently approved PSA to make that rate mechanism fairer and more effective in its dual role of cost recovery and providing price signals to our customers about the price of energy. For this filing, APS has also performed a technical update of the depreciation rates that were authorized in Decision No. 67744 and is requesting that the Commission approve those depreciation rates. APS is also requesting approval of current amortization rates, including two new rates, for certain of the Company's tangible and intangible property. Ms. Rockenberger discusses this latter request in her direct testimony.

Q. HOW WOULD THE GRANT OF EMERGENCY RATE RELIEF EFFECT THE RATE RELIEF SOUGHT IN THIS DOCKET?

A. If the Commission grants the emergency rate increase of $299 million that was requested in Docket No. E-01345A-06-0009, the Company's request for additional relief in this docket would be reduced incrementally by that amount.

B. Key Issues

Q. WHY MUST APS SEEK ANOTHER RATE INCREASE AFTER RECEIVING A RATE ADJUSTMENT IN APRIL 2005?

A. First of all, I must note that the April 2005 increase was requested in June of 2003, over 21 months earlier, and was largely based on 2002 costs. That being said, there are several factors that have caused APS to seek additional rate relief in a relatively short time period, but let me concentrate on two of the primary reasons. The first is the rising fuel and purchased power costs and the need to set the base fuel rate at the appropriate level. The second is the need for an

improved capital structure and higher equity return, so the Company can obtain financing at reasonable rates in order to make the capital investments necessary to address the needs of our fast-growing service territory.

Q. PLEASE EXPLAIN.

A. APS' fuel and purchased power costs have increased far beyond the level that existed when the 2004 Settlement was negotiated and have continued to increase since the 2004 Settlement was approved. Although other APS costs have increased as well, escalating fuel and purchased power expenses are clearly key drivers of this rate request. In his testimony, Mr. Ewen explains the compounding impact on these costs of both higher unit prices and growth. Mr. Robinson notes in his testimony that Decision No. 67744's imposition of a total fuel cost cap of approximately $776.2 million under the existing PSA mandates the filing of a new general rate case this year to lift that cap and update base fuel and purchased power costs, irrespective of other factors. Mr. Robinson also discusses, and I wish to echo the point, that the prospect of adding very significant new purchased power resources in 2007, as a result of the RFP process mandated by Decision No. 67744, emphasizes the importance of both retaining and improving upon the PSA mechanism and updating base fuel costs to 2006 levels, as we have proposed in this Application.

Also, meeting the demands of growth in APS' service territory is essential. APS has the second fastest growing service territory in the nation, as discussed later in my testimony. As such, it is critical to have access to capital at reasonable rates to provide the necessary infrastructure for these new customers. To maintain that access requires APS to strengthen its capital structure and earn its COE.

Q. ARE THERE OTHER SIGNIFICANT ISSUES RAISED IN THE COMPANY'S APPLICATION?

A. Yes, another significant issue is the changes to the PSA, which are discussed at length in Mr. Robinson's testimony. This issue impacts the calculation of base fuel costs through the implementation of our proposal to share the risks and rewards of hedging.

Another important area addressed in this Application is the significant programs that the Company is proposing to support renewable energy and protect the environment. This includes the implementation of the EIC and the Green Power and net metering offerings. Mr. Fox addresses these environmental proposals in his testimony; Mr. DeLizio addresses the mechanics of the EIC and the tariff offerings.

Q. WHAT ARE THE CHANGES TO THE PSA THAT THE COMPANY IS PROPOSING?

Mr. Robinson is the primary witness on this subject, so I will merely summarize our proposal. First, we are asking the Commission to permanently eliminate, or substantially raise, both the total fuel cost cap of $776.2 million and the $100 million surcharge "trigger." Second, APS believes the present four mill cumulative "lifetime" limit on annual PSA adjustments should be converted to an annual limit, consistent with the position taken by all the settling parties in the Company's last rate proceeding. Third, because the intent of the PSA is to encourage least cost resource acquisition, the 90/10 cost sharing mechanism should be modified to exclude certain resources, such as renewable energy and the resources acquired through competitive solicitation. Lastly, APS is proposing to share an additional 10% of the gains and losses from hedging activities, thus

effectively bearing a greater share of the risk of price volatility for the two most volatile components of fuel cost, which are gas and purchased power.

Q. WHAT IS THE EIC?

A. The EIC, as described by Mr. Fox and Mr. DeLizio, allows APS to recover the revenue requirements associated with environmental improvement programs, subject to approval in advance by the Commission. This will provide a dedicated funding source to allow the financing of these improvements and their subsequent operation in between general rate proceedings. As these costs are eventually rolled into base rates, the EIC will be adjusted downward.

B. The Challenges of Fast-Paced Service Territory Growth

Q. MR. WHEELER, WOULD YOU DISCUSS HOW RAPID GROWTH IN THE COMPANY'S SERVICE TERRITORY HAS AFFECTED APS?

A. Meeting the demands of growth in APS' service territory is a significant challenge for APS. A comparison of growth in retail electric sales for APS versus the country as a whole is shown on Attachment SMW-1. Since 1990, total retail electricity sales for APS have grown by 73%, or an estimated 30% faster than total U.S. electricity sales. By 2005, Arizona's population had increased by 36% more than the U.S. population over the same period.

APS' growth should come as no surprise. At its current rate of growth, the state of Arizona increases its population by 150,000 to 200,000 people annually, which is equivalent to adding a city the size of Tempe each year. All of these people need homes to live in, places to work, and businesses at which to shop. This explains why Arizona continues to rank so highly across the country in such indicators of economic growth as housing construction and job growth.

Typically, about half of this growth occurs in the APS service territory. In order to keep these new homes and businesses supplied with electricity, APS must invest in new electric generation, transmission, distribution, and supporting facilities on an on-going basis.

If growth were constant from year to year, planning for and adding these new facilities would be a routine matter. However, growth is not constant every year and, in fact, can be quite volatile depending on economic conditions. Although some of this volatility can be anticipated, particularly in the near-term, forecasting economic growth and the associated demand for electricity is, at best, an imprecise science. Therefore, the Company's plans must account for this uncertainty. With reliability as the cornerstone of resource planning, this means that APS must add generation and distribution facilities in advance of demand growth and during periods of heightened volatility, so that such investment may lead the demand growth by several years.

Q. HOW DOES GROWTH IN ARIZONA COMPARE WITH OTHER REGIONS OF THE COUNTRY?

A. Arizona has historically been and, for the foreseeable future, is expected to be one of the fastest-growing states in the country. For each decade in the 20th century, Arizona consistently ranked among the top five states for population growth in percentage terms, and is poised to do so again through at least the first decade of the 21st century. From 2000 to 2030, Arizona is projected to be the second fastest growing state (behind only Nevada). Often, one of the reasons that a region may have a large percentage increase in population is because a relatively modest absolute number of people are added to a small existing base. This was the case for Arizona when it was a small state (as measured by

population), even as late as the 1970's, but is less the case now as Arizona grows in size. Arizona is now the 18th most populous state in the country and continues to grow rapidly. Arizona is projected to be the 10th largest state by 2030. Indeed, a recent study showed that Phoenix was the fastest growing city, in terms of absolute numbers, in the United States.

To put this in context with national averages, Attachment SMW-2 shows how Arizona's population has grown since 1990 relative to U.S. population growth. Population levels are indexed against 1990 for both Arizona and the entire United States, so that an easy comparison can be made between the two. It is apparent from the chart how much difference in total population a growth rate three times the national average will make over a 10 or 15 year period. Through 2005, Arizona's population had increased by 36% more than the U.S. population over the same period.

Q. HOW SIGNIFICANT ARE THE CHANGES IN GROWTH RATES FROM YEAR TO YEAR IN DEVELOPING YOUR COMPANY'S PLANS?

A. The changes in annual growth are very significant in the Company's planning process. Population and household growth vary with the strength of the national economy, and this fact will be reflected in the number of new customers APS will serve in any given year. These new customers include both residential homes and apartments, as well as new commercial and industrial business establishments. Attachment SMW-3 shows the changes in APS average annual retail customer growth over the last 25 years. One can see that there are periods of high growth, such as in the mid to late 1990s and in 2004, and there are periods of relatively slower growth, which tend to be concentrated in and around

periods of economic recession, such as the early 1980s, the early 1990s and in 2001-2002.

This highlights the additional growth pressures that are present in Arizona and in the APS service territory that are over and above those seen at the national level. It also highlights why APS has to be so concerned about its future ability to meet the challenges of such growth, both from the standpoint of its financial strength and the consistency of its regulation.

Q. ARE THERE OTHER FACTORS THAT ADD TO THE UNCERTAINTY OF ELECTRICITY DEMAND GROWTH?

A. Yes. A large portion of the electricity demand APS serves is weather-sensitive, so the natural fluctuations in weather from year to year can have a dramatic effect on the peak demand that APS resources must meet and the total amount of energy that must be supplied in any given time period. In addition, unique factors emerge from time to time that have impacts on electricity demand beyond those related to overall economic growth or weather. For example, the decline in the relatively energy-intensive copper mining industry in the late 1990s has affected the growth rate in APS sales. Additionally, conservation efforts undertaken by our customers in the both the summers of 2001 and 2004 were factors that impacted the Company's sales growth in unpredictable ways.

Q. DOES APS EXPECT GROWTH TO CONTINUE INTO THE FUTURE?

A. Yes. APS' current forecast expects the Company's energy sales to grow at an average annual rate of 3.5% until 2010, based largely on the strength of the continued high population and customer growth.

Q. HAS GROWTH ALSO AFFECTED THE DELIVERY SIDE OF APS?

A. Yes. On the transmission, distribution and customer service side of APS' business, the challenges match, or perhaps even exceed, those on the generation side. The delivery challenges of meeting customer growth - while maintaining high levels of reliability at a reasonable cost - are multifaceted and formidable.

As noted earlier, over the last decade (1995-2005), APS has experienced annual customer growth of about 3.9%, adding nearly 315,000 new customers. This growth has not been exclusively a Phoenix phenomenon; growth in APS' five divisions, which includes rural areas, has averaged between 2.8 and 4.2% per year over the decade.

Despite this rapid growth, APS now provides service with fewer employees per customer. In 1995, APS served 167 customers per employee; in 2005, APS served 220 customers per employee, an increase in productivity of 32%. To service its over one million customers, APS owns and maintains 386 substations, 5039 miles of transmission lines, and 26,839 miles of distribution lines.

One aspect of the APS service territory often overlooked is that APS serves a large rural and sparsely populated area, in addition to the urbanized Valley region. Consequently, on average, APS serves just 21 customers per square mile. In contrast, SRP and Tucson Electric Power – the other two large Arizona electric utilities – serve 296 and 331 customers per square mile, respectively. Compared to urban areas, service territories with low customer density are more expensive to serve per customer. There are two reasons for this: the costs of wires, transformers, and other items must be recovered over a smaller base and the costs themselves are greater. It can also be more difficult to maintain

reliable service in these rural areas. In those areas, service lines are long and there are more opportunities for interruption due to factors such as fire or storm damage.

Q. WHAT ARE SOME OF THE SPECIFIC WAYS THE COMPANY HAS MET THE CHALLENGES OF GROWTH?

A. First, APS has made significant investments in essential facilities. Over the last decade (1995-2005), APS has invested $2 billion on transmission and distribution infrastructure to keep up with the rapid growth in the number of customers. APS also plans to invest approximately another $1 billion in its transmission and distribution systems over the next three years for growth alone.

APS has turned those expenditures into some impressive total increases in electrical infrastructure. To serve the 315,000 new customers, APS has added and built over the last decade:

- 4130 MW of distribution substation capacity, a 55.2% increase;
- 3427 MW of transmission capacity, a 18.0% increase;
- 52 new distribution substations and 5 new transmission substations;
- 339 new distribution feeders giving us an additional 4206 MW of feeder capacity, an increase of 54.1%;
- 236 miles of transmission lines (APS sole ownership); and
- 35.68 miles of transmission lines (Participant owned).

In addition, APS has completed nearly 6925 miles of distribution lines, an increase of about 34.8%.

Q. PLEASE DESCRIBE GENERALLY THE TYPE OF PROJECTS APS HAS PLANNED OVER THE NEXT THREE YEARS TO KEEP UP WITH GROWTH, AND MAINTAIN AND IMPROVE EXISTING FACILITIES.

A. There are three general components of the projects planned to meet growth – Transmission Additions and Improvements ("TA&I"), Distribution Additions and Improvements ("DA&I"), and Customer Service. The latter component includes meters, transformers, and the services and extensions associated with connecting new customers.

TA&I capital projects are designed to increase capacity on the 69kV, 230kV, 345kV and 500 kV transmission system to meet the system peak demand. Other projects include new 69kV line additions, rebuilds and reconductoring, and 230kV/69kV substation additions and upgrades.

As to the other two components of the delivery business, DA&I capital projects are designed to increase capacity on the distribution system to meet more local peak demands. Customer Service work projected over the next three years includes the installation of meters, transformers, and services and extensions infrastructure needed to provide electric service to approximately 120,000 new residential, commercial and industrial meters.

Q. IF POPULATION GROWTH IN APS' SERVICE TERRITORY CEASED TOMORROW, WOULD APS STILL HAVE WORK TO DO?

A. Yes. Even without any growth, APS would incur ongoing capital costs for the planned replacement of generation, transmission and distribution plant to assure continued high levels of reliability. To maintain and improve its existing facilities, APS plans to invest approximately $900 million in just the next three

years on production (generation) plant, which includes capital replacements and nuclear fuel, as well as transmission and distribution capital replacements.

D. Conservation and Demand Side Management Programs

Q. HOW DOES APS KEEP CUSTOMERS INFORMED ABOUT THEIR ENERGY USAGE AND CONSERVATION OPTIONS?

A. APS provides extensive information to customers about their energy use and how to improve energy efficiency through a variety of channels, including its website (APS.com), customer newsletters, brochures, energy guides, fact sheets, the APS Energy Answer Line (phone), bill messaging, TV, radio, and newspapers.

APS.com features an entire section devoted to saving energy, including a free on-line energy audit for both residential and small commercial customers. APS also has a wide variety of energy-efficiency brochures, including a series of 14 residential and 18 commercial "Energy Answers" fact sheets that cover specific energy-efficiency topics. The APS newsletter regularly features energy savings tips and information about APS energy efficiency programs and special promotions.

For customers in existing homes, APS provides referrals to qualified heating and cooling contractors who have met specific program training requirements. Participating contractors receive training in key installation issues to improve energy efficiency, such as refrigerant charging, sizing, and equipment airflow. This program has been offered since 1998. In just the first half of 2005, APS provided 3400 customer referrals and trained over 180 contractor technicians through this program. APS customers can learn about the features of

heating/cooling systems that effect their home's performance by reading the free 20-page "APS Consumer's Guide to an Energy Efficient AC System".

For new construction, APS promotes high efficiency construction practices that meet or exceed national Environmental Protection Agency ("EPA")/Department of Energy's ("DOE") "Energy Star" standards. In 2004, the APS new construction program won the Association of Energy Service Professionals national award for achievement in energy services programs. Since the program started in 2001, over 10,000 homes have been committed to be built to program standards. APS customers can learn more about energy efficiency features to consider in their new home by reading the free 20+ page "APS Homebuyer's Guide to an Energy Efficient New Home".

For residential customers that have been with the Company for at least six months, APS now offers an "annual use" letter that provides a summary of the previous year's electric consumption as well as informative messages about payment options and other messages tailored to their situation. For example, time-of-use customers receive tips on shifting energy use to off-peak hours.

Q. HAS THE COMPANY DEVELOPED ANY ADDITIONAL ENERGY EFFICIENCY PROGRAMS AS A RESULT OF DECISION NO. 67744?

A. Yes, as required by Decision No. 67744, APS will significantly increase DSM program activity. The Company was required to spend $48 million on DSM programs through 2007, which assumed timely Commission approval of sufficient DSM programs to achieve this goal. In addition, Decision No. 67744 required APS to implement and maintain a collaborative DSM working group, which includes representatives from the Residential Utility Consumer Office, Southwest Energy Efficiency Project, Western Resource Advocates, the

Department of Commerce Energy Office, Arizonans for Electric Choice and Competition, Commission Staff, and others. On July 1, 2005, APS submitted a "DSM Portfolio Plan" (Docket # E-01345A-05-0477) that was developed in conjunction with this collaborative group.

The DSM Portfolio Plan includes a balanced mix of ten energy efficiency DSM programs that will provide the opportunity to benefit from at least one program to all our customer segments. For residential customers, the portfolio includes programs for existing homes, new construction, consumer products, and special programming for low-income customers. For non-residential customers, the portfolio includes programs targeted to small commercial business customers, large existing facilities, and new construction. The plan includes specific funding to help schools save energy costs. The non-residential portfolio also includes funding for commercial building operator training and energy information services.

With $48 million in DSM spending, APS estimates that the DSM program portfolio, when approved by the Commission, will provide 51 MW of demand reduction over the expected life of all the DSM measures. This corresponds to 3.4 million in saved MWh.

Q. HAS APS IMPLEMENTED ANY OF THESE NEW DSM PROGRAMS AS A RESULT OF DECISION NO. 67744?

A. Yes. One program is currently being implemented, and as of the date of this filing, several others are waiting for Commission approval. The approved portion of the Consumer Products program, which promotes EPA/DOE Energy Star approved compact fluorescent lighting, commenced on October 5, 2005 as part of the national "Change a Light, Change the World" campaign. The

program works with retailers and lighting manufacturers to provide special discounted pricing on energy efficient compact fluorescent lamps ("CFLs") at local retail stores. This makes it easy for customers to participate and encourages high program participation rates. Since October 5, 2005, the program has already resulted in sales of more than 350,000 CFLs in the APS service area, resulting in estimated savings of more than 105,000 MWh over the expected life of the lightbulbs.

In addition, APS is currently conducting a DSM baseline and market potential study to form the basis for supporting and evaluating DSM programs. This study was approved by the Commission in Decision No. 67816.

Q. IS THERE ANYTHING ELSE THAT APS IS DOING RELATED TO DSM AT THIS TIME?

A. Yes. In addition to ongoing messages about energy conservation, APS encourages customers to manage their peak energy demand. Over 375,000 residential customers are currently enrolled in time-of-use rates that encourage customers to shift their usage to off-peak hours. This is a larger program than any other utility in the nation. APS has proposed additional time-of-use rate plans to further encourage customers to manage peak demand. The proposed new time-of-use rate is discussed in detail in Mr. Rumolo's testimony.

In addition, APS conducts seasonal promotions to manage summer peak energy demand. For the past five years APS has promoted Power Partners, a voluntary energy savings and peak demand management program for commercial customers who pledge to reduce consumption on peak summer days when temperatures exceed 110 degrees. Nearly 100 commercial customers have

participated each summer. As another reminder to customers to reduce peak demand, APS has promoted "energy, enough to use not enough to waste" messages as needed during the past few summers.

IV. CONCLUSION

Q. DO YOU HAVE ANY CONCLUDING REMARKS?

A. Yes. In this proceeding I hope that the Commission will recognize the need to set rates in a timely manner that reflect the higher costs APS is incurring to provide reliable service to its customers. In large part, these are higher fuel and purchased power costs that APS has only a very limited ability to control. APS also has significant capital requirements for reliability-related resources, such as the Sundance generation assets, as well as to meet the rapid growth of its delivery system. To meet those requirements, APS must be financially strong and must be perceived as such by the investment community.

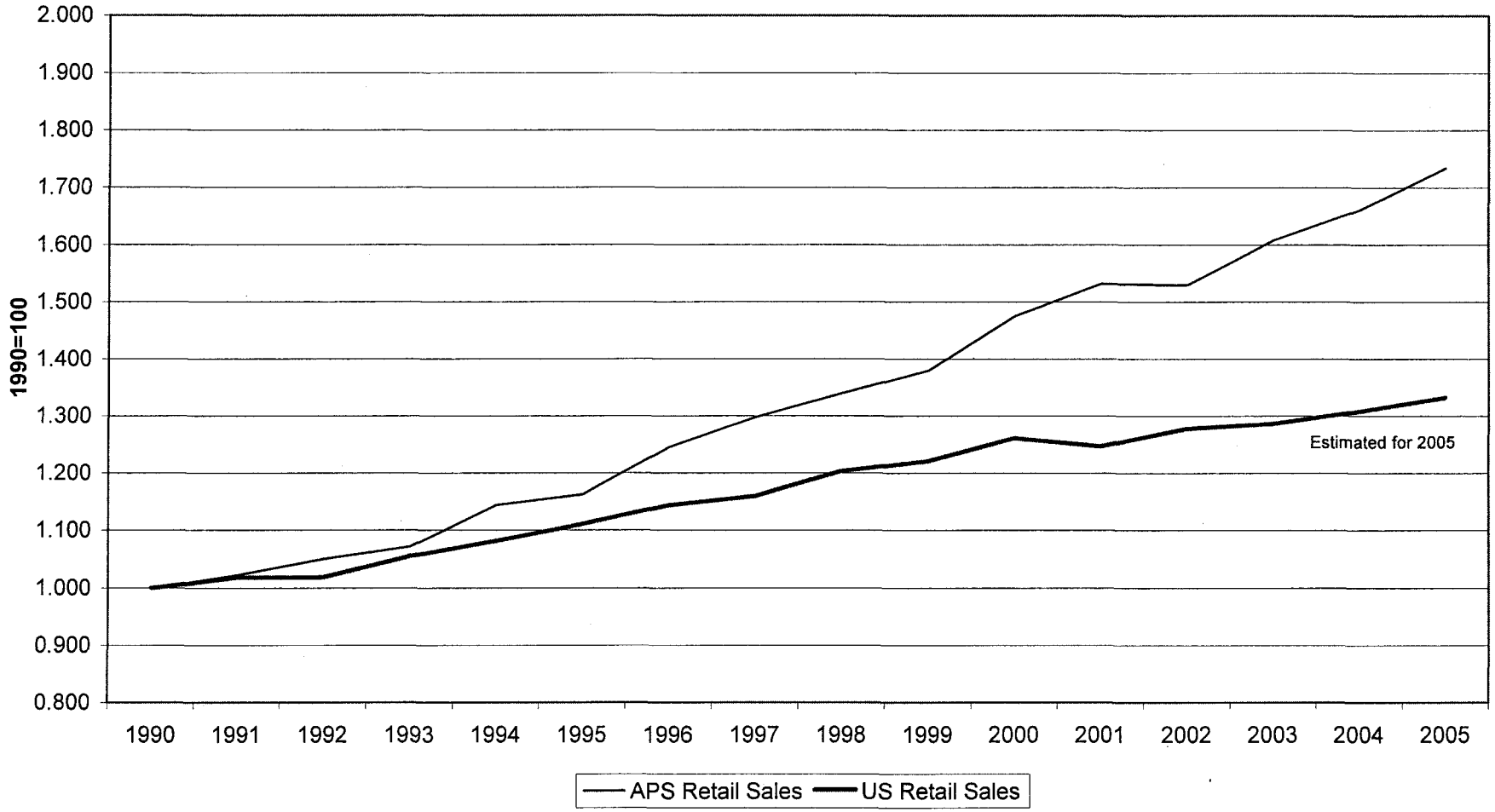
Q. DOES THAT CONCLUDE YOUR PREFILED DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes.

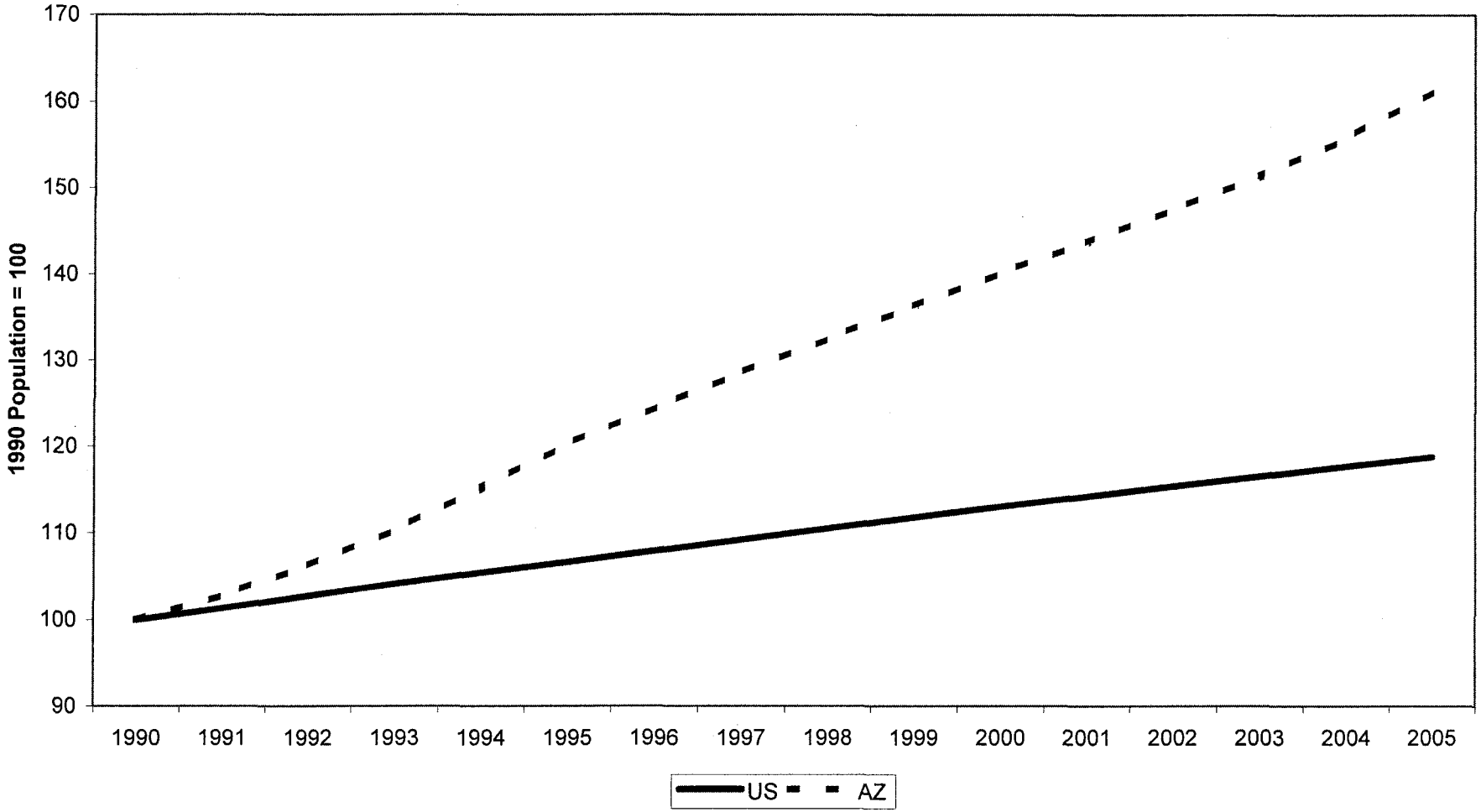
Retail Sales Growth

APS vs U.S.

Indexed to 1990

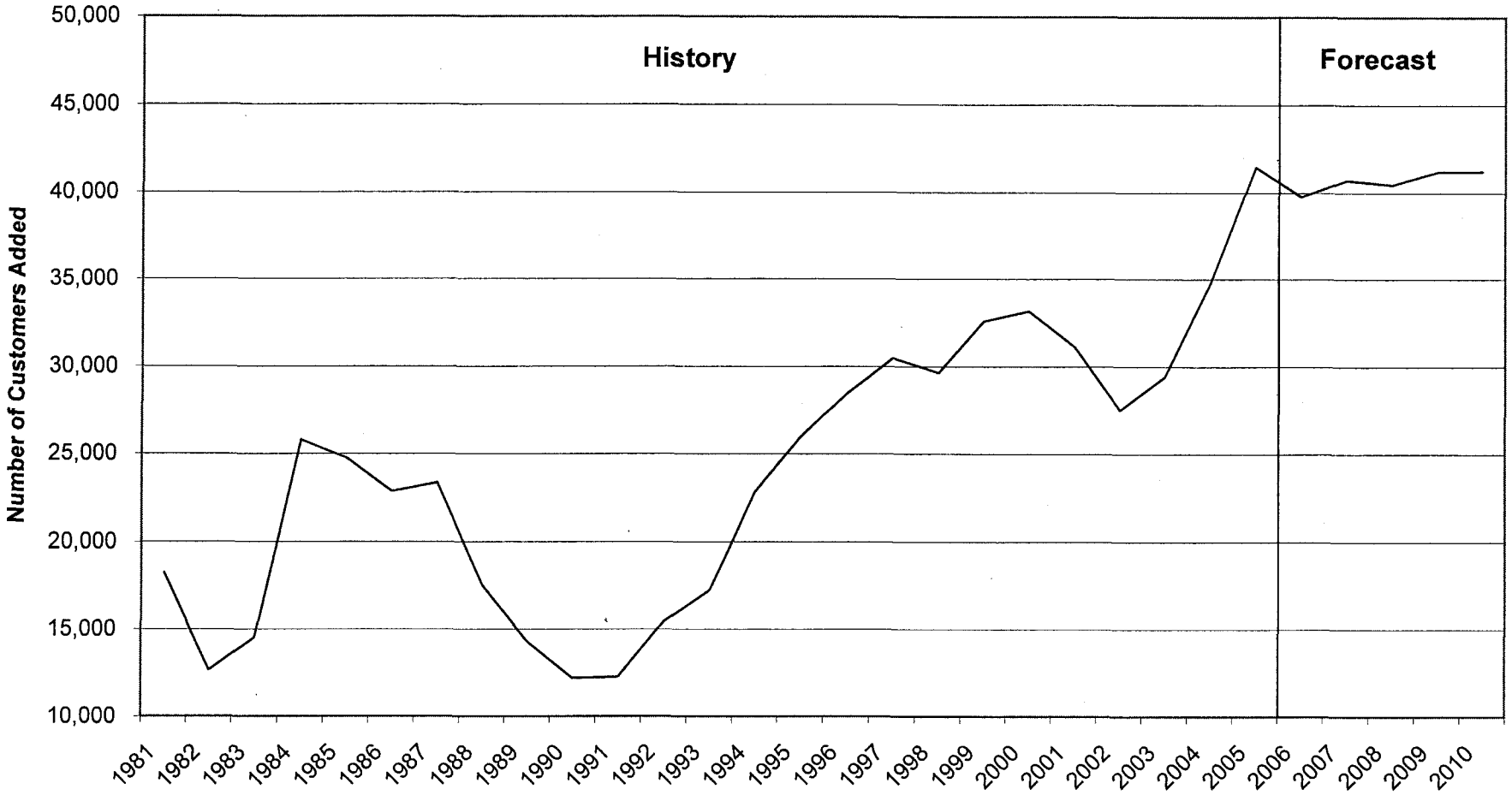


1990 - 2005 Population Growth
Arizona vs U.S.



APS Retail Customer Growth

Number of Customers Added Each Year



DONALD E. BRANDT

DIRECT TESTIMONY OF DONALD E. BRANDT

On Behalf of Arizona Public Service Company

Docket No. E-01345A-05-0816

January 31, 2006

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Aps Financial Indicators with Current Rates ..... Attachment DEB-2

Capital Structure ..... Attachment DEB-3

FFO/Debt Graph ..... Attachment DEB-4

DIRECT TESTIMONY OF DONALD E. BRANDT
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-05-0816)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, ADDRESS AND OCCUPATION.

A. My name is Donald E. Brandt. I am Executive Vice President and Chief Financial Officer for both Pinnacle West Capital Corporation ("Pinnacle West") and Arizona Public Service Company ("APS" or "Company"). I am responsible for the finance, treasury, accounting, tax, investor relations, financial planning, and power marketing and trading functions at Pinnacle West and APS. My business address is 400 North 5th Street, Phoenix, Arizona, 85004.

Q. WHAT IS YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND?

A. I received a Bachelor of Science degree in business administration with a major in accounting from St. Louis University in 1975. Before joining Pinnacle West and APS in 2003, I was Senior Vice President and Chief Financial Officer of Ameren Corporation, the parent company of the electric and gas utilities Union Electric Company (d/b/a AmerenUE) and Central Illinois Public Service Company (d/b/a AmerenCIPS).

Before joining Union Electric Company in 1983, I was a manager with Price Waterhouse where I provided audit and consulting services to public companies, with a concentration in the utility industry. I am a certified public accountant and a member of the American Institute of Certified Public Accountants and the Arizona Society of Certified Public Accountants.

Q. HAVE YOU EVER TESTIFIED BEFORE ANY FEDERAL OR STATE REGULATORY AGENCIES?

A. Yes. I submitted pre-filed testimony before the Arizona Corporation Commission ("Commission") in APS' last rate case that was the subject of Decision No. 67744 (April 7, 2005). I also testified in support of the Company's 2005 request for a power supply adjustor ("PSA") surcharge in Docket No. E-01345A-05-0526 and am a witness in Docket No. E-01345A-06-00009, which is the APS emergency interim rate proceeding. In addition, I have provided testimony before the Federal Energy Regulatory Commission ("FERC"), the Missouri Public Service Commission, and the Illinois Commerce Commission on numerous occasions.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I will address two broad issues: (i) the Company's financial condition under both Decision No. 67744 and the requested rate increase; and (ii) the Company's proposed capital structure. I will explain the financial results for APS if the APS rates approved in Decision No. 67744 remain in effect through 2007. I also will discuss the Company's projected results if the proposed rate increase is granted as of January 1, 2007. I am sponsoring the Company's projected financial results shown on Schedules A and F of the Commission's standard filing requirements ("SFRs" or "SFR Schedules"). Specifically, I am sponsoring the projected year information provided in SFR Schedules A-2 through A-5, and the projected information portion of SFR Schedules F-1 through F-4.

In addition, I will review the Company's capital requirements and the increased costs to APS and its customers resulting from the recent downgrade by Standard & Poor's ("S&P"), as well as the potential for and impacts of a further negative

evaluation resulting in non-investment grade status. Furthermore, I will provide highlights of the reaction from the financial community to recent regulatory actions and of Wall Street's future expectations for the Company. I will examine the critical need for an effective PSA and for the Company to receive fair and timely recovery under that PSA in order to maintain its current credit ratings. I also will explain the reasons for the Company's proposed capital structure.

II. SUMMARY

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. Since the late 1990s, we have been in the midst of one of the most turbulent business cycles in utility and energy industry history. The financial markets have reacted by becoming increasingly cautious and demanding in their evaluation of the financial condition of utilities. In reaction to the piecemeal reimposition of regulation across the country, the financial community has demonstrated heightened sensitivity to the financial stability of electric utilities and the impact of regulatory decisions on them.

APS has requested a rate increase in order to maintain financial ratios consistent with an investment grade credit rating needed to fund at a reasonable cost the significant infrastructure required to meet the needs of its rapidly growing customer base. This request will not allow the Company to improve its credit ratings to the more desirable "A" level, but, if timely implemented, it should prevent further deterioration of APS' credit ratings.

In addition to the requested rate increase, the credit rating agencies seriously weigh APS' regulatory environment in their assignment of ratings. Positive

regulatory consideration of the rate case, including the manner of treatment and timing of the PSA adjustor and surcharges, will provide the rating agencies an indication of the level of regulatory support for APS' credit ratings. When they assess the level of regulatory support as low, the rating agencies characterize the overall business risk of that company as higher. S&P's recent negative revision of APS' business profile from '5' to '6' means we must now meet more stringent financial metrics to maintain "BBB" credit ratings. As a result of this revision, APS' projected financial metrics rank below those needed for a typical "BBB" rating. This negative revision of APS' business profile and the consequent downgrade of its credit ratings to "BBB-" have already increased the Company's borrowing costs by approximately $1 million per year.

Should the Commission reject or substantially reduce the Company's rate request, the resultant downgrade to junk status would cause an initial annual increase in interest expense in the range of $15 million to $30 million. From 2007 through 2016, APS will go to the capital markets to issue several billion dollars of debt to fund its required infrastructure additions and improvements. The amount of additional annual interest expense would reach $115 million to $230 million by 2016. On a cumulative basis, this amounts to an additional $675 million to $1.3 billion in interest expense between 2007 and 2016 — an increase the customers would eventually shoulder. (The ranges of additional interest expense reflect estimated financing costs calculated using the upper and lower limits of the difference between historical interest rates for "BBB" rated and non-investment grade utility debt financings.)

Wall Street supplies the capital that will allow APS to grow to meet the energy needs of its customers. Non-investment grade credit ratings and a poor view of

APS by Wall Street would eliminate the Company's ability to attract capital at a reasonable cost.

The Company proposes to adjust its capital structure, as shown on Attachment DEB-3, to 46% debt/54% equity to buttress its financial metrics and prevent further degradation of its current credit ratings. Although APS' balance sheet would reflect this nominally stronger structure, the rating agencies routinely include items such as off-balance sheet financings, operating leases and debt imputed for purchased power agreements ("PPAs") in their analysis. Using these more rigorous criteria, our capital structure becomes more leveraged and hence more risky 50% debt/50% equity.

Q. ARE YOU SPONSORING ANY ATTACHMENTS TO YOUR TESTIMONY IN ADDITION TO THOSE PORTIONS OF THE SFR'S DESCRIBED ABOVE?

A. Yes. My testimony includes the following Attachments:

1. DEB-1 – APS Financial Indicators with Proposed Rates.
2. DEB-2 – APS Financial Indicators with Current Rates.
3. DEB-3 – Capital Structure.
4. DEB-4 – FFO/Debt Graph.

III. FINANCIAL RESULTS

Q. PLEASE DISCUSS THE CURRENT FINANCIAL CONDITION OF APS.

A. Perhaps a historical perspective would be helpful. As the Commission knows, APS' rates decreased throughout the 1990s until the Commission approved the rate increase included in Decision No. 67744. Although that rate increase helped to reinforce the Company's sliding financial metrics to some extent, APS' continued ability to earn a fair return and meet the financial criteria necessary to

prevent further downgrades remains at risk without the rate relief now being requested.

Please allow me to explain what this means in terms of the Company's current financial condition. In Attachment DEB-1, I provide some key financial metrics, including: (1) funds from operations ("FFO") interest coverage; (2) FFO to debt ("FFO/Debt"); (3) debt to capital ("Debt to Capital"); and (4) return on common equity ("ROE") for three historic (2003, 2004, and 2005) and two projected (2006 and 2007) years, with the proposed rate increase effective January 1, 2007. These calculations do not include the effects of the approval of the Interim Application filed on January 6, 2006, but they do assume that the Commission grants the Company fair and timely approval of surcharges and adjustors provided for under the PSA. Without such approvals, including that of the interim rate request, APS would suffer a dramatic and adverse financial impact.

The financial projections for 2006 under DEB-1 assume the annual adjustment mechanism goes into effect on April 1, not the recently approved accelerated date of February 1. I have also assumed an $80 million surcharge becomes effective February 1, 2006 with recovery over a two-year period. The Commission's actions last week made both assumptions inaccurate. Unfortunately, we did not have time to update the corporate financial model. Nevertheless, these actions have a minimal impact on the financial ratios and would actually result in a further deterioration of the metrics. The financial projections for 2006 under DEB-2 assume the same April 1 effective date for the annual adjustor and surcharge recovery beginning February 1. In addition, we

assumed that the Commission did not lift the $776.2 million cap. Again, minimal impacts resulted.

Furthermore, as demonstrated in Attachment DEB-1, the ROE reached 9.0% in 2004 and then declined in 2005 to 6.8%. The forecasted 7.9% ROE in 2006 falls substantially below the range that APS witness Dr. William Avera determined to be APS' appropriate cost of equity.

APS' ability to earn a fair rate of return and maintain investment grade credit ratings remains at risk without the requested rate increase and without the timely and fair implementation of PSA surcharges and adjustments. Indeed, without adequate permanent rate relief and a fully functional and effective PSA, APS will have no opportunity to recover its capital costs, which effectively would confiscate a portion of that capital in economic terms.

Q. WHAT DOES A CREDIT RATING AGENCY DO?

A. A credit rating agency provides opinions on the creditworthiness of an entity and its financial obligations (such as bonds, preferred stock, and commercial paper). Pursuant to its regulations, the U.S. Securities and Exchange Commission ("SEC") has denominated four of these credit rating agencies "Nationally Recognized Statistical Rating Organizations" or "NRSROs." The SEC currently includes as NRSROs Dominion Bond Rating Services Ltd. ("DBRS"), Fitch, Inc. ("Fitch"), Moody's Investors Service ("Moody's"), and S&P.

Generally, long-term debt credit ratings distinguish between investment grade and non-investment grade. For example, a credit rating agency may assign a "AAA" credit rating as its top investment grade rating for corporate bonds and a "BB" credit rating or below for non-investment grade or "junk" corporate bonds.

Rating designations of both Fitch and S&P have "BBB-" as the lowest investment grade rating and "BB+" as the highest non-investment grade rating. Comparable rating designations of Moody's are "Baa3" and "Ba1", respectively.

Commercial paper[1] credit ratings are designated by S&P as "A-1", "A-2", "A-3", and "B", with "A-1" indicating the highest quality rating and "B" being at the low end of the spectrum. Moody's has comparable ratings designations of "Prime-1", "Prime-2", "Prime-3", and "Not Prime" (abbreviated as "P-1", "P-2", "P-3", and "NP"). Critically, no market has developed for commercial paper rated below "A-3" by S&P or "P-3" by Moody's and even the A-3/P-3 market is of recent origin and lacks the liquidity of the market for higher grades of commercial paper.

Q. WHICH CREDIT RATING AGENCIES ISSUE CREDIT RATINGS ON THE DEBT OF PINNACLE WEST AND APS?

A. Moody's, S&P, and Fitch issue credit ratings on APS' debt. Moody's and S&P both issue credit ratings under a formal relationship under which they have access to the Company's nonpublic financial forecasts and data for their independent analytical purposes. Fitch issues credit ratings on Pinnacle West and APS based solely on its access to publicly available financial information, data and news.

Within the publicly traded debt markets, Moody's and S&P have the greatest influence. With rare exception, every mutual fund, insurance company, and

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[1] Commercial paper is a short-term, unsecured promissory note with a maturity ranging from 1 to 270 days commonly issued by corporations to finance working capital requirements. Because the notes are unsecured, large corporations with investment grade credit ratings dominate the commercial paper market.

other institutional debt investor require an entity to obtain credit ratings from Moody's and S&P before they will consider an investment in that entity's debt securities. Many institutional investors value Fitch credit ratings, particularly in connection with debt securities that have some unique or unusual provision.

Q. WHAT ARE THE CURRENT CREDIT RATINGS FOR APS?

A. The table below lists the current credit ratings:

	Moody's	S&P
Senior Unsecured Debt	Baa1	BBB-
Secured Lease Obligation Bonds	Baa1	BBB-
Commercial Paper	P-2	A-3
Ratings Outlook	Under Review For Possible Downgrade[2]	Stable[3]

Within the spectrum of investment grade debt, the financial markets consider these above ratings low investment grade.

Q. YOU MENTIONED THAT THE COMPANY NEEDS TO MEET CERTAIN FINANCIAL CRITERIA TO MAINTAIN ITS CREDIT RATINGS. WHAT ARE THESE FINANCIAL CRITERIA AND HOW DO THEY IMPACT THE COMPANY'S RATINGS?

A. Credit rating agencies have established certain financial results and ratios ("metrics") as guidelines for determining a credit rating. For example, the

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[2] A RUR (Rating(s) Under Review) designation indicates that the issuer has one or more ratings under review for possible change in the short term.

[3] "Ratings Outlook" indicates the possible direction a rating may move over the intermediate to longer term. "Positive" indicates ratings may be raised; "Negative" indicates ratings may be lowered; and "Stable" indicates ratings are not expected to change absent some significant positive or negative event.

published primary financial metrics required by S&P for a company with a business profile '6' to maintain "BBB" and "BB" category ratings are as follows:

	Business Profile 6	
	BBB	BB
FFO interest coverage	4.2 - 3.0	3.0 - 2.0
FFO/Debt	28% - 18%	18% - 12%
Debt to Capital	48% - 58%	58% - 62%

The other rating agencies use similar, although unpublished, criteria.

Q. WHY DO THE RATING AGENCIES CONSIDER THE FINANCIAL CRITERIA IMPORTANT?

A. Financial criteria measure a company's financial health, performance and risk. Although a strong relationship exists between earnings and cash flow, analysis of cash flow can reveal debt-servicing capability either stronger or weaker than otherwise apparent from earnings ratios. Thus, financial analysts use the FFO interest coverage ratio to measure the sufficiency of a company's cash flow to pay its interest costs. Debt to Capital measures a company's leverage. FFO/Debt measures the sufficiency of a company's cash flow to service both debt components - interest and debt principal - over time. FFO/Debt captures aspects of both interest coverage and the degree of leverage and, consequently, carries the most weight with the credit rating agencies in determining ratings.

Q. IF THE PROPOSED RATES ARE IMPLEMENTED ON JANUARY 1, 2007, HOW DO APS' FINANCIAL METRICS COMPARE WITH THOSE NEEDED TO MAINTAIN INVESTMENT GRADE RATINGS?

A. As you can see in Attachment DEB-1, APS' Interest Coverage stays relatively flat at 3.4 times from 2005 to 2006 even with the PSA increases and then improves to 4.3 times if the proposed base rate increase applies to the full year 2007. The FFO/Debt ended 2005 at 14.8%, improves slightly in 2006 to 16.0%, and increases to 21.9% at the end of 2007, assuming the proposed base rate increase is in effect for all of 2007. The Debt to Capital ratio demonstrates improvement from 2004 to 2005 after the infusion of equity into APS in 2005, ending 2005 at 50%. Even with the PSA increases in 2006 and the proposed base rate increase in 2007, Debt to Capital deteriorates to 53.4% by 2007 because capital expenditures exceed cash flows required to serve the rapid growth in APS' service territory. (The first three ratios set forth in Attachment DEB-1 and Attachment DEB-2 reflect the effects of including imputed debt and interest expense attributable to purchased power agreements and to the Palo Verde Unit 2 sale and leaseback, which are adjustments made by the rating agencies.) ROE remains very weak in 2006 at 7.9%, but improves to a still inadequate 9.8% in 2007 assuming the base rate increase is in effect for the full year. The 9.8% still remains below the Company's requested 11.5% return on equity due to the continued high level of capital expenditures required to serve the customer base, as well as inflationary impacts on operating costs and continued record high costs for natural gas and purchased power of which APS has to absorb approximately 10% of these higher fuel costs through the PSA.

Q. IN DETERMINING CREDIT RATINGS, DO THE CREDIT RATING AGENCIES LOOK AT MORE THAN THE FINANCIAL METRICS YOU DETAILED ABOVE?

A. Yes. The determination of credit ratings includes more than financial ratio analysis. The agencies determine their ratings based on a variety of both

quantitative and qualitative factors. For their quantitative analysis, the agencies look not only at the financial metrics of a company, but also at significant trends in financial performance. They review financial projections and make an independent assessment of the likelihood of various future financial scenarios. The agencies look for financial metrics that stay within the specified target ranges. While S&P publishes their ranges, Moody's informs a company if any of the ratios do not meet the level they determine appropriate for the existing credit rating.

In addition to the quantitative analysis, the agencies perform an extensive qualitative analysis. The rating agencies assess the regulatory environment in which a regulated utility operates, the various business and financial risks a company faces, and the utility's management and prior track record. After analyzing these quantitative and qualitative factors, the rating agencies determine a company's credit ratings. Moody's addresses this aspect of credit ratings on its website (Moodys.com):

> 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.

Q. HOW IMPORTANT IS THE REGULATORY ENVIRONMENT TO A RATING AGENCY'S QUALITATIVE ANALYSIS?

A. Rating agencies view the regulatory environment as a major factor in evaluating companies. In an article *New York Regulators' Consistency Supports Electric Utility Credit Quality* dated August 15, 2005, S&P states:

> Regulation defines the environment in which a utility operates and greatly influences a company's financial performance...To be viewed positively, regulatory treatment should be timely and allow consistent performance over time, given the importance of financial stability as a rating consideration."

In another article *Industry Report Card: U.S. Electric/Water/Gas*" dated July 6, 2005, S&P provides an overview of utilities' ratings and opens the report by stating, "[r]egulatory rulings have once again become a dominant factor in companies' credit quality."

Wachovia Securities, in a report *Utilities: The Dark Side of 'Back to Basics'* dated April 5, 2005, discussed the consequences of rising capital spending and the need for rate relief:

> Utilities are coming to regulators for rate increases to recover higher fuel prices, the cost of compliance with new environmental regulations, and investments for reliability improvements and for customer growth. With higher utility spending and the rising cost of fuel, electric utility revenue requirements are likely to grow faster than the general level of inflation for many years.

Q. WHAT IS THE CURRENT STATUS OF APS' CREDIT RATINGS?

A. APS' credit ratings are currently in the investment grade range ("BBB-" by S&P and "Baa1" by Moody's). On December 21, 2005, S&P downgraded APS' credit ratings from "BBB" to "BBB-", the **absolute** lowest investment grade credit rating. S&P expressed concern "that the Arizona Corporation Commission (ACC) is not expeditiously addressing APS' growing fuel and purchased-power cost deferrals...." S&P also noted that its decision to characterize APS' new, lower credit ratings as "stable" assumed "that the ACC will resolve at least a portion of APS's increasing deferred power costs in January 2006." S&P's *Research Update: Pinnacle West Capital's, Arizona Public Service's Ratings Lowered to 'BBB-'; Outlook Stable* dated December 21,

2005. On January 26, 2006, S&P affirmed the Company's credit ratings "following the generally constructive decisions made by the Arizona Corporation Commission (ACC) on Jan. 25... 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." S&P's *Research Update: APS, PWCC's 'BBB-' Corporate Credit Ratings Affirmed On ACC Vote But Challenges Continue* dated January 26, 2006.

On January 10, 2006, Moody's placed the long-term ratings of APS under review for possible downgrade. The agency declared that an uncertain regulatory environment in combination with the absence of timely recovery of increased fuel and purchased power costs precipitated this action. In its article *Moody's Places The Debt Ratings of Pinnacle West (Sr. Uns. Baa2) And Arizona Public Service Co. (Sr. Uns. Baa1) Under Review For Downgrade* dated January 10, 2006, Moody's wrote:

> The review is prompted by deterioration in the company's current and projected financial metrics as a result of increased fuel and purchased power costs that the company has not been able to recover on a timely basis....
>
> The review will focus on the outcomes of the various rate requests that APS has filed or is expected to file with Arizona Corporation Commission (ACC). Due to the substantial increase in market prices of fuel and electricity, APS is experiencing sharp cost increases. The magnitude of rate increases needed to cover these costs is sufficiently large to be likely to trigger regulatory and ratepayer resistance. In this context the recommendation by the administrative law judge does not bode well for full and timely recovery of increased costs....

> There remains a significant amount of uncertainty surrounding the ultimate amount of cash that APS and Pinnacle will generate in 2006. APS and Pinnacle's financial strength are highly dependent upon timely implementation of cost recovery mechanisms....
>
> Beyond 2006, supportive regulatory treatment remains key to the company's ability to maintain financial strength in light of significant needs for capital investment to serve a growing service territory.

Q. WHAT WOULD BE THE IMPACT ON THE COMPANY'S FINANCIAL CONDITION SHOULD THE COMMISSION REJECT OR SUBSTANTIALLY REDUCE APS' RATE REQUEST?

A. APS' financial condition would suffer prompt, severe and continued deterioration, resulting in a credit ratings downgrade to the non-investment grade level. In Attachment DEB-2, I show APS financial metrics assuming the denial of the instant rate application. Interest Coverage deteriorates from 3.3 times at the end of 2005 to 3.0 times at the end of 2007. FFO/Debt ends 2005 at 14.8% and further deteriorates to 13.7% by the end of 2007, both of which are in the non-investment grade range. Debt to Capital shows improvement from 2004 to 2005 because of the infusion of equity into APS in 2005. Without the proposed base rate increase, however, the metric climbs from 50% leverage at the end of 2005 to almost 57% at the end of 2007. In addition, 2007 common equity returns decline to 4.3%, clearly a small fraction of what Dr. Avera has determined to be APS' cost of equity. Significantly, such a return approximates that which an extremely cautious investor seeking a risk free fixed income investment would expect from long-term US Treasury Bonds. As I noted earlier, providing equity investors with no opportunity to earn at least the cost of that equity is economic confiscation of a portion of that equity's value. Further, Moody's noted in its *Rating Action* dated January 10, 2006:

> The ratings of APS and Pinnacle are likely to be downgraded unless there are clear signals that APS will receive timely and full recovery of its increased costs such that we would expect their credit metrics to return to levels commensurate with those of similarly rated utility companies.

The ratings agencies consider trends as well as the absolute level of the financial metrics. The rating agencies have already drawn negative inferences from the protracted time required to obtain cash recovery of deferrals and the resultant deterioration of APS' financial health.

Q. COULD APS RETAIN ITS INVESTMENT GRADE RATINGS UNDER THE ABOVE CIRCUMSTANCES?

A. No. APS will fall below investment grade. First, financial metrics alone would not support a continued "BBB" rating, especially in light of the continued trend of deterioration. Second, the Company could not demonstrate to the rating agencies any prospect of stopping further declines in its financial condition, let alone showing potential improvement in its financial metrics, unless the Commission continues to show support for APS' financial health. The Company's financial situation will be further exacerbated should it not receive timely and fair recovery of its fuel and purchased power costs under the pending interim emergency rate request.

Q. HOW IMPORTANT IS TIMELY AND SUFFICIENT RATE RELIEF TO APS' INVESTMENT GRADE CREDIT RATINGS?

A. It is of utmost importance. As APS witness Steve Fetter discusses in more detail and as I have already reviewed, rating agencies monitor more than just the financial metrics. They also look at qualitative factors, ranking regulatory treatment one of the most important. S&P and Moody's have cited regulatory

uncertainty as a source of credit challenge for APS. In its *Research Summary: Arizona Public Service Co.*, dated June 24, 2005, S&P noted:

> 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....
>
> 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.

In addition, Moody's *Analysis: Pinnacle West Capital Corporation* dated May 2005, cites the regulatory environment in Arizona as unpredictable and describes it as a credit challenge.

The rating agencies would regard the failure by this Commission to recognize the need for the rate increase contained in this request as an extremely significant negative. Such action could be interpreted by the rating agencies as indicating that the Commission will neither support APS taking the steps necessary to ensure the reliability of its system and responsibly address the needs of its customers nor to take measures to help the Company safeguard its financial integrity.

Q. HOW IMPORTANT WAS THE COMMISSION'S APPROVAL OF THE PSA FROM THE RATING AGENCIES' PERSPECTIVES?

A. The credit rating agencies viewed the approval of the PSA as one of the critical elements of the last rate case decision (the other two being the approval of the transfer of the PWEC assets and the modest rate increase). In its April 27, 2005, *Rating Action: Pinnacle West Capital Corporation,* Moody's attributed the

change in outlook to stable for APS at least in part to the approval of the PSA. The rating agencies view the existence of a PSA as reducing financial risk, especially for a company located in an area with growing customer and load requirements such as Arizona. In its May 4, 2005, *Credit Analysis: Arizona Public Service Co.,* Fitch noted that "the adoption of the PSA and transfer of the PWEC assets were, in Fitch's view, constructive developments that enhance APS's risk profile and creditworthiness."

However, S&P, in its April 1, 2005 *Research Update* on APS, reiterated that its longer-term view of the current PSA was cautious:

> [O]ver time, it is likely that APS will need a stronger PSA to maintain its current credit ratings, particularly given the expectation that over the next five years APS' fuel mix will become heavily concentrated in natural gas.

And, more recently, S&P noted:

> 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.

Research Summary, Arizona Public Service Co. dated October 4, 2005.

The agencies have noted that if APS loses the PSA or fails to receive timely and fair recovery of its fuel and purchased power costs, APS' financial profile will be significantly weakened.

Q. DO YOU AGREE WITH S&P'S CHARACTERIZATION OF THE PSA AS BEING WEAK? IF SO, WHY?

A. Yes. The current PSA has several critical weaknesses. Even in light of the Commission's recent and helpful interpretation of the impact of the $776.2 million annual "cap" on fuel cost recovery and, further, assuming the permanent

lifting of the "cap" as requested by the Company, the PSA continues to have structural weaknesses that we must address. First and foremost, APS may recover pursuant to the PSA only once a year rather than when the deferral balance reaches a certain level. The triggering of both the annual adjustment mechanism and the surcharge can take place only after we calculate the year-end deferral balance. Consequently, significant increases in deferral balances during the year face considerable regulatory lag prior to recovery. Second, the annual adjustor remains capped at 4 mills. This cap serves to impede timely recovery of accumulated deferrals. And third, the surcharge process has no specific timeline for cost recovery. All of these issues aggravate the substantial costs associated with the Company's growing reliance on natural gas.

Q. PLEASE PROVIDE SPECIFIC DETAILS REGARDING THE FINANCIAL IMPACT OF A CREDIT RATINGS DOWNGRADE ON APS.

A. Should the rating agencies lower the Company's ratings below investment grade to "junk" levels, the impact would be immediate and costly on a number of fronts:

1. Over the next ten years APS will need to issue several billion dollars of additional long-term debt to finance essential generation, environmental control, and transmission and distribution construction programs, and to refinance maturing long-term debt. APS would have no alternative but to turn to the "junk" bond market to finance this capital need.

   The non-investment grade fixed income market has far fewer buyers, much wider spreads to Treasuries, significantly shorter maturities, and exceedingly heightened volatility. The availability of funding in this market ebbs and flows with great speed, thus often depriving many needy

junk issuers of a reliable source of funds during times of heightened demand and competition.

As a result, by 2016, the Company's annual financing costs recoverable from customers would increase between $115 million and $230 million over projected amounts had APS not suffered the downgrade to "junk" status.

2. APS has $539 million of tax-exempt debt outstanding under remarketing programs whereby the securities are effectively issued with a daily or weekly maturity, with the intention that the securities will be continuously remarketed until their ultimate maturities in 2024 through 2034. The annual interest rate on this debt floats around 3.0%. Thus, the Company currently avails itself of extremely attractive short-term, tax-exempt interest rates, under the "umbrella" of a very long-term debt instrument. This debt requires bank letters of credit ("LOCs") or third party insurance to support its creditworthiness. The commercial banks and municipal bond insurance companies base their pricing on APS' credit ratings. Any further degradation in the ratings would increase such costs. Additionally, investors ordinarily require a higher yield due to the increased risk associated with the lower ratings. The increased fees and additional interest would increase financing costs $4 million per year that would need to be recovered from customers.

3. Given the seasonal nature of APS' cash flows, the Company places a heavy reliance on commercial paper for working capital needs. APS expects to average about $200 million of commercial paper outstanding

and could face peak liquidity needs of up to $400 million. As a result of the recent downgrade by S&P, APS' access to the commercial paper markets has been significantly curtailed. APS' commercial paper rating is currently A-3 and P-2 by S&P and Moody's, respectively. A significant number of commercial paper buyers cannot purchase "Third Tier" (A-3) paper because of prohibitions in their investment policies. Given that limited investor base, APS can no longer count on daily liquidity. At best, the Company can borrow up to one week, whereas commercial paper can typically be issued up to 270 days. Should APS suffer further downgrades to non-investment levels, its access to the commercial paper market would be eliminated. No institution purchases junk-rated commercial paper. APS would forfeit the significant advantages of commercial paper, daily liquidity and competitive pricing. As a direct consequence, APS would be forced to turn to more costly revolving credit agreements to satisfy its daily working capital needs. Such a situation would increase APS' overall cost of borrowing by about $1 million per year, ultimately leading to increased costs for APS' customers.

All of these costs would further burden APS, which already is laboring under the recent downgrade by S&P.

Q. ARE THERE ANY OTHER COSTS AND/OR RISKS TO APS AND ITS CUSTOMERS THAT WOULD RESULT FROM APS BEING DOWNGRADED TO A "JUNK" LEVEL CREDIT RATING?

A. A credit rating downgrade to "junk" would bring about additional negative impacts that, while difficult to quantify, carry the following additional costs and risks:

1. APS places significant reliance on bank credit agreements which it renews on a periodic basis. Non-investment grade credit ratings, forecasted weak cash flow, and deteriorated financial metrics, in combination with the unsupportive regulatory environment, would cause most banks to "run for the hills" upon the renewal date of such agreements. The few banks that might renew would demand significantly higher prices and extremely onerous covenants that, in the event of further financial stress, could potentially take APS to the brink of default and bankruptcy.

2. APS' marketing and trading function would suffer as a result of the downgrade of APS to a non-investment grade rating. Consistent throughout our energy trading business, most of APS' agreements with energy trading counterparties require, in the event of a downgrade to junk status, that APS provide the counterparty with cash collateral (termed a "collateral call") to cover the difference between the contract price and the then-existing market price of the commodity. This could place a significant liquidity strain on APS at a time when the Company has restricted access to the capital markets. Moody's highlighted this issue in its October 2002 publication, *U.S. Electric Utilities – 2002 Industry Outlook*:

> [T]he energy merchant sector carries significant liquidity risk due to its confidence-sensitive nature and to the system of credit allocation among energy traders that requires collateral postings in the event of rating downgrades. The structure relied on by the industry creates a type of pernicious rating trigger that became a key factor in creating distress situations for several energy traders. The existence of explicit and implicit rating triggers in most commercial contracts among the traders ensures that counterparty contracts either

> unwind or require additional cash collateralization if credit ratings decline below investment grade. As downgrades below investment grade occurred due primarily to Moody's concerns about weak cash flow generation from most energy merchant companies, the result was a sudden and precipitous call on liquidity at a time that these companies were least able to access the market.

3. In addition to cash collateral calls, energy trading counterparties place other onerous terms on their dealings with non-investment grade companies. APS would be forced to prepay for a large amount of the Company's power plant fuel and fuel transportation needs. Any form of longer-term commodity agreement would require the Company to provide up-front cash collateral. APS' costs of doing business in the wholesale markets would increase significantly and make it much more difficult to hedge the Company's commodity positions, further increasing the Company's risk profile.

Q. COULD YOU SUMMARIZE THE IMPACT OF A DOWNGRADE ON APS' FINANCING COSTS?

A. Yes. A downgrade of APS' credit ratings to non-investment grade would cause annual interest expense to increase approximately $15 million to $30 million in 2007. That annual increased interest expense would escalate to approximately $115 to $230 million by 2016. On a cumulative basis, over a ten-year period beginning in 2007, additional interest expense of $675 million to $1.3 billion, depending on actual interest rates paid, would be passed on to customers.

Q. WHAT SHOULD BE THE ULTIMATE GOAL FOR APS IN TERMS OF CREDIT QUALITY?

A. We have spent much time discussing the problems attendant upon APS falling below an investment grade credit rating. I do not believe that this Commission

wants to establish rate levels such that APS just barely qualifies for an investment grade credit rating. I have been the chief financial officer of an electric utility for more than 17 years, have almost 30 years of utility finance experience and, during that period of time, I have had experience working with utilities rated from "BBB-" up to a utility rated "AA-". A utility rated "A" or better always has far more attractive financing options, covenants and pricing than one rated below an "A". In addition, the market for non-investment grade debt, the so-called "high-yield" or "junk bond" market occasionally closes for indefinite periods of time. Should APS fall to "junk" status, we can have no confidence that APS could successfully issue the billions of dollars of "junk" bonds that would be required over the next ten years. Looking to the future, with the strong growth inherent in APS' service territory and APS' continuing need to make capital investments to meet the growing energy needs of its customers, APS must achieve a credit rating of "A" to provide it with the appropriate level of financial flexibility to minimize its financing costs and maximize its options over the long term.

IV. FINANCIAL COMMUNITY VIEW OF APS

Q. PLEASE SUMMARIZE HOW THE FINANCIAL COMMUNITY'S VIEW OF THE ELECTRIC INDUSTRY CHANGED BETWEEN 2000 AND TODAY.

A. In 2000, the electric utility industry sat atop the crest of an economic boom cycle. Many companies that had operated within a regulated environment had formed non-regulated affiliates in anticipation of the restructuring of the industry that swept across the country. Regional market conditions had driven up spark spreads and inflated forward price curves resulting in speculative power plant development. The participants in that market were highly rated,

financially robust companies that had ready access to the debt capital and bank credit markets. Financial institutions enthusiastically supported the extension of credit. By mid-2001, however, the California market imploded and FERC put price caps in place, effectively halting this rapid development. The financial community, including financial institutions and rating agencies, became concerned about what they came to view as an over-built market.

As restructuring came to a halt, and reversed in some cases, financial institutions and the rating agencies began to focus again on the regulatory environment in which companies operate. They started to examine more closely the nature of the relationships between the companies and their regulators. That scrutiny continues today. As S&P stated in its April 14, 2005 report *U.S. Utility Regulation Returns to Center Stage*:

> [T]he confluence of the approaching end of these transitions periods and the growing need in certain regions of the country for significant resource additions is quickly returning the regulatory arena to center stage. In assessing the regulatory environment in which a utility operates, Standard & Poor's analysis is guided by certain principles, most prominently consistency and predictability, as well as efficiency and timeliness. For a regulatory scheme to be considered supportive of credit quality, commissions must limit uncertainty in the recovery of a utility's investment. They must also eliminate, or at least greatly reduce, the issue of rate-case lag that may prove detrimental if a utility needs rate relief....
>
> While it is still too early to determine what trends may prevail regarding decisions for the post-transition market structure, it is noteworthy how credit quality is emerging as an integral component in recent rulings....

Q. SHOULD THIS COMMISSION CARE WHAT WALL STREET THINKS ABOUT ARIZONA REGULATION?

A. Yes. Wall Street supplies the capital that will allow APS to grow to meet the energy needs of its customers. Of course, one must ask "at what cost." What

Wall Street thinks of APS and this Commission's actions will have a great bearing on the ultimate costs charged to customers.

Q. DOES WALL STREET CONCENTRATE PRIMARILY ON "PRO-INVESTOR" AND "PRO-UTILITY" REGULATORY DECISIONS?

A. Wall Street analysts and bankers have to analyze each regulatory decision, regardless of its characterization. Every regulatory decision or action, whether "pro-consumer" or "pro-utility", alters the operating environment for a utility and, hence, the pricing of its equity and debt securities. Above everything else, they want to see fair, consistent, and responsive decision making rendered in a timely fashion in response to a utility's changed circumstances. Labels such as "pro-investor" and "pro-consumer" obscure the large community of interest these two groups share. If the Commission acquires the label of "pro-consumer," it might come at a debilitating financial cost to Arizona customers. Few people know better than I the frustrations and outright annoyance at the changing whims and recommendations of Wall Street analysts. We have to rise above the rhetoric and focus on the important and the immutable: Wall Street provides the capital in this country. They base the allocation and pricing of capital primarily upon their analysis of risk in all its guises. Without that capital, APS cannot continue to meet its customers' needs. For that reason, whether through inconsistent regulatory policy, depressed returns on equity, inadequate fuel and purchased power clauses, delays in decision making or other matters, Wall Street will extract a punishingly high cost from customers.

APS serves the electricity needs of much of the growing state of Arizona. Economic growth and development in the state relies on a number of complex interacting factors. A healthy, thriving state economy depends upon the steady

provision of dependable electric service. Understandably, all classes of customers expect reliable electric service and that requires APS to continue to invest in generation, transmission and distribution plant to meet the needs of the ever-growing customer base. APS needs consistent access to the capital and bank markets, in conjunction with reasonable price levels and terms to fund its growing infrastructure. Non-investment grade, "junk" credit ratings and a negative view of the Company by Wall Street will eliminate the Company's ability to attract capital at a reasonable cost.

Q. WHAT WAS WALL STREET'S REACTION TO LAST WEEK'S DECISION BY THE COMMISSION ON THE POWER SUPPLY ADJUSTOR?

A. Wall Street viewed certain parts of the ACC's decision as helpful for APS but, at the same time, voiced concerns over other aspects of the decision and future regulatory relief developments.

Wall Street termed positive the change in the PSA implementation date from April 1 to February 1 and the removal of $776.2 million annual cap. In its *Research Update* dated January 26, 2006, S&P wrote:

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

On the other hand, there remains great concern over the Commission's interpretation of the PSA surcharge mechanics. S&P further stated in the *Research Update* quoted above that "the surcharge vote removes potentially

critical flexibility for timely recovery of prudently incurred fuel and purchased power costs."

In addition, other Wall Street firms stated that despite the positive aspects of the Commission's decision, APS faces significant regulatory risk mainly regarding the emergency interim rate relief request.

> Despite this short term positive we still see significant go forward regulatory risk.... These decisions lessen the risk of further downgrades by the ratings agencies in the near term. However, APS' credit metrics remain in junk territory, baring passage of the interim rate filing. Lehman Brothers, *Pinnacle West Capital,* dated January 25, 2006.

> While the PSA adjustment does expedite the company's receipt of cash from customers, it only increases the collection by two months, resulting in approximately $15 million of additional cash in 2006. In addition, in its meeting the ACC fell short of providing PNW with other needed rate relief and essentially deferred those items to a future date. JPMorgan, *Pinnacle West Capital Corp PSA Adjusted; Other Items Remain - ALERT,* dated January 25, 2006.

V. CAPITAL STRUCTURE

Q. IS THE COMPANY PROPOSING ANY CHANGE TO ITS CAPITAL STRUCTURE IN THIS RATE CASE?

A. Yes. We are proposing a capital structure consisting of 46% long-term debt and 54% equity.

Q. WHAT ADJUSTMENTS DID YOU MAKE TO THE CAPITAL STRUCTURE?

A. As of September 30, 2005, the Company's capital structure consisted of 46% long-term debt and 54% equity. Attachment DEB-3 shows APS' long-term debt and common equity balances as of the end of the September 2005 test year. I have applied four pro forma adjustments to this September 30, 2005 actual cost of capital.

The first adjustment adds $360 million to APS' common equity. In 2005, Pinnacle West issued additional shares of common stock to the public and infused $250 million of the related net proceeds into APS. Pinnacle West also sold the Silverhawk Power Plant to Nevada Power Company in January of 2006 for $210 million. Pinnacle West had already infused $100 million of the common stock proceeds into APS during the test year. We contributed the remaining $150 million of common stock proceeds and $210 million Silverhawk disposition proceeds were infused in early 2006, thus giving rise to the $360 million pro forma adjustment.

The second adjustment reflects an annual APS dividend of $170 million. The third and fourth adjustments remove impacts to equity of non-cash accounting adjustments for pension and derivatives.

Q. WHY DID APS NEED THESE EQUITY INFUSIONS?

A. The Company needed additional equity to keep its financial metrics strong enough to maintain an investment grade credit rating. An investment grade credit rating ensures that the Company has ready access to the capital markets to finance the capital expenditures necessary to serve its rapidly growing customer base and to refinance existing debt maturities as they come due.

In determining credit ratings, the agencies place the greatest emphasis on the financial metric FFO/Debt. During the 2000 to 2002 time frame, APS' FFO/Debt ratio fell within the parameters for a credit rating of "A". See the graph attached as Attachment DEB-4. Over the period 2002 to 2004, however, this financial metric rapidly deteriorated into the category of non-investment or "junk" grade of "BB". Beginning in the fall of 2004 and continuing into the

spring of 2005, Pinnacle West and APS came under intense pressure from both S&P and Moody's to issue common equity to offset the amount of debt and to strengthen the deteriorating credit metrics. In response to this pressure, in May 2005, Pinnacle West sold approximately $250 million of common stock and announced the sale of the Silverhawk Power Plant. These two transactions generated approximately $460 million which we prudently transferred to APS to reduce debt levels.

As can be seen on Attachment DEB-4, the rate increase effective on April 1, 2005, combined with the assumption that the Company receives timely and fair recovery of fuel and purchased power costs under the PSA will not move the FFO/Debt financial metric out of the "junk" category. A downgrade of the Company's debt below investment grade could cost APS customers as much as $1.3 billion in higher interest costs over ten years beginning in 2007. In order to maintain the Company's investment grade credit ratings, APS needed the equity infusion to relieve the immediate pressure on its financial metrics.

Q. WHAT IS THE EFFECT OF THE HIGHER EQUITY RATIO ON APS?

A. With the addition of equity capital and the decrease in debt as a percent of capital, FFO/Debt remains relatively flat in 2005. See the graph attached as Attachment DEB-4.

During the spring of 2005, both S&P and Moody's commented favorably on Pinnacle West management's decision to authorize the issuance of additional equity by Pinnacle West, the sale of Silverhawk, and the subsequent equity infusions to APS, all aimed at reducing financial pressures on APS. On April 27, 2005, Moody's stated: "The change in outlook also reflects [APS']

demonstrated intent to improve its financial strength by financing a portion of its rising capital expenditures with equity." And on April 27, 2005, S&P wrote: "Both the equity issuance and the potential sale of Silverhawk were factored into Standard & Poor's action last month to revise the outlook on APS and PWCC's ratings to stable from negative."

More equity investment will mean less debt and less interest expense than will otherwise be the case. For every $100 million not borrowed, APS will save $50 million in interest over a ten-year period, even at a historically low interest rate of just 5%. Assuming a modest coverage ratio of 3.0 times, this means that for every dollar of saved interest cost, APS will need three fewer dollars of pre-tax earnings to maintain that coverage ratio.

VI. CONCLUSION

Q. DO YOU HAVE ANY CONCLUDING REMARKS TO YOUR DIRECT TESTIMONY?

A. Yes. We must maintain APS' investment grade credit and access to the capital markets at reasonable costs for the customers' best interests and the future economic growth of Arizona. APS' needs this rate increase to achieve and maintain financial metrics consistent with merely low investment grade credit ratings. In the long run, such investment grade credit ratings benefit APS customers because they allow the Company to fund at a reasonable cost the significant infrastructure required to meet the needs of its customers. Finally, the Company's proposal to augment the capital structure through the infusion of additional equity will bolster the Company's credit ratings to the benefit of APS and its customers.

Q. DOES THAT CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

Arizona Public Service Company
Financial Indicators with Proposed Rates

	Financial Indicator	2003	2004	2005	-----Projected----- 2006	2007
1	Funds from Operations Interest Coverage /1/ ("Interest Coverage")	4.0	3.0	3.3	3.4	4.3
2	Funds from Operations to Debt /1/ ("FFO/Debt")	20.2%	16.0%	14.8%	16.0%	21.9%
3	Debt to Capital /1/	57.7%	58.7%	50.1%	53.0%	53.4%
4	Return on Common Equity ("ROE")	8.4%	9.0%	6.8%	7.9%	9.8%

/1/ Includes impacts of imputed debt

Arizona Public Service Company
Financial Indicators with Current Rates

	Financial Indicator	2003	2004	2005	-----Projected----- 2006	2007
1	Funds from Operations Interest Coverage /1/ ("Interest Coverage")	4.0	3.0	3.3	3.4	3.0
2	Funds from Operations to Debt /1/ ("FFO/Debt")	20.2%	16.0%	14.8%	16.0%	13.7%
3	Debt to Capital /1/	57.7%	58.7%	50.1%	53.3%	56.9%
4	Return on Common Equity ("ROE")	8.4%	9.0%	6.8%	6.6%	4.3%

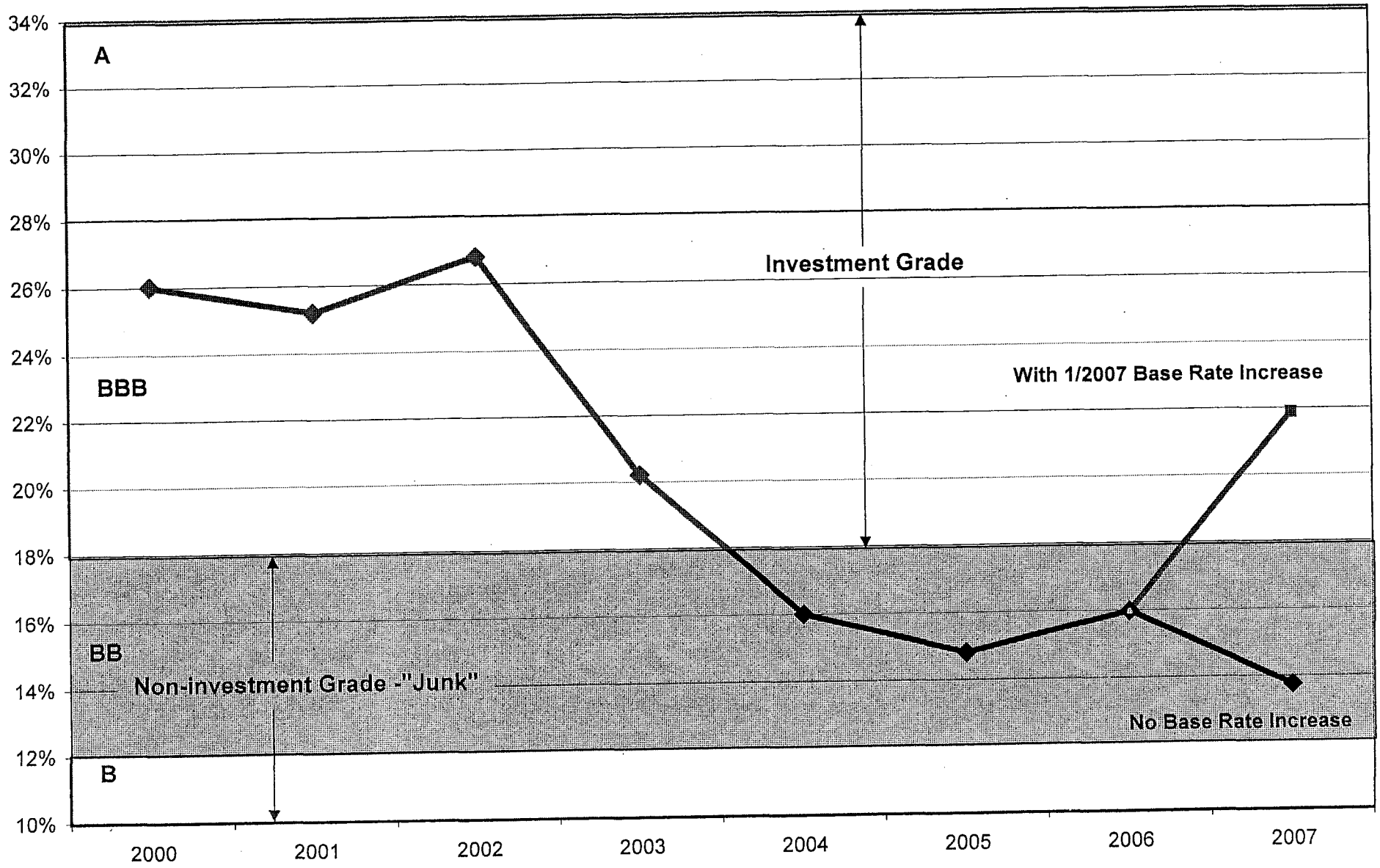
/1/ Includes impacts of imputed debt

ARIZONA PUBLIC SERVICE COMPANY
Capital Structure
Actual and Pro-forma for Equity Infusion
($ millions)

	Column 1		Column 2					
	9/30/2005 Actual		9/30/2005 Pro-forma					
			Proforma Adjustments (a)					
	Capital Amount	Capital Ratio	Remaining Equity Infusion	Remaining 2005 Dividend	Adjusted Pension OCI to Zero	Adjusted Derivative OCI to Zero	Capital Amount	Capital Ratio
Long-Term Debt	$ 2,575	46.0%	$ -	$ -	$ -	$ -	$ 2,575	45.5%
Common Equity	3,017	54.0%	$ 360	$ (128)	$ 71	$ (237)	$ 3,083	54.5%
Total Capitalization	$ 5,592	100.00%	$ 360	$ (128)	$ 71	$ (237)	$ 5,658	100.0%

Notes:
(a) See SFR D-1 pg 2

Arizona Public Service Company
FFO / Debt



STEVEN M. FETTER

DIRECT TESTIMONY OF STEVEN M. FETTER

ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY

DOCKET NO. E-01345A-05-0816

January 31, 2006

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TESTIMONY OF STEVEN M. FETTER
PRESIDENT, REGULATION UnFETTERED
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
DOCKET NO. E-01345A-05-0816
BEFORE THE
ARIZONA CORPORATION COMMISSION

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Steven M. Fetter, and my business address is 1489 West Warm Springs Road, Suite 110, Henderson, NV 89014.

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

A. I am President of REGULATION UnFETTERED, an energy advisory firm I started in April 2002. Prior to that, I was employed by Fitch, Inc. ("Fitch"), a credit rating agency based in New York and London. Prior to that, I served as Chairman of the Michigan Public Service Commission ("Michigan PSC" or "Michigan Commission").

Q. PLEASE BRIEFLY DESCRIBE YOUR ROLE AS PRESIDENT OF REGULATION UnFETTERED.

A. I formed an energy advisory firm to use my financial, regulatory, legislative and legal expertise to aid the deliberations of regulators, legislative bodies, and the courts, and to assist them in evaluating regulatory issues. My clients include electric and gas utilities, state public utility commissions

1 and consumer advocates, a non-utility energy supplier, international
2 financial services and consulting firms, and investors.
3
4 **Q. PLEASE BRIEFLY DESCRIBE FITCH'S BUSINESS DURING YOUR**
5 **TENURE THERE.**
6 A. Fitch is the third largest full service credit rating agency in the United
7 States – after its two major competitors, Standard & Poor's ("S&P") and
8 Moody's Investors Service ("Moody's") -- and the largest European rating
9 agency. It is one of four Nationally Recognized Statistical Rating
10 Organizations recognized by the U.S. Securities and Exchange
11 Commission. It is also recognized by the U.S. Department of Labor, state
12 bank and thrift regulators, and the National Association of Insurance
13 Commissioners. Fitch performs credit ratings of corporate obligations,
14 asset-backed transactions, and government and municipal debt. While
15 fees are paid by bond issuer clients, Fitch views its true clients to be bond
16 investors. Accordingly, bond ratings represent Fitch's independent
17 judgment based upon financial data provided by the bond issuer as well
18 as additional quantitative and qualitative information gathered from third-
19 party sources.
20
21 **Q. WHAT WAS YOUR ROLE DURING YOUR EMPLOYMENT WITH**
22 **FITCH?**

1 A. I was Group Head and Managing Director of the Global Power Group
2 within Fitch. In that role, I served as group manager of the combined 18-
3 person New York and Chicago utility team and was also responsible for
4 interpreting the impact of regulatory and legislative developments on utility
5 credit ratings. In April 2002, I left Fitch to start REGULATION
6 UnFETTERED, an energy advisory firm.
7
8 **Q. HOW LONG WERE YOU EMPLOYED BY FITCH?**
9 A. I was employed by Fitch from October 1993 until April 2002. In addition,
10 Fitch retained me as a consultant for a period of approximately six months
11 shortly after I resigned.
12
13 **Q. HOW DOES YOUR EXPERIENCE AT FITCH RELATE TO YOUR**
14 **TESTIMONY IN THIS PROCEEDING?**
15 A. At the time I was hired, Fitch intended to supplement the traditional
16 quantitative analysis that went into the firm's utility credit ratings with a
17 new emphasis on qualitative analysis. Fitch sought my assistance on the
18 regulatory, legislative and political credit rating factors that would
19 accompany U.S. movement toward a less regulated, more competitive
20 utility environment, both on the electric side as well as within the natural
21 gas industry. I guided the Global Power Group in incorporating these
22 issues into individual utility credit profiles.
23

1 My experience with Fitch has given me solid insight into the importance of
2 a regulator's role in both setting rates and also determining appropriate
3 terms and conditions of service. These are the factors that enter into the
4 process of utility credit analysis and formulation of individual company
5 credit ratings. It goes without saying that a company's credit ratings have
6 a significant impact as to whether a utility will be able to raise capital on a
7 timely basis and upon favorable terms.
8
9 **Q. PLEASE DESCRIBE YOUR SERVICE ON THE MICHIGAN PUBLIC**
10 **SERVICE COMMISSION.**
11 A. I was appointed as a Commissioner to the three-member Michigan PSC in
12 October 1987 by Democratic Governor James Blanchard. In January
13 1991, I was promoted to Chairman by incoming Republican Governor
14 John Engler, who reappointed me in July 1993. During my tenure as
15 Chairman, the Michigan PSC eliminated the agency's case backlog for the
16 first time in 23 years.
17
18 **Q. WAS THERE ANY ASPECT OF YOUR EXPERIENCE AT THE**
19 **MICHIGAN PSC THAT PARTICULARLY RELATES TO YOUR**
20 **TESTIMONY IN THIS PROCEEDING?**
21 A. Yes. During my six years at the Michigan PSC, my colleagues and I
22 sought to effectuate policies that would encourage regulated utilities to
23 provide customers with reliable electric and natural gas service in a cost-

effective manner. We also sought to ensure that the financial health of the state's utilities would remain sufficient for them to be able to provide reliable service to all consumers, and also that investors would maintain their interest in providing necessary funding on a timely basis upon reasonable terms.

Achieving these goals requires regulators to successfully strike a difficult balancing of interests. Investors provide financing to a utility so that company management can construct and maintain infrastructure adequate to ensure that customers will receive reliable service. In return, regulators must take timely action to provide an appropriate capital markets-based return to investors for company expenditures that are prudently made. A failure to carry out this regulatory responsibility in a timely manner will ultimately be detrimental to both investors and customers as investors will choose to take their funds elsewhere. Similarly, a regulatory or legislative determination that a utility should financially support certain public policy mandates without receiving timely recovery for prudent expenditures made in those efforts would undoubtedly lead investors to look to other jurisdictions where they believe their investments will be treated more fairly.

I believe that all of the circumstances I have describe above are relevant to the issues before the Arizona Corporation Commission ("Commission")

in this proceeding, and I will further elaborate upon these points within the remainder of my testimony.

Q. PLEASE DESCRIBE YOUR OTHER PRIOR PROFESSIONAL EXPERIENCE RELATED TO THE UTILITY INDUSTRY.

A. During my time on the Michigan PSC, I served as Chairman of the Board of Directors of the National Regulatory Research Institute ("NRRI") at Ohio State University, the regulatory research arm of the 50 state and District of Columbia public utility commissions. In 2003 I was appointed by the President of the National Association of Regulatory Utility Commissioners ("NARUC") to serve as a public member of the NRRI Board – the 20-member board includes ten state public utility commissioners. I was reappointed to the NRRI Board for a three-year term in June 2005. I also have served on the Keystone Center Energy Board (a nonprofit public policy board that brings together diverse stakeholders related to the energy industry as well as appointed and elected federal and state policymakers to discuss challenges facing the sector), after having participated in the Keystone Center Dialogues on Financial Markets and Energy Trading and on Regional Transmission Organizations. In February 2002, I was appointed to the Board of Directors of CH Energy Group, Inc. ("CHG"), the parent company of Central Hudson Gas & Electric in Poughkeepsie, New York. I currently serve as chairman of the CHG Audit Committee.

Q. HAVE YOU PREVIOUSLY SPONSORED TESTIMONY BEFORE REGULATORY AND LEGISLATIVE BODIES?

A. Since 1990, I have on numerous occasions testified before the U.S. Senate, the U.S. House of Representatives, the Federal Energy Regulatory Commission, and various state legislative and regulatory bodies on the subjects of credit risk within the utility sector, electric and natural gas utility restructuring, utility securitization bonds, and nuclear energy. During 2004, I sponsored testimony on behalf of Arizona Public Service Co. ("APS" or "Company") before the Commission in APS' general rate case, Docket No. E-01345A-03-0437. I also sponsored testimony on behalf of APS during the proceeding that followed to consider the appropriateness of the settlement agreement that was filed within that rate case. Finally, I have also filed testimony before this Commission in 2004 on behalf of Southwest Gas Corporation in Docket No. G-01551A-04-0876.

My full educational and professional background is attached in Appendix A.

II. SUMMARY

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

A. In this testimony, I offer my opinion, based upon my prior experience as head of the utility ratings practice at a major credit rating agency, chairman of a state public utility commission, and consultant to utilities, commissions and consumer advocates, as to what comprises fair and economically prudent regulation within today's electric utility industry. As part of that analysis, I will offer a brief discussion of the mechanics of the utility rate-setting process and how those steps help to ensure a regulated utility's financial viability and ability to provide service on a going-forward basis.

I further note my belief that the recent instability in the financial markets has created challenges for utility managements and regulators to an extent that has never existed in the past. Utilities possess an ongoing need for substantial amounts of funds for capital investment, both for infrastructure enhancement as well as maintenance of continuing reliability. Following the recent period of unprecedented volatility in the utility equity and debt markets, I believe that utilities operating within today's more stressful environment and their regulatory authorities should strive to minimize the regulatory uncertainties that could affect a utility's

1 financial profile, its credit ratings, and thus its access to capital on
2 favorable terms. Of course, a utility's ability to maintain its financial
3 strength also helps customers in that it allows the company's cost of
4 capital – that gets factored into rates -- to remain at reasonable levels.
5
6 In my testimony, I highlight recent statements from S&P as to what its
7 analysts look for to conclude that a constructive regulatory environment
8 exists within a particular jurisdiction: "...consistency and predictability, as
9 well as efficiency and timeliness," and limits on "uncertainty in the
10 recovery of a utility's investment [and] rate-case lag that may prove
11 detrimental if a utility needs rate relief."[1]
12
13 Moreover, for a utility like APS, whose customer growth means that it has
14 to rely upon a substantial amount of purchased power and Company-
15 owned natural gas generation, a power supply adjustor ("PSA") to reflect
16 actual costs is a key factor in the eyes of the financial community. While
17 Wall Street viewed the introduction of a PSA for APS last year as a
18 positive event, the way in which the PSA has operated has not been
19 consistent with the theoretical underpinning of other PSA-like mechanisms
20 that are being utilized across the U.S. nor, for that matter, as the PSA in
21 Arizona was intended to operate when it was negotiated by the parties to
22 APS' last rate case. I believe it is incumbent upon the Commission to
23 build upon its introduction of the concept and implement a PSA that bears

[1] S&P Research: "U.S. Utility Regulation Returns to Center Stage," April 14, 2005.

1 characteristics more consistent with the mainstream of regulatory practice
2 within the U.S. On this point, I discuss the workings of the existing PSA
3 that has resulted in large unrecovered power supply cost balances for
4 APS and how delays in dealing with these deferred amounts and
5 uncertainty with regard to ultimate recovery has led S&P to downgrade
6 APS' corporate credit rating to the lowest investment-grade level.
7
8 In view of the difficult circumstances confronting APS, I encourage the
9 Commission to be aggressive in dealing with these issues. Current
10 industry circumstances require more than just the passive regulatory
11 model that existed for the better part of a century, under which investors
12 were only interested in the results of rate cases, with the issuance of rate
13 case decisions occurring relatively infrequently. Rather, as I explain, a
14 proactive regulatory attitude best serves the interests of all stakeholders
15 affected by today's evolving utility industry.
16
17 By acting promptly to provide regulatory support for fair cost recovery in a
18 way that ensures the financial integrity of the utilities operating within their
19 jurisdictions, regulators can benefit customers of those utilities with
20 efficient and reliable service while respecting the interests of investors
21 who are continually called upon to provide the funding I describe above.
22 In addition, state and local economic development agencies often use the

availability of reliable energy supply at reasonable cost as a selling point in their efforts to attract new businesses to their areas.

III. UTILITY RATE-SETTING PROCESS

Q. COULD YOU PROVIDE A BRIEF EXPLANATION OF THE UTILITY RATE-SETTING PROCESS?

A. Yes I can. The intent of the rate-setting process for a regulated utility is to serve as a surrogate for the competitive market that non-regulated companies of any type operate within on a daily basis. The goals of rate-setting should be to ensure fair treatment of both the customers and the shareholders and bondholders of a regulated utility by providing prompt cost recovery of the prudent expenditures necessary for the provision of stable and reliable service. In short, the process begins with a regulatory determination of a revenue requirement, an estimate of the total costs (including O & M and return on rate base) a utility will incur in providing service in the future, and a determination as to the process through which those expenditures will be recovered.

Q. CAN YOU EXPLAIN HOW REGULATORS CONTINUE THE PROCESS OF SETTING A UTILITY'S REVENUE REQUIREMENT BY DETERMINING A RATE OF RETURN (INCLUDING A RETURN ON EQUITY) FOR A COMPANY?

A. As I mentioned, regulation serves as a surrogate for the competitive marketplace. The setting of a utility rate of return is based upon a regulatory calculation of the investment return necessary to attract investors to provide funds to the utility to carry out its service obligations to the public. The calculation incorporates two percentages: the amount of interest that bondholders will require before they will lend money to the utility and the return on equity that equity investors will demand in order to become part owners (through the holding of shares of stock) of the company. A weighted average of these two percentages results in the overall cost of capital, the level at which a utility will be able to attract the capital it needs in order to provide an appropriate level of reliable service to customers. The overall revenue requirement, whether based on original cost, "fair value," or replacement cost, must at a minimum include a sufficient return to recover a utility's cost of capital.

While the expense side of the revenue requirement calculation is relatively straightforward, the determination of the appropriate rate of return for a utility is a more complex and somewhat academic exercise, owing to the existence of two seminal U.S. Supreme Court decisions dating back more than 50 years ago: *Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia*[2] and *Federal Power Commission v. Hope Natural Gas Co.*[3]. The decisions in these two cases require

[2] 262 U.S. 679 (1923).
[3] 320 U.S. 591 (1944).

regulators to set a utility's rate of return at a level sufficient to attract capital on reasonable terms, to allow the utility to maintain its financial integrity, and to provide the utility with the opportunity to achieve earnings commensurate with the risks that it faces. Such determination is made on a case-by-case basis, depending upon the particular circumstances that an individual utility operates under. Although these decisions were framed in legal terms many years ago, they also reflected a prescience by the courts with regard to the economic realities of the manner in which the capital markets have evolved to the current time.

Q. HAS THE VOLATILITY THAT HAS CHARACTERIZED THE UTILITY SECTOR DURING THE PAST FIVE YEARS HAD AN IMPACT UPON THE RISK ASSESSMENT THAT GOES INTO DETERMINATION OF A FAIR RATE OF RETURN?

A. Yes, without a doubt, and it has affected both non-regulated and regulated utility operations. The two most jarring events to utility investors during the past several years – the California crisis and the Enron collapse – are good examples of the types of risk that were totally unforeseen at the start of the utility restructuring movement.

In California – where a state legislative/regulatory framework called for capped retail rates, notwithstanding exploding wholesale costs – reluctance on the part of state regulators (and legislators) to take proactive

steps necessary to remedy the dire situation resulted in the bankruptcy and near-bankruptcy of California's two largest *regulated* utilities, Pacific Gas & Electric Co. ("PG&E") and Southern California Edison Co. ("SCE"). The crisis had little to do with the unregulated affiliates of these two companies. The electric market problems in California also crossed state lines and brought financial harm to "innocent" regulated investor-owned utilities in Nevada and self-regulated public power utilities in the Pacific Northwest.

Conversely, the Enron collapse related almost solely to fraudulent behavior with regard to unregulated activities. What these two situations tell me is that the turmoil within the utility sector is not appropriately described as a dichotomy between higher risk unregulated activities and lower risk regulated activities. Rather, it is a succession of individual utility setbacks that has cut across the entire sector, affecting both regulated and unregulated companies.

Q. WHAT DO THOSE EXPERIENCES MEAN FOR INVESTORS?

A. Investors can choose to invest within the utility sector or they can invest in other sectors such as technology, financial services, or international (including emerging) markets. If they choose to invest in utilities, they must take the sector as they find it now – including its recent history of injurious regulatory policies and missteps. That said, risk profiles across

the industry are diverse, and an investor can choose to determine its risk tolerance and seek out a competitive energy company, regulated utility, or some combination of the two that falls within both its risk and return parameters. I emphasize, however, that an investor's decision to invest in a company with significant involvement in regulated utility services, like APS, does not shield that investor against all industry risk – as was so clearly seen in Nevada.

Integrated utilities cannot be viewed as they were several years ago. While a certain degree of industry risk resided in the minds of investors with regard to PG&E and SCE five years ago, the disasters that were to befall those two companies were inconceivable in the minds of Wall Street analysts and investors. In other words, what eventually occurred to these companies was not even within the realm of possibility based upon their risk profiles.

Unfortunately, what this means for current utility investors is that their risk radar is set at a much lower tolerance level today. Notwithstanding gradations among individual utilities, the entire sector bears the brunt of this more negative perception. Indeed, general concerns about a more volatile industry were reinforced by the August 14, 2003 blackout and then virtually overwhelmed by the damage wrought by Hurricanes Katrina and Rita, with the accompanying bankruptcy filing by Entergy New Orleans. It

has also become clear that, at least for the foreseeable future, there will be an ongoing need for substantial investment in transmission infrastructure for all utilities, as well as distribution system enhancement for regulated utilities in fast-growing regions of the country, such as APS.

Q. IN VIEW OF THESE UNPRECEDENTED EVENTS DURING THE PAST FIVE YEARS, DO THE ACTIONS OF UTILITY REGULATORS TODAY DRAW EVEN MORE ATTENTION FROM THE FINANCIAL COMMUNITY?

A. Yes, without a doubt. Regulation has always garnered the attention of Wall Street, but years ago, seemingly only during the days leading up to a commission's rate case decision. This began to change around the time that Fitch hired me in 1993 to serve in the role of regulatory analyst and assess regulatory and political factors that could impact upon a utility's financial strength. When California announced its ultimately ill-fated restructuring plan in 1994, the entire financial community, especially Fitch and its rating agency competitors S&P and Moody's, took much greater notice of regulators and how they carried out their responsibilities, not only with regard to rate-setting, but even more importantly the manner in which they undertook to change the way the entire utility industry had operated for over 100 years.

Under most restructuring plans, utilities have been directed to foster the

development of competitive markets, materially scale down their operations for certain functions (often including divestiture of generation), while at the same time retaining responsibility to produce or procure electricity for their core customers.

This situation thus affects utility investment decisions because, before major energy investors will be willing to put forward substantial sums of money, they will want to gain comfort that regulators understand the economic requirements and the financial and operational risks of a rapidly evolving industry and that their decision-making will be fair and will have a significant degree of predictability.

For these reasons, rating agencies look for the consistent application of sound economic regulatory principles by the commissions. If a regulatory body were to expect or encourage a company to make investments based upon an expectation of the opportunity to earn a reasonable return, and then did not apply regulatory principles in a manner consistent with such expectations, investor interest in providing funds to such utility would decline, debt ratings would likely suffer, and the utility's cost of capital would increase.

S&P highlighted the continuing importance of regulation to the financial community in two recent reports. In a report entitled "New York

Regulators' Consistency Supports Electric Utility Credit Quality," S&P offered general thoughts on the importance of regulation that apply within but also far beyond the borders of New York State:

> "Regulation defines the environment in which a utility operates and greatly influences a company's financial performance. A utility with a marginal financial profile can, at the same time, be considered highly creditworthy as a result of supportive regulation. Conversely, an unpredictable or antagonistic regulatory environment can undermine the financial position of utilities that are operationally very strong.
>
> To be viewed positively, regulatory treatment should be timely and allow consistent performance over time, given the importance of financial stability as a rating consideration. Also important is the transparency of regulatory policies..."[4]

Earlier, S&P had discussed how changing circumstances within the utility industry have elevated the importance of regulatory policies:

> "In recent years, [S&P's] emphasis on the decisions by state commissions has been less pronounced simply because so many jurisdictions have been working through multiyear restructuring transition periods. During this time, rates were frequently frozen, and companies and customers have been adjusting (albeit with limited success) to the opportunity that customers have to choose alternate power suppliers.
>
> But the confluence of the approaching end of these transition periods and the growing need in certain regions of the country for significant resource additions is quickly returning the regulatory arena to center stage. In assessing the regulatory environment in which a utility operates, [S&P's] analysis is guided by certain principles, most prominently consistency and predictability, as well as efficiency and timeliness. For a regulatory scheme to be considered supportive of credit quality, commissions must limit uncertainty in the recovery of a utility's investment. They must also eliminate, or at least greatly reduce, the issue of rate-case lag that may prove detrimental if a utility needs rate relief."[5]

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[4] S&P Research: "New York Regulators' Consistency Supports Electric Utility Credit Quality," August 15, 2005.

[5] S&P Research: "U.S. Utility Regulation Returns to Center Stage," April 14, 2005.

Q. IN VIEW OF THE IMPORTANCE THAT REGULATION HOLDS FOR INVESTORS, DID THE COMMISSION'S APPROVAL OF THE APS RATE CASE SETTLEMENT LAST YEAR RESOLVE ALL RISK CONCERNS RELATING TO APS IN THE MINDS OF INVESTORS?

No it did not. At the time, S&P explained that APS still faced near-term challenges and that they are largely regulatory:

> "Timely recovery of costs incurred in the rate base will remain challenges for the utility...Because these rates are based on a December 2002 test year, the utility will need to soon file a new rate case 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 between 4%-6% 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."[6]

S&P concluded that APS' ratings outlook was Stable, but that:

> "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 terms of the PSA present."

Q. S&P REFERS TO LIMITATIONS THAT CURRENTLY APPLY TO THE PSA. COULD YOU DISCUSS THAT ASPECT OF THE PSA?

[6] S&P Research Summary: "Arizona Public Service Co.," May 24, 2005.

1 A. Yes I can. First, the PSA as structured by the Commission last year
2 contains a four-tenths of a cent per kilowatt-hour cap on any fuel or
3 purchased power expense recovery by APS through the annual adjustor.
4 Second, there is a "lifetime" limit of this four-tenths of a cent per kilowatt-
5 hour cap. Third, there is a maximum recovery amount of $776 million
6 established. Finally, there is no automatic approval mechanism for the
7 company's annual application under this PSA. These types of items set
8 the structure of the existing PSA apart from other such mechanisms
9 utilized across the U.S.
10
11 **Q. COULD YOU DISCUSS THE SIGNIFICANCE OF THE $776 MILLION**
12 **CAP?**
13 A. Yes. Per Commission Decision 67744, "putting a 'cap' on recovery of
14 these costs will help insure that APS will file a rate application when
15 necessary". If the cap is removed before it is reached, it is not an issue.
16 However, if the cap remains, it is a significant issue.
17
18 **Q. COULD YOU EXPLAIN?**
19 A. Yes. Since the PSA is structured to reimburse APS *only for a portion of its*
20 *prudently-incurred* fuel and purchased power expenses, I find such a cap
21 to be outside the norm in a way that could defeat the intended purpose of
22 such an adjustment mechanism. Also, by dampening down the "true"
23 price of power by maintaining a cap that bears no relation to the prudency

of APS' actions, the PSA ends up sending improper price signals during a time when a wide range of industry stakeholders are seeking to tie actual prices to encouragement for substantially greater progress with regard to conservation, energy efficiency, and other demand side management initiatives.

Q. WHAT IMPACT COULD THAT CAP HAVE ON FUEL EXPENDITURES THAT ARE PRUDENTLY INCURRED BY APS IN ORDER TO PROVIDE RELIABLE SERVICE TO ITS NATIVE LOAD CUSTOMERS?

A. Such a cap could prevent APS from achieving recovery of its prudent fuel and purchased power expenditures as intended by the PSA (in the absence of the unusual cap). That result would certainly be viewed as a negative outcome by the financial community – one that would not be favorably received by the equity and credit rating analysts that follow APS' regulatory situation and either consider credit rating actions that affect debt investors or stock recommendations that impact equity investors. In fact, the Residential Utility Consumer Office ("RUCO") has stated that such denial of recovery for prudent fuel and purchased power expenditures was not intended when the PSA was structured and agreed to by the 20+ parties in APS' last rate case:

> "...the Commission modified certain aspects of the PSA from those proposed by the parties to the Settlement Agreement. However, those modifications did not change RUCO's view of the PSA, and any approved surcharges, as a device through which APS would recover ninety percent of its prudent costs of fuel and purchased

> power...none of the Commission's revisions changed the underlying premise that the costs would be recoverable."[7]

To the extent that the PSA as currently structured does **not** provide APS with recovery for its prudent fuel and purchased power expenditures, it would have to be changed in order to be consistent with the vast majority of such mechanisms around the country.

Q. HAVE GROWING POWER COST DEFERRALS INCREASED THE LEVEL OF CONCERN AMONG THE RATING AGENCIES?

A. Yes they have. In October 2005, S&P expressed increasing concern about APS' growing amount of deferrals, related both to day-to-day power supply for core customers, as well as replacement power related to a nuclear outage earlier this year:

> "...it is clear that timely near-term [power] 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."[8]

On December 21, 2005, S&P acted on its earlier warnings and lowered its corporate credit rating for APS to "BBB-" from "BBB". S&P concluded that "Any adverse regulatory development or continued delays in resolving the pending surcharge request could result in a downward revision of the

[7] Letter from RUCO to Commissioner Kristin K. Mayes, August 19, 2005.
[8] S&P Research: Arizona Public Service Co., October 4, 2005.

outlook or an adverse rating action."[9] This downgrade to the lowest investment-grade level of "BBB-" is a very negative financial event.

Q. WHAT ARE SOME OF THE CONSEQUENCES IF APS' CREDIT RATING WERE TO FALL BELOW INVESTMENT-GRADE QUALITY?

A. There would be a marked change in the investor profile for the Company. Major utility investors such as insurance companies and pension funds operate under legal restrictions that severely limit their ability to invest in below investment-grade debt instruments, or "junk bonds." Mutual funds could also be affected based upon what a particular fund has communicated to investors as to its investment profile. Moreover, a utility with a "junk bond" rating is likely to have to post bond or put up cash as collateral in various contracts (such as for power supply) or to meet certain regulatory commitments. This, of course, would come at a time when access to APS' existing credit facilities likely would be limited by the financial institutions previously providing the assistance. Finally, a utility with below investment-grade status is severely limited in its ability to access the commercial paper (short-term debt) market, if it can access it at all. Commercial paper is a key source of funding for utilities (including APS), many of which have revenues that vary substantially depending upon the time of year, and loss of access to that market can severely impair financial liquidity.

[9] S&P Research Update: "Pinnacle West Capital's, Arizona Public Service's Ratings Lowered To 'BBB-'; Outlook Stable," December 21, 2005.

Q. IS IT EASY FOR A COMPANY THAT HAS BEEN DOWNGRADED TO REGAIN ITS PRIOR CREDIT RATING?

A. No, not at all. It is important to emphasize that within the more volatile investment climate, it is far easier for a utility's ratings to slip down due to a financial "ding" than for that same utility to regain its earlier status once the deficiency has been remedied. For that reason, I do not believe that a continuation in the weakening of APS' credit profile now could, if the Commission changed its mind, be easily remedied in the Company's next proceeding. My advice to utility companies, investors and regulators alike is that nothing should be taken for granted in the current investing environment.

Q. ON THE OTHER SIDE OF THE COIN, CAN YOU OFFER EXAMPLES OF RECENT REGULATORY ACTIONS THAT HAVE IMPACTED IN A POSITIVE WAY HOW THE FINANCIAL COMMUNITY VIEWS REGULATION IN A PARTICULAR JURISDICTION?

A. Yes I can. First I would like to discuss recent activity in Missouri with which I was involved as an advisor assisting Great Plains Energy and its regulated utility Kansas City Power & Light Co. ("KCPL") in their interaction with state regulators.

Q. WHAT WERE THE CIRCUMSTANCES SURROUNDING KCPL'S

1 **INVOLVEMENT WITH MISSOURI REGULATORS?**

2 A. KCPL was facing a situation where it saw the need to expend a
3 substantial amount of capital (approximately $1.3 billion) over a five-year
4 period to assure adequate electricity supply for its core customer base. At
5 the same time, with its credit ratings at the "BBB" level, the company did
6 not want to stress its credit profile in a way that could lower them to low-
7 "BBB" status or even down into below-investment grade status.
8
9 To achieve its goal of assuring ongoing reliable service to its regulated
10 customers in a financially-prudent manner, KCPL interacted with Missouri
11 regulatory staff and other interested parties in public sessions that
12 ultimately resulted in a stipulated agreement with the Missouri Public
13 Service Commission ("Missouri Commission") Staff, the Missouri Office of
14 Public Counsel, and other interested parties. The upshot of this
15 agreement is that, after an initial rate freeze through 2006, KCPL will be
16 able to file annual rate cases for 2007 through 2009, without the risk of
17 intervention by signatories to the agreement.
18
19 It is noteworthy that rate relief in those proceedings will be based upon the
20 highly unusual but extremely innovative step of explicitly relying upon
21 S&P's publicly-disseminated credit ratio guidelines to ensure that KCPL's
22 key financial measures would remain at levels adequate for its "BBB"
23 credit ratings. In addition, the plan incorporates an option for the company

to implement an interim power cost adjustment clause during the life of the agreement. On July 28, 2005, the Missouri Commission unanimously approved the stipulated agreement and the Kansas Corporation Commission offered its unanimous support shortly thereafter.[10]

Q. HOW DID THE CREDIT RATING COMMUNITY REACT TO THE AGREEMENT NEGOTIATED BY GREAT PLAINS AND KCPL?

A. Positively. S&P viewed it very favorably, stating that the proposed proactive regulatory plan would provide "an adequate framework for rate relief both during and after" KCPL's $1.3 billion five-year capital investment program. S&P highlighted the availability of an interim power cost adjustment clause and the formulaic nature of the process of determining future rate relief in a less adversarial setting as supportive of S&P's affirmation of KCPL's and Great Plains Energy's credit ratings. Moreover, the plan's acknowledgement of the important connection between future rate levels and key credit rating financial measures supports the position that APS presented in its last general rate case. Finally, I found it noteworthy in view of the issues being considered in this APS proceeding that S&P concluded that:

> "Exceptionally strong regulatory support, project execution, and debt reduction could lead to an improved outlook for KCPL and Great Plains [, while, i]n contrast, failure to secure adequate rate relief or a fuel cost recovery mechanism by 2007 could have

[10] S&P Research: "MPSC Approval of Regulatory Plan Will Not Affect Kansas City Power & Light's Rating," July 29, 2005; "Kansas City Power & Light Begins Implementation of Long-Term Energy Plan," Business Wire, August 9, 2005.

negative credit implications."[11]

Q. ARE THERE OTHER RECENT EXAMPLES WHERE PROACTIVE REGULATION RESOUNDED TO POSITIVE EFFECT ON WALL STREET?

A. Yes. Last year, the Colorado Public Utility Commission ("Colorado Commission") approved a Comprehensive Settlement Agreement ("CSA") between Public Service Co. of Colorado ("PS Colorado") and major environmental and consumer groups. Similar to the Missouri agreement I just described, the intent of the CSA is to allow PS Colorado to proceed with a substantial capital investment program related to new coal-fired plant construction and environmental steps necessary to allow existing coal-fired power plants to meet current and future emission controls. Significantly, the CSA was designed to allow PS Colorado to proceed with its large construction program while ensuring that the company's credit profile would not be weakened by that costly effort.

Q. HOW EXACTLY WAS THE CSA STRUCTURED TO MAINTAIN PS COLORADO'S CREDIT PROFILE?

A. In a report published on March 29, 2005, S&P described the major points of the CSA that are pegged to PS Colorado's credit quality:

- PS Colorado will be allowed to increase equity up to 60% of capital to reflect the economic cost incurred by its existing purchased-power contracts,
- PS Colorado will be allowed to add "construction work in

[11] S&P Research Update: "Great Plains Energy and Unit Ratings Affirmed; Outlook Stable," April 1, 2005.

progress" (CWIP) to rate base in amounts that will be determined by current senior unsecured debt ratings and the capital structure,

- Plant construction costs (up to a confidential cap) and environmental control costs related to the 750 MW coal-fired Comanche Project are deemed prudent and are recoverable in rates, and
- The major costs associated with implementing this agreement are to be deemed prudent and recoverable in rates.[12]

Q. DOES S&P HAVE A POSITIVE VIEW OF THE CSA AND THE COLORADO COMMISSION'S APPROVAL OF IT?

A. Yes they do. S&P focuses on the fact that growing generation capacity needs will force utility managements to "consider strategies that will gain them the support of many diverse constituencies, many of whom will otherwise assuredly oppose their related rate requests before state regulators." Describing the CSA as "a successful outcome in this respect," S&P concludes that:

> "With this agreement, PS Colorado has effectively addressed the future costs associated with adequate supply and environmental compliance with a plan that will permit timely recovery of those costs. This is a major step forward in eliminating the tug-of-war over cost recovery that, in the past, has plagued the credit of so many utilities when the time comes to build again."

Q. YOU EARLIER SPOKE ABOUT MANDATORY EXPENDITURES REQUIRED OF UTILITIES, EITHER BY LAW OR REGULATORY POLICY, AND HOW THE FINANCIAL COMMUNITY VIEWS THE POTENTIAL RECOVERY OF SUCH COSTS. CAN YOU ELABORATE ON THAT THOUGHT?

[12] S&P Research: "PS Colorado Garners Support for Credit Quality Up-Front; A Viable Model for the Electric Industry?," March 29, 2005.

A. Yes I can. Good examples on this point are the state commissions that have proactively faced up to the likelihood that utilities will have to expend substantial sums of money for environmental compliance in the future, and have acknowledged that an early start on such activities that is facilitated by upfront regulatory support serves the public interest. For example, early regulatory action on environmental cost recovery mechanisms has already occurred in the following states:

- Florida (Fla. Stat. Sec. 366.8255 (2005): stating that electric utilities may submit a petition requesting recovery of the utility's proposed compliance activities and projected environmental costs, which are recoverable following a prudence review);
- West Virginia (W. Va. Code Sec. 24-2-1g (2005): commission may authorize "rate-making allowances" for investments in clean coal and clean air technology facilities or for purchases of power from clean coal technology facilities within the state);
- Kentucky (KRS Sec. 278.183 (2004): allows a utility to recover, through an environmental surcharge, costs of compliance with laws that apply to coal combustion wastes and by-products); and
- Indiana (Burns Ind. Code Ann. Sec. 8-1-27-6, 8-1-27-8 (2004): utility may voluntarily submit an environmental compliance plan to recover costs to comply with requirements of Clean Air Act Amendments of 1990, which are assessed based on

reasonableness, least cost strategy, and the public interest). Such proactive regulatory treatment for recovery of prudent expenditures that are made by utilities to further public policy goals is viewed very favorably by the Wall Street financial community.

Q. DO YOU SEE SPECIFIC APPLICABILITY OF THESE POSITIVE REGULATORY OUTCOMES AND THE ISSUES FACING THIS COMMISSION?

A. While there is certainly some clear applicability between the pending issues and concerns in those other jurisdictions and what is occurring in Arizona – *e.g.* the need for additional capacity, the use of a power supply adjustment mechanism, credit rating stresses of "BBB" credit profiles, and consideration of environmental compliance activities that will be escalating in the future – I think the more important message to take away is the benefit that can result for both customers and financial investors from the proactive involvement by an individual commission in seeking to solve the particular stresses confronting the regulated utilities within its jurisdiction. In other words, I am praising the proactive nature of the regulatory responses I described as opposed to embracing the idea that there is a "one-size-fits-all" solution that can be taken from the regulatory process in one state and plugged into another.

Q. WHY SHOULD REGULATORS BE CONCERNED WITH THE "UPS-

1 **AND-DOWNS" OF A UTILITY'S FINANCIAL SITUATION?**

2 A. I return to some of the themes I discussed in my testimony in the last APS
3 rate case. Customers benefit when their utility is able to easily access the
4 debt and equity markets on reasonable terms when needed to fund
5 infrastructure requirements necessary to ensure appropriate levels of
6 reliability or to meet growth in customer demand. This is especially true
7 when volatility in the energy/utility sector (like we have experienced during
8 the past few years) has tightened up liquidity within the capital markets.
9 While utility competition has not yet flourished within the consumer
10 marketplace, utilities compete with each other everyday for capital
11 financing. The ability to access the debt market when needed is important
12 because it allows a company to carry out its infrastructure and
13 environmental compliance planning on a timetable of its own formulation,
14 one that can maximize potential efficiencies within the process. Financial
15 strength helps to achieve this goal.
16
17 **Q. ARE THE VIEWS YOU EXPRESS HERE ABOUT PROACTIVE**
18 **REGULATORY BEHAVIOR AND SENSITIVITY TO A REGULATED**
19 **UTILITY'S FINANCIAL SITUATION CONSISTENT WITH THE POLICIES**
20 **YOU SUPPORTED AS A STATE REGULATOR?**

21 A. Yes, very much so. As I explained in my testimony in this Commission's
22 proceeding to review the settlement agreement of APS' last general rate
23 case, the most pressing issues I faced during my six years as a

Commissioner and then Chairman at the Michigan PSC were the financial condition of the state's two largest utilities, one electric (Detroit Edison) and the other electric and gas (Consumers Power), and the resulting effect on customers and the prospects for reliable service.

I described how Detroit Edison was reeling financially from construction expenditures at its Fermi nuclear plant and Consumers Power's abandonment of its Midland nuclear facility had placed it in a position where, without extraordinary rate relief, it likely would have had to file for bankruptcy. In 1988, the Michigan Commission approved a five-year rate settlement agreement for Detroit Edison that allowed the company to return to a degree of financial health during the term of the agreement and thereafter. With regard to Consumers Power, parties to a number of proceedings related to the abandonment of the Midland nuclear plant and its transition into a cogeneration facility negotiated during virtually my entire six-year tenure on the Michigan PSC before bringing to the Commission a global settlement of pending issues. The Michigan Commission's approval of that major settlement agreement allowed Consumers Power to also return to financial health.

I highlighted this sensitivity to a regulated utility's specific situation in an opinion piece I authored in Public Utilities Fortnightly. I emphasized the

fact that good regulatory policies flowed from good communication between the regulator and the regulated:

> "As a state regulator, I lived by one cardinal rule: The best consumer and investor protection is open and frank communication between regulators and utility management."[13]

Consistent with this regulatory "golden rule," I think it is important that the Commission and APS be on the same page with regard to beneficial capital investment, with the corollary that capital utilization in tune with this "meeting of the minds" should be recoverable in rates.

Starting my first day as a state regulator and carrying through my various roles within the utility industry, I have seen that there is not one exact level of system reliability that can be pinpointed and translated into a necessary spending level. Rather the process should be dynamic, with ongoing communication to ensure that the customer receives reliable service that can be counted upon, and that the investor is fairly compensated for the requisite level of financial commitment to maintain such level.

While these general principles I have enunciated are relevant in every jurisdiction, a record of regulatory distinction – respected by both customers and investors -- comes about where solutions are keyed to the particular problems at hand. I offered up examples in Michigan of what

[13] "Perspective: Don't Fence Me Out," Public Utilities Fortnightly, October 2004.

1 the problems were long ago along with an explanation of the solutions the
2 Michigan Commission found appropriate. I also have pointed to recent
3 examples in Missouri, Kansas, and Colorado. But I am NOT
4 recommending that any of the paths that regulators took under their
5 particular circumstances are right for the concerns that this Commission
6 is facing. Rather I am encouraging a sensitivity to local concerns and
7 circumstances followed by a proactive response that allows prudent
8 expenditures made for the benefit of customers to be timely recovered.
9
10 **Q. DOES THIS CONCLUDE YOUR TESTIMONY?**
11 A. Yes it does.

APPENDIX A

STEVEN M. FETTER

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Education University of Michigan Law School, J.D. 1979
Bar Memberships: U.S. Supreme Court, New York, Michigan
University of Michigan, A.B. (Communications) 1974

April 2002 – Present
President – REGULATION UnFETTERED – Rumson, NJ

Founder of advisory firm providing regulatory, legislative, financial, legal and strategic planning advisory services for the energy and telecommunications sectors; federal and state testimony; credit rating advisory services; negotiation, arbitration and mediation services; and skills training in ethics, negotiation, and management efficiency.

- Service on Boards of Directors of: CH Energy Group (Chairman, Audit Committee; Member, Governance and Nominating, Compensation, and Executive Committees), National Regulatory Research Institute (at Ohio State University), Keystone Energy Board, and Regulatory Information Technology Consortium; Member, Wall Street Utility Group and American Public Power Association; Participant, Keystone Center Dialogue on Financial Trading and Energy Markets.

October 1993 – April 2002
Group Head and Managing Director; Senior Director – Global Power Group, Fitch IBCA Duff & Phelps – New York/Chicago

Manager of 18-employee ($15 million revenue) group responsible for credit research and rating of fixed income securities of U.S. and foreign electric and natural gas companies and project finance.

- Led an effort to restructure the global power group that in three years time resulted in 75% new personnel and over 100% increase in revenues, transforming a group operating at a substantial deficit into a team-oriented profit center through a combination of revenue growth and expense reduction.

- Achieved national recognition as a speaker and commentator evaluating the effects of regulatory developments on the financial condition of the utility sector and individual companies; Cited by Institutional Investor (9/97) as one of top utility analysts at rating agencies; Frequently quoted in national newspapers and trade publications including

The New York Times, The Wall Street Journal, International Herald Tribune, Los Angeles Times, Atlanta Journal-Constitution, Forbes and Energy Daily; Featured speaker at conferences sponsored by Edison Electric Institute, Nuclear Energy Institute, American Gas Assn., Natural Gas Supply Assn., National Assn. of Regulatory Utility Commissioners (NARUC), Canadian Electricity Assn.; Frequent invitations to testify before U.S. Senate (on C-Span) and House of Representatives, and state legislatures and utility commissions.

- Participant, Keystone Center Dialogue on Regional Transmission Organizations; Member, International Advisory Council, Eisenhower Fellowships; Author, "A Rating Agency's Perspective on Regulatory Reform," book chapter published by Public Utilities Reports, Summer 1995; Advisory Committee, Public Utilities Fortnightly.

March 1994 – April 2002
Consultant -- NYNEX -- New York, Ameritech -- Chicago, Weatherwise USA -- Pittsburgh

Provided testimony before the Federal Communications Commission and state public utility commissions; Formulated and taught specialized ethics and negotiation skills training program for employees in positions of a sensitive nature due to responsibilities involving interface with government officials, marketing, sales or purchasing; Developed amendments to NYNEX Code of Business Conduct.

October 1987 - October 1993
Chairman; Commissioner -- Michigan Public Service Commission -- Lansing

Administrator of $15-million agency responsible for regulating Michigan's public utilities, telecommunications services, and intrastate trucking, and establishing an effective state energy policy; Appointed by Democratic Governor James Blanchard; Promoted to Chairman by Republican Governor John Engler (1991) and reappointed (1993).

- Initiated case-handling guideline that eliminated agency backlog for first time in 23 years while reorganizing to downsize agency from 240 employees to 205 and eliminate top tier of management; MPSC received national recognition for fashioning incentive plans in all regulated industries based on performance, service quality, and infrastructure improvement.

- Closely involved in formulation and passage of regulatory reform law (Michigan Telecommunications Act of 1991) that has served as a model for other states; Rejuvenated dormant twelve-year effort and successfully lobbied the Michigan Legislature to exempt the Commission from the Open Meetings Act, a controversial step that shifted power from the career staff to the three commissioners.

- Elected Chairman of the Board of the National Regulatory Research Institute (at Ohio State University); Adjunct Professor of Legislation, American University's Washington College of Law and Thomas M. Cooley Law School; Member of NARUC Executive, Gas, and International Relations Committees, Steering Committee of U.S. Environmental Protection Agency/State of Michigan Relative Risk Analysis Project, and Federal Energy Regulatory Commission Task Force on Natural Gas Deliverability;

Eisenhower Exchange Fellow to Japan and NARUC Fellow to the Kennedy School of Government; Ethics Lecturer for NARUC.

August 1985 - October 1987
Acting Associate Deputy Under Secretary of Labor; Executive Assistant to the Deputy Under Secretary -- U.S. Department of Labor -- Washington DC

Member of three-person management team directing the activities of 60-employee agency responsible for promoting use of labor-management cooperation programs. Supervised a legal team in a study of the effects of U.S. labor laws on labor-management cooperation that has received national recognition and been frequently cited in law reviews (U.S. Labor Law and the Future of Labor-Management Cooperation, w/S. Schlossberg, 1986).

January 1983 - August 1985
Senate Majority General Counsel; Chief Republican Counsel -- Michigan Senate -- Lansing

Legal Advisor to the Majority Republican Caucus and Secretary of the Senate; Created and directed 7-employee Office of Majority General Counsel; Counsel, Senate Rules and Ethics Committees; Appointed to the Michigan Criminal Justice Commission, Ann Arbor Human Rights Commission and Washtenaw County Consumer Mediation Committee.

March 1982 - January 1983
Assistant Legal Counsel -- Michigan Governor William Milliken -- Lansing

Legal and Labor Advisor (member of collective bargaining team); Director, Extradition and Clemency; Appointed to Michigan Supreme Court Sentencing Guidelines Committee, Prison Overcrowding Project, Coordination of Law Enforcement Services Task Force.

October 1979 - March 1982
Appellate Litigation Attorney -- National Labor Relations Board -- Washington DC

Other Significant Speeches and Publications

- Perspective: Don't Fence Me Out (Public Utilities Fortnightly, October 2004)

- Climate Change and the Electric Power Sector: What Role for the Global Financial Community (during Fourth Session of UN Framework Convention on Climate Change Conference of Parties, Buenos Aires, Argentina, November 3, 1998)(unpublished)

- Regulation UnFettered: The Fray By the Bay, Revisited (National Regulatory Research Institute Quarterly Bulletin, December 1997)

- The Feds Can Lead...By Getting Out of the Way (Public Utilities Fortnightly, June 1, 1996)

- Ethical Considerations Within Utility Regulation, w/M. Cummins (National Regulatory Research Institute Quarterly Bulletin, December 1993)

- Legal Challenges to Employee Participation Programs (American Bar Association, Atlanta, Georgia, August 1991) (unpublished)

- Proprietary Information, Confidentiality, and Regulation's Continuing Information Needs: A State Commissioner's Perspective (Washington Legal Foundation, July 1990)

DONALD G. ROBINSON

DIRECT TESTIMONY OF DONALD G. ROBINSON

On Behalf of Arizona Public Service Company

Docket No. E-01345A-05-0816

January 31, 2006

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DIRECT TESTIMONY OF DONALD G. ROBINSON
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-05-0816)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, ADDRESS AND OCCUPATION.

A. My name is Donald G. Robinson. I am Vice President of Planning for Arizona Public Service Company ("APS" or "Company"). I have responsibility for Corporate Planning, Resource Acquisition, Resource Planning, Budgets, Forecasts, Energy Risk Management, and New Business Ventures. My business address is 400 North Fifth Street, Phoenix, Arizona 85004.

Q. ARE YOUR EDUCATIONAL, BUSINESS, AND PROFESSIONAL QUALIFICATIONS SET FORTH IN APPENDIX A TO YOUR DIRECT TESTIMONY?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My direct testimony describes the current Power Supply Adjustment ("PSA") rate mechanism for APS. I go on to discuss the PSA's critical role in preserving the Company's financial integrity, promoting the Commission's goals regarding wholesale competition, and in providing our customers with timelier price signals concerning the use of energy. I also will propose some modifications to the PSA itself to remove counterproductive restrictions and limitations.

Q. IF APS ALREADY HAS A PSA, WHY ARE YOU SPONSORING DIRECT TESTIMONY ON THIS SUBJECT?

A. First of all, Decision No. 67744 (April 7, 2005) specifically indicated that continuation of the PSA would be an issue in the Company's next general rate proceeding. Second, that Decision invited the Company to address the issue of

the cap it placed on total fuel and purchased power costs by filing another rate proceeding. Third, as alluded to above and discussed in detail later in my direct testimony, APS is proposing some additional modifications to the PSA that are best addressed in this proceeding.

II. SUMMARY

Q. WOULD YOU PLEASE SUMMARIZE YOUR TESTIMONY?

A. The Company's last rate case request culminated in a settlement agreement ("2004 Settlement") that was adopted with modifications by the Commission in Decision No. 67744. In that Decision, the Commission authorized a PSA mechanism for APS, and established the amount to be recovered through base rates ("Base Fuel Recovery Amount") at $.020743 per kWh, which was based on 2003 costs. The PSA permitted the Company to defer for later recovery or refund, 90% of the fuel and purchased power costs that were in excess of or below the Base Fuel Recovery Amount. The other 10% was to be expensed (and paid for by APS shareholders, despite the fact that they were presumptively prudent costs incurred solely to provide service to APS customers) or retained as Other Income, depending on whether the costs were above or below the Base Fuel Recovery Amount plus the PSA factor.

APS has deferred nearly $170 million in higher fuel and purchased power costs since April 7, 2005 (the effective date of the PSA, pursuant to Decision No, 67744) through December 31, 2005, as well as interest on such under-recoveries. The remaining amounts of these higher costs, approximately $19 million, were expensed against income as a result of the 90/10 sharing, which therefore reduced the Company's earnings.

It was the Company's understanding pursuant to Decision No. 67744 that adjustments to PSA charges were made at least annually. Under that Decision, the annual change to the PSA Factor was to be made on April 1 of each year beginning in 2006, based on filing, which had to be filed by March 1st, but could be filed earlier[1]. That filing would compare fuel and purchased power costs per kWh for the preceding calendar year (in this first instance, April through December of 2005), as indicated by the PSA bank balance, after application of the 90/10 sharing provision with the Base Fuel Recovery Amount.

Pursuant to Decision No. 67744, APS was also authorized to request a special PSA surcharge. That Decision required that APS file a report with the Commission to either request a PSA surcharge or to explain why such a surcharge was unnecessary when fuel and purchased power cost deferrals reached $50 million. Decision No. 67744 also required the Company to seek such a surcharge before the bank balance of cost deferrals reached $100 million. Upon the date APS requested the PSA surcharge, the level of deferrals used to determine the timing of any subsequent surcharge application would be reduced by the amount requested.

Pursuant to this provision of Decision No. 67744, the Company requested a PSA surcharge on July 22, 2005 ("July Surcharge Request"). On January 13, 2006, APS also notified the Commission that the PSA bank balance had again reached $50 million (in addition to the $80 million subject to the July Surcharge Request,), but the Company did not request an additional PSA surcharge at that time.

---

[1] The timing of the PSA Factor was later changed to February 1 of each year, as I discuss later in my testimony.

The July Surcharge Request came before the Commission at the January 24th/25th, 2006 Open Meeting. During that Open Meeting, the Commission convened an A.R.S. § 40-252 evidentiary hearing to create an adequate record to advance the PSA adjustor date from April 1 to February 1. In Open Meeting on January 25, 2006, the Commission denied the Surcharge Request and modified some of the PSA provisions that were adopted in Decision No. 67744 ("January 25 Open Meeting Decision"[2]). I will discuss those specific modifications later in my testimony.

Rate adjustment mechanisms for fuel and purchased power costs have been and continue to be a routine regulatory practice in this country. As of the date this testimony was filed, some 40 jurisdictions having regulated electric utilities have adopted some manner of PSA mechanism and others have otherwise addressed the need to provide timely recovery of costs.

By the end of 2005, APS has under-recovered its fuel and purchased power costs by approximately $187 million (before the 90/10 sharing mechanism). The Company's 2005 earned return on equity ("ROE") of 6.8% was already well below the 10.25% cost of equity ("COE") established in Decision No. 67744 (and far below the COE of 11.5% recommended by Dr. William Avera in this filing).

For 2006, the financial implications would be worse absent the PSA. Unrecovered fuel and purchased power costs would accumulate to approximately $460 million. As noted in APS witness Donald Brandt's direct

[2] As of the filing of this testimony, the January 25 Open Meeting Decision has not been issued in written form, therefore the Company is unable to provide the Decision Number at this time.

testimony, even with the present PSA, the Company's financial results do not have the strength necessary to address current and future capital needs. This will directly impact both future costs of providing the service and, sooner or later, the adequacy of that service. The delays that have occurred in the recovery of fuel and purchased power costs through the PSA surcharge mechanism have already caused APS to be downgraded by Standard & Poors ("S&P") to BBB– status (which is one grade above "junk" status) in December 2005. S&P indicated at that time that further rating downgrades may result if there is not more prompt recovery of fuel costs. As discussed in Mr. Brandt's testimony, a downgrade to junk status would have significant and severe impacts upon the Company's ability to provide reliable electric service at reasonable rates to its customers.

The PSA does more than protect the Company's financial integrity, although that is certainly an important function that directly impacts both APS and its customers. The PSA also provides customers with relevant pricing information between general rate proceedings that can positively influence energy usage and their willingness to invest in energy efficiency. The PSA charges on a customer's bill appropriately reflect the changes in the market in a more timely manner, so customers can react to changes in the cost of this commodity by modifying their energy usage. Encouraging conservation and energy efficiency by more accurate pricing signals was one of the Commission's primary goals expressed in Decision No. 67744.

The PSA has other significant restrictions and limitations that were neither part of the comprehensive 2004 Settlement that was reached by APS with Staff and the twenty three other parties in August 2004, nor are they components of adjustment mechanisms for other Arizona utilities. These include:

1) A cap on total annual fuel and purchased power costs includable in PSA calculations of $776.2 million ("Total Fuel Cost Cap");
2) A limit on the annual PSA Factor adjustment to a maximum of $.004 per kWh over the duration of the PSA mechanism; and
3) A requirement that APS file a PSA surcharge request before the deferred costs reach $100 million

These restrictions and limitations were added to the 2004 Settlement in the Administrative Law Judge's ("ALJ") Recommended Order or during the Commission's Open Meeting deliberations that resulted in Decision No. 67744. All have the practical effect of requiring APS to file this rate case and perhaps future rate cases sooner and more often than might otherwise be the case.

The Total Fuel Cost Cap is especially troublesome because APS projects it will reach the $776.2 million Total Fuel Cost Cap during the fourth quarter of 2006. In its January 25 Open Meeting Decision, the Commission addressed the issue of the Total Fuel Cost Cap and stated that APS was permitted to continue to defer fuel and purchased power costs that were above the $776.2 million cap adopted in Decision No. 67744, and that it was never the Commission's intent that this "cap" create automatic disallowances of costs. If the Commission had not clarified that these costs could be deferred, APS would have been faced with

significant potential disallowances of legitimate fuel and purchased power costs. However, it is still unclear how costs above the "cap" will be recovered, unless the "cap" is permanently removed.

In the last APS rate case, the Total Fuel Cost Cap was at least partially premised on the theory that the additional recovery of fixed costs through sales growth would offset the known under-recovery of variable fuel and purchased power costs. This hypothesis was unproven by its proponents during the last rate proceeding and in fact was refuted by the only evidence of record in that proceeding. Again in this rate filing, APS has shown that this "growth pays for itself" theory is erroneous. This is demonstrated by Mr. Brandt's analyses of 2005-2006 financial results, which include the PSA, and indicate that the Company is experiencing a significant and rising level of under-earning. It is for these reasons that APS urges the Commission to permanently eliminate the Total Fuel Cost Cap. In the alternative, the Commission should increase the Total Fuel Cost Cap to at least $1.5 billion. This level should provide enough headroom for fuel and purchased power costs into the next decade, or roughly five years after the rates in this case have taken effect.

Second, the four mill cumulative cap on the PSA Factor should be made an annual cap, as was intended in the 2004 Settlement. With the volatility in the fuel and purchased power markets and with the January 25 Open Meeting Decision, which determined that a surcharge could only be implemented using the balance remaining after the annual PSA Factor adjustment was determined, the four mill cumulative cap is far too restrictive and does nothing but necessitate repeated PSA surcharge applications that otherwise might be addressed over time by additional PSA Factor adjustments.

A third reform to the PSA would be the elimination of the $100 million deferral "trigger" for mandatory PSA surcharge applications, because with the determination in the January 25 Open Meeting Decision that the surcharge can only be calculated once a year, the $100 million "limit" has been effectively mooted and should be eliminated.

APS also is requesting to modify the 90/10 cost sharing mechanism in the present PSA in the following respects. Renewable resources that are purchased and not covered by the Commission's Environmental Portfolio Standard ("EPS") surcharge are included in the PSA's calculation of fuel and purchased power costs. Because acquiring additional renewable resources is both required by Decision No. 67744 and is consistent with Commission policy, APS should not have to suffer an automatic 10% disallowance of such costs, as would happen under the current 90/10 cost sharing mechanism. Similarly, APS is proposing to exclude the demand costs of purchased power agreements ("PPAs") acquired through competitive processes from this cost sharing. Because the demand costs are fixed and market-based, APS has no ability to further reduce or avoid them, and thus the 90/10 "sharing" becomes simply an arbitrary disallowance of reasonable and prudent costs. The energy portion of the PPAs, i.e., the per MWH charge, would continue to be subject to 90/10 cost sharing.

Finally, APS proposes to exclude 10% of the realized gains or losses from hedging from the calculation of both base fuel cost and the PSA. The remainder (90%) of gains and losses would continue to be included in such calculations and would be subject to the 90/10 cost sharing mechanism.

Q. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?

A. I first describe the present PSA, as approved in Decision No. 67744, and the modifications that were made in the January 25 Open Meeting Decision. I next discuss the importance of retaining the PSA to both APS and its customers. Finally, I address the need to remove some of the restrictions and limitations imposed on the PSA and also some of the unfair results that have and can occur as a result of the 90/10 sharing mechanism currently in the PSA.

Q. ARE YOU SPONSORING ANY ATTACHMENTS TO YOUR TESTIMONY?

A. Yes. In addition to Appendix A, my testimony includes the following attachments:

1) Attachment DGR-1 – 2005 Financial Impacts from PSA
2) Attachment DGR-2 – 2006 Financial Impacts from PSA
3) Attachment DGR-3 – List of Jurisdictions with PSAs or Similar Rate Mechanisms

III. THE CURRENT PSA RATE MECHANISM

Q. PLEASE DESCRIBE THE PSA AS PROPOSED IN THE 2004 SETTLEMENT.

A. What I will describe as the "Settlement PSA" had the following key provisions:

- The PSA included both fuel and purchase power, but would provide no profit to the Company.
- The PSA Factor was initially set at zero and would not be adjusted for the first time until April 1, 2006.
- The maximum adjustment to the PSA Factor in April of each year would be plus or minus $0.004 per kilowatt hour ("kWh") with any additional amounts carried over.

- If at any time the PSA bank balance in the PSA balancing account reached plus or minus $50 million, APS would be required to either seek a surcharge to collect or refund the bank balance or justify in writing why such a surcharge was not necessary at that time.
- APS and its customers would share in the costs or savings on a 90% customers/10% APS basis.
- Subject to certain limited exceptions, customers would receive the benefits of all off-system sales.
- The Commission and its Staff would retain the ability to review the prudence of all fuel and power purchases at any time, and any costs flowed through the PSA would be subject to refund if the Commission subsequently found that such costs were not prudently incurred.
- APS would provide detailed and certified monthly reports encompassing an extensive amount of information relating not only to the PSA calculations, but also to the APS generating units and to its power and fuel purchases.
- The minimum life of the PSA was to be five years from the date that rates under the proceeding went into effect.
- The Base Fuel Recovery Amount reflected in APS' base rates was set at $0.020743 per kWh, which reflected a re-dispatch of APS resources based on adjusted 2003 retail sales and April 2003 fuel and purchased power prices.

Q. DID DECISION NO. 67744 ADOPT THE SETTLEMENT PSA?

A. In large part, yes. However, several significant changes were made that have adversely impacted the subsequent operation of the PSA and which could hinder its function in the future.

Q. PLEASE EXPLAIN.

A. The most important change was the imposition of the Total Fuel Cost Cap of $776.2 million. I believe the primary purpose of that limitation was to force APS into another general rate filing prior to its fuel and purchased power costs reaching the Total Fuel Cost Cap. As discussed by the Commissioners during the Open Meeting when Decision No. 67744 was adopted and affirmed in the January 25 Open Meeting Decision, the purpose was not to create an automatic disallowance of otherwise reasonable and prudent costs of providing service. Current projections are that APS will reach the Total Fuel Cost Cap sometime during the fourth quarter of 2006.

A second change was to take what was to have been an annual limit of four mills per kWh for the April adjustment to the PSA Factor and make it a cumulative "lifetime" limit. Because it was already anticipated at the time of Decision No. 67744 that 2006 fuel and purchased power costs would be considerably more than four mills above the Base Fuel Cost Recovery Amount, this meant that the PSA would chronically under-recover, producing large bank balances and repeated requests for surcharges, unless and until the Base Fuel Cost Recovery Amount could be increased in a general rate proceeding.

The PSA surcharge provision to the Settlement PSA was also modified to require a surcharge application prior to the bank balance reaching plus or minus $100 million.

Finally, the five-year minimum term of the Settlement PSA was essentially eliminated. Decision No. 67744 stated that if APS filed a rate case prior to the expiration of the five year term, the Commission could eliminate the PSA if appropriate.

Q. HOW WAS THE PSA MODIFIED IN THE JANUARY 25 OPEN MEETING DECISION?

A. In the January 25 Open Meeting Decision, the Commission took the following action:

- Denied the surcharge of $.001416 per kilowatt hour that was requested by the Company in the July Surcharge Request;
- Accelerated the collection of the PSA adjustor to begin as of February 1st of each year;
- Reset the adjustor rate to a positive $0.004 per kilowatt hour effective February 1, 2006;
- Clarified that the setting of the PSA adjustor was a condition precedent to the setting of the surcharge, and that the surcharge that could be requested was limited to the balance remaining in the Paragraph 19(d) balancing account after the adjustor had been calculated; and
- Clarified that APS was permitted to continue to defer the fuel and purchased power costs that were above the $776.2 million cap adopted in Decision No. 67744, and that it was never the Commission's intent that this "cap" create automatic disallowances of cost.

IV. IMPORTANCE OF PRESERVING THE PSA

Q. IS THE PSA CRITICAL TO MAINTAINING THE COMPANY'S FINANCIAL INTEGRITY?

A. Absolutely. As the Company explained in detail in both the PSA proceeding (Docket No. E-01345A-02-0403) and in our prior general rate proceeding (Docket No. E-01345A-03-0437), APS is increasingly dependent on natural gas, both to run its own generating facilities and through its rapidly increasing dependence on purchased power, which is predominantly generated by gas-fired plants. For example, between 1991 (the year after the Company's last fully litigated general rate case prior to Decision No. 67744) and 2006, APS' energy needs from gas-fired generating facilities and purchased power will increase from 9% to approximately 29%. As a result, gas and purchased power will constitute nearly 70% of the Company's total fuel and purchased power expenses by 2006, which is the first full year that the PSA would be effective. And, fuel and purchased power expense will constitute over one-third of all APS operating expenses in 2005, compared to one-fourth in 1991.

Looking further into the future, the situation is likely to become worse due to gas dependence. As a result of Decision No. 67744, the Company's future resource acquisition is increasingly likely to be in the form of long-term PPAs with merchant generators. Their generation is presently almost exclusively gas, as is the incremental generation of surrounding utilities that might be available for resale. In the recent Request for Proposal ("RFP") that was held pursuant to Decision No. 67744 to seek at least 1000 MW of new long-term generation supply beginning in 2007, no bidder was willing to accept the risk of gas price volatility. Although APS is committed to acquiring 10% of its incremental needs from renewable resources and to spend $48 million on conservation and energy efficiency programs, subject to Commission approval, these steps will unlikely

reverse the trend toward increased reliance on natural gas to generate electricity in the near future.

At the same time that APS is becoming more dependent on natural gas and purchased power, prices for both have become more volatile. Although Mr. Ewen addresses this in detail, I note that the average natural gas price for delivery at the San Juan Basin has ranged from $1.00 per MMBTU to $13.27 per MMBTU since 2002. At Henry Hub, the gas price has ranged from $1.98 per MMBTU to $18.60 per MMBTU during the same timeframe. Furthermore, Staff's fuel and purchased power witness in the Company's last rate proceeding, Douglas Smith, and its corresponding witness in Docket No. E-01345A-02-0403, Barbara Keene, both testified concerning the historical volatility in the natural gas market. Finally, the existence and impact of the natural gas volatility has been well-described by a number of the Commissioners in publicly-docketed letters over the past year and a half. (*See* Letter from then Chairman Marc Spitzer, Docket No. E-01345A-03-0437, February 19, 2004; Letter from Commissioner (now Chairman) Jeff Hatch-Miller to Senator John McCain, March 5, 2004; Letter from then Chairman Marc Spitzer to Fellow Commissioners, Docket Nos. G-01032A-03-0515; G-01032A-02-0598; G-01032A-02-0914; E-01032C-00-0751; E-01933A-02-0914; and E-01032C-02-0914. March 5, 2005; Letter from Commissioner William A Mundell to *Arizona Daily Star*, Docket No. RE-00000C-05-0030, April 29, 2005; and Letter from Commissioner Marc Spitzer to Fellow Commissioners, Docket No. RE-00000C-05-0030, June 29, 2005).

In addition, in a Commission workshop on natural gas prices held on September 8, 2005, Commission Staff Robert Gray commented that prior to Hurricane

Katrina, there was upward pressure on natural gas prices, a situation only worsened by the horrific hurricane season. He concluded that the rising natural gas prices would be a driving force in the increased costs utilities must recover from their customers. The same theme – that there had been unforeseeable increases in the price of natural gas due to tight market conditions, and that the damage from Hurricanes Katrina and Rita had caused damage to drilling rigs and other infrastructure which had added more uncertainty to the market and resulted in gas prices that would have been viewed as "impossible" in the pre-hurricane markets – was echoed by Staff witness William Gehlen in the PSA Surcharge docket.[3]

Power prices can be equally volatile, if not more so. In the period 2002-2005, the price of on-peak power at Palo Verde ranged from a low of $18.85/MWh to a high of $118.21/MWh. During 2005, prices have ranged from $42.78/MWH to $117.91/MWH, thus displaying continued volatility compared to most other costs experienced by the Company to provide service.

Both APS' increasing dependence on natural gas and purchased power, as well as continued volatility of both, unmistakably supported the adoption of a PSA in Decision No. 67744. Additionally, the fact is that a PSA facilitates competitive markets, as evidenced by the merchant generators support of the PSA mechanism during the 2004 Settlement negotiations. All of these factors support the retention of the PSA in this proceeding.

Q. WHAT WOULD BE THE IMPACT OF ELIMINATING THE PSA IN THIS PROCEEDING?

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[3] Gehlen Direct Testimony , pg. 6, lines 15-17. Docket Nos. E-01345A-05-0526, et al.

A. The elimination of the PSA would be disastrous for APS and its customers. Let me give some historical perspective on this issue. During 2005, APS deferred some $ 170 million (including interest) in fuel and purchased power costs above the Base Fuel Recovery Amount. Unless the Company's request for rate relief is granted sometime in 2006, APS will defer yet another $243 million in costs during 2006. Without the PSA mechanism, APS would have to expense these costs, i.e., charge them against earnings, which would have a very serious negative impact on the Company's financial integrity. As discussed in detail in Mr. Brandt's direct testimony, the Company expects to earn only a 6.6% ROE in 2006 even with the current PSA. Without it, the ROE for 2006 drops to 2.6%. This is clearly well below the 10.25% COE authorized in Decision No. 67744 and even more distant from the COE of 11.5% recommended by Dr. Avera. It is also well below the ROEs recommended by Commission Staff for either Tucson Electric Power Company or Southwest Gas Corporation.

Other key financial metrics such as Funds from Operations ("FFO") as a percent of debt are also affected by 2006 fuel and purchase power costs. Furthermore, in December 2005, S &P downgraded the Company's business profile from a "5" to a "6" (on a 10-point scale, where "1" is excellent). This business profile requires a FFO/debt ratio of at least 18% in order to be classified as investment-grade. Without the PSA in place, the Company's FFO/debt ratio would continue to erode. I have summarized these impacts in Table 1 below and in Attachments DGR-1 and DGR-2:

Table 1

Summary of Financial Impacts from PSA

		2006
Return on Equity	With PSA	6.6%
	Without PSA	2.6%
FFO Interest Coverage	With PSA	3.4
	Without PSA	2.9
FFO to Total Debt	With PSA	16.0%
	Without PSA	12.6%

As to the prospective impact of eliminating the PSA, let me say that even if the Commission were to adopt the higher base fuel allowance that is proposed by Mr. Ewen, APS would not recover anticipated 2007 fuel and purchased power costs. This would be the case even before factoring in the potential impacts on those costs of the recent RFPs for both renewable and conventional power resources. The conventional power resources RFP, as well as future solicitations required by Decision No. 67744, will steadily increase the Company's dependence on purchased power and natural gas. And although APS will be increasing its use of renewables, the amount of its energy needs derived either directly from natural gas or gas-dependent purchased power will increase in 2007 to 30% and to 34% by 2009.

Q. WHAT IS THE COMPANY DOING TO MANAGE ITS FUEL COSTS?

A. APS has taken a number of steps to manage its fuel costs, including hedging natural gas and purchased power requirements for native load customers. Price stability is the primary underlying goal of APS' hedging philosophy. Using this

approach, financial risks associated with projected fuel and purchased power requirements are systematically hedged at various levels during the three years prior to delivery. The Company's hedging practices involve setting definitive target hedge levels and strict compliance in meeting those hedge levels, all undertaken with senior management oversight and direction. By hedging 85% of the Company's purchased power and natural gas needs using pre-established intervals and hedge percentage levels over a three-year horizon, APS can mitigate the impact of volatile natural gas and purchase power prices and still allow for changes in load and other short term market variables.

In addition, APS recently executed a 19-year, 65 million ton coal supply agreement with Peabody Energy. In light of today's current market conditions, APS anticipates that this contract will result in improved economics for the Cholla Generating Station for future coal purchases.

Q. IF THE PSA WAS ABOLISHED, COULDN'T APS SIMPLY FILE GENERAL RATE CASES MORE FREQUENTLY?

A. Given the Commission's use of historical test periods and the time it has taken in the past to process APS general rate cases (usually 18 months and sometimes longer), this is simply not practical. And in periods of rapidly rising fuel costs, even the fastest turnaround of a general rate case would be inadequate. It should be noted that gas utilities in Arizona adjust their purchase gas adjustors monthly and still accumulate significant bank balances, which absent an adjustor mechanism, would result in the chronic inability to recover legitimate costs.

Q. HOW WOULD THE RATING AGENCIES AND THE FINANCIAL COMMUNITY IN GENERAL PERCEIVE A FAILURE IN THIS PROCEEDING TO RETAIN THE PSA?

A. Since the time the 2004 Settlement was announced, the PSA has been a critical factor in the financial community's evaluation of APS. For example, just two days after the 2004 Settlement was announced, S & P stated:

> 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.[4]

Moody's reaction was similar. Once the PSA was approved in Decision No. 67744, these agencies again cited the PSA as a significant positive factor that allowed them to take APS off negative credit watch.

In July 2005, six major equity analysts (Credit Suisse/First Boston, Harris Nesbitt, JP Morgan, Lehman Brothers, Merrill Lynch, and UBS) issued reports evaluating the Company's investment quality. Five of the analysts kept an essentially neutral position, while one downgraded Pinnacle West's stock. All mentioned the existence of the PSA as a positive aspect of the Commission's regulation of the Company. In October 2005, several of the equity analysts issued updated reports addressing the Company's outlook. While mounting deferred fuel and purchased power costs, as well as the prospect of the Company exceeding the $776 million cap, were items of concern, the Company's stock was not downgraded because the analysts believed that the PSA mechanism would ultimately lead to adequate cost recovery.

Q. DOES THE FINANCIAL COMMUNITY VIEW THE PSA AS HAVING STRUCTURAL WEAKNESS?

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[4] Standard & Poor's, "Research: Arizona Public Service's Proposed Rate Settlement is Reasonably Constructive," August 20, 2004.

A. Yes. This issue is discussed in Mr. Brandt's testimony as well. S& P has characterized the Company's PSA as "relatively weak" due to the Total Fuel Cost Cap, the four mill limit on the PSA Factor, and the length of time needed to actually recover fuel and purchased power costs. Other analysts have made similar observations.

Q. DURING THE 2004 SETTLEMENT PROCEEDING, THE MERCHANT GENERATION INTERESTS STRONGLY SUPPORTED ADOPTION OF THE PSA. HOW DOES RETENTION OF THE PSA SUPPORT WHOLESALE COMPETITION?

A. It does so in at least two ways. First, merchant generators are interested in doing business with financially strong and stable counterparties. If APS' credit deteriorates, fewer merchant counterparties will be willing to do business with the Company, and those that do will impose more onerous credit terms, such as collateral calls and even prepayment. This drives up the cost of purchased power for APS and its customers. Second, the financial community has increasingly come to regard purchased power as a form of debt that can strain utility cash resources without timely recovery of purchased power costs. The PSA, if allowed to operate effectively, helps to overcome the financial disincentives to enter into long term power agreements with merchant generators, especially in combination with the modification to the 90/10 sharing provision requested by the Company. Eliminating disincentives to enter into PPAs is also consistent with the provision in Decision No. 67744 that requires APS to first turn to the competitive market for incremental resources through 2015.

Q. DO APS CUSTOMERS BENEFIT FROM RETENTION OF THE PSA?

A. Absolutely. APS customers have a vital stake in the Company's ability to plan for and accommodate growth without compromising reliability. APS must be financially sound to accomplish this task in a manner economical to customers. Also, the PSA and the customer education program concerning the PSA provide APS customers with more timely information about the cost of power consumption and, conversely, the value of energy efficiency and conservation. Although these price signals are somewhat diluted by other features of the PSA that are designed to smooth and moderate short-term price volatility, they are still stronger and more accurate than would be the case in the absence of the PSA. Lastly, the potential benefits to APS customers from further development of the competitive wholesale market was a salient feature of both the 2004 Settlement and Decision No. 67744. As noted above, the pro-competition benefits from a PSA mechanism are well known and understood by those who are participants in that wholesale market.

Q. IS THE USE OF AN ADJUSTMENT MECHANISM TO RECOVER FUEL AND PURCHASED POWER COMMON IN THE UTILITY INDUSTRY?

A. Yes. Adjustment mechanisms are commonly used to recover both fuel and purchased power costs. These types of adjustments are utilized by both electric and natural gas utilities. The June 2, 2005 report from Regulatory Research Associates entitled "State Regulatory Overview – Energy Issues" provides a state-by-state review of cost pass-through programs. Forty states and Washington D.C. provided for commodity cost recovery. Of the states not expressly providing a cost recovery mechanism, at least some provided effective alternatives, while others have granted higher ROEs that could support the additional risk. *See* Attachment DGR-3. None have anywhere near the customer growth and fuel/purchased power cost exposure that the Company faces.

Furthermore, some Arizona utilities also have fuel adjustors. For example, both Southwest Gas and Unisource Gas have Purchased Gas Adjustors, which fluctuate monthly based on a rolling twelve month average of actual costs and sales. In addition, both APS and Tucson Electric Power have had fuel cost adjustment mechanisms in the past.

V. PROPOSED CHANGES TO THE CURRENT PSA

Q. WHAT CHANGES TO THE PSA IS THE COMPANY PROPOSING?

A. In order of importance: (1) the Total Fuel Cost Cap should be permanently eliminated or very substantially raised; (2) the cumulative four mill cap on the annual PSA adjustment should be changed to an annual cap; (3) the 90/10 cost sharing should not apply to renewable resources or to the fixed costs of PPAs acquired through competitive bidding or similar competitive processes; and (4) 10% of realized hedging gains and losses should be excluded from the calculation of fuel and purchased power costs both in determining the Base Fuel Recovery Amount and subsequent operation of the PSA (the remaining 90% to be included in PSA calculations subject to the 90/10 sharing).

Q. DID THE 2004 SETTLEMENT, WHICH WAS NEGOTIATED BY THE PARTIES, HAVE THE ALL THE LIMITATIONS OR RESTRICTIONS THAT THE CURRENT PSA HAS?

A. No, some limitations and restrictions were added later in Decision No. 67744 and in the January 25 Open Meeting Decision.

Q. WHY SHOULD THE COMMISSION ELIMINATE THE TOTAL FUEL COST CAP?

A. First of all, imposing any sort of involuntary limit or cap on the recovery of legitimate costs of providing service to our customers is unreasonable. That is why APS has always viewed the Total Fuel Cost Cap as an encouragement from

the Commission to file another general rate case to address the issue of escalating fuel and purchased power costs. Also, the imposition of the Total Fuel Cost Cap was, in the first instance, largely based on a demonstrably false premise that if revenues were rising faster than fixed costs, increasing fixed cost recovery would offset rising variable costs such as fuel and purchased power. The fact that APS will not earn anything close to the 10.25% COE authorized by Decision No. 67744 during the first full-year rates from that Decision are in effect, even with the PSA, is stark evidence that no such offset exists.

Q. IS THE TOTAL FUEL COST CAP SIMPLY A HYPOTHETICAL CONCERN?

A. No. By the end 2006, APS will have reached the Total Fuel Cost Cap set in Decision No. 67744. As discussed in Mr. Ewen's testimony, the increasing costs that the Company is experiencing is a result of a number of factors, including the dramatic increase in natural gas and purchased power prices, rising coal prices and the fact that the Company's incremental sales attributable to growth must be met primarily with high-cost natural gas and purchased power. In the January 25 Decision, the Commission permitted APS to continue to defer fuel and purchased power costs above the $776.2 million cap. With the combination of high priced gas and increasing load growth, maintaining the "cap" would result in disastrous financial results for the Company. Therefore, the Total Fuel Cost Cap should be permanently eliminated or increased to at least $1.5 billion. This figure is based on forecast fuel and purchased power costs in 2012, or roughly five years after the rates in this case have become effective.

Q. WHY SHOULD THE PSA ALLOW ANNUAL ADJUSTMENTS OF UP TO FOUR MILLS?

A. While APS agrees that there should normally be a limit on the size of annual PSA adjustments, it also believes that the PSA should not permit chronic and systematic under- or over-recoveries of fuel and purchased power costs. To do so increases the total cost to APS customers, dilutes the price signals from the PSA, creates inequities between current and future APS customers, strains cash resources of the Company needed elsewhere to fund operations and increase basic infrastructure, and leads to large bank balances that have to be cleared, which potentially lead to the large single-year price increases the Commission was trying to avoid in the first place with the annual four mill limit on the PSA adjustment.

Q. HOW SHOULD THE COMMISSION MODIFY THE 90/10 COST SHARING MECHANISM IN THE PSA?

A. APS is asking that the 90/10 cost sharing mechanism not apply to: (1) renewable resources; and (2) the fixed cost (demand) component of purchased power contracts acquired through a competitive acquisition process.

Q. WHY ARE THESE CHANGES TO THE 90/10 MECHANISM APPROPRIATE?

Both in Decision No. 67744 and in its deliberations on the Environmental Portfolio Standard embodied in A.A.C. R14-2-1618, the Commission has expressed a strong commitment to renewable energy. In furtherance of this commitment to renewable energy, in Decision No. 67744 the Commission required APS to issue a Renewable RFP, seeking at least 100 MW and 250,000 MWhs of energy from renewable resources. It did so despite the fact that in many of its present applications renewable energy is significantly more

expensive than conventional resources. Consistent with this Commission policy, APS should not be penalized by an automatic 10% cost disallowance when it acts in furtherance of that public policy by securing renewable resources that are not least-cost resources.

Similarly, the Commission has been a strong advocate of the competitive wholesale market and has encouraged APS to acquire resources through competitive means. In fact, the 90/10 sharing set forth in Decision No. 67744 was such an incentive. When resources have been "market tested," there is no need for any additional incentive to minimize costs. APS is only asking that this exemption apply to the fixed cost component of any market-acquired PPAs because (1) the Company may be acquiring the gas used by the merchant generator, and thus would have the same incentive to do so prudently as it would with regard to its owned units, and (2) this would place PPAs on the same footing with regard to cost recovery as APS-owned generation, which removes the disincentive for entering into long-term PPAs. In these instances, the 10% share of higher costs absorbed by APS through the sharing mechanism has nothing to do with the prudence of such costs or even whether they could have been avoided or reduced by any action of APS management. It is a pure disallowance of otherwise legitimate costs of providing service.

Q. WHAT IS THE COMPANY'S PROPOSAL WITH REGARD TO HEDGING GAINS AND LOSSES?

A. APS is suggesting that 10% of realized hedging gains and losses be removed from both the determination of the Base Fuel Recovery Amount and the fuel and purchased power costs above that Base Fuel Recovery Amount recorded in the PSA balance account. This would allow the Company to retain a small

additional percentage of realized gains in exchange for agreeing to absorb a similar additional percentage of realized losses. The remaining 90% of realized gains and losses from hedging would continue to be reflected in the PSA and subject to the usual 90/10 sharing.

V. CONCLUSION

Q. DO YOU HAVE ANY CONCLUDING REMARKS?

A. Yes. An effectively operating PSA is vital to the Company's financial integrity and its access to capital at reasonable prices, a critical factor given the large capital needs of APS during the coming years. It also benefits competition and provides customers with important information about the cost of energy consumption and the benefits of energy efficiency and conservation. For these reasons, and because of the extreme volatility of fuel prices, the continuation of the PSA is absolutely essential

Q. DOES THAT CONCLUDE YOUR PREFILED DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes.

Appendix A

Statement of Qualifications
Donald G. Robinson

Donald G. Robinson is Vice President of Planning for Arizona Public Service Company ("Company"). Mr. Robinson is responsible for the Company's corporate planning, resource acquisition, resource planning, budgets, forecasts, energy risk management and new business ventures.

Mr. Robinson was previously Vice President of Finance and Planning for Arizona Public Service Company. In this position, Mr. Robinson was responsible for the Company's financial planning, corporate planning, budgeting, forecasting, accounting, risk management, tax services and supply chain management.

Before the position above, Mr. Robinson was Vice President of Regulation and Planning for Arizona Public Service Company. In this position, Mr. Robinson was responsible for the Company's regulatory policies and activities before the Arizona Corporation Commission and the Federal Energy Regulatory Commission, as well as corporate planning.

Prior to the promotion above, Mr. Robinson was Director of Accounting, Regulation and Planning for Arizona Public Service Company. Mr. Robinson had responsibility for the Company's accounting, planning and regulatory policies and activities.

Mr. Robinson joined the Company in 1978 and held a number of supervisory positions in the accounting department. In 1981, he was named Manager of Regulatory Affairs and in 1998, Manager of Rates and Regulation. Mr. Robinson was a principal in the consulting firm Micon from 1992-1996. Mr. Robinson has a Bachelor of Science degree in Accounting.

Arizona Public Service Company
2005 Financial Impacts from PSA

2005 Return on Equity	
With PSA	6.8%
Without PSA	3.5%

2005 FFO Interest Coverage	
With PSA	3.3
Without PSA	3.4

2005 FFO to Total Debt	
With PSA	14.8%
Without PSA	15.5%

Arizona Public Service Company
2006 Financial Impacts from PSA

2006 Return on Equity	
With PSA	6.6%
Without PSA	2.6%

2006 FFO Interest Coverage	
With PSA	3.4
Without PSA	2.9

2006 FFO to Total Debt	
With PSA	16.0%
Without PSA	12.6%

Arizona Public Service Company
Jurisdictions with PSA or Similar Rate Mechanisms

State	Cost Pass-Through
AL	X
AR	X
CA	X
CO	X
CT	X
DC	
DE	X
FL	X
GA	X
HI	X
IA	X
ID	X
IL	X
IN	X
KS	X
KY	X
LA	X
MA	X
MD	
ME	
MI	X
MN	X
MO	X
MS	X
MT	X

State	Cost Pass-Through
NC	X
ND	X
NE	
NH	
NJ	
NM	X
NV	X
NY	X
OH	X
OK	X
OR	X
PA	
RI	X
SC	X
SD	X
TN	X
TX	X
UT	
VA	X
VT	
WA	X
WI	X
WV	X
WY	X

Sources: State Regulatory Overview -- Energy Issues, Regulatory Research Associates (June 2,2005) and the Special Report: Fuel and Wholesale Power Recovery, Regulatory Research Associates (July 26, 2004)

CHRIS N. FROGGATT

DIRECT TESTIMONY OF CHRIS N. FROGGATT

On Behalf of Arizona Public Service Company

Docket No. E-01345A-05-0816

January 31, 2006

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STATEMENT OF QUALIFICATIONS ..... Appendix A

ATTACHMENTS

- Regulatory Assessments & Franchise Fees ..... Attachment CNF 1-1
- Base Rate Component for EPS ..... Attachment CNF 1-2

Demand Side Management ..... Attachment CNF 1-3
Interest on Customer Deposits ..... Attachment CNF 1-4
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TESTIMONY OF CHRIS N. FROGGATT

ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY

(Docket No. E-01345A-05- 0816)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Chris N. Froggatt. My business address is 400 N. 5th Street, Phoenix, Arizona 85004.

Q. WHAT IS YOUR POSITION WITH ARIZONA PUBLIC SERVICE COMPANY?

A. I am Vice President and Controller for Arizona Public Service Company ("APS" or "Company"). My educational background and professional qualifications, as well as my professional experience, are set forth in Appendix A, which is attached to this testimony.

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

A. My testimony will primarily focus on the historical accounting data in the Company's filing, including unadjusted test year ended September 30, 2005 data ("Test Year"). I will also testify regarding how the capital structure proposed by APS witness Donald Brandt is used to calculate the Company's cost of capital.

II. SUMMARY OF TESTIMONY

Q. PLEASE PROVIDE A SUMMARY OF YOUR TESTIMONY.

A. My testimony addresses historical accounting data and pro forma adjustments that are required by various Standard Filing Requirement ("SFR") Schedules of the Arizona Corporation Commission ("Commission") to support the Company's rate

case filing. I will discuss information from the Test Year (twelve months ended September 30, 2005) and prior years relating to the Summary Schedules, SFR Schedules A-2 and A-3, and income statements relating to the Test Year and prior years, as set forth in SFR Schedule C-1. Of the pro formas set forth in SFR Schedule C-2, I will be sponsoring the following:

- Regulatory Assessments and Franchise Fees
- Environmental Portfolio Standard
- Demand Side Management
- Interest on Customer Deposits
- Amortization of Regulatory Assets
- Pinnacle West Energy Corporation ("PWEC") Loan
- Out of Period Income Tax Adjustments
- Generation Production Income Tax Deduction
- Income Tax / Interest Synchronization

I will discuss the factor used to gross up operating income to account for taxes, as set forth in SFR Schedule C-3. I will also discuss the capital structure of the Company and provide APS' actual overall cost of capital, as set forth in SFR Schedules D-1, D-2 and D-3. (Mr. Brandt will discuss the projected information on Schedule D-1.) This will include information on the cost of equity provided by Dr. William Avera, APS' return on equity ("ROE") witness, as well as the Company's cost of debt. In addition, I will sponsor the various schedules relating to the Company's financial statements, as set forth in SFR Schedules E-1, E-2, E-3, E-4, E-7, E-8 and E-9 (Mr. Brandt will discuss the projected information on these schedules). SFR Schedule E-6 is not applicable to APS. SFR Schedule E-5 will be addressed by Ms. Laura Rockenberger. Finally, I will sponsor the Test Year data on SFR Schedules F-1 and F-2, which address projected income statements and

projected changes in financial position. Mr. Brandt will address the projected information on those schedules.

III. HISTORICAL AND TEST YEAR ACCOUNTING DATA

Q. PLEASE DESCRIBE THE ACCOUNTING INFORMATION CONTAINED WITHIN THE SFR SCHEDULES THAT YOU ARE SPONSORING.

A. As the Controller of APS, I am responsible for the accounting and financial reporting by the Company. Thus, my testimony covers historical accounting data, including the actual data for the Test Year. The majority of this information is either directly or indirectly contained in both the APS and consolidated Pinnacle West Capital Corporation ("Pinnacle West") audited financial statements, which are included in filings made with the Securities and Exchange Commission ("SEC") for the relevant years.

Additionally, all of the accounting information provided in my testimony complies with Generally Accepted Accounting Principles ("GAAP"). These are the principles that accounting professionals use to prepare financial statements. One major goal of GAAP is to make financial statements comparable from year to year, from industry to industry, and from jurisdiction to jurisdiction. APS' accounting practices comply with other applicable utility accounting standards, such as the Federal Energy Regulatory Commission ("FERC") Uniform System of Accounts, which has also been adopted by the Commission. *See* A.A.C. R14-2-212(G).

In large part, my testimony supports the testimony of other APS witnesses. The direct testimony of Mr. Brandt addresses financial projections to actual Test Year data. Ms. Rockenberger addresses, among other things, Original Cost Rate Base, the PWEC and Sundance units, the nuclear decommissioning fund, depreciation and working capital requirements. Mr. Rumolo focuses on the jurisdictional

allocation of APS revenues, costs, and rate base items. Dr. Avera's testimony addresses the Company's ROE.

A. Summary Schedules

Q. PLEASE DESCRIBE THE HISTORICAL INFORMATION IN SFR SCHEDULE A-2.

A. SFR Schedule A-2 provides the "Summary Results of Operations" for the Test Year and the prior three calendar years. It also includes projected information for two calendar years after the Test Year. I am sponsoring the data contained in the first four columns of SFR Schedule A-2, which is historical data for the prior calendar years and the Test Year. Mr. Brandt is sponsoring the projected information on this SFR Schedule.

Q. PLEASE DISCUSS SFR SCHEDULE A-3.

A. SFR Schedule A-3 is the "Summary of Capital Structure" for APS, which is separated into the Test Year, three prior calendar years, and a projected period. As with SFR Schedule A-2, I am sponsoring the historical prior calendar years and Test Year data.

B. Test Year Income Statements

Q. PLEASE DISCUSS THE INFORMATION THAT YOU ARE SPONSORING IN SFR SCHEDULE C-1.

A. SFR Schedule C-1 is the summary of the Company's adjusted Test Year income statement. I am sponsoring the historical Test Year data in the first column of SFR Schedule C-1. This information provides the baseline from which pro forma adjustments are made and shows operating income and net income for the Test Year. As shown on the schedule, APS' operating income and net income during the

Test Year period were $ 377 million and $ 167 million, respectively, on revenues of nearly $ 3.4 billion.

Q. ARE YOU SPONSORING ANY OTHER RELATED SFR SCHEDULES?

A. Yes, I am sponsoring SFR Schedules C-2 and C-3. SFR Schedule C-2 presents the pro forma adjustments to the Company's Test Year operating income. I will discuss these adjustments in detail later in my testimony (see section IV "Pro Forma Adjustments"). SFR Schedule C-3 shows the computation of the gross revenue conversion factor.

Q. PLEASE DESCRIBE SFR SCHEDULE C-3.

A. SFR Schedule C-3 calculates the factor applied to "gross-up" income to account for income taxes so that taxes that must be paid by APS are reflected in the revenue requirement that APS is requesting. The Gross Revenue Conversion factor of 1.6407 (shown on line 5) is simply an algebraic transformation of APS' composite federal and state income tax rate of 39.05 percent. This factor is used on SFR Schedule A-1 (line 7) to arrive at the increase or decrease in Gross Revenue Requirements necessary to account for income taxes.

C. Capital Structure and Cost of Capital

Q. PLEASE DISCUSS THE COST OF CAPITAL INFORMATION THAT YOU ARE SPONSORING.

A. SFR Schedule D-1 is the summary of the Company's historical and projected cost of capital. I am sponsoring the Test Year data in this schedule. Mr. Brandt will discuss the Company's proposed capital structure and the pro forma adjustments to the cost of capital. SFR Schedule D-2 presents supporting detail for the long-term debt that is summarized on SFR Schedule D-1. SFR Schedule D-3, which addresses preferred stock, is included in the Company's schedules for

completeness, but it is not applicable because APS had no outstanding preferred stock at the end of September 2005 and in fact, has had none for many years. SFR Schedule D-4 addresses the Company's cost of common equity.

Q. PLEASE DISCUSS IN MORE DETAIL THE COMPANY'S OUTSTANDING LONG-TERM DEBT AS OF THE END OF THE TEST YEAR.

A. At the end of the Test Year, approximately 74 percent of APS' outstanding long-term debt consisted of unsecured notes with a weighted average interest rate of approximately 6 percent ($114,928,000 divided by $1,910,476,000). Most of the remainder of the long-term debt consisted of tax-advantaged pollution control bonds. This debt has weighted average interest rate of about 3.6 percent. APS also has a small amount of interest related to capital lease obligations and amortization of gains and losses on reacquired debt, both of which are classified as interest expense and are reflected on SFR Schedule D-2.

Q. WHAT WAS APS' CAPITAL STRUCTURE AT THE END OF THE TEST YEAR?

A. APS' total long-term debt and common equity was approximately $ 5.6 billion. This was comprised of approximately $ 2.6 billion in long-term debt (including current maturities) and approximately $ 3.0 billion in common equity. Thus APS' capital structure at the end of the Test Year was approximately 46 percent debt and 54 percent equity.

Q. WHAT IS THE COST OF CAPITAL THE COMPANY IS REQUESTING?

A. As discussed in Mr. Brandt's testimony, and set forth on SFR Schedule D-1, the adjusted cost of capital the Company is requesting is 8.73 percent.

D. Financial Statements

Q. ARE YOU SPONSORING SFR SCHEDULES E-1 THROUGH E-4, E-7, E-8 AND E-9?

A. Yes. These schedules relate primarily to historical financial and accounting information, as well as the notes to the financial statements. SFR Schedule E-6 is required only for combination utilities and therefore does not apply to APS.

Q. PLEASE DISCUSS SFR SCHEDULES E-1, E-2 AND E-3.

A. These three schedules contain information found on the balance sheet, the income statement and the cash flow statement for the Test Year period and the three prior calendar years. SFR Schedule E-1 provides comparative balance sheets for these periods, while SFR Schedules E-2 and E-3 provide comparative statements of income and comparative statements of cash flows, respectively. The calendar year financial statements were included in SEC Form 10-K filings for the relevant years.

Q. PLEASE DISCUSS SFR SCHEDULE E-4.

A. SFR Schedule E-4 shows changes in stockholders' equity for the Test Year and three prior calendar years. This schedule shows that stockholders' equity changed by net income, common stock dividends and other comprehensive income. APS' other comprehensive income includes minimum pension liability adjustments and unrealized gains and losses on derivative instruments used to hedge gas and power costs. Even though these items are not yet realized, GAAP requires these items to be reported in stockholders' equity through other comprehensive income or loss, rather than be reflected in net operating income.

Q. WHAT INFORMATION IS PROVIDED IN SFR SCHEDULE E-7?

A. SFR Schedule E-7 provides detailed information concerning APS' sales (in kWh), number of customers and average usage per customer over the last three years,

including the Test Year. This information is contained in or derived from APS' FERC Form 1 filings for the applicable periods, and is separated by customer classes to show residential, commercial, industrial, irrigation, public street and highway lighting, other sales to public authorities, and sales for resale. Additionally, SFR Schedule E-7 shows the average revenue per residential customer, which in 2004 was approximately 8.54¢/kWh. SFR Schedule E-7 also shows that the direct production expense per kWh and the direct transmission expense per kWh sold in Test Year were 4.0¢/kWh and 0.06¢/kWh, respectively.

Q. PLEASE DISCUSS SFR SCHEDULE E-8.

A. SFR Schedule E-8 provides a breakdown of the taxes paid by APS during the Test Year and the three prior calendar years, showing federal, state and local taxes paid. This tax figure is used to derive the gross-up factor used in SFR Schedule C-3.

Q. PLEASE DISCUSS SFR SCHEDULE E-9.

A. SFR Schedule E-9 sets forth the notes to the financial statements. These notes include, but are not limited to, the Company's accounting policies for depreciation, capitalized interest and income taxes. The notes also provide additional detailed information related to the income statement, the balance sheet and the cash flow statement. The Company is providing a copy of the Form 10-K for fiscal year ended December 31, 2004 and a copy of Form 10-Q for third quarter 2005 as an attachment to SFR Schedule E-9.

E. Projections and Forecasts

Q. PLEASE DISCUSS THE INFORMATION THAT YOU ARE SPONSORING IN SFR SCHEDULES F-1 AND F-2?.

A. SFR Schedule F-1 is a schedule that shows an income statement for the projected calendar year, compared with actual test year results, at present and proposed rates.

SFR Schedule F-2 shows projected changes in financial position for the projected year compared with the Test Year, at present and proposed rates. I am sponsoring the historical Test Year data in the first column of each of these SFR Schedules. Mr. Brandt will address the projected data on these SFR Schedules.

IV. PRO FORMA ADJUSTMENTS

A. Test Year

Q. WHAT TEST YEAR HAS APS PROPOSED IN ITS APPLICATION?

A. The twelve months ended September 30, 2005 is the Company's proposed Test Year. This represents the most recent historical calendar period for which complete cost of service information was available at the time we prepared this filing.

Q. ARE THERE ANY ADJUSTMENTS TO THE FINANCIAL RESULTS ACHIEVED BY THE COMPANY DURING THE TEST YEAR THAT THE COMMISSION SHOULD CONSIDER?

A. Yes. The Test Year must be adjusted for changes in operating expenses, revenues, and plant-in-service, among others, which are known, measurable, and capable of being reconciled with the Test Year to create a matching of costs and revenues. The objective of making adjustments to Test Year results is to reflect conditions expected to exist at the time the new rates become effective.

Q. WHAT DOES A "KNOWN AND MEASURABLE" ADJUSTMENT MEAN?

A. I consider an adjustment to be "known" when, given all the circumstances, its probability of occurrence is significantly greater than the chance it will not occur. An adjustment is "measurable" if it can be quantified in a meaningful fashion, such that the recognition of at least part of its effect on Test Year results will make the Test Year "more representative" than if the adjustment were omitted altogether.

Q. WHAT DOES IT MEAN THAT AN ADJUSTMENT MUST BE RECONCILED WITH TEST YEAR OPERATIONS?

A. This is generally known as the "matching principle." This principle states that revenues required equal the cost of service incurred. For example, a pro forma adjustment for increased electric sales should include a corresponding adjustment to expenses that recognize the additional cost of service needed to produce these sales. As with the concepts of "known and measurable," one cannot insist on a precise matching for all adjustments without effectively requiring a constantly updated Test Year. The issue is one of degree and of fairness.

Q. DID APS MAKE PRO FORMA ADJUSTMENTS TO TEST YEAR OPERATING INCOME?

A. Yes. Many adjustments were done to be consistent with Decision No. 67744, issued April 7, 2005, where the Commission adopted a settlement agreement to resolve the issues in the most recent APS rate case. ("2002 Test Year Settlement"). Test Year pro forma adjustments can be categorized into three basic types:

1) Accounting, *i.e.*, adjustments that remove expenses or revenues properly recorded during the Test Year but associated with prior periods;
2) Annualizations, *i.e.*, adjustments typically made in a rate case to annualize the full effect of events taking place during the Test Year; and
3) Known and measurable changes, *i.e.*, adjustments to expenses or revenues that took place or will take place after the end of the Test Year, and which are of such significance that they should be recognized for ratemaking purposes.

Q. HAS THE COMMISSION PREVIOUSLY ACCEPTED PRO FORMA ADJUSTMENTS TO THE COMPANY'S TEST YEAR?

A. The Commission's own rule specifically recognizes these types of adjustments. *See*

A.A.C. R14-2-103. It has been the consistent practice of the Commission to accept pro forma adjustments to Test Year rate base and operating income in rate cases.

B. Pro Forma Adjustments To Operating Income

Q. HAS APS MADE PRO FORMA ADJUSTMENTS TO TEST YEAR OPERATING INCOME?

A. Yes. These adjustments are set forth in Schedule C-2 of the Company's application. SFR Schedule C-2 provides total Company figures and Mr. Rumolo's jurisdictional allocation of my adjustments, which he will address in his testimony. The Total Company portion of this SFR Schedule corresponds directly with Attachments CNF 1-1 through CNF 1-9.

Q. IS INCOME TAX EXPENSE INCLUDED IN EACH OF YOUR OPERATING INCOME PRO FORMA ADJUSTMENTS?

A. Yes. Each pro forma adjustment identified in Attachments CNF 1-1 through CNF 1-9 includes an income tax calculation, at the current statutory combined state and federal income tax rate, so that the impact on net income for each adjustment can be determined. However, throughout most of my testimony I will be referring to pro forma adjustment amounts on a before income tax basis.

(i) Regulatory Assessments and Franchise Fees

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED TREATMENT OF REGULATORY ASSESSMENTS AND FRANCHISE FEES?

A. This pro forma adjustment is being made so that all regulatory assessments and franchise fees will be treated as pass-throughs and will not be included in base rates, which is consistent with the settlement adopted in Decision No. 67744. This adjustment removes assessments and franchise fees from both operating revenues and expenses in the Test Year in the amount of $ 15,947,000. *See* Attachment CNF 1-1.

(ii) Base Rates Component for EPS

Q. PLEASE DESCRIBE THE ADJUSTMENT TO THE ENVIRONMENTAL PORTFOLIO STANDARD ("EPS").

A. This pro forma adjustment reflects the Company's accounting for the $6 million authorized System Benefits Charge ("SBC") to fund the EPS. In the Test Year, the Company incurred capital costs related to EPS. Revenue of $ 6,779,000, which was equivalent to these costs, was reclassified to a contribution-in-aid-of-construction. Because the costs were charged to construction work in process rather than an Operation and Maintenance account, they are not reflected in the Test Year operating results. The pro forma adjustment is needed to properly reflect, for ratemaking treatment, revenue of $6,779,000 and $6,000,000, the allowed portion of expenses related to the base rate portion of the SBC used to fund the EPS. The pro forma adjustment to pre-tax operating income is $779,000, as shown on Attachment CNF 1-2.

(iii) Demand Side Management

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED ADJUSTMENT TO DEMAND SIDE MANAGEMENT ("DSM") COSTS.

A. Decision No. 67744 mandated that the Company spend $10 million annually on DSM programs, which are to be funded through base rates beginning in 2005. The actual DSM expense in the Test Year was $ 7,011,000, $ 2,989,000 less than is currently required on a going-forward basis. The DSM pro forma adjustment increases Test Year operating costs by the $ 2,989,000 and recognizes the corresponding reduction in revenue as a result of DSM programs, which is expected to be $ 4,907,000. *See* Attachment CNF 1-3. Mr. Peter Ewen discusses the revenue calculation in his testimony.

(iv) Interest On Customer Deposits

Q. PLEASE DESCRIBE THE ADJUSTMENT FOR INTEREST ON CUSTOMER DEPOSITS.

A. This pro forma adjustment reflects the annualized interest cost associated with customer deposits (interest expense) as an operating expense, because the customer deposit balances at the end of the Test Year are treated as a rate base deduction. This treatment conforms to the approach utilized by the Commission in previous Company rate cases. The pro forma adjustment was calculated by applying a 2.79 percent annual interest rate to the September 30, 2005 outstanding deposit balance. The annual interest rate is the rate required by APS tariffs for customer deposits – the established one-year Treasury Constant Maturities rate, effective on the first business day of each year, as published on the Federal Reserve website. This resulted in a reduction of pre-tax operating income of $ 1,529,000. *See* Attachment CNF 1-4.

(v) Amortization of Regulatory Assets

Q. WHAT IS THE BASIS FOR THE AMORTIZATION OF REGULATORY ASSETS PRO FORMA ADJUSTMENT?

A. This adjustment provides for the amortization of the Palo Verde Unit 2 Sale/Leaseback rent levelization regulatory asset over the remaining life of the lease, which is consistent with the 2002 Test Year Settlement adopted in Decision No. 67744. The net pretax adjustment is $ 381,000, as shown on Attachment CNF 1-5.

(vi) PWEC Loan

Q. PLEASE EXPLAIN THE COMPANY'S ADJUSTMENT RELATED TO THE 2.64 PERCENT INTEREST PREMIUM ON THE APS LOAN TO PWEC.

A. Commission Decision No. 65796 (April 4, 2003) authorized APS to issue non-secured debt in an amount up to $500 million and loan the proceeds to PWEC. That decision also required APS to charge PWEC a 2.64 percent interest premium, as long as the loan was outstanding. This operating income pro forma reflects the 2.64 percent interest premium credit, which includes the amount deferred through April 11, 2005, when the loan was repaid. In addition, consistent with Decision No. 67744, the amount deferred through December 31, 2004 is being amortized on a straight-line basis over five years, beginning April 1, 2005. Decision No. 67744 required that the amounts deferred after December 31, 2004 were to be reflected in APS' next general rate proceeding. Accordingly, the amount deferred after December 31, 2004, will be amortized on a straight-line basis over a five year period, beginning January 1, 2007. This pro forma includes an accrual of interest at the rate of six percent, as required by Decision No. 67744. The adjustment of $3,330,000 is an increase to pretax operating income, as shown on Attachment CNF 1-6.

(vii) Out of Period Income Tax Adjustments

Q. PLEASE DESCRIBE THE PRO FORMA ADJUSTMENT FOR OUT OF PERIOD INCOME TAX ADJUSTMENTS.

A. This pro forma adjustment removes income tax true-up items impacting income tax expense that were recorded during the Test Year period, but relate to a period earlier than the Test Year period. In addition, it adds income tax true-up items that relate to the Test Year period. Finally, it removes income tax expense recorded during the Test Year period related to non-recurring income tax items. This pro

forma decreases income tax expense by $1,287,000. The Test Year income tax expense still includes credits and other items related to the Test Year. *See* Attachment CNF 1-7.

(viii) Generation Production Income Tax Deduction

Q. PLEASE DESCRIBE THE PRO FORMA ADJUSTMENT FOR GENERATION PRODUCTION INCOME TAX DEDUCTION.

A. On October 11, 2004, President Bush signed into law the American Jobs Creation Act ("Act"). The Act created Internal Revenue Code Section 199 ("Section 199"), which provides a new income tax deduction related to income attributable to qualified production activities. On October 20, 2005, the Internal Revenue Service ("IRS") issued proposed regulations addressing Section 199. Electricity production is considered a qualified production activity for purposes of this Act; however transmission and distribution services are not. The proposed regulations provide that a joint owner who owns less than 50% of a generating facility will not be attributed the qualified production activity associated with such generation facility. This deduction applies to years beginning in 2005. For 2005, the deduction is equal to the lesser of three percent of the qualified production activities income ("QPAI") or the consolidated taxable income. The deduction increases to six percent in 2007 and increases again to nine percent in 2010. QPAI is equal to gross receipts, less the cost of production and other related direct and allocable indirect costs. In calculating this pro forma, gross receipts were determined by using the 12 months ended September 30, 2005 Test Year functionalized revenue requirement, excluding the impact of this deduction, for electricity production. The related direct and allocable indirect costs (except for interest expense) were determined by using the 12 months ended September 30, 2005 functionalized operating expenses for electric production. Functionalized interest expense for electric production was

determined by multiplying electric production for the Test Year rate base by the weighted interest rate component of the cost of capital. Next, adjustments were made to reflect items treated differently for GAAP and income tax purposes. Finally, a reduction was made to remove the QPAI generated by jointly-owned generating facilities in which APS owns 50% or less. This reduction was determined by first deriving the ratio of net book value of plant for the jointly-owned facilities divided by net book value for all generating facilities. This ratio was multiplied by the total generation QPAI, which was then subtracted from total generation QPAI to arrive at QPAI attributable to APS. QPAI for electric production activities associated with generating facilities wholly owned by APS for the 12 months ended September 30, 2005 Test Year is approximately $79 million. The deduction percentage in 2007, which is the year the new rates will become effective, is six percent. Therefore the deduction is approximately $4.8 million, which translates into a reduction in income tax expense of $1,862,000. The Proposed Regulations may be modified prior to becoming final regulations and the final regulations may change the amount of this deduction. This calculation is set forth in Attachment CNF 1-8.

(ix) Income Tax / Interest Synchronization

Q. PLEASE DESCRIBE THE ADJUSTMENT FOR INCOME TAX AND SYNCHRONIZATION OF INTEREST.

A. This adjustment reflects the synchronization of interest expense using the adjusted September 30, 2005 capital structure and cost of long-term debt, as well as the use of current statutory income tax rates. This pro forma adjusts after-tax operating income by $2,906,000, as set forth on Attachment CNF 1-9.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

Appendix A
Statement of Qualifications
Chris N. Froggatt

Chris N. Froggatt is Vice President and Controller for Arizona Public Service Company. Mr. Froggatt has responsibility for Accounting Services, Tax Services, Insurance Risk Management, Supply Chain, Transportation and Public Safety. These services are provided as needed across all of the Pinnacle West companies.

Mr. Froggatt graduated from Michigan State University in 1980 with a Bachelor's Degree in Accounting. He is a Certified Public Accountant and a member of both the American Institute of Certified Public Accountants and the Arizona Society of Certified Public Accountants.

Mr. Froggatt spent six and one-half years in public accounting upon graduation from college. He joined APS in December 1986 as Manager of Financial Reporting and became Director of Accounting Services in 1992. In July of 1997, Mr. Froggatt was named Controller for APS and had effectively the same responsibilities for Pinnacle West. He was promoted to Vice-President and Controller of Pinnacle West in July 1999.

1367762.1

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2
Total Company
(Thousands of Dollars)

PRO FORMA ADJUSTMENT: **REGULATORY ASSESSMENTS AND FRANCHISE FEES**

Adjustment to Test Year operations to exclude regulatory assessments and franchise fees from both operating revenue and operating expense.

Line No.	Description		Amount
1.	**REVENUES:**		
2.	Operating Revenue		
3.	Regulatory Assessments	$ (4,460)	
4.	Franchise Fees	(11,487)	
5.	Total Pro Forma Adjustment to Revenues		$ (15,947)
6.	**EXPENSES:**		
7.	Other Operating Expense		
8.	Operations Excluding Fuel Expenses		
9.	Regulatory Assessments	(4,460)	
10.	Franchise Fees	(11,487)	
11.	Total Pro Forma Adjustment to Expenses		(15,947)
12.	**OPERATING INCOME (*before income tax*)**		-
13.	Income Tax at 39.05%		-
14.	**OPERATING INCOME AFTER TAX**		$ -

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2
Total Company
(Thousands of Dollars)

PRO FORMA ADJUSTMENT:

BASE RATE COMPONENT FOR EPS
Adjustment to Test Year operations related to the base rate component of the Company's System Benefits Charge which is used to fund the Environmental Portfolio Standard. Revenue is adjusted to reverse Test Year entries to contributions in aid of construction and to include the expenses allowed by the Commisssion.

Line No.	Description	Amount
1.	**REVENUES:**	
2.	Operating Revenue	$ 6,779
3.	**EXPENSES:**	
4.	Other Operating Expense	6,000
5.	Renewables	**779**
6.	**OPERATING INCOME (before income tax)**	304
7.	Income Tax at 39.05%	**$ 475**
8.	**OPERATING INCOME AFTER TAX**	

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2
Total Company
(Thousands of Dollars)

PRO FORMA ADJUSTMENT: **DEMAND SIDE MANAGEMENT**

Adjustment to Test Year operations to reflect the operating income impact of Demand Side Management programs required by Decision No. 67744.

Line No.	Description	Amount
1.	**REVENUES:**	
2.	Operating Revenue	$ (4,907)
3.	**EXPENSES:**	
4.	Other Operating Expenses	2,989
5.	Operations Excluding Fuel Expenses	2,989
6.	Total Pro Forma Adjustment to Expenses	**(7,896)**
7.	**OPERATING INCOME (before income tax)**	(3,083)
8.	Income Tax at 39.05%	**$ (4,813)**
9.	**OPERATING INCOME AFTER TAX**	

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2
Total Company
(Thousands of Dollars)

PRO FORMA ADJUSTMENT:

INTEREST ON CUSTOMER DEPOSITS
Adjustment to test year operations to reflect the operating income impact of interest on customer deposits.

Line No.	Description	Amount
1.	**EXPENSES:**	
2.	*Other Operating Expenses*	$ 1,529
3.	Operations Excluding Fuel Expense	1,529
4.	Total Pro Forma Adjustment to Expenses	**(1,529)**
5.	**OPERATING INCOME (before income tax)**	(597)
6.	*Income Tax at 39.05%*	
7.	**OPERATING INCOME AFTER TAX**	**$ (932)**

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2
Total Company
(Thousands of Dollars)

PRO FORMA ADJUSTMENT: REGULATORY ASSETS
Adjustment to Test Year operations to include on-going amortization of regulatory assets.

Line No.	Description	Amount
1.	EXPENSES:	
2.	Other Operating Expenses	
3.	Depreciation and Amortization	$ 381
4.	Total Pro Forma Adjustment to Expenses	381
5.	OPERATING INCOME (before income tax)	(381)
6.	Income Tax at 39.05%	(149)
7.	OPERATING INCOME AFTER TAX	$ (232)

ARIZONA PUBLIC SERVICE COMPANY

Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2

Total Company

(Thousands of Dollars)

PRO FORMA ADJUSTMENT:

PWEC LOAN

Adjustment to Test Year operations to reflect a 264 basis point differential and amortization of loan proceeds as required in Decision Nos. 65796 and 67744.

Line No.	Description	Amount
1.	**EXPENSES:**	
2.	Other Operating Expenses	$ (3,330)
3.	Depreciation and Amortization	(3,330)
4.	Total Pro Forma Adjustment to Expenses	**3,330**
5.	**OPERATING INCOME (before income tax)**	1,300
6.	Income Tax at 39.05%	**$ 2,030**
7.	**OPERATING INCOME AFTER TAX**	

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2
Total Company
(Thousands of Dollars)

PRO FORMA ADJUSTMENT: OUT OF PERIOD INCOME TAX ADJUSTMENTS
Adjustment to Test Year operations for out-of-period income tax true-ups.

Line No.	Description	Amount
1.	OPERATING INCOME (before income tax)	$ -
2.	Income Tax at 39.05%	(1,287)
3.	OPERATING INCOME AFTER TAX	$ 1,287

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2
Total Company
(Thousands of Dollars)

PRO FORMA ADJUSTMENT:

GENERATION PRODUCTION INCOME TAX DEDUCTION
Adjustment to Test Year operations to reflect the tax benefit associated with the domestic manufacturing income tax deduction.

Line No.	Description	Amount
1.	OPERATING INCOME (before income tax)	$ -
2.	Income Tax at 39.05%	(1,862)
3.	OPERATING INCOME AFTER TAX	$ 1,862

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2
Total Company
(Thousands of Dollars)

PRO FORMA ADJUSTMENT:

INCOME TAX/INTEREST SYNCHRONIZATION
Adjustment to Test Year operations to reflect the synchronization of interest expense using the adjusted September 30, 2005 capital structure and cost of long-term debt, as well as the use of the statutory income tax rate.

Line No.	Description	Amount
1.	**OPERATING INCOME (before income tax)**	$ -
2.	Interest Expense	(7,442)
3.	**TAXABLE INCOME**	**7,442**
4.	Income Tax at 39.05%	2,906
5.	**OPERATING INCOME AFTER TAX**	**$ (2,906)**

PETER M. EWEN

DIRECT TESTIMONY OF PETER M. EWEN

On Behalf of Arizona Public Service Company

Docket No. E-01345A-05-0816

January 31, 2006

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DIRECT TESTIMONY OF PETER M. EWEN
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-05-0816)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Peter M. Ewen. My business address is 400 N. 5th Street, Phoenix, Arizona, 85004.

Q. WHAT IS YOUR POSITION WITH ARIZONA PUBLIC SERVICE COMPANY?

A. I am Manager of the Revenue and Fuel Analysis and Forecasts Department for Arizona Public Service Company ("APS" or "Company"). In that role, I am responsible for preparing the Company's short-range and long-range forecasts of system peak demand and energy sales and projecting the optimal dispatch of available resources to minimize the cost of meeting those energy requirements.

Q. WHAT IS YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND?

A. I received Bachelors and Masters degrees in Economics from Arizona State University in 1985 and 1988, respectively. I have analyzed and forecasted electric energy and demand growth since 1988, first as a Staff member of the Arizona Corporation Commission ("Commission") and, since 1990, as an employee for APS. I have specifically analyzed the actual dispatch of our generating units in combination with market purchases to serve native load demand since 1998, and assumed full responsibility for making the optimal dispatch and associated fuel cost projections in 2000. I was formerly President of the Arizona Economic Round Table, a group of Arizona-based economists that specialize in studying the Arizona economy, and I am still a member of that

organization. I also serve on the Joint Legislative Budget Committee's Finance Advisory Committee. This consists of a group of state economists who advise the Joint Legislative Budget Committee staff on the adequacy of the economic projections underlying their state revenue projections.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony sets forth the basis for the Company's requested base rate level of fuel and purchased power expenses of 3.1904 ¢/kWh, which reflects conditions expected to exist at, or prior to, the time the requested rates are likely to be in effect. The Company's current base rates include a base fuel rate of 2.0743¢/kWh. I discuss the reasons for this increase, in particular the increases in wholesale market prices and price volatility for natural gas and power, and describe the impact of the Company's hedging program on the Company's fuel expenses, which is a net benefit to customers of $169 million. Absent that benefit, the requested rate level would be 8 percentage points higher (approximately 29%). The discussion on price volatility provides support for APS witness Mr. Donald Robinson's testimony demonstrating the necessity of retaining the power supply adjustment ("PSA") mechanism authorized in Decision No. 67744.

I sponsor several pro forma adjustments to the Test Year set forth in SFR Schedule C-2, including:

1) Base Fuel and Purchased Power (Including Off-System Margin)
2) Normalize Non-Nuclear Maintenance Expense
3) Normalize Nuclear Maintenance Expense
4) Annualized Customer Levels
5) Normalize Weather Conditions

I also discuss the overhaul maintenance and revenue components of the Pinnacle West Energy Corporation ("PWEC") (Redhawk Units CC1 and CC2, West Phoenix Units CC4 and CC5, and Saguaro Unit CT3) and Sundance units operating income pro formas, and the operating revenue portion of the Demand Side Management ("DSM") pro forma.

II. SUMMARY OF TESTIMONY

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. APS' base fuel recovery amount of 2.0743 ¢/kWh established in Decision No. 67744, which was based on 2003 cost levels, is not adequate to compensate for the fuel and purchased power market price changes and load growth since 2003. APS is therefore requesting a rate increase to allow the Company to recover the costs that the Company incurred during the twelve months ending September 30, 2005 (the "Test Year") as adjusted to reflect the conditions the Company is expected to experience during 2006 (3.1904¢/kWh) to meet the needs of its customers. Attachment PME-1 shows these changes in fuel costs. My testimony focuses on the reasons for those increased costs.

The increasing costs that the Company is experiencing are the result of a number of factors, which are summarized in the following points.

- Incremental Sales Growth and Fuel Mix: APS has one of the fastest growing service territories in the country and growth is one of the dominant factors producing increased fuel and purchased power expenses. The Company's incremental sales attributable to growth must be met primarily with high-cost natural gas and purchased power (virtually all of which is derived from gas-fired generation). That incremental sales growth, therefore, is leading to

a shift in the Company's fuel mix to a heavier emphasis on natural gas. This factor alone accounts for $147 million of the requested rate increase.

- Natural Gas Prices: Natural gas prices have increased dramatically since 2003 and, coupled with purchased power price increases, are responsible for a $330 million increase in the Company's base cost of fuel (prior to the results of our hedging program). The Company's current base fuel rate set in Decision No. 67744 incorporated natural gas prices of $5.78/MMBTU. During the Test Year, natural gas prices jumped to $7.20/MMBTU, an increase of 25%. At the close of the market on November 30, 2005, delivered natural gas prices for calendar year 2006 averaged $10.74/MMBTU, a further 49% increase over the Test Year and 86% over the level included in the current base fuel rate.
- Purchased Power Prices: Prices for purchased power (most of which comes from natural gas generation) also increased significantly over the same time periods. The base rate set in Decision No. 67744 incorporates a purchased power price of $43.37/MWh, while the average price incurred by the Company during the Test Year was $57.50/MWh, a 33% increase. On November 30, 2005, purchased power prices were anticipated to average $87.56/MWh during 2006, an increase of 52% over the historical period and 102% over the level included in the current base fuel rate.
- Coal Prices: Although the dramatic increase in prices for natural gas and purchased power, when combined with the significant

growth that the Company is dealing with, represents the largest component of the requested rate increase, prices for coal resources also are increasing. Coal prices increased 13% between 2003 and the Test Year and are projected to increase an additional 6% in 2006. Cumulatively, higher coal prices have raised the Company's base cost of fuel by $34 million.

- Hedging: As discussed above, coal prices, natural gas prices and power prices all increased during the Test Year and are continuing to do so in 2006. Natural gas and power prices also continue to be volatile. APS's request would have been significantly higher absent the results of the Company's commodity hedging program. All of the price increases discussed above rolled together would have amounted to an increased fuel expense of approximately $364 million — $330 million for gas and power and $34 million for coal. In addition to mitigating the market volatility for natural gas and purchased power through its hedging program, the Company, was able to reduce fuel expense by more than $169 million. 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.

The following table summarizes these results on the Company's fuel expenses:

Incremental Sales Growth	$ 147 million
Natural Gas and Power Prices	$ 30 million
Coal Prices	$ 34 million
Hedge Value	$ (169) million
All Other Items	$ (43) million
Total of All Changes	$ 299 million

Attachment PME-1 quantifies the impact of these key factors on the Company's fuel cost trends. Attachment PME-2 shows graphically the differential in costs for the Company's various resources and the changes in those costs over time. One can plainly see the impact that a changing fuel mix toward natural gas and wholesale market purchases and rising prices across all fuel resources will have on the Company's costs. Attachment PME-3 provides the values of the key factors that contribute most to those costs. Attachment PME-4 shows the rising price environment that the Company and the country have faced over the last several years with respect to 2006 deliveries of natural gas at Henry Hub. Attachment PME-5 shows a similar trend for 2006 on-peak power prices at Palo Verde.

In light of the above factors, it is easy to see why the Company has requested an interim increase in the Base Fuel Recovery Amount in Docket No. E-01345A-06-0009 and this change in base fuel rates. I am proposing that the Base Fuel Recovery amount be set at 3.1904 ¢/kWh, which reflects normalized levels of power plant performance, expected 2006 fuel and purchased power prices and corresponding hedging results, a credit for anticipated off system sales margins,

and the effects of adding the Sundance units to the APS system. The method by which I calculated this new base fuel rate is identical to the one used by the Company and accepted by the Commission in Decision No. 67744.

III. TEST YEAR BASE FUEL AND PURCHASED POWER EXPENSE IS SIGNIFICANTLY HIGHER THAN RECOVERED IN CURRENT RATES

Q. HOW DO FUEL EXPENSES IN THE TEST YEAR COMPARE TO THE FUEL EXPENSE CURRENTLY ALLOWED IN BASE RATES?

A. For the Test Year ending September 30, 2005, the Company's actual average base fuel and purchased power expense, excluding the impact of the period's non-cash fuel cost deferrals, was 2.701 ¢/kWh.[1] The allowed average base fuel expense authorized in Decision No. 67744 was 2.0743 ¢/kWh based primarily on 2003 costs. Thus, the Test Year average fuel expense represents a 30.2% increase in less than two years. The annual impact of this higher average cost is an increase of $167.7 million on net native load fuel costs at the Test Year sales levels. These amounts include $53.6 million for the Bridge Purchased Power Agreement ("PPA") for the capacity rights to the PWEC units during April through July 2005 authorized in Decision No. 67744. Excluding these amounts, the Company's fuel expenses still increased $114.1 million, or 20.6%.

Q. WHAT FACTORS ARE MOST RESPONSIBLE FOR THESE COST INCREASES?

A. Increased market prices for natural gas and power, incremental sales growth that increased the share of relatively high-cost gas generation and market purchases,

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[1] Throughout the remainder of my testimony, the term "fuel expenses" may be used generically to refer to fuel and purchased power expenses.

and higher coal prices are the most significant factors. Favorable results from the Company's hedging program helped to partially offset these cost increases. A quantification of each of these factors can be seen in Attachment PME-1.

Q. WHAT WAS THE IMPACT OF HIGHER TEST YEAR FUEL PRICES?

A. These price increases drove fuel expenses higher by $116.0 million. Natural gas and power prices account for $94 million of this total increase. Delivered natural gas prices increased 25% from $5.78/MMBTU in the Company's base fuel rate to $7.20/MMBTU in the Test Year. Purchased power prices in the Test Year increased 33% over prices in the current base fuel rate, moving from an average of $43.37/MWh to $57.50/MWh. Coal prices increased 13%, largely due to increased transportation costs for the coal delivered to the Company's Cholla Generating Station, and resulted in a $22 million fuel cost increase.

Q. TO WHAT EXTENT DID THE COMPANY'S HEDGING PROGRAM OFFSET THESE PRICE INCREASES?

A. The Company realized a gain of more than $70 million through the liquidation of its natural gas and power hedges. Natural gas hedges provided savings of $64.7 million, or $1.68/MMBTU on the delivered natural gas quantities in the Test Year, and the power hedges saved almost $6 million.

Q. WHAT WAS THE IMPACT OF INCREMENTAL SALES GROWTH IN THE TEST YEAR?

A. Sales growth between the 2003 base rate calculation of 2.0743¢/kWh and the Test Year increased the Company's fuel expense by $59.5 million. The approximately 1,600 GWh of increased sales were largely met by relatively high-cost natural gas and purchased power (the majority of which is from natural gas-fired generation) and increased the share of the Company's

production coming from those resources by approximately 5 percentage points. The average price differential between such low-cost resources as nuclear and coal and the high-cost resources of natural gas and purchased power was approximately $47/MWh in the Test Year. This means that every 1% increase in natural gas and purchased power's share of the total energy mix, at the Test Year prices, translates into an increase in fuel expense of more than $12 million. This shift in resource mix will continue to put pressure on the Company's fuel expenses as we go forward in time. It is also the reason I am proposing a pro forma adjustment to Test Year fuel expenses in my testimony. Attachment PME-2 shows the average fuel cost for the Company's major resource types in the Test Year. It also compares these costs to the analogous costs in the Company's current authorized base fuel cost and the pro forma adjustment I am proposing.

Q. YOU HAVE DESCRIBED THE FACTORS THAT INCREASED THE TEST YEAR FUEL EXPENSE OVER 2003 LEVELS. WHAT IS THEIR SIGNIFICANCE TODAY?

A. Not only did the factors I describe above drive the Test Year fuel expense increases, those same factors continue to drive additional increases in fuel expense. Because they will continue to significantly affect fuel expense during the period in which the requested rates will be in effect, an adjustment to Test Year fuel expense is necessary to reflect the impact of these factors on the Company's operating income.

IV. BASE FUEL AND PURCHASED POWER PRO FORMA ADJUSTMENT TO TEST YEAR, INCLUDING OFF-SYSTEM MARGIN

Q. ARE YOU PROPOSING TO ADJUST THE COMPANY'S TEST YEAR FUEL EXPENSES FOR THE FACTORS YOU JUST DESCRIBED?

A. Yes. The factors that I described above, along with the removal of the impact of fuel expense deferrals and other additional changes discussed later in my testimony, are driving an adjustment to Test Year net fuel expense of approximately $244 million. The non-cash deferred fuel expenses account for $113 million and all other changes account for $131 million. The following table summarizes these adjustments along with the net fuel expense changes in the Test Year compared to the current base fuel rate of 2.0743¢/kWh:

Fuel Expense Changes

Test Year per books vs. Current Base Rates	
2.701¢/kWh vs. 2.0743¢/kWh	$ 168 million
TME 9/30/05 Fuel Cost Deferrals	$ (140) million
TME 9/30/05 Mark to Market Deferrals	$ 27 million
Net Change	$ 55 million
2006 Pro Forma vs. Test Year	
3.1904¢/kWh vs. 2.701¢/kWh	$ 131 million
Remove TME 9/30/05 Fuel Cost Deferrals	$ 140 million
Remove TME 9/30/05 Mark to Market Deferrals	$ (27) million
Net Change	$ 244 million
Total Change	$ 299 million

The adjustments proposed recognize known and measurable changes to Test Year conditions and are more representative of conditions that will be present prior to or when the Company's new rates are likely to take effect. Specifically, I am proposing to normalize Test Year fuel expenses and off-system margins for:

(1) increased electricity sales due to continued growth;

(2) higher commodity market prices for natural gas and power;

(3) 90% of the value of the Company's gas and power hedges;

(4) the expected impacts of the El Paso Pipeline rate filing;

(5) the inclusion of the PWEC and Sundance units for a full year;

(6) higher coal and nuclear fuel prices;

(7) increased production from Palo Verde Unit 1 as a result of the steam generator replacement in December 2005;

(8) normalized maintenance and unplanned outage times;

(9) the scheduled reduction in capacity from a power contract with Salt River Project; and

(10) other miscellaneous items, such as broker fees, third-party wheeling expenses, and short-term capacity costs.

Q. PLEASE EXPLAIN HOW THE PRO FORMAS FOR FUEL EXPENSE AND OFF-SYSTEM MARGIN ARE DEVELOPED.

A. The impacts of the adjustments I mentioned above have been simulated using the Company's production cost simulation tool RTSim. This computer model replicates the dispatch of the APS system and is the primary fuel expense and off-system sales forecasting tool used by the Company in preparing its annual budgets, long range fuel forecasts, and near-term operational plans. The vast majority of the adjustments I am proposing are the same as or consistent with the expected levels in the Company's 2005 Long Range Forecast ("LRF") for the year 2006, the 2006 Sales Budget, with appropriate customer annualizations, and the November 30, 2005 forward curve for natural gas and power prices and the corresponding valuation of the Company's hedges. This approach is entirely consistent with the method used by the Company and accepted by the Commission for establishing the Company's Base Fuel Rate in Decision No. 67744.

Q. HOW DOES THE PRODUCTION COST SIMULATION MODEL CALCULATE THE AVERAGE FUEL AND PURCHASED POWER COST?

A. The model simulates the dispatch of the APS generating units on a daily and hourly basis. It takes into account the APS system load shape, fuel prices (including wholesale market prices for power) and characteristics of APS owned generating plants (such as heat rates, overhaul cycles, unplanned outage rates, start-up costs and ramp rates, among others), along with commitments for purchases and sales of power. The model also simulates necessary market purchases for those times when load exceeds generating capacity, and likewise simulates market sales during those times when the system is not fully utilized but generating units are economic (or "in-the-money").

The projected hourly dispatch of each of the units, along with the wholesale market purchases and sales, are priced out at the corresponding contract or market price projections included in the model. Fixed costs – those expenses that do not vary with the level of production – are then added to the model results. These expenses include firm gas transportation, the T&C Agreement demand charge, fuel handling, third party wheeling costs, wholesale market capacity costs, and broker fees. The result is the total expected fuel expense and off-system sales revenue consistent with the assumptions used in the model.

Q. DO THESE RESULTS FLOW DIRECTLY INTO YOUR PROPOSED FUEL AND OFF-SYSTEM SALES MARGIN PRO FORMAS?

A. No. The intent of the process I have used is to capture the impacts of the relevant factors on the Company's *average* base fuel cost. The change in the average cost from the Company's Test Year amounts applied to the adjusted Test Year retail sales amounts produces the appropriate adjustment for the Test Year pro forma.

This calculation and the removal of the impact of the $139.8 million in PSA-related fuel deferrals and $26.9 million in deferred non-cash mark-to-market credits are shown on Attachment PME-6. The corresponding off-system sales margin calculation is shown on Attachment PME-7.

A. Commodity Prices

Q. ARE YOU PROPOSING ANY ADJUSTMENTS TO TEST YEAR FUEL EXPENSE FOR FUEL PRICE CHANGES?

A. Yes. Commodity prices for natural gas and wholesale market power have increased considerably since the Test Year and would translate into an increase in fuel expense of over $235 million. These changes do not include the results of the Company's hedging program, which has helped to ameliorate these cost impacts. I describe the impacts of the Company's hedging program later in my testimony. At the close of the market on November 30, 2005, delivered natural gas prices for calendar year 2006 averaged $10.74/MMBTU. Prices are almost $12/MMBTU for the months of January, February, and March; the lowest priced month is May at $10.11/MMBTU. These prices represent a 49% increase over the delivered prices the Company paid in the Test Year.

In addition, because natural gas is the marginal fuel source for most wholesale power transactions, power prices have risen in concert with gas prices. Prices for on-peak power delivered at Palo Verde for calendar year 2006 averaged $88.88/MWh on November 30, and the weighted average of the on-peak and off-peak 2006 energy prices the Company expects to pay is $87.56/MWh, a 52% increase over purchased power prices in the Test Year.

Q. WHY IS THE NOVEMBER 30, 2005 FORWARD MARKET THE APPROPRIATE REFERENCE POINT FOR NORMALIZING NATURAL GAS AND WHOLESALE POWER COMMODITY PRICES?

A. The November 30, 2005 forward market for natural gas and power prices works well as the reference date in this proceeding because it has allowed several months to pass since the hurricane-related disruptions to the market earlier in the year. At the end of August 2005, Hurricane Katrina swept through New Orleans and other Gulf Coast regions, severely disrupting oil and gas production facilities and driving prices for natural gas up substantially. For several days following the storm, natural gas prices at Henry Hub closed at more than $12.00/MMBTU for January and February 2006 contracts, fully $2 more than the market only two weeks earlier. Henry Hub is the key market delivery point in Southern Louisiana and is the most important benchmark price for natural gas in the United States. Most other natural gas basin prices are priced relative to the Henry Hub price, including the San Juan and Permian basins from which the Company acquires virtually all of its gas supply. Not long after Hurricane Katrina, Hurricane Rita swept through additional parts of the Gulf Coast region, further impacting natural gas production.

Since the end of August, gas prices and power prices have remained elevated. Attachment PME-4 shows the price range over which a set of 12 monthly contracts for 2006 natural gas at Henry Hub has traded in the last three years. Attachment PME-5 provides a similar view of on-peak power prices at Palo Verde.

Q. CAN WE BE CERTAIN THAT THE CURRENT MARKET WILL BE THE REALIZED PRICE WHEN THE COMPANY TAKES PHYSICAL DELIVERY OF ITS GAS AND POWER?

A. No. Because the forward market is reflecting all available information at a certain point in time, we can feel comfortable that it is providing useful insight into where realized spot prices may end up. We also know, however, that neither

the market nor any market participant can precisely predict the future for all relevant supply and demand conditions. Such factors as hurricanes, pipeline disruptions, economic growth, and weather-related energy demand are notoriously difficult to predict. As we have seen lately, markets react to news and predictions of these factors, but they cannot predict them. As a consequence, we have seen a significant increase in price volatility for natural gas and power, which is why APS witness Mr. Don Robinson has proposed the extension of the Company's Power Supply Adjustor ("PSA") in his testimony.

Q. HOW DOES NATURAL GAS PRICE VOLATILITY AFFECT THE COMPANY?

A. In order to serve retail customer energy demand, the Company expects to burn approximately 53 to 62 million MMBTU of natural gas in 2006 and 2007. Additionally, the Company anticipates purchasing between 1,400 and 2,100 GWh of electricity from the market in 2006 and 2007 to meet retail load. These volumes are up substantially from only a relatively short time ago, as incremental load growth must be served with increased gas generation or power purchases from the wholesale market. Compared to 2003 volumes, which were used for the Company's current base rates, the amount of natural gas being burned in 2006 will increase by 17% and the amount of purchased power will increase by 108%.

An upward move of $1/MMBTU in natural gas prices (with a corresponding increase in power prices of $8/MWh that maintains the average spark spread close to the levels experienced in the Test Year) translates into an additional cost to serve retail customers of around $70 million.

Q. HAVE RECENT MARKET PRICES BEEN VOLATILE?

A. Yes. Recent market prices for natural gas and purchased power have shown substantial volatility, highlighting the fact that the Company's recovery of fuel expenses can be drastically affected absent a fuel adjustment mechanism. In fact, prices for both gas and power increased from the Test Year to 2005 by about one and a half times the amounts used in the example above. Attachment PME-8 provides a summary of historical daily spot electric and natural gas prices over the last three and a half years. Natural gas prices are provided for two major delivery points – Henry Hub in Louisiana and the San Juan Basin in northern New Mexico. As I mentioned before, Henry Hub is an important market in the U.S. and is the basis against which most other natural gas markets trade. San Juan is a market from which the Company procures much of its gas.

Q. PLEASE BRIEFLY DESCRIBE ATTACHMENT PME-8.

A. The historical data on Attachment PME-8 shows that natural gas prices in the San Juan basin have averaged $5.09/MMBTU since 2002. Even more striking, however, is the range of prices seen over this period, from a low San Juan gas price of $1.00/MMBTU in 2002 to a high of $13.27/MMBTU this past year. The price at Henry Hub shows an even more extreme range with a low price of $1.98/MMBTU and a high price of $18.60/MMBTU. The standard deviation for gas prices over this period falls at $2.02/MMBTU for San Juan. The standard deviation is a widely accepted statistical measure of volatility and represents the point where the difference (plus or minus) from the average contains roughly two-thirds of the prices making up the average. For example, these standard deviations mean that San Juan daily prices have been within $2.02/MMBTU of the average price about two-thirds of the time, but importantly, they also have differed from the average price by more than $2.02/MMBTU about one-third of

the time. Notably, this standard deviation of $2.02/MMBTU represents a 40% difference from the average price of $5.09/MMBTU. Thus, this measure of volatility indicates that prices over this period have been 40% different from the average at least one-third of the time. Attachment PME-9 shows graphically the trend in San Juan daily spot market prices over this period.

Q. HAVE PURCHASED POWER PRICES SHOWN THIS SAME VOLATILITY?

A. Yes. Power prices also have exhibited a great deal of volatility since 2002. Although on-peak power prices at Palo Verde have averaged $50.39/MWh, the lowest price for on-peak power as reported by Dow Jones since 2002 is $18.85/MWh and the highest price is $118.21/MWh. The standard deviation of these power prices is $17.42/MWh. Attachment PME-10 shows graphically the trend in daily Palo Verde spot prices since 2002.

Q. IS THE MARKET VOLATILITY FOR NATURAL GAS AND POWER CONFINED TO THE DAILY SPOT MARKETS?

A. No. Over the last four years, forward price curves for both natural gas and power also have seen substantial volatility. Attachment PME-11 provides a summary of daily market quotations for natural gas at Henry Hub and San Juan, and on-peak power at Palo Verde, which are to be delivered over the calendar years 2005 through 2007. This summary shows that natural gas prices at the actively traded Henry Hub basin have ranged from a low of $3.24/MMBTU for delivery over the full year of 2005 to a high of $12.32/MMBTU for delivery over the full year of 2006. Prices for on-peak power on average at Palo Verde have ranged from a low of $31.25/MWh for delivery over the full year of 2005 to a high of $102.19/MWh for delivery over the full year of 2006. These statistics reflect the daily market quotes compiled over three years prior to commencement of

delivery. For example, the average price of $6.31/MMBTU for 2006 Henry Hub gas contracts is the average of daily market quotes for natural gas to be delivered at Henry Hub for the 12 months of 2006 compiled between January 1, 2003 and December 31, 2005.

Q. HOW DOES FORWARD MARKET VOLATILITY COMPARE TO DAILY SPOT MARKET VOLATILITY?

A. As a percentage of the average quoted price, the standard deviation of forward market quotes tends to be lower than the standard deviation of daily spot prices, but the timing and magnitude of price movements appears to be just as sporadic. The standard deviation of forward natural gas prices at Henry Hub has been as high as 34% on an average gas price of $6.31/MMBTU for 2006 delivery and as low as 23% on an average price of $4.85/MMBTU for delivery in 2005. For power, the comparable ratios show a high of as much as 25% on an average power price of $58.46/MWh for delivery in 2006 and a low of 16% on an average power price of $46.72/MWh for delivery in 2005. To put this volatility in perspective, a $1.85/MMBTU movement in gas prices (the 2006 San Juan standard deviation) applied to the Company's anticipated 2006 gas burn of approximately 53 million MMBTU translates into a change in expense of almost $100 million. Power price volatility adds more than $30 million to this $100 million. The price volatility is shown graphically in Attachments PME-12 through PME-14.

Q. PLEASE DESCRIBE THESE ATTACHMENTS.

A. Each graph in Attachments PME-12 through PME-14 provides the daily market quotations for a given calendar year for natural gas at Henry Hub and on-peak power at Palo Verde. Attachment PME-13, for example, portrays the changes in

these forward price quotes from January 2003 through December 31, 2005 for calendar year 2006 delivery. The quotes are characterized by periods of stability followed by periods of rapid price increases. Price movements of almost $1 or more can be seen in several periods on the graph.

Q. IS IT NECESSARY TO ADJUST TEST YEAR EXPENSE FOR VOLATILITY AND UPWARD PRICE PRESSURE?

A. Absolutely. The above data clearly shows that volatility of natural gas and purchased power prices has increased significantly in the last two years. Not only has price volatility increased, but the prices themselves have significantly increased since calendar year 2003, the period reflected in the current base fuel rate. Adjustments to test year expenses for these factors are the largest and most critical updates contained in the Company's proposed Base Fuel and Purchased Power pro forma.

B. Hedging

Q. IS THE COMPANY COMPLETELY EXPOSED TO THESE VOLATILE PRICE MOVEMENTS?

A. No. Over the past several years, the Company has successfully executed a hedging program that protects the Company and its customers from dramatic price swings in the commodity markets. By the end of August, 2005, the Company had hedged 85% of its native load natural gas and power requirements for the calendar year 2006. These hedges were purchased over the last two years, but the vast majority were purchased when prices were significantly lower than in recent weeks. As a result of this hedging program, the Company has generated significant value to offset the increase in costs related to the higher forward market prices as of November 30. Consistent with the hedge-sharing approach proposed by Mr. Robinson, the Company is reducing its 2006 fuel

expenses by $185.0 million, or $169.2 million on a jurisdictional adjusted Test Year basis. The value of these 2006 hedges is approximately $100 million more than the $70 million the Company earned from liquidating its power and gas hedge positions in the Test Year.

C. Transportation Prices

Q. WHY ARE YOU PROPOSING AN ADJUSTMENT TO TRANSPORTATION COSTS FOR NATURAL GAS?

A. There are four primary reasons for adjusting the Company's gas transportation expenses. First, the 10-year settlement governing the current rates, and terms and conditions under which the Company transports its gas on the El Paso pipeline expired on December 31, 2005. Second, on June 30, 2005, El Paso filed a rate application with the Federal Energy Regulatory Commission ("FERC") in Docket No RP05-422 requesting a rate increase, effective January 1, 2006, for its existing transportation services and seeking to change certain terms and conditions of the transportation service under which the Company currently transports its gas. Third, in the Test Year, the Company could not fully utilize the PWEC units for its customers. The increased utilization of these PWEC units will result in increased gas burns and transportation capacity requirements. Fourth, customer load growth has lead to increased gas burns and a corresponding increase in gas transport capacity requirements. All of these factors will increase the Company's fixed transportation expenses. In the Test Year, the Company paid $5.4 million for the firm reservation of capacity on the El Paso pipeline. Taking all of the listed changes into consideration, the Company expects to pay over $41 million beginning January 1, 2006 for the fixed gas transportation services it requires under its existing contracts.

D. Coal, Nuclear and SRP Contract Prices

Q. ARE YOU PROPOSING ANY ADJUSTMENTS FOR FUEL PRICES OTHER THAN NATURAL GAS AND POWER?

A. Yes. Both coal and nuclear prices have increased over the costs in the Test Year, as has the demand charge in the T&C Agreement.

Coal prices have continued to be pressured by inflationary factors that are elements of the Company's long-term coal contracts. Price indices for diesel fuel, steel, labor, and benefits costs have all increased at significant rates and these are some of the critical components in the Company's coal contracts. Because of these changes, coal costs are expected to average $15.91/MWh in 2006 compared to an average cost of $14.96/MWh in the Test Year. This is a 6% increase in average costs and translates into a $12 million increase in fuel expense for the more than 13,000 GWh of coal production expected in 2006.

Nuclear fuel prices also are higher. These costs, while still the lowest production costs in the Company's generation portfolio, have increased from $4.81/MWh in the test year to $5.24/MWh in 2006. This 9% increase translates into over $3 million of additional fuel expense. Approximately 60% of this increase is related to higher Independent Spent Fuel Storage Installation ("ISFSI") costs, which reflect the costs that must be accrued to pay for the storage of nuclear fuel for the balance of Palo Verde's operating life and beyond. The remainder of the cost increases are related to contract escalators.

Q. WHAT IS THE IMPACT OF THE SRP CONTRACT CHANGE?

A. The SRP demand charge under the T&C Agreement is affected by escalation in such items as labor costs, materials and supplies, and fuel oil, as well as the change in the El Paso rates. The average rate the Company paid in the Test Year for T&C Agreement capacity was $4.53/kW-month. The increase in gas

transportation costs that will be passed through to the Company in the T&C Agreement demand charge results in an increase in the Company's bill of $4.9 million, and raises the average cost of the demand charge by $1.14/kW-month. All of the other escalation items embedded in the contract add an additional $1.34/kW-month to the average cost, making the full cost change 10.7 million just due to the price changes associated with the contract.

E. Generation Capacity Resources

Q. ARE YOU MAKING ANY ADJUSTMENTS TO THE GENERATING RESOURCES AVAILABLE TO MEET CUSTOMER ELECTRICITY DEMAND?

A. Yes. The most significant adjustment is the inclusion of the recently acquired PWEC and Sundance units for a full calendar year. In the Test Year, the PWEC units were available to serve native load customer demand only during the Track B contract months of June through September. The Sundance units were not acquired by APS until mid-May 2005, well into the Test Year. These adjustments add more than 2,100 MW of combined capacity from the PWEC and Sundance units to the Company's resource portfolio in the months of January through May and October through December. The fuel expense and off-system margin impacts of this adjustment are included in Attachments PME-6 and PME-7, respectively.

Q. ARE OTHER RESOURCE CHANGES TAKING PLACE?

A. Yes. The Company's T&C Agreement with SRP provides firm capacity (with the amount depending on the year), 62 MW of non-firm capacity, and associated energy that is essentially indexed to the price of gas. A provision of the T&C Agreement allows SRP to cancel any or all of the capacity with three years notice. In May 2004, SRP notified the Company that it will be reducing the firm

contract demand by 150 MW effective June 1, 2007. Therefore, I am adjusting the capacity available under the T&C Agreement with SRP to the 2006 year-end capacity level of 372 MW less the 150 MW scheduled reduction in 2007.

At the Company's normalized 2006 sales levels, the Company's own load peak demand is expected to be 7,016 MW. Based on the Company's existing resources including the PWEC and Sundance units, the Company's required summer reserve margin of 15%, and the capacity adjustments I have just highlighted, the Company is short on capacity, to varying degrees, in the months of June through October. In June, 2006 the Company requires additional firm capacity from the market of only 224 MW. In July and August, 2006 this shortfall approaches 1,000 MW. As I discussed earlier in my testimony, the energy purchased to fulfill this shortfall is priced at the daily market price consistent with the monthly forward market price for power on November 30, 2005. Because this represents day-ahead power purchases, it does not capture the costs related to firm acquisition of capacity months in advance. To make up for this gap, the Company is adjusting its fuel expense by adding the cost of acquiring "at-the-money" options for the capacity shortfall I have identified here.

Q. ARE THERE ANY OTHER RESOURCE CHANGES THAT NEED TO BE REFLECTED IN THE FUEL EXPENSE PRO FORMA?

A. Yes. Albeit on a much smaller scale, the Company's hydroelectric production facilities at Childs/Irving were decommissioned on June 18, 2005. The capacity available from these units amounted to 4 MW in the Test Year. Because these units are no longer in service, the Company's fuel expenses have been adjusted to reflect the loss of this resource.

V. PRO FORMA ADJUSTMENTS TO NORMALIZE MAINTENANCE

Q. HAVE YOU MADE AN ADJUSTMENT TO NORMALIZE MAINTENANCE?

A. Yes, I am proposing to adjust both planned maintenance time and unplanned outage time to be consistent with an average year. This adjustment is necessary because outage time at each of the power plants in the Test Year for planned routine maintenance and unplanned forced outages are not indicative of the normal levels of availability. These adjustments have an impact on the Company's fuel expense, as well as operations and maintenance ("O&M") expense. On Attachment PME-15, pages 1 and 2, I have adjusted Test Year O&M expenses to normalize maintenance levels for the Company's production plant in service at September 30, 2005, excluding the Childs/Irving facilities and the recently acquired Sundance and PWEC units. This has been done separately for the Company's nuclear facilities and its non-nuclear facilities. Using this methodology, the non-nuclear generation maintenance pre-tax operating income adjustment is $0.9 million and the nuclear generation maintenance pre-tax operating income adjustment is $(0.7) million. The overhaul expense for the PWEC and Sundance units is adjusted in a similar manner, and the resulting O&M expense adjustments are included in the PWEC units pro forma and the Sundance units pro forma, respectively, sponsored by APS witness Ms. Laura Rockenberger. The fuel expense adjustments shown in Attachments PME-6 and PME-7 include the impacts of the outage time normalization for all of the units.

Q. HOW DID YOU ADJUST THE OUTAGE TIME TO NORMALIZE THE TEST YEAR RESULTS?

A. I used two separate approaches for normalizing outage time. Planned maintenance for each generating plant is an average over the routine overhaul

cycle for the plant type. For example, the Company's coal plants are on a six-year overhaul cycle, which means that each of the coal units should experience a major overhaul once in every six-year period. The nuclear units are on an 18-month refueling cycle. Any single year, such as the Test Year, does not represent the average maintenance time and expense levels that can reasonably be expected when rates established in this case will be in effect. Attachment PME-16 shows the resulting number of planned outage days by plant and the required adjustments in the RTSim model to the planned maintenance schedule from the Company's 2005 LRF.

Unplanned outage time is based on the Company's forecast of future plant performance included in the Company's 2005 LRF. These levels are determined by reviewing historical performance and adjusting for corrective measures expected to be put in place in future maintenance outages. Attachment PME-17 shows the comparison of normalized outage time, expressed as EFOR, to the historical rates experienced by the Company's plants. From the Attachment, one can see that the EFOR levels the Company is proposing generally are on par with or more aggressive than the rates historically experienced.

Q. HOW DID YOU ADJUST THE MAINTENANCE EXPENSES TO NORMALIZE THE TEST YEAR RESULTS?

A. The maintenance expenses were normalized in a similar fashion to the outage time. For non-nuclear generating units, normal maintenance levels are determined by averaging the maintenance expense at each power plant using the six-year average maintenance cycle. Normal Palo Verde expenses are based on historical expenses for a three-year period. Labor costs, including overtime costs, have been adjusted to reflect historical labor increases. Non-labor

maintenance costs were adjusted to current costs levels using the Handy-Whitman cost indices.

The non-nuclear pro forma adjustment also includes the costs associated with maintaining the renewable generation resources developed under the Environmental Portfolio Standard.

VI. PRO FORMA ADJUSTMENT TO NORMALIZE ELECTRICITY SALES

Q. WHAT IS THE COMPANY'S PROPOSED PRO FORMA ADJUSTMENT TO NORMALIZE TEST YEAR WEATHER CONDITIONS?

A. Attachment PME-18 shows an increase to Test Year revenues of $10.9 million and to Test Year operations expenses of $5.0 million that would have occurred if normal weather conditions had been experienced during the test year. Electricity sales to residential, commercial and industrial customers were lower by about 157,000 MWh than they otherwise would have been due to mild weather conditions during the winter and spring of 2005. December 2004 was actually somewhat colder than normal, and June and July 2005 were moderately hotter than normal. These months partially offset the milder weather months.

Q. HOW WAS THE SALES IMPACT OF NORMAL WEATHER CALCULATED?

A. The method used for normalizing the sales effects from abnormal weather conditions is the same methodology as has been accepted previously by the Commission. The calculation of weather-normalized sales applies the difference between actual weather conditions and normal weather conditions to a customer class-specific factor that tracks the sensitivity of average customer monthly usage to changes in weather conditions. Summer weather conditions are defined as the product of the number of cooling degree-days ("CDD") in the month and

the natural log of average humidity for the month. Winter weather conditions are defined as the number of heating degree-days ("HDD") in the month. The weather-sensitivity factor is calculated from a set of statistical models, which track the systematic correlation between average customer usage and weather over time for the residential and small, medium and large general service classes. As one would expect, the correlation between average monthly usage and our weather indices is very strong.

Q. HOW WAS NORMAL WEATHER DETERMINED?

A. The CDD and HDD data are based on temperature readings from the National Weather Service at Phoenix Sky Harbor International Airport. The humidity data used in the construction of the summer weather index also relates to Sky Harbor. Normal weather is computed for each month as the most recent 10-year average ending September 30, 2005. For example, normal weather for July is the average of actual weather in each July from 1996 through 2005.

Q. HOW WERE THE REVENUE ADJUSTMENTS DETERMINED IN THE WEATHER NORMALIZATION PRO FORMA ADJUSTMENT?

A. The difference between actual sales and weather normalized sales is multiplied by the September 30, 2005 rate levels, which reflects the rates authorized in Decision No. 67744. This calculation was made on a month-by-month basis for each class of customer.

Q. ARE CORRESPONDING EXPENSES NORMALIZED?

A. Yes. Test Year expenses directly affected by kWh consumption are normalized by multiplying the weather normalized kWh consumption by the Test Year average fuel expense and the Test Year average Open Access Transmission Tariff ("OATT") expense. Test Year average fuel expense was calculated as described

previously. As APS witness Mr. David J. Rumolo explains in his testimony, Test Year average OATT expense was determined by using the actual amount APS billed itself for retail network transmission service and ancillary services under FERC regulations. The total OATT charges were then divided by the corresponding OATT-billed kWh to determine the Test Year average OATT expense.

Q. ARE FUEL AND OATT EXPENSES THE ONLY EXPENSES THAT VARY SYSTEMATICALLY WITH ELECTRICITY SALES LEVELS?

A. Yes, which is why these are the only expenses that require adjustments corresponding to the revenue adjustments.

Q. ARE YOU ALSO PROPOSING A SALES-RELATED PRO FORMA ADJUSTMENT TO ANNUALIZE CUSTOMER COUNTS?

A. Yes. Attachment PME-19 shows the increase in Test Year revenues and expenses for this pro forma, which nets to a pre-tax operating income adjustment of $28.3 million. During the Test Year, APS added customers throughout the year such that the number of customers receiving service at September 30, 2005 was greater than the number of customers in every previous month. Because we believe these customers are here to stay, the Company annualizes the Test Year's customer levels by assuming that the September level of customers had been present for the full year. This adjustment is consistent with previous Commission decisions adopting pro forma adjustments for year-end customer levels.

Q. HOW WAS THE ANNUAL NUMBER OF CUSTOMERS DETERMINED?

A. The customer annualization pro forma adjusts the number of customers each month to be consistent with the number of customers at the end of the Test Year, while preserving the natural seasonality inherent in customer levels. The "ratio

of customer change" is the mechanism by which this is accomplished. These ratios use the midpoint of each month as a cut-off point for determining if customers have been billed in a month. The Company counts active accounts as customers only if they have been billed for more than half of the month. Therefore, customers added during the first half of the month are assumed to have been billed for consumption during the entire month, while customers added during the second half of the month are assumed to have been billed for zero consumption for that month. Accordingly, for September 2005, customers added during the second half of the month have not been billed for 1/24th of the Test Year. Customers added after the midpoint of August 2005 represent 3/24th of the annual increase in customers, which would have been billed for August if they had been in effect as of the start of August. Likewise, 5/24th for customers added after the midpoint of July 2005, 7/24th for customers added after the midpoint of June 2005, and so forth. These customer additions are then added to the actual customer counts for each month to arrive at the adjusted annualized counts.

Q. HOW WERE SALES AND REVENUE LEVELS THAT CORRESPOND WITH THESE CUSTOMER LEVELS DETERMINED?

A. The monthly adjustments to customer counts are multiplied by the corresponding monthly weather normalized kWh usage for residential and small, medium and large general service classes, or the actual monthly usage for the other classes, which are not weather normalized. The resulting kWh adjustment is then applied to the rate levels authorized in Decision No. 67744. This calculation was made on a month-by-month basis for each class of customer.

Q. ARE THERE CORRESPONDING EXPENSES THAT NEED TO BE ADJUSTED?

Yes. As is done in the weather normalization pro forma adjustment, Test Year expenses are then normalized by applying the kWh adjustment to the Test Year average fuel expense and the Test Year average OATT expense.

Q. WHAT OTHER SALES-RELATED REVENUES OR EXPENSES ARE YOU PROPOSING TO ADJUST?

A. An adjustment to Test Year revenues is required to reflect APS' acquisition of the PWEC units. Those units no longer purchase auxiliary power under Rate Schedule E-36, Station Use Service, from the Company. APS now self-supplies any auxiliary power needs for these plants. In the Test Year, APS received $1.8 million from PWEC for these power sales. The loss of this revenue requires a pre-tax operating income pro forma adjustment to the Test Year of $(1.1) million, and is included in the PWEC units pro forma in Schedule C-2.

Additionally, the specific spending level for DSM programs set in Decision No. 67744 requires an adjustment to both usage and revenue in the Test Year. The Company will experience a loss in revenue due to a reduction in customer usage as these programs are implemented and become successful. The expected usage reduction from the implementation of programs included in the Plan submitted to the Commission for approval on July 1, 2005 will average approximately 94,201 MWh annually over a three-year period. The resulting revenue loss is calculated by multiplying the Test Year revenue in cents/kWh, less the Test Year fuel cost in cents/kWh, by these expected MWh reductions. The pre-tax operating revenue adjustment of $(4.9) million resulting from these sales adjustments is included in the DSM pro forma as shown on Schedule C-2. APS witness Mr. Chris Froggatt discusses the remainder of that pro forma in his testimony.

VII. CONCLUSION

Q. DO YOU HAVE ANY FINAL REMARKS?

A. The volatility of natural gas and purchased power has been well documented over the last several years and is anticipated to persist into the future. In addition, the trend in prices for all of the fuel sources for electric generation, including natural gas, coal and nuclear, continues to be upwards, and fuel prices, natural gas in particular, are expected to remain high and volatile. Because the vast majority of the Company's incremental load growth is served by natural gas (either through the operation of the Company's own generating facilities or through purchased power), the Company's fuel expense has increased dramatically since 2003, the year used to set the base fuel amount currently in effect. Because these amounts clearly are necessary expenditures required to meet APS' customers' needs, the base fuel amount should be adjusted accordingly.

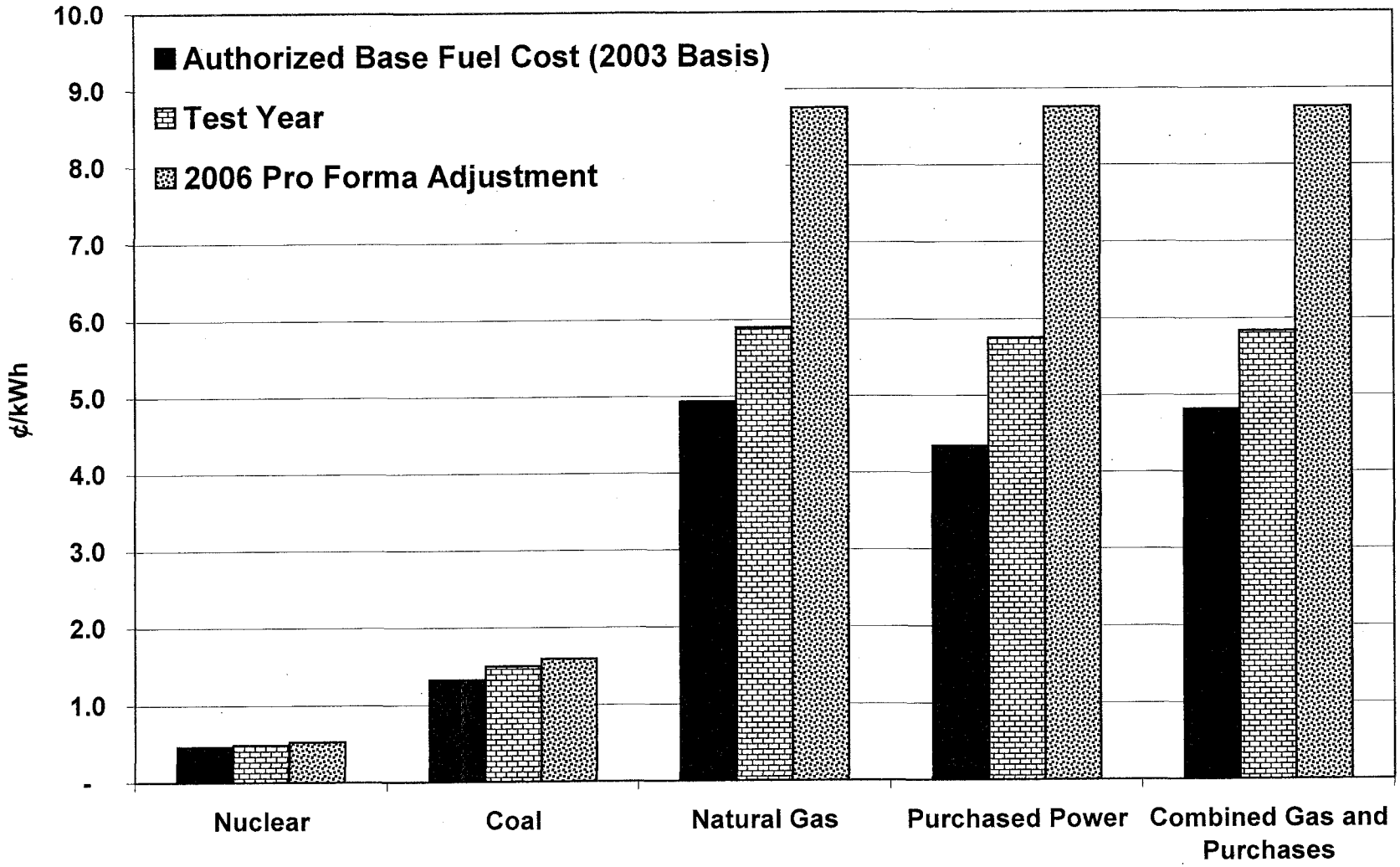
Q. DOES THIS CONCLUDE YOUR PREFILED DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes.

Arizona Public Service Company
Summary of Base Fuel Cost Changes

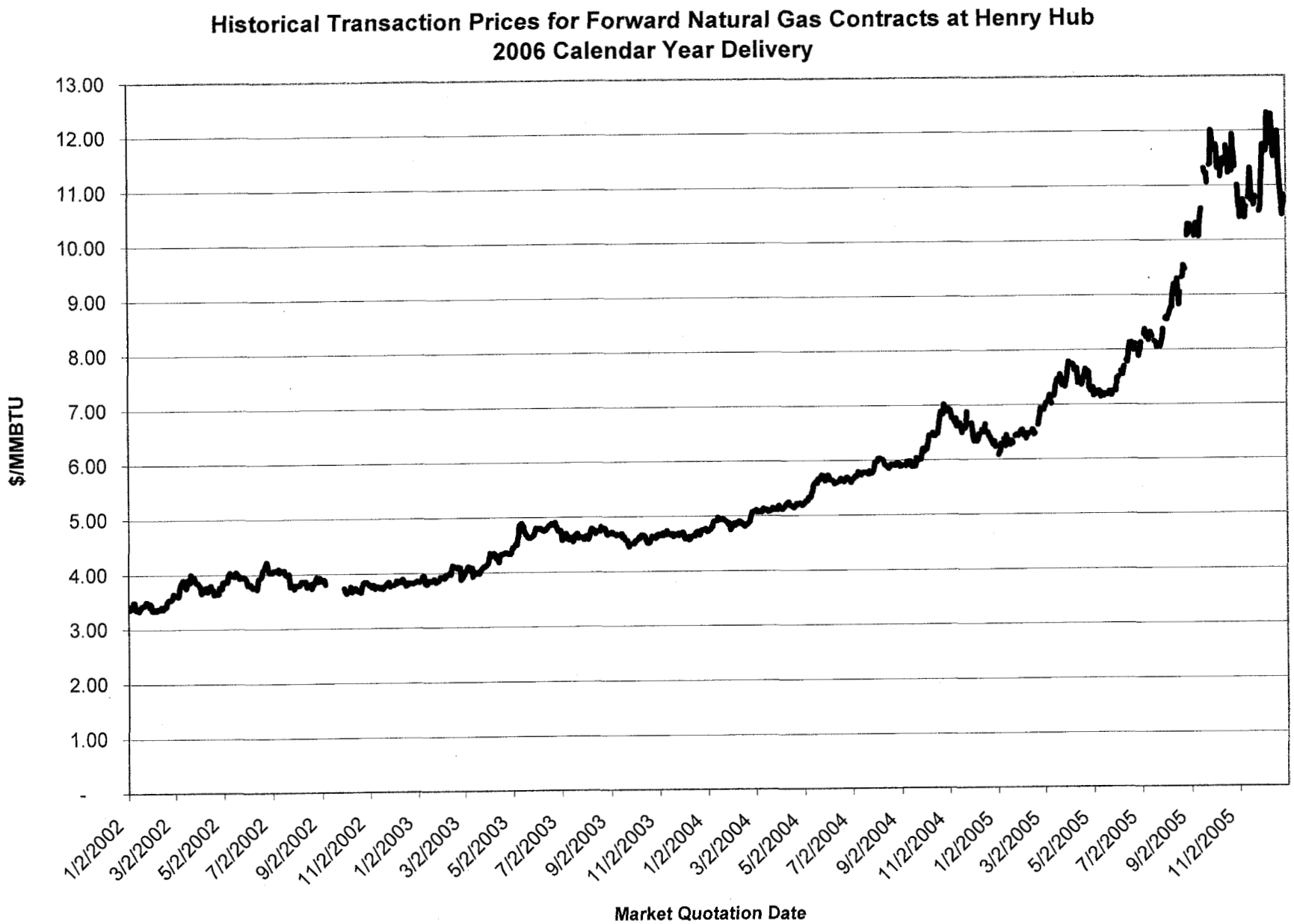
	Current Authorized Level (2003 Conditions)	Test Year Level (12ME 9/30/05)	Test Year vs. Current Authorized	Pro Forma Level (2006 Conditions)	Pro Forma vs. Test Year	Pro Forma vs. Current Authorized
Base Fuel Cost (¢/kWh)	2.0743	2.7010	0.6267	3.1904	0.4894	1.1161
Test Year Normalized Sales (GWh)	26,759	26,759		26,759		
Base Fuel Expense ($000,000)	555.1	722.8	**167.7**	853.7	**131.0**	**298.7**
Reasons for Change ($000,000)						
Increased Share of Natural Gas, Market Purchased Power			59.5		87.5	147.1
Prices for Natural Gas, Purchased Power			94.0		235.6	329.6
Value of Gas and Power Hedge Contracts			(70.5)		(98.7)	(169.2)
Net Effective Price of Natural Gas, Purchased Power			23.5		136.9	160.4
Coal Average Fuel Cost			21.9		11.9	33.8
PWEC Bridge PPA			53.6		(53.6)	-
All Other			9.2		(51.7)	(42.5)
Total			**167.7**		**131.0**	**298.7**

Arizona Public Service Company
Average Fuel Cost by Type of Resource



ARIZONA PUBLIC SERVICE COMPANY
FUEL AND PURCHASED POWER
SUMMARY OF KEY FACTORS

	2003 Authorized	TME 9/30/2005	Requested 2006 Normalized
Gas and Purchased Power Share of Native Load Energy	22.4%	28.3%	28.6%
Gas Prices			
Delivered ($/mmbtu)	5.78	7.20	10.74
Hedge Value ($/mmbtu)	-	(1.68)	(2.48)
Effective Gas Price ($/mmbtu)	5.78	5.52	8.26
Power Prices			
Palo Verde On-Peak ($/MWh)	53.21	58.75	88.88
Average Purchase Cost ($/MWh)	43.37	57.50	87.56
Average Coal Cost ($/MWh)	13.19	14.96	15.91
Average Nuclear Cost ($/MWh)	4.58	4.81	5.24


Historical Transaction Prices for Forward Natural Gas Contracts at Henry Hub
2006 Calendar Year Delivery
$/MMBTU
13.00
12.00
11.00
10.00
9.00
8.00
7.00
6.00
5.00
4.00
3.00
2.00
1.00
-
1/2/2002
3/2/2002
5/2/2002
7/2/2002
9/2/2002
11/2/2002
1/2/2003
3/2/2003
5/2/2003
7/2/2003
9/2/2003
11/2/2003
1/2/2004
3/2/2004
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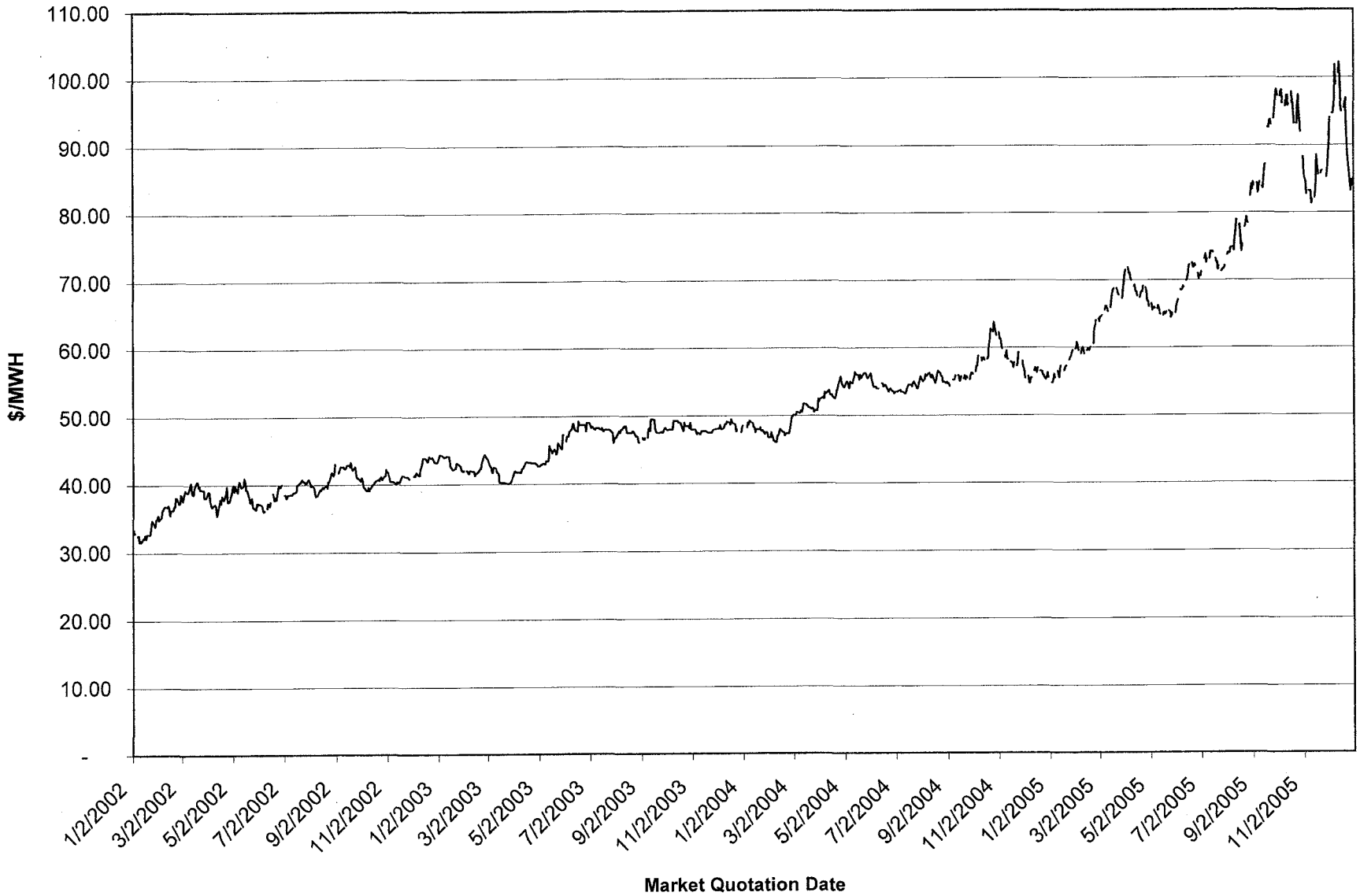
7/2/2004
9/2/2004
11/2/2004
1/2/2005
3/2/2005
5/2/2005
7/2/2005
9/2/2005
11/2/2005
Market Quotation Date

Historical Transaction Prices for Forward On-Peak Power Contracts at Palo Verde
2006 Calendar Year Delivery



ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2
(Thousands of Dollars)

PRO FORMA ADJUSTMENT: **BASE FUEL AND PURCHASED POWER**
Adjustment to Test Year operations to include 2006 base fuel and purchased power ¢/kWh costs at adjusted Test Year consumption, and to remove Deferred Fuel related to the PSA.

Line No.	Description		Amount
1.	**EXPENSES:**		
2.	Fuel and Purchased Power Expenses		
3.	Normalized 2006 Fuel and Purchased Power Costs (¢/kWh)	3.2859	
4.	Test Year Fuel and Purchased Power Costs (¢/kWh)	2.6983	
5.	Adjustment to Fuel and Purchased Power Costs (¢/kWh)	0.5876	
6.	Test Year Sales (MWh)	26,088,197	
7.	Pro Forma Adjustments to Test Year Billed Retail Sales (MWh)		
8.	To Adjust to Normal Weather	156,529	
9.	To Annualize to September 30, 2005 Customer Level	514,752	
10.	Adjusted Test Year Retail Sales (MWh)	26,759,478	
11.	Pro Forma Adjustment to Fuel and Purchased Power Expenses (Line 5 X Line 12)	157,239	
12.	Remove PSA Fuel Deferral		
13.	Retail PSA Fuel Deferral	139,768	
14.	Deferred Mark to Market on Native Load Hedge	(26,924)	
15.	Total PSA Fuel Deferral	112,844	
16.	Pro Forma Adjustment to Fuel and Purchased Power Expenses (Line 11+ Line 12)		$ 270,083
17.	**OPERATING INCOME (before income tax)**		**$ (270,083)**
18.	Income Tax at 39.05%		(105,467)
19.	**OPERATING INCOME AFTER TAX**		**$ (164,616)**

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2
(Thousands of Dollars)

PRO FORMA ADJUSTMENT: **NORMALIZE OFF-SYSTEM SALES**

Adjustment to Test Year operations to include off-system revenues consistent with the Base Fuel and Purchased Power pro forma adjustment.

Line No.	Description				Amount
1.	**REVENUES:**				
2.	Normalized Off-System Revenue	$	153,098		
3.	Test Year Off-System Revenue	$	74,619		
4.	Pro Forma Adjustment to Revenues			$	78,479
5.	**EXPENSES:**				
6.	Fuel and Purchased Power Expenses				
7.	Normalized Off-System Fuel and Purchased Power Expenses	$	127,134		
8.	Test Year Off-System Fuel and Purchased Power Expenses	$	75,344		
9.	Total Pro Forma Adjustment to Fuel and Purchased Power Expenses				51,790
10.	**OPERATING INCOME (before income tax)**			**$**	**26,689**
10.	**OPERATING INCOME (before income tax)**			**$**	**26,689**
11.	Income Tax at 39.05%				10,422
12.	**OPERATING INCOME AFTER TAX**			**$**	**16,267**

Historic Spot Market
Natural Gas and Power Prices

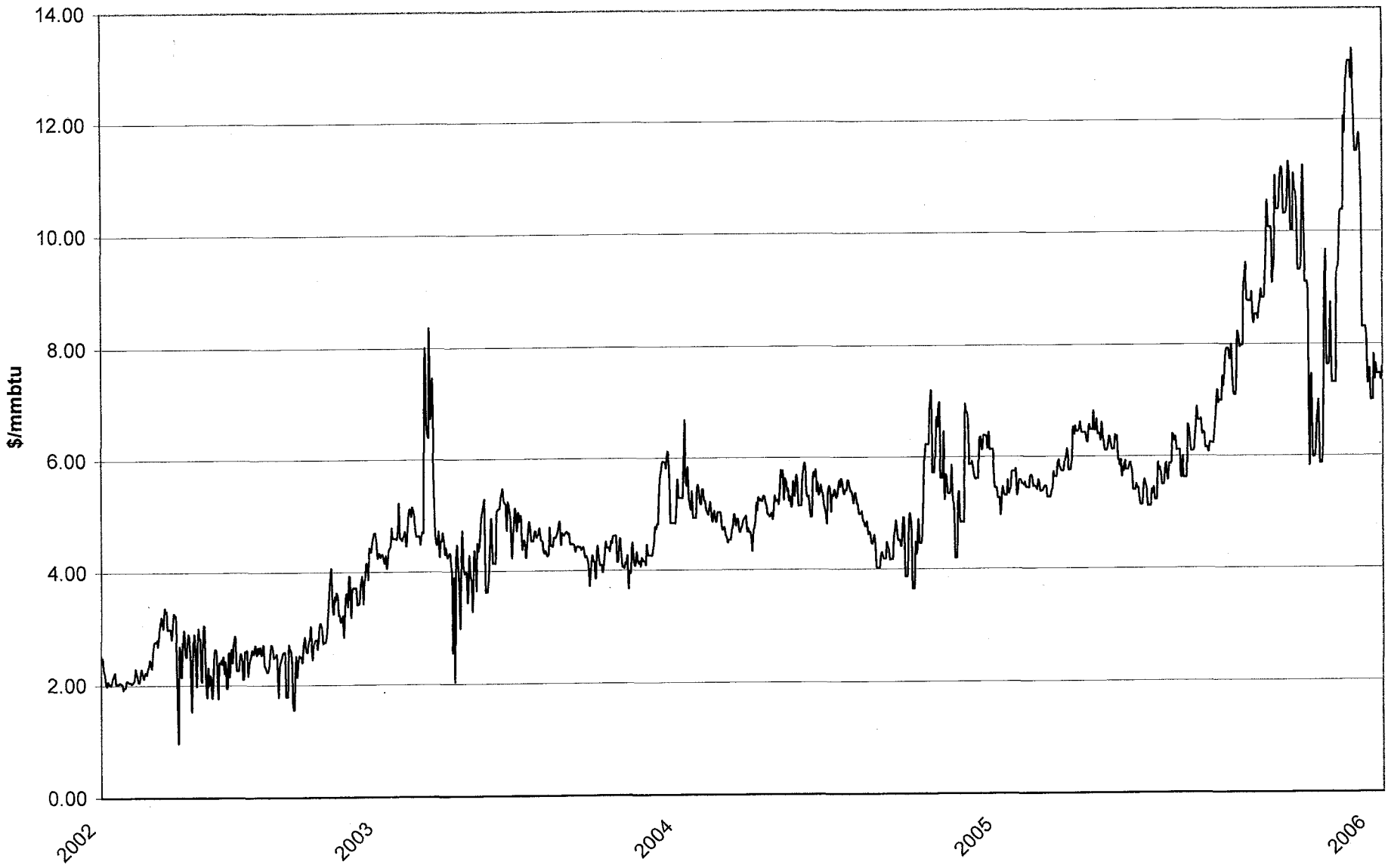
NATURAL GAS ($/mmbtu)	2002	2003	2004	2005	2002-2005
Henry Hub					
Average	3.35	5.44	5.87	8.90	6.11
Maximum	5.33	18.60	8.12	15.40	18.60
Minimum	1.98	3.99	4.34	5.53	1.98
Standard Deviation	0.71	1.23	0.66	2.87	2.66
San Juan					
Average	2.69	4.59	5.19	7.18	5.09
Maximum	4.69	8.36	7.18	13.27	13.27
Minimum	1.00	2.03	3.65	4.96	1.00
Standard Deviation	0.65	0.68	0.63	1.98	2.02
POWER ($/mwh)					
Palo Verde On-Peak					
Average	33.06	49.63	50.54	68.06	50.39
Maximum	70.09	118.21	79.11	117.91	118.21
Minimum	18.85	34.98	37.57	42.78	18.85
Standard Deviation	7.13	10.91	8.44	18.88	17.42

Sources:

Gas Daily - Reprinted with Permission of Platts 1998-2005

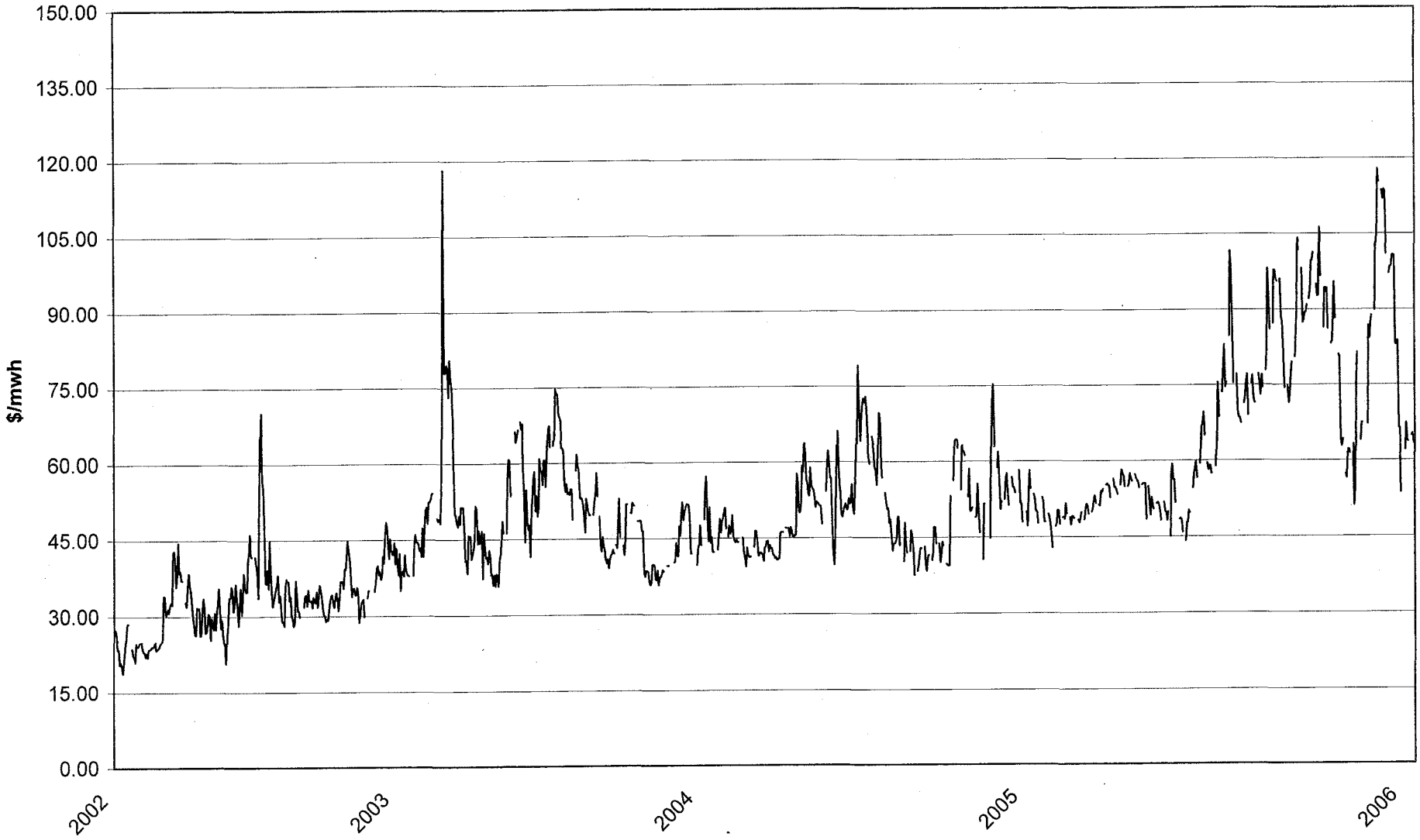
Dow Jones Palo Verde Electricity Indexes 1998-2005

Daily San Juan Basin Spot Prices
2002 - January 2006



Gas Daily - Reprinted with Permission of Platts

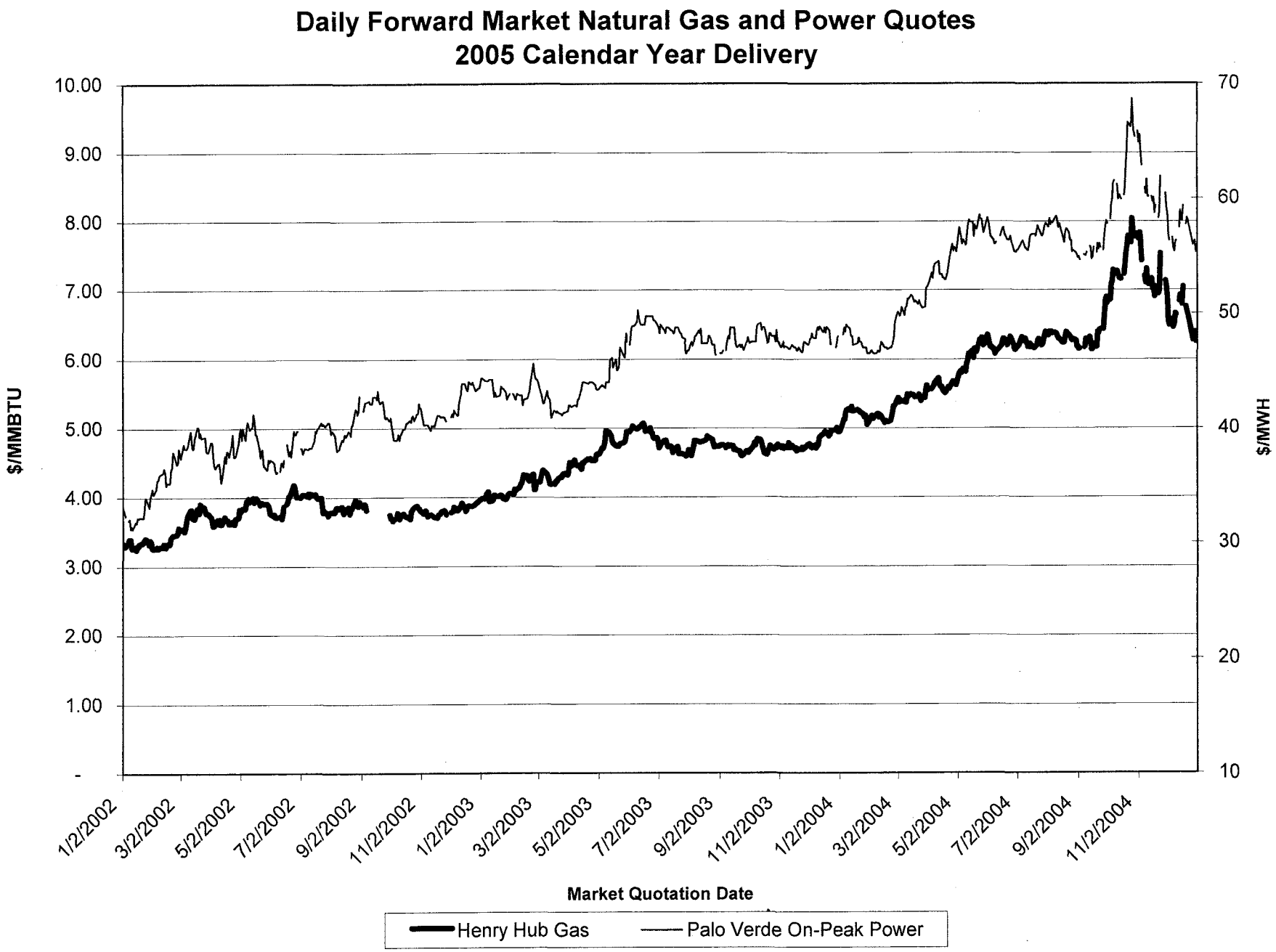
Daily Palo Verde Spot Market Power Prices
On Peak
2002 - January 2006



Forward Market Natural Gas and Power Prices

	Delivery Year*		
	2005	2006	2007
Natural Gas Price ($/MMBTU)			
Henry Hub			
Mean	4.85	6.31	5.94
Max	8.04	12.32	10.39
Min	3.24	3.79	3.83
Std Dev.	1.10	2.14	1.71
San Juan			
Mean	4.33	5.55	5.22
Max	7.23	10.83	8.94
Min	3.08	3.32	3.38
Std Dev.	0.94	1.85	1.44
Power Prices ($/MWH)			
PV On-Peak			
Mean	46.72	58.46	56.91
Max	68.69	102.19	87.50
Min	31.25	40.00	40.00
Std Dev.	7.56	14.66	12.37

* Prices for 2005 delivery reflect market quotations for 1/1/2002 to 12/31/2004.
Prices for 2006 and 2007 delivery reflect market quotations for 1/1/2003 to 12/30/05.


Daily Forward Market Natural Gas and Power Quotes
2005 Calendar Year Delivery
$/MMBTU
10.00
9.00
8.00
7.00
6.00
5.00
4.00
3.00
2.00
1.00
-
$/MWH
70
60
50
40
30
20
10
1/2/2002
3/2/2002
5/2/2002
7/2/2002
9/2/2002
11/2/2002
1/2/2003
3/2/2003
5/2/2003
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9/2/2003
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1/2/2004
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7/2/2004
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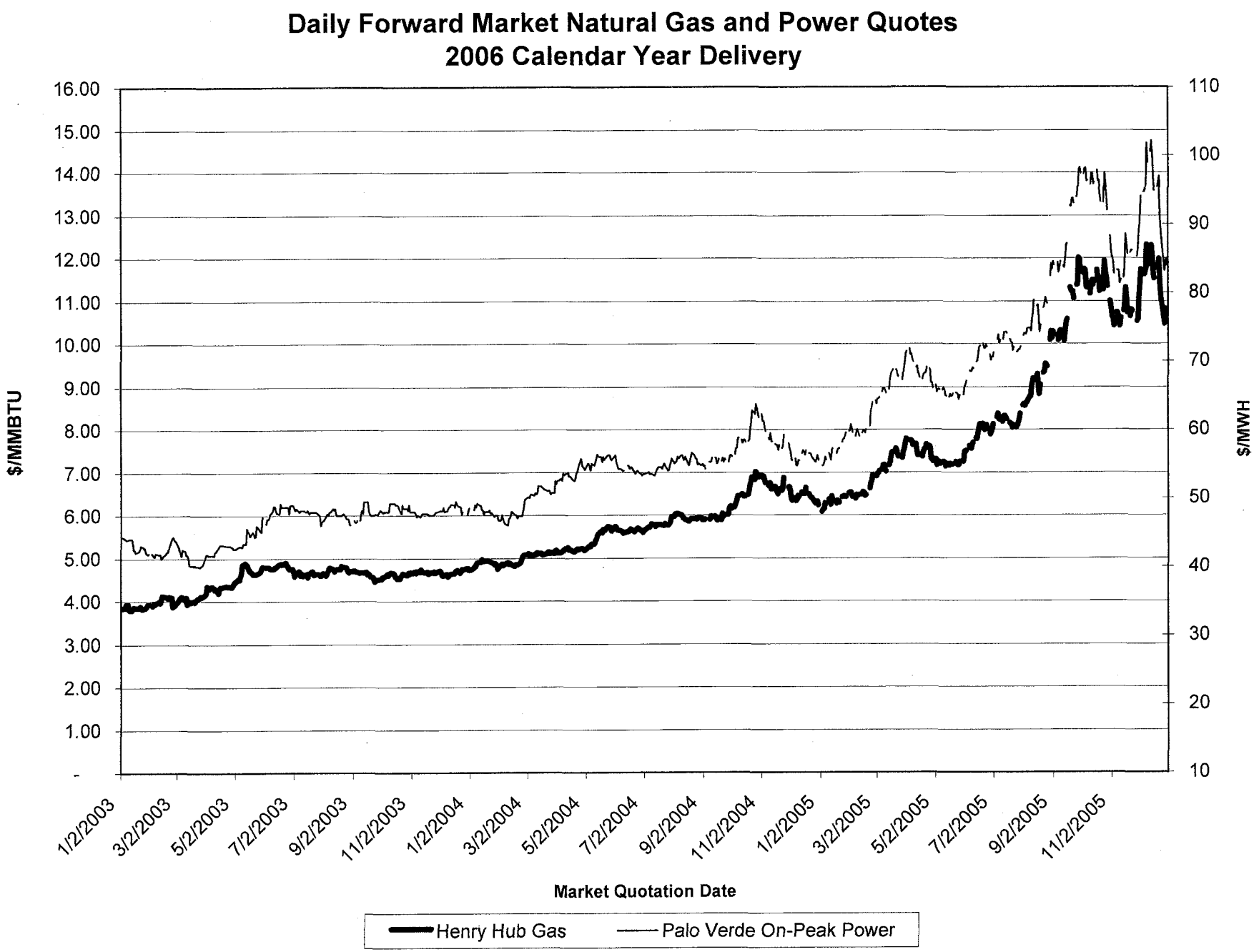
11/2/2004
Market Quotation Date
Henry Hub Gas
Palo Verde On-Peak Power


Daily Forward Market Natural Gas and Power Quotes
2006 Calendar Year Delivery
$/MMBTU
$/MWH
16.00
15.00
14.00
13.00
12.00
11.00
10.00
9.00
8.00
7.00
6.00
5.00
4.00
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110
100
90
80
70
60
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9/2/2003
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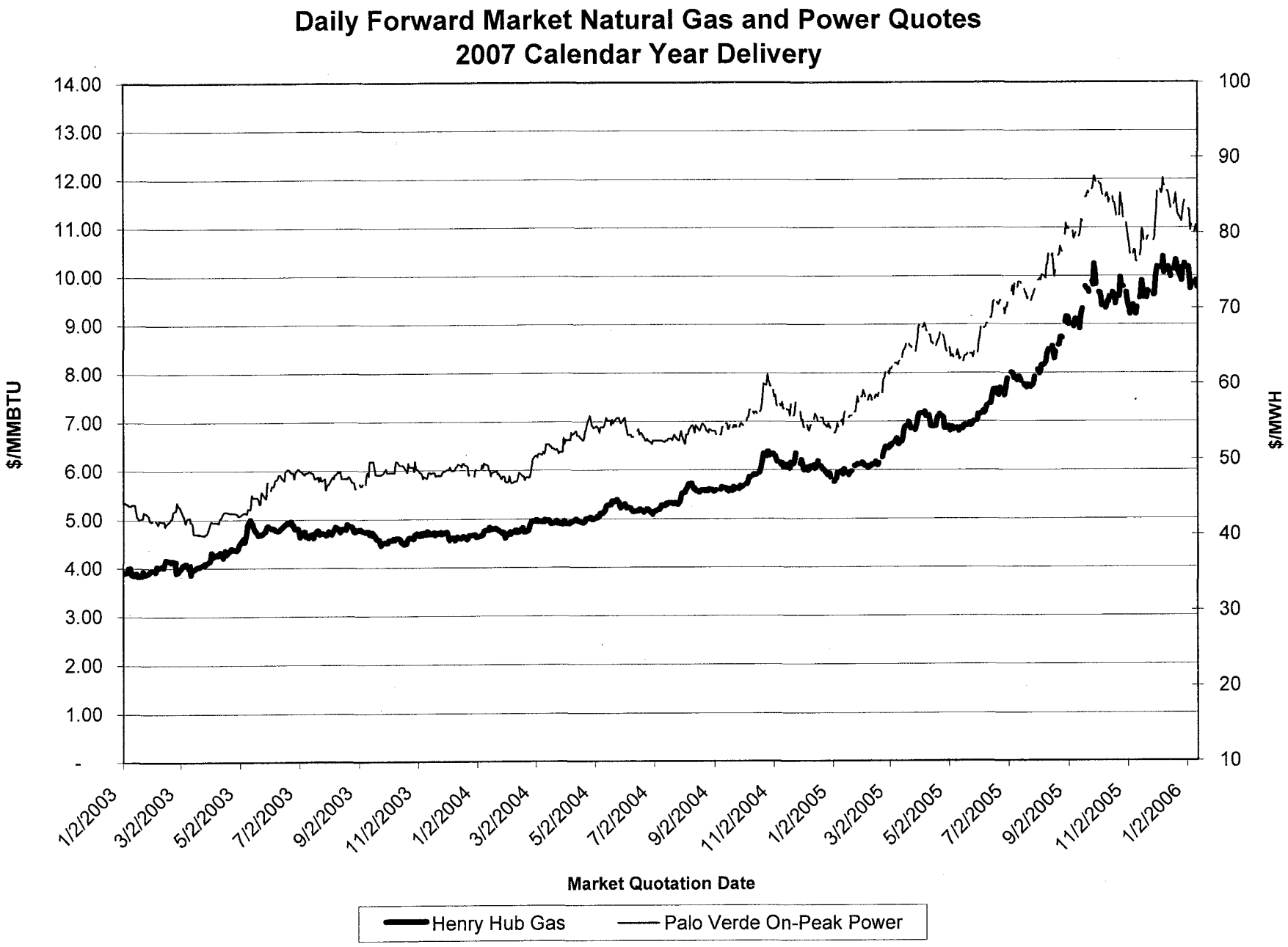
9/2/2005
11/2/2005
Market Quotation Date
Henry Hub Gas
Palo Verde On-Peak Power


Daily Forward Market Natural Gas and Power Quotes
2007 Calendar Year Delivery
$/MMBTU
$/MWH
14.00
13.00
12.00
11.00
10.00
9.00
8.00
7.00
6.00
5.00
4.00
3.00
2.00
1.00
-
100
90
80
70
60
50
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10
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3/2/2003
5/2/2003
7/2/2003
9/2/2003
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11/2/2004
1/2/2005
3/2/2005
5/2/2005
7/2/2005
9/2/2005
11/2/2005
1/2/2006
Market Quotation Date
Henry Hub Gas
Palo Verde On-Peak Power

Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2
Total Company
(Thousands of Dollars)

PRO FORMA ADJUSTMENT: **NORMALIZE NON-NUCLEAR MAINTENANCE EXPENSE**

Adjustment to Test Year operations to reflect the normalization of fossil production maintenance expense and to include the O&M costs of generators acquired for compliance with the Environmental Portfolio Standard.

Line No.	Description		Amount
1.	**EXPENSES:**		
2.	Other Operating Expenses		
3.	Environmental Portfolio Standard	$	567
4.	Fossil Generation Maintenance Normalization		889
5.	Total Pro Forma Adjustment to Expenses	$	1,456
6.	**OPERATING INCOME (before income tax)**	**$**	**(1,456)**
7.	Income Tax at 39.05%		(569)
8.	**OPERATING INCOME AFTER TAX**	**$**	**(887)**

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2
Total Company
(Thousands of Dollars)

PRO FORMA ADJUSTMENT: **NORMALIZE NUCLEAR MAINTENANCE EXPENSE**

Adjustment to Test Year operations to reflect the normalization of nuclear production maintenance expense.

Line No.	Description	Amount
1.	**EXPENSES:**	
2.	Other Operating Expenses	
3.	Maintenance	$ (729)
4.	Total Pro Forma Adjustment to Expenses	$ (729)
5.	**OPERATING INCOME (before income tax)**	**$ 729**
6.	Income Tax at 39.05%	285
7.	**OPERATING INCOME AFTER TAX**	**$ 444**

Arizona Public Service Company
Planned Outage Days

Plant	Avg Unit Capacity	Avg Annual Planned Outage MW Days	Avg Annual Planned Outage Days	RTSim Adjustment MW Days	RTSim Adjusted Planned Outage Days	Outage Dates		
						1	2	3
Palo Verde	376.2	35,321	94	9,981	26	4/1-5/04	9/30-11/28	
Four Corners	156.4	14,495	93	185	2	1/28-3/28	11/7-11/18	
Cholla	209.3	8,612	41	(3,598)	(14)	3/25-4/21	11/4-11/8	
Navajo	105	5,880	56	2,730	26	2/4-3/31		
West Phoenix CC1,2,3	85	8,755	103	1,615	19	1/7-3/17	3/25-4/19	4/22-4/28
West Phoenix CC4	107	963	9	(535)	(5)	2/27-3/7		
West Phoenix CC5A	246	1,230	5	(1,230)	(5)	4/1-4/5		
West Phoenix CC5B	246	1,230	5	(2,214)	(9)	10/14-10/18		
Redhawk CC1A	237	1,185	5	(2,844)	(12)	12/16-12/20		
Redhawk CC1B	237	1,185	5	(1,659)	(7)	12/09-12/13		
Redhawk CC2A	237	1,185	5	0	0	3/18-3/22		
Redhawk CC2B	237	1,185	5	0	0	3/18-3/22		
Ocotillo Steam	110	8,470	77	3,850	35	1/17-3/13	2/27-3/19	
Saguaro Steam	105	5,970	57	1,560	14	2/13-3/19	11/27-12/17	

ATTACHMENT PME-17

Arizona Public Service Company
Comparison of Historical EFOR to Normalized EFOR

	2001	2002	2003	2004	2005	5 Year Average	Normalized EFOR
Nuclear	1.3%	0.9%	2.4%	8.0%	8.8%	4.3%	2.5%
Four Corners	11.2%	10.8%	8.8%	7.0%	10.1%	9.6%	9.1%
Cholla	11.5%	5.0%	22.4%	2.6%	2.3%	8.8%	5.7%
Navajo	3.7%	3.2%	3.5%	2.1%	4.6%	3.4%	5.3%
West Phoenix CC1-3	5.3%	5.3%	5.3%	5.3%	7.0%	5.6%	7.0%
West Phoenix CC4		4.0%	1.5%	11.6%	36.3%	13.4%	7.0%
West Phoenix CC5			7.5%	11.7%	6.5%	8.6%	10.0%
Redhawk CC		16.0%	10.8%	7.8%	3.2%	9.4%	7.5%
Steam Plants	8.8%	8.4%	16.6%	24.5%	11.4%	13.9%	7.8%
Gas Turbines	8.9%	23.9%	47.2%	23.4%	28.8%	26.4%	10.7%

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2
Total Company
(Thousands of Dollars)

PRO FORMA ADJUSTMENT: **NORMALIZE WEATHER CONDITIONS**

Adjustment to Test Year operations to reflect normal weather conditions for the ten years ended September 30, 2005.

Line No.	Description		Amount
1.	**REVENUES:**		
2.	Operating Revenue		$ 10,938
3.	Adjustment to sales (MWh) for the difference between normalized weather sales and actual sales	156,529	
4.	**EXPENSES:**		
5.	Fuel and Purchased Power Expenses		
6.	Adjustment to Sales (MWh)	156,529	
7.	Test Year Fuel and Purchased Power Costs (¢/kWh)	2.6983	
8.	Pro Forma Adjustment to Fuel and Purchased Power Expenses		4,224
9.	Operating Revenues Less Fuel and Purchased Power Expenses		$ 6,714
10.	Other Operating Expenses		
11.	Adjustment to Sales (MWh)	156,529	
12.	Test Year Average OATT Expense (¢/kWh)	0.4770	
13.	Pro Forma Adjustment to OATT Expense		747
14.	**OPERATING INCOME (before income tax)**		**$ 5,967**
15.	Income Tax at 39.05%		2,330
16.	**OPERATING INCOME AFTER TAX**		**$ 3,637**

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2
Total Company
(Thousands of Dollars)

PRO FORMA ADJUSTMENT: **ANNUALIZE CUSTOMER LEVELS**
Adjustment to Test Year operations to reflect the annualization of customer levels at September 30, 2005.

Line No.	Description		Amount
1.	**REVENUES:**		
2.	Operating Revenue		$ 44,664
3.	Adjustment to sales (MWh) for the difference between customer annualized sales and actual sales	514,752	
4.	**EXPENSES:**		
5.	Fuel and Purchased Power Expenses:		
6.	Adjustment to Sales (MWh)	514,752	
7.	Test Year Fuel and Purchased Power Costs (¢/kWh)	2.6983	
8.	Pro Forma Adjustment to Fuel and Purchased Power Expenses		13,890
9.	Operating Revenues Less Fuel and Purchased Power Expenses		$ 30,774
10.	Other Operating Expenses		
11.	Adjustment to Sales (MWh)	514,752	
12.	Test Year Average OATT Expense (¢/kWh)	0.4770	
13.	Pro Forma Adjustment to OATT Expense		2,455
14.	**OPERATING INCOME (before income tax)**		**$ 28,319**
15.	Income Tax at 39.05%		11,059
16.	**OPERATING INCOME AFTER TAX**		**$ 17,260**

LAURA L. ROCKENBERGER

DIRECT TESTIMONY OF LAURA L. ROCKENBERGER

On Behalf of Arizona Public Service Company

Docket No. E-01345A-05-0816

January 31, 2006

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DIRECT TESTIMONY OF LAURA L. ROCKENBERGER
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-05-0816)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Laura L. Rockenberger. My business address is 400 North Fifth Street, Phoenix, Arizona, 85004.

Q. WHAT IS YOUR POSITION WITH ARIZONA PUBLIC SERVICE COMPANY?

A. I am the Manager of Operations Accounting for Arizona Public Service Company ("APS" or "Company"). My educational background and professional qualifications, as well as my professional experience, are set forth in Appendix A, which is attached to this testimony.

Q. WHAT SCHEDULES ARE YOU SPONSORING?

A. I am sponsoring the following Standard Filing Requirement ("SFR") Schedules: the historical and test year information contained in SFR Schedule A-4, related to Construction Expenditures and Gross Utility Plant in Service; the SFR Schedules B Rate Base information; certain operating income pro forma adjustments in SFR Schedule C-2; the historical and test year information contained in SFR Schedule E-5, Detail of Utility Plant; and the test year information contained in SFR Schedule F-3 related to construction requirements. The B schedules show the elements of APS' rate base at original cost and reconstructed cost new ("RCN") at September 30, 2005, as well as the pro forma adjustments to rate base.

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

A. Yes.

II. SUMMARY OF TESTIMONY

Q. PLEASE PROVIDE A SUMMARY OF YOUR TESTIMONY.

A. In large part, the pro forma adjustments to the test year rate base represent the implementation of Arizona Corporation Commission ("Commission" or "ACC") Decision No. 67744, issued April 7, 2005. Included in this Decision was Commission approval to transfer certain Pinnacle West Energy Corporation ("PWEC") units, specifically Redhawk Units 1 and 2, West Phoenix Units 4 and 5 and Saguaro Unit 3 ("PWEC Units") to APS. This subsequently occurred on July 29, 2005. In addition, in Decision No. 67504, issued January 20, 2005, the Commission authorized the purchase of the PPL Sundance Energy, LLC generating units ("Sundance Units") and approved an accounting order for the deferral of costs. The Sundance Units were subsequently acquired by APS on May 13, 2005. There are no Sundance Unit cost deferrals included in this filing because the criteria for cost deferrals, as allowed pursuant to Decision No. 67504, has not been met. The majority of the pro formas that I am sponsoring in this proceeding simply implement these Commission Decisions.

In response to a request from Commission Staff, APS has selected a fiscal year, the 12 months ending September 30, 2005, as a test period ("Test Year"). As such, the PWEC Units and the Sundance Units were included in the rate base at September 30, 2005. The Test Year was then adjusted to make it more representative of normal operations at the time new rates in this docket are approved by the Commission, which is assumed to be January 1, 2007.

My testimony addresses a number of accounting-related topics to support the Company's rate case application. I identify and explain adjustments to rate base and certain operating income adjustments. The rate base pro forma adjustments include the following adjustments: West Phoenix Unit 4 Regulatory Disallowance, Independent Spent Fuel Storage Installation ("ISFSI" or "Spent Fuel Storage") costs, Palo Verde Unit 1 steam generators ("PV Unit 1 Steam Generators") replacement costs, and deferred bark beetle remediation costs. For these items, there are corresponding operating income pro forma adjustments. In addition, there are operating income pro forma adjustments for the PWEC Units, the Sundance Units, nuclear plant decommissioning expense, coal reclamation costs, depreciation and amortization, property taxes, payroll, underfunded pension liability, advertising, and certain other miscellaneous adjustments in the SFR Schedule C-2 pro formas. The operating income pro formas also include an income tax calculation at the current statutory combined state and federal income tax rates. The SFR Schedule C-2 pro formas for the West Phoenix Unit 4 Regulatory Disallowance, Spent Fuel Storage, PV Unit 1 Steam Generators and bark beetle remediation include a calculation for the synchronization of interest expense used in the calculation of state and federal income tax expense. Mr. Chris Froggatt provides details regarding the income tax adjustment and interest synchronization adjustment in his testimony. I also provide direct testimony on an overall allowance for working capital and Reconstructed Cost New Less Depreciation ("RCND"), which is shown on SFR Schedule B-4. And finally, I sponsor SFR Schedule E-5 and actual Test Year information contained in SFR Schedule F-3.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. I will first discuss the items that have a pro forma adjustment to Original Cost Rate

Base, as set out in Attachments LLR-1-1 through LLR-1-5, and the corresponding pro forma adjustments to operating income. I will then discuss the remaining operating income pro forma adjustments. These pro forma adjustments, as set out in Attachments LLR-2-1 through LLR-2-17 and LLR-3, reflect total Company amounts prior to any jurisdictional allocation. Next I will present the results of the Company's Allowance for Working Capital (Attachment LLR-4), followed by the most recent RCN Study (Attachments LLR-5-1 and LLR-5-2) and SFR Schedule E-5, Detail of Utility Plant.

III. PRO FORMA ADJUSTMENTS AFFECTING BOTH RATE BASE & OPERATING INCOME

Q. WHAT ARE PRO FORMA ADJUSTMENTS?

A. Because the Commission requires a historical test year, it is necessary to adjust recorded revenues and expenses for known and measurable changes in rates or charges. The use of pro forma test year revenues and expenses more accurately reflects the level of revenues and expenses in the future, when the new rates will be in effect. Pro forma adjustments include normalizations, annualizations and known and measurable changes that affect actual rate base, revenues, and expenses in the test year.

Q. WHAT ARE "NORMALIZATIONS"?

A. Normalizations are adjustments that modify test year data to reflect a typical test year. These are generally accounting adjustments that remove expenses or revenues properly recorded during the Test Year, but are associated with prior periods.

Q. WHAT ARE "ANNUALIZATIONS"?

A. Annualizations are adjustments that compensate for timing differences, such as

adjusting the number of customers at the end of the test year, along with the sales revenues and expenses to reflect the revenues associated with those customers and the costs of serving that number of customers at the end of the test year.

Q. WHAT IS A "KNOWN AND MEASURABLE" ADJUSTMENT?

A. Known and measurable adjustments reflect the Company's expected financial conditions when the new rates are expected to be in effect. An adjustment is considered to be "known" when, given all the circumstances, its probability of occurrence is significantly greater than the chance it will not occur. An adjustment is "measurable" if it can be quantified in a meaningful fashion, such that the recognition of at least part of its effect on Test Year results will make the Test Year "more representative" than if the adjustment were omitted altogether.

A. PWEC Units - West Phoenix Unit 4 Regulatory Disallowance

Q. DID YOU RECORD THE REGULATORY DISALLOWANCE FOR THE PWEC UNITS IN ACCORDANCE WITH DECISION NO. 67744?

A. Yes. In Decision No. 67744, the Commission authorized a jurisdictional $700,000,000 original cost rate base ("OCRB") for the PWEC Units at December 31, 2004. Because the PWEC Units did not transfer to APS until July 29, 2005, the $700,000,000 OCRB was reduced by additional accumulated depreciation and related deferred taxes for the period of January 1, 2005 through July 29, 2005. Thus, the regulatory disallowance for the PWEC Units at July 29, 2005 reduced the net plant by $155,036,000. *See* Attachment LLR-1-1.

Q. ARE THERE DIFFERENCES BETWEEN THE REGULATORY ACCOUNTING FOR THE DISALLOWANCE AND THE ACCOUNTING UNDER GENERALLY ACCEPTED ACCOUNTING PRINCIPLES ("GAAP")?

A. Yes. Under GAAP, the portion of the regulatory disallowance related to West

Phoenix Unit 4 could not be recorded in the GAAP financial statements because the unit was not considered "recently completed".

Q. PLEASE DISCUSS THE ACCOUNTING GUIDANCE THAT WOULD NOT ALLOW THE WEST PHOENIX UNIT 4 REGULATORY DISALLOWANCE TO BE REFECTED IN YOUR GAAP FINAL STATEMENTS.

A. Statement of Financial Accounting Standards ("SFAS") No. 90, "Regulated Enterprises – Accounting for Abandonments and Disallowances of Plant Costs" was the authoritative accounting guidance we relied on in determining the amount of the loss that should be recorded for GAAP purposes. In accordance with the SFAS 90, when it becomes probable that part of the cost of a recently completed plant will be disallowed for rate-making purposes and a reasonable estimate of the amount of the disallowance can be made, the estimated amount of the probable disallowance shall be deducted from the reported cost of the plant and recognized as a loss.

SFAS 90 does not define "recently completed". Based on discussions with Deloitte, our external auditors, we concluded that a plant that was completed within twelve months of a rate filing is considered recently completed for purposes of SFAS 90. The in-service date for West Phoenix Unit 4 was June of 2001. Our rate filing requesting that West Phoenix Unit 4 be included in rates was made in June of 2003, two years after the in-service date. Thus, the plant was not considered recently completed and the disallowance could not be recorded for GAAP accounting purposes.

Q. PLEASE EXPLAIN THE RATE BASE PRO FORMA ADJUSTMENT FOR WEST PHOENIX UNIT 4 REGULATORY DISALLOWANCE.

A. Because the disallowance was not recorded for GAAP purposes, a pro forma

adjustment is needed to reduce the rate base by the disallowed amount. Accordingly, the rate base reduction for the West Phoenix Unit 4 regulatory disallowance at September 30, 2005 is $11,155,000. *See* Attachment LLR-1-2.

Q. IS THERE A CORRESPONDING OPERATING INCOME ADJUSTMENT FOR THE DEPRECIATION EXPENSE RELATED TO THE WEST PHOENIX UNIT 4 REGULATORY DISALLOWANCE?

A. Yes. The operating income pro forma reflects an annual reduction in depreciation expense of $230,000. *See* Attachment LLR-2-1.

B. INDEPENDENT SPENT FUEL STORAGE INSTALLATION

Q. WHY IS THERE A NEED FOR INDEPENDENT SPENT FUEL STORAGE INSTALLATION?

A. An Independent Spent Fuel Storage Installation is a dry storage facility for the temporary disposal of spent nuclear fuel. The fuel pools where the spent nuclear fuel from the Palo Verde Nuclear Generation Station ("Palo Verde") is currently stored have reached the maximum allowed capacity. Because the U.S. Department of Energy has delayed siting and constructing permanent spent nuclear fuel storage facilities, the continued operation of Palo Verde requires an alternative interim storage solution for spent nuclear fuel. The costs associated with Spent Fuel Storage are the costs of interim storage for spent nuclear fuel at Palo Verde.

Q. IS APS ASKING FOR CONTINUING RECOVERY OF SPENT FUEL STORAGE COSTS IN THIS RATE CASE FILING?

A. Yes. The Company has included pro forma adjustments for Spent Fuel Storage in a manner consistent with APS' last rate application. Specifically, APS is requesting recovery of its share of the ongoing costs associated with Spent Fuel Storage and an amortized portion of deferred amounts, as discussed below.

Q. WHAT IS THE BASIS FOR THE RECOVERY OF SPENT FUEL STORAGE COSTS?

A. Commission rule, A.A.C. R14-2-1608, provides for the recovery of interim spent nuclear fuel storage costs through a Systems Benefit Charge. The Commission first approved the recovery of system benefits costs for APS in Decision No. 61973, issued October 6, 1999, which adopted a settlement agreement that addressed electric restructuring.

Q. WHAT CHANGES RELATED TO SPENT FUEL STORAGE OCCURRED AS A RESULT OF DECISION NO. 67744?

A. On April 1, 2005 (the effective date of Decision No. 67744), APS commenced recovery for the amortization of prior deferred costs and the current accrual for Spent Fuel Storage costs associated with the current fuel burn. A portion of those costs represent post-shutdown Spent Fuel Storage costs that are being funded into the Palo Verde nuclear decommissioning trusts, which I discuss later in my testimony.

Q. HOW ARE THE COSTS ESTIMATED?

A. The cost estimates for Spent Fuel Storage are updated every three years and were most recently updated again by TLG Services, Inc. for 2004.

Q. PLEASE EXPLAIN THE SPENT FUEL STORAGE PRO FORMA RATE BASE ADJUSTMENT.

A. The net rate base reduction of $5,869,000 results from funds collected in regulated rates and reserved for the cost of current on-going and future activities in the decommissioning period to transfer spent nuclear fuel to the dry storage facility. *See* Attachment LLR-1-3.

Q. IS SPENT FUEL STORAGE EXPENSE INCLUDED IN NUCLEAR FUEL EXPENSE IN THE TEST YEAR?

A. Yes. Since the Test Year (ended September 30, 2005) occurred after the effective date of Decision No. 67744 (April 1, 2005), there are six months of Spent Fuel Storage expenses included in the unadjusted Test Year expenses. Thus the Spent Fuel Storage expense needs to be annualized in an operating income pro forma adjustment.

Q. PLEASE EXPLAIN THE CORRESPONDING OPERATING INCOME PRO FORMA ADJUSTMENT FOR SPENT FUEL STORAGE.

A. The total Test Year annualized nuclear fuel expense is $14,759,000. Of this amount, $3,667,000 represents ongoing Spent Fuel Storage expense, which is included in the Base Fuel and Purchase Power Expense pro forma, and is addressed in Mr. Ewen's testimony. The pro forma adjustment of $11,092,000 reflects the annual amortization of previously deferred amounts. This is shown on Attachment LLR-2-2.

Q. HOW DOES THE COMPANY PROPOSE TO ADDRESS THE AMORTIZATION OF PREVIOUSLY DEFERRED SPENT FUEL STORAGE EXPENSE?

A. The Spent Fuel Storage annualized expense for amounts previously deferred is $11,092,000, which is comprised of pre-shutdown costs of $9,976,000 and post-shutdown costs of $1,116,000. Consistent with Decision No. 67744, the Company proposes to amortize the costs associated with pre-shutdown activities over a five-year period. For Units 1 and 3, the post-shutdown costs are amortized over the license period, and for Unit 2, over the term of the sale/leaseback agreement (through December 31, 2015). This is also consistent with our last rate proceeding. The Company is requesting that the Commission's Decision in this docket

specifically provide for the amortization of the Spent Fuel Storage expense regulatory asset included in Attachment LLR-2-2.

Q. OF THESE PROPOSED AMOUNTS TO BE RECOVERED IN RATES, WHAT PORTION REPRESENTS POST-SHUTDOWN OPERATIONS TO BE FUNDED IN THE DECOMMISSIONING TRUSTS?

A. APS is requesting annual funding into the decommissioning trusts for the amounts approved in Decision No. 67744. Included in these amounts is $752,000, which represents post-shut down costs included in the ongoing accrual, and $792,000, which represents the amortization of previously deferred post-shut down amounts. *See* Attachment LLR-3. The amount that APS is requesting does not reflect the post-shutdown component of Spent Fuel Storage cost estimated in the 2004 study. The Company is deferring the difference for future recovery in subsequent rate proceedings.

Q. DO POST-SHUTDOWN SPENT FUEL COSTS QUALIFY FOR FAVORABLE TAX TREATMENT?

A. APS has filed a private letter ruling requesting Internal Revenue Service ("IRS") approval to use the qualified decommissioning funds for spent fuel costs. If such approval is granted, APS plans to use the qualified decommissioning funds for post-shutdown spent fuel costs to their fullest extent, as allowed under the federal income tax rules.

C. PALO VERDE UNIT 1 STEAM GENERATORS

Q. WHY HAS APS MADE AN ADJUSTMENT FOR THE REPLACEMENT OF PALO VERDE UNIT 1 ("PV UNIT 1") STEAM GENERATORS?

A. Like other nuclear generating stations throughout the nation, heat and corrosion have caused damage to the tubes in the Palo Verde ("PV") steam generators. The PV owners, including APS, have determined it is both necessary and economically

desirable to replace PV steam generators and related equipment in each unit to prevent a decrease in the unit's output and to maintain its reliability. The Unit 2 steam generators and related equipment were replaced in 2003, as addressed in Decision No. 67744. The Unit 1 steam generators and related equipment were replaced in 2005 and are included in this rate case. Unit 3 steam generators and related equipment are expected to be replaced in 2007, and recovery of the related costs will be requested in a subsequent rate proceeding.

Q. WHAT RELATED COMPONENTS WERE REPLACED DURING THE PROJECT FOR PV UNIT 1?

A. In addition to the two PV Unit 1 Steam Generators, three low-pressure turbine rotors, core protection calculators and pressurized heaters were replaced, which improves the future reliability and efficiency of PV Unit 1, as well as increases its output by approximately 22 megawatts. The 22 megawatt improvement was included in the simulation used to determine the Company's proposed fuel and purchased power expense and off-system margin, as sponsored by Mr. Ewen. Therefore, the PV Unit 1 Steam Generators rate base pro forma adjustment reflects the "matching principle," as well as fairness principles, which dictate that the investment required to generate the additional 22 megawatts, which are included in the fuel simulation, should also be included in rate base.

Q. WHEN WAS THE PV UNIT 1 STEAM GENERATORS REPLACEMENT PROJECT COMPLETED?

A. The PV Unit 1 Steam Generators replacement project was completed in December 2005, a full year before new rates from this case are likely to be in effect.

Q. WHAT IS THE BASIS FOR DETERMINING THE PV UNIT 1 STEAM GENERATORS RATE BASE ADJUSTMENT?

A. The $82,896,000 increase in rate base was calculated using the new Steam

Generators' estimated cost, as of December 31, 2005, when the Steam Generators were placed in service. *See* Attachment LLR-1-4.

Q. PLEASE EXPLAIN THE CORRESPONDING OPERATING INCOME ADJUSTMENT FOR THE PV UNIT 1 STEAM GENERATORS REPLACEMENT PROJECT.

A. Depreciation expense needs to be adjusted to include one full year of depreciation on the new PV Unit 1 Steam Generators and exclude the actual Test Year depreciation expense on the old PV Unit 1 Steam Generators. Because the fuel and purchased power operating income pro forma already reflects the impact of the PV Unit 1 Steam Generators replacement, there are no other test period results affected by this adjustment. This adjustment increases expenses for the Test Year by $2,047,000. *See* Attachment LLR-2-3.

D. BARK BEETLE REMEDIATION

Q. WHY WERE PRO FORMA ADJUSTMENTS FOR BARK BEETLE REMEDIATION NECESSARY?

A. Decision No. 67744 allows for the deferral of bark beetle remediation costs over and above the normal vegetation control expense. This "bucket of costs" can then be deferred, amortized and included in rates. A rate base pro forma is necessary to add the deferred bark beetle remediation costs to rate base. A corresponding operating income pro forma adjustment removes the actual bark beetle remediation costs from the Test Year and includes an annual amortization of the deferred costs.

Q. PLEASE EXPLAIN THE RATE BASE PRO FORMA ADJUSTMENT FOR BARK BEETLE REMEDIATION COSTS.

A. APS began deferring these dollars in 2005 and has estimated a total deferral of distribution-related bark beetle remediation costs of $11,288,000 by January 1, 2007, when rates are expected to be in place to recover these costs. This pro forma

adds $6,115,000 to rate base. *See* Attachment LLR-1-5. Mr. Stephen Bishoff discusses bark beetle remediation activities related to these costs in his testimony.

Q. PLEASE EXPLAIN THE CORRESPONDING OPERATING INCOME ADJUSTMENT FOR BARK BEETLE REMEDIATION.

A. As stated above, the Company expects to spend approximately $11,288,000 on distribution-related bark beetle remediation from January 1, 2005, to January 1, 2007, when it is anticipated that rates from this filing will be in place to recover these costs. APS is proposing a three-year amortization of these expenses, which is $3,763,000 in annual amortization expense. The $1,438,000 pro forma adjustment increases Test Year expenses and represents the difference between the proposed $3,763,000 annual amortization and the $2,325,000 actual expense included in the Test Year. *See* Attachment LLR-2-4.

Q. WHAT IS THE ANTICIPATED ONGOING BARK BEETLE REMEDIATION EXPENSE?

A. It is unknown whether the bark beetle remediation efforts will be completed by December 31, 2006, or if the actual costs will exceed the estimated costs as of that date. If the actual amounts exceed the estimated amounts included in this filing, and/or extend beyond 2006, such amounts will be deferred for recovery in a subsequent rate case.

IV. TOTAL RATE BASE ADJUSTMENTS

Q. PLEASE SUMMARIZE THE ADJUSTED TEST YEAR ORIGINAL RATE BASE PROPOSED BY APS.

A. At September 30, 2005, APS is proposing a total Company OCRB adjustment of $71,987,000 to increase the OCRB to $5,327,833,000. The jurisdictional allocation of the OCRB is $4,466,697,000, which is sponsored by Mr. David Rumolo. These adjustments are summarized in SFR Schedule B-2.

V. ADDITIONAL PRO FORMA ADJUSTMENTS TO OPERATING INCOME

A. PWEC UNITS

Q. WHY WERE PRO FORMA ADJUSTMENTS NECESSARY FOR THE PWEC UNITS?

A. The Commission authorized the transfer of the PWEC Units to APS in Decision No. 67744, and the Federal Energy Regulatory Commission ("FERC") approved the transfer on June 15, 2005. The PWEC Units then transferred to APS on July 29, 2005. Because the PWEC Units transferred to APS during the Test Year, the PWEC units are already included in the Test Year rate base; however, an operating income pro forma adjustment is necessary to annualize the PWEC Units operating expenses.

Q. WHAT IS THE OPERATING INCOME PRO FORMA ADJUSTMENT FOR THE PWEC UNITS?

A. The pro forma adjustment to operating income is for $53,644,000, which annualizes the revenue and operating expenses for the PWEC Units. *See* Attachment LLR-2-5.

Q. PLEASE EXPLAIN THE REDUCTION IN THE "OPERATING REVENUE LESS FUEL AND PURCHASE POWER EXPENSES" COMPONENT OF THE OPERATING INCOME PRO FORMA ADJUSTMENT FOR THE PWEC UNITS.

A. As discussed in Mr. Peter Ewen's testimony, the reduction of $1,125,000 is associated with auxiliary power purchased by PWEC from APS that is no longer applicable because the PWEC Units are now owned by APS.

Q. HOW WAS THE ROUTINE OPERATIONS AND MAINTENANCE EXPENSE COMPONENT OF THE OPERATING INCOME PRO FORMA ADJUSTMENT FOR THE PWEC UNITS CALCULATED?

A. Annualized routine operations and maintenance expense of $26,204,000 reflects the actual 2004 expenditures for the PWEC Units, adjusted for the expected

increase in average projected operating megawatt hours for 2006 through 2011. The $22,363,000 pro forma adjustment reflects the $26,204,000 annualized operations and maintenance expense reduced by $3,841,000, which represents two months of actual costs in the Test Year.

Q. IS THERE AN OVERHAUL MAINTENANCE EXPENSE COMPONENT OF THE OPERATING INCOME PRO FORMA ADJUSTMENT FOR THE PWEC UNITS?

A. Because the PWEC Units have recently been placed in-service, the Company has no historical cost basis for calculating overhaul costs. As discussed in Mr. Ewen's testimony, the normalized overhaul maintenance expense of $10,000,000 was estimated using a projected 12-year average, restated in 2004 dollars. The $9,741,000 pro forma adjustment reflects the $10,000,000 normalized cost reduced by $259,000, which represents two months of actual costs in the Test Year.

Q. PLEASE EXPLAIN THE ADMINISTRATIVE AND GENERAL ("A&G") EXPENSE COMPONENT OF THE OPERATING INCOME PRO FORMA ADJUSTMENT FOR THE PWEC UNITS.

A. The operating income pro forma for PWEC A&G expenses represents the portion of 2004 actual A&G expenses charged to the PWEC that will now be charged to APS in compliance with the Company's Affiliate Accounting policies. Thus, the ongoing A&G costs associated with the PWEC Units transferred to APS when the assets transferred. The $20,415,000 pro forma adjustment thus reflects ten months of A&G expense based on historical PWEC actual costs that were not included in the Test Year.

Q. IS THERE A DEPRECIATION AND AMORTIZATION EXPENSE COMPONENT OF THE OPERATING INCOME PRO FORMA ADJUSTMENT FOR THE PWEC UNITS?

A. Yes. The annualized depreciation and amortization expense and related pro forma

adjustment for the PWEC Units is included in the APS Depreciation and Amortization pro forma, which I discuss later in my testimony. *See* Attachments LLR-2-9 and LLR-2-10.

Q. IS THERE A PROPERTY TAX COMPONENT OF THE OPERATING INCOME PRO FORMA ADJUSTMENT FOR THE PWEC UNITS?

A. Yes, the annualized property tax expense and related pro forma adjustment is included in the APS Property Taxes pro forma, which I discuss later in my testimony. *See* Attachments LLR-2-12 and LLR-2-13.

B. SUNDANCE UNITS

Q. ARE THE SUNDANCE UNITS INCLUDED IN THIS FILING?

A. Yes. In January 2005, the Commission authorized APS to purchase the Sundance Units (Decision No. 67504). They were subsequently acquired on May 13, 2005 for $189,500,000 and are included in the rate base. SFR Schedule C-2 includes a pro forma adjustment to operating income, which is necessary to annualize the Test Year expense.

Q. PLEASE EXPLAIN THE CORRESPONDING OPERATING INCOME PRO FORMA ADJUSTMENT FOR THE SUNDANCE UNITS.

A. As shown in SFR Schedule C-2, the operating income pro forma adjustment of $4,860,000 includes non-fuel operations and maintenance expenses of the Sundance Units. *See* Attachment LLR-2-6.

Q. HOW WAS THE ROUTINE OPERATIONS AND MAINTENANCE ("O&M") COMPONENT OF THE OPERATING INCOME PRO FORMA ADJUSTMENT FOR THE SUNDANCE UNITS DETERMINED?

A. The annualized O&M expense of $6,410,000 includes $3,660,000, which reflects one full year of routine O&M expense and $2,750,000 of overhaul maintenance costs. The routine O&M expense was estimated based on the projected information

provided by PP&L Sundance Energy, LLC, as adjusted for the expected level of Company operation, as discussed in Mr. Ewen's testimony. The $4,860,000 pro forma adjustment reflects the difference between the $6,410,000 annualized costs and the Test Year actual costs of $1,550,000, which is about five months of actual costs.

Q. IS THERE A DEPRECIATION AND AMORTIZATION EXPENSE COMPONENT OF THE OPERATING INCOME PRO FORMA ADJUSTMENT FOR THE SUNDANCE UNITS DETERMINED?

A. Yes. The annualized depreciation and amortization expense and related operating income pro forma adjustment are included in the APS Depreciation and Amortization pro forma, which I discuss later in my testimony. *See* Attachments LLR-2- 9 and LLR-2-10.

Q. IS THERE ALSO A PROPERTY TAX COMPONENT OF THE OPERATING INCOME PRO FORMA ADJUSTMENT FOR THE SUNDANCE UNITS?

A. Yes. These amounts are included in the APS Property Taxes pro forma, which I discuss later in my testimony. *See* Attachments LLR-2-12 and LLR-2-13.

Q. DID THE COMPANY DEFER ANY COSTS RELATED TO THE SUNDANCE UNITS AS AUTHORIZED IN DECISION NO. 67504?

A. No. APS did not defer costs under the accounting order authorized in Decision No. 67504. This Decision allowed for the deferral of cost, net of savings, of owning, operating and maintaining the Sundance Units that were not recovered in the unbundled generation rates. The Sundance Units did not meet this threshold, as defined in the Commission's Decision.

C. NUCLEAR PLANT DECOMMISSIONING

Q. PLEASE EXPLAIN THE NUCLEAR DECOMMISSIONING EXPENSE.

A. Like all nuclear power plants, Palo Verde eventually will need to be decommissioned, an expensive and time consuming process. Regulatory agencies throughout the country, including this Commission, have required that the cost of the eventual decommissioning be recovered from utility customers during the operating life of the facility.

Q. WHAT IS MEANT BY A "QUALIFIED" DECOMMISSIONING FUND?

A. A qualified decommissioning fund is a segregated reserve fund dedicated exclusively to the payment of nuclear decommissioning costs and management costs and tax liability of the fund. Beneficial owners of the qualified decommissioning trust are allowed a deduction for cash payments to these funds. There is a preferential tax rate (of 20%) on realized gains associated with the assets held by the qualified decommissioning fund. Currently, the amounts collected from customers that relate to decommissioning of Palo Verde are being deposited into a "qualified" decommissioning fund. The Nuclear Regulatory Commission and most state regulators, including this Commission, prefer the external funding into qualified decommissioning funds for two reasons: (1) the increased security of the funding for its intended purpose; and (2) the income tax benefits afforded qualified decommissioning funds. The latter translates into lower annual decommissioning expense for our customers.

Q. PLEASE EXPLAIN THE NEED FOR A PRO FORMA ADJUSTMENT FOR THE NUCLEAR DECOMMISSIONING EXPENSE.

A. In Decision No. 67744, the Commission approved an annual decommissioning funding amount of $19,211,000, beginning April 1, 2005. *See* Attachment LLR-3.

A pro-forma adjustment of $3,883,000 is required to annualize the qualified funding levels to $19,211,000 as approved in Decision No. 67744. *See* Attachment LLR-2-7. The Company is requesting that the Commission's Decision in this docket specifically provide for approval of the $19,211,000 annual level of decommissioning funding. Attachment LLR-3 should be attached to any Commission Decision accepting these amounts.

D. FOUR CORNERS COAL RECLAMATION

Q. WHAT IS COAL RECLAMATION?

A. Coal reclamation is the process of returning the site of a coal mine to its original state. Coal reclamation is regulated by the Office of Surface Mining ("OSM"), an agency within the U.S. Department of Interior. The OSM has established standards and procedures for approving permits and inspecting active coal mining and reclamation operations. OSM requires the mine be brought back to its "Approximate Original Contour" ("AOC").

Q. WHY DOES APS HAVE TO PAY FOR COAL RECLAMATION?

A. APS is under contract with BHP Billiton until June 30, 2016, to receive coal for the Four Corners Power Plant. Pursuant to this contract, APS must pay for its share of final reclamation costs as a component of the price of coal.

Q. WHY IS THERE A NEED FOR A COAL RECLAMATION PRO FORMA ADJUSTMENT?

A. The estimate for final reclamation costs is generally revised every five years. The total costs are based on a study performed by Marston as of September 2004. The study reflects an onsite visit to the mine and a review of the AOC. The estimate is developed in two parts: ongoing reclamation while the mine is in operation and final reclamation at the end of the life cycle of the mining pit. The Company has

reduced the 2004 Marston study overhead costs to be more consistent with the OSM guidelines regarding overhead costs related to reclamation activities and has added royalties and revenue taxes to the study costs. A pro forma adjustment of $1,305,000 is included in SFR Schedule C-2 to reflect the annual expense based upon the 2004 Marston study. *See* Attachment LLR-2-8.

Q. HAS THE COMMISSION PREVIOUSLY AUTHORIZED THE INCLUSION OF COAL RECLAMATION COSTS IN REGULATED RATES?

A. Yes, in Decision No. 59601, the Commission approved the recovery of previously deferred coal reclamation costs. The Company is requesting a similar recovery in this case for the increase in coal reclamation cost estimates.

Q. WHY IS COAL RECLAMATION EXCLUDED FROM THE FUEL AND PURCHASE POWER PRO FORMA?

A. Coal reclamation is excluded from the Fuel and Purchase Power pro forma in order to exclude those costs that are not related to the current fuel burn from the Power Supply Adjustor calculation.

E. DEPRECIATION AND AMORTIZATION

Q. WHAT ADJUSTMENTS HAS THE COMPANY MADE TO DEPRECIATION AND AMORTIZATION EXPENSE?

A. Consistent with Decision No. 67744, as of April 1, 2005, APS implemented the depreciation rates ordered by the Commission. For this filing, Dr. Ronald White performed depreciation studies as of December 31, 2004, which included the APS assets and the PWEC Units. Dr. White's technical update of the depreciation rates that were authorized in Decision No. 67744 generally reflects the passage of time from December 31, 2002 through December 31, 2004. Please refer to Dr. White's testimony for further discussion of this point.

Based upon results of the technical update to the depreciation study, depreciation and amortization expense increases from $321,526,000 in the Test Year to $344,581,000. This pro forma adjustment increases annual expense by $23,055,000. *See* Attachments LLR-2-9 and LLR-2-10.

Q. WERE THE PWEC UNITS INCLUDED IN THE DEPRECIATION STUDIES PREPARED BY DR. WHITE?

A. Yes. The annualized depreciation expense was calculated based on the original cost of the PWEC Units at September 30, 2005, as reduced by the regulatory disallowance recorded under GAAP, and extended plant lives that were required by Decision No. 67744.

Q. WERE THE SUNDANCE UNITS INCLUDED IN THE DEPRECIATION STUDIES PREPARED BY DR. WHITE?

A. No. Since the Sundance Units were acquired after December 31, 2004 (the date of Dr. White's studies), these units were not included in the APS study. This annualized depreciation expense is based on the annual depreciation rates authorized in Decision No. 67744 for Saguaro Unit 3 combustion turbine generators, which are the APS units most nearly similar to the Sundance Units.

Q. DO THE DEPRECIATION RATES PROVIDE FOR A NET SALVAGE ALLOWANCE?

A. Yes. Consistent with the Commission's rules and depreciation rates approved in Decision No. 67744, APS provides for a net salvage allowance in the depreciation rates. As such, the Statement of Financial Accounting Standards 143: Asset Retirement Obligations has not been implemented for ratemaking purposes, which was also provided for in Decision No. 67744.

Q. PLEASE EXPLAIN THE OPERATING REVENUE INCLUDED ON THE DEPRECIATION AND AMORTIZATION PRO FORMA.

A. The depreciation study prepared by Dr. White does not include an allocation for Company depreciation to APS Energy Services ("Energy Services") or to Pinnacle West Capital Corporation ("PWCC") Marketing and Trading ("PWCC M&T"), which is in accordance with the Commission's Code of Conduct and the Company's Affiliate Accounting policies. Therefore, the pro forma includes an operating revenue adjustment of $480,000, which reflects the amounts received from other affiliates for their allocation of shared services depreciation expense. *See* Attachment LLR-2-9.

Q. PLEASE EXPLAIN THE AMORTIZATION OF GAIN INCLUDED ON THE DEPRECIATION AND AMORTIZATION PRO FORMA.

A. The $77,000 shown on Attachment LLR-2-9 is the operating income pro forma adjustment necessary to annualize the $155,000 gain amortization, which represents the annual amortization expense of the total $775,000 gain associated with the previously authorized sale of the Glen Canyon 230 kV line to PacifiCorp, pursuant to Decision No. 64306. A five year amortization of the gain is consistent with the treatment of this item in the Company's last rate case.

Q. IS THE COMPANY PROPOSING ANY CHANGES TO ITS EXISTING AMORTIZATION RATES?

A. No, APS is not requesting any change to the amortization rates authorized in Decision No. 67744. These rates are set out on Attachment LLR-2-11.

Q. IS THE COMPANY PROPOSING ANY NEW AMORTIZATION RATES?

A. Yes, the Company is requesting approval for two new rates to provide for the amortization of leased vehicles that are purchased by the Company at the end of the lease term. The Company is requesting a 50% amortization rate for vehicles with a

Gross Vehicle Weight ("GVW") under 26,000 pounds, and a 20% amortization rate for vehicles with a GVW greater than 26,000 pounds. The rates reflect what we believe will be the estimated lives for such vehicles. *See* Attachment LLR-2-11.

F. PROPERTY TAXES

Q. HAS APS PROPOSED AN ADJUSTMENT TO THE TEST YEAR AD VALOREM (PROPERTY) TAXES?

A. Yes, the pro forma adjustment is an increase in operating expense of $16,867,000. This adjustment includes amounts to annualize the PWEC Units property taxes, one full year of property taxes for the Sundance Units, estimated taxes for the full Maricopa Community College Bond, and an automatic 2007 increase in property taxes that will result when the PWEC Units have passed the "phase-in" period provided by A.R.S. § 42-14156, after which, the units will have to apply the Arizona Department of Revenue's ("ADOR") scheduled depreciated value in the same manner as all of APS' existing generation units. *See* Attachments LLR-2-12 and LLR-2-13.

Q. HOW WERE PROPERTY TAXES CALCULATED?

A. The property taxes reflect actual plant values received from the ADOR as of December 31, 2004. The 2005 tax year APS composite tax rate, which includes the PWEC Units, was calculated based on tax rates provided by the County Treasurer in each of the counties where APS has property. In addition to the APS composite tax rate, the actual 2005 tax rate for the Sundance Units was used. Finally, this pro forma adjustment takes into account the reduction in assessment ratio provided by House Bill 2779, which was passed during the 2005 legislative session.

G. PAYROLL

Q. DID APS ANNUALIZE TEST YEAR PAYROLL?

A. Yes. Attachment LLR-2-14 shows an increase to Test Year expenses of $9,239,000. This pro forma adjustment annualizes the Test Year payroll, benefits, and payroll tax expense to December 2005 employee levels, and includes December 2005 wage levels for performance review employees, April 2006 wage levels for union employees and no cash incentives for officers. This methodology for performance review employees and union employees is consistent with payroll annualization adjustments authorized by the Commission in prior APS cases. Officer salaries are included at 2004 levels. The net effect of these adjustments is an increase to Test Year operating expenses as a result of higher costs associated with a rising average salary and increased employee levels.

Q. DOES THIS TOTAL PAYROLL ADJUSTMENT ONLY AFFECT O&M?

A. Yes, this adjustment excludes those costs that are capitalized. This O&M adjustment was estimated by calculating the percentage of APS O&M payroll to total payroll during the Test Year. The resulting O&M payroll and payroll taxes were allocated to fuel, operations (excluding fuel), and maintenance based on the Test Year payroll amounts booked to each of these activities.

H. UNDERFUNDED PENSION LIABILITY

Q. PLEASE EXPLAIN THE PRO FORMA ADJUSTMENT FOR ACCELERATED RECOVERY OF THE UNDERFUNDED PENSION LIABILITY.

A. This adjustment is intended to accelerate the recovery of our underfunded pension liability over a five-year period beginning in 2007. This would be accomplished by increasing pension expense and establishing a regulatory liability. Amounts collected under this adjustment would be contributed to the pension plan. Since the

recovery is accelerated, the Company is proposing a ten year amortization of this regulatory liability, beginning in 2012. This would have the impact of reducing future pension expense during the amortization period.

Q. HOW WAS THE PRO FORMA ADJUSTMENT FOR ACCELERATED RECOVERY OF THE UNDERFUNDED PENSION LIABILITY DETERMINED?

A. PWCC sponsors a pension plan for all its employees, including employees of APS. As of December 31, 2004, the date of the most recent actuarial study, the projected benefit obligation ("PBO") of the pension plan was approximately $1,371 million. The fair value of the plan's assets was approximately $982 million. The difference of approximately $389 million represents the underfunded position of the pension plan. APS' share of the plan represents approximately 92% or approximately $358 million (Pinnacle West and the other subsidiaries make up the other 8%). At December 31, 2004, the portion attributable to APS ratepayers represents approximately 61% or $218 million of the underfunded pension liability. The remaining 39% relates to APS employees that support jointly owned facilities. Because we are proposing accelerated recovery over five years, the annual increase to pension expense proposed in this adjustment is approximately $44 million. *See* Attachment LLR-2-15. Again, since this is an accelerated recovery, we propose amortizing the regulatory liability and reducing pension expense over 10 years (beginning in 2012) in the amount of approximately $22 million.

I. ADVERTISING

Q. WHAT IS THE PURPOSE OF THE ADVERTISING PRO FORMA?

A. This pro forma adjustment reduces Test Year expenditures by $6,140,000 for all those advertising expenses that are related to branding or promotion. This approach is consistent with Staff's recommendation in the Company's prior rate case. *See*

Attachment LLR-2-16.

J. MISCELLANEOUS ADJUSTMENTS

Q. PLEASE EXPLAIN THE MISCELLANEOUS ADJUSTMENTS.

A. This pro forma adjustment eliminates non-recurring or out of period expenses or credits from the Test Year. The net increase to operating expense for these adjustments is $ 3,876,000. Individually, they are as follows:

Financial Data Warehouse Costs	$ (892,000)
Four Corners Severance Reserve True-Up	$ 1,748,000
FERC Audit Reserve	$ 2,000,000
APS Corporate Offices Rent Expense	$ 3,237,000
Bill Estimation Refund	$(2,217,000)

See Attachment LLR-2-17.

Q. PLEASE EXPLAIN THE MISCELLANEOUS PRO FORMA ADJUSTMENTS.

A. **Financial Data Warehouse:** APS terminated this project because it was determined it would not meet the Company's business needs. The adjustment removes the write-off of the prior year costs.

Four Corners Severance Reserve True-Up: A prior period reserve, which was associated with Four Corners' participant disputes, was settled in 2004.

FERC Audit Reserve: This adjustment eliminates an audit reserve reversal for a transmission audit issue that was successfully resolved without a finding against the Company.

APS Corporate Offices Rent Expense: This adjustment reflects the portion of the CHQ Rent true-up for calendar year 2004 that is outside the Test Year period.

Bill Estimation Refund: Adjustment to reverse the revenue impact of the Bill Estimation accrual, pursuant to Decision No. 68112.

VI. ALLOWANCE FOR WORKING CAPITAL

Q. WHAT IS THE ALLOWANCE FOR WORKING CAPITAL SHOWN ON SFR SCHEDULE B-1?

A. The allowance for working capital shown on SFR Schedule B-1 is $168,146,000. *See* Attachment LLR-4.

Q. PLEASE EXPLAIN SFR SCHEDULE B-5.

A. This SFR Schedule outlines the allowance for working capital to be included in the Company's rate base. Working capital represents the amount of cash, materials and supplies, fuel inventories, and prepayments needed to meet current expenses and contingencies that might ordinarily develop. Working capital is an investment just like other capital requirements, such as power plants and transmission and distribution infrastructure; thus it is part of APS' rate base. I am testifying to all of the data in SFR Schedule B-5, with the exception of the Working Capital calculation (line 1 of page 1), which Mr. Fred Balluff will address. My testimony presents the calculation of the allowance for working capital, which includes a cash working capital component determined using the lead/lag study methodology required by Decision No. 55931.

Q. WHAT IS THE ALLOWANCE FOR WORKING CAPITAL?

A. Based on APS Test Year balances, the calculation of a reasonable allowance for working capital results in an addition to rate base of $168,146,000. This includes $191,768,000 of materials, supplies and fuel inventories, and $5,517,000 of prepaid amounts. This amount is reduced by the net cash working capital of $29,139,000 that is provided by operations.

Q. HOW WAS THE CASH WORKING CAPITAL CALCULATED?

A. The net cash working capital is calculated by performing a "lead/lag" study. See Mr. Balluff's testimony for further discussion of this study and its results. The lead lag study days, which were calculated from the study of the calendar year 2004, were applied to the Test Year income statement.

VII. REPRODUCTION COST NEW STUDY

Q. WHAT IS MEANT BY THE TERMS "RCN" AND "RCND" AS USED IN YOUR TESTIMONY?

A. A.A.C. R14-2-103(A) (3) (n) defines "Reconstructed Cost New Less Depreciation" or "RCND" as:

> An amount consisting of the depreciated reconstruction cost new of property (exclusive of contributions and/or advances in aid of construction) at the end of the test year, used and useful, plus a proper allowance for working capital and including all applicable pro forma adjustments. Contributions and advances in aid of construction, if recorded in the accounts of the public service corporation, shall be increased to a reconstruction new basis.

Thus, Reproduction Cost New ("RCN") refers to the estimated costs that would be incurred if the utility properties of APS that were devoted to public service as of September 30, 2005 were to be reproduced or reconstructed as new properties using current cost levels. RCND is a net amount that results after deducting accumulated depreciation and amortization (both of which are also restated in current dollars) from the RCN amount.

Q. WHAT IS SHOWN ON SFR SCHEDULE B-4?

A. SFR Schedule B-4 presents the RCN and RCND amounts of APS' utility properties. These amounts were determined using an RCN Study performed by the Company. *See* Attachment LLR-5-2.

Q. WOULD YOU BRIEFLY DESCRIBE THE PROCEDURES YOU FOLLOWED IN CONDUCTING THE RCN STUDY?

A. Consistent with A.A.C. R14-2-103, the RCN study that supports SFR Schedule B-4 was conducted by taking depreciable plant at original cost by FERC account,[1] by vintage year, and adding back Contributions in Aid of Construction ("CIAC") at original cost. Electric and gas utilities are required by the Uniform System of Accounts to subtract CIAC from original cost plant-in-service, rather than record it as a separate liability account, as is done by water and sewer utilities. This amount was multiplied by the Handy-Whitman Index factor, based on vintage year, to arrive at RCN before CIAC adjustment. CIAC was also multiplied by the appropriate Handy-Whitman Index. The adjusted CIAC (which is a negative number) was added to the RCN determined before the CIAC adjustment, to arrive at the final RCN number shown in column (a) of SFR Schedule B-4.

Q. WOULD YOU EXPLAIN IN MORE DETAIL THE CONSIDERATION THAT YOU GAVE TO CIAC IN DETERMINING RCN?

A. Yes. CIAC is generally cash paid to APS by third parties for construction of facilities that will be owned by APS. Sometimes, it may also include property donated to the Company to provide service. Line extensions are the most common source of CIAC. As with original cost plant, CIAC is indexed using the Handy-

[1] The Commission has adopted the FERC Uniform System of Accounts ("USOA") in A.A.C. R14-2-212(G).

Whitman Index, as required by A.A.C R14-2-103, to arrive at RCN. A summary of CIAC is provided in column (b) of Attachment LLR-5-1.

Q. WHAT IS THE HANDY-WHITMAN INDEX?

A. The Handy-Whitman Index is recognized by the utility industry as an equivalent to a Consumers Price Index for electric utility property. It compares the current cost of constructing electric utility property with past construction costs, and presents the comparison in the form of a cost index. For example, assume that transmission towers and fixtures were purchased by APS in 1985 at an original cost of $400,000. To determine RCN, the original cost would be multiplied by the appropriate Handy-Whitman index factor for towers and fixtures. In this case, the index factor is determined by dividing the current year index of 388 for 2004 by the vintage year index of 245 for 1985, or 388/245, which equals 1.58. The index factor of 1.58 multiplied by the original cost of $400,000 equals the current reproduction cost or RCN of $632,000.

Q. WERE ALL ASSETS INDEXED AS YOU JUST DESCRIBED?

A. No, land and land rights, intangibles, capitalized leases, and leasehold improvements are included in RCN at their original cost levels only, consistent with previous treatment of these assets by the Commission.

Q. PLEASE DEFINE INTANGIBLES AND DESCRIBE THE AMOUNT OF INTANGIBLES THAT ARE INCLUDED IN RCN AS SHOWN ON SFR SCHEDULE B-4?

A. Intangibles are assets that provide future economic benefit but have no physical substance. Examples include patents and computer software. APS' intangible plant is included in column (a), line 4 of SFR Schedule B-4 at its original cost of $285,337,000 on September 30, 2005.

Q. BASED ON YOUR STUDY, WHAT IS THE RCN OF APS' UTILITY PROPERTY DEVOTED TO SERVICE TO THE PUBLIC AS OF THE END OF THE TEST YEAR?

A. Total RCN for APS' utility property is $17,767,330,000 including the $285,337,000 of intangible plant discussed above. This total amount is shown in column (c) of Attachment LLR-5-1, and in column (a) of SFR Schedule B-4.

Q. WOULD YOU EXPLAIN HOW RCND WAS CALCULATED AS SHOWN ON SFR SCHEDULE B-4?

A. Yes. RCN by FERC account (or Plant account) number is shown in column (a) of SFR Schedule B-4. To arrive at RCND, RCN is multiplied by a "condition percent," also known as a net book value percent, which is shown in column (b). RCND is shown in column (c). The condition percent used to convert RCN to RCND is calculated by first taking the original cost less accumulated depreciation (in other words, the net book value) for all depreciable plant by FERC account. This is divided by the original cost for each FERC account to arrive at condition percent. Thus, the condition percent is the percentage that results when one compares original cost less accumulated depreciation and the original cost of plant in service.

For example, using the same hypothetical that I used earlier, assume again that transmission towers and fixtures have an original cost of $400,000, and assume accumulated depreciation of $250,000. The original cost less accumulated depreciation would be $150,000, which is $400,000 minus $250,000. Also, assume the towers and fixtures were purchased in 1985 and have a RCN value of $632,000. Using these assumptions, the condition percent is calculated by dividing original cost less accumulated depreciation by original cost, or $150,000/$400,000,

resulting in 37.5%. Multiplying RCN by the condition percent yields RCND. In this hypothetical, $632,000 x 37.5% = $237,000.

Q. WOULD YOU PLEASE EXPLAIN SFR SCHEDULE B-4A?

A. SFR Schedule B-4A shows the computation of adjusted jurisdictional RCND rate base as of September 30, 2005. Column (a) presents data for Total RCND rate base. Mr. Rumolo has provided the jurisdictional allocations of the Electric RCND rate base between "ACC" and "Other," which is presented in columns (b) and (c) respectively.

Q. HOW DID YOU ARRIVE AT THE AMOUNTS SHOWN ON LINES 9 THROUGH 23 OF SFR SCHEDULE B-4A?

A. The amounts shown on lines 9 through 23 of SFR Schedule B-4A for other rate base elements were obtained from SFR Schedule B-1, column (a), which is sponsored by Mr. Froggatt. As in past presentations and consistent with past Commission practice, the RCND of these rate base elements are stated at their original cost levels.

Q. WOULD YOU PLEASE EXPLAIN LINES 25 AND 26 OF SFR SCHEDULE B-4A?

A. The amounts shown on line 25 represent the RCND rate base on September 30, 2005. However, the end of test year data needs to be adjusted to more closely reflect the value of certain items of property when the proposed rates become effective. Therefore, it was necessary to reflect the pro forma rate base adjustments in the RCND rate base. The RCND amounts of the pro forma adjustments are shown in detail on SFR Schedule B-3; the total is shown on line 26 of SFR Schedule B-4A.

Q. WHAT IS THE TOTAL ADJUSTED RCND RATE BASE?

A. The total Company RCND rate base, as adjusted, is approximately $9.2 billion. This is shown in SFR Schedule B-4A, column (a), line 28.

Q. PLEASE EXPLAIN HOW YOU COMPUTED COLUMNS (B) THROUGH (E) ON SFR SCHEDULE B-4A TO REFLECT THE JURISDICTIONAL ALLOCATION?

A. The jurisdictional allocation of the RCND rate base elements between state retail service (the Commission) and other jurisdictions (primarily FERC) was made by applying the original cost jurisdiction relationships derived from SFR Schedule G-7, which is sponsored by Mr. Rumolo. The relationships of the allocations shown on line 2, excluding the Southern California Edison ("SCE") 500 kV columns, were used to allocate between jurisdictions on line 8. Total RCN excludes the SCE 500 kV amounts. The data shown in column (d) for the SCE 500 kV line represents known or directly computed information. The jurisdictional allocations of lines 9 through 23, because they are stated at original cost, were obtained directly from SFR Schedule G-7.

Q. WOULD YOU PLEASE SUMMARIZE THE JURISDICTIONAL ALLOCATION OF THE RCND RATE BASE AS OF DECEMBER 31, 2004 AFTER MAKING THE PRO FORMA ADJUSTMENTS?

A. The total Commission-jurisdictional RCND rate base after adjustments is approximately $7.8 billion (SFR Schedule B-4A, column (b), line 28). After pro forma adjustments, the Total All Other RCND rate base is approximately $1.4 billion (SFR Schedule B-4A, column (c)). The sum of columns (b) and (c) equals the Total RCND rate base shown in column (a).

VIII. DETAIL OF UTILITY PLANT

Q. PLEASE DISCUSS SFR SCHEDULE E-5.

A. SFR Schedule E-5 is the detailed statement of utility plant that makes up the Company's rate base, broken down by account number under the Uniform System of Accounts. The first page of SFR Schedule E-5 is a summary, which includes balances for gross plant in service, accumulated depreciation, nuclear fuel, work in progress, and plant held for future use. The remainder of the schedule presents supporting detail by account.

IX. CONSTRUCTION REQUIREMENTS

Q. PLEASE DISCUSS SFR SCHEDULE F-3.

A. SFR Schedule F-3 shows the projected annual construction requirements, by property classification, for 1 to 3 years subsequent to the Test Year. I am sponsoring the actual Test Year information; Mr. Brandt is sponsoring the rest of the information on SFR Schedule F-3.

X. COMMISSION ACTION REQUESTED

Q. PLEASE SUMMARIZE THE SPECIFIC COMMISSION ACTION THAT THE COMPANY IS REQUESTING REGARDING THE DECOMMISSIONING AND SPENT FUEL STORAGE EXPENSES DISCUSSED IN YOUR TESTIMONY.

A. The Company is requesting that the Commission's Decision in this docket specifically provide for approval of the annual level of decommissioning funding and Spent Fuel Storage costs, as set forth on Attachment LLR-3, as well as the amortization of the Spent Fuel Cost regulatory asset included in Attachment LLR-2-2. Attachment LLR-3 should be attached to any Commission Decision accepting these amounts.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

Appendix A
Statement of Qualifications
Laura L. Rockenberger

Laura L. Rockenberger is the Manager of Operations Accounting in the Shared Services Finance organization for Arizona Public Service Company ("APS"). In this position, Ms. Rockenberger has responsibility for Generation and Energy Delivery Operations & Maintenance and Fuel accounting; Asset Accounting; Accounting Services Administration, *including* payroll and accounts payable; and Accounting Systems. These accounting services are provided as needed to support the Pinnacle West Capital Corporation entities.

Ms. Rockenberger graduated cum laude from Miami University in 1982 with a Bachelor of Science Degree in Business with an emphasis in Accounting and is a member of Beta Gamma Sigma. Ms. Rockenberger also has a Bachelor of Arts with an emphasis in Music, graduating cum laude from the University of South Carolina, and is a member of Phi Beta Kappa. Ms. Rockenberger has been a Certified Public Accountant in Arizona since 1985 and is a member of the Arizona Society of Certified Public Accountants and the American Institute of Certified Public Accountants. Ms. Rockenberger has been elected to the Board of Directors for the Society of Depreciation Professionals effective January 1, 2006.

Ms. Rockenberger was employed in public accounting by Price Waterhouse from 1982 to 1984. She joined APS in 1985 as an Internal Auditor and held positions at the Palo Verde Nuclear Generating Station and Pinnacle West Capital Corporation. In 1987 Ms. Rockenberger joined SunCor Development Company ("SunCor"), a real estate subsidiary of Pinnacle West Capital Corporation. At SunCor, she held positions as the Director of Finance and Controller. In 1998 she joined APS as the Manager of Operations Accounting, her current position.

PWEC UNITS
REGULATORY AND GAAP DISALLOWANCE CALCULATION AT JULY 31, 2005
(000's)

	Total Company 12/31/2004	Total Company 7/31/2005	FERC Jurisdictional 7/31/2005	ACC Jurisdictional 7/31/2005	Regulatory Disallowance as a % of Plant	ACC Jurisdictional Regulatory Disallowance	ACC Jurisdictional 7/31/2005 after Regulatory Disallowance	GAAP 7/31/2005 Disallowance
Rate Base Calculation								
Redhawk 1	273,238	273,238	474	272,764	17.3426%	(47,304)	225,460	(47,304)
Redhawk 2	273,123	273,123	474	272,649	17.3426%	(47,284)	225,365	(47,284)
Redhawk Trans	49,000	49,000	22,883	26,117	17.3426%	(4,529)	21,588	(4,529)
WP 4	**79,760**	**79,760**	**138**	**79,622**	**17.3426%**	**(13,809)**	**65,813**	-
WP 5	309,464	309,464	537	308,927	17.3426%	(53,576)	255,351	(53,576)
Saguaro	36,645	36,645	64	36,581	17.3426%	(6,344)	30,237	(6,344)
Gross Plant	1,021,230	1,021,230	24,570	996,660		(172,846)	823,814	(159,037)
Redhawk 1	26,508	31,066	54	31,012	17.3426%	(5,378)	25,634	(5,378)
Redhawk 2	26,503	31,056	54	31,002	17.3426%	(5,377)	25,625	(5,377)
Redhawk Trans	3,915	4,416	2,062	2,354	17.3426%	(408)	1,946	(408)
WP 4	**10,462**	**11,493**	**20**	**11,473**	**17.3426%**	**(1,990)**	**9,483**	-
WP 5	17,795	23,063	40	23,023	17.3426%	(3,993)	19,030	(3,993)
Saguaro	3,236	3,837	7	3,830	17.3426%	(664)	3,166	(664)
Less Accum Depr	88,419	104,931	2,237	102,694		(17,810)	84,884	(15,820)
Redhawk 1	246,730	242,172	420	241,752	17.3426%	(41,926)	199,826	(41,926)
Redhawk 2	246,620	242,067	420	241,647	17.3426%	(41,907)	199,740	(41,907)
Redhawk Trans	45,085	44,584	20,821	23,763	17.3426%	(4,121)	19,642	(4,121)
WP 4	**69,298**	**68,267**	**118**	**68,149**	**17.3426%**	**(11,819)**	**56,330**	-
WP 5	291,669	286,401	497	285,904	17.3426%	(49,583)	236,321	(49,583)
Saguaro	33,409	32,808	57	32,751	17.3426%	(5,680)	27,071	(5,680)
Net Plant	932,811	916,299	22,333	893,966		(155,036)	738,930	(143,217)
Redhawk 1	8,775	9,702	17	9,685	17.3426%	(1,680)	8,005	
Redhawk 2	8,780	9,707	17	9,690	17.3426%	(1,680)	8,010	
Redhawk Trans	2,560	2,831	1,322	1,509	17.3426%	(262)	1,247	
WP 4	3,380	3,737	7	3,730	17.3426%	(647)	3,083	
WP 5	35,809	39,592	68	39,524	17.3426%	(6,854)	32,670	
Saguaro	5,347	5,912	10	5,902	17.3426%	(1,024)	4,878	
Less Accum Def Inc Taxes	64,651	71,482	1,442	70,040		(12,147)	57,893	-
Redhawk 1	237,955	232,470	403	232,067		(40,246)	191,821	
Redhawk 2	237,840	232,360	403	231,957		(40,227)	191,730	
Redhawk Trans	42,525	41,753	19,499	22,254		(3,859)	18,395	
WP 4	65,918	64,530	112	64,418		(11,172)	53,246	
WP 5	255,860	246,809	428	246,381		(42,729)	203,652	
Saguaro	28,062	26,896	47	26,849		(4,656)	22,193	
Rate Base	868,160	844,817	20,891	823,926		(142,889)	681,037	-

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Original Cost Rate Base as Shown on Schedule B-2
Total Company
(Thousands of Dollars)

PRO FORMA ADJUSTMENT: PWEC UNITS

Adjustment to reduce Test Year rate base for the regulatory disallowance for West Phoenix Unit 4 as required in Decision No. 67744.

Line No.	Description	Total Company Amount
1.	Gross Utility Plant in Service	$ (13,833)
2.	Less: Accumulated Depreciation and Amortization	$ (2,032)
3.	Net Utility Plant in Service	$ (11,801)
4.	Less: Total Deductions	$ (646)
5.	Total Additions	$ -
6.	Total Rate Base	$ (11,155)

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Original Cost Rate Base as Shown on Schedule B-2
Total Company
(Thousands of Dollars)

PRO FORMA ADJUSTMENT: SPENT FUEL STORAGE

Adjustment to Test Year rate base to include System Benefit related Spent Fuel Storage costs consistent with Decision No. 67744.

Line No.	Description	Amount
1.	Gross Utility Plant in Service	$ -
2.	Less: Accumulated Depreciation and Amortization	$ -
3.	Net Utility Plant in Service	$ -
4.	Less: Total Deductions	$ (3,761)
5.	Total Additions	$ (9,630)
6.	Total Rate Base	$ (5,869)

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Original Cost Rate Base as Shown on Schedule B-2
Total Company
(Thousands of Dollars)

PRO FORMA ADJUSTMENT: PALO VERDE UNIT 1 STEAM GENERATORS

Adjustment to Test Year rate base to include the replacement of the Palo Verde Unit 1 Steam Generators in 2005.

Line No.	Description	Amount
1.	Gross Utility Plant in Service	$ 88,813
2.	Less: Accumulated Depreciation and Amortization	$ 47
3.	Net Utility Plant in Service	$ 88,766
4.	Less: Total Deductions	$ 5,870
5.	Total Additions	$ -
6.	Total Rate Base	$ 82,896

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Original Cost Rate Base as Shown on Schedule B-2
Total Company
(Thousands of Dollars)

PRO FORMA ADJUSTMENT: BARK BEETLE REGULATORY ASSET

Adjustment to Test Year rate base to include the bark beetle remediation regulatory asset.

Line No.	Description	Amount
1.	Gross Utility Plant in Service	$ -
2.	Less: Accumulated Depreciation and Amortization	$ -
3.	Net Utility Plant in Service	$ -
4.	Less: Total Deductions	$ -
5.	Total Additions	$ 6,115
6.	Total Rate Base	$ 6,115

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2
Total Company
(Thousands of Dollars)

PRO FORMA ADJUSTMENT: **West Phoenix 4 Regulatory Disallowance**

Adjustment to Test Year operations to reflect depreciation of the regulatory disallowance of West Phoenix Unit 4 over the remaining life of the plant.

Line No.	Description	Amount
1.	**REVENUES:**	$ -
2.	Operating Revenue	-
3.	Fuel and Purchased Power Expense	$ -
4.	Operating Revenues less Fuel and Purchased Power Expenses	
5.	**EXPENSES:**	
6.	Other Operating Expense	-
7.	Operations Excluding Fuel Expense	-
8.	Maintenance	-
9.	Subtotal	(230)
10.	Depreciation and Amortization	-
11.	Amortization of Gain	-
12.	Administrative and General	-
13.	Other Taxes	(230)
14.	Total	$ 230
15.	**OPERATING INCOME (before income tax)**	(275)
16.	Interest Expense	$ 505
17.	**Taxable Income**	197
18.	Income Tax at 39.05%	$ 33
19.	**OPERATING INCOME AFTER TAX**	

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2
Total Company
(Thousands of Dollars)

PRO FORMA ADJUSTMENT: **SPENT FUEL STORAGE**

Adjustment to Test Year operations to amortize deferred Spent Fuel Storage expenses consistent with Decision No. 67744.

Line No.	Description	Amount
1.	**EXPENSES:**	$ 11,092
2.	Fuel Expenses	
3.	Other Operating Expenses	
4.	Operations Excluding Fuel Expenses	
5.	Maintenance	$ 11,092
6.	Total Pro Forma Adjustment to Expenses	**$ (11,092)**
7.	**OPERATING INCOME (before income tax)**	(144)
8.	Interest Expense	**$ (10,948)**
9.	**Taxable Income**	(4,275)
10.	Income Tax at 39.05%	**$ (6,817)**
11.	**OPERATING INCOME AFTER TAX**	

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2
Total Company
(Thousands of Dollars)

PRO FORMA ADJUSTMENT: **PALO VERDE UNIT 1 STEAM GENERATORS REPLACEMENT DEPRECIATION**

Adjustment to Test Year depreciation related to the replacement of the Palo Verde Unit 1 steam generators.

Line No.	Description	Amount
1.	**EXPENSES:**	
2.	Other Operating Expenses	$ 2,047
3.	Depreciation and Amortization	$ 2,047
4.	Total Pro Forma Adjustment to Expenses	$ **(2,047)**
5.	**OPERATING INCOME (before income tax)**	2,041
6.	Interest Expense	$ **(4,088)**
7.	**Taxable Income**	(1,596)
8.	Income Tax at 39.05%	$ **(451)**
9.	**OPERATING INCOME AFTER TAX**	

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2
Total Company
(Thousands of Dollars)

PRO FORMA ADJUSTMENT: **Bark Beetle**

Adjustment to Test Year operations to exclude expenses related to bark beetle remediation over and above normal 2002 operational expense as required by Decision No. 67744 and to amortize 2005 - 2006 estimated costs over a three year period.

Line No.	Description	Amount
1.	**EXPENSES:**	
2.	Other Operating Expenses	$ 1,438
3.	Operations Excluding Fuel Expenses	$ 1,438
4.	Total Pro Forma Adjustment to Expenses	**$ (1,438)**
5.	**OPERATING INCOME (before income tax)**	151
6.	Interest Expense	**$ (1,589)**
7.	**Taxable Income**	(621)
8.	Income Tax at 39.05%	**$ (817)**
9.	**OPERATING INCOME AFTER TAX**	

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2
Total Company
(Thousands of Dollars)

PRO FORMA ADJUSTMENT: **PWEC Units**

Adjustment to Test Year operations to annualize operating costs for the PWEC Units, which transferred to APS at 7/29/05, as authorized by Decision No. 67744. The PWEC Units include West Phoenix Combined Cycles No. 4 and No. 5, Redhawk Combined Cycles No.1 and No. 2, and Saguaro Combustion Turbine No. 3. Includes revenue adjustment related to plant auxiliary power.

Line No.	Description	Amount
1.	**REVENUES:**	$ (1,791)
2.	Operating Revenue	(666)
3.	Fuel and Purchased Power Expense	$ (1,125)
4.	Operating Revenues less Fuel and Purchased Power Expenses	
5.	**EXPENSES:**	
6.	Other Operating Expense	22,363
7.	Operations Excluding Fuel Expense	9,741
8.	Maintenance	32,104
9.	Subtotal	-
10.	Depreciation and Amortization	-
11.	Amortization of Gain	20,415
12.	Administrative and General	-
13.	Other Taxes	52,519
14.	Total	$ **(53,644)**
15.	**OPERATING INCOME (before income tax)**	-
16.	Interest Expense	$ **(53,644)**
17.	**Taxable Income**	(20,948)
18.	Income Tax at 39.05%	$ **(32,696)**
19.	**OPERATING INCOME AFTER TAX**	

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2
Total Company
(Thousands of Dollars)

PRO FORMA ADJUSTMENT: **SUNDANCE UNITS**

Adjustment to Test Year operations to include a projected year of O&M for the Sundance Units as authorized by Decision No. 67504.

Line No.	Description	Amount
1.	**REVENUES:**	$ -
2.	Operating Revenue	-
3.	Fuel and Purchased Power Expense	$ -
4.	Operating Revenues less Fuel and Purchased Power Expenses	
5.	**EXPENSES:**	
6.	Other Operating Expense	2,110
7.	Operations Excluding Fuel Expense	2,750
8.	Maintenance	4,860
9.	Subtotal	-
10.	Depreciation and Amortization	-
11.	Amortization of Gain	-
12.	Administrative and General	-
13.	Other Taxes	4,860
14.	Total	$ (4,860)
15.	**OPERATING INCOME (before income tax)**	-
16.	Interest Expense	$ (4,860)
17.	**Taxable Income**	(1,898)
18.	Income Tax at 39.05%	$ (2,962)
19.	**OPERATING INCOME AFTER TAX**	

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2
Total Company
(Thousands of Dollars)

PRO FORMA ADJUSTMENT: **NUCLEAR DECOMMISSIONING EXPENSE**

Adjustment to Test Year operations to increase contributions to the nuclear decommissioning trust funds to the amount authorized by Decision No. 67744.

Line No.	Description	Amount
1.	**EXPENSES:**	
2.	Other Operating Expenses	$ 3,883
3.	Depreciation and Amortization	$ 3,883
4.	Total Pro Forma Adjustment to Expenses	**$ (3,883)**
5.	**OPERATING INCOME (before income tax)**	(1,516)
6.	Income Tax at 39.05%	**$ (2,367)**
7.	**OPERATING INCOME AFTER TAX**	

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2
Total Company
(Thousands of Dollars)

PRO FORMA ADJUSTMENT: FOUR CORNERS COAL RECLAMATION

Adjustment to Test Year operations to reflect the annual final coal reclamation expense for the Four Corners Power Plant.

Line No.	Description	Amount
1.	**EXPENSES:**	
2.	Fuel Expenses	$ 1,305
3.	Other Operating Expenses	
4.	Operations Excluding Fuel Expenses	
5.	Maintenance	
6.	Total Pro Forma Adjustment to Expenses	$ 1,305
7.	**OPERATING INCOME (before income tax)**	**$ (1,305)**
8.	Interest Expense	
9.	**Taxable Income**	**$ (1,305)**
10.	Income Tax at 39.05%	(510)
11.	**OPERATING INCOME AFTER TAX**	**$ (795)**

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2
Total Company
(Thousands of Dollars)

PRO FORMA ADJUSTMENT: **ANNUALIZE DEPRECIATION AND AMORTIZATION**

Adjustment to Test Year operations to include depreciation and amortization expense based on the technical update to the depreciation rates authorized in Decision No. 67744; operating revenue related to depreciation and amortization billed to APSES; and amortization of gain authorized in Decision No. 64306.

Line No.	Description	Amount
1.	**REVENUES:**	$ 480
2.	Operating Revenue	-
3.	Fuel and Purchased Power Expense	$ 480
4.	Operating Revenues less Fuel and Purchased Power Expenses	
5.	**EXPENSES:**	
6.	Other Operating Expense	-
7.	Operations Excluding Fuel Expense	-
8.	Maintenance	-
9.	Subtotal	23,055
10.	Depreciation and Amortization	(77)
11.	Amortization of Gain	-
12.	Administrative and General	-
13.	Other Taxes	22,978
14.	Total	$ (22,498)
15.	**OPERATING INCOME (before income tax)**	-
16.	Interest Expense	$ (22,498)
17.	**Taxable Income**	(8,785)
18.	Income Tax at 39.05%	$ (13,713)
19.	**OPERATING INCOME AFTER TAX**	

ARIZONA PUBLIC SERVICE COMPANY
Depreciation and Amortization Expense
Analysis for Rate Case Test Year 9/30/05

Line No	DEPRECIATION/AMORTIZATION	Original Cost as of Sept 30, 2005	Proposed Expense Rate Case	Actual Expense for TME 9/30/05	Proforma Adjustments (B - C)
		A	B	C	D
	Production				
1	Steam	1,408,146,703	53,458,148	43,970,164	9,487,984
2	Nuclear	2,442,093,756	70,594,467	77,569,136	(6,974,669)
3	Nuclear - Decommissioning (a)	0	15,327,864	15,327,864	0
4	Hydro	0	0	1,008,972	(1,008,972)
5	Hydro Decommissioning	0	0	1,556,713	(1,556,713)
6	Other Production (Gas, Oil & Solar) (W Phx, Yucca, Ocotillo)	210,429,541	6,178,589	7,110,031	(931,442)
	Total APS Production Depreciation	4,060,669,999	145,559,069	146,542,880	(983,811)
7	Other Production (PWEC Units)	808,262,684	21,856,238	3,912,868	17,943,369
8	Other Production (Sundance)	273,489,133	5,258,765	2,040,208	3,218,557
	Total PWEC Units & Sundance Production Depreciation	1,081,751,817	27,115,003	5,953,076	21,161,926
9	Total Production [Total Lines 1 - 8]	5,142,421,816	172,674,071	152,495,956	20,178,115
	Transmission				
10	Transmission - SCE and Limited Term Land Rights	65,756,449	1,175,864	1,419,006	(243,142)
11	Transmission Depreciation - ACC	44,199,297	495,786	471,342	24,444
12	Transmission Depreciation - FERC	1,107,261,158	23,926,588	22,941,241	985,347
13	Transmission Depreciation - Sundance	4,481,838	74,847	8,814	66,032
14	Transmission Depreciation - PWEC Units	38,629,154	667,089	117,605	549,484
15	Total Transmission [Total Lines 10-14]	1,260,327,898	26,340,174	24,958,009	1,382,165
	Distribution				
16	Distribution Depreciation	3,531,491,685	87,424,209	97,064,283	(9,640,074)
17	Distribution - Limited Term Land Rights and Leased Property	2,258,798	131,607	167,551	(35,943)
18	Total Distribution [Total Lines 16-17]	3,533,750,483	87,555,816	97,231,833	(9,676,017)
	General & Intangible & Land				
	Total General (Studied)				
19	General (Studied)	338,363,809	19,459,245	18,329,278	1,129,967
20	General - Sundance	3,437,728	46,388	7,731	38,657
21	General & Intangible (Not Studied)	540,599,777	38,505,181	28,502,759	10,002,422
22	Total General & Intangible	882,401,314	58,010,814	46,839,768	11,171,046
23	**Total Depreciation & Amortization**	10,818,901,511	344,580,875	321,525,566	23,055,309

NOTE: **(a)** - Proposed rates (column B) does not include the $3.878 million increase in decommissioning which is included in a separate Proforma in decommissioning funding.

ARIZONA PUBLIC SERVICE
Amortization Rate Summary
Related to Electric Plant at December 31, 2004

Amortization Group		Amortization Rate
Rates from Decision No. 67744		
INTANGIBLES		
FERC 301	Organization	0.00%
FERC 302	Franchise and Consents	4.00%
FERC 303L	PV Unit 2 Sale & Leaseback-Software	Over Life of lease
FERC 303	Misc Intangible-Contributed Plant	10.00%
FERC 303	Misc Intangible -Mexico Tie	20.00%
FERC 3031	Computer Software-5year life	20.00%
FERC 3032	Computer Software-10year life- Projects greater than $10 million	10.00%
PRODUCTION		
FERC 321-325	PV Unit 2 & Common-Sale & Leaseback	Over Life of lease
LAND RIGHTS		
FERC 3303	Limited Term Land Rights-Hydro Plants	Over Remaining Life of Plant
FERC 3503	Limited Term Land Rights-Transmission Lines	Over Life of Land Right
FERC 3503	Limited Term Land Rights-SCE	Over Life of Land Right
FERC 3603	Limited Term Land Rights-Distribution Lines	Over Life of Land Right
DISTRIBUTION PLANT		
FERC 361-368-371	Distribution Plant Leased Property	Over Life of Each Lease
GENERAL PLANT		
FERC 390	Buildings- Leasehold Improvements	Over Life of Each Lease
FERC 391	Capital Lease-Computer Equipment	Over Life of Each Lease
FERC 392	Capital Lease-Transportation Vehicles	Over Life of Each Lease
FERC 392	Transportation Vehicles	Depreciated by Vehicle Class(1)
FERC 396	Power Operated Equipment	Depreciated by Vehicle Class(1)
FERC 397	PV Common Sale & Lease Back	Over Life of Lease
New Amortization Rates		
FERC 392.1	Vehicles Purchased Off Lease Less Than 26,000 GVW	50.00%
FERC 392.2	Vehicles Purchased Off Lease Greater Than 26,000 GVW	20.00%

(1) The depreciation study did not include accounts 392 or 396, therefore no changes are being proposed in this study. See attached schedule for rate by vehicle class.

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2
Total Company
(Thousands of Dollars)

PRO FORMA ADJUSTMENT: **ANNUALIZE PROPERTY TAXES**

Adjustment to Test Year operations to annualize property taxes calculated using December 31, 2004 plant balances.

Line No.	Description	Amount
1.	**EXPENSES:**	
2.	Other Operating Expenses	$ 16,867
3.	Other Taxes	$ 16,867
4.	Total Pro Forma Adjustment to Expenses	**$ (16,867)**
5.	**OPERATING INCOME (before income tax)**	(6,587)
6.	Income Tax at 39.05%	**$ (10,280)**
7.	**OPERATING INCOME AFTER TAX**	

ARIZONA PUBLIC SERVICE COMPANY
TWELVE MONTHS ENDED 9/30/05 PROPERTY TAX PRO FORMA

	PRO FORMAS						
	APS		PWEC UNITS		SUNDANCE UNITS		TOTAL
	Ref.		Ref.		Ref.		
Twelve Months Ended 9/30/05 Accrued O&M Property Taxes	A20	121,736,987	A20	1,666,666		0	123,403,653
Less:							
New Mexico	A20	(9,450,000)		0		0	(9,450,000)
Nevada	A20	(40,971)		0		0	(40,971)
California	A20	(26,687)		0		0	(26,687)
A&G Allocation	A20	84,000		0		0	84,000
Navajo County Refund (2003)	A40	1,281		0		0	1,281
CIAC Reserve (2003)	A40	(496,875)		0		0	(496,875)
O&M Property Taxes For Twelve Months Ended 9/30/05		111,807,734		1,666,666		0	113,474,401
2006 Estimated O&M Property Taxes	A50	110,784,101	A50	13,072,585		0	123,856,686
Add:							
Maricopa Community College Bond (2006)	A55	617,997	A55	17,177		0	635,173
Sundance Units Estimated Property Tax for 2006:		0		0	A80	4,141,256	4,141,256
Phase-In Adjustment for PWEC Units: Increase from 2005 to 2007		0	A90	1,708,338		0	1,708,338
Normalized Pro Forma O&M Property Taxes		111,402,098		14,798,100		4,141,256	130,341,454
Total Pro Forma O&M Adjustment		(405,636)		13,131,433		4,141,256	16,867,053

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2
Total Company
(Thousands of Dollars)

PRO FORMA ADJUSTMENT: ANNUALIZE PAYROLL

Adjustment to Test Year operations to reflect the annualization of payroll, payroll tax, and benefit expenses to December 2005 employee levels, December 2005 wage levels for performance review employees, and April 2006 wage levels for union employees.
Adjustment to Test Year to remove officer incentive expense.

Line No.	Description		Amount
1.	**EXPENSES:**	$ -	
2.	Fuel Expenses	5,326	
3.	Other Operating Expenses	3,913	
4.	Operations Excluding Fuel Expenses		
5.	Maintenance		$ 9,239
6.	Total Pro Forma Adjustment to Expenses		**$ (9,239)**
7.	**OPERATING INCOME (before income tax)**		(3,608)
8.	Income Tax at 39.05%		**$ (5,631)**
9.	**OPERATING INCOME AFTER TAX**		

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2
Total Company
(Thousands of Dollars)

PRO FORMA ADJUSTMENT: **UNDERFUNDED PENSION LIABILITY**

Adjustment to Test Year operations to increase pension expense to accelerate the recovery of the Company's underfunded pension liability.

Line No.	Description	Amount
1.	**EXPENSES:**	
2.	Other Operating Expenses	$ 43,695
3.	Operations Excluding Fuel Expenses	$ 43,695
4.	Total Pro Forma Adjustment to Expenses	**$ (43,695)**
5.	**OPERATING INCOME (before income tax)**	(17,063)
6.	Income Tax at 39.05%	**$ (26,632)**
7.	**OPERATING INCOME AFTER TAX**	

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2
Total Company
(Thousands of Dollars)

PRO FORMA ADJUSTMENT: **ADVERTISING**

Adjustment to Test Year operations to exclude advertising expenses related to Company branding.

Line No.	Description	Amount
1.	**EXPENSES:**	
2.	Other Operating Expenses	$ (6,140)
3.	Operations Excluding Fuel Expenses	$ (6,140)
4.	Total Pro Forma Adjustment to Expenses	**$ 6,140**
5.	**OPERATING INCOME (before income tax)**	2,398
6.	Income Tax at 39.05%	**$ 3,742**
7.	**OPERATING INCOME AFTER TAX**	

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2
Total Company
(Thousands of Dollars)

PRO FORMA ADJUSTMENT: MISCELLANEOUS ADJUSTMENTS

Adjustment to Test Year operations to eliminate non-recurring and out-of-period expenses.

Line No.	Description	Amount
1.	**REVENUES:**	
2.	Operating Revenue	$ 2,217
3.	Fuel and Purchased Power Expense	-
4.	Operating Revenues less Fuel and Purchased Power Expenses	$ 2,217
5.	**EXPENSES:**	
6.	Other Operating Expense	
7.	Operations Excluding Fuel Expense	6,093
8.	Maintenance	-
9.	Total	6,093
10.	**OPERATING INCOME (before income tax)**	**$ (3,876)**
11.	Interest Expense	-
12.	**Taxable Income**	**$ (3,876)**
13.	Income Tax at 39.05%	(1,514)
14.	**OPERATING INCOME AFTER TAX**	**$ (2,362)**

ARIZONA PUBLIC SERVICE COMPANY
SCHEDULE OF AMOUNTS TO BE DEPOSITED IN THE
DECOMMISSIONING TRUSTS INCLUDED IN COST OF SERVICE
PALO VERDE TOTAL
(Thousands of Dollars)
(APS Share)

LINE	YEAR	POST SHUTDOWN ON-GOING ISFSI ANNUAL CONTRIBUTION REQUIRED	POST SHUTDOWN ISFSI REGULATORY ASSET AMORTIZATION ANNUAL CONTRIBUTION REQUIRED	DECOMMISSIONING ANNUAL CONTRIBUTION REQUIRED	TOTAL ANNUAL CONTRIBUTION REQUIRED	ACC JURISDICTIONAL AMOUNT /1/
1	2004	$ 376	$ 396	$ 15,328	$ 16,100	$ 15,865
2	2005	752	792	19,211	20,755	20,452
3	2006	752	792	19,211	20,755	20,452
4	2007	752	792	19,211	20,755	20,452
5	2008	752	792	19,211	20,755	20,452
6	2009	1,816	792	19,211	21,819	21,500
7	2010	4,481	792	19,211	24,484	24,127
8	2011	4,481	792	19,211	24,484	24,127
9	2012	4,481	792	19,211	24,484	24,127
10	2013	4,481	792	19,211	24,484	24,127
11	2014	4,481	792	19,211	24,484	24,127
12	2015	4,481	792	19,211	24,484	24,127
13	2016	1,920	404	11,139	13,463	13,266
14	2017	1,920	404	11,139	13,463	13,266
15	2018	1,920	404	11,139	13,463	13,266
16	2019	1,920	404	11,139	13,463	13,266
17	2020	1,920	404	11,139	13,463	13,266
18	2021	1,920	404	11,139	13,463	13,266
19	2022	1,920	404	11,139	13,463	13,266
20	2023	1,920	404	11,139	13,463	13,266
21	2024	1,920	404	11,139	13,463	13,266
22	2025	960	190	6,017	7,167	7,062
23	2026	1,004	238	6,017	7,259	7,153
		$ 51,330	$ 13,172	$ 338,934	$ 403,436	$ 397,546

/1/ ACC Jurisdictional share is approximately 98.54%.

ARIZONA PUBLIC SERVICE COMPANY
SCHEDULE OF AMOUNTS TO BE DEPOSITED IN THE
DECOMMISSIONING TRUSTS INCLUDED IN COST OF SERVICE
PALO VERDE UNIT 1
(Thousands of Dollars)
(APS Share)

LINE	YEAR	POST SHUTDOWN ON-GOING ISFSI ANNUAL CONTRIBUTION REQUIRED	POST SHUTDOWN ISFSI REGULATORY ASSET AMORTIZATION ANNUAL CONTRIBUTION REQUIRED	DECOMMISSIONING ANNUAL CONTRIBUTION REQUIRED	TOTAL ANNUAL CONTRIBUTION REQUIRED	ACC JURISDICTIONAL AMOUNT /1/
1	2004	$ 125	$ 107	$ 4,077	$ 4,309	$ 4,246
2	2005	251	214	5,122	5,587	5,505
3	2006	251	214	5,122	5,587	5,505
4	2007	251	214	5,122	5,587	5,505
5	2008	251	214	5,122	5,587	5,505
6	2009	605	214	5,122	5,941	5,854
7	2010	960	214	5,122	6,296	6,204
8	2011	960	214	5,122	6,296	6,204
9	2012	960	214	5,122	6,296	6,204
10	2013	960	214	5,122	6,296	6,204
11	2014	960	214	5,122	6,296	6,204
12	2015	960	214	5,122	6,296	6,204
13	2016	960	214	5,122	6,296	6,204
14	2017	960	214	5,122	6,296	6,204
15	2018	960	214	5,122	6,296	6,204
16	2019	960	214	5,122	6,296	6,204
17	2020	960	214	5,122	6,296	6,204
18	2021	960	214	5,122	6,296	6,204
19	2022	960	214	5,122	6,296	6,204
20	2023	960	214	5,122	6,296	6,204
21	2024	960	214	5,122	6,296	6,204
22	2025					
23	2026					
		$ 16,134	$ 4,387	$ 106,517	$ 127,038	$ 125,183

/1/ ACC Jurisdictional share is approximately 98.54%.

ARIZONA PUBLIC SERVICE COMPANY
SCHEDULE OF AMOUNTS TO BE DEPOSITED IN THE
DECOMMISSIONING TRUSTS INCLUDED IN COST OF SERVICE
PALO VERDE UNIT 2
(Thousands of Dollars)
(APS Share)

LINE	YEAR	POST SHUTDOWN ON-GOING ISFSI ANNUAL CONTRIBUTION REQUIRED	POST SHUTDOWN ISFSI REGULATORY ASSET AMORTIZATION ANNUAL CONTRIBUTION REQUIRED	DECOMMISSIONING ANNUAL CONTRIBUTION REQUIRED	TOTAL ANNUAL CONTRIBUTION REQUIRED	ACC JURISDICTIONAL AMOUNT /1/
1	2004	$ 126	$ 194	$ 6,153	$ 6,473	$ 6,378
2	2005	250	388	8,072	8,710	8,583
3	2006	250	388	8,072	8,710	8,583
4	2007	250	388	8,072	8,710	8,583
5	2008	250	388	8,072	8,710	8,583
6	2009	606	388	8,072	9,066	8,934
7	2010	2,561	388	8,072	11,021	10,860
8	2011	2,561	388	8,072	11,021	10,860
9	2012	2,561	388	8,072	11,021	10,860
10	2013	2,561	388	8,072	11,021	10,860
11	2014	2,561	388	8,072	11,021	10,860
12	2015	2,561	388	8,072	11,021	10,860
13	2016					
14	2017					
15	2018					
16	2019					
17	2020					
18	2021					
19	2022					
20	2023					
21	2024					
22	2025					
23	2026					
		$ 17,098	$ 4,462	$ 94,945	$ 116,505	$ 114,804

/1/ ACC Jurisdictional share is approximately 98.54%.

ARIZONA PUBLIC SERVICE COMPANY
SCHEDULE OF AMOUNTS TO BE DEPOSITED IN THE
DECOMMISSIONING TRUSTS INCLUDED IN COST OF SERVICE
PALO VERDE UNIT 3
(Thousands of Dollars)
(APS Share)

LINE	YEAR	POST SHUTDOWN ON-GOING ISFSI ANNUAL CONTRIBUTION REQUIRED	POST SHUTDOWN ISFSI REGULATORY ASSET AMORTIZATION ANNUAL CONTRIBUTION REQUIRED	DECOMMISSIONING ANNUAL CONTRIBUTION REQUIRED	TOTAL ANNUAL CONTRIBUTION REQUIRED	ACC JURISDICTIONAL AMOUNT /1/
1	2004	$ 125	$ 95	$ 5,098	$ 5,318	$ 5,240
2	2005	251	190	6,017	6,458	6,364
3	2006	251	190	6,017	6,458	6,364
4	2007	251	190	6,017	6,458	6,364
5	2008	251	190	6,017	6,458	6,364
6	2009	605	190	6,017	6,812	6,713
7	2010	960	190	6,017	7,167	7,062
8	2011	960	190	6,017	7,167	7,062
9	2012	960	190	6,017	7,167	7,062
10	2013	960	190	6,017	7,167	7,062
11	2014	960	190	6,017	7,167	7,062
12	2015	960	190	6,017	7,167	7,062
13	2016	960	190	6,017	7,167	7,062
14	2017	960	190	6,017	7,167	7,062
15	2018	960	190	6,017	7,167	7,062
16	2019	960	190	6,017	7,167	7,062
17	2020	960	190	6,017	7,167	7,062
18	2021	960	190	6,017	7,167	7,062
19	2022	960	190	6,017	7,167	7,062
20	2023	960	190	6,017	7,167	7,062
21	2024	960	190	6,017	7,167	7,062
22	2025	960	190	6,017	7,167	7,062
23	2026	1,004	238	6,017	7,259	7,153
		$ 18,098	$ 4,323	$ 137,472	$ 159,893	$ 157,559

/1/ ACC Jurisdictional share is approximately 98.54%.

ARIZONA PUBLIC SERVICE COMPANY
COMPUTATION OF ALLOWANCE FOR WORKING CAPITAL
TWELVE MONTHS ENDED SEPTEMBER 30, 2005

LINE	DESCRIPTION		AMOUNT	
1	WORKING CAPITAL - OPERATIONS	$	(29,139)	
2	MATERIALS & SUPPLIES[1]		106,427	a
3	FUEL - COAL AND OIL		25,452	b
4	FUEL - NUCLEAR, NET		59,889	c
5	PREPAYMENTS		5,517	
6	ALLOWANCE FOR WORKING CAPITAL	$	168,146	
	a+b+c=		191,768	

Note [1]: APS Materials and Supplies include FERC 154 & 156

Attachment LLR-5-1

ARIZONA PUBLIC SERVICE COMPANY
RCN by Major Plant Accounts
With Contribution In Aid of Construction Identified by Function
Test year September 30, 2005
(Thousands of Dollars)

Line No.	Description	Gross Amount (a)	Contributions In Aid Of Construction (b)	Net Amount (c)
1.	Intangible Plant	$ 285,337	$ -	$ 285,337
2.	Production Plant	9,052,491	(88,770)	$ 8,963,721
3.	Transmission Plant	2,922,088	(244,751)	$ 2,677,337
4.	Distribution Plant	5,361,101	(179,408)	$ 5,181,693
5.	General Plant	668,325	(9,083)	$ 659,242
6.	Utility Plant In Service	$ 18,289,342	$ (522,012)	$ 17,767,330

ARIZONA PUBLIC SERVICE COMPANY
RCND BY MAJOR PLANT ACCOUNTS
TEST YEAR ENDING 9-30-2005
(Thousands of Dollars)

SCHEDULE B-4

Line	Function	PLANT ACCOUNT	DESCRIPTION	RCN (a)	CONDITION PERCENT Percent (b)	RCND (c)
	INTANGIBLES	301	Organization	$74	100.00%	$74
2.		302	Franchises and consents	2,964	78.61%	2,330
3.		303	Miscellaneous intangible plant	282,299	37.61%	106,168
4.			SUBTOTAL	$285,337		$108,572
5.	PRODUCTION	310	Land and Land Rights	3,308	100.00%	3,308
6.		310	Limit Term Land Rights	64	35.12%	22
7.		311	Structures and improvements	256,142	46.36%	118,748
8.		312	Boiler plant equipment	1,996,765	41.76%	833,910
9.		314	Turbogenerator units	609,483	46.23%	281,756
10.		315	Accessory electric equipment	431,039	38.33%	165,236
11.		316	Miscellaneous power plant equip.	114,110	57.52%	65,638
12.		320	Land and land rights	3,502	100.00%	3,502
13.		321	Structures and improvements	1,032,084	52.35%	540,328
14.		322	Reactor plant equipment	1,645,347	52.13%	857,675
15.		323	Turbogenerator units	572,968	52.21%	299,120
16.		324	Accessory electric equipment	574,278	48.88%	280,703
17.		325	Misc power plant equip	221,602	50.96%	112,923
18.		330	Limit Term Land Rights	0	0.00%	0
19.		331	Structures and improvements	0	0.00%	0
20.		332	Reservoirs, dams, and waterways	0	0.00%	0
21.		333	Water wheels, turbines and generators	0	0.00%	0
22.		334	Accessory electric equipment	0	0.00%	0
23.		335	Miscellaneous power plant equip.	0	0.00%	0
24.		336	Roads, railroads and bridges	0	0.00%	0
25.		340	Land and land rights	3,158	100.00%	3,158
26.		341	Structures and improvements	58,435	77.07%	45,033
27.		342	Fuel holders, products, and accessories	57,147	63.19%	36,110
28.		343	Prime movers	680,365	75.46%	513,379
29.		344	Generators	545,368	82.98%	452,526
30.		345	Accessory electric equipment	145,429	71.11%	103,414
31.		346	Miscellaneous power plant equip.	13,127	47.14%	6,188
32.			SUBTOTAL	$8,963,721		$4,722,677
33.	TRANSMISSION	350	Land and land rights	44,721	100.00%	44,721
34.		350	Limit Term Land Rights	18,288	49.82%	9,111
35.		352	Structures and improvements	54,233	52.24%	28,332
36.		353	Station equipment	1,063,880	72.82%	774,735
37.		354	Towers and fixtures	313,974	30.32%	95,194
38.		355	Poles and fixtures	390,956	72.09%	281,828
		356	Overhead conductors and devices	714,447	53.84%	384,657
		357	Underground conduit	29,887	70.32%	21,017
		358	Underground conductors and devices	46,951	53.51%	25,124
			SUBTOTAL	$2,677,337		$1,664,719
43.	DISTRIBUTION	360	Land and land rights	32,572	100.00%	32,572
44.		360	Limit Term Land Rights	1,823	73.30%	1,336
45.		361	Structures and improvements	55,723	59.39%	33,091
46.		362	Station equipment	435,463	74.96%	326,404
47.		364	Poles, towers, and fixtures	619,812	75.81%	469,876
48.		365	Overhead conductors and devices	442,054	86.72%	383,334
49.		366	Underground conduit	698,391	91.47%	638,841
50.		367	Underground conductors and devices	1,347,195	66.75%	899,221
51.		368	Line transformers	742,797	51.88%	385,391
52.		369	Services	401,744	59.01%	237,085
53.		370	Meters	233,878	69.96%	163,611
54.		371	Installations on customers' premises	60,020	84.06%	50,453
55.		373	Street lighting and signal systems	110,221	60.77%	66,977
56.			SUBTOTAL	$5,181,693		$3,688,192
1.	GENERAL	389	Land and land rights	10,640	100.00%	10,640
2.		390	Structures and improvements	209,593	65.90%	138,112
3.		391	Office furniture and equipment	126,667	41.16%	52,137
4.		391	Capitalized Lease-Computer Equipment	8,776	14.74%	1,294
5.		392	Transportation equipment	34,806	2.37%	825
6.		392	Capitalized Lease-Transportation Equip.	12,518	58.03%	7,265
7.		393	Stores equipment	5,821	-5.42%	-315
8.		394	Tools, shop and garage equipment	21,543	68.84%	14,831
9.		395	Laboratory equipment	3,255	49.95%	1,626
10.		396	Power operated equipment	32,427	28.15%	9,127
11.		397	Communication equipment	184,924	52.16%	96,455
12.		398	Miscellaneous equipment	8,272	91.45%	7,565
13.			SUBTOTAL	$659,242		$339,562
14.		TOTAL PLANT		$17,767,330		$10,523,722

Supporting Schedules
RCND Study

ReCap Schedules
(a) B-3

RONALD E. WHITE

DIRECT TESTIMONY
OF
DR. RONALD E. WHITE

ARIZONA PUBLIC SERVICE COMPANY
DOCKET NO. E01345A-05-0816

January 31, 2006

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APPENDIX A – PROFESSIONAL QUALIFICATIONS

ATTACHMENTS:

REW–1: 2005 TECHNICAL UPDATE (ARIZONA PUBLIC SERVICE COMPANY)

REW–2: 2005 TECHNICAL UPDATE (PWEC UNITS ACQUIRED BY ARIZONA PUBLIC SERVICE COMPANY)

DIRECT TESTIMONY
OF
DR. RONALD E. WHITE
ARIZONA PUBLIC SERVICE COMPANY
DOCKET NO._E01345A-05-0816

Q. WOULD YOU PLEASE STATE YOUR NAME AND BUSINESS ADDRESS?

A. My name is Ronald E. White. My business address is 17595 S. Tamiami Trail, Suite 212, Fort Myers, Florida 33908.

Q. WHAT IS YOUR OCCUPATION?

A. I am an Executive Vice President and Senior Consultant of Foster Associates, Inc.

I. QUALIFICATIONS

Q. WOULD YOU BRIEFLY DESCRIBE YOUR EDUCATIONAL TRAINING AND PROFESSIONAL BACKGROUND?

A. I received a B.S. degree in Engineering Operations and an M.S. degree and Ph.D. (1977) in Engineering Valuation from Iowa State University. I have taught graduate and undergraduate courses in industrial engineering, engineering economics, and engineering valuation at Iowa State University and previously served on the faculty for Depreciation Programs for public utility commissions, companies, and consultants, sponsored by Depreciation Programs, Inc., in cooperation with Western Michigan University. I also conduct courses in depreciation and public utility economics for clients of the firm.

I have prepared and presented a number of papers to professional organizations, committees, and conferences and have published several articles on matters relating to depreciation, valuation and economics. I am a past member of the Board of Directors of the Iowa State Regulatory Conference and an affiliate member of the joint American Gas Association (A.G.A.) – Edison Electric Institute (EEI) Depreciation Accounting Committee, where I previously served as chairman of a standing committee on capital recovery and its effect on corporate economics. I am also a member

of the American Economic Association, the Financial Management Association, the Midwest Finance Association, the Electric Cooperatives Accounting Association (ECAA), and a founding member of the Society of Depreciation Professionals.

Q. WHAT IS YOUR PROFESSIONAL EXPERIENCE?

A. I joined the firm of Foster Associates in 1979, as a specialist in depreciation, the economics of capital investment decisions, and cost of capital studies for ratemaking applications. Prior to joining Foster Associates, I was employed by Northern States Power Company (1968–1979) in various assignments related to finance and treasury activities. As Manager of the Corporate Economics Department, I was responsible for book depreciation studies, studies involving staff assistance from the Corporate Economics Department in evaluating the economics of capital investment decisions, and the development and execution of innovative forms of project financing. As Assistant Treasurer at Northern States, I was responsible for bank relations, cash requirements planning, and short–term borrowings and investments.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE A REGULATORY BODY?

A. Yes. I have testified in numerous proceedings before administrative and judicial bodies in Alabama, Arizona, California, Colorado, Connecticut, Delaware, Hawaii, Idaho, Illinois, Iowa, Kansas, Maryland, Massachusetts, Michigan, Minnesota, Missouri, Montana, Nevada, New Hampshire, New Jersey, North Carolina, North Dakota, Ohio, Oregon, Pennsylvania, Rhode Island, South Carolina, South Dakota, Tennessee, Vermont, Virginia, Wisconsin, and the District of Columbia. I have also testified before the Federal Energy Regulatory Commission, the Federal Power Commission, the Alberta Energy Board, the Ontario Energy Board, and the Securities and Exchange Commission. I have sponsored position statements before the Federal Communication Commission and numerous local franchising authorities in matters relating to the regulation of telephone and cable television. A more detailed description of my professional qualifications is attached as Appendix A.

II. PURPOSE OF TESTIMONY

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

A. Foster Associates was engaged by Arizona Public Service Company (APS or Company) to conduct 2005 technical updates of depreciation rates for APS and for certain Pinnacle West Energy Corporation generating units (PWEC Units) acquired by APS. The purpose of my testimony is to sponsor and describe the studies conducted by Foster Associates. Depreciation rates currently used by APS and for the PWEC Units were approved by the Arizona Corporation Commission (ACC) pursuant to a settlement agreement in Docket No. E–01345A–03–0437 (Decision No. 67744, dated April 7, 2005).

III. IDENTIFICATION OF ATTACHMENTS

Q. DO YOU SPONSOR ANY ATTACHMENTS IN SUPPORT OF YOUR TESTIMONY?

A. Yes, I do. I sponsor Attachment REW–1, a document titled "2005 Technical Update (Arizona Public Service Company)." I also sponsor Attachment REW–2, a document titled "2005 Technical Update (PWEC Units Acquired by Arizona Public Service Company)." These documents were prepared by me or under my direction and supervision.

IV. DEVELOPMENT OF DEPRECIATION RATES

Q. WHY ARE DEPRECIATION STUDIES NEEDED FOR ACCOUNTING AND RATEMAKING PURPOSES?

A. The goal of depreciation accounting is to charge to operations a reasonable estimate of the cost of the service potential of an asset (or group of assets) consumed during an accounting interval. A number of depreciation systems have been developed to achieve this objective, most of which employ time as the apportionment base.

Implementation of a time–based (or age–life) system of depreciation accounting requires the estimation of several parameters or statistics related to a plant account. The average service life of a vintage, for example, is a statistic that will not be known

with certainty until all units from the original placement have been retired from service. A vintage average service life, therefore, must be estimated initially and periodically revised as indications of the eventual average service life become more certain. Future net salvage rates and projection curves, which describe the expected distribution of retirements over time, are also estimated parameters of a depreciation system that are subject to future revisions. Depreciation studies should be conducted periodically to assess the continuing reasonableness of parameters and accrual rates derived from prior estimates.

The need for periodic depreciation studies is also a derivative of the ratemaking process that establishes prices for utility services based on costs. Absent regulation, deficient or excessive depreciation rates will produce no adverse consequence other than a systematic over or understatement of the accounting measurement of earnings. While a continuance of such practices may not comport with the goals of depreciation accounting, the achievement of capital recovery is not dependent upon either the amount or the timing of depreciation expense for an unregulated firm. In the case of a regulated utility, however, recovery of investor–supplied capital is dependent upon allowed revenues, which are in turn dependent upon approved levels of depreciation expense. Periodic reviews of depreciation rates are, therefore, essential to the achievement of timely capital recovery for a regulated utility.

It is also important to recognize that revenue associated with depreciation is a significant source of internally generated funds used to finance plant replacements and new capacity additions. It can be shown that, given the same financing requirements and the same dividend payout ratio, an increase in internal cash generation will accelerate per–share growth in earnings, dividends, and book value over the business life of a firm. Financial theory provides that the marginal cost of external financing will be reduced by these enhanced measurements of financial performance. This is not to suggest that internal cash generation should be substituted for the goals of depreciation accounting. However, the potential for realizing a reduction in the mar-

ginal cost of external financing provides an added incentive for conducting periodic depreciation studies and adopting proper depreciation rates.

Q. WHAT ARE THE PRINCIPAL ACTIVITIES UNDERTAKEN IN CONDUCTING A FULL DEPRECIATION STUDY?

A. The first step in conducting a depreciation study is the collection of plant accounting data needed to conduct a statistical analysis of past retirement experience. Data are also collected to permit an analysis of the relationship between retirements and realized gross salvage and removal expense. The data collection phase should include a verification of the accuracy of the plant accounting records and a reconciliation of the assembled data to the official plant records of the company.

The next step in a depreciation study is the estimation of service life statistics from an analysis of past retirement experience. The term *life analysis* is used to describe the activities undertaken in this step to obtain a mathematical description of the forces of retirement acting upon a plant category. The mathematical expressions used to describe these forces are known as survival functions or survivor curves.

Life indications obtained from an analysis of past retirement experience are blended with expectations about the future to obtain an appropriate projection life curve. This step, called *life estimation*, is concerned with predicting the expected remaining life of property units still exposed to the forces of retirement. The amount of weight given to the analysis of historical data will depend upon the extent to which past retirement experience is considered descriptive of the future.

An estimate of the net salvage rate applicable to future retirements is usually obtained from an analysis of the gross salvage and removal expense realized in the past. An analysis of past experience (including an examination of trends over time) provides a baseline for estimating future salvage and cost of removal. Consideration, however, should be given to events that may cause deviations from the net salvage realized in the past. Among the factors that should be considered are the age of plant retirements, the portion of retirements that will be reused, changes in the method of removing plant, the type of plant to be retired in the future, inflation expectations, the

shape of the projection life curve, and economic conditions that may warrant greater or lesser weight to be given to the net salvage observed in the past.

A comprehensive depreciation study will also include an analysis of the adequacy of the recorded depreciation reserve. The purpose of such an analysis is to compare the current balance in the recorded reserve with the balance required to achieve the goals and objectives of depreciation accounting if the amount and timing of future retirements and net salvage are realized exactly as predicted. The difference between the required (or theoretical) reserve and the recorded reserve provides a measurement of the expected excess or shortfall that will remain in the depreciation reserve if corrective action is not taken to extinguish the reserve imbalance.

Although reserve records are typically maintained by various account classifications, the total reserve for a company is the most important reflection of the company's depreciation practices. Differences between the theoretical reserve and the recorded reserve will arise as a normal occurrence when service lives, dispersion patterns and salvage estimates are adjusted in the course of depreciation reviews. Differences will also arise due to plant accounting activity such as transfers and adjustments, which require an identification of reserves at a different level from that maintained in the accounting system. It is appropriate, therefore, and consistent with group depreciation theory, to periodically redistribute recorded reserves among primary accounts based on the most recent estimates of retirement dispersion and salvage. A redistribution of the recorded reserve will provide an initial reserve balance for each primary account consistent with the estimates of retirement dispersion selected to describe mortality characteristics of the accounts and establish a baseline against which future comparisons can be made.

Finally, parameters estimated from service life and net salvage studies are integrated into an appropriate formulation of an accrual rate based upon a selected depreciation system. Three elements are needed to describe a depreciation system. These elements (*i.e.*, method, procedure and technique) can be visualized as three dimensions of a cube in which each face describes a variety of sub--elements that can be

combined to form a system. A depreciation system is therefore formed by selecting a sub–element from each face such that the system contains one method, one procedure and one technique. The sub–elements most widely used in constructing a depreciation system are shown in Table 1.

Methods	Procedures	Techniques
Retirement	Total Company	Whole-Life
Compound-Interest	Broad Group	Remaining-Life
Sinking-Fund	Vintage Group	Probable-Life
Straight-Line	Equal-Life Group	
Declining Balance	Unit Summation	
Sum-of-Years'-Digits	Item	
Expensing		
Unit-of-Production		
Net Revenue		

Table 1. Elements of a Depreciation System

V. 2005 TECHNICAL UPDATES

Q. WOULD YOU PLEASE DESCRIBE THE SCOPE OF A TECHNICAL UPDATE?

A. Unlike a full depreciation study in which projection curves, projection lives and future net salvage rates are estimated from a statistical analysis of recorded retirements and net salvage realized in the past, a technical update generally retains the parameters currently used or proposed by the utility and adjusts depreciation rates for known and measurable changes in the age distributions of surviving plant, depreciation reserves, and average net salvage rates due to the passage of time. A technical update, therefore, is intended to align depreciation rates with the accounting year the rates will become effective. The steps involved in preparing a technical update generally include a) data collection; b) calculation of service life statistics; c) computation of average net salvage rates; d) rebalancing of depreciation reserves; and e) development of accrual rates.

Q. DID APS PROVIDE FOSTER ASSOCIATES PLANT ACCOUNTING DATA FOR CONDUCTING THE 2005 TECHNICAL UPDATES?

A. Yes, they did. The databases used in the 2005 updates for APS and the PWEC Units were provided to Foster Associates in an electronic format containing plant and reserve activity over the period 1972–2004 and age distributions of surviving plant at December 31, 2004. Data used in the updates were limited to the age distributions of surviving plant. Depreciation rates currently used by APS and for the PWEC Units were developed using a broad–group procedure. The realized life of surviving vintages derived from the dollar–years of service provided by each vintage is not relevant to an update of broad–group depreciation rates. Therefore, plant transactions recorded in prior activity years were not used in the update.

Reserve transactions recorded in prior activity years were also not used in the 2005 updates. Depreciation rates currently used by APS and for the PWEC Units were derived without consideration of the distinction between average and future net salvage rates. The assumed equivalency between average and future net salvage rates was retained in the 2005 updates without introducing prior realized net salvage amounts in the computation of average net salvage rates.

Q. DID FOSTER ASSOCIATES CALCULATE SERVICE LIFE STATISTICS IN THE 2005 TECHNICAL UPDATES FOR APS AND THE PWEC UNITS?

A. Yes, we did. The scope of the updates and calculations performed by Foster Associates are described in the Study Procedures section of Attachment REW–1 and Attachment REW–2.

Q. DID FOSTER ASSOCIATES DERIVE AVERAGE NET SALVAGE RATES IN THE 2005 TECHNICAL UPDATES FOR APS AND THE PWEC UNITS?

A. No, we did not. As noted earlier, depreciation rates currently used by APS and for the PWEC Units were derived without consideration of the distinction between average and future net salvage rates. The assumed equivalency between average and future net salvage rates was retained in the 2005 updates without introducing prior realized net salvage amounts in the computation of average net salvage rates.

However, future net salvage rates for steam production facilities were adjusted in the 2005 update for estimated terminal dismantlement costs. The treatment of

dismantlement costs in prior studies (and in the depreciation rates currently used by APS) reflects an assumption that interim and future net salvage rates will be equal. This assumption was relaxed in the 2005 update by: a) retaining an interim net salvage rate of –20 percent; and b) adjusting terminal dismantlement costs to reflect costs per kW estimated in dismantling studies conducted in 2002 for the Navajo and Four Corners generating stations. An inflation rate of three percent was used to escalate 2002 dollars to estimated years of final retirement.

Q. DID FOSTER ASSOCIATES REBALANCE DEPRECIATION RESERVES IN THE 2005 TECHNICAL UPDATES FOR APS AND THE PWEC UNITS?

A. Yes, we did. A rebalancing of recorded reserves is consistent with the objectives of a technical update and is considered appropriate for both APS and the PWEC Units. Depreciation rates adopted in Docket No. E–01345A–03–0437 were derived from rebalanced reserves obtained from a set of parameters different from those used in the formulation of the settled remaining–life accrual rates. Reserve imbalances amortized in the settled rates are therefore inconsistent with the realigned depreciation reserves. The rebalancing of reserves undertaken in the 2005 updates will reestablish consistency between measured reserve imbalances and the parameters used in the formulation of updated remaining–life accrual rates.

A redistribution of the recorded reserve was achieved for both APS and the PWEC Units by multiplying the calculated reserve for each primary account within a function (or plant location) by the ratio of the function (or location) total recorded reserve to the function (or location) total calculated reserve. The sum of the redistributed reserves within a function (or location) is, therefore, equal to the function (or location) total recorded depreciation reserve before the redistribution.

Q. HOW DO THE DEPRECIATION RATES AND ACCRUALS DERIVED IN THE 2005 TECHNICAL UPDATES COMPARE WITH THOSE CURRENTLY USED BY APS AND FOR THE PWEC UNITS?

A. Table 2 provides a comparison of present and proposed depreciation rates and accruals derived in the 2005 Technical Update for APS.

Function	Accrual Rate			2005 Annualized Accrual		
	Present	Proposed	Difference	Present	Proposed	Difference
A	B	C	D=C-B	E	F	G=F-E
Production						
Steam	3.34%	3.83%	0.49%	$45,731,277	$52,392,026	$6,660,749
Nuclear	2.95%	2.78%	-0.17%	70,195,368	66,186,908	(4,008,460)
Other	2.93%	2.93%	0.00%	6,039,806	6,030,434	(9,372)
Transmission	1.55%	1.12%	-0.43%	685,384	496,457	(188,927)
Distribution	2.43%	2.47%	0.04%	81,502,058	82,773,852	1,271,794
General Plant	5.30%	5.75%	0.45%	17,462,319	18,958,703	1,496,384
Total	2.89%	2.95%	0.06%	$221,616,212	$226,838,380	$5,222,168

Table 2. Present and Proposed APS Depreciation Rates and Accruals

Adjustments developed in the technical update for APS produce a composite depreciation rate of 2.95 percent. Depreciation expense is presently accrued at an equivalent rate of 2.89 percent. The proposed change in the composite depreciation rate represents an increase of 0.06 percentage points.

A continued application of rates currently approved would provide annual depreciation expense of $221,616,212 compared with an annual expense of $226,838,380 using the rates developed in the update. The proposed expense increase of $5,222,168 is largely attributable to: a) a change in the mix of plant investments among primary accounts; b) changes in the age distributions of surviving plant; and c) plant additions to Four Corners generating station.

Table 3 provides a comparison of present and proposed depreciation rates and accruals derived in the 2005 Technical Update for the PWEC Units.

Function	Accrual Rate			2005 Annualized Accrual		
	Present	Proposed	Difference	Present	Proposed	Difference
A	B	C	D=C-B	E	F	G=F-E
Production	2.92%	2.71%	-0.21%	$28,002,769	$26,066,384	($1,936,385)
Transmission	1.83%	1.73%	-0.10%	787,163	742,858	(44,305)
Total	2.87%	2.67%	-0.20%	$28,789,932	$26,809,242	($1,980,690)

Table 3. Present and Proposed PWEC Assets Depreciation Rates and Accruals

Adjustments developed in the technical update for the PWEC Units produce a composite depreciation rate of 2.67 percent. Depreciation expense is presently accrued at an equivalent rate of 2.87 percent. The proposed change in the composite depreciation rate represents a reduction of 0.20 percentage points.

A continued application of rates currently approved would provide annual depreciation expense of $28,789,932 compared with an annual expense of $26,809,242 using the rates developed in the update. The proposed expense decrease of $1,980,690 is largely attributable to: a) a change in the mix of plant investments among primary accounts; b) changes in the age distributions of surviving plant; and c) the estimation of parameters for West Phoenix Unit 5.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

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Education

1961 - 1964 Valparaiso University
Major: Electrical Engineering

1965 Iowa State University
B.S., Engineering Operations

1968 Iowa State University
M.S., Engineering Valuation
Thesis: The Multivariate Normal Distribution and the Simulated Plant Record Method of Life Analysis

1977 Iowa State University
Ph.D., Engineering Valuation
Minor: Economics
Dissertation: A Comparative Analysis of Various Estimates of the Hazard Rate Associated With the Service Life of Industrial Property

Employment

1996 - Present Foster Associates, Inc.
Executive Vice President

1988 - 1996 Foster Associates, Inc.
Senior Vice President

1979 - 1988 Foster Associates, Inc.
Vice President

1978 - 1979 Northern States Power Company
Assistant Treasurer

1974 - 1978 Northern States Power Company
Manager, Corporate Economics

1972 - 1974 Northern States Power Company
Corporate Economist

1970 - 1972 Iowa State University
Graduate Student and Instructor

1968 - 1970 Northern States Power Company
Valuation Engineer

1965 - 1968 Iowa State University
Graduate Student and Teaching Assistant

Publications

A New Set of Generalized Survivor Tables, Journal of the Society of *Depreciation Professionals, October*, 1992.

The Theory and Practice of Depreciation Accounting Under Public Utility Regulation, Journal of the Society of Depreciation Professionals, December, 1989.

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How Dependable are Simulated Plant-Record Estimates?, paper presented at the Iowa State University Conference on Public Utility Valuation and the Rate Making Process, April, 1968.

Expert Opinion

Alabama Public Service Commission, Docket No. 18488, General Telephone Company of the Southeast; testimony concerning engineering economy study techniques.

Alabama Public Service Commission, Docket No. 20208, General Telephone Company of the South; testimony concerning the equal-life group procedure and remaining-life technique.

Alberta Energy and Utilities Board, Application No. 1250392, Aquila Networks Canada; rebuttal testimony supporting proposed depreciation rates.

Alberta Energy and Utilities Board, Case No. RE95081, Edmonton Power Inc.; rebuttal evidence concerning appropriate depreciation rates.

Alberta Energy and Utilities Board, 1999/2000 General Tariff Application, Edmonton Power Inc.; direct and rebuttal evidence concerning appropriate depreciation rates.

Arizona Corporation Commission, Docket No. T-01051B-97-0689, U S West Communications, Inc.; testimony concerning appropriate depreciation rates.

Arizona Corporation Commission, Docket No. G-1032A-02-0598, Citizens Communications Company; testimony supporting proposed depreciation rates.

Arizona Corporation Commission, Docket No. E–0135A–03–0437, Arizona Public Service Company; rebuttal testimony supporting net salvage rates.

Arizona State Board of Equalization, Docket No. 6302-07-2, Arizona Public Service Company; testimony concerning valuation and assessment of contributions in aid of construction.

California Public Utilities Commission, Case Nos. A.92-06-040, 92-06-042, GTE California Incorporated; rebuttal testimony supporting depreciation study techniques.

Public Utilities Commission of the State of Colorado, Application No. 36883-Reopened. U S WEST Communications; testimony concerning equal-life group procedure.

State of Connecticut Department of Public Utility Control, Docket No. 05–03–17, The Southern Connecticut Gas Company; testimony supporting recommended depreciation rates.

Delaware Public Service Commission, Docket No. 81-8, Diamond State Telephone Company; testimony concerning the amortization of inside wiring.

Delaware Public Service Commission, Docket No. 82-32, Diamond State Telephone Company; testimony concerning the equal-life group procedure and remaining-life technique.

Public Service Commission of the District of Columbia, Formal Case No. 842, District of Columbia Natural Gas; testimony concerning depreciation rates.

Public Service Commission of the District of Columbia, Formal Case No. 1016, Washington Gas Light Company - District of Columbia; testimony supporting proposed depreciation rates.

Federal Communications Commission, Prescription of Revised Depreciation Rates for AT&T Communications; statement concerning depreciation, regulation and competition.

Federal Communications Commission, Petition for Modification of FCC Depreciation Prescription Practices for AT&T; statement concerning alignment of depreciation expense used for financial reporting and regulatory purposes.

Federal Communications Commission, Docket No. 99-117, Bell Atlantic; affidavit concerning revenue requirement and capital recovery implications of omitted plant retirements.

Federal Energy Regulatory Commission, Docket No. ER95-267-000, New England Power Company; testimony supporting proposed depreciation rates.

Federal Energy Regulatory Commission, Docket No. RP89-248, Mississippi River Transmission Corporation; rebuttal testimony concerning appropriateness of net salvage component in depreciation rates.

Federal Energy Regulatory Commission, Docket No. ER91-565, New England Power Company; testimony supporting proposed depreciation rates.

Federal Energy Regulatory Commission, Docket No. ER78-291, Northern States Power Company; testimony concerning rate of return and general financial requirements.

Federal Energy Regulatory Commission, Docket Nos. RP80-97 and RP81-54, Tennessee Gas Pipeline Company; testimony concerning offshore plant depreciation rates.

Federal Power Commission, Docket No. E-8252, Northern States Power Company; testimony concerning general financial requirements and measurements of financial performance.

Federal Power Commission, Docket No. E-9148, Northern States Power Company; testimony concerning general financial requirements and measurements of financial performance.

Federal Power Commission, Docket No. ER76-818, Northern States Power Company; testimony concerning rate of return and general financial requirements.

Federal Power Commission, Docket No. RP74-80, Northern Natural Gas Company; testimony concerning depreciation expense.

Public Utilities Commission of the State of Hawaii, Docket No. 00-0309, The Gas Company; testimony supporting proposed depreciation rates.

Public Utilities Commission of the State of Hawaii, Docket No. 94-0298, GTE Hawaiian Telephone Company Incorporated; testimony concerning the need for shortened service lives and disclosure of asset impairment losses.

Idaho Public Utilities Commission, Case No. U-1002-59, General Telephone Company of the Northwest, Inc.; testimony concerning the remaining-life technique and the equal-life group procedure.

Illinois Commerce Commission, Case No. 04–0476, Illinois Power Company, testimony supporting proposed depreciation rates.

Illinois Commerce Commission, Docket No. 94-0481, Citizens Utilities Company of Illinois; rebuttal testimony concerning applications of the Simulated Plant-Record method of life analysis.

Iowa State Commerce Commission, Docket No. RPU 82-47, North Central Public Service Company; testimony on depreciation rates.

Iowa State Commerce Commission, Docket No. RPU 84-34, General Telephone Company of the Midwest; testimony concerning the remaining-life technique and the equal-life group procedure.

Iowa State Utilities Board, Docket No. DPU-86-2, Northwestern Bell Telephone Company; testimony concerning capital recovery in competition.

Iowa State Utilities Board, Docket No. RPU-84-7, Northwestern Bell Telephone Company; testimony concerning the deduction of a reserve deficiency from the rate base.

Iowa State Utilities Board, Docket No. DPU-88-6, U S WEST Communications; testimony concerning depreciation subject to refund.

Iowa State Utilities Board, Docket No. RPU-90-9, Central Telephone Company of Iowa; testimony concerning depreciation rates.

Iowa State Utilities Board, Docket No. RPU-93-9, U S WEST Communications; testimony concerning principles of depreciation accounting and abandonment of FASB 71.

Iowa State Utilities Board, Docket No. DPU-96-1, U S WEST Communications; testimony concerning principles of depreciation accounting and abandonment of FASB 71.

Iowa State Utilities Board, Docket No. RPU-05-2, Aquila Networks; testimony supporting recommended depreciation rates.

Kansas Corporation Commission, Docket No. 04–AQLE–1065–RTS, testimony supporting proposed depreciation rates.

Kansas Corporation Commission, Docket No. 03–KGSG–602–RTS, Kansas Gas Service, a Division of ONEOK, Inc., rebuttal testimony supporting net salvage rates.

Kentucky Public Service Commission, Case No. 97-224, Jackson Purchase Electric Cooperative Corporation; rebuttal testimony supporting proposed depreciation rates.

Maryland Public Service Commission, Case No. 8485, Baltimore Gas and Electric Company; testimony supporting proposed depreciation rates.

Maryland Public Service Commission, Case No. 7689, Washington Gas Light Company; testimony concerning life analysis and net salvage.

Maryland Public Service Commission, Case No. 8960, Washington Gas Light Company; testimony supporting proposed depreciation rates.

Massachusetts Department of Public Utilities, Case No. DPU 91-52, Massachusetts Electric Company; testimony supporting proposed depreciation rates which include a net salvage component.

Michigan Public Service Commission, Case No. U13899, Michigan Consolidated Gas Company, testimony concerning service life estimates.

Michigan Public Service Commission, Case No. U-13393, Aquila Networks – MGU; testimony supporting proposed depreciation rates.

Michigan Public Service Commission, Case No. U-12395, Michigan Gas Utilities; testimony supporting proposed depreciation rates including amortization accounting and redistribution of recorded reserves.

Michigan Public Service Commission, Case No. U-6587, General Telephone Company of Michigan; testimony concerning use of a theoretical depreciation reserve with the remaining-life technique.

Michigan Public Service Commission, Case No. U-7134, General Telephone Company of Michigan; testimony concerning the equal-life group depreciation procedure.

Minnesota District Court. In Re: Northern States Power Company v. Ronald G. Blank, *et. al.* File No. 394126; testimony concerning depreciation and engineering economics.

Minnesota Public Service Commission, Docket No. E-611, Northern States Power Company; testimony concerning rate of return and general financial requirements.

Minnesota Public Service Commission, Docket No. E-1086, Northern States Power Company; testimony concerning depreciation rates.

Minnesota Public Service Commission, Docket No. G-1015, Northern States Power Company; testimony concerning rate of return and general financial requirements.

Public Service Commission of the State of Missouri, Case No. ER-2001-672, Missouri Public Service, a division of Utilicorp United Inc.; surrebuttal testimony regarding computation of income tax expense.

Public Service Commission of the State of Missouri, Case No. TO-82-3, Southwestern Bell Telephone Company; rebuttal testimony concerning the remaining-life technique and the equal-life group procedure.

Public Service Commission of the State of Missouri, Case No. GO-97-79, Laclede Gas Company; rebuttal testimony concerning adequacy of database for conducting depreciation studies.

Public Service Commission of the State of Missouri, Case No. GR-99-315, Laclede Gas Company; rebuttal testimony concerning treatment of net salvage in development of depreciation rates.

Public Service Commission of the State of Missouri, Case No. HR–2004–0024, Aquila Inc. d/b/a/ Aquila Networks–L & P, testimony supporting depreciation rates.

Public Service Commission of the State of Missouri, Case No. ER–2004–0034, Aquila Inc. d/b/a/ Aquila Networks–L & P and Aquila Networks–MPS, testimony supporting depreciation rates.

Public Service Commission of the State of Missouri, Case No. GR–2004–0072, Aquila Inc. d/b/a/ Aquila Networks–L & P and Aquila Networks–MPS, testimony supporting depreciation rates.

Public Service Commission of the State of Montana, Docket No. 88.2.5, Mountain State Telephone and Telegraph Company; rebuttal testimony concerning the equal-life group procedure and amortization of reserve imbalances.

Montana Public Service Commission, Docket No. D95.9.128, The Montana Power Company; testimony supporting proposed depreciation rates.

Public Service Commission of Nevada, Docket No. 92-7002, Central Telephone Company-Nevada; testimony supporting proposed depreciation rates.

Public Service Commission of Nevada, Docket No. 91-5054, Central Telephone Company-Nevada; testimony supporting proposed depreciation rates.

New Hampshire Public Utilities Commission, Docket No. DR95-169, Granite State Electric Company; testimony supporting proposed net salvage rates.

New Jersey Board of Public Utilities, Docket No. GR 87060552, New Jersey Natural Gas Company; testimony concerning depreciation rates.

New Jersey Board of Regulatory Commissioners, Docket No. GR93040114J, New Jersey Natural Gas Company; testimony concerning depreciation rates.

North Carolina Utilities Commission, Docket No. E-7, SUB 487, Duke Power Company; rebuttal testimony concerning proposed depreciation rates.

North Carolina Utilities Commission, Docket No. P-19, SUB 207, General Telephone Company of the South; rebuttal testimony concerning the equal-life group depreciation procedure.

North Dakota Public Service Commission, Case No. 8860, Northern States Power Company; testimony concerning general financial requirements.

North Dakota Public Service Commission, Case No. 9634, Northern States Power Company; testimony concerning rate of return and general financial requirements.

North Dakota Public Service Commission, Case No. 9666, Northern States Power Company; testimony concerning rate of return and general financial requirements.

North Dakota Public Service Commission, Case No. 9741, Northern States

Power Company; testimony concerning rate of return and general financial requirements.

Ontario Energy Board, E.B.R.O. 385, Tecumseh Gas Storage Limited; testimony concerning depreciation rates.

Ontario Energy Board, E.B.R.O. 388, Union Gas Limited; testimony concerning depreciation rates.

Ontario Energy Board, E.B.R.O. 456, Union Gas Limited; testimony concerning depreciation rates.

Ontario Energy Board, E.B.R.O. 476-03, Union Gas Limited; testimony concerning depreciation rates.

Public Utilities Commission of Ohio, Case No. 81-383-TP-AIR, General Telephone Company of Ohio; testimony in support of the remaining-life technique.

Public Utilities Commission of Ohio, Case No. 82-886-TP-AIR, General Telephone Company of Ohio; testimony concerning the remaining-life technique and the equal-life group procedure.

Public Utilities Commission of Ohio, Case No. 84-1026-TP-AIR, General Telephone Company of Ohio; testimony in support of the equal-life group procedure and the remaining-life technique.

Public Utilities Commission of Ohio, Case No. 81-1433, The Ohio Bell Telephone Company; testimony concerning the remaining-life technique and the equal-life group procedure.

Public Utilities Commission of Ohio, Case No. 83-300-TP-AIR, The Ohio Bell Telephone Company; testimony concerning straight-line age-life depreciation.

Public Utilities Commission of Ohio, Case No. 84-1435-TP-AIR, The Ohio Bell Telephone Company; testimony in support of test period depreciation expense.

Public Utilities Commission of Oregon, Docket No. UM 204, GTE of the Northwest; testimony concerning the theory and practice of depreciation accounting under public utility regulation.

Public Utilities Commission of Oregon, Docket No. UM 840, GTE Northwest Incorporated; rebuttal testimony concerning principles of capital recovery.

Pennsylvania Public Utility Commission, Docket No. R-80061235, The Bell Telephone Company of Pennsylvania; testimony concerning the proper depreciation reserve to be used with an original cost rate base.

Pennsylvania Public Utility Commission, Docket No. R-811512, General Telephone Company of Pennsylvania; testimony concerning the proper depreciation reserve to be used with an original cost rate base.

Pennsylvania Public Utility Commission, Docket No. R-811819, The Bell Telephone Company of Pennsylvania; testimony concerning the proper depreciation reserve to be used with an original cost rate base.

Pennsylvania Public Utility Commission, Docket No. R-822109, General Telephone Company of Pennsylvania; testimony in support of the remaining-life technique.

Pennsylvania Public Utility Commission, Docket No. R-850229, General Telephone Company of Pennsylvania; testimony in support of the remaining-

life technique and the proper depreciation reserve to be used with an original cost rate base.

Pennsylvania Public Utility Commission, Docket No. C-860923, The Bell Telephone Company of Pennsylvania; testimony concerning capital recovery under competition.

Rhode Island Public Utilities Commission, Docket No. 2290, The Narragansett Electric Company; testimony supporting proposed net salvage rates and depreciation rates.

South Carolina Public Service Commission, Docket No. 91-216-E, Duke Power Company; testimony supporting proposed depreciation rates.

Public Utilities Commission of the State of South Dakota, Case No. F-3062, Northern States Power Company; testimony concerning general financial requirements and measurements of financial performance.

Public Utilities Commission of the State of South Dakota, Case No. F-3188, Northern States Power Company; testimony concerning rate of return and general financial requirements.

Securities and Exchange Commission, File No. 3-5749, Northern States Power Company; testimony concerning the financial and ratemaking implications of an affiliation with Lake Superior District Power Company.

Tennessee Public Service Commission, Docket No. 89-11041, United Inter-Mountain Telephone Company; testimony concerning depreciation principles and capital recovery under competition.

State of Vermont Public Service Board, Docket No. 6596, Citizens Communications Company – Vermont Electric Division, testimony supporting recommended depreciation rates.

State of Vermont Public Service Board, Docket No. 6946 and 6988, Central Vermont Public Service Corporation, testimony supporting net salvage rates.

Commonwealth of Virginia State Corporation Commission, Case No. PUE-2002-00364, Washington Gas Light Company; testimony supporting proposed depreciation rates.

Public Service Commission of Wisconsin, Docket No. 2180-DT-3, General Telephone Company of Wisconsin; testimony concerning the equal-life group depreciation procedure.

Other Consulting Activities

Moran Towing Corporation. In Re: Barge TEXAS-97 CIV. 2272 (ADS) and Tug HEIDE MORAN – 97 CIV. 1947 (ADS), United States District Court, Southern District of New York.

John Reigle, et al. v. Baltimore Gas & Electric Co., et al., Case No. C-2001-73230-CN, Circuit Court for Anne Arundel County, Maryland.

SR International Business Insurance Co. vs. WTC Properties et. al., 01,CV–9291 (JSM) and other related cases.

BellSouth Telecommunications, Inc. v. Citizens Utilities Company d/b/a/ Louisiana Gas Service Company, CA No. 95-2207, United States District Court, Eastern District of Louisiana.

Affidavit on behalf of Continental Cablevision, Inc. and its operating cable television systems regarding basic broadcast tier and equipment and installation cost-of-service rate justification.

Office of Chief Counsel, Internal Revenue Service. In Re: Kansas City Southern Railway Co., et. al. Docket Nos. 971-72, 974-72, and 4788-73.

Office of Chief Counsel, Internal Revenue Service. In Re: Northern Pacific Railway Co., Docket No. 4489-69.

United States Department of Justice. In Re: Burlington Northern Inc. v. United States, Ct. Cl. No. 30-72.

Faculty

Depreciation Programs for public utility commissions, companies, and consultants, sponsored by Depreciation Programs, Inc., in cooperation with Western Michigan University. (1980 - 1999)

United States Telephone Association (USTA), Depreciation Training Seminar, November 1999.

Depreciation Advocacy Workshop, a three-day team-training workshop on preparation, presentation, and defense of contested depreciation issues, sponsored by Gilbert Associates, Inc., October, 1979.

Corporate Economics Course, Employee Education Program, Northern States Power Company. (1968 - 1979)

Perspectives of Top Financial Executives, Course No. 5-300, University of Minnesota, September, 1978.

Depreciation Programs for public utility commissions, companies, and consultants, jointly sponsored by Western Michigan University and Michigan Technological University, 1973.

Professional Associations

Advisory Committee to the Institute for Study of Regulation, sponsored by the American University and The University of Missouri-Columbia.

American Economic Association.

American Gas Association - Edison Electric Institute Depreciation Accounting Committee.

Board of Directors, Iowa State Regulatory Conference.

Edison Electric Institute, Energy Analysis Division, Economic Advisory Committee, 1976-1980.

Financial Management Association.

The Institute of Electrical and Electronics Engineers, Inc., Power Engineering Society, Engineering and Planning Economics Working Group.

Midwest Finance Association.

Society of Depreciation Professionals (Founding Member and Chairman, Policy Committee

Moderator

Depreciation Open Forum, Iowa State University Regulatory Conference, May 1991.

The Quantification of Risk and Uncertainty in Engineering Economic Studies, Iowa State University Regulatory Conference, May 1989.

Plant Replacement Decisions with Added Revenue from New Service Offerings, Iowa State University Regulatory Conference, May 1988.

Economic Depreciation, Iowa State University Regulatory Conference, May 1987.

Opposing Views on the Use of Customer Discount Rates in Revenue Requirement Comparisons, Iowa State University Regulatory Conference, May 1986.

Cost of Capital Consequences of Depreciation Policy, Iowa State University Regulatory Conference, May 1985.

Concepts of Economic Depreciation, Iowa State University Regulatory Conference, May 1984.

Ratemaking Treatment of Large Capacity Additions, Iowa State University Regulatory Conference, May 1983.

The Economics of Excess Capacity, Iowa State University Regulatory Conference, May 1982.

New Developments in Engineering Economics, Iowa State University Regulatory Conference, May 1980.

Training in Engineering Economy, Iowa State University Regulatory Conference, May 1979.

The Real Time Problem of Capital Recovery, Missouri Public Service Commission, Regulatory Information Systems Conference, September 1974.

Speaker

Depreciation Studies for Cooperatives and Small Utilities. TELERGEE CFO and Controllers Conference, November, 2004.

Finding the "D" in RCNLD (Valuation Applications of Depreciation), Society of Depreciation Professionals Annual Meeting, September 2001.

Capital Asset and Depreciation Accounting, City of Edmonton Value Engineering Workshop, April 2001.

A Valuation View of Economic Depreciation, Society of Depreciation Professionals Annual Meeting, October 1999.

Capital Recovery in a Changing Regulatory Environment, Pennsylvania Electric Association Financial-Accounting Conference, May 1999.

Depreciation Theory and Practice, Southern Natural Gas Company Accounting and Regulatory Seminar, March 1999.

Depreciation Theory Applied to Special Franchise Property, New York Office of Real Property Services, March 1999.

Capital Recovery in a Changing Regulatory Environment, PowerPlan Consultants Annual Client Forum, November 1998.

Economic Depreciation, AGA Accounting Services Committee and EEI Property Accounting and Valuation Committee, May 1998.

Discontinuation of Application of FASB Statement No. 71, Southern Natural Gas Company Accounting Seminar, April 1998.

Forecasting in Depreciation, Society of Depreciation Professionals Annual Meeting, September 1997.

Economic Depreciation In Response to Competitive Market Pricing, 1997 TELUS Depreciation Conference, June 1997.

Valuation of Special Franchise Property, City of New York, Department of Finance Valuation Seminar, March 1997.

Depreciation Implications of FAS Exposure Draft 158-B, 1996 TLG

Decommissioning Conference, October 1996.

Why Economic Depreciation?, American Gas Association Depreciation Accounting Committee Meeting, August 1995.

The Theory of Economic Depreciation, Society of Depreciation Professionals Annual Meeting, November 1994.

Vintage Depreciation Issues, G & T Accounting and Finance Association Conference, June 1994.

Pricing and Depreciation Strategies for Segmented Markets (Regulated and Competitive), Iowa State Regulatory Conference, May 1990.

Principles and Practices of Depreciation Accounting, Canadian Electrical Association and Nova Scotia Power Electric Utility Regulatory Seminar, December 1989.

Principles and Practices of Depreciation Accounting, Duke Power Accounting Seminar, September 1989.

The Theory and Practice of Depreciation Accounting Under Public Utility Regulation, GTE Capital Recovery Managers Conference, February 1989.

Valuation Methods for Regulated Utilities, GTE Capital Recovery Managers Conference, January 1988.

Depreciation Principles and Practices for REA Borrowers, NRECA 1985 National Accounting and Finance Conference, September 1985.

Depreciation Principles and Practices for REA Borrowers, Kentucky Association of Electric Cooperatives, Inc., Summer Accountants Association Meeting, June 1985.

Considerations in Conducting a Depreciation Study, NRECA 1984 National Accounting and Finance Conference, October 1984.

Software for Conducting Depreciation Studies on a Personal Computer, United States Independent Telephone Association, September 1984.

Depreciation—An Assessment of Current Practices, NRECA 1983 National Accounting and Finance Conference, September 1983

Depreciation—An Assessment of Current Practices, REA National Field Conference, September 1983.

An Overview of Depreciation Systems, Iowa State Commerce Commission, October 1982.

Depreciation Practices for Gas Utilities, Regulatory Committee of the Canadian Gas Association, September 1981.

Practice, Theory, and Needed Research on Capital Investment Decisions in the Energy Supply Industry, workshop, sponsored by Michigan State University and the Electric Power Research Institute, November 1977.

Depreciation Concepts Under Regulation, Public Utilities Conference, sponsored by The University of Texas at Dallas, July 1976.

Electric Utility Economics, Mid-Continent Area Power Pool, May 1974.

Honors and Awards

The Society of Sigma Xi.

Professional Achievement Citation in Engineering, Iowa State University, 1993.

Attachment REW–1

2005 Technical Update

Arizona Public Service Company

Prepared by
Foster Associates, Inc.

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July 2005

EXECUTIVE SUMMARY

INTRODUCTION

This report presents the findings and recommendations developed in a 2005 Technical Update of depreciation rates for Arizona Public Service Company (APS) prepared by Foster Associates, Inc. Parameters (*i.e.*, projection curves, projection lives and future net salvage rates) used in the update were accepted by the Arizona Corporation Commission (ACC) pursuant to a settlement agreement in Docket No. E–01345A–03–0437 (Decision No. 67744, dated April 7, 2005). Age distributions of surviving plant at December 31, 2004 were used in the 2005 update to derive composite service life statistics and computed or theoretical depreciation reserves.

Foster Associates is a public utility economic consulting firm headquartered in Bethesda, Maryland offering economic research and consulting services on issues and problems arising from governmental regulation of business. Areas of specialization supported by our Fort Myers office include property service–life forecasting, depreciation estimation, and valuation of industrial property.

Foster Associates has undertaken numerous depreciation engagements for both public and privately owned business entities, including detailed statistical life studies, analyses of required net salvage rates, and the selection of depreciation systems that will most nearly achieve the goals of depreciation accounting under the constraints of either government regulation or competitive market pricing. Foster Associates is widely recognized for industry leadership in the development of depreciation systems, life analysis techniques and computer software for conducting depreciation and valuation studies.

The purpose of a technical update is to adjust depreciation rates for changes in the variables associated with a remaining–life accrual rate. The variables for a plant account include the age distribution of surviving plant, the recorded depreciation reserve and the average net salvage rate used in the calculation of a theoretical reserve. A technical update retains the parameters developed and/or approved in the most recent full depreciation study and adjusts depreciation rates for subsequent changes in plant, reserves and realized net salvage activity.

The principal findings from the 2005 review are summarized in the attached statements. Statement A provides a comparative summary of present and proposed annual depreciation rates for each rate category. Statement B provides a comparison of present and proposed annual depreciation accruals. Statement C provides a comparison of the computed and redistributed depreciation reserve for each rate category. Statement D provides a summary of the components used to obtain a weighted–average net salvage rate for each plant account. Statement E provides a computation of the estimated future net salvage rate for steam production facilities. Statement F contains the computation of terminal dismantlement costs for

steam production facilities. Statement G provides a comparative summary of present and proposed parameters and statistics including projection life, projection curve, average service life, average remaining life, and average and future net salvage rates.

SCOPE OF STUDY

Unlike a full depreciation study in which service life and net salvage parameters are estimated from a blending of quantitative analyses and informed judgment, the current study retains the parameters accepted in Docket No. E–01345A–03–0437 and provides an update of depreciation rates based on account age distributions and reserve balances at December 31, 2004.

The principal activities undertaken in the course of conducting the 2005 Technical Update included:

- Collection of plant data;
- Reconciliation of data to the official records of the Company;
- Computation of future net salvage rates for steam production facilities;
- Rebalancing of depreciation reserves; and
- Development of adjusted accrual rates for each rate category.

DEPRECIATION SYSTEM

A depreciation rate is formed by combining the elements of a depreciation system. A depreciation system is composed of a method, a procedure and a technique. A depreciation method (*e.g.*, straight–line) describes the component of the system that determines the acceleration or deceleration of depreciation accruals in relation to either time or use. A depreciation procedure (*e.g.*, vintage group) identifies the level of grouping or sub–grouping of assets within a plant category. The level of grouping dictates the weighting used to obtain composite life statistics for an account. A depreciation technique (*e.g.*, remaining–life) describes the life statistic used in the system.

APS is currently using a depreciation system composed of the straight–line method, broad group procedure, and remaining–life technique for all plant categories. The present system was accepted by the ACC in Docket No. E–01345A–03–0437 without comment as to the appropriateness of the system or a consideration of alternative systems. Accordingly, depreciation rates in the 2005 update were developed using the currently approved system.

PROPOSED DEPRECIATION RATES

Table 1 provides a summary of the changes in annual rates and accruals resulting from the 2005 Technical Update. Rates proposed for each primary account include an allowance for net salvage.

Function	Accrual Rate			2005 Annualized Accrual		
	Present	Proposed	Difference	Present	Proposed	Difference
A	B	C	D=C-B	E	F	G=F-E
Production						
Steam	3.34%	3.83%	0.49%	$45,731,277	$52,392,026	$6,660,749
Nuclear	2.95%	2.78%	-0.17%	70,195,368	66,186,908	(4,008,460)
Other	2.93%	2.93%	0.00%	6,039,806	6,030,434	(9,372)
Transmission	1.55%	1.12%	-0.43%	685,384	496,457	(188,927)
Distribution	2.43%	2.47%	0.04%	81,502,058	82,773,852	1,271,794
General Plant	5.30%	5.75%	0.45%	17,462,319	18,958,703	1,496,384
Total Utility	2.89%	2.95%	0.06%	$221,616,212	$226,838,380	$5,222,168

Table 1. Present and Proposed Rates and Accruals

Adjustments developed in the technical update produce a composite depreciation rate of 2.95 percent. Depreciation expense is presently accrued at an equivalent rate of 2.89 percent. The proposed change in the composite depreciation rate represents an increase of 0.06 percentage points.

A continued application of rates currently approved would provide annual depreciation expense of $221,616,212 compared with an annual expense of $226,838,380 using the rates developed in the update. The proposed expense increase of $5,222,168 is largely attributable to: a) a change in the mix of plant investments among primary accounts; b) changes in the age distributions of surviving plant; and c) plant additions to Four Corners generating station.

STUDY PROCEDURE

INTRODUCTION

Unlike a full depreciation study in which projection curves, projection lives and future net salvage rates are estimated from a statistical analysis of recorded retirements and net salvage realized in the past, a technical update generally retains the parameters currently used by the utility and adjusts depreciation rates for known and measurable changes in the age distributions of surviving plant, depreciation reserves, and average net salvage rates due to the passage of time. A technical update is intended to align depreciation rates with the accounting year the rates will become effective.

SCOPE

The steps involved in preparing a technical update can be grouped into five principal activities:

- Data collection;
- Calculation of service life statistics;
- Computation of average net salvage rates;
- Rebalancing of depreciation reserves; and
- Development of accrual rates.

The scope of the 2005 update for APS included a consideration of each of these tasks as described below.

DATA COLLECTION

The database used in the 2005 update was provided to Foster Associates in an electronic format containing plant and reserve activity over the period 1972–2004 and age distributions of surviving plant at December 31, 2004. Data used in the update were limited to the age distributions of surviving plant. Depreciation rates currently used by APS were developed using a broad–group procedure. The realized life of surviving vintages derived from the dollar–years of service provided by each vintage is not relevant to an update of broad–group depreciation rates. Therefore, plant transactions recorded in prior activity years were not used in the update.

Reserve transactions recorded in prior activity years were also not used in the 2005 update. Depreciation rates currently used by APS were derived without consideration of the distinction between average and future net salvage rates. The assumed equivalency between average and future net salvage rates was retained in the 2005 update without introducing prior realized net salvage amounts in the computation of average net salvage rates.

CALCULATION OF SERVICE LIFE STATISTICS

The composite remaining life and average service life of a plant category used in the calculation of depreciation rates are derived from a tabular arrangement of the age distribution of surviving plant and related statistics. The format of such a table is called a *generation arrangement*.

The age distribution of surviving plant is a column of numbers showing the dollar amount of investment remaining in service at the beginning of a study year from each of the vintages installed in prior years. The sum of an age distribution is the total plant in service for a plant category. The source of data used to construct an age distribution is a company's Continuing Property Record (CPR).

Statistics for each vintage (*i.e.*, average service life and remaining life) contained in a generation arrangement are derived from a mathematical function called a *survivor curve*. The survivor curve most descriptive of the forces of retirement acting upon a plant category is identified from a statistical analysis of past retirement experience, coupled with a consideration of how these forces are likely to change in the future. The collection of past retirements used in the statistical analysis can be viewed as a random sample from an unknown parent population. The objective of a life analysis is to estimate the parameters (*i.e.*, mean service life and dispersion characteristics) of the parent population. The mean service life of the population which best describes the timing of past and future retirements is called a *projection life* and the survivor curve selected to describe the forces of retirement acting upon the population is called a *projection curve*. A technical update generally retains the service life parameters estimated in a full depreciation study. Statistics for each vintage, however, are updated to reflect known and measurable changes in the age distributions of surviving plant.

COMPUTATION OF AVERAGE NET SALVAGE RATES

Estimates of the net salvage rates applicable to future retirements are derived in a full depreciation study from an analysis of gross salvage and removal expense realized in the past and a consideration of future expectations which may dictate a departure from historical indications. Future net salvage rates adopted from such an analysis are retained as fixed parameters in a technical update.

The average net salvage rate for an account or plant function is derived from a direct dollar weighting of a) historical retirements with historical (or realized) net salvage rates and b) future retirements (*i.e.*, surviving plant) with the estimated future net salvage rate. Average net salvage rates will change, therefore, as additional years of retirement and net salvage activity become available and as subsequent plant additions alter the weighting of future net salvage estimates.

As noted earlier, depreciation rates currently used by APS were derived with-

out consideration of the distinction between average and future net salvage rates. The assumed equivalency between average and future net salvage rates was retained in the 2005 update without introducing prior realized net salvage amounts in the computation of average net salvage rates.

Although arguably beyond the scope of a technical update, future net salvage rates for steam production facilities were adjusted in the 2005 update for estimated terminal dismantlement costs. The treatment of dismantlement costs in prior studies (and in the depreciation rates currently used by APS) reflects an assumption that interim and future net salvage rates will be equal. This assumption was relaxed in the 2005 update by: a) retaining an interim net salvage rate of –20 percent; and b) adjusting terminal dismantlement costs to reflect costs per kW estimated in dismantling studies conducted in 2002 for the Navajo and Four Corners generating stations. An inflation rate of three percent was used to escalate 2002 dollars to estimated years of final retirement. Statement F provides a computation of terminal dismantlement costs used in Statement E to derive future net salvage rates for steam production facilities. The retained equivalency of average and future net salvage rates is shown in Statement D.

REBALANCING OF DEPRECIATION RESERVES

Although reserve records are typically maintained by various account classifications, the total reserve for a company is the most important measure of the status of the company's depreciation practices and procedures. If a company has not previously conducted statistical life studies or considered retirement dispersion in setting depreciation rates, it is likely that some accounts will be overdepreciated and other accounts will be underdepreciated relative to a calculated theoretical reserve. Differences between theoretical and recorded reserves will also arise as a normal occurrence when service lives, dispersion patterns and net salvage estimates are changed in the course of depreciation reviews. It is appropriate, therefore, and consistent with group depreciation theory to periodically redistribute recorded reserves among the various primary accounts based upon the most recent estimates of retirement dispersion and net salvage rates.

A rebalancing of recorded reserves is consistent with the objectives of a technical update and is considered appropriate for APS. Depreciation rates adopted in Docket No. E–01345A–03–0437 were derived from rebalanced reserves obtained from a set of parameters different from those used in the formulation of the settled remaining–life accrual rates. Reserve imbalances amortized in the settled rates are therefore inconsistent with the realigned depreciation reserves. The rebalancing of reserves undertaken in the 2005 update will reestablish consistency between measured reserve imbalances and the parameters used in the formulation of updated remaining–life accrual rates.

A redistribution of the recorded reserve was achieved for APS by multiplying the calculated reserve for each primary account within a function (or plant location) by the ratio of the function (or location) total recorded reserve to the function (or location) total calculated reserve. The sum of the redistributed reserves within a function (or location) is, therefore, equal to the function (or location) total recorded depreciation reserve before the redistribution.

Statement C provides a comparison of the recorded, computed and rebalanced reserves for APS at December 31, 2004. The recorded reserve was $3,114,473,674, or 50.0 percent of the depreciable plant investment. The corresponding computed reserve is $2,771,955,374 or 48.0 percent of the depreciable plant investment. A proportionate amount of the measured reserve excess of $342,518,300 will be amortized over the composite weighted–average remaining life of each rate category.

DEVELOPMENT OF ACCRUAL RATES

The goal or objective of depreciation accounting is cost allocation over the economic life of an asset in proportion to the consumption of service potential. Ideally, the cost of an asset—which represents the cost of obtaining a bundle of service units—should be allocated to future periods of operation in proportion to the amount of service potential expended during an accounting interval. The service potential of an asset is the present value of future net revenue (*i.e.*, revenue less expenses exclusive of depreciation and other non-cash expenses) or cash inflows attributable to the use of that asset alone.

Depreciation rates currently used by APS were developed using a system composed of the straight–line method, broad–group procedure, remaining–life technique. Depreciation rates proposed in the update were developed using the currently approved system.

STATEMENTS

INTRODUCTION

This section provides a comparative summary of depreciation rates, annual depreciation accruals, recorded and computed depreciation reserves, and present and proposed service life and net salvage parameters for APS. The content of these statements is briefly described below.

- Statement A provides a comparative summary of present and proposed annual depreciation rates for calendar year 2005 using the straight–line method, broad group procedure, remaining–life technique.
- Statement B provides a comparison of present and proposed annualized depreciation accruals for calendar year 2005 based upon the rates developed in Statement A.
- Statement C provides a comparison of recorded and computed reserves for each rate category and sets forth the computations used to redistribute recorded reserves among primary plant accounts.
- Statement D provides a summary of the components used to obtain a weighted average net salvage rate for each rate category.
- Statement E provides a computation of the estimated future net salvage rate for steam production facilities.
- Statement F contains the computation of terminal dismantlement costs for steam production facilities.
- Statement G provides a comparative summary of present and proposed parameters including projection life, projection curve and future net salvage rates. The statement also contains present and proposed statistics including average service life, average remaining life, and average net salvage rates.

Present depreciation accruals shown on Statement B are the product of plant investments (Column B) and the present depreciation rates (Column D) shown on Statement A. These are the effective rates used by APS for the mix of investments recorded on December 31, 2004. Similarly, proposed depreciation accruals shown on Statement B are the product of plant investments and proposed depreciation rates (Column H) shown on Statement A. Proposed accrual rates shown on Statement A are given by:

$$Accrual\ Rate = \frac{1.0 - Reserve\ Ratio - Future\ Net\ Salvage\ Rate}{Remaining\ Life}.$$

ARIZONA PUBLIC SERVICE COMPANY Statement A

Comparison of Present and Proposed Accrual Rates
Present: BG Procedure / RL Technique
Proposed: BG Procedure / RL Technique

	Present			Proposed (at December 31, 2004)			
Account Description	Rem. Life	Net Salvage	Accrual Rate	Rem. Life	Net Salvage	Reserve Ratio	Accrual Rate
A	B	C	D	E	F	G	H
STEAM PRODUCTION							
311.00 Structures and Improvements			2.96%	18.47	-18.7%	50.17%	3.75%
312.00 Boiler Plant Equipment			3.52%	15.64	-18.8%	57.35%	3.97%
314.00 Turbogenerator Units			3.00%	17.74	-20.6%	57.01%	3.64%
315.00 Accessory Electric Equipment			2.71%	20.34	-19.2%	60.07%	2.95%
316.00 Misc. Power Plant Equipment			4.21%	16.98	-21.1%	43.49%	4.60%
Total Steam Production Plant			3.34%	16.64	-19.2%	56.27%	3.83%
NUCLEAR PRODUCTION							
321.00 Structures and Improvements			2.60%	20.63		45.97%	2.62%
322.00 Reactor Plant Equipment			2.86%	19.58	-0.2%	44.69%	2.84%
322.10 Steam Generators			8.39%	1.71		95.73%	2.17%
323.00 Turbogenerator Units			2.90%	19.08	-0.4%	45.83%	2.86%
324.00 Accessory Electric Equipment			2.78%	18.99	-0.5%	49.17%	2.70%
325.00 Misc. Power Plant Equipment			3.59%	17.27	-0.8%	43.01%	3.35%
Total Nuclear Production Plant			2.95%	18.78	-0.2%	46.75%	2.78%
OTHER PRODUCTION							
341.00 Structures and Improvements			2.71%	18.52	-4.8%	48.33%	2.43%
342.00 Fuel Holders, Products and Accessories			2.87%	22.27	-5.0%	39.18%	2.78%
343.00 Prime Movers			1.25%	11.58		83.08%	1.45%
344.00 Generators and Devices			3.59%	17.27	-1.4%	36.00%	3.55%
345.00 Accessory Electric Equipment			2.27%	19.53		48.77%	2.40%
346.00 Misc. Power Plant Equipment			2.56%	16.90		52.37%	2.71%
Total Other Production Plant			2.93%	17.35	-1.6%	46.10%	2.93%
TOTAL PRODUCTION PLANT			3.08%	17.92		50.02%	3.15%
TRANSMISSION							
352.00 Structures and Improvements	35.20	-5.0%	1.70%	21.69	-5.0%	110.65%	-0.26%
353.00 Station Equipment	45.70		1.52%	39.98		55.57%	1.11%
354.00 Towers and Fixtures	38.30	-35.0%	2.08%	42.49	-35.0%	73.33%	1.45%
355.00 Poles and Fixtures - Wood	38.50	-35.0%	2.72%	18.51	-15.0%	142.00%	-1.46%
356.00 Overhead Conductors and Devices	38.50	-35.0%	2.32%	37.51	-35.0%	79.90%	1.47%
Total Transmission Plant			1.55%	39.97	-1.5%	56.57%	1.12%
DISTRIBUTION							
361.00 Structures and Improvements	33.10	-10.0%	2.10%	33.18	-10.0%	38.78%	2.15%
362.00 Station Equipment	36.90		2.04%	36.73		22.18%	2.12%
364.00 Poles, Towers and Fixtures - Wood	30.90	-10.0%	2.64%	29.41	-10.0%	33.37%	2.61%
364.10 Poles, Towers and Fixtures - Steel	46.60	-5.0%	2.03%	46.78	-5.0%	9.08%	2.05%
365.00 Overhead Conductors and Devices	47.70	-10.0%	1.99%	46.65	-10.0%	17.69%	1.98%
366.00 Underground Conduit	82.40	-5.0%	1.20%	82.10	-5.0%	6.39%	1.20%
367.00 Underground Conductors and Devices	22.90	-5.0%	3.18%	22.28	-5.0%	32.66%	3.25%
368.00 Line Transformers	24.60	-5.0%	2.30%	23.63	-5.0%	48.43%	2.39%
369.00 Services	27.90	-10.0%	2.60%	26.72	-10.0%	41.02%	2.58%
370.00 Meters	21.80		2.84%	21.24		35.92%	3.02%
370.10 Meters - Electronic	23.30		3.61%	23.06		15.18%	3.68%
371.00 Installations on Customers' Premises	45.00	-20.0%	2.33%	45.48	-20.0%	14.56%	2.32%
373.00 Street Lighting and Signal Systems	25.90	-20.0%	3.10%	24.32	-20.0%	49.15%	2.91%
Total Distribution Plant			2.43%	30.41	-6.1%	29.53%	2.47%

ARIZONA PUBLIC SERVICE COMPANY Statement A

Comparison of Present and Proposed Accrual Rates
Present: BG Procedure / RL Technique
Proposed: BG Procedure / RL Technique

	Present			Proposed (at December 31, 2004)			
Account Description	Rem. Life	Net Salvage	Accrual Rate	Rem. Life	Net Salvage	Reserve Ratio	Accrual Rate
A	B	C	D	E	F	G	H
GENERAL							
390.00 Structures and Improvements	30.70	-15.0%	2.93%	29.54	-15.0%	28.01%	2.94%
391.00 Office Furn. and Equip. - Furniture	10.10		4.16%	12.23		39.00%	4.99%
391.10 Office Furn. and Equip. - PC Equipment	5.30		11.43%	4.28		46.69%	12.46%
391.20 Office Furn. and Equip. - Other	14.80		4.17%	13.44		39.06%	4.53%
393.00 Stores Equipment	2.80			2.14		89.66%	4.83%
394.00 Tools, Shop and Garage Equipment	13.70		4.61%	12.20		39.16%	4.99%
395.00 Laboratory Equipment	12.00		5.07%	11.99		40.21%	4.99%
397.00 Communication Equipment	12.00		4.74%	11.53		39.47%	5.25%
398.HH Miscellaneous Equipment - Hydrogen			20.00%	2.50		50.20%	19.92%
398.00 Miscellaneous Equipment	16.60		3.85%	20.91		12.93%	4.16%
Total General			5.30%	11.41	-4.7%	36.88%	5.75%
TOTAL UTILITY			2.89%	22.24	-5.9%	40.55%	2.95%
STEAM PRODUCTION (BY UNIT)							
Cholla							
311.00 Structures and Improvements			2.27%	27.11	-19.2%	57.24%	2.28%
312.00 Boiler Plant Equipment			2.78%	19.78	-19.4%	63.40%	2.83%
314.00 Turbogenerator Units			2.63%	24.85	-19.9%	49.55%	2.81%
315.00 Accessory Electric Equipment			2.33%	24.71	-19.4%	61.20%	2.35%
316.00 Misc. Power Plant Equipment			3.38%	20.65	-19.2%	48.43%	3.42%
Total Cholla			2.66%	21.89	-19.5%	59.71%	2.72%
Cholla Unit 1							
311.00 Structures and Improvements	14.00	-20.0%	2.44%	11.97	-15.8%	84.63%	2.60%
312.00 Boiler Plant Equipment	13.40	-20.0%	3.98%	11.20	-16.3%	68.47%	4.27%
314.00 Turbogenerator Units	14.00	-20.0%	3.46%	11.90	-15.8%	74.85%	3.44%
315.00 Accessory Electric Equipment	13.90	-20.0%	3.20%	11.86	-15.9%	75.87%	3.38%
316.00 Misc. Power Plant Equipment	13.50	-20.0%	5.08%	11.63	-16.1%	56.79%	5.10%
Total Cholla Unit 1			3.77%	11.44	-16.1%	70.74%	3.97%
Cholla Unit 2							
311.00 Structures and Improvements	29.00	-20.0%	2.69%	26.78	-18.1%	49.48%	2.56%
312.00 Boiler Plant Equipment	22.00	-20.0%	2.65%	20.46	-19.0%	65.37%	2.62%
314.00 Turbogenerator Units	27.50	-20.0%	2.39%	25.56	-18.3%	59.67%	2.29%
315.00 Accessory Electric Equipment	26.80	-20.0%	2.26%	25.09	-18.4%	62.71%	2.22%
316.00 Misc. Power Plant Equipment	22.10	-20.0%	2.97%	20.74	-19.1%	56.37%	3.02%
Total Cholla Unit 2			2.55%	21.99	-18.8%	63.58%	2.51%
Cholla Unit 3							
311.00 Structures and Improvements	29.90	-20.0%	2.20%	27.97	-21.7%	58.20%	2.27%
312.00 Boiler Plant Equipment	22.90	-20.0%	2.62%	21.56	-20.9%	62.35%	2.72%
314.00 Turbogenerator Units	29.70	-20.0%	2.60%	28.16	-21.8%	37.15%	3.01%
315.00 Accessory Electric Equipment	28.50	-20.0%	2.30%	26.87	-21.5%	58.38%	2.35%
316.00 Misc. Power Plant Equipment	23.80	-20.0%	3.02%	21.91	-20.8%	53.53%	3.07%
Total Cholla Unit 3			2.55%	24.25	-21.2%	55.38%	2.72%
Cholla Common							
311.00 Structures and Improvements	29.90	-20.0%	2.23%	28.01	-18.9%	56.45%	2.23%
312.00 Boiler Plant Equipment	24.80	-20.0%	2.82%	23.38	-19.3%	50.89%	2.93%
314.00 Turbogenerator Units	29.00	-20.0%	2.30%	27.18	-19.0%	58.21%	2.24%
315.00 Accessory Electric Equipment	28.70	-20.0%	2.33%	27.19	-19.0%	50.96%	2.50%
316.00 Misc. Power Plant Equipment	25.80	-20.0%	3.32%	24.23	-19.3%	38.04%	3.35%
Total Cholla Common			2.55%	25.69	-19.1%	52.31%	2.60%

ARIZONA PUBLIC SERVICE COMPANY Statement A

Comparison of Present and Proposed Accrual Rates
Present: BG Procedure / RL Technique
Proposed: BG Procedure / RL Technique

Account Description	Present Rem. Life	Present Net Salvage	Present Accrual Rate	Proposed (at December 31, 2004) Rem. Life	Proposed Net Salvage	Proposed Reserve Ratio	Proposed Accrual Rate
A	B	C	D	E	F	G	H
Four Corners							
311.00 Structures and Improvements			3.49%	13.52	-18.5%	42.70%	5.54%
312.00 Boiler Plant Equipment			4.13%	12.87	-18.1%	53.27%	5.01%
314.00 Turbogenerator Units			3.58%	13.24	-17.8%	53.95%	4.79%
315.00 Accessory Electric Equipment			3.70%	14.61	-19.3%	55.04%	4.36%
316.00 Misc. Power Plant Equipment			4.72%	15.90	-21.7%	41.99%	4.96%
Total Four Corners			4.00%	13.18	-18.3%	52.12%	4.98%
Four Corners Units 1-3							
311.00 Structures and Improvements	13.30	-20.0%	4.02%	11.39	-14.1%	36.62%	6.80%
312.00 Boiler Plant Equipment	12.70	-20.0%	4.84%	10.76	-14.8%	50.84%	5.94%
314.00 Turbogenerator Units	13.10	-20.0%	3.96%	11.08	-14.5%	53.98%	5.46%
315.00 Accessory Electric Equipment	13.20	-20.0%	4.68%	11.21	-14.3%	53.65%	5.41%
316.00 Misc. Power Plant Equipment	13.10	-20.0%	7.53%	11.15	-14.4%	29.52%	7.61%
Total Four Corners Units 1-3			4.68%	10.90	-14.7%	49.72%	5.96%
Four Corners Units 4-5							
311.00 Structures and Improvements	26.80	-20.0%	2.40%	24.80	-26.8%	57.08%	2.81%
312.00 Boiler Plant Equipment	22.10	-20.0%	2.82%	20.40	-24.1%	57.62%	3.26%
314.00 Turbogenerator Units	26.30	-20.0%	2.70%	24.09	-26.4%	50.68%	3.14%
315.00 Accessory Electric Equipment	25.90	-20.0%	2.51%	24.24	-26.4%	50.75%	3.12%
316.00 Misc. Power Plant Equipment	23.00	-20.0%	3.37%	20.22	-23.8%	49.96%	3.65%
Total Four Corners Units 4-5			2.77%	21.23	-24.6%	56.30%	3.22%
Four Corners Common							
311.00 Structures and Improvements	26.80	-20.0%	2.37%	24.71	-29.0%	51.89%	3.12%
312.00 Boiler Plant Equipment	22.80	-20.0%	2.39%	19.62	-25.3%	63.41%	3.15%
314.00 Turbogenerator Units	23.30	-20.0%	1.79%	21.73	-26.4%	81.01%	2.09%
315.00 Accessory Electric Equipment	21.00	-20.0%	1.85%	20.44	-25.2%	79.18%	2.25%
316.00 Misc. Power Plant Equipment	23.20	-20.0%	3.33%	21.37	-25.8%	47.46%	3.67%
Total Four Corners Common			2.64%	21.73	-26.4%	57.96%	3.15%
Navajo Units 1-3							
311.00 Structures and Improvements	22.80	-20.0%	3.29%	20.78	-14.5%	44.27%	3.38%
312.00 Boiler Plant Equipment	20.60	-20.0%	3.55%	18.52	-15.8%	48.18%	3.65%
314.00 Turbogenerator Units	22.00	-20.0%	2.76%	20.00	-14.9%	57.66%	2.86%
315.00 Accessory Electric Equipment	22.00	-20.0%	2.82%	19.88	-15.1%	56.77%	2.93%
316.00 Misc. Power Plant Equipment	20.20	-20.0%	3.74%	18.57	-15.9%	40.79%	4.04%
Total Navajo Units 1-3			3.39%	19.00	-15.5%	48.96%	3.50%
Ocotillo Units 1-2							
311.00 Structures and Improvements	17.10	-20.0%	3.80%	15.05	-37.9%	61.04%	5.11%
312.00 Boiler Plant Equipment	15.20	-20.0%	3.02%	12.89	-32.9%	77.61%	4.29%
314.00 Turbogenerator Units	16.80	-20.0%	2.76%	14.30	-36.1%	78.82%	4.01%
315.00 Accessory Electric Equipment	16.30	-20.0%	2.20%	13.90	-35.0%	77.01%	4.17%
316.00 Misc. Power Plant Equipment	16.20	-20.0%	5.24%	14.61	-36.8%	29.79%	7.32%
Total Octillo Units 1-2			3.18%	13.77	-34.7%	71.81%	4.57%
Saguaro Units 1-2							
311.00 Structures and Improvements	11.30	-20.0%	3.42%	9.28	-29.0%	72.94%	6.04%
312.00 Boiler Plant Equipment	11.10	-20.0%	4.69%	8.61	-27.8%	79.46%	5.61%
314.00 Turbogenerator Units	11.20	-20.0%	3.44%	9.15	-28.8%	85.64%	4.72%
315.00 Accessory Electric Equipment	11.20	-20.0%	2.79%	8.99	-28.5%	89.22%	4.37%
316.00 Misc. Power Plant Equipment	10.90	-20.0%	7.16%	8.96	-28.4%	55.15%	8.18%
Total Saguaro Units 1-2			4.24%	8.87	-28.3%	80.06%	5.44%

ARIZONA PUBLIC SERVICE COMPANY Statement A

Comparison of Present and Proposed Accrual Rates

Present: BG Procedure / RL Technique

Proposed: BG Procedure / RL Technique

Account Description	Present Rem. Life	Present Net Salvage	Present Accrual Rate	Proposed (at December 31, 2004) Rem. Life	Proposed Net Salvage	Proposed Reserve Ratio	Proposed Accrual Rate
A	B	C	D	E	F	G	H
NUCLEAR PRODUCTION (BY UNIT)							
Palo Verde							
321.00 Structures and Improvements			2.60%	20.63		45.97%	2.62%
322.00 Reactor Plant Equipment			2.86%	19.58	-0.2%	44.69%	2.84%
322.10 Steam Generators			8.39%	1.71		95.73%	2.17%
323.00 Turbogenerator Units			2.90%	19.08	-0.4%	45.83%	2.86%
324.00 Accessory Electric Equipment			2.78%	18.99	-0.5%	49.17%	2.70%
325.00 Misc. Power Plant Equipment			3.59%	17.27	-0.8%	43.01%	3.35%
Total Palo Verde			2.95%	18.78	-0.2%	46.75%	2.78%
Palo Verde Unit 1							
321.00 Structures and Improvements	21.20		2.68%	18.78		50.61%	2.63%
322.00 Reactor Plant Equipment	20.60	-2.0%	2.88%	18.37	-0.2%	49.47%	2.76%
322.10 Steam Generators	3.00	-17.0%	9.09%	1.00		98.53%	1.47%
323.00 Turbogenerator Units	19.90	-2.0%	2.93%	17.81	-0.4%	49.80%	2.84%
324.00 Accessory Electric Equipment	20.00	-2.0%	2.79%	17.80	-0.4%	52.35%	2.70%
325.00 Misc. Power Plant Equipment	17.70	-2.0%	3.52%	15.87	-0.8%	48.80%	3.28%
Total Palo Verde Unit 1			3.07%	17.85	-0.2%	51.79%	2.71%
Palo Verde Unit 2							
321.00 Structures and Improvements	22.00		2.55%	19.70		46.20%	2.73%
322.00 Reactor Plant Equipment	21.50	-2.0%	2.83%	19.32	-0.2%	38.02%	3.22%
322.10 Steam Generators	1.00	-17.0%	17.01%				
323.00 Turbogenerator Units	20.80	-2.0%	2.87%	18.74	-0.4%	41.76%	3.13%
324.00 Accessory Electric Equipment	20.90	-2.0%	2.78%	18.71	-0.5%	46.96%	2.86%
325.00 Misc. Power Plant Equipment	18.70	-2.0%	3.69%	16.82	-0.7%	39.57%	3.63%
Total Palo Verde Unit 2			2.83%	19.06	-0.3%	41.25%	3.10%
Palo Verde Unit 3							
321.00 Structures and Improvements	23.30		2.59%	21.58		45.56%	2.52%
322.00 Reactor Plant Equipment	22.60	-2.0%	2.85%	21.03	-0.3%	44.21%	2.67%
322.10 Steam Generators	5.00	-17.0%	7.63%	2.50		92.71%	2.92%
323.00 Turbogenerator Units	21.80	-2.0%	2.89%	20.33	-0.4%	44.88%	2.73%
324.00 Accessory Electric Equipment	22.10	-2.0%	2.77%	20.40	-0.5%	47.03%	2.62%
325.00 Misc. Power Plant Equipment	19.20	-2.0%	3.51%	17.88	-0.8%	43.64%	3.20%
Total Palo Verde Unit 3			2.98%	20.13	-0.3%	46.52%	2.67%
Palo Verde Water Reclamation							
321.00 Structures and Improvements	23.20		2.56%	21.55		42.72%	2.66%
322.00 Reactor Plant Equipment	23.00	-2.0%	4.18%	21.36	-0.2%	13.25%	4.07%
322.10 Steam Generators							
323.00 Turbogenerator Units	22.00	-2.0%	3.04%	20.51	-0.4%	37.48%	3.07%
324.00 Accessory Electric Equipment							
325.00 Misc. Power Plant Equipment	19.50	-2.0%	3.63%	18.15	-0.8%	38.20%	3.45%
Total Palo Verde Water Reclamation			2.56%	21.53	0.0%	42.68%	2.66%
Palo Verde Common							
321.00 Structures and Improvements	23.20		2.58%	21.59		43.59%	2.61%
322.00 Reactor Plant Equipment	22.60	-2.0%	2.91%	21.05	-0.3%	42.59%	2.74%
322.10 Steam Generators							
323.00 Turbogenerator Units	22.20	-2.0%	3.32%	20.63	-0.4%	35.84%	3.13%
324.00 Accessory Electric Equipment	22.00	-2.0%	2.78%	20.36	-0.5%	45.85%	2.68%
325.00 Misc. Power Plant Equipment	19.40	-2.0%	3.62%	18.04	-0.8%	40.98%	3.32%
Total Palo Verde Common			2.90%	20.40	-0.3%	42.99%	2.81%

ARIZONA PUBLIC SERVICE COMPANY Statement A

Comparison of Present and Proposed Accrual Rates
Present: BG Procedure / RL Technique
Proposed: BG Procedure / RL Technique

Account Description	Present Rem. Life	Present Net Salvage	Present Accrual Rate	Proposed (at December 31, 2004) Rem. Life	Proposed Net Salvage	Proposed Reserve Ratio	Proposed Accrual Rate
A	B	C	D	E	F	G	H
OTHER PRODUCTION (BY UNIT)							
Douglas CT							
341.00 Structures and Improvements	13.90	-5.0%	1.01%	12.01	-5.0%	96.08%	0.74%
342.00 Fuel Holders, Products and Accessories	14.00	-5.0%	2.31%	12.08	-5.0%	80.67%	2.01%
343.00 Prime Movers	14.20		0.65%	11.65		91.77%	0.71%
344.00 Generators and Devices	9.70		0.17%	8.41		98.99%	0.12%
345.00 Accessory Electric Equipment	13.10		0.86%	11.06		90.19%	0.89%
346.00 Misc. Power Plant Equipment	13.80		1.90%	11.86		78.04%	1.85%
Total Douglas CT			0.69%	11.44	-0.3%	92.39%	0.69%
Ocotillo CT Units 1-2							
341.00 Structures and Improvements	14.50	-5.0%	2.40%	12.12	-5.0%	75.23%	2.46%
342.00 Fuel Holders, Products and Accessories	14.00	-5.0%	2.36%	12.11	-5.0%	77.54%	2.27%
343.00 Prime Movers	14.10		1.06%	11.73		83.82%	1.38%
344.00 Generators and Devices	13.60		3.33%	11.60		61.21%	3.34%
345.00 Accessory Electric Equipment	13.20		1.08%	11.29		80.92%	1.69%
346.00 Misc. Power Plant Equipment	14.00		1.74%	11.81		76.69%	1.97%
Total Ocotillo CT Units 1-2			2.07%	11.66	-0.4%	73.86%	2.27%
Saguaro CT Units 1-2							
341.00 Structures and Improvements	14.40	-5.0%	4.77%	12.34	-5.0%	44.74%	4.88%
342.00 Fuel Holders, Products and Accessories	14.00	-5.0%	1.92%	12.00	-5.0%	83.06%	1.83%
343.00 Prime Movers	13.80		1.29%	11.77		83.03%	1.44%
344.00 Generators and Devices	13.00		3.09%	10.88		60.02%	3.67%
345.00 Accessory Electric Equipment	13.40		1.42%	11.28		84.83%	1.34%
346.00 Misc. Power Plant Equipment	14.10		3.41%	12.00		59.00%	3.42%
Total Saguaro CT Units 1-2			2.15%	11.56	-0.8%	73.64%	2.35%
Solar Units							
341.00 Structures and Improvements	3.60			2.03		121.49%	-10.59%
342.00 Fuel Holders, Products and Accessories							
343.00 Prime Movers				11.50		6.09%	8.17%
344.00 Generators and Devices	7.80		6.74%	7.56		54.10%	6.07%
345.00 Accessory Electric Equipment	9.90		7.71%	7.86		50.45%	6.30%
346.00 Misc. Power Plant Equipment							
Total Solar Units			6.58%	7.82		55.59%	5.68%
West Phoenix							
341.00 Structures and Improvements			2.38%	24.31	-5.0%	43.23%	2.51%
342.00 Fuel Holders, Products and Accessories			3.20%	24.77	-5.0%	26.12%	3.15%
343.00 Prime Movers			2.07%	11.86		72.42%	2.33%
344.00 Generators and Devices			3.24%	23.01	-1.9%	25.79%	3.28%
345.00 Accessory Electric Equipment			2.64%	23.25		33.87%	2.77%
346.00 Misc. Power Plant Equipment			2.69%	20.03		43.10%	2.80%
Total West Pheonix			3.03%	22.53	-2.2%	31.12%	3.09%
West Phoenix CT Units 1-2							
341.00 Structures and Improvements	14.20	-5.0%	1.61%	12.12	-5.0%	85.24%	1.63%
342.00 Fuel Holders, Products and Accessories	14.00	-5.0%	1.92%	12.03	-5.0%	82.07%	1.91%
343.00 Prime Movers	14.20		2.07%	11.86		72.42%	2.33%
344.00 Generators and Devices	12.30		1.80%	10.75		68.68%	2.91%
345.00 Accessory Electric Equipment	13.20		1.18%	11.27		83.49%	1.46%
346.00 Misc. Power Plant Equipment	14.10		3.33%	12.02		57.98%	3.50%
Total West Ploenix CT Units 1-2			1.96%	11.49	-0.5%	72.76%	2.42%

ARIZONA PUBLIC SERVICE COMPANY *Statement A*

Comparison of Present and Proposed Accrual Rates
Present: BG Procedure / RL Technique
Proposed: BG Procedure / RL Technique

Account Description	Present			Proposed (at December 31, 2004)			
	Rem. Life	Net Salvage	Accrual Rate	Rem. Life	Net Salvage	Reserve Ratio	Accrual Rate
A	B	C	D	E	F	G	H
West Phoenix CC Units 1-3							
341.00 Structures and Improvements	28.10	-5.0%	2.44%	25.21	-5.0%	40.18%	2.57%
342.00 Fuel Holders, Products and Accessories	27.70	-5.0%	3.30%	25.65	-5.0%	21.95%	3.24%
343.00 Prime Movers							
344.00 Generators and Devices	26.20	-2.0%	3.33%	23.95	-2.0%	23.04%	3.30%
345.00 Accessory Electric Equipment	27.80		2.82%	24.59		27.63%	2.94%
346.00 Misc. Power Plant Equipment	26.60		2.47%	24.26		38.00%	2.56%
Total West Phoenix CC Units 1-3			3.20%	24.35	-2.4%	24.71%	3.19%
Yucca CT Units 1-4							
341.00 Structures and Improvements	13.40	-5.0%	4.16%	11.35	-5.0%	61.13%	3.87%
342.00 Fuel Holders, Products and Accessories	12.90	-5.0%	1.28%	11.00	-5.0%	94.51%	0.95%
343.00 Prime Movers	14.20		0.55%	10.81		93.27%	0.62%
344.00 Generators and Devices	11.60		1.64%	9.09		87.36%	1.39%
345.00 Accessory Electric Equipment	13.00		1.24%	10.37		87.09%	1.24%
346.00 Misc. Power Plant Equipment	13.20		1.23%	10.90		80.29%	1.81%
Total Yucca CT Units 1-4			1.14%	10.24	-0.9%	90.11%	1.06%

ARIZONA PUBLIC SERVICE COMPANY Statement B

Comparison of Present and Proposed Accruals
Present: BG Procedure / RL Technique
Proposed: BG Procedure / RL Technique

Account Description	12/31/04 Plant Investment	2005 Annualized Accrual Present	Proposed	Difference
A	B	C	D	E=D-C
STEAM PRODUCTION				
311.00 Structures and Improvements	$131,870,408	$3,902,247	$4,939,665	$1,037,418
312.00 Boiler Plant Equipment	837,866,945	29,500,044	33,265,700	3,765,656
314.00 Turbogenerator Units	201,179,564	6,040,327	7,332,245	1,291,918
315.00 Accessory Electric Equipment	138,223,358	3,742,018	4,071,592	329,574
316.00 Misc. Power Plant Equipment	60,433,389	2,546,641	2,782,824	236,183
Total Steam Production Plant	$1,369,573,664	$45,731,277	$52,392,026	$6,660,749
NUCLEAR PRODUCTION				
321.00 Structures and Improvements	$640,003,980	$16,629,867	$16,763,507	$133,640
322.00 Reactor Plant Equipment	939,061,294	26,844,521	26,663,549	(180,972)
322.10 Steam Generators	52,865,345	4,434,434	1,145,606	(3,288,828)
323.00 Turbogenerator Units	342,424,222	9,933,350	9,796,470	(136,880)
324.00 Accessory Electric Equipment	272,624,619	7,581,450	7,365,529	(215,921)
325.00 Misc. Power Plant Equipment	132,963,906	4,771,746	4,452,247	(319,499)
Total Nuclear Production Plant	$2,379,943,366	$70,195,368	$66,186,908	($4,008,460)
OTHER PRODUCTION				
341.00 Structures and Improvements	$10,180,396	$275,443	$247,818	($27,625)
342.00 Fuel Holders, Products and Accessories	26,096,001	749,643	725,004	(24,639)
343.00 Prime Movers	32,466,268	406,130	469,913	63,783
344.00 Generators and Devices	111,753,871	4,017,508	3,963,121	(54,387)
345.00 Accessory Electric Equipment	19,867,012	451,140	476,544	25,404
346.00 Misc. Power Plant Equipment	5,460,622	139,942	148,034	8,092
Total Other Production Plant	$205,824,170	$6,039,806	$6,030,434	($9,372)
TOTAL PRODUCTION PLANT	$3,955,341,200	$121,966,451	$124,609,368	$2,642,917
TRANSMISSION				
352.00 Structures and Improvements	$95,935	$1,631	($249)	($1,880)
353.00 Station Equipment	42,249,917	642,199	468,974	(173,225)
354.00 Towers and Fixtures	1,329,316	27,650	19,275	(8,375)
355.00 Poles and Fixtures - Wood	11,064	301	(162)	(463)
356.00 Overhead Conductors and Devices	586,319	13,603	8,619	(4,984)
Total Transmission Plant	$44,272,551	$685,384	$496,457	($188,927)
DISTRIBUTION				
361.00 Structures and Improvements	$30,704,475	$644,794	$660,146	$15,352
362.00 Station Equipment	242,575,593	4,948,542	5,142,603	194,061
364.00 Poles, Towers and Fixtures - Wood	296,506,680	7,827,776	7,738,824	(88,952)
364.10 Poles, Towers and Fixtures - Steel	73,766,423	1,497,458	1,512,212	14,754
365.00 Overhead Conductors and Devices	233,951,705	4,655,639	4,632,244	(23,395)
366.00 Underground Conduit	509,266,861	6,111,202	6,111,202	
367.00 Underground Conductors and Devices	908,715,823	28,897,163	29,533,264	636,101
368.00 Line Transformers	537,581,653	12,364,378	12,848,202	483,824
369.00 Services	268,098,185	6,970,553	6,916,933	(53,620)
370.00 Meters	91,949,592	2,611,368	2,776,878	165,510
370.10 Meters - Electronic	65,427,927	2,361,948	2,407,748	45,800
371.00 Installations on Customers' Premises	31,927,745	743,916	740,724	(3,192)
373.00 Street Lighting and Signal Systems	60,236,149	1,867,321	1,752,872	(114,449)
Total Distribution Plant	$3,350,708,811	$81,502,058	$82,773,852	$1,271,794

ARIZONA PUBLIC SERVICE COMPANY Statement B

Comparison of Present and Proposed Accruals
Present: BG Procedure / RL Technique
Proposed: BG Procedure / RL Technique

Account Description	12/31/04 Plant Investment	2005 Annualized Accrual Present	Proposed	Difference
A	B	C	D	E=D-C
GENERAL				
390.00 Structures and Improvements	$103,793,498	$3,041,149	$3,051,529	$10,380
391.00 Office Furn. and Equip. - Furniture	31,890,832	1,326,659	1,591,353	264,694
391.10 Office Furn. and Equip. - PC Equipment	49,510,133	5,659,008	6,168,963	509,955
391.20 Office Furn. and Equip. - Other	9,016,492	375,988	408,447	32,459
393.00 Stores Equipment	1,235,839		59,691	59,691
394.00 Tools, Shop and Garage Equipment	14,047,955	647,611	700,993	53,382
395.00 Laboratory Equipment	1,609,510	81,602	80,315	(1,287)
397.00 Communication Equipment	109,319,204	5,181,730	5,739,258	557,528
398.HH Miscellaneous Equipment - Hydrogen	4,904,211	980,842	976,919	(3,923)
398.00 Miscellaneous Equipment	4,356,614	167,730	181,235	13,505
Total General	$329,684,288	$17,462,319	$18,958,703	$1,496,384
TOTAL UTILITY	$7,680,006,850	$221,616,212	$226,838,380	$5,222,168
STEAM PRODUCTION (BY UNIT)				
Cholla				
311.00 Structures and Improvements	$53,689,761	$1,221,222	$1,225,028	$3,806
312.00 Boiler Plant Equipment	299,852,771	8,323,190	8,490,406	167,216
314.00 Turbogenerator Units	85,609,508	2,251,696	2,406,285	154,589
315.00 Accessory Electric Equipment	82,574,161	1,926,680	1,941,557	14,877
316.00 Misc. Power Plant Equipment	20,057,407	677,442	685,125	7,683
Total Cholla	$541,783,608	$14,400,230	$14,748,401	$348,171
Cholla Unit 1				
311.00 Structures and Improvements	$2,116,308	$51,638	$55,024	$3,386
312.00 Boiler Plant Equipment	27,464,546	1,093,089	1,172,736	79,647
314.00 Turbogenerator Units	10,355,816	358,311	356,240	(2,071)
315.00 Accessory Electric Equipment	4,790,621	153,300	161,923	8,623
316.00 Misc. Power Plant Equipment	2,432,224	123,557	124,043	486
Total Cholla Unit 1	$47,159,515	$1,779,895	$1,869,966	$90,071
Cholla Unit 2				
311.00 Structures and Improvements	$4,866,784	$130,916	$124,590	($6,326)
312.00 Boiler Plant Equipment	144,102,635	3,818,720	3,775,489	(43,231)
314.00 Turbogenerator Units	29,198,775	697,851	668,652	(29,199)
315.00 Accessory Electric Equipment	42,759,226	966,359	949,255	(17,104)
316.00 Misc. Power Plant Equipment	5,232,429	155,403	158,019	2,616
Total Cholla Unit 2	$226,159,849	$5,769,249	$5,676,005	($93,244)
Cholla Unit 3				
311.00 Structures and Improvements	$9,637,296	$212,021	$218,767	$6,746
312.00 Boiler Plant Equipment	103,136,479	2,702,176	2,805,312	103,136
314.00 Turbogenerator Units	45,423,639	1,181,015	1,367,252	186,237
315.00 Accessory Electric Equipment	30,152,547	693,509	708,585	15,076
316.00 Misc. Power Plant Equipment	4,319,200	130,440	132,599	2,159
Total Cholla Unit 3	$192,669,161	$4,919,161	$5,232,515	$313,354
Cholla Common				
311.00 Structures and Improvements	$37,069,373	$826,647	$826,647	
312.00 Boiler Plant Equipment	25,149,111	709,205	736,869	27,664
314.00 Turbogenerator Units	631,278	14,519	14,141	(378)
315.00 Accessory Electric Equipment	4,871,767	113,512	121,794	8,282
316.00 Misc. Power Plant Equipment	8,073,554	268,042	270,464	2,422
Total Cholla Common	$75,795,083	$1,931,925	$1,969,915	$37,990

ARIZONA PUBLIC SERVICE COMPANY Statement B

Comparison of Present and Proposed Accruals
Present: BG Procedure / RL Technique
Proposed: BG Procedure / RL Technique

Account Description	12/31/04 Plant Investment	2005 Annualized Accrual Present	Proposed	Difference
A	B	C	D	E=D-C
Four Corners				
311.00 Structures and Improvements	$43,005,911	$1,500,545	$2,380,558	$880,013
312.00 Boiler Plant Equipment	335,046,039	13,842,074	16,769,459	2,927,385
314.00 Turbogenerator Units	59,158,016	2,120,544	2,831,863	711,319
315.00 Accessory Electric Equipment	29,825,484	1,104,477	1,301,339	196,862
316.00 Misc. Power Plant Equipment	17,243,295	813,806	855,859	42,053
Total Four Corners	$484,278,745	$19,381,446	$24,139,078	$4,757,632
Four Corners Units 1-3				
311.00 Structures and Improvements	$29,002,681	$1,165,908	$1,972,182	$806,274
312.00 Boiler Plant Equipment	218,326,908	10,567,022	12,968,618	2,401,596
314.00 Turbogenerator Units	42,777,597	1,693,993	2,335,657	641,664
315.00 Accessory Electric Equipment	17,232,291	806,471	932,267	125,796
316.00 Misc. Power Plant Equipment	5,676,014	427,404	431,945	4,541
Total Four Corners Units 1-3	$313,015,491	$14,660,798	$18,640,669	$3,979,871
Four Corners Units 4-5				
311.00 Structures and Improvements	$9,201,539	$220,837	$258,563	$37,726
312.00 Boiler Plant Equipment	112,898,782	3,183,746	3,680,500	496,754
314.00 Turbogenerator Units	14,652,943	395,629	460,102	64,473
315.00 Accessory Electric Equipment	9,853,384	247,320	307,426	60,106
316.00 Misc. Power Plant Equipment	3,029,198	102,084	110,566	8,482
Total Four Corners Units 4-5	$149,635,846	$4,149,616	$4,817,157	$667,541
Four Corners Common				
311.00 Structures and Improvements	$4,801,691	$113,800	$149,813	$36,013
312.00 Boiler Plant Equipment	3,820,349	91,306	120,341	29,035
314.00 Turbogenerator Units	1,727,476	30,922	36,104	5,182
315.00 Accessory Electric Equipment	2,739,809	50,686	61,646	10,960
316.00 Misc. Power Plant Equipment	8,538,083	284,318	313,348	29,030
Total Four Corners Common	$21,627,408	$571,032	$681,252	$110,220
Navajo Units 1-3				
311.00 Structures and Improvements	$28,391,046	$934,065	$959,617	$25,552
312.00 Boiler Plant Equipment	156,202,698	5,545,196	5,701,398	156,202
314.00 Turbogenerator Units	24,699,305	681,701	706,400	24,699
315.00 Accessory Electric Equipment	20,448,549	576,649	599,142	22,493
316.00 Misc. Power Plant Equipment	14,618,062	546,716	590,570	43,854
Total Navajo Units 1-3	$244,359,660	$8,284,327	$8,557,127	$272,800
Ocotillo Units 1-2				
311.00 Structures and Improvements	$3,792,708	$144,123	$193,807	$49,684
312.00 Boiler Plant Equipment	24,174,538	730,071	1,037,088	307,017
314.00 Turbogenerator Units	15,372,486	424,281	616,437	192,156
315.00 Accessory Electric Equipment	2,670,248	58,745	111,349	52,604
316.00 Misc. Power Plant Equipment	5,258,871	275,565	384,949	109,384
Total Octillo Units 1-2	$51,268,851	$1,632,785	$2,343,630	$710,845
Saguaro Units 1-2				
311.00 Structures and Improvements	$2,990,982	$102,292	$180,655	$78,363
312.00 Boiler Plant Equipment	22,590,899	1,059,513	1,267,349	207,836
314.00 Turbogenerator Units	16,340,249	562,105	771,260	209,155
315.00 Accessory Electric Equipment	2,704,916	75,467	118,205	42,738
316.00 Misc. Power Plant Equipment	3,255,754	233,112	266,321	33,209
Total Saguaro Units 1-2	$47,882,800	$2,032,489	$2,603,790	$571,301

ARIZONA PUBLIC SERVICE COMPANY Statement B

Comparison of Present and Proposed Accruals
Present: BG Procedure / RL Technique
Proposed: BG Procedure / RL Technique

Account Description	12/31/04 Plant Investment	2005 Annualized Accrual Present	Proposed	Difference
A	B	C	D	E=D-C
NUCLEAR PRODUCTION (BY UNIT)				
Palo Verde				
321.00 Structures and Improvements	$640,003,980	$16,629,867	$16,763,507	$133,640
322.00 Reactor Plant Equipment	939,061,294	26,844,521	26,663,549	(180,972)
322.10 Steam Generators	52,865,345	4,434,434	1,145,606	(3,288,828)
323.00 Turbogenerator Units	342,424,222	9,933,350	9,796,470	(136,880)
324.00 Accessory Electric Equipment	272,624,619	7,581,450	7,365,529	(215,921)
325.00 Misc. Power Plant Equipment	132,963,906	4,771,746	4,452,247	(319,499)
Total Palo Verde	$2,379,943,366	$70,195,368	$66,186,908	($4,008,460)
Palo Verde Unit 1				
321.00 Structures and Improvements	$154,544,487	$4,141,792	$4,064,520	($77,272)
322.00 Reactor Plant Equipment	361,739,876	10,418,108	9,984,021	(434,087)
322.10 Steam Generators	27,452,571	2,495,439	403,553	(2,091,886)
323.00 Turbogenerator Units	118,250,432	3,464,738	3,358,312	(106,426)
324.00 Accessory Electric Equipment	114,359,460	3,190,629	3,087,705	(102,924)
325.00 Misc. Power Plant Equipment	29,942,323	1,053,970	982,108	(71,862)
Total Palo Verde Unit 1	$806,289,149	$24,764,676	$21,880,219	($2,884,457)
Palo Verde Unit 2				
321.00 Structures and Improvements	$90,520,213	$2,308,265	$2,471,202	$162,937
322.00 Reactor Plant Equipment	226,227,486	6,402,238	7,284,525	882,287
322.10 Steam Generators				
323.00 Turbogenerator Units	78,129,616	2,242,320	2,445,457	203,137
324.00 Accessory Electric Equipment	50,011,285	1,390,314	1,430,323	40,009
325.00 Misc. Power Plant Equipment	26,698,465	985,173	969,154	(16,019)
Total Palo Verde Unit 2	$471,587,065	$13,328,310	$14,600,661	$1,272,351
Palo Verde Unit 3				
321.00 Structures and Improvements	$160,291,956	$4,151,562	$4,039,357	($112,205)
322.00 Reactor Plant Equipment	323,919,702	9,231,712	8,648,656	(583,056)
322.10 Steam Generators	25,412,774	1,938,995	742,053	(1,196,942)
323.00 Turbogenerator Units	144,585,131	4,178,510	3,947,174	(231,336)
324.00 Accessory Electric Equipment	89,504,541	2,479,276	2,345,019	(134,257)
325.00 Misc. Power Plant Equipment	27,547,817	966,928	881,530	(85,398)
Total Palo Verde Unit 3	$771,261,921	$22,946,983	$20,603,789	($2,343,194)
Palo Verde Water Reclamation				
321.00 Structures and Improvements	$128,265,752	$3,283,603	$3,411,869	$128,266
322.00 Reactor Plant Equipment	133,326	5,573	5,426	(147)
322.10 Steam Generators				
323.00 Turbogenerator Units	235,152	7,149	7,219	70
324.00 Accessory Electric Equipment				
325.00 Misc. Power Plant Equipment	88,819	3,224	3,064	(160)
Total Palo Verde Water Reclamation	$128,723,049	$3,299,549	$3,427,578	$128,029
Palo Verde Common				
321.00 Structures and Improvements	$106,381,572	$2,744,645	$2,776,559	$31,914
322.00 Reactor Plant Equipment	27,040,904	786,890	740,921	(45,969)
322.10 Steam Generators				
323.00 Turbogenerator Units	1,223,891	40,633	38,308	(2,325)
324.00 Accessory Electric Equipment	18,749,333	521,231	502,482	(18,749)
325.00 Misc. Power Plant Equipment	48,686,482	1,762,451	1,616,391	(146,060)
Total Palo Verde Common	$202,082,182	$5,855,850	$5,674,661	($181,189)

ARIZONA PUBLIC SERVICE COMPANY

Statement B

Comparison of Present and Proposed Accruals
Present: BG Procedure / RL Technique
Proposed: BG Procedure / RL Technique

Account Description	12/31/04 Plant Investment	2005 Annualized Accrual Present	Proposed	Difference
A	B	C	D	E=D-C
OTHER PRODUCTION (BY UNIT)				
Douglas CT				
341.00 Structures and Improvements	$4,562	$46	$34	($12)
342.00 Fuel Holders, Products and Accessories	137,759	3,182	2,769	(413)
343.00 Prime Movers	1,101,449	7,159	7,820	661
344.00 Generators and Devices	551,765	938	662	(276)
345.00 Accessory Electric Equipment	353,277	3,038	3,144	106
346.00 Misc. Power Plant Equipment	40,913	777	757	(20)
Total Douglas CT	$2,189,725	$15,140	$15,186	$46
Ocotillo CT Units 1-2				
341.00 Structures and Improvements	$430,899	$10,342	$10,600	$258
342.00 Fuel Holders, Products and Accessories	719,859	16,989	16,341	(648)
343.00 Prime Movers	6,540,275	69,327	90,256	20,929
344.00 Generators and Devices	6,424,357	213,931	214,574	643
345.00 Accessory Electric Equipment	1,590,924	17,182	26,887	9,705
346.00 Misc. Power Plant Equipment	558,648	9,720	11,005	1,285
Total Ocotillo CT Units 1-2	$16,264,962	$337,491	$369,663	$32,172
Saguaro CT Units 1-2				
341.00 Structures and Improvements	$1,380,611	$65,855	$67,374	$1,519
342.00 Fuel Holders, Products and Accessories	1,304,977	25,056	23,881	(1,175)
343.00 Prime Movers	8,047,527	103,813	115,884	12,071
344.00 Generators and Devices	4,001,509	123,647	146,855	23,208
345.00 Accessory Electric Equipment	1,626,802	23,101	21,799	(1,302)
346.00 Misc. Power Plant Equipment	790,906	26,970	27,049	79
Total Saguaro CT Units 1-2	$17,152,332	$368,442	$402,842	$34,400
Solar Units				
341.00 Structures and Improvements	$352,259		($37,304)	($37,304)
342.00 Fuel Holders, Products and Accessories				
343.00 Prime Movers	20,596		1,683	1,683
344.00 Generators and Devices	14,326,036	965,575	869,590	(95,985)
345.00 Accessory Electric Equipment	166,465	12,834	10,487	(2,347)
346.00 Misc. Power Plant Equipment				
Total Solar Units	$14,865,356	$978,409	$844,456	($133,953)
West Phoenix				
341.00 Structures and Improvements	$7,550,035	$179,980	$189,233	$9,253
342.00 Fuel Holders, Products and Accessories	20,688,419	662,880	651,186	(11,694)
343.00 Prime Movers	8,794,167	182,039	204,904	22,865
344.00 Generators and Devices	81,091,743	2,625,538	2,656,957	31,419
345.00 Accessory Electric Equipment	13,957,323	368,049	387,291	19,242
346.00 Misc. Power Plant Equipment	3,590,505	96,575	100,541	3,966
Total West Pheonix	$135,672,192	$4,115,061	$4,190,112	$75,051
West Phoenix CT Units 1-2				
341.00 Structures and Improvements	$510,951	$8,226	$8,329	$103
342.00 Fuel Holders, Products and Accessories	1,437,533	27,601	27,457	(144)
343.00 Prime Movers	8,794,167	182,039	204,904	22,865
344.00 Generators and Devices	4,889,963	88,019	142,298	54,279
345.00 Accessory Electric Equipment	1,557,744	18,381	22,743	4,362
346.00 Misc. Power Plant Equipment	917,431	30,550	32,110	1,560
Total West Ploenix CT Units 1-2	$18,107,789	$354,816	$437,841	$83,025

ARIZONA PUBLIC SERVICE COMPANY Statement B

Comparison of Present and Proposed Accruals
Present: BG Procedure / RL Technique
Proposed: BG Procedure / RL Technique

Account Description	12/31/04 Plant Investment	2005 Annualized Accrual		
		Present	Proposed	Difference
A	B	C	D	E=D-C
West Phoenix CC Units 1-3				
341.00 Structures and Improvements	$7,039,084	$171,754	$180,904	$9,150
342.00 Fuel Holders, Products and Accessories	19,250,886	635,279	623,729	(11,550)
343.00 Prime Movers				
344.00 Generators and Devices	76,201,780	2,537,519	2,514,659	(22,860)
345.00 Accessory Electric Equipment	12,399,579	349,668	364,548	14,880
346.00 Misc. Power Plant Equipment	2,673,074	66,025	68,431	2,406
Total West Phoenix CC Units 1-3	$117,564,403	$3,760,245	$3,752,271	($7,974)
Yucca CT Units 1-4				
341.00 Structures and Improvements	$462,030	$19,220	$17,881	($1,339)
342.00 Fuel Holders, Products and Accessories	3,244,987	41,536	30,827	(10,709)
343.00 Prime Movers	7,962,254	43,792	49,366	5,574
344.00 Generators and Devices	5,358,461	87,879	74,483	(13,396)
345.00 Accessory Electric Equipment	2,172,221	26,936	26,936	
346.00 Misc. Power Plant Equipment	479,650	5,900	8,682	2,782
Total Yucca CT Units 1-4	$19,679,603	$225,263	$208,175	($17,088)

ARIZONA PUBLIC SERVICE COMPANY

Statement C

Depreciation Reserve Summary
Company Broad Group Procedure
December 31, 2004

Account Description	Plant Investment	Recorded Reserve		Computed Reserve		Redistributed Reserve	
		Amount	Ratio	Amount	Ratio	Amount	Ratio
A	B	C	D=C/B	E	F=E/B	G	H=G/B
STEAM PRODUCTION							
311.00 Structures and Improvements	$131,870,408	$67,445,386	51.15%	$64,733,598	49.09%	$66,163,395	50.17%
312.00 Boiler Plant Equipment	837,866,945	479,297,335	57.20%	477,835,629	57.03%	480,552,478	57.35%
314.00 Turbogenerator Units	201,179,564	114,837,083	57.08%	114,972,594	57.15%	114,684,530	57.01%
315.00 Accessory Electric Equipment	138,223,358	83,976,384	60.75%	80,076,560	57.93%	83,029,523	60.07%
316.00 Misc. Power Plant Equipment	60,433,389	25,153,908	41.62%	25,811,216	42.71%	26,280,170	43.49%
Total Steam Production Plant	$1,369,573,664	$770,710,095	56.27%	$763,429,596	55.74%	$770,710,095	56.27%
NUCLEAR PRODUCTION							
321.00 Structures and Improvements	$640,003,980	$294,926,651	46.08%	$280,574,366	43.84%	$294,231,705	45.97%
322.00 Reactor Plant Equipment	939,061,294	418,593,472	44.58%	400,836,955	42.68%	419,696,028	44.69%
322.10 Steam Generators	52,865,345	44,686,406	84.53%	47,690,929	90.21%	50,608,283	95.73%
323.00 Turbogenerator Units	342,424,222	158,086,020	46.17%	149,701,098	43.72%	156,938,919	45.83%
324.00 Accessory Electric Equipment	272,624,619	135,152,824	49.57%	127,776,396	46.87%	134,042,038	49.17%
325.00 Misc. Power Plant Equipment	132,963,906	61,253,702	46.07%	54,195,350	40.76%	57,182,102	43.01%
Total Nuclear Production Plant	$2,379,943,366	$1,112,699,075	46.75%	$1,060,775,093	44.57%	$1,112,699,075	46.75%
OTHER PRODUCTION							
341.00 Structures and Improvements	$10,180,396	$4,948,991	48.61%	$3,967,997	38.98%	$4,920,040	48.33%
342.00 Fuel Holders, Products and Accessories	26,096,001	10,109,160	38.74%	8,278,795	31.72%	10,224,943	39.18%
343.00 Prime Movers	32,466,268	27,452,832	84.56%	21,743,886	66.97%	26,971,556	83.08%
344.00 Generators and Devices	111,753,871	39,690,442	35.52%	31,766,947	28.43%	40,227,388	36.00%
345.00 Accessory Electric Equipment	19,867,012	9,740,972	49.03%	7,850,706	39.52%	9,688,695	48.77%
346.00 Misc. Power Plant Equipment	5,460,622	2,949,944	54.02%	2,327,457	42.62%	2,859,718	52.37%
Total Other Production Plant	$205,824,170	$94,892,341	46.10%	$75,935,790	36.89%	$94,892,341	46.10%
TOTAL PRODUCTION PLANT	$3,955,341,200	$1,978,301,511	50.02%	$1,900,140,479	48.04%	$1,978,301,511	50.02%
TRANSMISSION							
352.00 Structures and Improvements	$95,935	$54,278	56.58%	$57,034	59.45%	$106,151	110.65%
353.00 Station Equipment	42,249,917	23,903,897	56.58%	12,615,677	29.86%	23,480,053	55.57%
354.00 Towers and Fixtures	1,329,316	752,092	56.58%	523,717	39.40%	974,732	73.33%
355.00 Poles and Fixtures - Wood	11,064	3,130	28.29%	8,442	76.30%	15,711	142.00%
356.00 Overhead Conductors and Devices	586,319	331,724	56.58%	251,707	42.93%	468,472	79.90%
Total Transmission Plant	$44,272,551	$25,045,120	56.57%	$13,456,577	30.39%	$25,045,120	56.57%

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Account Description	Plant Investment	Recorded Reserve Amount	Recorded Reserve Ratio	Computed Reserve Amount	Computed Reserve Ratio	Redistributed Reserve Amount	Redistributed Reserve Ratio
A	B	C	D=C/B	E	F=E/B	G	H=G/B
DISTRIBUTION							
361.00 Structures and Improvements	$30,704,475	$12,042,606	39.22%	$8,871,546	28.89%	$11,907,311	38.78%
362.00 Station Equipment	242,575,593	64,729,721	26.68%	40,080,104	16.52%	53,795,161	22.18%
364.00 Poles, Towers and Fixtures - Wood	296,506,680	89,060,664	30.04%	73,728,727	24.87%	98,958,045	33.37%
364.10 Poles, Towers and Fixtures - Steel	73,766,423			4,988,086	6.76%	6,694,964	9.08%
365.00 Overhead Conductors and Devices	233,951,705	30,388,795	12.99%	30,833,069	13.18%	41,383,873	17.69%
366.00 Underground Conduit	509,266,861	40,709,016	7.99%	24,249,393	4.76%	32,547,321	6.39%
367.00 Underground Conductors and Devices	908,715,823	304,969,939	33.56%	221,099,960	24.33%	296,758,411	32.66%
368.00 Line Transformers	537,581,653	260,493,316	48.46%	193,954,981	36.08%	260,324,660	48.43%
369.00 Services	268,098,185	108,995,654	40.66%	81,936,602	30.56%	109,974,583	41.02%
370.00 Meters	91,949,592	48,455,598	52.70%	24,604,443	26.76%	33,023,865	35.92%
370.10 Meters - Electronic	65,427,927			7,398,389	11.31%	9,930,052	15.18%
371.00 Installations on Customers' Premises	31,927,745	4,779,055	14.97%	3,463,522	10.85%	4,648,708	14.56%
373.00 Street Lighting and Signal Systems	60,236,149	24,926,973	41.38%	22,056,757	36.62%	29,604,384	49.15%
Total Distribution Plant	$3,350,708,811	$989,551,337	29.53%	$737,265,577	22.00%	$989,551,337	29.53%
GENERAL							
390.00 Structures and Improvements	$103,793,498	$20,371,993	19.63%	$28,953,063	27.89%	$29,068,539	28.01%
391.00 Office Furn. and Equip. - Furniture	31,890,832	12,370,125	38.79%	12,389,588	38.85%	12,439,003	39.00%
391.10 Office Furn. and Equip. - PC Equipment	49,510,133	26,510,343	53.55%	23,022,212	46.50%	23,114,033	46.69%
391.20 Office Furn. and Equip. - Other	9,016,492	4,147,881	46.00%	3,508,235	38.91%	3,522,227	39.06%
393.00 Stores Equipment	1,235,839	1,302,760	105.42%	1,103,604	89.30%	1,108,006	89.66%
394.00 Tools, Shop and Garage Equipment	14,047,955	4,371,066	31.12%	5,478,702	39.00%	5,500,554	39.16%
395.00 Laboratory Equipment	1,609,510	739,810	45.96%	644,609	40.05%	647,180	40.21%
397.00 Communication Equipment	109,319,204	49,673,034	45.44%	42,979,708	39.32%	43,151,128	39.47%
398.HH Miscellaneous Equipment - Hydrogen	4,904,211	1,458,353	29.74%	2,452,106	50.00%	2,461,885	50.20%
398.00 Miscellaneous Equipment	4,356,614	630,341	14.47%	560,914	12.88%	563,151	12.93%
Total General	$329,684,288	$121,575,706	36.88%	$121,092,741	36.73%	$121,575,706	36.88%
TOTAL UTILITY	$7,680,006,850	$3,114,473,674	40.55%	$2,771,955,374	36.09%	$3,114,473,674	40.55%

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Account Description	Plant Investment	Recorded Reserve		Computed Reserve		Redistributed Reserve	
		Amount	Ratio	Amount	Ratio	Amount	Ratio
A	B	C	D=C/B	E	F=E/B	G	H=G/B
STEAM PRODUCTION (BY UNIT)							
Cholla							
311.00 Structures and Improvements	$53,689,761	$31,497,995	58.67%	$28,184,072	52.49%	$30,734,212	57.24%
312.00 Boiler Plant Equipment	299,852,771	189,075,083	63.06%	175,407,073	58.50%	190,104,861	63.40%
314.00 Turbogenerator Units	85,609,508	41,625,055	48.62%	39,353,428	45.97%	42,415,335	49.55%
315.00 Accessory Electric Equipment	82,574,161	51,127,041	61.92%	46,576,654	56.41%	50,535,008	61.20%
316.00 Misc. Power Plant Equipment	20,057,407	10,178,638	50.75%	8,960,322	44.67%	9,714,396	48.43%
Total Cholla	$541,783,608	$323,503,812	59.71%	$298,481,548	55.09%	$323,503,812	59.71%
Cholla Unit 1							
311.00 Structures and Improvements	$2,116,308	$1,925,703	90.99%	$1,714,372	81.01%	$1,791,033	84.63%
312.00 Boiler Plant Equipment	27,464,546	18,449,220	67.17%	17,999,638	65.54%	18,804,526	68.47%
314.00 Turbogenerator Units	10,355,816	7,812,007	75.44%	7,419,615	71.65%	7,751,397	74.85%
315.00 Accessory Electric Equipment	4,790,621	3,804,092	79.41%	3,478,947	72.62%	3,634,515	75.87%
316.00 Misc. Power Plant Equipment	2,432,224	1,371,741	56.40%	1,322,169	54.36%	1,381,292	56.79%
Total Cholla Unit 1	$47,159,515	$33,362,763	70.74%	$31,934,742	67.72%	$33,362,763	70.74%
Cholla Unit 2							
311.00 Structures and Improvements	$4,866,784	$2,522,137	51.82%	$2,194,517	45.09%	$2,408,131	49.48%
312.00 Boiler Plant Equipment	144,102,635	94,756,814	65.76%	85,845,707	59.57%	94,201,913	65.37%
314.00 Turbogenerator Units	29,198,775	16,595,620	56.84%	15,876,244	54.37%	17,421,635	59.67%
315.00 Accessory Electric Equipment	42,759,226	27,059,465	63.28%	24,436,624	57.15%	26,815,281	62.71%
316.00 Misc. Power Plant Equipment	5,232,429	2,862,430	54.71%	2,687,869	51.37%	2,949,505	56.37%
Total Cholla Unit 2	$226,159,849	$143,796,466	63.58%	$131,040,962	57.94%	$143,796,466	63.58%
Cholla Unit 3							
311.00 Structures and Improvements	$9,637,296	$5,722,402	59.38%	$5,226,138	54.23%	$5,608,972	58.20%
312.00 Boiler Plant Equipment	103,136,479	63,860,217	61.92%	59,912,254	58.09%	64,301,048	62.35%
314.00 Turbogenerator Units	45,423,639	16,851,724	37.10%	15,723,045	34.61%	16,874,816	37.15%
315.00 Accessory Electric Equipment	30,152,547	17,916,292	59.42%	16,401,188	54.39%	17,602,636	58.38%
316.00 Misc. Power Plant Equipment	4,319,200	2,349,081	54.39%	2,154,424	49.88%	2,312,244	53.53%
Total Cholla Unit 3	$192,669,161	$106,699,716	55.38%	$99,417,050	51.60%	$106,699,716	55.38%
Cholla Common							
311.00 Structures and Improvements	$37,069,373	$21,327,753	57.53%	$19,049,044	51.39%	$20,926,075	56.45%
312.00 Boiler Plant Equipment	25,149,111	12,008,832	47.75%	11,649,474	46.32%	12,797,375	50.89%
314.00 Turbogenerator Units	631,278	365,704	57.93%	334,523	52.99%	367,486	58.21%

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A	B	C	D=C/B	E	F=E/B	G	H=G/B
315.00 Accessory Electric Equipment	4,871,767	2,347,192	48.18%	2,259,894	46.39%	2,482,577	50.96%
316.00 Misc. Power Plant Equipment	8,073,554	3,595,386	44.53%	2,795,859	34.63%	3,071,354	38.04%
Total Cholla Common	$75,795,083	$39,644,867	52.31%	$36,088,794	47.61%	$39,644,867	52.31%
Four Corners							
311.00 Structures and Improvements	$43,005,911	$18,727,855	43.55%	$19,291,732	44.86%	$18,363,290	42.70%
312.00 Boiler Plant Equipment	335,046,039	179,324,368	53.52%	188,726,706	56.33%	178,472,313	53.27%
314.00 Turbogenerator Units	59,158,016	32,032,214	54.15%	33,859,657	57.24%	31,917,842	53.95%
315.00 Accessory Electric Equipment	29,825,484	15,933,859	53.42%	17,236,471	57.79%	16,415,425	55.04%
316.00 Misc. Power Plant Equipment	17,243,295	6,391,419	37.07%	7,369,456	42.74%	7,240,844	41.99%
Total Four Corners	$484,278,745	$252,409,714	52.12%	$266,484,021	55.03%	$252,409,714	52.12%
Four Corners Units 1-3							
311.00 Structures and Improvements	$29,002,681	$11,052,292	38.11%	$11,417,617	39.37%	$10,619,761	36.62%
312.00 Boiler Plant Equipment	218,326,908	110,558,755	50.64%	119,340,422	54.66%	111,000,988	50.84%
314.00 Turbogenerator Units	42,777,597	23,891,374	55.85%	24,828,045	58.04%	23,093,077	53.98%
315.00 Accessory Electric Equipment	17,232,291	9,133,612	53.00%	9,939,643	57.68%	9,245,067	53.65%
316.00 Misc. Power Plant Equipment	5,676,014	998,137	17.59%	1,801,139	31.73%	1,675,277	29.52%
Total Four Corners Units 1-3	$313,015,491	$155,634,170	49.72%	$167,326,866	53.46%	$155,634,170	49.72%
Four Corners Units 4-5							
311.00 Structures and Improvements	$9,201,539	$5,343,337	58.07%	$5,408,515	58.78%	$5,251,860	57.08%
312.00 Boiler Plant Equipment	112,898,782	65,985,603	58.45%	66,989,181	59.34%	65,048,878	57.62%
314.00 Turbogenerator Units	14,652,943	6,759,235	46.13%	7,646,872	52.19%	7,425,385	50.68%
315.00 Accessory Electric Equipment	9,853,384	4,634,182	47.03%	5,150,023	52.27%	5,000,855	50.75%
316.00 Misc. Power Plant Equipment	3,029,198	1,518,064	50.11%	1,558,587	51.45%	1,513,444	49.96%
Total Four Corners Units 4-5	$149,635,846	$84,240,421	56.30%	$86,753,178	57.98%	$84,240,421	56.30%
Four Corners Common							
311.00 Structures and Improvements	$4,801,691	$2,332,226	48.57%	$2,465,601	51.35%	$2,491,669	51.89%
312.00 Boiler Plant Equipment	3,820,349	2,780,010	72.77%	2,397,103	62.75%	2,422,447	63.41%
314.00 Turbogenerator Units	1,727,476	1,381,605	79.98%	1,384,740	80.16%	1,399,381	81.01%
315.00 Accessory Electric Equipment	2,739,809	2,166,064	79.06%	2,146,805	78.36%	2,169,502	79.18%
316.00 Misc. Power Plant Equipment	8,538,083	3,875,218	45.39%	4,009,729	46.96%	4,052,123	47.46%
Total Four Corners Common	$21,627,408	$12,535,123	57.96%	$12,403,978	57.35%	$12,535,123	57.96%

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A	B	C	D=C/B	E	F=E/B	G	H=G/B
Navajo Units 1-3		$12,873,807					
311.00 Structures and Improvements	$28,391,046		45.34%	$12,492,607	44.00%	$12,569,144	44.27%
312.00 Boiler Plant Equipment	156,202,698	73,810,721	47.25%	74,804,572	47.89%	75,262,869	48.18%
314.00 Turbogenerator Units	24,699,305	14,876,258	60.23%	14,154,187	57.31%	14,240,904	57.66%
315.00 Accessory Electric Equipment	20,448,549	12,198,031	59.65%	11,538,812	56.43%	11,609,506	56.77%
316.00 Misc. Power Plant Equipment	14,618,062	5,886,171	40.27%	5,926,258	40.54%	5,962,565	40.79%
Total Navajo Units 1-3	$244,359,660	$119,644,988	48.96%	$118,916,436	48.66%	$119,644,988	48.96%
Ocotillo Units 1-2							
311.00 Structures and Improvements	$3,792,708	$2,209,808	58.26%	$2,507,430	66.11%	$2,315,191	61.04%
312.00 Boiler Plant Equipment	24,174,538	19,181,771	79.35%	20,319,309	84.05%	18,761,475	77.61%
314.00 Turbogenerator Units	15,372,486	12,138,271	78.96%	13,122,581	85.36%	12,116,503	78.82%
315.00 Accessory Electric Equipment	2,670,248	2,096,391	78.51%	2,227,128	83.41%	2,056,379	77.01%
316.00 Misc. Power Plant Equipment	5,258,871	1,190,149	22.63%	1,696,943	32.27%	1,566,842	29.79%
Total Octillo Units 1-2	$51,268,851	$36,816,390	71.81%	$39,873,391	77.77%	$36,816,390	71.81%
Saguaro Units 1-2							
311.00 Structures and Improvements	$2,990,982	$2,135,921	71.41%	$2,257,757	75.49%	$2,181,557	72.94%
312.00 Boiler Plant Equipment	22,590,899	17,905,392	79.26%	18,577,970	82.24%	17,950,961	79.46%
314.00 Turbogenerator Units	16,340,249	14,165,285	86.69%	14,482,740	88.63%	13,993,946	85.64%
315.00 Accessory Electric Equipment	2,704,916	2,621,062	96.90%	2,497,495	92.33%	2,413,205	89.22%
316.00 Misc. Power Plant Equipment	3,255,754	1,507,531	46.30%	1,858,238	57.08%	1,795,522	55.15%
Total Saguaro Units 1-2	$47,882,800	$38,335,191	80.06%	$39,674,200	82.86%	$38,335,191	80.06%
NUCLEAR PRODUCTION (BY UNIT)							
Palo Verde							
321.00 Structures and Improvements	$640,003,980	$294,926,651	46.08%	$280,574,366	43.84%	$294,231,705	45.97%
322.00 Reactor Plant Equipment	939,061,294	418,593,472	44.58%	400,836,955	42.68%	419,696,028	44.69%
322.10 Steam Generators	52,865,345	44,686,406	84.53%	47,690,929	90.21%	50,608,283	95.73%
323.00 Turbogenerator Units	342,424,222	158,086,020	46.17%	149,701,098	43.72%	156,938,919	45.83%
324.00 Accessory Electric Equipment	272,624,619	135,152,824	49.57%	127,776,396	46.87%	134,042,038	49.17%
325.00 Misc. Power Plant Equipment	132,963,906	61,253,702	46.07%	54,195,350	40.76%	57,182,102	43.01%
Total Palo Verde	$2,379,943,366	$1,112,699,075	46.75%	$1,060,775,093	44.57%	$1,112,699,075	46.75%

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A	B	C	D=C/B	E	F=E/B	G	H=G/B
Palo Verde Unit 1							
321.00 Structures and Improvements	$154,544,487	$78,515,153	50.80%	$74,765,887	48.38%	$78,210,215	50.61%
322.00 Reactor Plant Equipment	361,739,876	180,009,884	49.76%	171,073,536	47.29%	178,954,580	49.47%
322.10 Steam Generators	27,452,571	25,026,450	91.16%	25,857,419	94.19%	27,048,623	98.53%
323.00 Turbogenerator Units	118,250,432	58,348,538	49.34%	56,294,607	47.61%	58,887,997	49.80%
324.00 Accessory Electric Equipment	114,359,460	60,327,856	52.75%	57,230,513	50.04%	59,867,018	52.35%
325.00 Misc. Power Plant Equipment	29,942,323	15,351,016	51.27%	13,967,029	46.65%	14,610,465	48.80%
Total Palo Verde Unit 1	$806,289,149	$417,578,897	51.79%	$399,188,991	49.51%	$417,578,897	51.79%
Palo Verde Unit 2							
321.00 Structures and Improvements	$90,520,213	$43,834,353	48.42%	$42,009,653	46.41%	$41,822,707	46.20%
322.00 Reactor Plant Equipment	226,227,486	84,750,018	37.46%	86,402,668	38.19%	86,018,171	38.02%
322.10 Steam Generators							
323.00 Turbogenerator Units	76,129,616	29,449,584	37.69%	32,775,604	41.95%	32,629,751	41.76%
324.00 Accessory Electric Equipment	50,011,285	24,628,890	49.25%	23,591,185	47.17%	23,486,203	46.96%
325.00 Misc. Power Plant Equipment	26,698,465	11,859,655	44.42%	10,612,894	39.75%	10,565,666	39.57%
Total Palo Verde Unit 2	$471,587,065	$194,522,500	41.25%	$195,392,005	41.43%	$194,522,500	41.25%
Palo Verde Unit 3							
321.00 Structures and Improvements	$160,291,956	$72,430,006	45.19%	$67,678,826	42.22%	$73,029,492	45.56%
322.00 Reactor Plant Equipment	323,919,702	142,473,826	43.98%	132,698,285	40.97%	143,189,369	44.21%
322.10 Steam Generators	25,412,774	19,659,956	77.36%	21,833,510	85.92%	23,559,660	92.71%
323.00 Turbogenerator Units	144,585,131	69,756,458	48.25%	60,139,750	41.59%	64,894,380	44.88%
324.00 Accessory Electric Equipment	89,504,541	41,716,681	46.61%	39,007,530	43.58%	42,091,453	47.03%
325.00 Misc. Power Plant Equipment	27,547,817	12,748,970	46.28%	11,140,758	40.44%	12,021,543	43.64%
Total Palo Verde Unit 3	$771,261,921	$358,785,897	46.52%	$332,498,658	43.11%	$358,785,897	46.52%
Palo Verde Water Reclamation							
321.00 Structures and Improvements	$128,265,752	$54,775,645	42.70%	$53,255,523	41.52%	$54,797,862	42.72%
322.00 Reactor Plant Equipment	133,326	15,679	11.76%	17,169	12.88%	17,666	13.25%
322.10 Steam Generators							
323.00 Turbogenerator Units	235,152	108,203	46.01%	85,665	36.43%	88,146	37.48%
324.00 Accessory Electric Equipment							
325.00 Misc. Power Plant Equipment	88,819	38,072	42.86%	32,970	37.12%	33,925	38.20%
Total Palo Verde Water Reclamation	$128,723,049	$54,937,599	42.68%	$53,391,327	41.48%	$54,937,599	42.68%

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A	B	C	D=C/B	E	F=E/B	G	H=G/B
Palo Verde Common							
321.00 Structures and Improvements	$106,381,572	$45,371,494	42.65%	$42,864,477	40.29%	$46,371,429	43.59%
322.00 Reactor Plant Equipment	27,040,904	11,344,065	41.95%	10,645,298	39.37%	11,516,241	42.59%
322.10 Steam Generators							
323.00 Turbogenerator Units	1,223,891	423,237	34.58%	405,472	33.13%	438,645	35.84%
324.00 Accessory Electric Equipment	18,749,333	8,479,397	45.23%	7,947,167	42.39%	8,597,363	45.85%
325.00 Misc. Power Plant Equipment	48,686,482	21,255,989	43.66%	18,441,698	37.88%	19,950,503	40.98%
Total Palo Verde Common	$202,082,182	$86,874,182	42.99%	$80,304,111	39.74%	$86,874,182	42.99%
OTHER PRODUCTION (BY UNIT)							
Douglas CT							
341.00 Structures and Improvements	$4,562	$4,408	96.62%	$3,458	75.81%	$4,383	96.08%
342.00 Fuel Holders, Products and Accessories	137,759	108,165	78.52%	87,675	63.64%	111,124	80.67%
343.00 Prime Movers	1,101,449	999,227	90.72%	797,520	72.41%	1,010,821	91.77%
344.00 Generators and Devices	551,765	548,900	99.48%	430,954	78.10%	546,215	98.99%
345.00 Accessory Electric Equipment	353,277	329,529	93.28%	251,393	71.16%	318,630	90.19%
346.00 Misc. Power Plant Equipment	40,913	32,871	80.34%	25,189	61.57%	31,927	78.04%
Total Douglas CT	$2,189,725	$2,023,100	92.39%	$1,596,190	72.89%	$2,023,100	92.39%
Ocotillo CT Units 1-2							
341.00 Structures and Improvements	$430,899	$226,540	52.57%	$263,744	61.21%	$324,148	75.23%
342.00 Fuel Holders, Products and Accessories	719,859	559,611	77.74%	454,159	63.09%	558,173	77.54%
343.00 Prime Movers	6,540,275	5,631,883	86.11%	4,460,648	68.20%	5,482,249	83.82%
344.00 Generators and Devices	6,424,357	3,791,607	59.02%	3,199,669	49.81%	3,932,473	61.21%
345.00 Accessory Electric Equipment	1,590,924	1,347,573	84.70%	1,047,459	65.84%	1,287,353	80.92%
346.00 Misc. Power Plant Equipment	558,648	455,619	81.56%	348,599	62.40%	428,437	76.69%
Total Ocotillo CT Units 1-2	$16,264,962	$12,012,833	73.86%	$9,774,278	60.09%	$12,012,833	73.86%
Saguaro CT Units 1-2							
341.00 Structures and Improvements	$1,380,611	$565,934	40.99%	$501,149	36.30%	$617,623	44.74%
342.00 Fuel Holders, Products and Accessories	1,304,977	1,094,962	83.91%	879,545	67.40%	1,083,964	83.06%
343.00 Prime Movers	8,047,527	6,900,269	85.74%	5,421,539	67.37%	6,681,580	83.03%
344.00 Generators and Devices	4,001,509	2,246,764	56.15%	1,948,873	48.70%	2,401,818	60.02%
345.00 Accessory Electric Equipment	1,626,802	1,360,609	83.64%	1,119,747	68.83%	1,379,992	84.83%
346.00 Misc. Power Plant Equipment	790,906	463,051	58.55%	378,618	47.87%	466,614	59.00%
Total Saguaro CT Units 1-2	$17,152,332	$12,631,589	73.64%	$10,249,470	59.76%	$12,631,589	73.64%

ARIZONA PUBLIC SERVICE COMPANY
Depreciation Reserve Summary
Company Broad Group Procedure
December 31, 2004

Statement C

Account Description	Plant Investment	Recorded Reserve Amount	Recorded Reserve Ratio	Computed Reserve Amount	Computed Reserve Ratio	Redistributed Reserve Amount	Redistributed Reserve Ratio
A	B	C	D=C/B	E	F=E/B	G	H=G/B
Solar Units							
341.00 Structures and Improvements	$352,259	$550,087	156.16%	$292,669	83.08%	$427,943	121.49%
342.00 Fuel Holders, Products and Accessories							
343.00 Prime Movers	20,596			858	4.17%	1,255	6.09%
344.00 Generators and Devices	14,326,036	7,656,927	53.45%	5,300,633	37.00%	7,750,639	54.10%
345.00 Accessory Electric Equipment	166,465	56,798	34.12%	57,430	34.50%	83,975	50.45%
346.00 Misc. Power Plant Equipment							
Total Solar Units	$14,865,356	$8,263,812	55.59%	$5,651,590	38.02%	$8,263,812	55.59%
West Phoenix							
341.00 Structures and Improvements	$7,550,035	$3,346,000	44.32%	$2,684,799	35.56%	$3,263,509	43.23%
342.00 Fuel Holders, Products and Accessories	20,688,419	5,296,086	25.60%	4,444,862	21.48%	5,404,818	26.12%
343.00 Prime Movers	8,794,167	6,378,511	72.53%	5,221,066	59.37%	6,368,916	72.42%
344.00 Generators and Devices	81,091,743	20,856,645	25.72%	17,204,490	21.22%	20,915,229	25.79%
345.00 Accessory Electric Equipment	13,957,323	4,740,678	33.97%	3,886,511	27.85%	4,726,974	33.87%
346.00 Misc. Power Plant Equipment	3,590,505	1,609,136	44.82%	1,272,088	35.43%	1,547,611	43.10%
Total West Pheonix	$135,672,192	$42,227,056	31.12%	$34,713,816	25.59%	$42,227,056	31.12%
West Phoenix CT Units 1-2							
341.00 Structures and Improvements	$510,951	$466,054	91.21%	$357,024	69.87%	$435,516	85.24%
342.00 Fuel Holders, Products and Accessories	1,437,533	1,201,191	83.56%	967,212	67.28%	1,179,853	82.07%
343.00 Prime Movers	8,794,167	6,378,511	72.53%	5,221,066	59.37%	6,368,916	72.42%
344.00 Generators and Devices	4,889,963	3,219,230	65.83%	2,753,089	56.30%	3,358,355	68.68%
345.00 Accessory Electric Equipment	1,557,744	1,382,142	88.73%	1,066,123	68.44%	1,300,510	83.49%
346.00 Misc. Power Plant Equipment	917,431	527,987	57.55%	436,090	47.53%	531,964	57.98%
Total West Ploenix CT Units 1-2	$18,107,789	$13,175,115	72.76%	$10,800,604	59.65%	$13,175,115	72.76%
West Phoenix CC Units 1-3							
341.00 Structures and Improvements	$7,039,084	$2,879,946	40.91%	$2,327,775	33.07%	$2,827,993	40.18%
342.00 Fuel Holders, Products and Accessories	19,250,886	4,094,895	21.27%	3,477,650	18.06%	4,224,964	21.95%
343.00 Prime Movers							
344.00 Generators and Devices	76,201,780	17,637,415	23.15%	14,451,401	18.96%	17,556,874	23.04%
345.00 Accessory Electric Equipment	12,399,579	3,358,536	27.09%	2,820,388	22.75%	3,426,463	27.63%
346.00 Misc. Power Plant Equipment	2,673,074	1,081,149	40.45%	835,998	31.27%	1,015,647	38.00%
Total West Phoenix CC Units 1-3	$117,564,403	$29,051,941	24.71%	$23,913,212	20.34%	$29,051,941	24.71%

ARIZONA PUBLIC SERVICE COMPANY

Statement C

Depreciation Reserve Summary
Company Broad Group Procedure
December 31, 2004

Account Description	Plant Investment	Recorded Reserve		Computed Reserve		Redistributed Reserve	
		Amount	Ratio	Amount	Ratio	Amount	Ratio
A	B	C	D=C/B	E	F=E/B	G	H=G/B
Yucca CT Units 1-4							
341.00 Structures and Improvements	$462,030	$256,022	55.41%	$222,178	48.09%	$282,435	61.13%
342.00 Fuel Holders, Products and Accessories	3,244,987	3,050,336	94.00%	2,412,555	74.35%	3,066,865	94.51%
343.00 Prime Movers	7,962,254	7,542,942	94.73%	5,842,255	73.37%	7,426,735	93.27%
344.00 Generators and Devices	5,358,461	4,589,599	85.65%	3,682,328	68.72%	4,681,014	87.36%
345.00 Accessory Electric Equipment	2,172,221	1,905,785	87.73%	1,488,166	68.51%	1,891,772	87.09%
346.00 Misc. Power Plant Equipment	479,650	389,267	81.16%	302,962	63.16%	385,129	80.29%
Total Yucca CT Units 1-4	$19,679,603	$17,733,951	90.11%	$13,950,445	70.89%	$17,733,951	90.11%

ARIZONA PUBLIC SERVICE COMPANY
Average Net Salvage

Statement D

Account Description	Plant Investment			Salvage Rate		Net Salvage			Average Rate
	Additions	Retirements	Survivors	Realized	Future	Realized	Future	Total	
A	B	C	D=B-C	E	F	G=E*C	H=F*D	I=G+H	J=I/B
STEAM PRODUCTION									
311.00 Structures and Improvements	$131,870,408		$131,870,408		-18.7%		($24,682,073)	($24,682,073)	-18.7%
312.00 Boiler Plant Equipment	837,866,945		837,866,945		-18.8%		(157,666,781)	(157,666,781)	-18.8%
314.00 Turbogenerator Units	201,179,564		201,179,564		-20.6%		(41,464,729)	(41,464,729)	-20.6%
315.00 Accessory Electric Equipment	138,223,358		138,223,358		-19.2%		(26,587,001)	(26,587,001)	-19.2%
316.00 Misc. Power Plant Equipment	60,433,389		60,433,389		-21.1%		(12,772,863)	(12,772,863)	-21.1%
Total Steam Production Plant	$1,369,573,664		$1,369,573,664		-19.2%		($263,173,446)	($263,173,446)	-19.2%
NUCLEAR PRODUCTION									
321.00 Structures and Improvements	$640,003,980		$640,003,980						
322.00 Reactor Plant Equipment	939,061,294		939,061,294		-0.2%		(2,229,083)	(2,229,083)	-0.2%
322.10 Steam Generators	52,865,345		52,865,345						
323.00 Turbogenerator Units	342,424,222		342,424,222		-0.4%		(1,369,697)	(1,369,697)	-0.4%
324.00 Accessory Electric Equipment	272,624,619		272,624,619		-0.5%		(1,248,764)	(1,248,764)	-0.5%
325.00 Misc. Power Plant Equipment	132,963,906		132,963,906		-0.8%		(1,037,013)	(1,037,013)	-0.8%
Total Nuclear Production Plant	$2,379,943,366		$2,379,943,366		-0.2%		($5,884,557)	($5,884,557)	-0.2%
OTHER PRODUCTION									
341.00 Structures and Improvements	$10,180,396		$10,180,396		-4.8%		($491,407)	($491,407)	-4.8%
342.00 Fuel Holders, Products and Accessories	26,096,001		26,096,001		-5.0%		(1,304,800)	(1,304,800)	-5.0%
343.00 Prime Movers	32,466,268		32,466,268						
344.00 Generators and Devices	111,753,871		111,753,871		-1.4%		(1,524,036)	(1,524,036)	-1.4%
345.00 Accessory Electric Equipment	19,867,012		19,867,012						
346.00 Misc. Power Plant Equipment	5,460,622		5,460,622						
Total Other Production Plant	$205,824,170		$205,824,170		-1.6%		($3,320,243)	($3,320,243)	-1.6%
TOTAL PRODUCTION PLANT	$3,955,341,200		$3,955,341,200		-6.9%		($272,378,245)	($272,378,245)	-6.9%
TRANSMISSION									
352.00 Structures and Improvements	$95,935		$95,935		-5.0%		($4,797)	($4,797)	-5.0%
353.00 Station Equipment	42,249,917		42,249,917						
354.00 Towers and Fixtures	1,329,316		1,329,316		-35.0%		(465,261)	(465,261)	-35.0%
355.00 Poles and Fixtures - Wood	11,064		11,064		-15.0%		(1,660)	(1,660)	-15.0%
356.00 Overhead Conductors and Devices	586,319		586,319		-35.0%		(205,212)	(205,212)	-35.0%
Total Transmission Plant	$44,272,551		$44,272,551		-1.5%		($676,929)	($676,929)	-1.5%
DISTRIBUTION									
361.00 Structures and Improvements	$30,704,475		$30,704,475		-10.0%		($3,070,448)	($3,070,448)	-10.0%
362.00 Station Equipment	242,575,593		242,575,593						
364.00 Poles, Towers and Fixtures - Wood	296,506,680		296,506,680		-10.0%		(29,650,668)	(29,650,668)	-10.0%
364.10 Poles, Towers and Fixtures - Steel	73,766,423		73,766,423		-5.0%		(3,688,321)	(3,688,321)	-5.0%
365.00 Overhead Conductors and Devices	233,951,705		233,951,705		-10.0%		(23,395,171)	(23,395,171)	-10.0%
366.00 Underground Conduit	509,266,861		509,266,861		-5.0%		(25,463,343)	(25,463,343)	-5.0%
367.00 Underground Conductors and Devices	908,715,823		908,715,823		-5.0%		(45,435,791)	(45,435,791)	-5.0%

ARIZONA PUBLIC SERVICE COMPANY
Average Net Salvage

Statement D

Account Description	Plant Investment			Salvage Rate		Net Salvage			Average
	Additions	Retirements	Survivors	Realized	Future	Realized	Future	Total	Rate
A	B	C	D=B-C	E	F	G=E*C	H=F*D	I=G+H	J=I/B
368.00 Line Transformers	537,581,653		537,581,653		-5.0%		(26,879,083)	(26,879,083)	-5.0%
369.00 Services	268,098,185		268,098,185		-10.0%		(26,809,819)	(26,809,819)	-10.0%
370.00 Meters	91,949,592		91,949,592						
370.10 Meters - Electronic	65,427,927		65,427,927						
371.00 Installations on Customers' Premises	31,927,745		31,927,745		-20.0%		(6,385,549)	(6,385,549)	-20.0%
373.00 Street Lighting and Signal Systems	60,236,149		60,236,149		-20.0%		(12,047,230)	(12,047,230)	-20.0%
Total Distribution Plant	$3,350,708,811		$3,350,708,811		-6.1%		($202,825,421)	($202,825,421)	-6.1%
GENERAL									
390.00 Structures and Improvements	$103,793,498		$103,793,498		-15.0%		($15,569,025)	($15,569,025)	-15.0%
391.00 Office Furn. and Equip. - Furniture	31,890,832		31,890,832						
391.10 Office Furn. and Equip. - PC Equipment	49,510,133		49,510,133						
391.20 Office Furn. and Equip. - Other	9,016,492		9,016,492						
393.00 Stores Equipment	1,235,839		1,235,839						
394.00 Tools, Shop and Garage Equipment	14,047,955		14,047,955						
395.00 Laboratory Equipment	1,609,510		1,609,510						
397.00 Communication Equipment	109,319,204		109,319,204						
398.HH Miscellaneous Equipment - Hydrogen	4,904,211		4,904,211						
398.00 Miscellaneous Equipment	4,356,614		4,356,614						
Total General	$329,684,288		$329,684,288		-4.7%		($15,569,025)	($15,569,025)	-4.7%
TOTAL UTILITY	$3,680,990,482		$3,680,990,482		-5.9%		($218,601,317)	($218,601,317)	-5.9%
STEAM PRODUCTION (BY UNIT)									
Cholla									
311.00 Structures and Improvements	$53,689,761		$53,689,761		-19.2%		($10,312,669)	($10,312,669)	-19.2%
312.00 Boiler Plant Equipment	299,852,771		299,852,771		-19.4%		(58,265,524)	(58,265,524)	-19.4%
314.00 Turbogenerator Units	85,609,508		85,609,508		-19.9%		(17,001,891)	(17,001,891)	-19.9%
315.00 Accessory Electric Equipment	82,574,161		82,574,161		-19.4%		(16,037,840)	(16,037,840)	-19.4%
316.00 Misc. Power Plant Equipment	20,057,407		20,057,407		-19.2%		(3,847,572)	(3,847,572)	-19.2%
Total Cholla	$541,783,608		$541,783,608		-19.5%		($105,465,496)	($105,465,496)	-19.5%
Cholla Unit 1									
311.00 Structures and Improvements	$2,116,308		$2,116,308		-15.8%		($334,377)	($334,377)	-15.8%
312.00 Boiler Plant Equipment	27,464,546		27,464,546		-16.3%		(4,476,721)	(4,476,721)	-16.3%
314.00 Turbogenerator Units	10,355,816		10,355,816		-15.8%		(1,636,219)	(1,636,219)	-15.8%
315.00 Accessory Electric Equipment	4,790,621		4,790,621		-15.9%		(761,709)	(761,709)	-15.9%
316.00 Misc. Power Plant Equipment	2,432,224		2,432,224		-16.1%		(391,588)	(391,588)	-16.1%
Total Cholla Unit 1	$47,159,515		$47,159,515		-16.1%		($7,600,613)	($7,600,613)	-16.1%

ARIZONA PUBLIC SERVICE COMPANY
Average Net Salvage

Statement D

Account Description	Plant Investment			Salvage Rate		Net Salvage			Average
	Additions	Retirements	Survivors	Realized	Future	Realized	Future	Total	Rate
A	B	C	D=B-C	E	F	G=E*C	H=F*D	I=G+H	J=I/B
Cholla Unit 2									
311.00 Structures and Improvements	$4,866,784		$4,866,784		-18.1%		($880,888)	($880,888)	-18.1%
312.00 Boiler Plant Equipment	144,102,635		144,102,635		-19.0%		(27,379,501)	(27,379,501)	-19.0%
314.00 Turbogenerator Units	29,198,775		29,198,775		-18.3%		(5,343,376)	(5,343,376)	-18.3%
315.00 Accessory Electric Equipment	42,759,226		42,759,226		-18.4%		(7,867,698)	(7,867,698)	-18.4%
316.00 Misc. Power Plant Equipment	5,232,429		5,232,429		-19.1%		(999,394)	(999,394)	-19.1%
Total Cholla Unit 2	$226,159,849		$226,159,849		-18.8%		($42,470,856)	($42,470,856)	-18.8%
Cholla Unit 3									
311.00 Structures and Improvements	$9,637,296		$9,637,296		-21.7%		($2,091,293)	($2,091,293)	-21.7%
312.00 Boiler Plant Equipment	103,136,479		103,136,479		-20.9%		(21,555,524)	(21,555,524)	-20.9%
314.00 Turbogenerator Units	45,423,639		45,423,639		-21.8%		(9,902,353)	(9,902,353)	-21.8%
315.00 Accessory Electric Equipment	30,152,547		30,152,547		-21.5%		(6,482,798)	(6,482,798)	-21.5%
316.00 Misc. Power Plant Equipment	4,319,200		4,319,200		-20.8%		(898,394)	(898,394)	-20.8%
Total Cholla Unit 3	$192,669,161		$192,669,161		-21.2%		($40,930,362)	($40,930,362)	-21.2%
Cholla Common									
311.00 Structures and Improvements	$37,069,373		$37,069,373		-18.9%		($7,006,111)	($7,006,111)	-18.9%
312.00 Boiler Plant Equipment	25,149,111		25,149,111		-19.3%		(4,853,778)	(4,853,778)	-19.3%
314.00 Turbogenerator Units	631,278		631,278		-19.0%		(119,943)	(119,943)	-19.0%
315.00 Accessory Electric Equipment	4,871,767		4,871,767		-19.0%		(925,636)	(925,636)	-19.0%
316.00 Misc. Power Plant Equipment	8,073,554		8,073,554		-19.3%		(1,558,196)	(1,558,196)	-19.3%
Total Cholla Common	$75,795,083		$75,795,083		-19.1%		($14,463,664)	($14,463,664)	-19.1%
Four Corners									
311.00 Structures and Improvements	$43,005,911		$43,005,911		-18.5%		($7,947,881)	($7,947,881)	-18.5%
312.00 Boiler Plant Equipment	335,046,039		335,046,039		-18.1%		(60,487,537)	(60,487,537)	-18.1%
314.00 Turbogenerator Units	59,158,016		59,158,016		-17.8%		(10,527,182)	(10,527,182)	-17.8%
315.00 Accessory Electric Equipment	29,825,484		29,825,484		-19.3%		(5,755,943)	(5,755,943)	-19.3%
316.00 Misc. Power Plant Equipment	17,243,295		17,243,295		-21.7%		(3,741,121)	(3,741,121)	-21.7%
Total Four Corners	$484,278,745		$484,278,745		-18.3%		($88,459,664)	($88,459,664)	-18.3%
Four Corners Units 1-3									
311.00 Structures and Improvements	$29,002,681		$29,002,681		-14.1%		($4,089,378)	($4,089,378)	-14.1%
312.00 Boiler Plant Equipment	218,326,908		218,326,908		-14.8%		(32,312,382)	(32,312,382)	-14.8%
314.00 Turbogenerator Units	42,777,597		42,777,597		-14.5%		(6,202,752)	(6,202,752)	-14.5%
315.00 Accessory Electric Equipment	17,232,291		17,232,291		-14.3%		(2,464,218)	(2,464,218)	-14.3%
316.00 Misc. Power Plant Equipment	5,676,014		5,676,014		-14.4%		(817,346)	(817,346)	-14.4%
Total Four Corners Units 1-3	$313,015,491		$313,015,491		-14.7%		($45,886,076)	($45,886,076)	-14.7%
Four Corners Units 4-5									
311.00 Structures and Improvements	$9,201,539		$9,201,539		-26.8%		($2,466,012)	($2,466,012)	-26.8%
312.00 Boiler Plant Equipment	112,898,782		112,898,782		-24.1%		(27,208,606)	(27,208,606)	-24.1%
314.00 Turbogenerator Units	14,652,943		14,652,943		-26.4%		(3,868,377)	(3,868,377)	-26.4%
315.00 Accessory Electric Equipment	9,853,384		9,853,384		-26.4%		(2,601,293)	(2,601,293)	-26.4%

ARIZONA PUBLIC SERVICE COMPANY
Average Net Salvage

Statement D

Account Description	Plant Investment			Salvage Rate		Net Salvage			Average
	Additions	Retirements	Survivors	Realized	Future	Realized	Future	Total	Rate
A	B	C	D=B-C	E	F	G=E*C	H=F*D	I=G+H	J=I/B
316.00 Misc. Power Plant Equipment	3,029,198		3,029,198		-23.8%		(720,949)	(720,949)	-23.8%
Total Four Corners Units 4-5	$149,635,846		$149,635,846		-24.6%		($36,865,238)	($36,865,238)	-24.6%
Four Corners Common									
311.00 Structures and Improvements	$4,801,691		$4,801,691		-29.0%		($1,392,490)	($1,392,490)	-29.0%
312.00 Boiler Plant Equipment	3,820,349		3,820,349		-25.3%		(966,548)	(966,548)	-25.3%
314.00 Turbogenerator Units	1,727,476		1,727,476		-26.4%		(456,054)	(456,054)	-26.4%
315.00 Accessory Electric Equipment	2,739,809		2,739,809		-25.2%		(690,432)	(690,432)	-25.2%
316.00 Misc. Power Plant Equipment	8,538,083		8,538,083		-25.8%		(2,202,825)	(2,202,825)	-25.8%
Total Four Corners Common	$21,627,408		$21,627,408		-26.4%		($5,708,350)	($5,708,350)	-26.4%
Navajo Units 1-3									
311.00 Structures and Improvements	$28,391,046		$28,391,046		-14.5%		($4,116,702)	($4,116,702)	-14.5%
312.00 Boiler Plant Equipment	156,202,698		156,202,698		-15.8%		(24,680,026)	(24,680,026)	-15.8%
314.00 Turbogenerator Units	24,699,305		24,699,305		-14.9%		(3,680,196)	(3,680,196)	-14.9%
315.00 Accessory Electric Equipment	20,448,549		20,448,549		-15.1%		(3,087,731)	(3,087,731)	-15.1%
316.00 Misc. Power Plant Equipment	14,618,062		14,618,062		-15.9%		(2,324,272)	(2,324,272)	-15.9%
Total Navajo Units 1-3	$244,359,660		$244,359,660		-15.5%		($37,888,927)	($37,888,927)	-15.5%
Ocotillo Units 1-2									
311.00 Structures and Improvements	$3,792,708		$3,792,708		-37.9%		($1,437,436)	($1,437,436)	-37.9%
312.00 Boiler Plant Equipment	24,174,538		24,174,538		-32.9%		(7,953,423)	(7,953,423)	-32.9%
314.00 Turbogenerator Units	15,372,486		15,372,486		-36.1%		(5,549,467)	(5,549,467)	-36.1%
315.00 Accessory Electric Equipment	2,670,248		2,670,248		-35.0%		(934,587)	(934,587)	-35.0%
316.00 Misc. Power Plant Equipment	5,258,871		5,258,871		-36.8%		(1,935,265)	(1,935,265)	-36.8%
Total Octillo Units 1-2	$51,268,851		$51,268,851		-34.7%		($17,810,178)	($17,810,178)	-34.7%
Saguaro Units 1-2									
311.00 Structures and Improvements	$2,990,982		$2,990,982		-29.0%		($867,385)	($867,385)	-29.0%
312.00 Boiler Plant Equipment	22,590,899		22,590,899		-27.8%		(6,280,270)	(6,280,270)	-27.8%
314.00 Turbogenerator Units	16,340,249		16,340,249		-28.8%		(4,705,992)	(4,705,992)	-28.8%
315.00 Accessory Electric Equipment	2,704,916		2,704,916		-28.5%		(770,901)	(770,901)	-28.5%
316.00 Misc. Power Plant Equipment	3,255,754		3,255,754		-28.4%		(924,634)	(924,634)	-28.4%
Total Saguaro Units 1-2	$47,882,800		$47,882,800		-28.3%		($13,549,182)	($13,549,182)	-28.3%
NUCLEAR PRODUCTION (BY UNIT)									
Palo Verde									
321.00 Structures and Improvements	$640,003,980		$640,003,980						
322.00 Reactor Plant Equipment	939,061,294		939,061,294		-0.2%		(2,229,083)	(2,229,083)	-0.2%
322.10 Steam Generators	52,865,345		52,865,345						
323.00 Turbogenerator Units	342,424,222		342,424,222		-0.4%		(1,369,697)	(1,369,697)	-0.4%
324.00 Accessory Electric Equipment	272,624,619		272,624,619		-0.5%		(1,248,764)	(1,248,764)	-0.5%
325.00 Misc. Power Plant Equipment	132,963,906		132,963,906		-0.8%		(1,037,013)	(1,037,013)	-0.8%
Total Palo Verde	$2,379,943,366		$2,379,943,366		-0.2%		($5,884,557)	($5,884,557)	-0.2%

ARIZONA PUBLIC SERVICE COMPANY
Average Net Salvage

Statement D

Account Description	Plant Investment			Salvage Rate		Net Salvage			Average
	Additions	Retirements	Survivors	Realized	Future	Realized	Future	Total	Rate
A	B	C	D=B-C	E	F	G=E*C	H=F*D	I=G+H	J=I/B
Palo Verde Unit 1									
321.00 Structures and Improvements	$154,544,487		$154,544,487						
322.00 Reactor Plant Equipment	361,739,876		361,739,876		-0.2%		(723,480)	(723,480)	-0.2%
322.10 Steam Generators	27,452,571		27,452,571						
323.00 Turbogenerator Units	118,250,432		118,250,432		-0.4%		(473,002)	(473,002)	-0.4%
324.00 Accessory Electric Equipment	114,359,460		114,359,460		-0.4%		(457,438)	(457,438)	-0.4%
325.00 Misc. Power Plant Equipment	29,942,323		29,942,323		-0.8%		(239,539)	(239,539)	-0.8%
Total Palo Verde Unit 1	$806,289,149		$806,289,149		-0.2%		($1,893,458)	($1,893,458)	-0.2%
Palo Verde Unit 2									
321.00 Structures and Improvements	$90,520,213		$90,520,213						
322.00 Reactor Plant Equipment	226,227,486		226,227,486		-0.2%		(452,455)	(452,455)	-0.2%
322.10 Steam Generators									
323.00 Turbogenerator Units	78,129,616		78,129,616		-0.4%		(312,518)	(312,518)	-0.4%
324.00 Accessory Electric Equipment	50,011,285		50,011,285		-0.5%		(250,056)	(250,056)	-0.5%
325.00 Misc. Power Plant Equipment	26,698,465		26,698,465		-0.7%		(186,889)	(186,889)	-0.7%
Total Palo Verde Unit 2	$471,587,065		$471,587,065		-0.3%		($1,201,919)	($1,201,919)	-0.3%
Palo Verde Unit 3									
321.00 Structures and Improvements	$160,291,956		$160,291,956						
322.00 Reactor Plant Equipment	323,919,702		323,919,702		-0.3%		(971,759)	(971,759)	-0.3%
322.10 Steam Generators	25,412,774		25,412,774						
323.00 Turbogenerator Units	144,585,131		144,585,131		-0.4%		(578,341)	(578,341)	-0.4%
324.00 Accessory Electric Equipment	89,504,541		89,504,541		-0.5%		(447,523)	(447,523)	-0.5%
325.00 Misc. Power Plant Equipment	27,547,817		27,547,817		-0.8%		(220,383)	(220,383)	-0.8%
Total Palo Verde Unit 3	$771,261,921		$771,261,921		-0.3%		($2,218,005)	($2,218,005)	-0.3%
Palo Verde Water Reclamation									
321.00 Structures and Improvements	$128,265,752		$128,265,752						
322.00 Reactor Plant Equipment	133,326		133,326		-0.2%		(267)	(267)	-0.2%
322.10 Steam Generators									
323.00 Turbogenerator Units	235,152		235,152		-0.4%		(941)	(941)	-0.4%
324.00 Accessory Electric Equipment									
325.00 Misc. Power Plant Equipment	88,819		88,819		-0.8%		(711)	(711)	-0.8%
Total Palo Verde Water Reclamation	$128,723,049		$128,723,049		0.0%		($1,918)	($1,918)	
Palo Verde Common									
321.00 Structures and Improvements	$106,381,572		$106,381,572						
322.00 Reactor Plant Equipment	27,040,904		27,040,904		-0.3%		(81,123)	(81,123)	-0.3%
322.10 Steam Generators									
323.00 Turbogenerator Units	1,223,891		1,223,891		-0.4%		(4,896)	(4,896)	-0.4%
324.00 Accessory Electric Equipment	18,749,333		18,749,333		-0.5%		(93,747)	(93,747)	-0.5%
325.00 Misc. Power Plant Equipment	48,686,482		48,686,482		-0.8%		(389,492)	(389,492)	-0.8%
Total Palo Verde Common	$202,082,182		$202,082,182		-0.3%		($569,257)	($569,257)	-0.3%

ARIZONA PUBLIC SERVICE COMPANY
Average Net Salvage

Statement D

Account Description	Plant Investment			Salvage Rate		Net Salvage			Average
	Additions	Retirements	Survivors	Realized	Future	Realized	Future	Total	Rate
A	B	C	D=B-C	E	F	G=E*C	H=F*D	I=G+H	J=I/B
OTHER PRODUCTION (BY UNIT)									
Douglas CT									
341.00 Structures and Improvements	$4,562		$4,562		-5.0%		($228)	($228)	-5.0%
342.00 Fuel Holders, Products and Accessories	137,759		137,759		-5.0%		(6,888)	(6,888)	-5.0%
343.00 Prime Movers	1,101,449		1,101,449						
344.00 Generators and Devices	551,765		551,765						
345.00 Accessory Electric Equipment	353,277		353,277						
346.00 Misc. Power Plant Equipment	40,913		40,913						
Total Douglas CT	$2,189,725		$2,189,725		-0.3%		($7,116)	($7,116)	-0.3%
Ocotillo CT Units 1-2									
341.00 Structures and Improvements	$430,899		$430,899		-5.0%		($21,545)	($21,545)	-5.0%
342.00 Fuel Holders, Products and Accessories	719,859		719,859		-5.0%		(35,993)	(35,993)	-5.0%
343.00 Prime Movers	6,540,275		6,540,275						
344.00 Generators and Devices	6,424,357		6,424,357						
345.00 Accessory Electric Equipment	1,590,924		1,590,924						
346.00 Misc. Power Plant Equipment	558,648		558,648						
Total Ocotillo CT Units 1-2	$16,264,962		$16,264,962		-0.4%		($57,538)	($57,538)	-0.4%
Saguaro CT Units 1-2									
341.00 Structures and Improvements	$1,380,611		$1,380,611		-5.0%		($69,031)	($69,031)	-5.0%
342.00 Fuel Holders, Products and Accessories	1,304,977		1,304,977		-5.0%		(65,249)	(65,249)	-5.0%
343.00 Prime Movers	8,047,527		8,047,527						
344.00 Generators and Devices	4,001,509		4,001,509						
345.00 Accessory Electric Equipment	1,626,802		1,626,802						
346.00 Misc. Power Plant Equipment	790,906		790,906						
Total Saguaro CT Units 1-2	$17,152,332		$17,152,332		-0.8%		($134,279)	($134,279)	-0.8%
Solar Units									
341.00 Structures and Improvements	$352,259		$352,259						
342.00 Fuel Holders, Products and Accessories									
343.00 Prime Movers	20,596		20,596						
344.00 Generators and Devices	14,326,036		14,326,036						
345.00 Accessory Electric Equipment	166,465		166,465						
346.00 Misc. Power Plant Equipment									
Total Solar Units	$14,865,356		$14,865,356						
West Phoenix									
341.00 Structures and Improvements	$7,550,035		$7,550,035		-5.0%		($377,502)	($377,502)	-5.0%
342.00 Fuel Holders, Products and Accessories	20,688,419		20,688,419		-5.0%		(1,034,421)	(1,034,421)	-5.0%
343.00 Prime Movers	8,794,167		8,794,167						

ARIZONA PUBLIC SERVICE COMPANY
Average Net Salvage

Statement D

Account Description	Plant Investment			Salvage Rate		Net Salvage			Average Rate
	Additions	Retirements	Survivors	Realized	Future	Realized	Future	Total	
A	B	C	D=B-C	E	F	G=E*C	H=F*D	I=G+H	J=I/B
344.00 Generators and Devices	81,091,743		81,091,743		-1.9%		(1,524,036)	(1,524,036)	-1.9%
345.00 Accessory Electric Equipment	13,957,323		13,957,323						
346.00 Misc. Power Plant Equipment	3,590,505		3,590,505						
Total West Pheonix	$135,672,192		$135,672,192		-2.2%		($2,935,958)	($2,935,958)	-2.2%
West Phoenix CT Units 1-2									
341.00 Structures and Improvements	$510,951		$510,951		-5.0%		($25,548)	($25,548)	-5.0%
342.00 Fuel Holders, Products and Accessories	1,437,533		1,437,533		-5.0%		(71,877)	(71,877)	-5.0%
343.00 Prime Movers	8,794,167		8,794,167						
344.00 Generators and Devices	4,889,963		4,889,963						
345.00 Accessory Electric Equipment	1,557,744		1,557,744						
346.00 Misc. Power Plant Equipment	917,431		917,431						
Total West Pioenix CT Units 1-2	$18,107,789		$18,107,789		-0.5%		($97,424)	($97,424)	-0.5%
West Phoenix CC Units 1-3									
341.00 Structures and Improvements	$7,039,084		$7,039,084		-5.0%		($351,954)	($351,954)	-5.0%
342.00 Fuel Holders, Products and Accessories	19,250,886		19,250,886		-5.0%		(962,544)	(962,544)	-5.0%
343.00 Prime Movers									
344.00 Generators and Devices	76,201,780		76,201,780		-2.0%		(1,524,036)	(1,524,036)	-2.0%
345.00 Accessory Electric Equipment	12,399,579		12,399,579						
346.00 Misc. Power Plant Equipment	2,673,074		2,673,074						
Total West Phoenix CC Units 1-3	$117,564,403		$117,564,403		-2.4%		($2,838,534)	($2,838,534)	-2.4%
Yucca CT Units 1-4									
341.00 Structures and Improvements	$462,030		$462,030		-5.0%		($23,102)	($23,102)	-5.0%
342.00 Fuel Holders, Products and Accessories	3,244,987		3,244,987		-5.0%		(162,249)	(162,249)	-5.0%
343.00 Prime Movers	7,962,254		7,962,254						
344.00 Generators and Devices	5,358,461		5,358,461						
345.00 Accessory Electric Equipment	2,172,221		2,172,221						
346.00 Misc. Power Plant Equipment	479,650		479,650						
Total Yucca CT Units 1-4	$19,679,603		$19,679,603		-0.9%		($185,351)	($185,351)	-0.9%

ARIZONA PUBLIC SERVICE COMPANY
Future Net Salvage
Steam and Nuclear Production

Statement E

Account Description	12/31/04 Plant Investment	Future Retirements Interim	Future Retirements Final	Net Salvage Rate Interim	Net Salvage Rate Final	Future Net Salvage Interim	Future Net Salvage Final	Future Net Salvage Total	Future Rate
A	B	C	D=B-C	E	F	G=C*E	H=D*F	I=G+H	J=I/B
STEAM PRODUCTION (BY UNIT)									
Cholla									
311.00 Structures and Improvements	$53,689,761	$10,375,910	$43,313,851	-20.0%	-19.1%	($2,075,182)	($8,256,542)	($10,331,724)	-19.2%
312.00 Boiler Plant Equipment	299,852,771	159,093,636	140,759,135	-20.0%	-18.8%	(31,818,727)	(26,498,336)	(58,317,063)	-19.4%
314.00 Turbogenerator Units	85,609,508	16,496,198	69,113,310	-20.0%	-19.8%	(3,299,240)	(13,707,416)	(17,006,656)	-19.9%
315.00 Accessory Electric Equipment	82,574,161	23,510,891	59,063,270	-20.0%	-19.2%	(4,702,178)	(11,362,910)	(16,065,088)	-19.5%
316.00 Misc. Power Plant Equipment	20,057,407	10,288,403	9,769,004	-20.0%	-18.3%	(2,057,681)	(1,791,991)	(3,849,672)	-19.2%
Total Cholla	$541,783,608	$219,765,038	$322,018,570	-20.0%	-19.1%	($43,953,008)	($61,617,194)	($105,570,202)	-19.5%
Cholla Unit 1									
311.00 Structures and Improvements	$2,116,308	$186,585	$1,929,723	-20.0%	-15.4%	($37,317)	($296,750)	($334,067)	-15.8%
312.00 Boiler Plant Equipment	27,464,546	5,583,370	21,881,176	-20.0%	-15.4%	(1,116,674)	(3,364,856)	(4,481,530)	-16.3%
314.00 Turbogenerator Units	10,355,816	1,024,966	9,330,850	-20.0%	-15.4%	(204,993)	(1,434,885)	(1,639,878)	-15.8%
315.00 Accessory Electric Equipment	4,790,621	518,533	4,272,088	-20.0%	-15.4%	(103,707)	(656,956)	(760,662)	-15.9%
316.00 Misc. Power Plant Equipment	2,432,224	354,729	2,077,495	-20.0%	-15.4%	(70,946)	(319,474)	(390,420)	-16.1%
Total Cholla Unit 1	$47,159,515	$7,668,182	$39,491,333	-20.0%	-15.4%	($1,533,636)	($6,072,921)	($7,606,557)	-16.1%
Cholla Unit 2									
311.00 Structures and Improvements	$4,866,784	$736,061	$4,130,723	-20.0%	-17.8%	($147,212)	($734,392)	($881,604)	-18.1%
312.00 Boiler Plant Equipment	144,102,635	80,560,476	63,542,159	-20.0%	-17.8%	(16,112,095)	(11,297,013)	(27,409,108)	-19.0%
314.00 Turbogenerator Units	29,198,775	6,981,868	22,216,907	-20.0%	-17.8%	(1,396,374)	(3,949,892)	(5,346,266)	-18.3%
315.00 Accessory Electric Equipment	42,759,226	12,620,318	30,138,908	-20.0%	-17.8%	(2,524,064)	(5,358,327)	(7,882,390)	-18.4%
316.00 Misc. Power Plant Equipment	5,232,429	3,175,378	2,057,051	-20.0%	-17.8%	(635,076)	(365,718)	(1,000,794)	-19.1%
Total Cholla Unit 2	$226,159,849	$104,074,101	$122,085,748	-20.0%	-17.8%	($20,814,820)	($21,705,342)	($42,520,162)	-18.8%
Cholla Unit 3									
311.00 Structures and Improvements	$9,637,296	$1,975,388	$7,661,908	-20.0%	-22.2%	($395,078)	($1,700,873)	($2,095,951)	-21.7%
312.00 Boiler Plant Equipment	103,136,479	60,480,584	42,655,895	-20.0%	-22.2%	(12,096,117)	(9,469,216)	(21,565,333)	-20.9%
314.00 Turbogenerator Units	45,423,639	8,327,471	37,096,168	-20.0%	-22.2%	(1,665,494)	(8,235,008)	(9,900,502)	-21.8%
315.00 Accessory Electric Equipment	30,152,547	9,040,163	21,112,384	-20.0%	-22.2%	(1,808,033)	(4,686,755)	(6,494,788)	-21.5%
316.00 Misc. Power Plant Equipment	4,319,200	2,764,303	1,554,897	-20.0%	-22.2%	(552,861)	(345,173)	(898,033)	-20.8%
Total Cholla Unit 3	$192,669,161	$82,587,910	$110,081,251	-20.0%	-22.2%	($16,517,582)	($24,437,025)	($40,954,607)	-21.3%
Cholla Common									
311.00 Structures and Improvements	$37,069,373	$7,477,876	$29,591,497	-20.0%	-18.7%	($1,495,575)	($5,524,527)	($7,020,102)	-18.9%
312.00 Boiler Plant Equipment	25,149,111	12,469,206	12,679,905	-20.0%	-18.7%	(2,493,841)	(2,367,250)	(4,861,091)	-19.3%
314.00 Turbogenerator Units	631,278	161,892	469,386	-20.0%	-18.7%	(32,378)	(87,631)	(120,010)	-19.0%
315.00 Accessory Electric Equipment	4,871,767	1,331,877	3,539,890	-20.0%	-18.7%	(266,375)	(660,873)	(927,248)	-19.0%
316.00 Misc. Power Plant Equipment	8,073,554	3,993,993	4,079,561	-20.0%	-18.7%	(798,799)	(761,626)	(1,560,424)	-19.3%
Total Cholla Common	$75,795,083	$25,434,845	$50,360,238	-20.0%	-18.7%	($5,086,969)	($9,401,906)	($14,488,875)	-19.1%

ARIZONA PUBLIC SERVICE COMPANY
Future Net Salvage
Steam and Nuclear Production

Statement E

Account Description	12/31/04 Plant Investment	Future Retirements Interim	Future Retirements Final	Net Salvage Rate Interim	Net Salvage Rate Final	Future Net Salvage Interim	Future Net Salvage Final	Future Net Salvage Total	Future Rate
A	B	C	D=B-C	E	F	G=C*E	H=D*F	I=G+H	J=I/B
Four Corners									
311.00 Structures and Improvements	$43,005,911	$2,805,904	$40,200,007	-20.0%	-18.4%	($561,181)	($7,396,835)	($7,958,016)	-18.5%
312.00 Boiler Plant Equipment	335,046,039	85,660,518	249,385,521	-20.0%	-17.4%	(17,132,104)	(43,366,910)	(60,499,014)	-18.1%
314.00 Turbogenerator Units	59,158,016	6,918,532	52,239,484	-20.0%	-17.5%	(1,383,706)	(9,127,052)	(10,510,758)	-17.8%
315.00 Accessory Electric Equipment	29,825,484	4,372,258	25,453,226	-20.0%	-19.2%	(874,452)	(4,885,256)	(5,759,708)	-19.3%
316.00 Misc. Power Plant Equipment	17,243,295	5,830,409	11,412,886	-20.0%	-22.6%	(1,166,082)	(2,577,497)	(3,743,579)	-21.7%
Total Four Corners	$484,278,745	$105,587,621	$378,691,124	-20.0%	-19.1%	($21,117,524)	($67,353,550)	($88,471,074)	-18.3%
Four Corners Units 1-3									
311.00 Structures and Improvements	$29,002,681	$609,936	$28,392,745	-20.0%	-14.0%	($121,987)	($3,980,847)	($4,102,834)	-14.1%
312.00 Boiler Plant Equipment	218,326,908	28,507,881	189,819,027	-20.0%	-14.0%	(5,701,576)	(26,613,860)	(32,315,436)	-14.8%
314.00 Turbogenerator Units	42,777,597	3,201,876	39,575,721	-20.0%	-14.0%	(640,375)	(5,548,773)	(6,189,148)	-14.5%
315.00 Accessory Electric Equipment	17,232,291	921,516	16,310,775	-20.0%	-14.0%	(184,303)	(2,286,877)	(2,471,180)	-14.3%
316.00 Misc. Power Plant Equipment	5,676,014	369,045	5,306,969	-20.0%	-14.0%	(73,809)	(744,072)	(817,881)	-14.4%
Total Four Corners Units 1-3	$313,015,491	$33,610,254	$279,405,237	-20.0%	-14.0%	($6,722,051)	($39,174,428)	($45,896,479)	-14.7%
Four Corners Units 4-5									
311.00 Structures and Improvements	$9,201,539	$1,434,534	$7,767,005	-20.0%	-28.0%	($286,907)	($2,177,958)	($2,464,865)	-26.8%
312.00 Boiler Plant Equipment	112,898,782	55,251,132	57,647,650	-20.0%	-28.0%	(11,050,226)	(16,165,071)	(27,215,298)	-24.1%
314.00 Turbogenerator Units	14,652,943	3,035,336	11,617,607	-20.0%	-28.0%	(607,067)	(3,257,712)	(3,864,779)	-26.4%
315.00 Accessory Electric Equipment	9,853,384	2,046,089	7,807,295	-20.0%	-28.0%	(409,218)	(2,189,256)	(2,598,474)	-26.4%
316.00 Misc. Power Plant Equipment	3,029,198	1,584,816	1,444,382	-20.0%	-28.0%	(316,963)	(405,022)	(721,985)	-23.8%
Total Four Corners Units 4-5	$149,635,846	$63,351,907	$86,283,939	-20.0%	-28.0%	($12,670,381)	($24,195,020)	($36,865,401)	-24.6%
Four Corners Common									
311.00 Structures and Improvements	$4,801,691	$761,434	$4,040,257	-20.0%	-30.6%	($152,287)	($1,238,030)	($1,390,316)	-29.0%
312.00 Boiler Plant Equipment	3,820,349	1,901,505	1,918,844	-20.0%	-30.6%	(380,301)	(587,979)	(968,280)	-25.3%
314.00 Turbogenerator Units	1,727,476	681,320	1,046,156	-20.0%	-30.6%	(136,264)	(320,567)	(456,831)	-26.4%
315.00 Accessory Electric Equipment	2,739,809	1,404,654	1,335,155	-20.0%	-30.6%	(280,931)	(409,123)	(690,054)	-25.2%
316.00 Misc. Power Plant Equipment	8,538,083	3,876,548	4,661,535	-20.0%	-30.6%	(775,310)	(1,428,404)	(2,203,713)	-25.8%
Total Four Corners Common	$21,627,408	$8,625,461	$13,001,947	-20.0%	-30.6%	($1,725,092)	($3,984,102)	($5,709,194)	-26.4%
Navajo Units 1-3									
311.00 Structures and Improvements	$28,391,046	$2,287,537	$26,103,509	-20.0%	-14.0%	($457,507)	($3,659,761)	($4,117,269)	-14.5%
312.00 Boiler Plant Equipment	156,202,698	46,699,705	109,502,993	-20.0%	-14.0%	(9,339,941)	(15,352,527)	(24,692,468)	-15.8%
314.00 Turbogenerator Units	24,699,305	3,811,459	20,887,846	-20.0%	-14.0%	(762,292)	(2,928,516)	(3,690,807)	-14.9%
315.00 Accessory Electric Equipment	20,448,549	3,569,128	16,879,421	-20.0%	-14.0%	(713,826)	(2,366,527)	(3,080,352)	-15.1%
316.00 Misc. Power Plant Equipment	14,618,062	4,527,393	10,090,669	-20.0%	-14.0%	(905,479)	(1,414,731)	(2,320,209)	-15.9%
Total Navajo Units 1-3	$244,359,660	$60,895,222	$183,464,438	-20.0%	-14.0%	($12,179,044)	($25,722,062)	($37,901,106)	-15.5%

ARIZONA PUBLIC SERVICE COMPANY
Future Net Salvage
Steam and Nuclear Production

Statement E

Account Description	12/31/04 Plant Investment	Future Retirements		Net Salvage Rate		Future Net Salvage			Future Rate
		Interim	Final	Interim	Final	Interim	Final	Total	
A	B	C	D=B-C	E	F	G=C*E	H=D*F	I=G+H	J=I/B
Ocotillo Units 1-2									
311.00 Structures and Improvements	$3,792,708	$239,811	$3,552,897	-20.0%	-39.1%	($47,962)	($1,390,767)	($1,438,730)	-37.9%
312.00 Boiler Plant Equipment	24,174,538	7,885,863	16,288,675	-20.0%	-39.1%	(1,577,173)	(6,376,138)	(7,953,311)	-32.9%
314.00 Turbogenerator Units	15,372,486	2,484,703	12,887,783	-20.0%	-39.1%	(496,941)	(5,044,872)	(5,541,813)	-36.1%
315.00 Accessory Electric Equipment	2,670,248	584,327	2,085,921	-20.0%	-39.1%	(116,865)	(816,526)	(933,391)	-35.0%
316.00 Misc. Power Plant Equipment	5,258,871	654,022	4,604,849	-20.0%	-39.1%	(130,804)	(1,802,550)	(1,933,354)	-36.8%
Total Octillo Units 1-2	$51,268,851	$11,848,726	$39,420,125	-20.0%	-39.1%	($2,369,745)	($15,430,853)	($17,800,599)	-34.7%
Saguaro Units 1-2									
311.00 Structures and Improvements	$2,990,982	$141,155	$2,849,827	-20.0%	-29.5%	($28,231)	($840,140)	($868,371)	-29.0%
312.00 Boiler Plant Equipment	22,590,899	4,039,244	18,551,655	-20.0%	-29.5%	(807,849)	(5,469,100)	(6,276,948)	-27.8%
314.00 Turbogenerator Units	16,340,249	1,209,818	15,130,431	-20.0%	-29.5%	(241,964)	(4,460,509)	(4,702,473)	-28.8%
315.00 Accessory Electric Equipment	2,704,916	291,926	2,412,990	-20.0%	-29.5%	(58,385)	(711,359)	(769,744)	-28.5%
316.00 Misc. Power Plant Equipment	3,255,754	356,960	2,898,794	-20.0%	-29.5%	(71,392)	(854,576)	(925,968)	-28.4%
Total Saguaro Units 1-2	$47,882,800	$6,039,103	$41,843,697	-20.0%	-29.5%	($1,207,821)	($12,335,683)	($13,543,504)	-28.3%
NUCLEAR PRODUCTION (BY UNIT)									
Palo Verde									
321.00 Structures and Improvements	$640,003,980	$60,095,953	$579,908,027						
322.00 Reactor Plant Equipment	939,061,294	116,478,646	822,582,648	-2.0%		(2,329,573)		(2,329,573)	-0.2%
322.10 Steam Generators	52,865,345		52,865,345						
323.00 Turbogenerator Units	342,424,222	65,002,666	277,421,556	-2.0%		(1,300,053)		(1,300,053)	-0.4%
324.00 Accessory Electric Equipment	272,624,619	63,727,095	208,897,524	-2.0%		(1,274,542)		(1,274,542)	-0.5%
325.00 Misc. Power Plant Equipment	132,963,906	52,869,726	80,094,180	-2.0%		(1,057,395)		(1,057,395)	-0.8%
Total Palo Verde	$2,379,943,366	$358,174,085	$2,021,769,281	-1.7%	-19.1%	($5,961,563)		($5,961,563)	-0.3%
Palo Verde Unit 1									
321.00 Structures and Improvements	$154,544,487	$13,159,762	$141,384,725						
322.00 Reactor Plant Equipment	361,739,876	42,619,943	319,119,933	-2.0%		(852,399)		(852,399)	-0.2%
322.10 Steam Generators	27,452,571		27,452,571	-17.0%					
323.00 Turbogenerator Units	118,250,432	21,267,191	96,983,241	-2.0%		(425,344)		(425,344)	-0.4%
324.00 Accessory Electric Equipment	114,359,460	25,373,943	88,985,517	-2.0%		(507,479)		(507,479)	-0.4%
325.00 Misc. Power Plant Equipment	29,942,323	11,388,165	18,554,158	-2.0%		(227,763)		(227,763)	-0.8%
Total Palo Verde Unit 1	$806,289,149	$113,809,004	$692,480,145	-1.8%		($2,012,985)		($2,012,985)	-0.2%

ARIZONA PUBLIC SERVICE COMPANY
Future Net Salvage
Steam and Nuclear Production

Statement E

Account Description	12/31/04 Plant Investment	Future Retirements Interim	Future Retirements Final	Net Salvage Rate Interim	Net Salvage Rate Final	Future Net Salvage Interim	Future Net Salvage Final	Future Net Salvage Total	Future Rate
A	B	C	D=B-C	E	F	G=C*E	H=D*F	I=G+H	J=I/B
Palo Verde Unit 2									
321.00 Structures and Improvements	$90,520,213	$8,240,388	$82,279,825						
322.00 Reactor Plant Equipment	226,227,486	26,699,745	199,527,741	-2.0%		(533,995)		(533,995)	-0.2%
322.10 Steam Generators									
323.00 Turbogenerator Units	78,129,616	14,061,735	64,067,881	-2.0%		(281,235)		(281,235)	-0.4%
324.00 Accessory Electric Equipment	50,011,285	11,287,835	38,723,450	-2.0%		(225,757)		(225,757)	-0.5%
325.00 Misc. Power Plant Equipment	26,698,465	9,831,171	16,867,294	-2.0%		(196,623)		(196,623)	-0.7%
Total Palo Verde Unit 2	$471,587,065	$70,120,874	$401,466,191	-1.8%		($1,237,610)		($1,237,610)	-0.3%
Palo Verde Unit 3									
321.00 Structures and Improvements	$160,291,956	$15,554,217	$144,737,739						
322.00 Reactor Plant Equipment	323,919,702	43,548,455	280,371,247	-2.0%		(870,969)		(870,969)	-0.3%
322.10 Steam Generators	25,412,774		25,412,774	-17.0%					
323.00 Turbogenerator Units	144,585,131	29,410,073	115,175,058	-2.0%		(588,201)		(588,201)	-0.4%
324.00 Accessory Electric Equipment	89,504,541	22,323,751	67,180,790	-2.0%		(446,475)		(446,475)	-0.5%
325.00 Misc. Power Plant Equipment	27,547,817	11,675,724	15,872,093	-2.0%		(233,514)		(233,514)	-0.8%
Total Palo Verde Unit 3	$771,261,921	$122,512,219	$648,749,702	-1.7%		($2,139,160)		($2,139,160)	-0.3%
Palo Verde Water Reclamation									
321.00 Structures and Improvements	$128,265,752	$12,883,471	$115,382,281						
322.00 Reactor Plant Equipment	133,326	14,018	119,308	-2.0%		(280)		(280)	-0.2%
322.10 Steam Generators									
323.00 Turbogenerator Units	235,152	44,537	190,615	-2.0%		(891)		(891)	-0.4%
324.00 Accessory Electric Equipment									
325.00 Misc. Power Plant Equipment	88,819	35,558	53,261	-2.0%		(711)		(711)	-0.8%
Total Palo Verde Water Reclamation	$128,723,049	$12,977,584	$115,745,465	0.0%		($1,882)		($1,882)	
Palo Verde Common									
321.00 Structures and Improvements	$106,381,572	$10,258,114	$96,123,458						
322.00 Reactor Plant Equipment	27,040,904	3,596,486	23,444,418	-2.0%		(71,930)		(71,930)	-0.3%
322.10 Steam Generators									
323.00 Turbogenerator Units	1,223,891	219,130	1,004,761	-2.0%		(4,383)		(4,383)	-0.4%
324.00 Accessory Electric Equipment	18,749,333	4,741,566	14,007,767	-2.0%		(94,831)		(94,831)	-0.5%
325.00 Misc. Power Plant Equipment	48,686,482	19,939,109	28,747,373	-2.0%		(398,782)		(398,782)	-0.8%
Total Palo Verde Common	$202,082,182	$38,754,405	$163,327,777	-1.5%		($569,926)		($569,926)	-0.3%

ARIZONA PUBLIC SERVICE COMPANY Statement F

Dismantlement Costs

Steam Production

Unit	Capacity (MW)	Cost per kW	2002 Cost	Plant	Distributed Cost	Inflation Rate	Year Spent	Trended Cost	Accrual Rate
A	B	C	D=B*C*1000	E	F	G	H	I	J=I/E
Cholla									
1	110	40.00	$4,400,000	$47,159,515	$3,784,444	3.00%	2017	$6,072,921	12.9%
2	245	40.00	9,800,000	226,159,849	8,428,988	3.00%	2033	21,705,342	9.6%
3	260	40.00	10,400,000	192,669,161	8,945,049	3.00%	2035	24,437,025	12.7%
C				75,795,083	3,441,520	3.00%	2035	9,401,906	12.4%
	615		$24,600,000	$541,783,608	$24,600,000			$61,617,194	11.4%
	Allocated to Common:		3,441,520						
	Allocated to Units:		$21,158,480						
Four Corners									
1-3	560	47.00	$26,320,000	$313,015,491	$25,144,575	3.00%	2016	$39,174,428	12.5%
4-5	222	47.00	10,434,000	149,635,846	9,968,028	3.00%	2031	24,195,020	16.2%
C				21,627,408	1,641,397	3.00%	2031	3,984,102	18.4%
	782		$36,754,000	$484,278,745	$36,754,000			$67,353,550	13.9%
	Allocated to Common:		1,641,397						
	Allocated to Units:		$35,112,603						
Navajo									
1-3	315	39.00	$12,285,000	$244,359,660	$12,285,000	3.00%	2026	$25,722,062	10.5%
C									
	315		$12,285,000	$244,359,660	$12,285,000			$25,722,062	10.5%
	Allocated to Common:								
	Allocated to Units:		$12,285,000						
Ocotillo									
1-2	220	40.00	$8,800,000	$51,268,851	$8,800,000	3.00%	2020	$15,430,853	30.1%
C									
	220		$8,800,000	$51,268,851	$8,800,000			$15,430,853	30.1%
	Allocated to Common:								
	Allocated to Units:		$8,800,000						
Saguaro									
1-2	210	40.00	$8,400,000	$47,882,800	$8,400,000	3.00%	2014	$12,335,683	25.8%
C									
	210		$8,400,000	$47,882,800	$8,400,000			$12,335,683	25.8%
	Allocated to Common:								
	Allocated to Units:		$8,400,000						
Palo Verde									
1	1243			$806,289,149		3.00%	2024		
2	1335			471,587,065		3.00%	2025		
3	1247			771,261,921		3.00%	2027		
WR				128,723,049		3.00%	2027		
C				202,082,182		3.00%	2027		
	3825			$2,379,943,366					
	Allocated to WR:								
	Allocated to Common:								
	Allocated to Units:								

ARIZONA PUBLIC SERVICE COMPANY
Present and Proposed Parameters
Company Broad Group Procedure

Statement G

Account Description	Present Parameters P-Life/ AYFR	Curve Shape	BG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	Proposed Parameters (at December 31, 2004) P-Life/ AYFR	Curve Shape	BG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
STEAM PRODUCTION												
311.00 Structures and Improvements									31.41	18.47	-18.7	-18.7
312.00 Boiler Plant Equipment									30.01	15.64	-18.8	-18.8
314.00 Turbogenerator Units									33.62	17.74	-20.6	-20.6
315.00 Accessory Electric Equipment									39.56	20.34	-19.2	-19.2
316.00 Misc. Power Plant Equipment									26.26	16.98	-21.1	-21.1
Total Steam Production Plant									31.20	16.64	-19.2	-19.2
NUCLEAR PRODUCTION												
321.00 Structures and Improvements									36.73	20.63		
322.00 Reactor Plant Equipment									34.10	19.58	-0.2	-0.2
322.10 Steam Generators									17.47	1.71		
323.00 Turbogenerator Units									33.80	19.08	-0.4	-0.4
324.00 Accessory Electric Equipment									35.60	18.99	-0.5	-0.5
325.00 Misc. Power Plant Equipment									29.00	17.27	-0.8	-0.8
Total Nuclear Production Plant									33.82	18.78	-0.2	-0.2
OTHER PRODUCTION												
341.00 Structures and Improvements									29.51	18.52	-4.8	-4.8
342.00 Fuel Holders, Products and Accessories									31.92	22.27	-5.0	-5.0
343.00 Prime Movers									35.08	11.58		
344.00 Generators and Devices									24.04	17.27	-1.4	-1.4
345.00 Accessory Electric Equipment									32.29	19.53		
346.00 Misc. Power Plant Equipment									29.45	16.90		
Total Other Production Plant									27.31	17.35	-1.6	-1.6
TOTAL PRODUCTION PLANT									32.47	17.92		
TRANSMISSION												
352.00 Structures and Improvements	50.00	R4	50.00	35.20		-5.0	50.00	R4	50.00	21.69	-5.0	-5.0
353.00 Station Equipment	57.00	R1.5	57.00	45.70			57.00	R1.5	57.00	39.98		
354.00 Towers and Fixtures	60.00	R3	60.00	38.30		-35.0	60.00	R3	60.00	42.49	-35.0	-35.0
355.00 Poles and Fixtures - Wood	48.00	R1.5	48.00	38.50		-35.0	55.00	R3	55.00	18.51	-15.0	-15.0
356.00 Overhead Conductors and Devices	55.00	R3	55.00	38.50		-35.0	55	R3	55.00	37.51	-35.0	-35.0

ARIZONA PUBLIC SERVICE COMPANY
Present and Proposed Parameters
Company Broad Group Procedure

Statement G

Account Description	Present Parameters P-Life/ AYFR	Curve Shape	BG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	Proposed Parameters (at December 31, 2004) P-Life/ AYFR	Curve Shape	BG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
Total Transmission Plant									57.04	39.97	-1.5	-1.5
DISTRIBUTION												
361.00 Structures and Improvements	45.00	R2.5	45.00	33.10		-10.0	45.00	R2.5	45.00	33.18	-10.0	-10.0
362.00 Station Equipment	44.00	L0.5	44.00	36.90			44.00	L0.5	44.00	36.73		
364.00 Poles, Towers and Fixtures - Wood	38.00	R0.5	38.00	30.90		-10.0	38.00	R0.5	38.00	29.41	-10.0	-10.0
364.10 Poles, Towers and Fixtures - Steel	50.00	R3	50.00	46.60		-5.0	50.00	R3	50.00	46.78	-5.0	-5.0
365.00 Overhead Conductors and Devices	53.00	O1	53.00	47.70		-10.0	53.00	SC	53.00	46.65	-10.0	-10.0
366.00 Underground Conduit	86.00	O1	86.00	82.40		-5.0	86.00	SC	86.00	82.10	-5.0	-5.0
367.00 Underground Conductors and Devices	29.00	L1	29.00	22.90		-5.0	29.00	L1	29.00	22.28	-5.0	-5.0
368.00 Line Transformers	36.00	R3	36.00	24.60		-5.0	36.00	R3	36.00	23.63	-5.0	-5.0
369.00 Services	37.00	S2	37.00	27.90		-10.0	37.00	S2	37.00	26.72	-10.0	-10.0
370.00 Meters	29.00	L0	29.00	21.80			29.00	L0	29.00	21.24		
370.10 Meters - Electronic	26.00	R1.5	26.00	23.30			26.00	R1.5	26.00	23.06		
371.00 Installations on Customers' Premises	50.00	O2	50.00	45.00		-20.0	50.00	O2	50.00	45.48	-20.0	-20.0
373.00 Street Lighting and Signal Systems	35.00	R2.5	35.00	25.90		-20.0	35.00	R2.5	35.00	24.32	-20.0	-20.0
Total Distribution Plant									38.35	30.41	-6.1	-6.1
GENERAL												
390.00 Structures and Improvements	39.00	R1	39.00	30.70		-15.0	39.00	R1	39.00	29.54	-15.0	-15.0
391.00 Office Furn. and Equip. - Furniture	20.00	SQ	20.00	10.10			20.00	SQ	20.00	12.23		
391.10 Office Furn. and Equip. - PC Equipment	8.00	R3	8.00	5.30			8.00	R3	8.00	4.28		
391.20 Office Furn. and Equip. - Other	22.00	R4	22.00	14.80			22.00	R4	22.00	13.44		
393.00 Stores Equipment	20.00	SQ	20.00	2.80			20.00	SQ	20.00	2.14		
394.00 Tools, Shop and Garage Equipment	20.00	SQ	20.00	13.70			20.00	SQ	20.00	12.20		
395.00 Laboratory Equipment	20.00	L1	20.00	12.00			20.00	L1	20.00	11.99		
397.00 Communication Equipment	19.00	S1.5	19.00	12.00			19.00	S1.5	19.00	11.53		

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Account Description	Present Parameters P-Life/ AYFR	Curve Shape	BG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	Proposed Parameters (at December 31, 2004) P-Life/ AYFR	Curve Shape	BG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
398.HH Miscellaneous Equipment - Hydrogen	5.00	SQ	5.00				5.00	SQ	5.00	2.50		
398.00 Miscellaneous Equipment	24.00	S1.5	24.00	16.60			24.00	S1.5	24.00	20.91		
Total General									17.71	11.41	-4.7	-4.7
TOTAL UTILITY									33.60	22.24	-5.9	-5.9
STEAM PRODUCTION (BY UNIT)												
Cholla												
311.00 Structures and Improvements									48.46	27.11	-19.2	-19.2
312.00 Boiler Plant Equipment									38.79	19.78	-19.4	-19.4
314.00 Turbogenerator Units									40.45	24.85	-19.9	-19.9
315.00 Accessory Electric Equipment									46.87	24.71	-19.4	-19.4
316.00 Misc. Power Plant Equipment									33.05	20.65	-19.2	-19.2
Total Cholla									40.66	21.89	-19.5	-19.5
Cholla Unit 1												
311.00 Structures and Improvements	2017	75-S1.5		14.00		-20.0	2017	75-S1.5	39.84	11.97	-15.8	-15.8
312.00 Boiler Plant Equipment	2017	48-L2		13.40		-20.0	2017	48-L2	25.66	11.20	-16.3	-16.3
314.00 Turbogenerator Units	2017	65-R2		14.00		-20.0	2017	65-R2	31.21	11.90	-15.8	-15.8
315.00 Accessory Electric Equipment	2017	60-R2.5		13.90		-20.0	2017	60-R2.5	31.76	11.86	-15.9	-15.9
316.00 Misc. Power Plant Equipment	2017	40-R2		13.50		-20.0	2017	40-R2	21.87	11.63	-16.1	-16.1
Total Cholla Unit 1									27.46	11.44	-16.1	-16.1
Cholla Unit 2												
311.00 Structures and Improvements	2033	75-S1.5		29.00		-20.0	2033	75-S1.5	43.32	26.78	-18.1	-18.1
312.00 Boiler Plant Equipment	2033	48-L2		22.00		-20.0	2033	48-L2	40.97	20.46	-19.0	-19.0
314.00 Turbogenerator Units	2033	65-R2		27.50		-20.0	2033	65-R2	47.30	25.56	-18.3	-18.3
315.00 Accessory Electric Equipment	2033	60-R2.5		26.80		-20.0	2033	60-R2.5	48.50	25.09	-18.4	-18.4
316.00 Misc. Power Plant Equipment	2033	40-R2		22.10		-20.0	2033	40-R2	36.47	20.74	-19.1	-19.1
Total Cholla Unit 2									42.90	21.99	-18.8	-18.8
Cholla Unit 3												
311.00 Structures and Improvements	2035	75-S1.5		29.90		-20.0	2035	75-S1.5	50.45	27.97	-21.7	-21.7
312.00 Boiler Plant Equipment	2035	48-L2		22.90		-20.0	2035	48-L2	41.50	21.56	-20.9	-20.9
314.00 Turbogenerator Units	2035	65-R2		29.70		-20.0	2035	65-R2	39.34	28.16	-21.8	-21.8

ARIZONA PUBLIC SERVICE COMPANY
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Account Description	Present Parameters P-Life/ AYFR	Curve Shape	BG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	Proposed Parameters (at December 31, 2004) P-Life/ AYFR	Curve Shape	BG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
315.00 Accessory Electric Equipment	2035	60-R2.5		28.50		-20.0	2035	60-R2.5	48.65	26.87	-21.5	-21.5
316.00 Misc. Power Plant Equipment	2035	40-R2		23.80		-20.0	2035	40-R2	37.32	21.91	-20.8	-20.8
Total Cholla Unit 3									42.19	24.25	-21.2	-21.2
Cholla Common												
311.00 Structures and Improvements	2035	75-S1.5		29.90		-20.0	2035	75-S1.5	49.33	28.01	-18.9	-18.9
312.00 Boiler Plant Equipment	2035	48-L2		24.80		-20.0	2035	48-L2	38.22	23.38	-19.3	-19.3
314.00 Turbogenerator Units	2035	65-R2		29.00		-20.0	2035	65-R2	49.00	27.18	-19.0	-19.0
315.00 Accessory Electric Equipment	2035	60-R2.5		28.70		-20.0	2035	60-R2.5	44.56	27.19	-19.0	-19.0
316.00 Misc. Power Plant Equipment	2035	40-R2		25.80		-20.0	2035	40-R2	34.14	24.23	-19.3	-19.3
Total Cholla Common									42.87	25.69	-19.1	-19.1
Four Corners												
311.00 Structures and Improvements									21.68	13.52	-18.5	-18.5
312.00 Boiler Plant Equipment									24.61	12.87	-18.1	-18.1
314.00 Turbogenerator Units									25.83	13.24	-17.8	-17.8
315.00 Accessory Electric Equipment									28.40	14.61	-19.3	-19.3
316.00 Misc. Power Plant Equipment									24.43	15.90	-21.7	-21.7
Total Four Corners									24.65	13.18	-18.3	-18.3
Four Corners Units 1-3												
311.00 Structures and Improvements	2016	75-S1.5		13.30		-20.0	2016	75-S1.5	17.39	11.39	-14.1	-14.1
312.00 Boiler Plant Equipment	2016	48-L2		12.70		-20.0	2016	48-L2	20.54	10.76	-14.8	-14.8
314.00 Turbogenerator Units	2016	65-R2		13.10		-20.0	2016	65-R2	22.47	11.08	-14.5	-14.5
315.00 Accessory Electric Equipment	2016	60-R2.5		13.20		-20.0	2016	60-R2.5	22.63	11.21	-14.3	-14.3
316.00 Misc. Power Plant Equipment	2016	40-R2		13.10		-20.0	2016	40-R2	15.43	11.15	-14.4	-14.4
Total Four Corners Units 1-3									20.42	10.90	-14.7	-14.7
Four Corners Units 4-5												
311.00 Structures and Improvements	2031	75-S1.5		26.80		-20.0	2031	75-S1.5	46.23	24.80	-26.8	-26.8
312.00 Boiler Plant Equipment	2031	48-L2		22.10		-20.0	2031	48-L2	39.09	20.40	-24.1	-24.1
314.00 Turbogenerator Units	2031	65-R2		26.30		-20.0	2031	65-R2	41.03	24.09	-26.4	-26.4

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Account Description	Present Parameters						Proposed Parameters (at December 31, 2004)					
	P-Life/ AYFR	Curve Shape	BG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	P-Life/ AYFR	Curve Shape	BG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
315.00 Accessory Electric Equipment	2031	60-R2.5		25.90		-20.0	2031	60-R2.5	41.33	24.24	-26.4	-26.4
316.00 Misc. Power Plant Equipment	2031	40-R2		23.00		-20.0	2031	40-R2	34.60	20.22	-23.8	-23.8
Total Four Corners Units 4-5									39.69	21.23	-24.6	-24.6
Four Corners Common												
311.00 Structures and Improvements	2031	75-S1.5		26.80		-20.0	2031	75-S1.5	41.05	24.71	-29.0	-29.0
312.00 Boiler Plant Equipment	2031	48-L2		22.80		-20.0	2031	48-L2	39.30	19.62	-25.3	-25.3
314.00 Turbogenerator Units	2031	65-R2		23.30		-20.0	2031	65-R2	59.40	21.73	-26.4	-26.4
315.00 Accessory Electric Equipment	2031	60-R2.5		21.00		-20.0	2031	60-R2.5	54.63	20.44	-25.2	-25.2
316.00 Misc. Power Plant Equipment	2031	40-R2		23.20		-20.0	2031	40-R2	34.10	21.37	-25.8	-25.8
Total Four Corners Common									39.77	21.73	-26.4	-26.4
Navajo Units 1-3												
311.00 Structures and Improvements	2026	75-S1.5		22.80		-20.0	2026	75-S1.5	33.75	20.78	-14.5	-14.5
312.00 Boiler Plant Equipment	2026	48-L2		20.60		-20.0	2026	48-L2	31.58	18.52	-15.8	-15.8
314.00 Turbogenerator Units	2026	65-R2		22.00		-20.0	2026	65-R2	39.90	20.00	-14.9	-14.9
315.00 Accessory Electric Equipment	2026	60-R2.5		22.00		-20.0	2026	60-R2.5	39.00	19.88	-15.1	-15.1
316.00 Misc. Power Plant Equipment	2026	40-R2		20.20		-20.0	2026	40-R2	28.56	18.57	-15.9	-15.9
Total Navajo Units 1-3									32.83	19.00	-15.5	-15.5
Ocotillo Units 1-2												
311.00 Structures and Improvements	2020	75-S1.5		17.10		-20.0	2020	75-S1.5	28.91	15.05	-37.9	-37.9
312.00 Boiler Plant Equipment	2020	48-L2		15.20		-20.0	2020	48-L2	35.07	12.89	-32.9	-32.9
314.00 Turbogenerator Units	2020	65-R2		16.80		-20.0	2020	65-R2	38.36	14.30	-36.1	-36.1
315.00 Accessory Electric Equipment	2020	60-R2.5		16.30		-20.0	2020	60-R2.5	36.37	13.90	-35.0	-35.0
316.00 Misc. Power Plant Equipment	2020	40-R2		16.20		-20.0	2020	40-R2	19.12	14.61	-36.8	-36.8
Total Octillo Units 1-2									32.66	13.77	-34.7	-34.7
Saguaro Units 1-2												
311.00 Structures and Improvements	2014	75-S1.5		11.30		-20.0	2014	75-S1.5	22.37	9.28	-29.0	-29.0
312.00 Boiler Plant Equipment	2014	48-L2		11.10		-20.0	2014	48-L2	24.15	8.61	-27.8	-27.8
314.00 Turbogenerator Units	2014	65-R2		11.20		-20.0	2014	65-R2	29.34	9.15	-28.8	-28.8

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Account Description	Present Parameters P-Life/ AYFR	Curve Shape	BG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	Proposed Parameters (at December 31, 2004) P-Life/ AYFR	Curve Shape	BG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
315.00 Accessory Electric Equipment	2014	60-R2.5		11.20		-20.0	2014	60-R2.5	31.94	8.99	-28.5	-28.5
316.00 Misc. Power Plant Equipment	2014	40-R2		10.90		-20.0	2014	40-R2	16.13	8.96	-28.4	-28.4
Total Saguaro Units 1-2									25.04	8.87	-28.3	-28.3
NUCLEAR PRODUCTION (BY UNIT)												
Palo Verde												
321.00 Structures and Improvements									36.73	20.63		
322.00 Reactor Plant Equipment									34.10	19.58	-0.2	-0.2
322.10 Steam Generators									17.47	1.71		
323.00 Turbogenerator Units									33.80	19.08	-0.4	-0.4
324.00 Accessory Electric Equipment									35.60	18.99	-0.5	-0.5
325.00 Misc. Power Plant Equipment									29.00	17.27	-0.8	-0.8
Total Palo Verde									33.82	18.78	-0.2	-0.2
Palo Verde Unit 1												
321.00 Structures and Improvements	2024	65-R2.5		21.20			2024	65-R2.5	36.38	18.78		
322.00 Reactor Plant Equipment	2024	70-R1		20.60		-2.0	2024	70-R1	34.79	18.37	-0.2	-0.2
322.10 Steam Generators	2005	25-SQ		3.00		-17.0	2005	25-SQ	17.21	1.00		
323.00 Turbogenerator Units	2024	60-S0		19.90		-2.0	2024	60-S0	33.87	17.81	-0.4	-0.4
324.00 Accessory Electric Equipment	2024	45-R3		20.00		-2.0	2024	45-R3	35.49	17.80	-0.4	-0.4
325.00 Misc. Power Plant Equipment	2024	35-R0.5		17.70		-2.0	2024	35-R0.5	29.54	15.87	-0.8	-0.8
Total Palo Verde Unit 1									33.64	17.85	-0.2	-0.2
Palo Verde Unit 2												
321.00 Structures and Improvements	2025	65-R2.5		22.00			2025	65-R2.5	36.76	19.70		
322.00 Reactor Plant Equipment	2025	70-R1		21.50		-2.0	2025	70-R1	31.22	19.32	-0.2	-0.2
322.10 Steam Generators	2003	25-SQ		1.00		-17.0						
323.00 Turbogenerator Units	2025	60-S0		20.80		-2.0	2025	60-S0	32.19	18.74	-0.4	-0.4
324.00 Accessory Electric Equipment	2025	45-R3		20.90		-2.0	2025	45-R3	35.26	18.71	-0.5	-0.5
325.00 Misc. Power Plant Equipment	2025	35-R0.5		18.70		-2.0	2025	35-R0.5	27.79	16.82	-0.7	-0.7
Total Palo Verde Unit 2									32.49	19.06	-0.3	-0.3

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Account Description	Present Parameters P-Life/ AYFR	Curve Shape	BG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	Proposed Parameters (at December 31, 2004) P-Life/ AYFR	Curve Shape	BG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
Palo Verde Unit 3												
321.00 Structures and Improvements	2027	65-R2.5		23.30			2027	65-R2.5	37.35	21.58		
322.00 Reactor Plant Equipment	2027	70-R1		22.60		-2.0	2027	70-R1	35.55	21.03	-0.3	-0.3
322.10 Steam Generators	2007	25-SQ		5.00		-17.0	2007	25-SQ	17.75	2.50		
323.00 Turbogenerator Units	2027	60-S0		21.80		-2.0	2027	60-S0	34.71	20.33	-0.4	-0.4
324.00 Accessory Electric Equipment	2027	45-R3		22.10		-2.0	2027	45-R3	36.02	20.40	-0.5	-0.5
325.00 Misc. Power Plant Equipment	2027	35-R0.5		19.20		-2.0	2027	35-R0.5	29.86	17.88	-0.8	-0.8
Total Palo Verde Unit 3									34.42	20.13	-0.3	-0.3
Palo Verde Water Reclamation												
321.00 Structures and Improvements	2027	65-R2.5		23.20			2027	65-R2.5	36.85	21.55		
322.00 Reactor Plant Equipment	2027	70-R1		23.00		-2.0	2027	70-R1	24.51	21.36	-0.2	-0.2
322.10 Steam Generators												
323.00 Turbogenerator Units	2027	60-S0		22.00		-2.0	2027	60-S0	32.19	20.51	-0.4	-0.4
324.00 Accessory Electric Equipment												
325.00 Misc. Power Plant Equipment	2027	35-R0.5		19.50		-2.0	2027	35-R0.5	28.73	18.15	-0.8	-0.8
Total Palo Verde Water Reclamation									36.81	21.53		0.0
Palo Verde Common												
321.00 Structures and Improvements	2027	65-R2.5		23.20			2027	65-R2.5	36.16	21.59		
322.00 Reactor Plant Equipment	2027	70-R1		22.60		-2.0	2027	70-R1	34.65	21.05	-0.3	-0.3
322.10 Steam Generators												
323.00 Turbogenerator Units	2027	60-S0		22.20		-2.0	2027	60-S0	30.79	20.63	-0.4	-0.4
324.00 Accessory Electric Equipment	2027	45-R3		22.00		-2.0	2027	45-R3	35.21	20.36	-0.5	-0.5
325.00 Misc. Power Plant Equipment	2027	35-R0.5		19.40		-2.0	2027	35-R0.5	28.90	18.04	-0.8	-0.8
Total Palo Verde Common									33.80	20.40	-0.3	-0.3
OTHER PRODUCTION (BY UNIT)												
Douglas CT												
341.00 Structures and Improvements	2017	80-S1		13.90		-5.0	2017	80-S1	43.20	12.01	-5.0	-5.0
342.00 Fuel Holders, Products and Accessories	2017	70-S1		14.00		-5.0	2017	70-S1	30.67	12.08	-5.0	-5.0
343.00 Prime Movers	2017	70-L1.5		14.20			2017	70-L1.5	42.22	11.65		
344.00 Generators and Devices	2017	37-R3		9.70			2017	37-R3	38.41	8.41		

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A	B	C	D	E	F	G	H	I	J	K	L	M
345.00 Accessory Electric Equipment	2017	50-S2		13.10			2017	50-S2	38.35	11.06		
346.00 Misc. Power Plant Equipment	2017	70-L1		13.80			2017	70-L1	30.86	11.86		
Total Douglas CT									39.39	11.44	-0.3	-0.3
Ocotillo CT Units 1-2												
341.00 Structures and Improvements	2017	80-S1		14.50		-5.0	2017	80-S1	29.06	12.12	-5.0	-5.0
342.00 Fuel Holders, Products and Accessories	2017	70-S1		14.00		-5.0	2017	70-S1	30.34	12.11	-5.0	-5.0
343.00 Prime Movers	2017	70-L1.5		14.10			2017	70-L1.5	36.89	11.73		
344.00 Generators and Devices	2017	37-R3		13.60			2017	37-R3	23.11	11.60		
345.00 Accessory Electric Equipment	2017	50-S2		13.20			2017	50-S2	33.05	11.29		
346.00 Misc. Power Plant Equipment	2017	70-L1		14.00			2017	70-L1	31.41	11.81		
Total Ocotillo CT Units 1-2									29.06	11.66	-0.4	-0.4
Saguaro CT Units 1-2												
341.00 Structures and Improvements	2017	80-S1		14.40		-5.0	2017	80-S1	18.86	12.34	-5.0	-5.0
342.00 Fuel Holders, Products and Accessories	2017	70-S1		14.00		-5.0	2017	70-S1	33.51	12.00	-5.0	-5.0
343.00 Prime Movers	2017	70-L1.5		13.80			2017	70-L1.5	36.07	11.77		
344.00 Generators and Devices	2017	37-R3		13.00			2017	37-R3	21.21	10.88		
345.00 Accessory Electric Equipment	2017	50-S2		13.40			2017	50-S2	36.19	11.28		
346.00 Misc. Power Plant Equipment	2017	70-L1		14.10			2017	70-L1	23.02	12.00		
Total Saguaro CT Units 1-2									28.43	11.56	-0.8	-0.8
Solar Units												
341.00 Structures and Improvements	12.00	SQ		3.60			12	SQ	12.00	2.03		
342.00 Fuel Holders, Products and Accessories												
343.00 Prime Movers							12	SQ	12.00	11.50		
344.00 Generators and Devices	12.00	SQ		7.80			12	SQ	12.00	7.56		
345.00 Accessory Electric Equipment	12.00	SQ		9.90			12	SQ	12.00	7.86		
346.00 Misc. Power Plant Equipment												
Total Solar Units									12.00	7.82		
West Phoenix												
341.00 Structures and Improvements									36.76	24.31	-5.0	-5.0
342.00 Fuel Holders, Products and Accessories									31.14	24.77	-5.0	-5.0

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Account Description	Present Parameters P-Life/ AYFR	Curve Shape	BG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	Proposed Parameters (at December 31, 2004) P-Life/ AYFR	Curve Shape	BG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
343.00 Prime Movers									29.19	11.86		
344.00 Generators and Devices									29.08	23.01	-1.9	-1.9
345.00 Accessory Electric Equipment									32.22	23.25		
346.00 Misc. Power Plant Equipment									31.01	20.03		
Total West Pheonix									30.09	22.53	-2.2	-2.2
West Phoenix CT Units 1-2												
341.00 Structures and Improvements	2017	80-S1		14.20		-5.0	2017	80-S1	36.23	12.12	-5.0	-5.0
342.00 Fuel Holders, Products and Accessories	2017	70-S1		14.00		-5.0	2017	70-S1	33.49	12.03	-5.0	-5.0
343.00 Prime Movers	2017	70-L1.5		14.20			2017	70-L1.5	29.19	11.86		
344.00 Generators and Devices	2017	37-R3		12.30			2017	37-R3	24.60	10.75		
345.00 Accessory Electric Equipment	2017	50-S2		13.20			2017	50-S2	35.71	11.27		
346.00 Misc. Power Plant Equipment	2017	70-L1		14.10			2017	70-L1	22.91	12.02		
Total West Ploenix CT Units 1-2									28.26	11.49	-0.5	-0.5
West Phoenix CC Units 1-3												
341.00 Structures and Improvements	2031	80-S1		28.10		-5.0	2031	80-S1	36.80	25.21	-5.0	-5.0
342.00 Fuel Holders, Products and Accessories	2031	70-S1		27.70		-5.0	2031	70-S1	30.98	25.65	-5.0	-5.0
343.00 Prime Movers												
344.00 Generators and Devices	2031	37-R3		26.20		-2.0	2031	37-R3	29.42	23.95	-2.0	-2.0
345.00 Accessory Electric Equipment	2031	50-S2		27.80			2031	50-S2	31.83	24.59		
346.00 Misc. Power Plant Equipment	2031	70-L1		26.60			2031	70-L1	35.30	24.26		
Total West Phoenix CC Units 1-3									30.39	24.35	-2.4	-2.4
Yucca CT Units 1-4												
341.00 Structures and Improvements	2016	80-S1		13.40		-5.0	2016	80-S1	20.94	11.35	-5.0	-5.0
342.00 Fuel Holders, Products and Accessories	2016	70-S1		12.90		-5.0	2016	70-S1	37.68	11.00	-5.0	-5.0
343.00 Prime Movers	2016	70-L1.5		14.20			2016	70-L1.5	40.60	10.81		
344.00 Generators and Devices	2016	37-R3		11.60			2016	37-R3	29.06	9.09		
345.00 Accessory Electric Equipment	2016	50-S2		13.00			2016	50-S2	32.93	10.37		
346.00 Misc. Power Plant Equipment	2016	70-L1		13.20			2016	70-L1	29.59	10.90		
Total Yucca CT Units 1-4									34.47	10.24	-0.9	-0.9

Attachment REW–2

2005 Technical Update

PWEC Units Acquired by Arizona Public Service Company

Prepared by
Foster Associates, Inc.

FOSTER ASSOCIATES INCORPORATED

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July 2005

EXECUTIVE SUMMARY

INTRODUCTION

This report presents the findings and recommendations developed in a 2005 Technical Update of depreciation rates prepared by Foster Associates, Inc., for certain Pinnacle West Energy Corporation generating units (PWEC Units) acquired by Arizona Public Service Company. Parameters (*i.e.*, projection curves, projection lives and future net salvage rates) used in the update were accepted by the Arizona Corporation Commission (ACC) pursuant to a settlement agreement in Docket No. E–01345A–03–0437 (Decision No. 67744, dated April 7, 2005). Age distributions of surviving plant at December 31, 2004 were used in the 2005 update to derive composite service life statistics and computed or theoretical depreciation reserves.

Foster Associates is a public utility economic consulting firm headquartered in Bethesda, Maryland offering economic research and consulting services on issues and problems arising from governmental regulation of business. Areas of specialization supported by our Fort Myers office include property service–life forecasting, depreciation estimation, and valuation of industrial property.

Foster Associates has undertaken numerous depreciation engagements for both public and privately owned business entities, including detailed statistical life studies, analyses of required net salvage rates, and the selection of depreciation systems that will most nearly achieve the goals of depreciation accounting under the constraints of either government regulation or competitive market pricing. Foster Associates is widely recognized for industry leadership in the development of depreciation systems, life analysis techniques and computer software for conducting depreciation and valuation studies.

The purpose of a technical update is to adjust depreciation rates for changes in the variables associated with a remaining–life accrual rate. The variables for a plant account include the age distribution of surviving plant, the recorded depreciation reserve and the average net salvage rate used in the calculation of a theoretical reserve. A technical update retains the parameters developed and/or approved in the most recent full depreciation study and adjusts depreciation rates for subsequent changes in plant, reserves and realized net salvage activity.

The principal findings from the 2005 review are summarized in the attached statements. Statement A provides a comparative summary of present and proposed annual depreciation rates for each rate category. Statement B provides a comparison of present and proposed annual depreciation accruals. Statement C provides a comparison of the computed and redistributed depreciation reserve for each rate category. Statement D provides a summary of the components used to obtain a weighted–average net salvage rate for each plant account. Statement E provides a comparative summary of present and proposed parameters and statistics including

projection life, projection curve, average service life, average remaining life, and average and future net salvage rates.

SCOPE OF STUDY

Unlike a full depreciation study in which service life and net salvage parameters are estimated from a blending of quantitative analyses and informed judgment, the current study retains the parameters accepted in Docket No. E–01345A–03–0437 and provides an update of depreciation rates based on account age distributions and reserve balances at December 31, 2004.

The principal activities undertaken in the course of conducting the 2005 Technical Update included:

- Collection of plant data;
- Reconciliation of data to the official records of the Company;
- Rebalancing of depreciation reserves; and
- Development of adjusted accrual rates for each rate category.

DEPRECIATION SYSTEM

A depreciation rate is formed by combining the elements of a depreciation system. A depreciation system is composed of a method, a procedure and a technique. A depreciation method (*e.g.*, straight–line) describes the component of the system that determines the acceleration or deceleration of depreciation accruals in relation to either time or use. A depreciation procedure (*e.g.*, vintage group) identifies the level of grouping or sub–grouping of assets within a plant category. The level of grouping dictates the weighting used to obtain composite life statistics for an account. A depreciation technique (*e.g.*, remaining–life) describes the life statistic used in the system.

The depreciation system currently used for PWEC Units is composed of the straight–line method, broad group procedure, and remaining–life technique for all plant categories. The present system was accepted by the ACC in Docket No. E–01345A–03–0437 without comment as to the appropriateness of the system or a consideration of alternative systems. Accordingly, depreciation rates in the 2005 update were developed using the currently approved system.

PROPOSED DEPRECIATION RATES

Table 1 provides a summary of the changes in annual rates and accruals resulting from the 2005 Technical Update. Rates proposed for each primary account include an allowance for net salvage.

Function	Accrual Rate			2005 Annualized Accrual		
	Present	Proposed	Difference	Present	Proposed	Difference
A	B	C	D=C-B	E	F	G=F-E
Production	2.92%	2.71%	-0.21%	$28,002,769	$26,066,384	($1,936,385)
Transmission	1.83%	1.73%	-0.10%	787,163	742,858	(44,305)
Total Utility	*2.87%*	*2.67%*	*-0.20%*	*$28,789,932*	*$26,809,242*	*($1,980,690)*

Table 1. Present and Proposed Rates and Accruals

Adjustments developed in the technical update produce a composite depreciation rate of 2.67 percent. Depreciation expense is presently accrued at an equivalent rate of 2.87 percent. The proposed change in the composite depreciation rate represents a reduction of 0.20 percentage points.

A continued application of rates currently approved would provide annual depreciation expense of $28,789,932 compared with an annual expense of $26,809,242 using the rates developed in the update. The proposed expense decrease of $1,980,690 is largely attributable to: a) a change in the mix of plant investments among primary accounts; b) changes in the age distributions of surviving plant; and c) the estimation of parameters for West Phoenix Unit 5.

STUDY PROCEDURE

INTRODUCTION

Unlike a full depreciation study in which projection curves, projection lives and future net salvage rates are estimated from a statistical analysis of recorded retirements and net salvage realized in the past, a technical update generally retains the parameters currently used by the utility and adjusts depreciation rates for known and measurable changes in the age distributions of surviving plant, depreciation reserves, and average net salvage rates due to the passage of time. A technical update is intended to align depreciation rates with the accounting year the rates will become effective.

SCOPE

The steps involved in preparing a technical update can be grouped into five principal activities:

- Data collection;
- Calculation of service life statistics;
- Computation of average net salvage rates;
- Rebalancing of depreciation reserves; and
- Development of accrual rates.

The scope of the 2005 update for PWEC Units included a consideration of each of these tasks as described below.

DATA COLLECTION

The database used in the 2005 update was provided to Foster Associates in an electronic format containing plant and reserve activity over the period 2001–2004 and age distributions of surviving plant at December 31, 2004. Data used in the update were limited to the age distributions of surviving plant. Depreciation rates currently used by for PWEC Units were developed using a broad–group procedure. The realized life of surviving vintages derived from the dollar–years of service provided by each vintage is not relevant to an update of broad–group depreciation rates. Therefore, plant transactions recorded in prior activity years were not used in the update.

Reserve transactions recorded in prior activity years were also not used in the 2005 update. Depreciation rates currently used for PWEC Units were derived without consideration of the distinction between average and future net salvage rates. The assumed equivalency between average and future net salvage rates was retained in the 2005 update without introducing prior realized net salvage amounts in the computation of average net salvage rates.

CALCULATION OF SERVICE LIFE STATISTICS

The composite remaining life and average service life of a plant category used in the calculation of depreciation rates are derived from a tabular arrangement of the age distribution of surviving plant and related statistics. The format of such a table is called a *generation arrangement.*

The age distribution of surviving plant is a column of numbers showing the dollar amount of investment remaining in service at the beginning of a study year from each of the vintages installed in prior years. The sum of an age distribution is the total plant in service for a plant category. The source of data used to construct an age distribution is a company's Continuing Property Record (CPR).

Statistics for each vintage (*i.e.*, average service life and remaining life) contained in a generation arrangement are derived from a mathematical function called a *survivor curve*. The survivor curve most descriptive of the forces of retirement acting upon a plant category is identified from a statistical analysis of past retirement experience, coupled with a consideration of how these forces are likely to change in the future. The collection of past retirements used in the statistical analysis can be viewed as a random sample from an unknown parent population. The objective of a life analysis is to estimate the parameters (*i.e.*, mean service life and dispersion characteristics) of the parent population. The mean service life of the population which best describes the timing of past and future retirements is called a *projection life* and the survivor curve selected to describe the forces of retirement acting upon the population is called a *projection curve*. A technical update generally retains the service life parameters estimated in a full depreciation study. Statistics for each vintage, however, are updated to reflect known and measurable changes in the age distributions of surviving plant.

COMPUTATION OF AVERAGE NET SALVAGE RATES

Estimates of net salvage rates applicable to future retirements are derived in a full depreciation study from an analysis of gross salvage and removal expense realized in the past and a consideration of future expectations that may dictate a departure from historical indications. Future net salvage rates adopted from such an analysis are retained as fixed parameters in a technical update.

The average net salvage rate for an account or plant function is derived from a direct dollar weighting of a) historical retirements with historical (or realized) net salvage rates and b) future retirements (*i.e.*, surviving plant) with the estimated future net salvage rate. Average net salvage rates will change, therefore, as additional years of retirement and net salvage activity become available and as subsequent plant additions alter the weighting of future net salvage estimates.

As noted earlier, Depreciation rates currently used by PWEC were derived

without consideration of the distinction between average and future net salvage rates. The assumed equivalency between average and future net salvage rates was retained in the 2005 update without introducing prior realized net salvage amounts in the computation of average net salvage rates. The retained equivalency of average and future net salvage rates is shown in Statement D.

REBALANCING OF DEPRECIATION RESERVES

Although reserve records are typically maintained by various account classifications, the total reserve for a company is the most important measure of the status of the company's depreciation practices and procedures. If a company has not previously conducted statistical life studies or considered retirement dispersion in setting depreciation rates, it is likely that some accounts will be overdepreciated and other accounts will be underdepreciated relative to a calculated theoretical reserve. Differences between theoretical and recorded reserves will also arise as a normal occurrence when service lives, dispersion patterns and net salvage estimates are changed in the course of depreciation reviews. It is appropriate, therefore, and consistent with group depreciation theory to periodically redistribute recorded reserves among the various primary accounts based upon the most recent estimates of retirement dispersion and net salvage rates.

A rebalancing of recorded reserves is consistent with the objectives of a technical update and is considered appropriate for PWEC Units. Depreciation rates adopted in Docket No. E–01345A–03–0437 were derived from rebalanced reserves obtained from a set of parameters different from those used in the formulation of the settled remaining–life accrual rates. Reserve imbalances amortized in the settled rates are therefore inconsistent with the realigned depreciation reserves. The rebalancing of reserves undertaken in the 2005 update will reestablish consistency between measured reserve imbalances and the parameters used in the formulation of updated remaining–life accrual rates.

A redistribution of the recorded reserve was achieved for PWEC Units by multiplying the calculated reserve for each primary account within a function (or plant location) by the ratio of the function (or location) total recorded reserve to the function (or location) total calculated reserve. The sum of the redistributed reserves within a function (or location) is, therefore, equal to the function (or location) total recorded depreciation reserve before the redistribution.

Statement C provides a comparison of the recorded, computed and rebalanced reserves for PWEC at December 31, 2004. The recorded reserve was $87,128,993, or 8.7 percent of the depreciable plant investment. The corresponding computed reserve is $33,816,272 or 3.4 percent of the depreciable plant investment. A proportionate amount of the measured reserve excess of $53,312,721 will be amortized over the composite weighted–average remaining life of each rate category.

DEVELOPMENT OF ACCRUAL RATES

The goal or objective of depreciation accounting is cost allocation over the economic life of an asset in proportion to the consumption of service potential. Ideally, the cost of an asset—which represents the cost of obtaining a bundle of service units—should be allocated to future periods of operation in proportion to the amount of service potential expended during an accounting interval. The service potential of an asset is the present value of future net revenue (*i.e.*, revenue less expenses exclusive of depreciation and other non-cash expenses) or cash inflows attributable to the use of that asset alone.

Depreciation rates currently used for PWEC Units were developed using a system composed of the straight–line method, broad–group procedure, remaining–life technique. Depreciation rates proposed in the update were developed using the currently approved system.

STATEMENTS

INTRODUCTION

This section provides a comparative summary of depreciation rates, annual depreciation accruals, recorded and computed depreciation reserves, and present and proposed service life and net salvage parameters for PWEC Units. The content of these statements is briefly described below.

- Statement A provides a comparative summary of present and proposed annual depreciation rates for calendar year 2005 using the straight–line method, broad group procedure, remaining–life technique.
- Statement B provides a comparison of present and proposed annualized depreciation accruals for calendar year 2005 based upon the rates developed in Statement A.
- Statement C provides a comparison of recorded and computed reserves for each rate category and sets forth the computations used to redistribute recorded reserves among primary plant accounts.
- Statement D provides a summary of the components used to obtain a weighted average net salvage rate for each rate category.
- Statement E provides a comparative summary of present and proposed parameters including projection life, projection curve and future net salvage rates. The statement also contains present and proposed statistics including average service life, average remaining life, and average net salvage rates.

Present depreciation accruals shown on Statement B are the product of plant investments (Column B) and the present depreciation rates (Column D) shown on Statement A. These are the effective rates used for PWEC Units for the mix of investments recorded on December 31, 2004. Similarly, proposed depreciation accruals shown on Statement B are the product of plant investments and proposed depreciation rates (Column H) shown on Statement A. Proposed accrual rates shown on Statement A are given by:

$$Accrual\ Rate = \frac{1.0 - Reserve\ Ratio - Future\ Net\ Salvage\ Rate}{Remaining\ Life}.$$

PWEC UNITS Statement A

Comparison of Present and Proposed Accrual Rates
Present: BG Procedure / RL Technique
Proposed: BG Procedure / RL Technique

Account Description	Present Rem. Life	Present Net Salvage	Present Accrual Rate	Proposed (at December 31, 2004) Rem. Life	Proposed Net Salvage	Proposed Reserve Ratio	Proposed Accrual Rate
A	B	C	D	E	F	G	H
OTHER PRODUCTION							
341.00 Structures and Improvements			2.89%	35.00	-3.8%	8.76%	2.72%
342.00 Fuel Holders, Products and Accessories			2.14%	46.34	-5.0%	12.74%	1.99%
343.00 Prime Movers			2.86%	35.22	-2.6%	8.90%	2.66%
344.00 Generators and Devices			2.96%	34.04	-2.4%	8.60%	2.76%
345.00 Accessory Electric Equipment			2.98%	34.11	-3.7%	8.37%	2.80%
346.00 Misc. Power Plant Equipment			2.14%	46.63	-5.0%	9.28%	2.05%
Total Other Production Plant			2.92%	34.60	-2.6%	8.74%	2.71%
TRANSMISSION							
353.00 Station Equipment			1.80%	55.02		7.18%	1.68%
355.00 Poles and Fixtures - Wood			2.08%	45.95	-15.0%	10.21%	2.28%
356.00 Overhead Conductors and Devices			2.45%	52.54	-35.0%	12.55%	2.33%
Total Transmission Plant			1.83%	54.56	-1.7%	7.47%	1.73%
TOTAL UTILITY			2.87%	35.15	-25.0%	8.68%	2.67%
OTHER PRODUCTION (BY UNIT)							
Redhawk CC Units 1-2							
341.00 Structures and Improvements	34.03	-3.0%	2.95%	33.94	-3.0%	9.75%	2.75%
342.00 Fuel Holders, Products and Accessories							
343.00 Prime Movers	34.03	-3.0%	2.95%	33.94	-3.0%	9.75%	2.75%
344.00 Generators and Devices	34.03	-3.0%	2.95%	33.94	-3.0%	9.75%	2.75%
345.00 Accessory Electric Equipment	34.03	-3.0%	2.95%	33.94	-3.0%	9.75%	2.75%
346.00 Misc. Power Plant Equipment							
Total Redhawk CC Units 1-2			2.95%	33.91	-3.0%	9.75%	2.75%
Saguaro CT Unit 3							
341.00 Structures and Improvements							
342.00 Fuel Holders, Products and Accessories							
343.00 Prime Movers	35.49		2.81%	33.54		8.86%	2.72%
344.00 Generators and Devices	35.49		2.81%	33.54		8.86%	2.72%
345.00 Accessory Electric Equipment	35.49		2.81%	33.54		8.86%	2.72%
346.00 Misc. Power Plant Equipment							
Total Saguaro CT Unit 3			2.81%	33.51		8.86%	2.72%
West Phoenix							
341.00 Structures and Improvements			2.82%	36.57	-5.0%	7.40%	2.67%
342.00 Fuel Holders, Products and Accessories			2.14%	46.34	-5.0%	12.74%	1.99%
343.00 Prime Movers			2.75%	36.98	-2.0%	7.84%	2.55%
344.00 Generators and Devices			3.02%	34.30	-2.0%	6.69%	2.78%
345.00 Accessory Electric Equipment			3.03%	34.41	-5.0%	5.92%	2.88%
346.00 Misc. Power Plant Equipment			2.14%	46.63	-5.0%	9.28%	2.05%
Total West Pheonix			2.88%	35.69	-2.3%	7.29%	2.66%
West Phoenix CC Unit 4							
341.00 Structures and Improvements	49.71	-5.0%	2.08%	47.72	-5.0%	12.46%	1.94%
342.00 Fuel Holders, Products and Accessories	48.32	-5.0%	2.14%	46.34	-5.0%	12.74%	1.99%
343.00 Prime Movers	46.94	-2.0%	2.14%	45.03	-2.0%	12.47%	1.99%
344.00 Generators and Devices	35.47	-2.0%	2.87%	33.60	-2.0%	16.10%	2.56%
345.00 Accessory Electric Equipment	48.32	-5.0%	2.14%	47.20	-5.0%	1.91%	2.18%
346.00 Misc. Power Plant Equipment	48.32	-5.0%	2.14%	46.63	-5.0%	9.28%	2.05%
Total West Ploenix CC Unit 4			2.28%	42.48	-2.3%	13.18%	2.10%

PWEC UNITS Statement A

Comparison of Present and Proposed Accrual Rates
Present: BG Procedure / RL Technique
Proposed: BG Procedure / RL Technique

	Present			Proposed (at December 31, 2004)			
Account Description	Rem. Life	Net Salvage	Accrual Rate	Rem. Life	Net Salvage	Reserve Ratio	Accrual Rate
A	B	C	D	E	F	G	H
West Phoenix CC Unit 5							
341.00 Structures and Improvements			3.03%	34.37	-5.0%	5.94%	2.88%
342.00 Fuel Holders, Products and Accessories							
343.00 Prime Movers			3.03%	34.37	-2.0%	5.77%	2.80%
344.00 Generators and Devices			3.03%	34.37	-2.0%	5.77%	2.80%
345.00 Accessory Electric Equipment			3.03%	34.37	-5.0%	5.94%	2.88%
346.00 Misc. Power Plant Equipment							
Total West Phoenix CC Unit 5			3.03%	34.37	-2.3%	5.78%	2.81%
TRANSMISSION (BY UNIT)							
Redhawk CC Units 1-2							
353.00 Station Equipment	56.59		1.75%	54.95		7.47%	1.68%
355.00 Poles and Fixtures - Wood	54.50	-15.0%	2.08%	45.95	-15.0%	10.21%	2.28%
356.00 Overhead Conductors and Devices	54.50	-35.0%	2.45%	52.54	-35.0%	12.55%	2.33%
Total Redhawk CC Units 1-2			1.80%	54.39	-2.2%	7.82%	1.74%
Saguaro CT Unit 3							
353.00 Station Equipment	35.49		2.81%	54.95		8.25%	1.67%
355.00 Poles and Fixtures - Wood							
356.00 Overhead Conductors and Devices							
Total Saguaro CT Unit 3			2.81%	54.94		8.25%	1.67%
West Phoenix							
353.00 Station Equipment			1.74%	55.35		5.71%	1.70%
355.00 Poles and Fixtures - Wood							
356.00 Overhead Conductors and Devices							
Total West Pheonix			1.74%	55.35		5.71%	1.70%
West Phoenix CC Unit 4							
353.00 Station Equipment	55.77		1.73%	54.14		10.84%	1.65%
355.00 Poles and Fixtures - Wood							
356.00 Overhead Conductors and Devices							
Total West Ploenix CC Unit 4			1.73%	54.04		10.84%	1.65%
West Phoenix CC Unit 5							
353.00 Station Equipment	56.59		1.75%	55.77		3.91%	1.72%
355.00 Poles and Fixtures - Wood							
356.00 Overhead Conductors and Devices							
Total West Phoenix CC Unit 5			1.75%	55.87		3.91%	1.72%

PWEC UNITS Statement B

Comparison of Present and Proposed Accruals
Present: BG Procedure / RL Technique
Proposed: BG Procedure / RL Technique

Account Description	12/31/04 Plant Investment	2005 Annualized Accrual Present	Proposed	Difference
A	B	C	D	E=D-C
OTHER PRODUCTION				
341.00 Structures and Improvements	$40,104,209	$1,160,733	$1,089,316	($71,417)
342.00 Fuel Holders, Products and Accessories	4,135,109	88,491	82,289	(6,202)
343.00 Prime Movers	399,447,583	11,437,064	10,629,666	(807,398)
344.00 Generators and Devices	476,614,814	14,123,897	13,145,180	(978,717)
345.00 Accessory Electric Equipment	40,055,435	1,192,405	1,119,761	(72,644)
346.00 Misc. Power Plant Equipment	8,374	179	172	(7)
Total Other Production Plant	$960,365,524	$28,002,769	$26,066,384	($1,936,385)
TRANSMISSION				
353.00 Station Equipment	$40,015,163	$719,213	$673,708	($45,505)
355.00 Poles and Fixtures - Wood	1,500,000	31,200	34,200	3,000
356.00 Overhead Conductors and Devices	1,500,000	36,750	34,950	(1,800)
Total Transmission Plant	$43,015,163	$787,163	$742,858	($44,305)
TOTAL UTILITY	$1,003,380,687	$28,789,932	$26,809,242	($1,980,690)
OTHER PRODUCTION (BY UNIT)				
Redhawk CC Units 1-2				
341.00 Structures and Improvements	$23,274,636	$686,602	$640,052	($46,550)
342.00 Fuel Holders, Products and Accessories				
343.00 Prime Movers	221,481,610	6,533,707	6,090,744	(442,963)
344.00 Generators and Devices	273,599,371	8,071,181	7,523,983	(547,198)
345.00 Accessory Electric Equipment	25,524,567	752,975	701,926	(51,049)
346.00 Misc. Power Plant Equipment				
Total Redhawk CC Units 1-2	$543,880,184	$16,044,465	$14,956,705	($1,087,760)
Saguaro CT Unit 3				
341.00 Structures and Improvements				
342.00 Fuel Holders, Products and Accessories				
343.00 Prime Movers	775,091	21,780	21,082	(698)
344.00 Generators and Devices	33,896,968	952,505	921,998	(30,507)
345.00 Accessory Electric Equipment	148,212	4,165	4,031	(134)
346.00 Misc. Power Plant Equipment				
Total Saguaro CT Unit 3	$34,820,271	$978,450	$947,111	($31,339)
West Phoenix				
341.00 Structures and Improvements	$16,829,573	$474,131	$449,264	($24,867)
342.00 Fuel Holders, Products and Accessories	4,135,109	88,491	82,289	(6,202)
343.00 Prime Movers	177,190,882	4,881,577	4,517,840	(363,737)
344.00 Generators and Devices	169,118,475	5,100,211	4,699,199	(401,012)
345.00 Accessory Electric Equipment	14,382,656	435,265	413,804	(21,461)
346.00 Misc. Power Plant Equipment	8,374	179	172	(7)
Total West Pheonix	$381,665,069	$10,979,854	$10,162,568	($817,286)
West Phoenix CC Unit 4				
341.00 Structures and Improvements	$3,768,898	$78,393	$73,117	($5,276)
342.00 Fuel Holders, Products and Accessories	4,135,109	88,491	82,289	(6,202)
343.00 Prime Movers	54,753,590	1,171,727	1,089,596	(82,131)
344.00 Generators and Devices	15,049,070	431,908	385,256	(46,652)
345.00 Accessory Electric Equipment	59,412	1,271	1,295	24
346.00 Misc. Power Plant Equipment	8,374	179	172	(7)
Total West Ploenix CC Unit 4	$77,774,453	$1,771,969	$1,631,725	($140,244)

PWEC UNITS Statement B

Comparison of Present and Proposed Accruals
Present: BG Procedure / RL Technique
Proposed: BG Procedure / RL Technique

Account Description	12/31/04 Plant Investment	2005 Annualized Accrual Present	Proposed	Difference
A	B	C	D	E=D-C
West Phoenix CC Unit 5				
341.00 Structures and Improvements	$13,060,675	$395,738	$376,147	($19,591)
342.00 Fuel Holders, Products and Accessories				
343.00 Prime Movers	122,437,292	3,709,850	3,428,244	(281,606)
344.00 Generators and Devices	154,069,405	4,668,303	4,313,943	(354,360)
345.00 Accessory Electric Equipment	14,323,244	433,994	412,509	(21,485)
346.00 Misc. Power Plant Equipment				
Total West Phoenix CC Unit 5	$303,890,616	$9,207,885	$8,530,843	($677,042)
TRANSMISSION (BY UNIT)				
Redhawk CC Units 1-2				
353.00 Station Equipment	$30,683,150	$536,955	$515,477	($21,478)
355.00 Poles and Fixtures - Wood	1,500,000	31,200	34,200	3,000
356.00 Overhead Conductors and Devices	1,500,000	36,750	34,950	(1,800)
Total Redhawk CC Units 1-2	$33,683,150	$604,905	$584,627	($20,278)
Saguaro CT Unit 3				
353.00 Station Equipment	$1,824,367	$51,265	$30,467	($20,798)
355.00 Poles and Fixtures - Wood				
356.00 Overhead Conductors and Devices				
Total Saguaro CT Unit 3	$1,824,367	$51,265	$30,467	($20,798)
West Phoenix				
353.00 Station Equipment	$7,507,646	$130,993	$127,764	($3,229)
355.00 Poles and Fixtures - Wood				
356.00 Overhead Conductors and Devices				
Total West Pheonix	$7,507,646	$130,993	$127,764	($3,229)
West Phoenix CC Unit 4				
353.00 Station Equipment	$1,953,105	$33,789	$32,226	($1,563)
355.00 Poles and Fixtures - Wood				
356.00 Overhead Conductors and Devices				
Total West Ploenix CC Unit 4	$1,953,105	$33,789	$32,226	($1,563)
West Phoenix CC Unit 5				
353.00 Station Equipment	$5,554,541	$97,204	$95,538	($1,666)
355.00 Poles and Fixtures - Wood				
356.00 Overhead Conductors and Devices				
Total West Phoenix CC Unit 5	$5,554,541	$97,204	$95,538	($1,666)

PWEC UNITS
Depreciation Reserve Summary
Company Broad Group Procedure
December 31, 2004

Statement C

Account Description	Plant Investment	Recorded Reserve		Computed Reserve		Redistributed Reserve	
		Amount	Ratio	Amount	Ratio	Amount	Ratio
A	B	C	D=C/B	E	F=E/B	G	H=G/B
OTHER PRODUCTION							
341.00 Structures and Improvements	$40,104,209	$3,292,671	8.21%	$1,305,072	3.25%	$3,513,414	8.76%
342.00 Fuel Holders, Products and Accessories	4,135,109	536,579	12.98%	303,286	7.33%	526,716	12.74%
343.00 Prime Movers	399,447,583	35,949,342	9.00%	13,722,765	3.44%	35,543,746	8.90%
344.00 Generators and Devices	476,614,814	40,779,645	8.56%	15,788,049	3.31%	40,978,113	8.60%
345.00 Accessory Electric Equipment	40,055,435	3,356,149	8.38%	1,145,419	2.86%	3,352,291	8.37%
346.00 Misc. Power Plant Equipment	8,374	672	8.02%	447	5.34%	777	9.28%
Total Other Production Plant	$960,365,524	$83,915,057	8.74%	$32,265,039	3.36%	$83,915,057	8.74%
TRANSMISSION							
353.00 Station Equipment	$40,015,163	$3,010,030	7.52%	$1,386,989	3.47%	$2,872,587	7.18%
355.00 Poles and Fixtures - Wood	1,500,000	101,953	6.80%	73,672	4.91%	153,112	10.21%
356.00 Overhead Conductors and Devices	1,500,000	101,953	6.80%	90,573	6.04%	188,237	12.55%
Total Transmission Plant	$43,015,163	$3,213,936	7.47%	$1,551,234	3.61%	$3,213,936	7.47%
TOTAL UTILITY	$1,003,380,687	$87,128,993	8.68%	$33,816,272	3.37%	$87,128,993	8.68%
OTHER PRODUCTION (BY UNIT)							
Redhawk CC Units 1-2							
341.00 Structures and Improvements	$23,274,636	$2,045,863	8.79%	$772,437	3.32%	$2,268,143	9.75%
342.00 Fuel Holders, Products and Accessories							
343.00 Prime Movers	221,481,610	21,471,522	9.69%	7,350,512	3.32%	21,583,668	9.75%
344.00 Generators and Devices	273,599,371	26,977,169	9.86%	9,080,191	3.32%	26,662,611	9.75%
345.00 Accessory Electric Equipment	25,524,567	2,507,271	9.82%	847,107	3.32%	2,487,402	9.75%
346.00 Misc. Power Plant Equipment							
Total Redhawk CC Units 1-2	$543,880,184	$53,001,824	9.75%	$18,050,247	3.32%	$53,001,824	9.75%
Saguaro CT Unit 3							
341.00 Structures and Improvements							
342.00 Fuel Holders, Products and Accessories							
343.00 Prime Movers	775,091	68,682	8.86%	52,764	6.81%	68,682	8.86%
344.00 Generators and Devices	33,896,968	3,003,648	8.86%	2,307,518	6.81%	3,003,648	8.86%
345.00 Accessory Electric Equipment	148,212	13,133	8.86%	10,089	6.81%	13,133	8.86%
346.00 Misc. Power Plant Equipment							
Total Saguaro CT Unit 3	$34,820,271	$3,085,463	8.86%	$2,370,371	6.81%	$3,085,463	8.86%

PWEC UNITS
Depreciation Reserve Summary
Company Broad Group Procedure
December 31, 2004

Statement C

Account Description	Plant Investment	Recorded Reserve		Computed Reserve		Redistributed Reserve	
		Amount	Ratio	Amount	Ratio	Amount	Ratio
A	B	C	D=C/B	E	F=E/B	G	H=G/B
West Phoenix							
341.00 Structures and Improvements	$16,829,573	$1,246,808	7.41%	$532,636	3.16%	$1,245,271	7.40%
342.00 Fuel Holders, Products and Accessories	4,135,109	536,579	12.98%	303,286	7.33%	526,716	12.74%
343.00 Prime Movers	177,190,882	14,409,138	8.13%	6,319,489	3.57%	13,891,396	7.84%
344.00 Generators and Devices	169,118,475	10,798,829	6.39%	4,400,340	2.60%	11,311,854	6.69%
345.00 Accessory Electric Equipment	14,382,656	835,745	5.81%	288,222	2.00%	851,756	5.92%
346.00 Misc. Power Plant Equipment	8,374	672	8.02%	447	5.34%	777	9.28%
Total West Pheonix	$381,665,069	$27,827,770	7.29%	$11,844,421	3.10%	$27,827,770	7.29%
West Phoenix CC Unit 4							
341.00 Structures and Improvements	$3,768,898	$486,569	12.91%	$270,416	7.17%	$469,631	12.46%
342.00 Fuel Holders, Products and Accessories	4,135,109	536,579	12.98%	303,286	7.33%	526,716	12.74%
343.00 Prime Movers	54,753,590	7,282,275	13.30%	3,931,543	7.18%	6,827,913	12.47%
344.00 Generators and Devices	15,049,070	1,941,561	12.90%	1,395,459	9.27%	2,423,495	16.10%
345.00 Accessory Electric Equipment	59,412	2,013	3.39%	654	1.10%	1,136	1.91%
346.00 Misc. Power Plant Equipment	8,374	672	8.02%	447	5.34%	777	9.28%
Total West Ploenix CC Unit 4	$77,774,453	$10,249,668	13.18%	$5,901,805	7.59%	$10,249,668	13.18%
West Phoenix CC Unit 5							
341.00 Structures and Improvements	$13,060,675	$760,239	5.82%	$262,220	2.01%	$775,640	5.94%
342.00 Fuel Holders, Products and Accessories							
343.00 Prime Movers	122,437,292	7,126,864	5.82%	2,387,946	1.95%	7,063,483	5.77%
344.00 Generators and Devices	154,069,405	8,857,268	5.75%	3,004,881	1.95%	8,888,359	5.77%
345.00 Accessory Electric Equipment	14,323,244	833,731	5.82%	287,569	2.01%	850,620	5.94%
346.00 Misc. Power Plant Equipment							
Total West Phoenix CC Unit 5	$303,890,616	$17,578,102	5.78%	$5,942,616	1.96%	$17,578,102	5.78%
TRANSMISSION (BY UNIT)							
Redhawk CC Units 1-2							
353.00 Station Equipment	$30,683,150	$2,430,879	7.92%	$1,103,517	3.60%	$2,293,436	7.47%
355.00 Poles and Fixtures - Wood	1,500,000	101,953	6.80%	73,672	4.91%	153,112	10.21%
356.00 Overhead Conductors and Devices	1,500,000	101,953	6.80%	90,573	6.04%	188,237	12.55%
Total Redhawk CC Units 1-2	$33,683,150	$2,634,785	7.82%	$1,267,761	3.76%	$2,634,785	7.82%

PWEC UNITS
Depreciation Reserve Summary
Company Broad Group Procedure
December 31, 2004

Statement C

Account Description	Plant Investment	Recorded Reserve		Computed Reserve		Redistributed Reserve	
		Amount	Ratio	Amount	Ratio	Amount	Ratio
A	B	C	D=C/B	E	F=E/B	G	H=G/B
Saguaro CT Unit 3							
353.00 Station Equipment	$1,824,367	$150,428	8.25%	$65,613	3.60%	$150,428	8.25%
355.00 Poles and Fixtures - Wood							
356.00 Overhead Conductors and Devices							
Total Saguaro CT Unit 3	$1,824,367	$150,428	8.25%	$65,613	3.60%	$150,428	8.25%
West Phoenix							
353.00 Station Equipment	$7,507,646	$428,724	5.71%	$217,859	2.90%	$428,724	5.71%
355.00 Poles and Fixtures - Wood							
356.00 Overhead Conductors and Devices							
Total West Pheonix	$7,507,646	$428,724	5.71%	$217,859	2.90%	$428,724	5.71%
West Phoenix CC Unit 4							
353.00 Station Equipment	$1,953,105	$211,789	10.84%	$97,998	5.02%	$211,789	10.84%
355.00 Poles and Fixtures - Wood							
356.00 Overhead Conductors and Devices							
Total West Ploenix CC Unit 4	$1,953,105	$211,789	10.84%	$97,998	5.02%	$211,789	10.84%
West Phoenix CC Unit 5							
353.00 Station Equipment	$5,554,541	$216,935	3.91%	$119,861	2.16%	$216,935	3.91%
355.00 Poles and Fixtures - Wood							
356.00 Overhead Conductors and Devices							
Total West Phoenix CC Unit 5	$5,554,541	$216,935	3.91%	$119,861	2.16%	$216,935	3.91%

PWEC UNITS
Average Net Salvage

Statement D

Account Description	Plant Investment			Salvage Rate		Net Salvage			Average
	Additions	Retirements	Survivors	Realized	Future	Realized	Future	Total	Rate
A	B	C	D=B-C	E	F	G=E*C	H=F*D	I=G+H	J=I/B
OTHER PRODUCTION									
341.00 Structures and Improvements	$40,104,209		$40,104,209		-3.8%		($1,539,718)	($1,539,718)	-3.8%
342.00 Fuel Holders, Products and Accessories	4,135,109		4,135,109		-5.0%		(206,755)	(206,755)	-5.0%
343.00 Prime Movers	399,447,583		399,447,583		-2.6%		(10,188,266)	(10,188,266)	-2.6%
344.00 Generators and Devices	476,732,853	118,039	476,614,814		-2.4%		(11,590,351)	(11,590,351)	-2.4%
345.00 Accessory Electric Equipment	40,055,435		40,055,435		-3.7%		(1,484,870)	(1,484,870)	-3.7%
346.00 Misc. Power Plant Equipment	8,374		8,374		-5.0%		(419)	(419)	-5.0%
Total Other Production Plant	$960,483,563	$118,039	$960,365,524		-2.6%		($25,010,378)	($25,010,378)	-2.6%
TRANSMISSION									
353.00 Station Equipment	$40,015,163		$40,015,163						
355.00 Poles and Fixtures - Wood	1,500,000		1,500,000		-15.0%		(225,000)	(225,000)	-15.0%
356.00 Overhead Conductors and Devices	1,500,000		1,500,000		-35.0%		(525,000)	(525,000)	-35.0%
Total Transmission Plant	$43,015,163		$43,015,163		-1.7%		($750,000)	($750,000)	-1.7%
TOTAL UTILITY	$3,000,000		$3,000,000		-25.0%		($750,000)	($750,000)	-25.0%
OTHER PRODUCTION (BY UNIT)									
Redhawk CC Units 1-2									
341.00 Structures and Improvements	$23,274,636		$23,274,636		-3.0%		($698,239)	($698,239)	-3.0%
342.00 Fuel Holders, Products and Accessories									
343.00 Prime Movers	221,481,610		221,481,610		-3.0%		(6,644,448)	(6,644,448)	-3.0%
344.00 Generators and Devices	273,599,371		273,599,371		-3.0%		(8,207,981)	(8,207,981)	-3.0%
345.00 Accessory Electric Equipment	25,524,567		25,524,567		-3.0%		(765,737)	(765,737)	-3.0%
346.00 Misc. Power Plant Equipment									
Total Redhawk CC Units 1-2	$543,880,184		$543,880,184		-3.0%		($16,316,406)	($16,316,406)	-3.0%
Saguaro CT Unit 3									
341.00 Structures and Improvements									
342.00 Fuel Holders, Products and Accessories									
343.00 Prime Movers	775,091		775,091						
344.00 Generators and Devices	33,896,968		33,896,968						
345.00 Accessory Electric Equipment	148,212		148,212						
346.00 Misc. Power Plant Equipment									
Total Saguaro CT Unit 3	$34,820,271		$34,820,271						
West Phoenix									
341.00 Structures and Improvements	$16,829,573		$16,829,573		-5.0%		($841,479)	($841,479)	-5.0%
342.00 Fuel Holders, Products and Accessories	4,135,109		4,135,109		-5.0%		(206,755)	(206,755)	-5.0%
343.00 Prime Movers	177,190,882		177,190,882		-2.0%		(3,543,818)	(3,543,818)	-2.0%
344.00 Generators and Devices	169,236,514	118,039	169,118,475		-2.0%		(3,382,370)	(3,382,370)	-2.0%
345.00 Accessory Electric Equipment	14,382,656		14,382,656		-5.0%		(719,133)	(719,133)	-5.0%
346.00 Misc. Power Plant Equipment	8,374		8,374		-5.0%		(419)	(419)	-5.0%
Total West Pheonix	$381,783,108	$118,039	$381,665,069		-2.3%		($8,693,973)	($8,693,973)	-2.3%

PWEC UNITS
Average Net Salvage

Statement D

Account Description	Plant Investment			Salvage Rate		Net Salvage			Average
	Additions	Retirements	Survivors	Realized	Future	Realized	Future	Total	Rate
A	B	C	D=B-C	E	F	G=E*C	H=F*D	I=G+H	J=I/B
West Phoenix CC Unit 4									
341.00 Structures and Improvements	$3,768,898		$3,768,898		-5.0%		($188,445)	($188,445)	-5.0%
342.00 Fuel Holders, Products and Accessories	4,135,109		4,135,109		-5.0%		(206,755)	(206,755)	-5.0%
343.00 Prime Movers	54,753,590		54,753,590		-2.0%		(1,095,072)	(1,095,072)	-2.0%
344.00 Generators and Devices	15,167,109	118,039	15,049,070		-2.0%		(300,981)	(300,981)	-2.0%
345.00 Accessory Electric Equipment	59,412		59,412		-5.0%		(2,971)	(2,971)	-5.0%
346.00 Misc. Power Plant Equipment	8,374		8,374		-5.0%		(419)	(419)	-5.0%
Total West Ploenix CC Unit 4	$77,892,492	$118,039	$77,774,453		-2.3%		($1,794,643)	($1,794,643)	-2.3%
West Phoenix CC Unit 5									
341.00 Structures and Improvements	$13,060,675		$13,060,675		-5.0%		($653,034)	($653,034)	-5.0%
342.00 Fuel Holders, Products and Accessories									
343.00 Prime Movers	122,437,292		122,437,292		-2.0%		(2,448,746)	(2,448,746)	-2.0%
344.00 Generators and Devices	154,069,405		154,069,405		-2.0%		(3,081,388)	(3,081,388)	-2.0%
345.00 Accessory Electric Equipment	14,323,244		14,323,244		-5.0%		(716,162)	(716,162)	-5.0%
346.00 Misc. Power Plant Equipment									
Total West Phoenix CC Unit 5	$303,890,616		$303,890,616		-2.3%		($6,899,330)	($6,899,330)	-2.3%
TRANSMISSION (BY UNIT)									
Redhawk CC Units 1-2									
353.00 Station Equipment	$30,683,150		$30,683,150						
355.00 Poles and Fixtures - Wood	1,500,000		1,500,000		-15.0%		(225,000)	(225,000)	-15.0%
356.00 Overhead Conductors and Devices	1,500,000		1,500,000		-35.0%		(525,000)	(525,000)	-35.0%
Total Redhawk CC Units 1-2	$33,683,150		$33,683,150		-2.2%		($750,000)	($750,000)	-2.2%
Saguaro CT Unit 3									
353.00 Station Equipment	$1,824,367		$1,824,367						
355.00 Poles and Fixtures - Wood									
356.00 Overhead Conductors and Devices									
Total Saguaro CT Unit 3	$1,824,367		$1,824,367						
West Phoenix									
353.00 Station Equipment	$7,507,646		$7,507,646						
355.00 Poles and Fixtures - Wood									
356.00 Overhead Conductors and Devices									
Total West Pheonix	$7,507,646		$7,507,646						
West Phoenix CC Unit 4									
353.00 Station Equipment	$1,953,105		$1,953,105						
355.00 Poles and Fixtures - Wood									
356.00 Overhead Conductors and Devices									
Total West Ploenix CC Unit 4	$1,953,105		$1,953,105						
West Phoenix CC Unit 5									
353.00 Station Equipment	$5,554,541		$5,554,541						
355.00 Poles and Fixtures - Wood									
356.00 Overhead Conductors and Devices									
Total West Phoenix CC Unit 5	$5,554,541		$5,554,541						

PWEC UNITS
Present and Proposed Parameters
Company Broad Group Procedure

Statement E

Account Description	Present Parameters						Proposed Parameters (at December 31, 2004)					
	P-Life/ AYFR	Curve Shape	BG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	P-Life/ AYFR	Curve Shape	BG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
OTHER PRODUCTION												
341.00 Structures and Improvements									36.13	35.00	-3.8	-3.8
342.00 Fuel Holders, Products and Accessories									49.82	46.34	-5.0	-5.0
343.00 Prime Movers									36.44	35.22	-2.6	-2.6
344.00 Generators and Devices									35.18	34.04	-2.4	-2.4
345.00 Accessory Electric Equipment									35.08	34.11	-3.7	-3.7
346.00 Misc. Power Plant Equipment									49.13	46.63	-5.0	-5.0
Total Other Production Plant									35.78	34.60	-2.6	-2.6
TRANSMISSION												
353.00 Station Equipment									57.00	55.02		
355.00 Poles and Fixtures - Wood									48.00	45.95	-15.0	-15.0
356.00 Overhead Conductors and Devices									55.00	52.54	-35.0	-35.0
Total Transmission Plant									56.56	54.56	-1.7	-1.7
TOTAL UTILITY									36.35	35.15	-25.0	-25.0
OTHER PRODUCTION (BY UNIT)												
Redhawk CC Units 1-2												
341.00 Structures and Improvements	2057	70-O4		34.03		-3.0	2057	70-O4	35.07	33.94	-3.0	-3.0
342.00 Fuel Holders, Products and Accessories												
343.00 Prime Movers	2057	70-O4		34.03		-3.0	2057	70-O4	35.07	33.94	-3.0	-3.0
344.00 Generators and Devices	2057	70-O4		34.03		-3.0	2057	70-O4	35.07	33.94	-3.0	-3.0
345.00 Accessory Electric Equipment	2057	70-O4		34.03		-3.0	2057	70-O4	35.07	33.94	-3.0	-3.0
346.00 Misc. Power Plant Equipment												
Total Redhawk CC Units 1-2									35.07	33.91	-3.0	-3.0

PWEC UNITS
Present and Proposed Parameters
Company Broad Group Procedure

Statement E

Account Description	Present Parameters						Proposed Parameters (at December 31, 2004)					
	P-Life/ AYFR	Curve Shape	BG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	P-Life/ AYFR	Curve Shape	BG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
Saguaro CT Unit 3												
341.00 Structures and Improvements												
342.00 Fuel Holders, Products and Accessories												
343.00 Prime Movers	2047	37-R3		35.49			2047	37-R3	35.99	33.54		
344.00 Generators and Devices	2047	37-R3		35.49			2047	37-R3	35.99	33.54		
345.00 Accessory Electric Equipment	2047	37-R3		35.49			2047	37-R3	35.99	33.54		
346.00 Misc. Power Plant Equipment												
Total Saguaro CT Unit 3									35.99	33.51		
West Phoenix												
341.00 Structures and Improvements									37.71	36.57	-5.0	-5.0
342.00 Fuel Holders, Products and Accessories									49.82	46.34	-5.0	-5.0
343.00 Prime Movers									38.32	36.98	-2.0	-2.0
344.00 Generators and Devices									35.20	34.30	-2.0	-2.0
345.00 Accessory Electric Equipment									35.08	34.41	-5.0	-5.0
346.00 Misc. Power Plant Equipment									49.13	46.63	-5.0	-5.0
Total West Pheonix									36.81	35.69	-2.3	-2.3
West Phoenix CC Unit 4												
341.00 Structures and Improvements	2056	80-S1		49.71		-5.0	2056	80-S1	51.22	47.72	-5.0	-5.0
342.00 Fuel Holders, Products and Accessories	2056	70-S1		48.32		-5.0	2056	70-S1	49.82	46.34	-5.0	-5.0
343.00 Prime Movers	2056	70-L1.5		46.94		-2.0	2056	70-L1.5	48.44	45.03	-2.0	-2.0
344.00 Generators and Devices	2056	37-R3		35.47		-2.0	2056	37-R3	36.96	33.60	-2.0	-2.0
345.00 Accessory Electric Equipment	2056	70-S1		48.32		-5.0	2056	70-S1	47.70	47.20	-5.0	-5.0
346.00 Misc. Power Plant Equipment	2056	70-S1		48.32		-5.0	2056	70-S1	49.13	46.63	-5.0	-5.0
Total West Ploenix CC Unit 4									45.87	42.48	-2.3	-2.3
West Phoenix CC Unit 5												
341.00 Structures and Improvements							2058	70-O4	35.04	34.37	-5.0	-5.0
342.00 Fuel Holders, Products and Accessories												
343.00 Prime Movers							2058	70-O4	35.04	34.37	-2.0	-2.0

PWEC UNITS
Present and Proposed Parameters
Company Broad Group Procedure

Statement E

Account Description	Present Parameters						Proposed Parameters (at December 31, 2004)					
	P-Life/ AYFR	Curve Shape	BG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	P-Life/ AYFR	Curve Shape	BG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
344.00 Generators and Devices							2058	70-O4	35.04	34.37	-2.0	-2.0
345.00 Accessory Electric Equipment							2058	70-O4	35.04	34.37	-5.0	-5.0
346.00 Misc. Power Plant Equipment												
Total West Phoenix CC Unit 5									35.04	34.37	-2.3	-2.3
TRANSMISSION (BY UNIT)												
Redhawk CC Units 1-2												
353.00 Station Equipment	57.00	R1.5	42.00	56.59			57.00	R1.5	57.00	54.95		
355.00 Poles and Fixtures - Wood	55.00	R3	55.00	54.50		-15.0	48.00	R1.5	48.00	45.95	-15.0	-15.0
356.00 Overhead Conductors and Devices	55.00	R3	55.00	54.50		-35.0	55.00	R3	55.00	52.54	-35.0	-35.0
Total Redhawk CC Units 1-2									56.44	54.39	-2.2	-2.2
Saguaro CT Unit 3												
353.00 Station Equipment	2047	37-R3		35.49			57.00	R1.5	57.00	54.95		
355.00 Poles and Fixtures - Wood												
356.00 Overhead Conductors and Devices												
Total Saguaro CT Unit 3									57.00	54.94		
West Phoenix												
353.00 Station Equipment									57.00	55.35		
355.00 Poles and Fixtures - Wood												
356.00 Overhead Conductors and Devices												
Total West Pheonix									57.00	55.35		
West Phoenix CC Unit 4												
353.00 Station Equipment	57.00	R1.5	57.00	55.77			57.00	R1.5	57.00	54.14		
355.00 Poles and Fixtures - Wood												
356.00 Overhead Conductors and Devices												
Total West Ploenix CC Unit 4									57.00	54.04		
West Phoenix CC Unit 5												
353.00 Station Equipment	57.00	R1.5	42.00	56.59			57.00	R1.5	57.00	55.77		
355.00 Poles and Fixtures - Wood												
356.00 Overhead Conductors and Devices												
Total West Phoenix CC Unit 5									57.00	55.87		

FRED BALLUF

DIRECT TESTIMONY OF FRED H. BALLUFF

On Behalf of Arizona Public Service Company

Docket No. E-01345A-05-0816

January 31, 2006

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CASH WORKING CAPITAL REQUIRED FOR
OPERATING EXPENSES – LEAD LAG STUDY.....Attachment FHB-1

DIRECT TESTIMONY OF FRED H. BALLUFF

ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-05-0816)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND ADDRESS.

A. My name is Fred H. Balluff. My address is 238 Elm Park Avenue, Elmhurst, Illinois 60126.

Q. PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL QUALIFICATIONS.

A. I graduated from St. Ambrose College, Davenport, Iowa in 1963 with a Bachelor of Arts degree, majoring in accounting with a minor in economics. I received my MBA from Tulane University in 1985.

I joined the firm of Deloitte Haskins & Sells ("DH&S") in 1963. DH&S merged with Touche Ross & Co. in 1989, forming the firm of Deloitte & Touche ("D&T"). From 1963 to 1973, I was in the Chicago office of DH&S. During that time, I participated in audits of companies in a broad range of industries including public utilities, manufacturing, finance, retailing and construction. I was the audit manager responsible for such utility clients as Interstate Power Company, Wisconsin Southern Gas Company and Hot Springs Water Company. From 1973 to 1981, I was a member of the Public Utilities Department of DH&S located in Washington, D.C., where my activities included accounting research, preparation and presentation of training programs, consideration of specific accounting, auditing, and regulatory questions, consulting for clients in rate proceedings and management audits. As a Partner of DH&S, I held the position of National

Industry Accounting and Auditing Coordinator for the public utility industry, which was the top technical position at DH&S serving the utility industry.

From 1981 to 1988, I was the Director of Internal Auditing for MSS System Services, Inc. ("MSS"), a company serving the Middle South Utility System. Middle South Utilities has since changed its name to the Entergy Corporation. The Entergy system provides electric service to 2.4 million customers in Arkansas, Louisiana, Mississippi, and Texas. At MSS, I directed financial and management audits as well as consulted on financial and management matters.

I was a faculty member of the College of Business Administration at the University of Illinois at Chicago from August 1988 to September 1, 1999. I have taught accounting theory, financial and management accounting, and auditing. I have also provided consulting services as a Special Project Associate of NorthPoint Consulting Group or its predecessor, Bower Rohr & Associates since 1988.

I am a Certified Public Accountant and a member of the American Institute of Certified Public Accountants and the Illinois CPA Society. I have appeared as an expert witness in public utility rate proceedings before the Illinois Commerce Commission, the Indiana Utility Regulatory Commission, the Maryland Public Service Commission, the New Hampshire Public Utilities Commission, the New Jersey Board of Public Utilities, the New Jersey Department of Environmental Protection and Energy, the Public Utilities Commission of Ohio, the Pennsylvania Public Utility Commission, the Vermont Public Service Board and the Public Service Commission of the District of Columbia.

Q. PLEASE BRIEFLY DESCRIBE YOUR EXPERIENCE WITH RESPECT TO RATEMAKING?

A. I have participated in numerous rate proceedings involving electric, gas, water, sewer, cable, steam heat, chilled water, and solid waste entities. My experience includes:

- Prepared or reviewed class cost of service allocation and rate design studies for electric, gas, water, and sewer entities.
- Reviewed and analyzed working capital studies.
- Participated in and managed audits of electric, gas distribution, and water companies.
- Preparation of continuing education courses in accounting, auditing, and ratemaking.
- Testimony as an expert witness in rate proceedings for electric, gas, water, sewer, steam heat, chilled water, and solid waste entities on rate base including working capital requirements, cost of service including deferred income taxes and attrition, adjustment clauses, cost allocations including jurisdictional separations, class cost of service, rate design, and management of fuel procurement practices.

A more detailed description of my professional qualifications and experience is attached as Appendix A.

Q. WHAT IS YOUR ROLE IN THIS PROCEEDING?

A. Arizona Public Service Company ("APS") has engaged NorthPoint Consulting Group to help determine the Company's cash working capital requirement.

Q. WHAT WAS THE SCOPE OF YOUR WORK?

A. I provided consulting services to APS related to the determination of the Company's cash working capital requirements. I prepared the approach to be taken for a lead/lag study; discussed in detail the procedures used with appropriate APS personnel, and reviewed and tested the accuracy of their calculations. .

Q. PLEASE IDENTIFY THE ATTACHMENTS WHICH YOU WILL BE SPONSORING AND FOR WHICH YOU WILL BE PROVIDING TESTIMONY.

A. I am sponsoring Attachment FHB-1, Cash Working Capital Required for Operating Expenses – Lead Lag Study.

II. SUMMARY OF TESTIMONY

Q. WOULD YOU PLEASE SUMMARIZE YOUR DIRECT TESTIMONY?

A. My testimony presents the lead/lag approach used by APS to determine the cash working capital to be included in rate base. Based on the lead/lag study, APS has a negative cash working capital requirement of $29,372,869, which reduced the APS test year rate base.

III. CASH WORKING CAPITAL REQUIREMENT

Q. PLEASE PROVIDE YOUR DEFINITION OF RATE BASE AND CASH WORKING CAPITAL.

A. Cash working capital is a part of the investment made to provide utility service to customers and thus is a component of rate base. It therefore has the same overall purpose of total rate base. Rate base represents the investment in plant and other assets used in providing utility service, for which a fair return must be provided to the sources of capital. In the determination of rate base, adjustments should be made to allow investors to earn a return on unrecovered investment, but not on

funds provided by customers that may provide cost-free funds on a temporary basis. Recognition of depreciation as a cost-of-service item allows a utility to recover its investment in plant through the rate making process. Accordingly, rate base is reduced by accumulated depreciation. Deferred income taxes may also provide funds that are available for investment if deferred income tax expense is included in cost-of service because, as the name implies, deferred income taxes represent an expense that is not currently payable. Accordingly, rate base is reduced by accumulated deferred income taxes.

Cash working capital represents the amount of capital required of investors above the investment in plant and other rate base items to cover cash requirements. The primary reason why this capital is required at any point in time is generally due to the delay in the collection of revenues.

Q. PLEASE GIVE A BRIEF EXPLANATION OF THE LEAD/LAG APPROACH.

A. A lead/lag study measures the difference between the time services are rendered until cash for services are collected in rates (the revenue lag) and compares it to the time that operating services are incurred until they are paid (the expense lag). The difference between these two periods is expressed in days. The resulting number of days times the average daily operating expense produces the working capital requirement for most operating expenses.

Q. WHAT WAS THE OBJECTIVE OF THE STUDY OF CASH WORKING CAPITAL REQUIREMENTS?

A. The objective of the cash working capital study was to determine the amount that is necessary to include in rate base so that investors are adequately compensated for the funds needed to maintain cash operating requirements. In addition, one must also

make adjustments to reflect the fact that certain offsets to rate base, specifically accumulated depreciation and deferred taxes, have not actually been recovered by investors at any single point of time due to the lag in receiving the associated revenues.

Q. WHAT WAS YOUR APPROACH TO THE CASH WORKING CAPITAL STUDY?

A. A lead/lag study was completed to determine the gap between the time that expenditures for current operations are made and when revenues are collected in rates. Consideration was given to the treatment accorded other working capital components and the special treatment required for prepayments, depreciation and amortization, deferred income taxes, inventories, and sales taxes.

Q. PLEASE DESCRIBE ATTACHMENT FHB-1.

A. Attachment FHB-1 lists the operating expenses and sales taxes accrued for the Test Year ending September 30, 2005. The revenue lag days represents the number of days between the time services are rendered and the time the related revenues are collected from customers. The expense lags generally represent the time between when expenses are incurred until the related expense is paid. Certain expenses don't have expense lags. These expenses are discussed later in my testimony.

Q. DOES THE REVENUE LAG RELATE ONLY TO REVENUES FROM ARIZONA RETAIL CONSUMERS?

A. No. The revenue lag represents a composite lag, which includes Arizona retail customers, transmission revenue, sales for resale, and other revenues that are part of the determination of revenue requirements for both state and federal purposes.

Q. PLEASE DESCRIBE HOW THE REVENUE LAG FOR RETAIL CUSTOMERS WAS DETERMINED.

A. The overall revenue lag is comprised of three components: the service lag, the billing lag, and the collection lag.

The service lag is an estimate of the time between the time service is provided and the end of the billing period. The Company reads its meters once a month on a cycle basis. The average midpoint of service for this purpose was calculated by dividing the normal year of 365 days by 12 months by 2 to arrive at a service lag of 15.21 days.

The billing lag is the lag days between the meter read date and billing date. To estimate this lag, APS calculated the billing lag for each billing cycle. The sum of these billing lags for each month were divided by the number of billing cycles in each month to produce average billing lags for each month. These monthly billing lags were multiplied by the average daily revenues (including sales tax) for each month to produce monthly revenue dollar days. These monthly revenue dollar days were summed. The total of the monthly dollar days for the year were divided by the total revenues (including sales tax) to arrive at a weighted average billing lag of 5.03 days.

The collection lag represents the time it takes to collect the amounts billed. This lag was calculated by dividing the average daily outstanding accounts receivable balances by the average daily revenues including sale taxes to arrive at a collection lag of 16.70 days.

Q. PLEASE DESCRIBE HOW THE EXPENSE LAGS WERE CALCULATED.

A. The lag for expenditures is the time between when a service or benefit is received and payment is made. This lag should represent the mid-point of the service period plus

the time from the end of the service period to the date of payment. For an expenditure selected on a sample basis, the lag days for the selected item were multiplied by the dollar amount of the item to obtain the weighted dollar days. The total dollar days were divided by the related total sampled expenditures to obtain the weighted average lag days. For expenditures paid in installments, such as income taxes currently payable, percentages instead of dollars were used to obtain the weighted average lag days. As stated earlier in my testimony, special treatment was required for prepayments, depreciation and amortization, deferred income taxes, inventories, and sales taxes to avoid either over or under recovery of the cost of capital.

Q. WHY DOES INSURANCE EXPENSE ONLY HAVE A REVENUE LAG?

A. Insurance is paid in advance. Therefore, insurance has a lead time (negative lag). There are two basic methods used to permit utilities to recover their cost of capital related to a prepaid expense. Both methods produce similar results. Under the lead/lag formula, the insurance could be included in the cash working capital study as the difference between the payment date and the average expense date (the mid-point of the benefit period). This would produce a lead period or negative lag. However, APS has included prepayments as another component in rate base. Including prepaid expense as a separate component of rate base and including a negative lag in the cash working capital study would overstate rate base. To avoid duplicating the return on prepayments, we carefully considered the effect that rate base had on revenue requirements. Theoretically, a return on an investment is earned when it is in rate base. When the prepayment is charged to expense, rate base is reduced and recovery of the return stops. Therefore, insurance expense is included in the lead/lag study

with only a revenue lag to bridge the gap between the time rate base is reduced by the charge to expense and when that amount is recovered in rates (the revenue lag).

Q. WHAT APPROACH DID YOU USE WITH RESPECT TO EXPENSE LAGS FOR INVENTORIES OF FUEL AND MATERIALS AND SUPPLIES?

A. Investors are entitled to earn a return on their investment in inventories, including fuel, materials and supplies and other inventories used in the utility business. These inventories are presumed to be included in rate base and a return earned when inventories are received. The expense lags represent an estimate of the time, on a dollar weighted basis, between the date inventory is received and the date the invoice is paid. These lags are applied to the fuel and inventory amounts expensed for the year.

Q. WHY DID YOU MEASURE ONLY THE REVENUE LAG FOR DEPRECIATION AND AMORTIZATION AMOUNTS IN THE LEAD/LAG CALCULATIONS?

A. Recognition of a revenue lag is necessary to bridge the gap between the time rate base is reduced by the charge to expense and when that amount is recovered in rates. Plant and nuclear fuel are presumed to be included in rate base at the time such plant is placed in service. Plant expenditures are made during the course of construction. There is not an "expense lag" as generally defined when depreciation and amortization are charged to expense. Cash is not expended at the time depreciation is recorded. Depreciation expense is an allocation of an investment already made. However, rate base is presumed to be reduced at the time depreciation is recorded. As stated above, accumulated depreciation is used to reduce rate base because depreciation for utilities represents both an allocation of costs and a recovery of costs. That means that rate base is reduced during the benefit period when the expense is incurred. The reason that rate base is reduced by accumulated depreciation is to

prevent investors from earning a return on investments made with funds recovered from customers. However, depreciation is recorded before the Company recovers the revenues related to depreciation. Thus, investors would be prevented from earning a return on their investment between the time depreciation is expensed and the time that such depreciation is recovered in rates if the related lag in revenues is not recognized.

Q. WHY DID YOU MEASURE ONLY THE REVENUE LAG FOR DEFERRED INCOME TAXES IN THE LEAD/LAG CALCULATIONS?

A. As with depreciation, accumulated deferred income taxes are used to reduce rate base at the time deferred income taxes are recorded. Recognition of a revenue lag is necessary to bridge the gap between the time rate base is reduced by the charge to expense and when that amount is recovered in rates. Deferred income tax expense is not generally considered a cash expense. However, cash expenditures will normally be required in the future. For example, deferred tax procedures are generally required for the difference between tax and book depreciation. Assuming there are no basis differences in a depreciable plant, tax depreciation and book depreciation will be equal over the entire life of a plant item. However, accelerated tax depreciation for tax purposes will produce an excess of tax depreciation over book depreciation in the early years of an asset's life and will produce an excess of book depreciation over tax depreciation in later years. The increase in tax depreciation in the early years will reduce taxes currently payable in those years. These differences are timing differences. Deferred income taxes are recorded for the tax effect of these timing differences. Eventually, book depreciation will exceed tax depreciation thereby increasing taxes payable. The cash flows provided by a reduction in taxes payable in the early years are paid back in the later years. But the issue is not whether it is a cash or non-cash expense. As with depreciation expense, deferred income tax expenses that increase deferred tax liabilities are included in revenue requirements.

Rate base is reduced by deferred income taxes payable to prevent investors from earning a return on investments made with funds provided by consumers. However, the funds have not been provided by consumers until paid by consumers. That has to be recognized in the lead/lag study.

Q. PLEASE DESCRIBE HOW THE REVENUE AND EXPENSE LAGS RELATED TO SALES TAXES WERE DETERMINED.

A. Most of the sales tax shown in the lead/lag study represents amounts billed to customers. Sales taxes are paid on the 25th of the month after such accounts are billed. Thus, APS has temporary use of these funds, and thus we must recognize such funds as part of the cash working capital study. The revenue lag days represent the collection lag for revenues. The expense lag represents an estimate of the time between the time of billing and the end of the billing month (15.21 days), plus the 25 days APS has use of the funds in the month such taxes are paid. This method is also consistent with the approach proposed by the Commission Staff in the Company's last rate case.

Q. WHAT IS APS' CASH WORKING CAPITAL REQUIREMENT?

A. As set forth in Attachment FHB-1, APS has a negative cash working capital requirement of $29,372,869. As discussed in Ms. Rockenberger's testimony, the negative cash working capital requirement reduces the APS test year rate base.

Q. DOES THAT CONCLUDE YOUR PRE FILED DIRECT TESTIMONY?

A. Yes.

ARIZONA PUBLIC SERVICE COMPANY
CASH WORKING CAPITAL REQUIRED FOR OPERATING EXPENSES - LEAD LAG STUDY
TWELVE MONTHS ENDED SEPTEMBER 30, 2005

LINE	DESCRIPTION	AMOUNT	REVENUE LAG DAYS	EXPENSE LAG DAYS	NET LAG DAYS	CWC FACTOR	WORKING CAPITAL REQUIREMENT
		(1)	(2)	(3)	(4)	(5)	(6)
1	FUEL FOR ELECTRIC GENERATION:						
2	COAL	200,856,342	36.95027	32.36664	4.58363	0.01256	2,522,756
3	NATURAL GAS	237,557,927	36.95027	44.25857	-7.30830	-0.02002	(4,755,910)
4	FUEL OIL	1,077,082	36.95027	32.34060	4.60967	0.01263	13,604
5	NUCLEAR:						
6	AMORTIZATION	34,445,413	36.95027	0.00000	36.95027	0.10123	3,486,909
7	SPENT FUEL	7,336,099	36.95027	76.35359	-39.40333	-0.10795	(791,932)
8	TOTAL NUCLEAR FUEL	41,781,512					2,694,977
9							
10	TOTAL FUEL	481,272,863					475,427
11							
12	PURCHASED POWER	1,313,764,296	36.95027	38.15020	-1.19994	-0.00329	(4,322,285)
13	TRANSMISSION BY OTHERS	14,391,245	36.95027	33.69389	3.25638	0.00892	128,370
14	TOTAL PURCHASED POWER & TRANSMISSION	1,328,155,540					(4,193,915)
15							
16	TOTAL FUEL AND PURCHASED POWER	1,809,428,404					(3,718,488)
17							
18	OTHER OPERATIONS & MAINTENANCE:						
19	PAYROLL	240,714,447	36.95027	15.00192	21.94835	0.06013	14,474,160
20	INCENTIVE	8,653,091	36.95027	214.50000	-177.54973	-0.48644	(4,209,209)
21	PENSION AND OPEB	38,986,000	36.95027	77.71371	-40.76344	-0.11168	(4,353,956)
22	EMPLOYEE BENEFITS	26,995,515	36.95027	20.35895	16.59132	0.04546	1,227,216
23	PAYROLL TAXES	18,118,131	36.95027	21.78589	15.16438	0.04155	752,808
24	MATERIALS & SUPPLIES	53,466,114	36.95027	24.22000	12.73027	0.03488	1,864,898
25	FRANCHISE PAYMENTS	11,986,402	36.95027	52.83966	-15.88940	-0.04353	(521,768)
26	VEHICLE LEASE PAYMENTS	3,169,771	36.95027	7.43789	29.51238	0.08086	256,308
27	RENTS	6,776,038	36.95027	-33.48601	70.43627	0.19298	1,307,640
28	PALO VERDE LEASE	45,900,681	36.95027	47.31849	-10.36823	-0.02841	(1,304,038)
29	PALO VERDE S/L GAIN AMORT	(4,575,722)	36.95027	0.00000	36.95027	0.10123	(463,200)
30	INSURANCE	4,639,562	36.95027	0.00000	36.95027	0.10123	469,663
31	OTHER	119,131,971	36.95027	35.39000	1.56027	0.00427	508,694
32	TOTAL	573,962,000					10,009,216
33							
34	DEPRECIATION & AMORTIZATION	321,525,565	36.95027	0.00000	36.95027	0.10123	32,548,033
35	AMORT OF ELECTRIC PLT ACQ ADJ	0	36.95027	0.00000	36.95027	0.10123	0
36	AMORT OF PROP LOSSES & REG STUDY COSTS	(2,564,492)	36.95027	0.00000	36.95027	0.10123	(259,604)
37	TOTAL	318,961,073					32,288,429
38							
39	INCOME TAXES:						
40	CURRENT:						
41	FEDERAL	59,824,326	36.95027	58.95000	-21.99973	-0.06027	(3,605,612)
42	STATE	16,379,288	36.95027	58.95000	-21.99973	-0.06027	(987,180)
43	DEFERRED	77,758,889	36.95027	0.00000	36.95027	0.10123	7,871,532
44	TOTAL	153,962,503					3,278,740
45							
46	OTHER TAXES:						
47	PROPERTY TAXES	123,403,653	36.95027	211.94223	-174.99196	-0.47943	(59,163,413)
48	SALES TAXES	158,240,555	16.69615	40.21000	-23.51385	-0.06442	(10,193,857)
49	FRANCHISE TAXES	18,920,381	16.69615	52.83966	-36.14352	-0.09902	(1,873,496)
50	TOTAL OTHER TAXES	300,564,589					(71,230,766)
51							
52	TOTAL	3,156,878,568					(29,372,869)

Attachment FB-1

DR. WILLIAM AVERA

BEFORE THE

ARIZONA CORPORATION COMMISSION

DIRECT TESTIMONY OF

WILLIAM E. AVERA

On Behalf of Arizona Public Service Company

Docket No. E-01345A-05-0816

January 31, 2006

DIRECT TESTIMONY OF WILLIAM E. AVERA

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DIRECT TESTIMONY OF WILLIAM E. AVERA

ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY

(Docket No. E-01345A-05-0816)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. William E. Avera, 3907 Red River, Austin, Texas, 78751.

Q. IN WHAT CAPACITY ARE YOU EMPLOYED?

A. I am the President of FINCAP, Inc., a firm providing financial, economic, and policy consulting services to business and government.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. A description of my background and qualifications, including a resume containing the details of my experience, is attached as Appendix A.

A. Overview

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to present to the Arizona Corporation Commission ("ACC" or the "Commission") my independent assessment of the fair rate of return on equity ("ROE") for the jurisdictional electric utility operations of Arizona Public Service Company ("APS" or "the Company"). In addition, I also examined the reasonableness of APS' requested capital structure, considering both the specific risks faced by APS and other industry guidelines

Q. PLEASE SUMMARIZE THE BASIS OF YOUR KNOWLEDGE AND CONCLUSIONS CONCERNING THE ISSUES TO WHICH YOU ARE TESTIFYING IN THIS HEARING.

A. To prepare my testimony, I used information from a variety of sources that would normally be relied upon by a person in my capacity. In connection with the present filing, I considered and relied upon corporate disclosures and management discussions, publicly available financial reports and filings, and other published information relating to APS and its parent company, Pinnacle West Capital Corporation ("Pinnacle West"). I also reviewed information relating generally to capital market conditions and specifically to investor perceptions, requirements, and expectations for electric utilities. These sources, coupled with my experience in the fields of finance and utility regulation, have given me a working knowledge of investors' requirements for APS as it competes to attract capital, and they form the basis of my analyses and conclusions.

Q. WHAT IS THE ROLE OF THE COST OF CAPITAL IN SETTING A UTILITY'S RATES?

A. The cost of capital compensates investors for the use of their capital to finance the plant and equipment necessary to provide utility service. Investors commit capital only if they expect to earn a return on their investment commensurate with returns available from alternative investments with comparable risks. To be consistent with sound regulatory economics and the standards set forth by the United States Supreme Court in the *Bluefield*[1] and *Hope*[2] cases, a utility's allowed cost of capital should be sufficient to (1) fairly compensate the utility's capital investors, (2)

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[1] *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n*, 262 U.S. 679 (1923).

[2] *Fed. Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944).

enable the utility to offer a return adequate to attract new capital on reasonable terms, and (3) maintain the utility's financial integrity.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. I first reviewed the operations and finances of APS and the general conditions in the electric utility industry and the economy. With this as a background, I developed the principles underlying the cost of equity concept and then conducted various quantitative analyses to estimate the cost of equity for a group of reference utilities. These included discounted cash flow ("DCF") analyses, risk premium methods encompassing alternative approaches and studies, and reference to comparable earned rates of return expected for utilities and industrial firms. From the cost of equity range indicated by my analyses, a fair rate of return on equity was selected taking into account the economic requirements and specific risks and potential challenges for APS, as well as other factors (*e.g.*, flotation costs) that are properly considered in setting a fair rate of return on equity for the Company's jurisdictional electric utility operations in Arizona.

B. Summary of Conclusions

Q. WHAT ARE YOUR FINDINGS REGARDING THE FAIR RATE OF RETURN ON EQUITY FOR APS?

A. Based on the results of my analyses and the economic requirements necessary to support continuous access to capital, I recommend that APS be authorized a fair rate of return on equity of 11.5%. The bases for my conclusion are summarized below:

- Considering investors' expectations for capital markets, the substantial funding requirements faced by APS, and the need to support financial integrity and fund crucial capital investment even

under adverse circumstances, it is my opinion that 11.5% is a reasonable ROE for APS. Specifically, I concluded that:

- Applications of alternative quantitative methods to a proxy group of other electric utilities operating in the Western U.S. implied a cost of equity range of 10.8% to 11.8%, before considering an allowance for flotation costs;
- Expectations for higher interest rates should be considered in establishing a fair rate of return for APS;
- Incorporating a 20 basis-point allowance for equity flotation costs resulted in a fair rate of return range for the electric utility proxy group of 11.0% to 12.0%; and
- Based on the midpoint of this range, 11.5% represents a reasonable rate of return on common equity for APS.

Q. WHAT IS YOUR CONCLUSION AS TO THE REASONABLENESS OF THE COMPANY'S CAPITAL STRUCTURE?

A. Based on my evaluation, I concluded that a common equity ratio of approximately 55% represents a reasonable basis from which to calculate APS' overall rate of return. This conclusion was based on the following findings:

- APS' requested capitalization is consistent with the Company's need to strengthen its credit standing and financial flexibility as it seeks to raise additional capital to fund significant system investments and meet the requirements of its growing service territory;
- APS' proposed common equity ratio is consistent with expectations for the electric utilities in the proxy group used to estimate the cost of equity;

- Regulatory support for higher equity levels is necessary to support APS' financial flexibility and preserve the Company's capacity to fund investments that will ensure reliable service and facilitate further development of electric utility infrastructure in Arizona.

Q. WHAT OTHER EVIDENCE DID YOU CONSIDER IN EVALUATING YOUR RECOMMENDATION IN THIS CASE?

A. My recommendation was reinforced by the following findings:

- Considering investors' heightened awareness of the risks associated with the electric power industry and the damage that results when a utility's financial flexibility is compromised, supportive regulation is perhaps more crucial now than at any time in the recent past;
- Sensitivity to regulatory uncertainties has increased dramatically and investors recognize that constructive regulation is a key ingredient in supporting utility credit ratings and financial integrity;
- APS must compete for investors' capital with other utilities and businesses of comparable risk. Standard & Poor's Corporation ("S&P's") corporate credit rating for APS falls at the bottom of the range for the proxy group and represents the lowest rating on the investment grade scale. If APS is not provided an opportunity to earn a return that is sufficient to compensate for the underlying risks, investors will be unwilling to supply capital;
- Ultimately, it is customers and the service area economy that benefit when the utility has the opportunity to maintain the financial wherewithal that is necessary, not just to maintain short-term liquidity, but to take actions to provide an efficient, reliable energy

supply over the long-term.

II. FUNDAMENTAL ANALYSES

Q. WHAT IS THE PURPOSE OF THIS SECTION?

A. As a predicate to subsequent quantitative analyses, this section briefly reviews the operations and finances of APS. In addition, it examines the risks and prospects for the electric utility industry and conditions in the capital markets and the general economy. An understanding of the fundamental factors driving the risks and prospects of electric utilities is essential in developing an informed opinion of investors' expectations and requirements that are the basis of a fair rate of return.

A. Arizona Public Service Company

Q. BRIEFLY DESCRIBE APS.

A. The principal subsidiary of Pinnacle West, APS is primarily engaged in the generation, transmission, and distribution of electric power to more than a million customers in 11 of Arizona's 15 counties, with the major exceptions of about one-half of the Phoenix metropolitan area, the Tucson metropolitan area and Mohave County in northwestern Arizona. As of December 31, 2004, APS had total assets of approximately $8.1 billion, with operating revenues totaling approximately $2.2 billion.

The Company's retail electric operations are subject to the jurisdiction of the ACC, with transmission operations being regulated by the Federal Energy Regulatory Commission ("FERC"). Additionally, APS' nuclear facilities are subject to licensing and oversight by the Nuclear Regulatory Commission ("NRC"). State

legislation has significantly restructured the electric utility industry in Arizona. Under the Retail Electric Competition Rules approved by the ACC,[3] retail access became available to all APS retail electricity customers effective January 1, 2001 and Arizona utilities were required to unbundle rates for noncompetitive services. In addition, all competitive electric assets and services were to be sold to an unaffiliated party or transferred to a separate corporate affiliate.

In the wake of the Western energy crisis in 2000-2001, however, the ACC effectively halted restructuring to review its policies. In September 2002, the ACC issued the "Track A" Order, which reversed the requirement to transfer competitive assets and directed APS to cancel its transfer of generation assets to PWEC. In March 2003, the ACC issued its "Track B" Order, which required investor-owned utilities subject to its jurisdiction to solicit competitive bids for certain estimated capacity and energy requirements beginning July 2003. More recently, the ACC affirmed the Company's ability to build and acquire generation to meet its native load requirements and authorized the transfer of approximately 1,800 Megawatts ("MW") of generating capacity built by PWEC in Arizona to APS. Currently, APS is prohibited from building new generating capacity through January 1, 2015, unless adequate power supply cannot be obtained in the wholesale market at reasonable cost.

The regulatory developments and challenges surrounding the Retail Electric Competition Rules have raised considerable uncertainty about the status and pace of retail electric competition and of electric restructuring in Arizona. Although some very limited retail competition existed in APS' service area in 1999 and 2000,

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[3] A.A.C. R14-2-1601.

there are currently no active retail competitors providing unbundled energy or other utility services to APS' customers.

Q. PLEASE DESCRIBE APS' ELECTRIC UTILITY OPERATIONS.

A. APS employs about 6,100 individuals, with energy sales amounting to over 57.2 million megawatt ("MW") hours during 2004. Approximately 50% of 2004 retail electric revenues were attributable to residential customers, with 42% from commercial and 8% from industrial and other users. The Company's generating facilities include its 29.1% interest in the three nuclear units of the Palo Verde Nuclear Generating Station ("Palo Verde"), with a total capacity of approximately 1,107 MW. In 2004, nuclear generation accounted for approximately 14% of the electric energy provided by APS, with coal at 21%, and natural gas at 2%.

In addition to its own generating capacity, APS relied on purchased power arrangements for the remaining 63% of its 2004 energy needs.[4] One of the most important of APS' purchase power agreements is a long-term contract with Salt River Project. The generating capacity available to APS pursuant to the contract is 350 MW, which will be reduced to 150 MW in 2007.

APS' transmission and distribution facilities consist of approximately 17,800 pole miles of overhead lines and approximately 13,764 miles of underground lines. Along with other owners of electric transmission lines in the southwestern U.S., APS has been participating in the evaluation of a proposal that would satisfy the FERC's requirements for the formation of a Regional Transmission Organization ("RTO"). At December 31, 2004, APS' investment in net utility plant was approximately $6.3 billion.

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[4] Includes energy attributable to the PWEC generating facilities that were transferred to APS in 2005.

Q. DOES APS ANTICIPATE THE NEED TO ACCESS THE CAPITAL MARKETS GOING FORWARD?

A. Most definitely. APS will require capital investment to meet customer growth, provide for necessary maintenance and replacements of its utility infrastructure, as well as fund new investment in electric generation, transmission and distribution facilities. APS' service area is the second-fastest growing region in the U.S. (behind Las Vegas), and the Company anticipates continued expansion on the order of 3% annually, with demand expected to increase on the order of 5,000 MW over the next ten years. In order to keep pace with customer growth and enhance utility infrastructure, APS anticipates construction expenditures of approximately $1.2 billion for 2005 and 2006 alone.[5] Support for APS' financial integrity and flexibility will be instrumental in attracting the capital necessary to fund these projects in an effective manner.

Q. HOW ARE FLUCTUATIONS IN APS' OPERATING EXPENSES CAUSED BY VARYING FUEL AND POWER MARKET CONDITIONS ACCOMMODATED IN ITS RATES?

A. Beginning April 1, 2005, APS implemented a power supply adjuster ("PSA") for recovery of variations in purchased power and fuel costs. Under the PSA, actual costs for purchased power and fuel are compared with the amount included in retail base rates and, subject to certain limits and restrictions, differences will be deferred for future recovery or refund. The PSA provides for an incentive mechanism where APS and its customers share 10% and 90%, respectively, in any higher costs or savings. The implicit assumption of such a mechanism is, of course, that management has some limited means to influence these costs.

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[5] Pinnacle West Capital Corporation, Form 10-Q Report (June 30, 2005) at 49.

Under the PSA, annual changes in the adjustor are limited to plus or minus $0.004 per kilowatt hour ("kWh"), with additional amounts being recorded in a balancing account. Subject to ACC approval, a surcharge is possible if the balancing account reaches $50 million, with APS filing its first request to implement an adjustor surcharge under the PSA on July 22, 2005.[6] The PSA provides that the Commission or ACC Staff may review the prudence of fuel and power purchases at any time and all costs flowed through the adjustor are subject to refund if the Commission later determines that the amounts were not prudently incurred.

Q. WHAT CREDIT RATINGS HAVE BEEN ASSIGNED TO APS?

A. Citing increased regulatory and operating risks related to growing balances of deferred fuel and power costs, on December 21, 2005 Standard & Poor's Corporation ("S&P") lowered the corporate credit ratings of APS and Pinnacle West from "BBB" to "BBB-".[7] While Moody's Investors Service ("Moody's) and Fitch Ratings ("Fitch") have at the time of the filing maintained their long-term credit ratings of Baa1 and BBB respectively, for APS, both agencies have placed the Company under review for a possible downgrade.[8]

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[6] Docket No. 0E-1345A-03-0437 and 0E-1345A-05-0526.

[7] Standard & Poor's Corporation, "Research Update: Pinnacle West Capital's, Arizona Public Service's Ratings Lowered to 'BBB-'; Outlook Stable," *RatingsDirect* (Dec. 21, 2005).

[8] Moody's Investors Service, "Rating Action: Arizona Public Service Company," *Credit Research* (Jan. 10, 2006); Fitch Ratings Ltd., "Fitch Places PNW and APS on Rating Watch Negative" (Jan. 6, 2006).

B. Electric Utility Industry

Q. WHAT GENERAL CONDITIONS HAVE RECENTLY CHARACTERIZED THE ELECTRIC UTILITY INDUSTRY?

A. Over the past decade, the industry has experienced significant structural change resulting from market forces and decontrol initiatives. At least initially, this process was largely driven by regulatory reforms at the federal level. The national Energy Policy Act of 1992 greatly increased prospective competition for the production and sale of power at the wholesale level, with FERC being an aggressive proponent for actions designed to foster greater competition in markets for wholesale power supply.

Most market observers agree that, while "open access" to FERC-jurisdictional transmission facilities has resulted in more competition in wholesale energy markets, it has also introduced substantial risks – particularly for utilities (like APS) that depend on wholesale markets for a portion of their resource requirements.

Q. WHAT IMPACT DID THE WESTERN POWER CRISIS HAVE ON INVESTORS' RISK PERCEPTIONS FOR FIRMS INVOLVED IN THE ELECTRIC POWER INDUSTRY?

A. Events of the last several years caused investors to rethink their assessment of the relative risks associated with the electric power industry. A well-publicized energy crisis throughout the West wreaked havoc on the customers, utilities, and policymakers. It also had dramatic repercussions for wholesale power markets and investors and utilities nationwide. In many states -- including Arizona -- regulators and legislators placed restructuring initiatives for the retail sector of the electric industry on hold as the financial implications of the Western energy crisis brought the uncertainties associated with today's power markets into sharp focus for the

investment community and other stakeholders. While the case of California represents an extreme example, there is every indication that investors' risk perceptions for all electric utilities shifted sharply upward in response to these events.

Q. HOW WERE WESTERN UTILITIES IMPACTED BY CONDITIONS IN THE ELECTRIC POWER INDUSTRY?

A. The financial integrity of many utilities in the region was severely damaged by the maelstrom of the Western energy crisis. While a full description of the Western power crisis and its effects is beyond the scope of this testimony, the chaotic market conditions were felt directly and with full force. S&P cited the debilitating impact of these developments on investors' willingness to provide capital and recognized that the end result of investors' waning confidence in the industry was reduced access to capital.[9]

Utilities were forced to use cash flows from operations, various bank borrowings, and short- and long-term debt to fund unrecovered energy supply costs. This led to a sharp deterioration in financial condition, a severe liquidity crunch, and a dramatic increase in credit risk. As a result, commercial banks were highly reticent to extend financing for ongoing operations or new construction and counterparties involved in meeting the utilities' energy needs became unwilling to transact business absent special credit terms. To varying degrees, utilities throughout the western U.S. were confronted with the difficult task of maintaining reliable service and financial integrity in a power market characterized by short supply and unprecedented price volatility. As a result, investors recognize that volatile markets

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[9] Standard & Poor's Corporation, "U.S. Power Industry Experiences Precipitous Credit Decline in 2002; Negative Slope Likely to Continue," *RatingsDirect* (Jan. 15, 2003).

and inopportune reliance on wholesale purchases to meet resource needs can constitute a dangerous combination, exposing the utility to the risk of reduced cash flows and unrecovered power supply costs.

Q. WAS THERE A CORRESPONDING IMPACT ON THE INDUSTRY'S CREDIT STANDING?

A. Yes. The last several years witnessed steady erosion in credit quality throughout the utility industry, both as a result of revised perceptions of the risks in the industry and the weakened finances of the utilities themselves. For example, during 2002, S&P recorded 182 downgrades in the utility industry, versus only 15 upgrades,[10] while Moody's downgraded 109 utility issuers and upgraded 3.[11] Credit quality continued to decline during 2003, with S&P reporting that downgrades outpaced upgrades by more than 15 to one in the fourth quarter of 2003.[12] While the pace and scale of negative ratings actions has since diminished, S&P reported that the majority of the companies in the utility sector now fall in the triple-B rating category and noted a continued negative bias in the credit outlook.[13]

Q. IS THERE ANY INDICATION THAT THE IMPORTANCE OF THESE CONSIDERATIONS HAS DIMINISHED IN THE EYES OF INVESTORS?

A. No. Investors recognize that the continuing prospect of further turmoil in Western energy markets cannot be discounted, with S&P reporting continued spikes in wholesale market prices in the aftermath of the crisis:

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[10] Standard & Poor's Corporation, "U.S. Power Industry Experiences Precipitous Credit Decline In 2002; Negative Slope Likely to Continue," *RatingsDirect* (Jan. 15, 2003).

[11] Moody's Investors Service, *Credit Perspectives* (Jul. 14, 2003) at 33.

[12] Standard & Poor's Corporation, "U.S. Utilities' Ratings Decline Continued in 2003, But Pace Slows," *RatingsDirect* (Feb. 2, 2004).

[13] Standard & Poor's Corporation, "U.S. Utility Upgrades Beat Downgrades In Second Quarter, But Negative Watch Listings Grew," *RatingsDirect* (Jul. 28, 2005).

> For 2003, record-high wholesale power prices were the defining feature of the U.S. merchant power markets. ...Power prices across the U.S. continent generally rose on the order of 50% or more in 2003. ...Prices in the western regions were also the highest on record outside of the 2000-2001 California energy crisis.[14]

More recently, S&P concluded that, while the severe distortions that characterized the energy crisis of 2000-2001 have faded, "[n]atural gas volatility, poor hydro conditions in the Northwest, the Southwest's sustained drought, and uncertainty over future generation development" are "daily reminders" of the challenges to the financial health of Western utilities.[15] Meanwhile, the FERC Staff has warned of the ongoing potential for market disruption in the West, as a recent report concluded:

> Our review of supply and demand conditions in the west this summer indicates that there may be periods of market tightness most likely expressed as price spikes and possible interruptions.[16]

Additionally, in recent years utilities and their customers have also had to contend with dramatic fluctuations in gas costs due to ongoing price volatility in the spot markets.[17] S&P noted the danger posed by "high and volatile natural gas prices," which increase the uncertainties associated with power supply costs.[18] As the

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[14] Standard & Poor's Corporation, "Energy Commodity Report: U.S. Power Prices Record High in 2003," *RatingsDirect* (Jan. 15, 2004).

[15] Standard & Poor's Corporation, *Utilities & Perspectives* (Oct. 18, 2004).

[16] Federal Energy Regulatory Commission, Office of Market Oversight and Investigations, "Summer Energy Market Assessment 2005," (May 4, 2005) at 9.

[17] For example, the Energy Information Administration ("EIA") reported that the average spot gas price at the Henry Hub spiked to $18.85 per MMBtu in February 2003, before declining to approximately $5.00. More recently, EIA noted that "prices at the Henry Hub on Wednesday, October 12 exceeded last year's level by $8.36 per MMBtu or about 156 percent." (*Natural Gas Weekly Update,* Mar. 27, 2003 and Oct. 13, 2005).

[18] Standard & Poor's Corporation, "Prolonged High Natural Gas Prices May Increase Credit Risk for U.S. Gas Distributors," *RatingsDirect* (Jan. 19, 2005)

Economist Intelligence Unit, Ltd. indicated, this sensitivity has only been magnified by fallout of the natural disaster in the Gulf Coast region:

> Hurricane Katrina has sent gas prices to new record levels, exacerbating an already supply-tight market that has seen high prices for the last two years. There is little indication that the situation will improve in 2006...[19]

Similarly, ACC Chairman Jeff Hatch-Miller warned Arizona consumers to prepare for the future in light of the "meteoric rise" in the cost of natural gas.[20]

In addition, while coal has historically been a relatively stable source of fuel, rising prices have raised investors' concerns. In an article entitled "Rising Coal Prices May Threaten U.S. Utility Credit Profiles," S&P noted that:

> More recently, several current and structural developments for the coal mining industry have resulted in a dramatic increase in spot coal prices.[21]

Q. DOES THE PSA REMOVE THE RISK ASSOCIATED WITH FLUCTUATIONS IN POWER SUPPLY COSTS?

A. No. While approval of the PSA was a positive step and supportive of the Company's financial integrity, it does not apply to 100% of APS' power costs. Moreover, even for utilities with permanent energy cost adjustment mechanisms in place, there can be a significant lag between the time the utility actually incurs the expenditure and when it is recovered from ratepayers. Citing the example of a gas utility, S&P observed that:

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[19] Economist Intelligence Unit, Ltd., "World Commodities – Natural gas market outlook," (Sep. 1, 2005) at 1.

[20] Arizona Corporation Commission, "Natural Gas Forum: What Utilities & Consumer Groups are Doing to Prepare Customers for the Winter Ahead," *News Releases* (Sep. 1, 2005).

[21] Standard & Poor's Corporation, "Rising Coal Prices May Threaten U.S. Utility Credit Profiles," *RatingsDirect* (Aug. 12, 2004).

> Slow recovery could impinge on the firm's liquidity as short-term funds are consumed to finance high-cost gas purchases. In turn, this may necessitate a large bank line that increases borrowing costs.[22]

In the case of APS, the PSA applies to 90% of the deviation between actual power supply costs and normalized rates. In addition, annual changes in the adjustor are limited to $0.004 per kWh lifetime cap, with additional amounts being deferred to a balancing account. A surcharge to address such deferrals is only possible when the balancing account reaches $50 million, and then only with ACC approval. Under the PSA, the total amount of annual fuel and purchased power costs that APS may recoup was capped at $776.2 million. Thus, in addition to absorbing 10% of energy cost increases above base rates and being subject to a cap on total costs, the PSA does not insulate APS from the need to finance accrued power production and supply costs.

Q. HAVE THE LIMITATIONS ASSOCIATED WITH THE PSA AND ITS IMPLEMENTATION BEEN RECOGNIZED BY THE INVESTMENT COMMUNITY?

A. Yes. In spite of the PSA, the impact of uncollected power costs on APS' cash flow metrics and ongoing uncertainty over the Company's ability to recover these expenses have sparked concern in the investment community. As noted earlier, sustained increases in power cost deferrals and a lack of clarity over the timing of rate relief led S&P to downgrade APS to "BBB-", the lowest rung on the ladder of the investment grade ratings scale. S&P noted that "by design, aspects of the PSA make it a weak tool for fuel and power cost recovery,"[23] observing that:

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[22] Standard & Poor's Corporation, "Prolonged High Natural Gas Prices May Increase Credit Risk for U.S. Gas Distributors," *RatingsDirect* (Jan. 19, 2005).

[23] Standard & Poor's Corporation, "Pinnacle West Capital Corp.," *RatingsDirect* (Dec. 16, 2005).

> [T]he 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 2006. ... In addition to a certain wait of four months for PSA adjustments to be authorized, upward adjustments are capped at 4 mils per kilowatt-hour for the life of the mechanism. As a result, all or nearly all of the PSA capacity is likely to be absorbed in APS' first PSA filing, and the utility is expected to end the summer of 2006 needing another surcharge to address additional balances that will accumulate.[24]

Indeed, S&P concluded that "the longer term risks that the terms of the PSA present" foreclosed any improvements in APS' credit standing in the short-term.[25]

Q. DOES THE PSA PROTECT APS FROM THE POTENTIAL FOR REGULATORY DISALLOWANCES?

A. No. Even with an energy cost adjustment mechanism, investors recognize the ongoing potential for regulatory disallowances. As S&P observed:

> [Fuel and purchased power adjustment mechanisms (FPPA)] vary substantially in their ability to protect utilities daily and under catastrophic market movement. Moreover, it is critical to note that FPPAs are not a substitute for supportive regulation; the regulator's ability to disallow costs through ex-post prudency review, regardless of the existence of a FPPA, is a fact of life for utilities.[26]

Similarly, Fitch noted that "because of the lag between when the excess costs are incurred and when they are recovered and the potential substantial disallowances of such costs," significant uncertainties remain even for utilities with fuel and purchased power cost adjustment mechanisms.[27]

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[24] Standard & Poor's Corporation, "Research Update: Pinnacle West Capital's, Arizona Public Service's Ratings Lowered To 'BBB-'," *RatingsDirect* (Dec. 21, 2005).

[25] Standard & Poor's Corporation, "Summary: Arizona Public Service Co.," *RatingsDirect* (May 24, 2005).

[26] Standard & Poor's Corporation, *Utilities & Perspectives* (Oct. 18, 2004).

[27] FitchRatings, "Outlook 2005: U.S. Power & Gas," *Global Power/North America Special Report* (Jan. 6, 2005) at 26.

Q. WHAT OTHER DEVELOPMENTS HAVE CONTRIBUTED TO INVESTORS' REASSESSMENT OF THE RISKS ASSOCIATED WITH THE ELECTRIC UTILITY INDUSTRY?

A. Policy evolution in the electric transmission area has been wide-reaching and investors have increasingly focused on uncertainty over operating rules and market development. Virtually all industry stakeholders have recognized that regulatory uncertainties increase the risks associated with the utility industry. For example, the Department of Energy ("DOE") identified "reducing regulatory uncertainty" as critical in stimulating increased investment in the power industry and noted that lack of clarity in the regulatory structure was inhibiting planning and investment.[28] The DOE also recognized the impact that this regulatory uncertainty has on investors' required rates of return for electric utilities:

> Because transmission assets are long lived, regulatory uncertainty increases the risks to investors and, therefore, increases the returns they need to justify transmission system investments.[29]

The 2003 blackout only served to reinforce the importance of regulatory risks for investors. The Wall Street Journal cited the debilitating impact of an "unsteady regulatory situation" and the "chaotic combination of regulated and deregulated markets" in explaining inhibitions to increased investment in the electric utility system.[30] Similarly, S&P warned investors that the partial reforms presently characterizing wholesale power markets invite prolonged dysfunction and that elevated risks will discourage new capital, "or at least make it more expensive."[31]

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[28] U.S. Department of Energy, *National Transmission Grid Study* (May 2002), at 24 and 31.

[29] *Id.* at 31.

[30] Smith, Rebecca, "Overloaded Circuits: Blackout Signals Major Weakness in U.S. Power Grid," The Wall Street Journal (Aug. 18, 2003).

[31] Standard & Poor's Corporation, "Electric Utility Blackouts Put Spotlight on Political and Regulatory Credit Risk," *RatingsDirect* (Aug. 21, 2003).

Investors recognize the potential for ongoing market volatility and remain sensitive to the strain such events can imply for regulated utilities. Investors are mindful that, even when regulation is supportive and market conditions appear relatively stable, unexpected events can trigger rapid financial deterioration before regulatory authorities are able to react.

Q. ARE INVESTORS LIKELY TO CONSIDER THE IMPACT OF THESE MARKET CONDITIONS IN ASSESSING THEIR REQUIRED RATE OF RETURN FOR APS?

A. Absolutely. While the future course of restructuring in Arizona is unclear, APS continues to face the impact of fundamental industry reforms, as Fitch recently noted:

> With the March 2005 ACC order in APS' GRC, the state has migrated to a hybrid model that relies on an integrated utility structure while providing the potential for development of a robust wholesale power market to supply customer needs over time.[32]

Fitch concluded that the development of the wholesale power market, the structure of power supply in Arizona, and the utility's role in power procurement are expected "to evolve slowly and remain subject to significant uncertainty."[33] Similarly, Moody's cited uncertainty regarding the future of competition in Arizona as a key credit challenge facing APS.[34] In addition, APS continues to confront uncertain market trends and the prospect of FERC-driven changes in the electric transmission function of the Company's business, including the uncertainties associated with the establishment of RTOs.

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[32] Fitch Ratings, "Arizona Public Service Company," *Global Power/North America Credit Analysis* (May 4, 2005).
[33] *Id.*
[34] Moody's Investors Service, "Arizona Public Service Company," *Global Credit Research Credit Opinion* (Apr. 28, 2005).

Because of potential exposure to wholesale markets, the risks of transmission uncertainties and volatile energy markets are intensified for utilities that depend on purchased power, especially for those located in the West. Reliance on purchased power to meet resource needs or fill potential shortfalls in generation magnifies the importance of maintaining the financial flexibility necessary to fund an adequate and reliable utility system. At the same time, it also exposes utilities and their investors to the ongoing regulatory uncertainties and other risks imposed by restructuring of wholesale power markets. In the minds of investors, this dependence on wholesale markets entails significant risk, which exposes the Company to the risk of reduced cash flows and unrecovered power supply costs. These challenges posed by an increasingly complex marketplace heighten the uncertainties associated with APS' utility operations while requiring the commitment of significant new capital investment to maintain and enhance service capabilities.

Q. ARE THESE UNCERTAINTIES THE ONLY RISKS BEING FACED BY APS?

A. No. Apart from these factors, APS continues to face the normal risks inherent in operating electric utility systems, including the potential adverse effects of inflation, interest rate changes, growth, the general economy, and regulatory uncertainty and lag. As Fitch noted in a recent review of the utility industry:

> Taking a longer view, over the coming five years through 2009, the sector will increasingly face some potentially negative factors. These include rising interest rates, higher capital expenditures and volatile commodity prices.[35]

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[35] Fitch Ratings, Ltd., "Outlook 2005: U.S. Power & Gas," *Global Power North American Special Report* (Jan. 6, 2005) at 2.

Electric utilities are also confronting increased pension costs and environmental pressures that leave them exposed to uncertainties regarding emissions and potential contamination. S&P recognized the potential financial challenges posed by such factors:

> Pension obligations, environmental liabilities, and serious legal problems restrict flexibility, apart from the obligations' direct financial implications.[36]

Nuclear risk persists for those utilities involved in nuclear plants, although the exposure has shifted from construction to operating and decommissioning uncertainties. Electric utilities also remain exposed to economic vagaries within their service territories that cause service revenues and costs to fluctuate. Investors also understand that there is the potential for a significant lag between the time costs are incurred and when they are reflected in rates, and they recognize the ongoing possibility of future cost disallowances. Regulated utilities also continue to face other risks associated with operating a utility system, including the impact of adverse weather and extraordinary risks such as legal liabilities and natural disasters.

C. Economy and Capital Markets

Q. WHAT HAS BEEN THE PATTERN OF INTEREST RATES OVER THE LAST DECADE?

A. Average long-term public utility bond rates, the monthly average prime rate, and inflation as measured by the consumer price index since 1990 are plotted in the graph below. After rising to approximately 10% in mid-1990, the average yield on long-term public utility bonds generally fell as economic conditions weakened in

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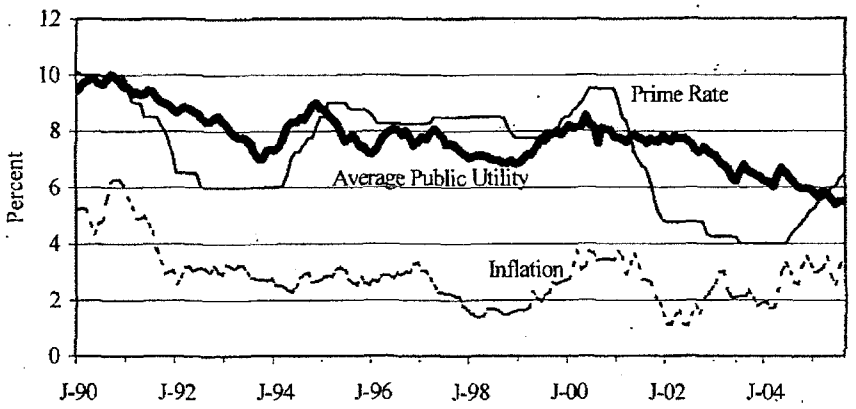
[36] Standard & Poor's Corporation, *Corporate Ratings Criteria* at 32, available at www.standardandpoors.com/ratings.

the aftermath of the 1991 Gulf war, with rates dipping below 7% in late 1993. Yields subsequently rose again in 1994, before beginning a general decline, with investors requiring approximately 5.5% from average public utility bonds in August 2005:



Q. ARE INVESTORS LIKELY TO ANTICIPATE ANY SUBSTANTIAL DECLINE IN INTEREST RATES GOING FORWARD?

A. No. Since early 2001, a great deal of attention has been focused on the actions of the Federal Reserve Board ("Fed") as it has moved successively to lower short-term interest rates in response to weakness in the United States economy. But while interest rates are currently at relatively low levels, investors are unlikely to expect any further significant declines going forward. Indeed, on December 13, 2005 the Fed raised interest rates for the thirteenth time since June 2004. The latest quarter-point increase raised the discount rate to 4.25%, or over four times the 46-year low of 1.00% in effect when the Fed began its credit-tightening campaign in 2004. As Value Line noted,[37] the general expectation is that interest rates will continue to rise with strengthening economic growth. The Wall Street Journal

[37] The Value Line Investment Survey, *Selection & Opinion* (Jun. 24, 2005) at 1659.

reported that, with growing inflationary concerns, investors are concerned that the Fed will adopt a more aggressive stance:

> [S]igns have emerged that inflation may be working itself into the economy. That would be bad news for stocks, notably because it likely would prompt the Federal Reserve to try to cool the economy by pushing interest rates higher, raising borrowing costs for businesses and consumers alike. ... Particularly worrisome to investors was the sight this week of the presidents of three regional Federal Reserve banks publicly warning the Fed is concerned about inflation. The Fed can't "let the inflation virus infect the blood supply and poison the system," said Dallas Fed President Richard Fisher yesterday. Investors took that to mean the Fed, which already has boosted short-term interest rates 11 times in the past 15 months, could continue to do so for some time.[38]

Consistent with the general expectations that these actions will also translate into higher long-term bond yields, the most recent forecast of GlobalInsight, a widely referenced forecasting service, calls for double-A public utility bond yields to reach 6.41% in 2006, averaging 6.99% over the next five years.[39] Meanwhile, the Energy Information Administration ("EIA"), a statistical agency of the DOE, anticipates that the double-A public utility bond yield will average 7.16% over the 2006-2010 period.[40] The September 1, 2005 edition of Blue Chip Financial Forecasts ("Blue Chip") also anticipates that bond yields will rise significantly over the coming year.[41]

Q. HOW HAS THE MARKET FOR COMMON EQUITY CAPITAL PERFORMED?

A. Between 1990 and early 2000 stock prices pushed steadily higher as the longest bull market in United States history continued unabated. While the S&P 500 had

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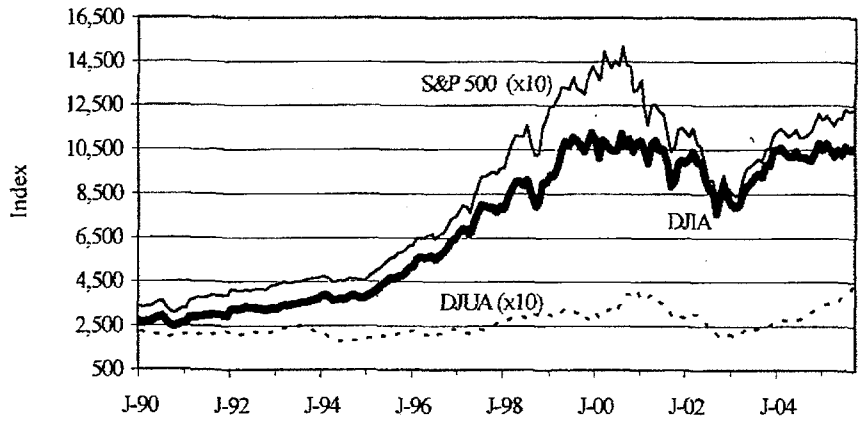
[38] Browning, E.S., "Inflation Worries Send Shivers Through Markets – Investors See Warning Signs Despite Falling Oil Prices; Watching Earnings Season," The Wall Street Journal (Oct. 7, 2005) at A1.

[39] GlobalInsight, "The U.S. Economy: The 25-Year Focus", Table 33 (First Quarter 2005).

[40] Energy Information Administration, "Annual Energy Outlook 2005", Table 19.

[41] *Blue Chip Financial Forecasts (Sep. 1, 2005) at 2.*

increased over four times in value by August 2000, mounting concerns regarding prospects for future growth, particularly for firms in the high technology sector, pushed equity prices lower, in some cases precipitously. While common stock prices have recovered strongly from their lows, the market remains volatile, with share values routinely changing in full percentage points during a single day's trading. The graph below plots the performances of the Dow-Jones Industrial Average, the S&P 500, and the Dow Jones Utility Average since 1990 (the latter two indices were scaled for comparability):



Q. WHAT IS THE OUTLOOK FOR THE UNITED STATES ECONOMY?

A. While the economic picture has brightened significantly since the downturn that began in 2001, growth in gross domestic product slowed to 3.2% in the second quarter of 2005. Uncertainties over the durability and pace of economic growth continue to be impacted by overhanging government and trade deficits and higher energy prices, which have been exacerbated by the fallout from the natural disasters experienced in the Gulf Coast region. Continued conflict and instability in Iraq and the ongoing threat of terrorism also undermine consumer confidence and contribute to global economic uncertainty. These

factors cause the outlook to remain tenuous, with persistent stock and bond price volatility providing tangible evidence of the uncertainties faced by the United States economy.

Q. HOW DO THESE ECONOMIC UNCERTAINTIES AFFECT ELECTRIC UTILITIES?

A. Uncertainties over the extent and durability of the economic recovery have combined to heighten the risks faced by utilities. Stagnant economic growth would undoubtedly mean flat sales, while the potential for higher inflation and interest rates would place additional pressure on the adequacy of existing service rates. Meanwhile, the aftermath of hurricanes Katrina and Rita, coupled with continued conflict and instability in the Middle East, intensifies concerns over prolonged volatility in oil and gas prices. While the economy may ultimately return to a path of steady growth and the volatility in the capital and energy markets may abate, the underlying weaknesses now present cause considerable uncertainties to persist, which increase the risks faced by the utility industry.

III. CAPITAL MARKET ESTIMATES

Q. WHAT IS THE PURPOSE OF THIS SECTION?

A. In this section, capital market estimates of the cost of equity are developed for a benchmark group of electric utilities. First, I examine the concept of the cost of equity, along with the risk-return tradeoff principle fundamental to capital markets. Next, I describe DCF and risk premium analyses conducted to estimate the cost of equity for the reference group of electric utilities.

A. Economic Standards

Q. WHAT ROLE DOES THE RATE OF RETURN ON COMMON EQUITY PLAY IN A UTILITY'S RATES?

A. The return on common equity is the cost of inducing and retaining investment in the utility's physical plant and assets. This investment is necessary to finance the asset base needed to provide utility service. Competition for investor funds is

intense and investors are free to invest their funds wherever they choose. They will commit money to a particular investment only if they expect it to produce a return commensurate with those from other investments with comparable risks. Moreover, the return on common equity is integral in achieving the sound regulatory objectives of rates that are sufficient to: 1) fairly compensate capital investment in the utility, 2) enable the utility to offer a return adequate to attract new capital on reasonable terms, and 3) maintain the utility's financial integrity. Meeting these objectives allows the utility to fulfill its obligation to provide reliable service while meeting the needs of customers through necessary system expansion.

Q. WHAT FUNDAMENTAL ECONOMIC PRINCIPLE UNDERLIES THIS COST OF EQUITY CONCEPT?

A. Unlike debt capital, there is no contractually guaranteed return on common equity capital since shareholders are the residual owners of the utility. Nonetheless, common equity investors still require a return on their investment, with the cost of equity being the minimum "rent" that must be paid for the use of their money. This cost of equity typically serves as the starting point for determining a fair rate of return on common equity.

The cost of equity concept is predicated on the notion that investors are risk averse, and will willingly bear additional risk only if they expect compensation for doing so. In capital markets where relatively risk-free assets are available (*e.g.*, U.S. Treasury securities) investors can be induced to hold more risky assets only if they are offered a premium, or additional return, above the rate of return on a risk-free asset. Since all assets compete with each other for investors' funds, more risky

assets must yield a higher expected rate of return than less risky assets in order for investors to be willing to hold them.

Given this risk-return tradeoff, the required rate of return (k) from an asset (i) can be generally expressed as:

$$k_i = R_f + RP_i$$

where: R_f = Risk-free rate of return; and

RP_i = Risk premium required to hold risky asset i.

Thus, the required rate of return for a particular asset at any point in time is a function of: 1) the yield on risk-free assets, and 2) its relative risk, with investors demanding correspondingly larger risk premiums for assets bearing greater risk.

Q. DOES THE RISK-RETURN TRADEOFF PRINCIPLE ACTUALLY OPERATE IN THE CAPITAL MARKETS?

A. Yes. The risk-return tradeoff is readily observable in certain segments of the capital markets where required rates of return can be directly inferred from market data and generally accepted measures of risk exist. Bond yields, for example, reflect investors' expected rates of return, and bond ratings measure the risk of individual bond issues. The observed yields on federal government securities, which are considered free of default risk, and bonds of various rating categories demonstrate that the risk-return tradeoff does, in fact, exist in the capital markets.

Q. DOES THE RISK-RETURN TRADEOFF OBSERVED WITH FIXED INCOME SECURITIES EXTEND TO COMMON STOCKS AND OTHER ASSETS?

A. It is generally accepted that the risk-return tradeoff evidenced with long-term debt extends to all assets. However, documenting the risk-return tradeoff for assets

other than fixed income securities is complicated by two factors. First, there is no standard measure of risk applicable to all assets. Second, for most assets – including common stock – required rates of return cannot be directly observed. Nevertheless, it is a fundamental tenet that investors exhibit risk aversion in deciding whether or not to hold common stocks and other assets, just as when choosing among fixed income securities. This has been supported and demonstrated by considerable empirical research in the field of finance and is confirmed by reference to historical earned rates of return, with realized rates of return on common stocks exceeding those on government and corporate bonds over the long-term.

Q. IS THIS RISK-RETURN TRADEOFF LIMITED TO DIFFERENCES BETWEEN FIRMS?

A. No. The risk-return tradeoff principle applies not only to investments in different firms, but also to different securities issued by the same firm. Debt, preferred stock, and common equity vary considerably in risk because they have different characteristics and priorities.

When investors loan money in the form of debt (*e.g.*, long-term bonds), they enter into a contract whereby the utility agrees to pay the bondholders a specified amount of interest and to repay the principal of the loan in full. The bondholders have a senior claim on available cash flow for these payments, and if the utility fails to make them, they may force it into bankruptcy and liquidation for settlement of unpaid claims. Similarly, when a utility sells investors preferred stock, the utility promises to pay preferred stockholders specified dividends and, typically, to retire the preferred stock on a predetermined schedule. While the rights of preferred stockholders to available cash flow for these payments are junior to

creditors, and preferred stockholders cannot compel bankruptcy, their claims are senior to those of common shareholders.

The last investors in line are common shareholders. They receive only the cash flow, if any, that remains after all other claimants – employees, suppliers, governments, lenders, and preferred stockholders – have been paid. As a result, the rate of return that investors require from a utility's common stock, the most junior and riskiest of its securities, is considerably higher than the yield on the utility's long-term debt or preferred stock, which have more certain, senior claims.

Q. WHAT DOES THE ABOVE DISCUSSION IMPLY WITH RESPECT TO ESTIMATING THE COST OF EQUITY?

A. Although the cost of equity cannot be observed directly, it is a function of the returns available from other investment alternatives and the risks to which the equity capital is exposed. Because it is unobservable, the cost of equity for a particular utility must be estimated by analyzing information about capital market conditions generally, assessing the relative risks of the company specifically, and employing various quantitative methods that focus on investors' required rates of return. These various quantitative methods typically attempt to infer investors' required rates of return from stock prices, interest rates, and other capital market data.

Q. DID YOU RELY ON A SINGLE METHOD TO ESTIMATE THE COST OF EQUITY FOR APS?

A. No. In my opinion, no single method or model should be relied upon to determine a utility's cost of equity because no single approach can be regarded as wholly reliable. As the Federal Communications Commission recognized:

> Equity prices are established in highly volatile and uncertain capital markets... Different forecasting methodologies compete with each

> other for eminence, only to be superceded by other methodologies as conditions change... In these circumstances, we should not restrict ourselves to one methodology, or even a series of methodologies, that would be applied mechanically. Instead, we conclude that we should adopt a more accommodating and flexible position.[42]

Therefore, I used both the DCF model and risk premium methods to estimate the cost of equity. In addition, I also evaluated a fair rate of return using a comparable earnings approach based on investors' current expectations in the capital markets. In my opinion, comparing estimates produced by one method with those produced by other approaches ensures that estimates of the cost of equity pass fundamental tests of reasonableness and economic logic.

B. Discounted Cash Flow Analyses

Q. HOW ARE DCF MODELS USED TO ESTIMATE THE COST OF EQUITY?

A. The use of DCF models is essentially an attempt to replicate the market valuation process that sets the price investors are willing to pay for a share of a company's stock. The model rests on the assumption that investors evaluate the risks and expected rates of return from all securities in the capital markets. Given these expected rates of return, the price of each stock is adjusted by the market until investors are adequately compensated for the risks they bear. Therefore, we can look to the market to determine what investors believe a share of common stock is worth. By estimating the cash flows investors expect to receive from the stock in the way of future dividends and capital gains, we can calculate their required rate of return. In other words, the cash flows that investors expect from a stock are estimated, and given its current market price, we can "back-into" the discount rate,

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[42] Federal Communications Commission, Report and Order 42-43, CC Docket No. 92-133 (1995).

or cost of equity, that investors presumptively used in bidding the stock to that price.

Q. WHAT MARKET VALUATION PROCESS UNDERLIES DCF MODELS?

A. DCF models are derived from a theory of valuation which assumes that the price of a share of common stock is equal to the present value of the expected cash flows (i.e., future dividends and stock price) that will be received while holding the stock, discounted at investors' required rate of return, or the cost of equity. Notationally, the general form of the DCF model is as follows:

$$P_0 = \frac{D_1}{(1+k_e)^1} + \frac{D_2}{(1+k_e)^2} + \cdots + \frac{D_t}{(1+k_e)^t} + \frac{P_t}{(1+k_e)^t}$$

where: P_0 = Current price per share;

P_t = Expected future price per share in period t;

D_t = Expected dividend per share in period t;

k_e = Cost of equity.

That is, the cost of equity is the discount rate that will equate the current price of a share of stock with the present value of all expected cash flows from the stock.

Q. HAS THIS GENERAL FORM OF THE DCF MODEL CUSTOMARILY BEEN USED TO ESTIMATE THE COST OF EQUITY IN RATE CASES?

A. No. In an effort to reduce the number of required estimates and computational difficulties, the general form of the DCF model has been simplified to a "constant growth" form. But converting the general form of the DCF model to the constant growth DCF model requires a number of strict assumptions. These include:

- A constant growth rate for both dividends and earnings;
- A stable dividend payout ratio;

- A discount rate exceeding the growth rate;
- A constant growth rate for book value and price;
- A constant earned rate of return on book value;
- No sales of stock at a price above or below book value;
- A constant price-earnings ratio;
- A constant discount rate (i.e., no changes in risk or interest rate levels and a flat yield curve); and
- All of the above extend to infinity.

Given these assumptions, the general form of the DCF model can be reduced to the more manageable formula of:

$$P_0 = \frac{D_1}{k_e - g}$$

where: g = Investors' long-term growth expectations.

The cost of equity (k_e) can be isolated by rearranging terms:

$$k_e = \frac{D_1}{P_0} + g$$

This constant growth form of the DCF model recognizes that the rate of return to stockholders consists of two parts: 1) dividend yield (D_1/P_0), and 2) growth (g). In other words, investors expect to receive a portion of their total return in the form of current dividends and the remainder through price appreciation.

Q. ARE THE ASSUMPTIONS UNDERLYING THE CONSTANT GROWTH FORM OF THE DCF MODEL MET IN THE REAL WORLD?

A. In practice, none of the assumptions required to convert the general form of the DCF model to the constant growth form are ever strictly met. Nevertheless, where earnings are derived from stable activities, and earnings, dividends, and book value

track fairly closely, the constant growth form of the DCF model offers a reasonable working approximation of stock valuation that provides useful insight as to investors' required rate of return.

Q. HOW DID YOU IMPLEMENT THE DCF MODEL TO ESTIMATE THE COST OF EQUITY FOR APS?

A. In estimating the cost of equity, the DCF model is typically applied to publicly traded firms engaged in similar business activities. In order to reflect the risks and prospects associated with APS' jurisdictional utility operations, my DCF analyses focused on a reference group of other electric utilities composed of those companies included by Value Line in their Electric Utilities (West) Industry group. Excluded from my analyses were five firms that either do not pay common dividends or were rated below investment grade by S&P.

The consolidated corporate credit ratings published by S&P for the individual firms in the electric utility proxy group ranged from "BBB-" to "A-", with the average being "BBB". As noted earlier, following S&P's December 2005 downgrade, APS is currently assigned a rating of "BBB-", which corresponds to the very bottom end of the proxy group range and represents the lowest investment grade rating. Given that these ten utilities are all engaged in utility operations in the Western region of the U.S., investors are likely to regard this group as facing similar market conditions and having comparable risks and prospects. The Supreme Court recognized the relevance of geographical location in *Bluefield,* noting that utilities are entitled to earn a return equal to those being made by firms of comparable risk "in the same general part of the country."[43] Indeed, there are important factors

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[43] *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n,* 262 U.S. 679, 692 (1923).

distinguishing Western utilities from those located in other regions, such as the ongoing uncertainties associated with Western energy markets, that are important considerations in evaluating investors' required rate of return for APS.

Q. WHY DID YOU EXCLUDE FIRMS THAT DO NOT PAY COMMON DIVIDENDS OR HAVE BELOW INVESTMENT GRADE BOND RATINGS FROM YOUR BENCHMARK GROUP?

A. As discussed earlier, under the DCF approach, observable stock prices are a function of the cash flows that investors expect to receive, discounted at their required rate of return. Because dividend payments are a key parameter required to apply the DCF method, this hinders application of the DCF model to firms that do not pay common dividends. Meanwhile, the financial stress and lack of stability that accompanies below investment grade bond ratings violates the comparable-risk standard and greatly complicates any determination of investors' long-term expectations that form the basis for DCF applications.

Q. WHAT OTHER CONSIDERATIONS SUPPORT THE USE OF A PROXY GROUP IN ESTIMATING THE COST OF EQUITY FOR APS?

A. Apart from recognizing the inherent risks and prospects for comparable risk utilities, reference to a proxy group of utilities is essential to insulate against vagaries that can result when the stochastic process involved in estimating the cost of equity is applied to a single company. The cost of equity is inherently unobservable and can only be inferred indirectly by reference to available capital market data. To the extent that the data used to apply the DCF model does not capture the expectations that investors have incorporated into current stock prices, the resulting cost of equity estimates will be biased and fail to reflect investors' required rate of return.

As the FERC noted in its July 3, 2003 *Order on Initial Decision* in Docket No. RP00-107-000, even using a limited group of companies does not remove the potential for error:

> Both Staff and Williston agreed that a proxy group of only three companies presented problems because "a single company will have a magnified influence on the group results." It was with those changing market dynamics in mind that witnesses of both Staff and Williston proposed to expand the group of proxy companies to determine a zone of reasonableness.

The 10-company proxy group composed of utilities operating in the Western U.S. is consistent not only with shared investment risks, but also with the need to ensure against the potential that a single cost of equity estimate may not reflect investors' required rate of return.

Q. HOW IS THE CONSTANT GROWTH FORM OF THE DCF MODEL TYPICALLY USED TO ESTIMATE THE COST OF EQUITY?

A. The first step in implementing the constant growth DCF model is to determine the expected dividend yield (D_1/P_0) for the firm in question. This is usually calculated based on an estimate of dividends to be paid in the coming year divided by the current price of the stock. The second, and more controversial, step is to estimate investors' long-term growth expectations (g) for the firm. Since book value, dividends, earnings, and price are all assumed to move in lock-step in the constant growth DCF model, estimates of expected growth are sometimes derived from historical rates of growth in these variables under the presumption that investors expect these rates of growth to continue into the future. Alternatively, a firm's internal growth can be estimated based on the product of its earnings retention ratio and earned rate of return on equity. This growth estimate may rely on either historical or projected data, or both. A third approach is to rely on security analysts' projections of growth as proxies for investors' expectations. The final step

is to sum the firm's dividend yield and estimated growth rate to arrive at an estimate of its cost of equity.

Q. HOW WAS THE DIVIDEND YIELD FOR THE PROXY GROUP OF ELECTRIC UTILITIES DETERMINED?

A. Estimates of dividends to be paid by each of these electric utilities over the next twelve months, obtained from Value Line, served as D_1. This annual dividend was then divided by the corresponding stock price for each utility to arrive at the expected dividend yield. The expected dividends, stock prices, and resulting dividend yields for the firms in the electric utility proxy group are presented on Attachment WEA-1. As shown there, dividend yields for the ten firms in the electric utility proxy group ranged from 2.2% to 4.6%, with the average being 3.5%.

Q. WHAT ARE INVESTORS MOST LIKELY TO CONSIDER IN DEVELOPING THEIR LONG-TERM GROWTH EXPECTATIONS?

A. In constant growth DCF theory, earnings, dividends, book value, and market price are all assumed to grow in lockstep, and the growth horizon of the DCF model is infinite. But implementation of the DCF model is more than just a theoretical exercise; it is an attempt to replicate the mechanism investors used to arrive at observable stock prices. Thus, the only "g" that matters in applying the DCF model is that which investors expect and have embodied in current market prices.

Q. ARE HISTORICAL DIVIDEND GROWTH RATES LIKELY TO PROVIDE A MEANINGFUL GUIDE TO INVESTORS' GROWTH EXPECTATIONS FOR ELECTRIC UTILITIES?

A. No. In response to more accentuated business risks in the industry, electric utilities adopted dividend policies that were much more conservative than in the past. As a result, dividend growth in the electric utility industry has remained largely stagnant

in recent years as utilities conserved financial resources to provide a hedge against heightened uncertainties. Responding to this trend, investors' focus increasingly shifted from dividends to earnings as a measure of long-term growth, as payout ratios for firms in the electric utility industry trended downward from approximately 80% historically to on the order of 60%.[44]

Q. WHAT ARE INVESTORS LIKELY EXPECTING IN THE WAY OF GROWTH FOR THE ELECTRIC UTILITY PROXY GROUP?

A. As the industry recovers from the financial challenges of the last several years, some electric utilities have begun to reevaluate their dividend policies and reinstate increases to their quarterly payout. While investors have recently expressed renewed interest in dividend payments, Value Line's most recent forecast indicates negative projected dividend growth for one of the proxy firms, while one is listed as "Nil" and another as "NMF".[45] Negative or zero growth rates imply a cost of equity equal to, or below, the utility's dividend yield. Such nonsensical results provide little guidance as to investors' expectations for the electric utility proxy group.

Q. WHAT OTHER TRENDS DO INVESTORS CONSIDER IN DEVELOPING GROWTH EXPECTATIONS?

A. Trends in earnings, which ultimately support future dividends and share prices, are likely to play a pivotal role in determining investors' long-term growth expectations. Indeed, the importance of earnings in evaluating investors' expectations and requirements is well accepted in the investment community. As

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[44] See, *e.g.*, The Value Line Investment Survey (Sep. 15, 1995 at 161, Aug. 12, 2005 at 1776).

[45] The Value Line Investment Survey (Aug. 12, 2005).

noted in *Finding Reality in Reported Earnings* published by the Association for Investment Management and Research:

> [E]arnings, presumably, are the basis for the investment benefits that we all seek. "Healthy earnings equal healthy investment benefits" seems a logical equation, but earnings are also a scorecard by which we compare companies, a filter through which we assess management, and a crystal ball in which we try to foretell future performance.[46]

Value Line's near-term projections and its Timeliness Rank, which is the principal investment rating assigned to each individual stock, are also based primarily on various quantitative analyses of earnings. As Value Line explained:

> The future earnings rank accounts for 65% in the determination of relative price change in the future; the other two variables (current earnings rank and current price rank) explain 35%.[47]

The fact that investment advisory services, such as Value Line and I/B/E/S International, Inc. ("IBES"), focus on growth in earnings indicates that the investment community regards this as a superior indicator of future long-term growth. Indeed, "A Study of Financial Analysts: Practice and Theory," published in the *Financial Analysts Journal*, reported the results of a survey conducted to determine what analytical techniques investment analysts actually use.[48] Respondents were asked to rank the relative importance of earnings, dividends, cash flow, and book value in analyzing securities. Of the 297 analysts that responded, only 3 ranked dividends first while 276 ranked it last. The article concluded:

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[46] Association for Investment Management and Research, "Finding Reality in Reported Earnings: An Overview", p. 1 (Dec. 4, 1996).

[47] The Value Line Investment Survey, *Subscriber's Guide*, p. 53.

[48] Block, Stanley B., "A Study of Financial Analysts: Practice and Theory", *Financial Analysts Journal* (July/August 1999).

> Earnings and cash flow are considered far more important than book value and dividends.[49]

Q. WHAT ARE SECURITY ANALYSTS CURRENTLY PROJECTING IN THE WAY OF EARNINGS GROWTH FOR THE FIRMS IN THE ELECTRIC UTILITY PROXY GROUP?

A. The earnings growth projections for each of the firms in the electric utility proxy group reported by IBES and published in S&P's *Earnings Guide* are displayed on Attachment WEA-2. Also presented are the earnings per share ("EPS") growth projections reported by Value Line, First Call Corporation ("First Call"), Zacks Investment Research ("Zacks"), and Reuters, Inc. ("Reuters"). As shown there, these security analysts' projections suggested growth on the order of 5.4% to 5.7% for the reference group of electric utilities:

Electric Utility Proxy Group

Service	Growth Rate
IBES	5.4%
Value Line	5.5%
First Call	5.5%
Zacks	5.7%
Reuters	5.7%

Q. WHAT CONSIDERATIONS ARE RELEVANT IN EVALUATING THESE NEAR-TERM GROWTH RATES FOR ELECTRIC UTILITIES?

A. Short-term projected growth rates may be colored by lingering uncertainties regarding the near-term direction of the economy in general and the spate of

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[49] *Id.* at 88.

challenges recently faced in the electric power industry specifically. This short-term "hangover" is exemplified by Value Line, which has assigned its Utilities sector the lowest ranking of all 10 sectors it covers for year-ahead stock price performance,[50] while noting that "[t]he electric utility industry carries a below-average industry Timeliness rank."[51] While this cautious outlook may be indicative of relatively low near-term growth projections, it does not necessarily reflect investors' long-term expectations for the industry.

Q. HOW ELSE ARE INVESTORS' EXPECTATIONS OF FUTURE LONG-TERM GROWTH PROSPECTS OFTEN ESTIMATED FOR USE IN THE CONSTANT GROWTH DCF MODEL?

A. Based on the assumptions underlying constant growth theory, conventional applications of the constant growth DCF model often examine the relationships between retained earnings and earned rates of return as an indication of the sustainable growth investors might expect from the reinvestment of earnings within a firm. The sustainable growth rate is calculated by the formula, $g = br+sv$, where "b" is the expected retention ratio, "r" is the expected earned return on equity, "s" is the percent of common equity expected to be issued annually as new common stock, and "v" is the equity accretion rate.

Q. WHAT IS THE PURPOSE OF THE "SV" TERM?

A. Under DCF theory, the "sv" factor is a component of the growth rate designed to capture the impact of issuing new common stock at a price above, or below, book value. When a company's stock price is greater than its book value per share, the per-share contribution in excess of book value associated with new stock issues

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[50] The Value Line Investment Survey, *Selection & Opinion* (Jul. 29, 2005) at 1606.

[51] The Value Line Investment Survey (July 1, 2005) at 695.

will accrue to the current shareholders. This increase to the book value of existing shareholders leads to higher expected earnings and dividends, with the "sv" factor incorporating this additional growth component.

Q. WHAT GROWTH RATE DOES THE EARNINGS RETENTION METHOD SUGGEST FOR THE PROXY GROUP OF ELECTRIC UTILITIES?

A. The sustainable, "br+sv" growth rates for each firm in the proxy group are shown on Attachment WEA-3. For each firm, the expected retention ratio (b) was calculated based on Value Line's projected dividends and earnings per share. Likewise, each firm's expected earned rate of return (r) was computed by dividing projected earnings per share by projected average net book value. Because Value Line reports end-of-year book values, an adjustment was incorporated to compute an average rate of return over the year, consistent with the theory underlying this approach to estimating investors' growth expectations. Meanwhile, the percent of common equity expected to be issued annually as new common stock (s) was equal to the product of the projected market-to-book ratio and growth in common shares outstanding, while the equity accretion rate (v) was computed as 1 minus the inverse of the projected market-to-book ratio. As shown there, incorporating this method resulted in an average expected growth rate for the group of electric utilities of 4.6%.

Q. WHAT DID YOU CONCLUDE WITH RESPECT TO THE GROWTH EXPECTATIONS IMPLIED FOR THE PROXY GROUP OF WESTERN UTILITIES?

A. I concluded that the measures discussed above indicated growth on the order of 5.5% for the average firm in the utility proxy group.

Q. WHAT COST OF EQUITY WAS IMPLIED FOR THE PROXY GROUP OF UTILITIES USING THE DCF MODEL?

A. Combining the 3.5% average dividend yield with a growth rate of 5.5% implied a DCF cost of equity of 9.0%.

Q. DO YOU BELIEVE THIS CONSTANT GROWTH DCF ESTIMATE REPRESENTS A REASONABLE COST OF EQUITY FOR APS OR THE PROXY GROUP OF ELECTRIC UTILITIES?

A. No. As I noted earlier, because the cost of equity is unobservable, no single method should be viewed in isolation. While the DCF model has been routinely relied on in regulatory proceedings as one guide to investors' required return, it is a blunt tool that should never be used exclusively, and regulators have customarily considered the results of alternative approaches in determining allowed returns. The need to consider alternative methods is especially important where the results of one approach deviate significantly from cost of equity estimates produced by other applications. Indeed, as discussed subsequently, the results of alternative risk premium methods and the comparable earnings approach suggest a cost of equity far in excess of this single DCF value.

Moreover, as noted earlier, the short-term projected growth rates typically used to apply the DCF model may be colored by lingering economic and industry uncertainties, as exemplified by Value Line's relatively pessimistic rankings for the utility sector. As a result of this cautious near-term outlook, DCF growth rates do not necessarily capture investors' long-term expectations for the industry, and the resulting cost of equity estimates will be downward-biased. Accordingly, it would be unreasonable to establish an ROE based on this single DCF approach.

C. Risk Premium Analyses

Q. WHAT OTHER ANALYSES DID YOU CONDUCT TO ESTIMATE THE COST OF EQUITY?

A. As I mentioned previously, because the cost of equity is inherently unobservable, no single method should be considered a reliable guide to investors' required rate of return. Accordingly, I also evaluated the cost of equity for APS using the risk premium method. My applications of the risk premium method provide alternative approaches to measure equity risk premiums that focus specifically on data for electric utilities and employ alternative estimates of investors' required rates of return.

Q. BRIEFLY DESCRIBE THE RISK PREMIUM METHOD.

A. The risk premium method of estimating investors' required rate of return extends the risk-return tradeoff observed with bonds to common stocks. The cost of equity is estimated by first determining the additional return investors require to forego the relative safety of bonds and to bear the greater risks associated with common stock, and then adding this equity risk premium to the current yield on bonds. Like the DCF model, the risk premium method is capital market oriented. However, unlike DCF models, which indirectly impute the cost of equity, the risk premium method directly estimates investors' required rate of return by adding an equity risk premium to observable bond yields.

Q. HOW DID YOU IMPLEMENT THE RISK PREMIUM METHOD?

A. I based my estimates of equity risk premiums for electric utilities on (1) surveys of previously authorized rates of return on common equity, (2) realized rates of return, and (3) alternative applications of the Capital Asset Pricing Model ("CAPM").

Authorized returns presumably reflect regulatory commissions' best estimates of the cost of equity, however determined, at the time they issued their final order. Such returns should represent a balanced and impartial outcome that considers the need to maintain a utility's financial integrity and ability to attract capital. Moreover, allowed returns are an important consideration for investors and have the potential to influence other observable investment parameters, including credit ratings and borrowing costs. Thus, this data provides a logical and frequently referenced basis for estimating equity risk premiums.

Under the realized-rate-of-return approach, equity risk premiums are calculated by measuring the rate of return (including dividends, interest, and capital gains and losses) actually realized on an investment in common stocks and bonds over historical periods. The realized rate of return on bonds is then subtracted from the return earned on common stocks to measure equity risk premiums.

The CAPM approach measures the market-expected return for a security as the sum of a risk-free rate and a risk premium based on the portion of a security's risk that cannot be eliminated by holding a well-diversified portfolio. Under the CAPM, risk is represented by the beta coefficient (β), which measures the volatility of a security's price relative to the market as a whole. While controversy surrounds the use of beta to measure an individual utility's investment risk, the CAPM is routinely referenced in the financial literature and in regulatory proceedings.

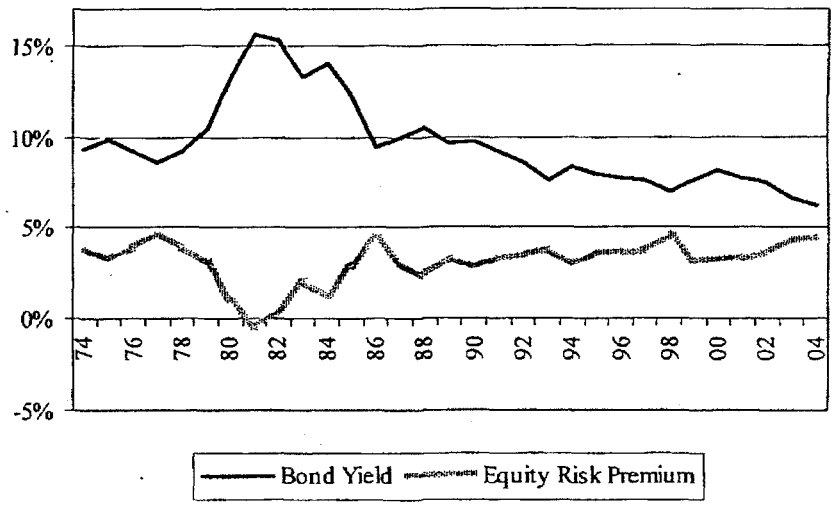
While these methods are premised on different assumptions, each having their own strengths and weaknesses, they are widely accepted approaches that have been routinely referenced in estimating the cost of equity for regulated utilities.

Q. HOW DID YOU IMPLEMENT THE RISK PREMIUM APPROACH USING SURVEYS OF ALLOWED RATES OF RETURN?

A. Surveys of previously authorized rates of return on common equity are frequently referenced as the basis for estimating equity risk premiums. The rates of return on common equity authorized utilities by regulatory commissions across the U.S. are compiled by Regulatory Research Associates ("RRA") and published in its Regulatory Focus report. In Attachment WEA-4, the average yield on public utility bonds is subtracted from the average allowed rate of return on common equity for electric utilities to calculate equity risk premiums for each year between 1974 and 2004. Over this 31-year period, these equity risk premiums for electric utilities averaged 3.17%, and the yield on public utility bonds averaged 9.59%.

Q. IS THERE ANY RISK PREMIUM BEHAVIOR THAT NEEDS TO BE CONSIDERED WHEN IMPLEMENTING THE RISK PREMIUM METHOD?

A. Yes. There is considerable evidence that the magnitude of equity risk premiums is not constant and that equity risk premiums tend to move inversely with interest rates. In other words, when interest rate levels are relatively high, equity risk premiums narrow, and when interest rates are relatively low, equity risk premiums widen. To illustrate, the graph below plots the yields on public utility bonds (solid line) and equity risk premiums (shaded line) shown on Attachment WEA-4:



The graph clearly illustrates that the higher the level of interest rates, the lower the equity risk premium, and vice versa. The implication of this inverse relationship is that the cost of equity does not move as much as, or in lockstep with, interest rates. Accordingly, for a 1% increase or decrease in interest rates, the cost of equity may only rise or fall, say, 50 basis points. Therefore, when implementing the risk premium method, adjustments may be required to incorporate this inverse relationship if current interest rate levels have changed since the equity risk premiums were estimated. Finally, it is important to recognize that the historical focus of the risk premium studies almost certainly ensures that they fail to fully capture the significantly greater risks that investors now associate with providing electric utility service. As a result, they are likely to understate the cost of equity for a firm operating in today's electric power industry.

Q. WHAT COST OF EQUITY IS IMPLIED BY SURVEYS OF ALLOWED RATES OF RETURN ON EQUITY?

A. As illustrated above, the inverse relationship between interest rates and equity risk premiums is evident. Based on the regression output between the interest rates and

equity risk premiums displayed at the bottom of page 1 of Attachment WEA-4, the equity risk premium for electric utilities increased approximately 43 basis points for each percentage point drop in the yield on average public utility bonds.[52] As illustrated there, with the average yield on public utility bonds in August 2005 being 5.51%, this implied a current equity risk premium of 4.93% for electric utilities. Adding this equity risk premium to the August 2005 average yield on triple-B public utility bonds of 5.80% produces a current cost of equity for the utilities in the benchmark group of approximately 10.7%.

Q. WHAT ELSE SHOULD BE CONSIDERED IN APPLYING RISK PREMIUM METHODS?

A. As discussed earlier, there is widespread consensus that interest rates will increase as the economy continues to strengthen, with the Fed's recent actions indicative of tighter credit conditions and higher interest rates in the years ahead. As a result, current bond yields are likely to understate capital market requirements at the time the outcome of this proceeding becomes effective. Accordingly, in addition to the use of current bond yields, I also applied the alternative risk premium methods using forecasted bond yields for 2006, based on an average of the projections published by GlobalInsight, EIA, and Blue Chip.[53]

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[52] The average public utility bond yield reflects the average of the yields for bonds rated "Aa", "A", and "Baa" by Moody's.

[53] An analogous approach using forecasted interest rates was adopted by the staff of the Florida Public Service Commission ("FPSC") in a May 20, 2004 *Memorandum* in Docket No. 040006-WS and in the testimony of FPSC staff witness Andrew L. Maurey in Docket No. 000824-EI (Jan. 2002).

Q. WHAT COST OF EQUITY WAS PRODUCED BY THE AUTHORIZED RATE OF RETURN APPROACH AFTER INCORPORATING THE AVERAGE BOND YIELD FORECAST?

A. As shown on page 2 of Attachment WEA-4, incorporating a forecasted yield for 2006 and adjusting for changes in interest rates since the study period implied an equity risk premium of 4.37% for electric utilities. Adding this equity risk premium to the implied yield on triple-B public utility bonds for 2006 of 7.0% resulted in an implied cost of equity of approximately 11.4%.

Q. HOW DID YOU APPLY THE REALIZED-RATE-OF-RETURN APPROACH?

A. Widely used in academia, the realized-rate-of-return approach is based on the assumption that, given a sufficiently large number of observations over long historical periods, average realized market rates of return will converge to investors' required rates of return. From a more practical perspective, investors may base their expectations for the future on, or may have come to expect that they will earn, rates of return corresponding to those realized in the past. Indeed, average realized rates of return for historical periods are widely reported to investors in the financial press and by investment advisory services as a guide to future performance. By focusing on data for utilities specifically, my realized rate of return approach avoided the need to make assumptions regarding relative risk (*e.g.*, beta) that are often embodied in applications of this method.

Stock price and dividend data for the electric utilities included in the S&P 500 Composite Index ("S&P 500") are available for the period 1946 through 2004. As shown in Attachment WEA-5, over this 58-year period realized rates of return for these utilities have exceeded those on average public utility bonds by an average of 4.04%. In contrast to other risk premium approaches, the realized-rate-of-return

method assumes that equity risk premiums are stationary over time; therefore, no adjustment for the inverse relationship between equity risk premiums and interest rates was made. Adding this 4.04% equity risk premium to the August 2005 yield of 5.80% on triple-B public utility bonds produces a current cost of equity for the electric utility proxy group of approximately 9.8%.

Once again, however, this does not consider the anticipated increase in bond yields through 2006. Adding this 4.04% equity risk premium to the 7.0% forecasted yield on triple-B public utility bonds for 2006 implies a cost of equity of approximately 11.0%.

Q. PLEASE DESCRIBE YOUR APPLICATION OF THE CAPM.

A. The CAPM is a theory of market equilibrium that measures risk using the beta coefficient. Under the CAPM, investors are assumed to be fully diversified, so the relevant risk of an individual asset (*e.g.*, common stock) is its volatility relative to the market as a whole. Beta reflects the tendency of a stock's price to follow changes in the market. A stock that tends to respond relatively less to market movements has a beta less than 1.00, while stocks that tend to move more than the market have betas greater than 1.00. The CAPM is mathematically expressed as:

$$R_j = R_f + \beta_j(R_m - R_f)$$

Where: R_j = required rate of return for stock j;

R_f = risk-free rate;

R_m = expected return on the market portfolio; and,

β_j = beta, or systematic risk, for stock j.

I applied the CAPM to the seventeen companies in the electric utility proxy group using market risk premiums (R_m - R_f) based on (1) forward-looking estimates of investors' required rates of return and (2) historical realized rates of return.

Q. PLEASE DESCRIBE YOUR FORWARD-LOOKING APPLICATION OF THE CAPM.

A. Application of the CAPM to the utilities in the proxy group based on a forward-looking estimate for investors' required rate of return from common stocks is presented on Attachment WEA-6. Rather than using historical data, the expected market rate of return was estimated by conducting a DCF analysis on the 356 dividend paying firms in the S&P 500, with each firm's dividend yield and growth rate being weighted by its proportionate share of total market value.[54]

The dividend yield for each firm was obtained from Value Line, with the growth rate being equal to the average of the earnings growth projections for each firm published by IBES and Value Line. Based on the weighted average of the projections for the 356 individual firms, current estimates imply an average growth rate over the next five years of 11.4%. Combining this average growth rate with a dividend yield of 2.1% results in a current cost of equity estimate for the market as a whole of approximately 13.5%. Subtracting a 4.5% risk-free rate based on the September 2005 average yield on 20-year Treasury bonds from the 13.5% forward-looking rate of return produced a market equity risk premium of 9.0%. Multiplying this risk premium by the average Value Line beta of 0.89 for the utilities in the proxy group, and then adding the resulting 8.0% risk premium to the

[54] This is analogous to the approach relied on by the Illinois Commerce Commission Staff in Docket No. 96-0486 (*Testimony of Joy Nicdao-Cuyygan*).

September 2005 average long-term Treasury bond yield, resulted in a current cost of equity of approximately 12.5%.

Q. WHAT COST OF EQUITY IS IMPLIED BY THIS FORWARD-LOOKING APPLICATION OF THE CAPM AFTER INCORPORATING PROJECTED GOVERNMENT BOND YIELDS FOR 2006?

A. As shown on page 2 of Attachment WEA-6, interest rate projections published by GlobalInsight, EIA, and Blue Chip imply a projected yield on 20-year Treasury bonds of 5.5% for 2006, which results in a market risk premium of 8.0%. Once again multiplying the market risk premium by the average Value Line beta of 0.89 for the electric utilities in the proxy group, and then adding the resulting 7.1% risk premium to the 5.5% long-term Treasury bond yield for 2006, implied a cost of equity of approximately 12.6%.

Q. WHAT OTHER CAPM ANALYSES DID YOU CONDUCT TO ESTIMATE THE COST OF EQUITY?

A. I also applied the CAPM using risk premiums based on historical realized rates of return. This approach to estimating investors' equity risk premiums is premised on the assumption that, given a sufficiently large number of observations over long, historical periods, average realized market rates of return will converge to investors' required rates of return.

Q. WHAT CAPM COST OF EQUITY IS PRODUCED BASED ON HISTORICAL REALIZED RATES OF RETURN FOR STOCKS AND LONG-TERM GOVERNMENT BONDS?

A. I applied the CAPM using data published by Ibbotson Associates, which is perhaps the most exhaustive and widely referenced annual study of realized rates of return. Application of the CAPM based on historical realized rates of return is presented in Attachment WEA-7. In their *2005 Yearbook, Valuation Edition*, Ibbotson Associates reported that, over the period from 1926 through 2004, the arithmetic

mean realized rate of return on the S&P 500 exceeded that on long-term government bonds by 7.2%.[55] Multiplying this historical market risk premium by the average Value Line beta of 0.89 produced an equity risk premium of 6.4% for the electric utility proxy group. As shown on page 1 of Attachment WEA-7, adding this equity risk premium to the September 2005 average yield on 20-year Treasury bonds of 4.5% resulted in an implied cost of equity of 10.9%. As shown on page 2 of Attachment WEA-7, after incorporating a the 5.5% projected government bond yield for 2006, application of the CAPM based on historical realized rates of return implied a cost of equity of 11.9%.

Q. WHAT ELSE SHOULD BE CONSIDERED IN APPLYING THE CAPM USING HISTORICAL REALIZED RATES OF RETURN?

A. The CAPM model, like the DCF approach, is an *ex-ante*, or forward-looking model based on expectations of the future. As a result, in order to accurately estimate required returns the CAPM must be applied using data that reflects the expectations of actual investors. While reference to historical data represents one way to apply the CAPM, these realized rates of return reflect, at best, an indirect estimate of investors' current requirements. As a result, applications of the CAPM that look directly at investors' expectations in the capital markets are apt to provide a more meaningful guide to investors' required rate of return. Accordingly, because the historical approach does not incorporate forward-looking estimates, it was given less weight in arriving at my recommended return on equity.

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[55] Ibbotson Associates computes the equity risk premium by subtracting the income return (not the total return) on long-term Treasury bonds from the return on common stocks. As Ibbotson Associates noted [*2005 Yearbook, Valuation Edition* at 75]:

> Price changes in bonds due to unanticipated changes in yields introduce price risk into the total return. Therefore, the total return on the bond series does not represent the riskless rate of return. The income return better represents the unbiased estimate of the purely riskless rate of return, since an investor can hold a bond to maturity and be entitled to the income return with no capital loss.

Q. PLEASE SUMMARIZE THE RESULTS OF YOUR RISK PREMIUM ANALYSES.

A. The cost of equity estimates implied by my risk premium analyses are summarized in the following table:

Risk Premium Approach	Cost of Equity Estimate
Authorized Returns	
Current Yield	10.7%
Projected Yield	11.4%
Realized Rates of Return	
Current Yield	9.8%
Projected Yield	11.0%
CAPM - Forward-looking	
Current Yield	12.5%
Projected Yield	12.6%
CAPM - Historical	
Current Yield	10.9%
Projected Yield	11.9%

D. Comparable Earnings Method

Q. WHAT OTHER ANALYSES DID YOU CONDUCT TO ESTIMATE THE COST OF EQUITY?

A. As I noted earlier, I also evaluated the cost of equity using the comparable earnings method. Reference to rates of return available from alternative investments of comparable risk can provide an important benchmark in assessing the return

necessary to assure confidence in the financial integrity of a firm and its ability to attract capital. This comparable earnings approach is consistent with the economic underpinnings for a fair rate of return established by the Supreme Court. Moreover, it avoids the complexities and limitations of capital market methods and instead focuses on the returns earned on book equity, which are readily available to investors.

Q. WHAT RATES OF RETURN ON EQUITY ARE INDICATED FOR UTILITIES BASED ON THIS APPROACH?

A. With respect to expectations for electric utilities specifically, the most recent edition of Value Line reports that its analysts anticipate an average rate of return on common equity for the electric utility industry of 10.5% in 2005 and 2006, increasing to 11.0% over its three-to-five year forecast horizon.[56] Meanwhile, Value Line expects that natural gas distribution utilities will earn an average rate of return on common equity of 12.0% in 2005 and 2006, and 12.5% for 2008-2010.[57]

Q. CAN THE COMPARABLE EARNINGS METHOD BE APPLIED TO OTHER FIRMS OF SIMILAR RISK?

A. Yes. Under the regulatory standards established by *Hope* and *Bluefield*, the salient criteria in establishing a meaningful benchmark to evaluate a fair rate of return is relative risk, not the particular business activity or degree of regulation. Utilities must compete for capital, not just against firms in their own industry, but with other investment opportunities of comparable risk. Consistent with this accepted regulatory standard, I also applied the comparable earnings approach based on a reference group of companies in the unregulated sector of the economy.

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[56] The Value Line Investment Survey (Sep. 2, 2005) at 156.

[57] The Value Line Investment Survey (Sep. 16, 2005) at 459.

My assessment of comparable risk relied on two objective benchmarks for the risks associated with common stocks -- Value Line's Safety Rank and beta. The Safety Rank, which ranges from "1" (Safest) to "5" (Riskiest), is intended to capture the total risk of a stock, and incorporates elements of stock price stability and financial strength. As discussed earlier, Value Line's beta values provide a measure of stock price variability as compared with the firms in the New York Stock Exchange Composite Index, with a beta less than 1.0 indicating that a stock tends to fluctuate less than the market as a whole (lower risk) while a beta greater than 1.0 indicates that the stock tends to fluctuate more than the market (greater risk).

The average Value Line Safety Ranking for the firms in the proxy group is "2", with beta values for the ten electric utilities ranging from 0.70 to 1.05. Accordingly, my reference group was composed of those U.S. companies followed by Value Line that 1) pay common dividends, 2) have a Safety Rank of "2", and 3) have beta values between 0.70 and 1.05. Value Line's projections indicate that its analysts expect that rates of return on shareholders' equity for the resulting group of 151 firms will average 15.7%, with the median being 14.0%.[58]

Q. WHAT RETURN ON EQUITY IS INDICATED BY THE RESULTS OF THE COMPARABLE EARNINGS APPROACH?

A. Based on the results discussed above, I concluded that the comparable earnings approach implies a fair rate of return on equity of at least 11.0% to 12.0%.

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[58] www.valueline.com (Retrieved Oct. 11, 2005).

E. Proxy Group Cost of Equity

Q. WHAT DID YOU CONCLUDE WITH RESPECT TO THE COST OF EQUITY FOR THE PROXY GROUP OF UTILITIES?

A. In light of anticipated capital market trends and the recent challenges experienced in the electric utility industry, caution should be exercised in interpreting the results of DCF and risk premium applications. As noted earlier, the single constant growth DCF result is out of line with the preponderance of estimates produced by the risk premium and comparable earnings approaches and should not be viewed in isolation, especially considering the potential for downward bias when DCF growth rates do not capture investors' long-term expectations. Moreover, accelerating economic growth and expectations for higher interest rates suggest that 2006 estimates should receive more weight. Accordingly, based on the results of my quantitative analyses, and my assessment of the relative strengths and weaknesses inherent in each method, I concluded that the cost of equity for the electric utility proxy group is in the 10.8% to 11.8% range.

F. Flotation Costs

Q. WHAT OTHER CONSIDERATIONS ARE RELEVANT IN SETTING THE RETURN ON EQUITY FOR A UTILITY?

A. The common equity used to finance the investment in utility assets is provided from either the sale of stock in the capital markets or from retained earnings not paid out as dividends. When equity is raised through the sale of common stock, there are costs associated with "floating" the new equity securities. These flotation costs include services such as legal, accounting, and printing, as well as the fees and discounts paid to compensate brokers for selling the stock to the public. Also, some argue that the "market pressure" from the additional supply of common stock

and other market factors may further reduce the amount of funds a utility nets when it issues common equity.

Q. IS THERE AN ESTABLISHED MECHANISM FOR A UTILITY TO RECOGNIZE EQUITY ISSUANCE COSTS?

A. No. While debt flotation costs are recorded on the books of the utility, amortized over the life of the issue, and thus increase the effective cost of debt capital, there is no similar accounting treatment to ensure that equity flotation costs are recorded and ultimately recognized. Alternatively, no rate of return is authorized on flotation costs necessarily incurred to obtain a portion of the equity capital used to finance plant. In other words, equity flotation costs are not included in a utility's rate base because neither that portion of the gross proceeds from the sale of common stock used to pay flotation costs is available to invest in plant and equipment, nor are flotation costs capitalized as an intangible asset. Unless some provision is made to recognize these issuance costs, a utility's revenue requirements will not fully reflect all of the costs incurred for the use of investors' funds. Because there is no accounting convention to accumulate the flotation costs associated with equity issues, they must be accounted for indirectly, with an upward adjustment to the cost of equity being the most logical mechanism.

Q. WHAT IS THE MAGNITUDE OF THE ADJUSTMENT TO THE "BARE BONES" COST OF EQUITY TO ACCOUNT FOR ISSUANCE COSTS?

A. One of the most common methods used to account for flotation costs in regulatory proceedings is to apply an average flotation-cost percentage to a utility's dividend yield. Based on a review of the finance literature, *Regulatory Finance: Utilities' Cost of Capital* concluded:

> The flotation cost allowance requires an estimated adjustment to the return on equity of approximately 5% to 10%, depending on the size and risk of the issue.[59]

Alternatively, a study of recent data from Morgan Stanley regarding issuance costs associated with utility common stock issuances suggests an average flotation cost percentage of 3.6%.[60] Similarly, Pinnacle West incurred flotation costs equal to approximately 3.5% of net proceeds in connection with its sale of additional common shares in 2005.[61]

Applying these expense percentages to a representative dividend yield for a utility of 3.5% implies a flotation cost adjustment on the order of 12 to 35 basis points.[62]

Q. IS THE NEED FOR A FLOTATION COST ADJUSTMENT TO COMPENSATE FOR PAST EQUITY ISSUES RECOGNIZED IN THE FINANCIAL LITERATURE?

A. Yes. In a *Public Utilities Fortnightly* article, Brigham, Aberwald, and Gapenski demonstrated that even if no further stock issues are contemplated, a flotation cost adjustment in all future years is required to keep shareholders whole, and that the flotation cost adjustment must consider total equity, including retained earnings.[63] Similarly, *Regulatory Finance: Utilities' Cost of Capital* contains the following discussion:

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[59] Morin, Roger A., "Regulatory Finance: Utilities' Cost of Capital," Public Utility Reports (1994) at 166.

[60] *Application of Yankee Gas Services Company for a Rate Increase*, DPUC Docket No. 04-06-01, Direct Testimony of George J. Eckenroth (Jul. 2, 2004) at Exhibit GJE-11.1. Updating the results presented by Mr. Eckenroth through April 2005 also resulted in an average flotation cost percentage of 3.6%.

[61] Legal and other underwriting costs totaled $8,569,675, while net proceeds from the stock issuance amounted to $247,420,325.

[62] As shown on Attachment WEA-1, Pinnacle West's dividend yield is significantly higher than the average for the group, at 4.5%. Accordingly, the implied flotation cost adjustment would be correspondingly higher, at 16 to 45 basis points.

[63] Brigham, E.F., Aberwald, D.A., and Gapenski, L.C., "Common Equity Flotation Costs and Rate Making," *Public Utilities Fortnightly* (May, 2, 1985).

> Another controversy is whether the underpricing allowance should still be applied when the utility is not contemplating an imminent common stock issue. Some argue that flotation costs are real and should be recognized in calculating the fair rate of return on equity, but only at the time when the expenses are incurred. In other words, the flotation cost allowance should not continue indefinitely, but should be made in the year in which the sale of securities occurs, with no need for continuing compensation in future years. This argument implies that the company has already been compensated for these costs and/or the initial contributed capital was obtained freely, devoid of any flotation costs, which is an unlikely assumption, and certainly not applicable to most utilities. ... The flotation cost adjustment cannot be strictly forward-looking unless all past flotation costs associated with past issues have been recovered.[64]

Q. CAN YOU PROVIDE A SIMPLE NUMERICAL EXAMPLE ILLUSTRATING WHY A FLOTATION COST ADJUSTMENT IS NECESSARY TO ACCOUNT FOR PAST FLOTATION COSTS?

A. Yes. The following example demonstrates that investors will not have the opportunity to earn their required rate of return (*i.e.*, dividend yield plus expected growth) unless an allowance for past flotation costs is included in the allowed rate of return on equity. Assume a utility sells $10 worth of common stock at the beginning of year 1. If the utility incurs flotation costs of $0.48 (5% of the net proceeds), then only $9.52 is available to invest in rate base. Assume that common shareholders' required rate of return is 11.5%, the expected dividend in year 1 is $0.50 (*i.e.*, a dividend yield of 5%), and that growth is expected to be 6.5% annually. As developed below, if the allowed rate of return on common equity is only equal to the utility's 11.5% "bare bones" cost of equity, common stockholders will not earn their required rate of return on their $10 investment, since growth will really only be 6.25%, instead of 6.5%:

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[64] Morin, Roger A., "Regulatory Finance: Utilities' Cost of Capital," Public Utilities Reports (1994) at 175.

DAVID J. RUMOLO

DIRECT TESTIMONY OF DAVID J. RUMOLO

On Behalf of Arizona Public Service Company

Docket No. E-01345A-05-0816

January 31, 2006

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DIRECT TESTIMONY OF DAVID J. RUMOLO
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-05- 0816)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is David Rumolo. My business address is 400 North Fifth Street, Phoenix, Arizona 85004.

Q. BY WHOM ARE YOU EMPLOYED AND WHAT IS YOUR POSITION?

A. I am employed by Arizona Public Service Company ("APS" or "Company") as Manager of Regulation and Pricing. I am responsible for the establishment and administration of APS tariffs and contract provisions that are under the jurisdiction of the Arizona Corporation Commission ("Commission") or the Federal Energy Regulatory Commission ("FERC").

Q. WOULD YOU DISCUSS YOUR EDUCATIONAL BACKGROUND AND BUSINESS EXPERIENCE?

A. My background and experience are set forth in Appendix A to this testimony.

Q. ARE YOU SPONSORING ANY STANDARD FILING REQUIREMENTS ("SFR") SCHEDULES?

A. Yes. I am sponsoring required SFR Schedules G, and H, and portions of SFR Schedules B-1, B-2, C-1, and C-2, as well as the proposed rate schedules. Although not specifically required by the SFR, I am also sponsoring some additional schedules that have been designated as Schedule GJ (Attachment DJR-1), Schedule GE1 (Attachment DJR-2), Schedule GE2 (Attachment DJR-3), and Schedule GE3 (Attachment DJR-4) and are attached to my testimony.

II. SUMMARY

Q. WOULD YOU SUMMARIZE YOUR TESTIMONY?

A. My testimony addresses two general areas. The first area discusses the cost-of-service study prepared to Functionalize, Classify, and then Allocate test year costs and revenues first between wholesale and retail customers and then to the various classes of retail service. It is this cost allocation study that allows us to determine the rate of return produced by each class and subclass of customer, as well as the unit costs to provide service to each customer grouping. The second area discusses the proposed rate schedules and related service provisions which will recover the costs of providing service to our customers.

Q. WOULD YOU PLEASE SUMMARIZE THE PROPOSED RESIDENTIAL RATE SCHEDULE CHANGES?

A. We are proposing the following:

- Each residential rate schedule will be adjusted to improve cost tracking and reflect increased revenue requirements. The residential class base rate increase is comparable to the overall requested revenue increase of 21.14 %. The increases in Rate Schedules ET-1, ECT-1R, and E-12 are 24%, 19.7% and 15.6% respectively.
- Frozen Rate Schedules E-10 and EC-1 will be eliminated, and customers will select another rate option or be transferred to Schedule E-12 or Schedule ECT-1R by default, as meters are exchanged.
- The discounts available under the low income and medical equipment rates, Rate Schedules E-3 and E-4 respectively, will remain unchanged from the levels found in Decision No. 67744.

Q. WOULD YOU PLEASE SUMMARIZE THE PROPOSED CHANGES TO THE GENERAL SERVICE SCHEDULES?

A. Yes, the most significant changes are:

- All rate schedules have increased charges to reflect increased revenue requirements. The majority of the increases reflects increased fuel and purchased power expenses and is reflected in the power supply component of the unbundled rates.
- Rate Schedule E-32 will be increased to reflect increased revenue requirements, especially higher energy costs.
- Rate Schedules E-34 and E-35 will be increased slightly more than the average overall rate increase proposed in this application because customers on these rates use large amounts of energy and thus are more impacted by increased fuel and purchased power expenses.
- Time of Use ("TOU") Rate Schedules E-21, E-22, E-23, and E-24 will be eliminated and customers on those rates transferred to E-32TOU.
- Schedules E-38 and E-38-8T will be eliminated and customers on those rates transferred to Schedule E-221 in accordance with Decision No 67744.
- The basis for computing the energy portion of Schedule E-36 bills will change from system incremental cost to an index-based cost that is consistent with the computation of energy imbalances charges under the Company's OATT.

Q. ARE YOU PROPOSING ANY OTHER CHANGES TO THE APS TARIFF?

A. Yes. I am proposing modifications to the APS line extension policy found in Service Schedule 3. The primary modifications are to eliminate the existing

$25,000 extension condition and to change the policy from one based on a footage allowance to an equipment-based allowance for residential extensions.

III. COST-OF-SERVICE STUDY

Q. WAS AN EMBEDDED CLASS COST-OF-SERVICE STUDY USED IN THE DEVELOPMENT OF APS' PROPOSED RATE SCHEDULES?

A. Yes. An embedded and fully allocated cost-of-service study, with the twelve-month period ending September 30, 2005 as the test period, was a major input for designing the proposed rates. The study results provided both rate of return for the customer classes as well as Functionalization, Classification, and Allocation of costs.

Q. WAS THE USE OF A TWELVE-MONTH TEST YEAR ENDING SEPTEMBER 30, 2005 SUITABLE FOR THIS COST-OF-SERVICE STUDY?

A. Yes. The test year data provides the most recent calendar year financial and operational information, and is, therefore, consistent with the Company's revenue requirements. Although a future test year is more reflective of the period in which the proposed rates will be in effect, such a future test period is not generally used in Arizona. However, the Company's analysis does include a number of pro forma adjustments to the test year to reflect known changes and to better match the costs and revenues with the period in which the proposed rates will be in effect, as well as other adjustments to normalize the test period. For example, wages and salaries are adjusted through a pro forma adjustment to account for current levels and employee count.

Q. WHAT DO YOU MEAN BY NORMALIZING THE TEST YEAR INFORMATION?

A. Normalization refers to eliminating the effect of conditions or situations that would not ordinarily occur or be expected to occur in a normal test year, or that recur periodically but should be averaged out over a period of years. The purpose of normalization is to produce a test year that will be more representative of conditions that will exist during the period in which the proposed rates will be in effect.

Q. HOW DO YOU TREAT PRO FORMA AND NORMALIZATION ADJUSTMENTS TO THE TEST YEAR IN YOUR COST-OF-SERVICE STUDY?

A. Other APS witnesses' testimony sponsor a number of pro forma adjustments that were incorporated into the adjusted test year cost-of-service study. Testimony of APS witnesses Chris Froggatt, Laura Rockenberger, and Peter Ewen list, by rate base and expense category, the monetized amount of each proposed pro forma adjustment. These amounts were then Functionalized, Classified, and Allocated to the retail and wholesale customer classes as part of the process in performing the cost-of-service study. The adjusted test year cost-of-service study reflects all the proposed pro forma adjustments.

Q. WOULD YOU DISCUSS THE DEVELOPMENT OF THE EMBEDDED COST ALLOCATION STUDY?

A. This study was prepared using industry accepted cost-of-service principles of Functionalization, Classification, and Allocation and is generally consistent with historical APS practices.

"Functionalizaton" refers to the process of attributing a particular rate base or expense item to a particular function, namely Production, Transmission, or Distribution, in the provision of electric service. An easy and obvious example is

the assignment of the costs of building and operating the Company's power plants to the Production function.

"Classification" refers to the process of determining the factor or factors that compel the magnitude of the cost. For example, if a cost is driven by the amount of energy consumed, it is classified as Energy; if a cost is driven by the rate at which energy is consumed, it is classified as Demand; or if a cost is driven by the number of customers taking service on the APS system irrespective of either demand or energy utilized, it is classified as Customer.

"Allocation" occurs once a cost has been functionalized and classified. This is the process in which allocation factors are applied to spread the costs to particular jurisdictions, customer classes, and rate schedules. A simple example is the allocation of energy related costs by kilowatt-hour ("kWh") consumption.

In the cost-of-service study, the expense and rate base items that comprise APS' costs were grouped into major categories, such as Plant in Service or Operating & Maintenance Expense. Each of these categories was first functionalized into Production, Transmission, or Distribution related costs, then classified as Demand, Energy, or Customer related. Allocation factors based on kilowatts, kilowatt-hours, and number of customers were then developed so that allocations of the functionalized and classified costs could be made to the federal and state jurisdictions and to the various retail customer classes and sub-classes. When necessary, procedures were used to reflect unusual or changing circumstances, as discussed later in my testimony.

Q. WHAT BASIS IS USED TO ALLOCATE FUNCTIONALIZED COSTS BETWEEN JURISDICTIONS AND AMONG CUSTOMER CLASSES?

A. Production-related and Transmission-related assets, and their associated costs, are generally designed and built to enable the Company to meet its system peak load. Therefore, they are allocated on the basis of the average of the system peak demands occurring in the months of June, July, August, and September ("4CP"). Distribution plant, unlike Production and Transmission plant is generally designed to meet a customer class' peak load, which may or may not be coincident with the system peak load. Thus, allocations of costs related to Distribution substations and primary Distribution lines are made on the basis of non-coincident peak loads ("NCP"). Allocations of costs related to Distribution transformers and secondary Distribution lines are made on the basis of the summation of the individual peak loads or demands of all customers within a particular customer class ("ΣNCP").

Q. WHAT IS THE BASIS OF THE "ALL OTHER" OR NON-JURISDICTION SEGMENT OF YOUR COST-OF-SERVICE STUDY?

A. The "All Other" segment, which appears as a column in the cost-of-service study, represents the rate base, expenses, and revenues associated with service to long-term firm FERC jurisdictional resale customers that APS serves, as well as transmission services APS provides to a number of entities. Because APS plans and utilizes Company facilities in order to fulfill these obligations, we have allocated and assigned a portion of APS Production, Transmission, and Distribution facilities to these non-jurisdictional customers in the same manner as we would to our classes of retail jurisdictional customers in preparing the cost-of-service study.

Q. WOULD YOU EXPLAIN THE USE OF REVENUE CREDITS IN THE COST-OF-SERVICE STUDY?

A. In addition to the transactions described for inclusion in the All Other column depicted in the cost-of-service study, APS makes off-system sales to third-party entities. In order to be certain that the benefits of such transactions flow through to our retail customers, the revenues derived from these transactions, which more than cover the incremental costs associated with producing or acquiring the required energy, are allocated to all customers. Thus, the margin or profit that APS realizes from such non-retail transactions is attributed to each class through the Revenue Credit, which benefits all customers by lowering their otherwise determined revenue requirement.

The somewhat opportunistic and non-firm short-term transactions that are included in Transmission for Others and a number of small items such as Rent from Electric Property, Forfeited Discounts, Miscellaneous Service Revenues, sales to Rate Schedule E-36 customers, and Other Electric Revenues are also treated as Revenue Credits.

Q. IS THIS THE SAME REVENUE CREDIT TREATMENT USED BY THE COMMISSION IN PRIOR APS RATE PROCEEDINGS?

A. Yes.

IV. PRO FORMA ADJUSTMENTS

Q. WERE YOU RESPONSIBLE FOR THE PREPARATION OF ANY PRO FORMA ADJUSTMENTS?

A. Yes.

Q. WERE YOU RESPONSIBLE FOR THE PREPARATION OF ANY PRO FORMA ADJUSTMENTS?

A. Yes, I was responsible for preparing three pro forma adjustments. The first pro forma adjustment was to annualize the revenue APS receives from retail customers to reflect the change in retail rates that became effective April 1,

2005. This was accomplished by taking test year billing determinants from our Customer Information System ("CIS") and applying the April 1, 2005 rates to those determinants. The revenue annualization proforma is summarized in Attachment DJR-5.

The second pro forma adjustment was an adjustment to test year operating expenses to reflect the increased promotional expenses for our low-income rate options. These promotional expenses are consistent with what was required by Decision No. 67744. This pro forma is shown on Attachment DJR-6.

The third pro forma adjustment I developed was an income adjustment to reflect the increased revenue levels that resulted in changes in miscellaneous customer charges in accordance with Service Schedule 1. These customer charges are consistent with those authorized and approved in Decision No. 67744 and the pro forma adjustment to reflect them is shown on Attachment DJR-7.

V. SPECIALLY-HANDLED COST ITEMS

Q. HAVE ANY SPECIALIZED PROCEDURES BEEN USED IN PERFORMING THIS COST ALLOCATION STUDY?

A. Yes. Consistent with the methods adopted in our last rate case, transmission-related costs were treated in a different manner.

Q. WOULD YOU EXPLAIN HOW TRANSMISSION COSTS WERE TREATED IN THE COST-OF-SERVICE STUDY?

A. The revenue requirement for transmission services was computed based on the FERC jurisdictional rates found in the APS Open Access Transmission Tariff (OATT).

The APS Scheduling Coordinator for Standard Offer customers is responsible for procuring transmission service, including ancillary services, and pays APS' OATT rates for Transmission and Ancillary Services needed to deliver electric power and energy to APS retail customers. Since FERC has jurisdiction over setting transmission rates, we removed transmission rate base and expenses from the retail customer class. This was accomplished by allocating all transmission and ancillary service cost to the "All Other" class in the cost-of-service study. Test year average OATT expense was determined by using the amount APS billed itself for retail network transmission service and ancillary services. The total OATT service charges were then divided by the corresponding OATT-billed kWh to determine the test year average OATT expense.

Q. HOW HAVE YOU HANDLED FRANCHISE FEES?

A. The APS Rate Schedules currently in effect (approved in Decision No. 67744) exclude franchise fees. Historically, franchise fees were recovered in base rates but Decision No. 67744 unbundled franchise fees so that the fees are collected directly from customers through location-specific charges in a manner similar to transaction privilege taxes. For the purpose of the cost-of-service study, expenses associated with Franchise Fees and associated revenues have been excluded.

Q. HAVE YOU CALCULATED THE COSTS, RATE BASE, AND RATE OF RETURN BASED ON THE ADJUSTED TEST YEAR?

A. Yes. In addition to establishing the Production, Transmission, and Distribution functions and the Demand, Energy, and Customer classifications for each class of retail business, the rate of return for each class under test year and proposed

Rate Schedules appear in the SFR "G" Schedules associated with this application.

VI. "G" SCHEDULES

Q. MR. RUMOLO, WOULD YOU DESCRIBE THE SFR "G" SCHEDULES?

A. Yes. The following is a summary of these Schedules:

- SFR Schedule G-1 shows the rate-of-return at existing rates by customer class, based on the adjusted test year cost-of-service study.
- SFR Schedule G-2 is similar to Schedule G-1, except this Schedule reflects returns by class that would result under APS' proposed rates.
- SFR Schedule G-3 shows the $ and % amount of adjusted Rate Base allocated to each retail customer class.
- SFR Schedule G-4 shows the amount of operating expenses allocated to each retail customer class.
- SFR Schedule G-5 shows the amount of functionalized adjusted Rate Base allocated to ACC jurisdictional customers.
- SFR Schedule G-6 shows the amount of functionalized adjusted operating expense allocated to the ACC jurisdictional customers.
- SFR Schedule G-7 lists the allocation factors used in preparing the test year cost-of-service study.

Q. DO YOU HAVE ANY ADDITIONAL SCHEDULES RELATED TO THE COST-OF-SERVICE STUDY THAT YOU ARE SPONSORING?

A. Yes. The following filed additional Schedules relate to the study:

- Schedule GJ is a summary of the cost-of-service study showing the jurisdictional separation of Rate Base costs, revenues, and operating expenses.

- Schedule GE1 is a summary of the cost-of-service study showing, by retail customer class, the allocation of total ACC allocated rate base costs, revenues, and operating expenses and the rate-of-return for each major customer class.
- Schedule GE2 is a summary of the cost-of-service study showing, by each General Service sub-class, the allocation of rate base costs, revenues, and operating expenses and the rate-of-return.
- Schedule GE3 is a summary cost-of-service study showing, by each Residential sub-class, the allocation of rate base costs, revenues, and operating expenses and the rate-of-return.

Q. BASED ON THE RESULTS OF YOUR ADJUSTED TEST YEAR COST-OF-SERVICE STUDY, WHAT CONCLUSIONS HAVE YOU MADE?

A. I believe it is apparent from the "G", GJ, and GE Schedules that there are disparities in the rates of return that the different customer classes are providing to the Company. Although the disparities have decreased due to the rate designs implemented as a result of the settlement reached in our last case, the residential class continues to provide a lower rate of return than the general service class. Specifically, under current rates and adjusted operating expenses, the residential class rate of return is 1.52% while the general service class rate of return is 3.91%. Overall, the retail rate of return under current rates is 2.59% based on an adjusted original cost rate base. This is significantly below cost of service.

VII. RATE DESIGN

Q. WOULD YOU DESCRIBE THE OVERALL OBJECTIVES OF THE PROPOSED RATE DESIGNS?

A. In the APS rate case and settlement that resulted in Decision No. 67744, APS' retail rates were significantly modified. The principal modification was to

unbundle the retail rates in accordance with the objectives established by the Commission in the Commission's Electric Competition Rules. We also strove to improve the rate designs by improving cost tracking, offering additional rate options and improving rate clarity. In this case, we are building on the improvements established in Decision No. 67744.

Q. WOULD YOU EXPLAIN WHAT YOU MEAN BY "IMPROVE THE COST TRACKING OF THE VARIOUS ELEMENTS OF OUR RATE SCHEDULES?"

A. Historically, many rate changes were made on the basis of "across the board" percentage changes as a result of rate case settlements. This resulted in some rate distortions that took our rates away from tracking costs, both as to rate level and rate design. In our last case, the process of unbundling our retail rates identified instances in which our rates were obviously not following costs. While the last case made improvements in that regard, the proposed rates in this case continue to address this concern.

Q. WOULD YOU DESCRIBE THE PROCESS USED TO DEVELOP THE PROPOSED RATES?

A. The starting point in the rate design process is the cost-of-service study discussed earlier in my testimony. The cost-of-service study allocates the costs of providing service to each of the major classes of customers, as well as various sub-classes and rate schedules. If the cost-of-service study was the only determinant for setting rates, each rate classification would recover APS' proposed rate of return, and all rate schedules would be expressed in the form of unit costs and expressed as Demand Charges, Energy Charges, and Customer Charges. However, many other considerations were taken into account in designing the proposed rates, which resulted in individual rate schedules that

differ from the overall proposed rate of return and rate designs that differ in appearance and application.

Q. OTHER THAN THE COST-OF-SERVICE STUDY, WHAT OTHER FACTORS WERE CONSIDERED WHEN DESIGNING THE PROPOSED RATES?

A. We considered several other factors. Among the most important were rate stability and continuity. For this reason, the major classes of customers—Residential, General Service, Irrigation, Street Lighting, and Dusk to Dawn—have each been given a percentage increase that is approximately the same as the overall requested increase, even though strict adherence to the results of the cost-of-service study would indicate higher increases are supportable. In addition, the individual rate schedules have been designed to depart from strict cost-of-service adherence as necessary, so that differences in the increases that individual customers will experience will be moderated to the extent we believe reasonable. An additional consideration in developing the proposed rate schedules was customer understandability and ease of administration. In other words, we attempted to simplify the specific rate schedules and the presentation of the tariff in general. Consideration of these factors is in conformance with the traditional aspects of rate design.

VIII. RECOVERY OF OTHER COST ELEMENTS

Q. ARE THERE ANY COST ELEMENTS THAT RECEIVE RECOVERY TREATMENT OUTSIDE OF THE BASE RATE SCHEDULES?

A. Yes. Decision No. 67744 authorized a series of adjustment clauses including the Power Supply Adjustment ("PSA"), the Demand Side Management Adjustment Clause ("DSMAC"), the Transmission Cost Adjuster ("TCA"), the Environmental Portfolio Surcharge ("EPS-1"), the Competition Rules

Compliance Charge ("CRCC"), the Returning Customer Direct Assignment Charge ("RCDAC"), and the System Benefits Adjustment Charge ("SBAC"). Regulatory Assessments, sales/transaction privilege taxes, and franchise fees are also charged outside of base rates.

Q. ARE YOU PROPOSING ANY ADDITIONAL ADJUSTORS OR SURCHARGES IN THIS APPLICATION?

A. Yes. In this application, we have requested approval of an Environmental Improvement Charge ("EIC"). The purpose of the charge is to provide a funding mechanism for investments that will reduce emissions associated with burning fossil fuels at our power plants. This proposed charge is discussed in detail in the testimony of APS Witness Gregory Delizio.

Q. DOES THIS APPLICATION IMPACT THE PSA THAT WAS APPROVED IN DECISION N0. 67744?

A. Yes. The calculations found in the PSA were based on a Base Rate Power Supply Cost of $0.020743 per kWh, as approved in Decision No. 67744. The proposed new Base Rate Power Supply Cost is $0.031904 per kWh, as discussed in detail in the testimony of APS Witness Peter Ewen. A description of other requested PSA changes is found in the testimony of APS Witness Don Robinson.

Q. DOES THIS APPLICATION IMPACT ANY OF THE OTHER ADJUSTERS THAT WERE APPROVED IN DECISION N0. 67744?

A. Yes. We are proposing a change in the Demand Side Management Adjustment Charge. The current methodology does not provide for interest earnings on the account balance. Since recovery of DSM expenditures is in arrears, it is appropriate to include an interest charge. We propose the unrecovered DSM cost accrue interest using the one-year Nominal Treasury Constant Maturities rate that is contained in the Federal Reserve Statistical Release H-15 or its successor

publication. This is the same rate that is used in the PSA and for customer deposits. A revised Plan of Administration is attached and marked Attachment DJR-8.

IX. RESIDENTIAL RATE SCHEDULES

Q. WOULD YOU PLEASE GIVE A GENERAL DESCRIPTION OF THE EXISTING RESIDENTIAL RETAIL RATE SCHEDULES?

A. Currently, APS has seven active residential rate schedules. In addition, two new schedules were filed with the Commission prior to this application and are pending Commission action. Two of the rate schedules are for special programs that APS actively supports. Schedule E-3 provides discounts for qualifying low-income customers. Schedule E-4 provides a discounted rate to customers who must use electricity for medical care equipment. These discounts were increased by Decision No. 67744.

We currently have three non time-of-use ("TOU") differentiated Rate Schedules (E-10, E-12, and EC-1). Rate Schedules E-10 and EC-1 were frozen by the Commission in previous proceedings and have not been available to new customers for over 10 years. In accordance with Decision No. 67744, these frozen schedules will be eliminated. We also have two active TOU Rate Schedules. Schedule ET-1 is a time differentiated energy rate schedule. Schedule ECT-1R is time differentiated and also includes a metered demand charge. In September 2005, we filed an application with the Commission to introduce two new TOU rate schedules, designated Rate Schedule ET-2 and Rate Schedule ECT-2. These schedules offer alternative on-peak pricing time periods and have been filed as experimental rate schedules to allow for examination of both customer interest and customer demand response.

Q. WOULD YOU PLEASE DESCRIBE THE PROVISIONS OF DECISION NO. 67744 THAT WERE APPLICABLE TO RESIDENTIAL RETAIL RATE SCHEDULES?

A. Decision No. 67744 had several provisions of importance to residential customers. As I noted earlier, we unbundled the Standard Offer rate schedules in our last rate case to comply with the Competition Rules. Decision No. 67744 impacted residential customers as follows: 1) Frozen Schedules EC-1 and E-10 were continued but are to be eliminated in APS' next rate case, 2) APS was required to study rate designs that encourage energy efficiency, discourage wasteful and uneconomic use of energy and reduce peak demand, 3) APS was ordered to file additional TOU rate schedules with different peak schedules, 4) APS was ordered to evaluate the break points and tier pricing in Schedule E-12 in the next rate, and 5) APS was directed to evaluate SurePay and examine the possibility of providing discounts to customers who participate in SurePay.

Q. WOULD YOU PLEASE DESCRIBE APS' COMPLIANCE WITH THE REQUIREMENTS OF DECISION NO. 67744 AS APPLICABLE TO RESIDENTIAL CUSTOMERS.

A. In this Application, we are implementing the elimination of Schedules EC-1 and E-10. We have prepared a report (Attachment DJR-9) that: 1) examines rate design alternatives that encourage energy efficiency; and 2) evaluates the breakpoints and rate in Schedule E-12. On October 7, 2005, we filed two other reports with Commission Staff in accordance with Decision No. 67744. The reports examined: 1) the issue of TOU rate schedules and rate designs that encourage rate flexibility; and 2) the possibility of providing discounts to customers who participate in SurePay. These reports and the October 7, 2005 transmittal letter are Attachment DJR-10 to my testimony. As noted previously, we recently filed an application for approval of two additional residential TOU

rate schedules. These rate schedules are based on on-peak pricing time periods of 12:00 P.M. to 7:00 P.M. on weekdays, weekends are off-peak, and the holidays recognized by the National Electric Reliability Council ("NERC") are off-peak.

Q. PLEASE SUMMARIZE THE RESULTS OF THE REPORT THAT YOU FILED AND HOW IT IMPACTS THE RATE SCHEDULES FOUND IN THIS RATE SCHEDULE APPLICATION.

A. On the topic of rate designs that encourage energy efficiency, we have concluded that we are leaders in the industry in many aspects. For example, our non-TOU residential rates are inclining block rates that have the effect of charging more for higher consumption levels. We have the greatest percentage of residential customers on TOU rates than almost any other utility nationally and we are one of the few utilities that offer residential rates with an explicit demand charge. The rate designs for general service customers that were implemented in our last case provide strong demand conservation price signals because of cost-based pricing. Because of the nature of our customer base and metering limitations, we do not believe it is appropriate to mandate TOU pricing for general service customers. The rate designs that we are proposing in this application provide strong price signals. This case is being driven chiefly by the rapid increase in fuel and energy costs. Because of this, our proposed rate designs appropriately recover these increased energy costs through the energy charges.

Our analysis also concludes that our current blocks in Schedule E-12 are appropriate. This conclusion is based on a review of bill frequency analyses and the pricing implications of alternative block sizes. Lowering the initial block in the rate would have the effect of shifting consumption to higher priced blocks

and shift revenue recovery to the second tier. The net benefits of lowering the block size of the first tier and lowering the price for the first tier would be limited to customers whose marginal usage is at or near the block limit. Also, some customers served on Rate Schedule E-12 also receive discounts under Schedule E-3. Shifting the cost recovery to the second rate tier would adversely impact those customers since many of the customers receiving the discount purchase significant energy in the second tier of the rate.

Q. PLEASE SUMMARIZE THE RESULTS OF THE REPORTS THAT YOU FILED IN OCTOBER REGARDING TOU RATE FLEXIBILITY AND THE APS SUREPAY PROGRAM.

A. The study regarding the potential of providing additional flexibility in our TOU programs concluded that we have significant obstacles to overcome before rate flexibility can be offered on a widespread basis. First, we have approximately 400,000 customers on TOU rate schedules. To accommodate changes in TOU rate schedules, meters must be re-programmed or replaced. Current technology does not allow us to reprogram meters in the field with our meter reading equipment. The meters can only be field programmed with laptop computers which is not a practical solution. However, we are investigating new technologies that may allow us to have greater flexibility in the future. For example, we are in the process of rolling out an advanced metering system ("AMS") pilot. This system uses radio frequency and cell phone technology to read meters and gather customer information. Because of software flexibility in the AMS, it will be easier in the future to provide customers rate options as AMS is rolled out. Software limitations also affect the number of rate options that we can offer. A change in rate structures necessitates changes in many computer systems ranging from the meter-reading system, to the software used by the

customer call center to provide information to customers, to the bill printing systems, to the APS website. These software changes are expensive to implement and require significant resource commitments for coding and testing software changes. However, as indicated earlier, we have filed an application with the Commission to request approval for two new experimental TOU rate schedules that will provide rate options with alternative TOU time periods. Customer reaction to these new rate offerings will be one indicator whether we will expand the experiment to a broader group of customers.

Our review of the SurePay program leads us to the conclusion that offering discounts to encourage participation is not warranted. We currently offer two automatic payment options to customers. SurePay authorizes a customer's bank to transfer funds to APS. AutoPay is an on-line version of SurePay in which the customer will get an e-mail notification when the fund transfers occur. AutoPay customers can print a paper copy of their bill from APS.COM if the customer so desires. We do not believe that a discount is required to encourage participation since we have a high level of participation in the automatic payment programs even when compared to companies that offer financial inducements. Also, our analysis indicates that many of the inducements offered by other companies are not cost effective and result in cost shifting from customers who participate to customers who do not elect to participate.

Q. WOULD YOU PLEASE DESCRIBE THE PROPOSED RESIDENTIAL RATE SCHEDULES?

A. As described earlier in my testimony, the changes proposed for the residential rate schedules are refinements of the changes that were made in the last case. This rate application is being driven primarily by increases in the cost of

generation resources including fuel, purchased power expense, and the inclusion of new generation in rate base. Therefore, the proposed rate changes primarily influence the power supply element of our unbundled rate schedules. We have also included the impact of the energy efficiency demand side management programs on expected sales volumes through a slight reduction in billing determinants used to develop the proposed rates.

Q. PLEASE DESCRIBE THE PROPOSED CHANGES TO RESIDENTIAL RATE SCHEDULES ET-1, ECT-1R AND E-12.

A. The only changes we are proposing at this time are increases in the revenue levels produced by the rates, with most of the increase reflected in the generation component. We are also modifying the winter-summer rate differentials to better reflect the higher energy costs APS faces in the summer months. The basic unbundled structure of the rates will not be changed. The proposed base rate increase for the residential customer class is approximately 21.1%. On a rate schedule basis, the proposed increases for Schedules ET-1, ECT-1R, and E-12 are 24.5%, 19.7% and 15.6% respectively, excluding customers who are transferring to these schedules from cancelled schedules. These increases are computed based on total schedule results excluding the EIC. Individual customers may experience changes higher or lower than the schedule averages depending on individual consumption patterns.

Q. WHAT ARE YOUR INTENTIONS FOR FROZEN RATE SCHEDULE EC-1 AND ITS CUSTOMERS?

A. We will eliminate frozen Rate Schedule EC-1 as provided for in Decision No. 67744. Rate Schedule EC-1 customers would be transferred to Rate Schedule ECT-1R unless they choose an alternative rate schedule. Rate Schedule ECT-1R has been selected as the default rate schedule as both rate schedules have

explicitly billed demand components, and many customers currently on Rate Schedule EC-1 are managing their demand through load controllers or timers. These customers are familiar with demand-based rates and the potential for saving money by actively managing their peak load. Rate Schedule ECT-1R encourages customers who are actively managing demand to continue to do so with the addition of a TOU element. Therefore, we believe that the transition from Rate Schedule EC-1 to Rate Schedule ECT-1R would provide the best continuity for the Rate Schedule EC-1 customers as the default rate, should the customer not select from the available rate schedules on their own.

In this application, we have also included a revised Rate Schedule EC-1 which will be used during the transition until all customers are transferred to other schedules. A transition period is required because of the potential requirement for meter changes. For example, if an EC-1 customer moves to Rate Schedule ECT-1R, a meter exchange may be required. Although meter exchanges may not be required on all 22,000 customers currently on Rate Schedule EC-1, we anticipate a large number of exchanges will be required.

Q. IS A TRANSITION PERIOD REQUIRED FOR THE ELIMINATION OF RATE SCHEDULE E-10?

A. No, since our basic assumption is that E-10 customers will transition to Rate Schedule E-12, meter exchanges will likely not be necessary in most instances. However, if a Schedule E-10 customer selects another schedule such as Rate Schedule ET-1, it may be necessary to exchange meters and that exchange will be worked in our normal meter exchange process. The customer would be billed on the default rate until the meter exchange occurs.

Q. PLEASE DESCRIBE HOW E-10 AND EC-1 CUSTOMERS WILL BE INFORMED OF THEIR NEW RATE OPTIONS ONCE THESE RATES ARE ELIMINATED.

A. APS would like to explore, with the Commission Staff, various opportunities to proactively inform and educate E-10 and EC-1 customers about their rate options once these rates are eliminated. Our initial thought would be to inform customers of this change through APS.COM and through bill inserts targeted towards the E-10 and EC-1 rate codes. Key components of our message should inform them of the option to choose an alternative residential rate schedule once these rates are eliminated, and describe the actions needed by them to make their rate selection. However, our message will also need to inform them that no action by a certain date will cause them to be placed on the appropriate default rate as I described earlier in my testimony.

Q. WHAT IF A CUSTOMER IS PLACED ON A DEFAULT RATE AND LATER WANTS TO SELECT ANOTHER RATE OPTION?

A. If a customer is placed on a default rate as a result of E-10 or EC-1 being eliminated, they will be able to subsequently select another rate option.

Q. DOES THIS APPLICATION AFFECT THE EXPERIMENTAL TOU RATES THAT APS FILED ON SEPTEMBER 22, 2005?

A. Yes. Schedules ET-2 and ECT-2 that were filed in September were based on costs and revenues that were developed in the Settlement Agreement and Decision No. 67744. We are filing revisions to the new rates in this application that reflect the results of the latest cost-of-service study. At the time of the writing of this testimony, the Commission has not yet acted on the application for approval of the new rates, therefore, revenue impacts cannot be calculated. However, the concepts behind the modifications found in this application are

consistent with the original rate design, i.e., if all ET-1 customers moved to ET-2 the move would be revenue neutral.

Q. WOULD YOU PLEASE SUMMARIZE THE PROPOSED RESIDENTIAL RATE SCHEDULE CHANGES?

A. We are proposing the following:

- Each residential rate schedule has been designed to improve cost tracking.
- Rate Schedule EC-1 will be eliminated and customers will select another rate option or be transferred to Rate Schedule ECT-1R by default, as meters are exchanged. The interim rate that will be applied during the transition will be an increase of approximately 26 % compared to EC-1 and is comparable to the increase the customers will experience when moved to Rate Schedule ECT-1R.
- Rate Schedule E-10 will be eliminated. Customers will have the option to choose another rate, or will be transferred to Schedule E-12 by default if no choice is made.
- Rate Schedules E-12, ET-1, ECT-1R, ET-2 and ECT-2 will be increased to reflect increased revenue requirements.
- The discounts available under the low income and medical equipment rates, Rate Schedules E-3 and E-4 respectively, will remain unchanged from the levels found in Decision No. 67744.

X. <u>GENERAL SERVICE RATE SCHEDULES</u>

Q. WOULD YOU PLEASE DESCRIBE APS' GENERAL SERVICE RATE SCHEDULES?

A. APS has eleven general service rate schedules. These are used for serving our commercial and industrial loads as well as specialized applications. There are

five TOU schedules, one schedule for unmetered service, one schedule for athletic stadiums and arenas, a seasonal schedule, schedules for partial requirements service and schedules for dusk-to-dawn and street lighting services. There are two demand based, non-TOU differentiated schedules. Approximately 95% of our general service customers are served on Rate Schedule E-32. Rate Schedule E-34 and TOU Rate Schedule E-35 are available for customers whose loads exceed three megawatts.

Q. WOULD YOU PLEASE SUMMARIZE THE ASPECTS OF DECISION NO. 67744 THAT PERTAIN TO APS' GENERAL SERVICE RATE SCHEDULES?

A. Decision No. 67744 provided that Rate Schedules E-21, E-22, E-23 and E-24, would be eliminated in the next APS rate proceeding. These were introduced many years ago as experimental TOU schedules. It is proposed that these customers be transferred to Rate Schedule E-32TOU. Rate Schedule E-20, a TOU schedule that is applicable to houses of worship, was frozen to new customers. New customers would take service on Rate Schedule E-32TOU or another general service rate schedule of their choice. Decision No. 67744 also provided for the elimination of Rate Schedules E-38 and E-38-8T in the next APS rate proceeding. We propose that customers currently on these schedules be transferred to Rate Schedule E-221. Decision No. 67744 also required that we examine rate designs that would encourage energy efficiency and reduce peak demand. These topics have been addressed in the report described earlier in my testimony.

Q. WOULD YOU PLEASE DESCRIBE THE PROPOSED RATE SCHEDULE E-32?

A. Rate Schedule E-32 was extensively modified in the last APS rate proceeding. In this Application, we are proposing the basic rate structure developed in the last case be retained. The charges in the schedule have been increased to reflect increased revenue requirements. The cost emphasis is shifted to high energy use customers to reflect the dramatically increased energy costs that APS is incurring to serve its customers. This will also encourage energy conservation through an energy-driven price signal.

Q. HAVE YOU MODIFIED RATE SCHEDULE E-32R?

A. Rate Schedule E-32R provides for partial requirements customers taking service under Rate Schedule E-32. Therefore, the changes proposed for Rate Schedule E-32 impact customers served under Rate Schedule E-32R.

Q. WOULD YOU PLEASE DESCRIBE THE PROPOSED CHANGES TO THE GENERAL SERVICE TOU SCHEDULES?

A. Yes. Decision No. 67744 directed that Rate Schedules E-21, E-22, E-23 and E-24 be eliminated in the next APS rate proceeding and that customers be transferred to Rate Schedule E-32TOU. Customers have been notified of that change and will be notified in conjunction with this application. The design of Rate Schedule E-32TOU has been modified to replace the existing "excess capacity" charge with an off-peak demand charge. The rate has been designed so that customers who shift demand to off-peak hours can realize significant savings. However, some customers who are on existing general service TOU rates and have not made shifts in consumption patterns may transfer to Rate Schedule E-32. Currently there are approximately 240 customers on Rate Schedules E-21, E-22, E-23 and E-24 combined.

Q. WOULD YOU PLEASE DESCRIBE THE PROPOSED CHANGES TO RATE SCHEDULES E-34 AND E-35?

A. Yes. Rate Schedules E-34 and E-35 are the rate schedules that are applicable to APS' largest customers, i.e., general service customers with loads over 3 MW. We are not proposing changes to the basic rate structure for Schedule E-34. The billing charges have been increased to reflect increased revenue requirements and most of the increase is in the generation component of the unbundled rate to reflect higher generation, purchased power and fuel expenses. Schedule E-35 billing charges have also been increased to reflect increased revenue requirements. The structure of Schedule E-35 has been modified to substitute an off-peak charge for the "excess capacity" charge that currently exists. This change was made to simplify rate calculations and improve rate clarity. We have also modified the metering charge found in these two schedules for new transmission voltage customers. Transmission voltage metering installations for customers served at higher voltages (i.e., greater than 69 kV) are site specific. Rather than attempting to develop an average cost for universal application, we propose that the charge be based on the carrying cost of the investment. A fixed charge rate will be applied to the actual installed cost of the metering system. The charge will be identified in the service contract between APS and the customer.

Q. ARE YOU PROPOSING CHANGES TO THE STREET LIGHTING AND DUSK TO DAWN LIGHTING SCHEDULES?

A. In our last case, we reformatted Rate Schedule E-47 (Dusk to Dawn) and Rate Schedule E-58 (Street Lighting) to improve cost tracking. Because customers on these rate schedules often request different combinations of poles, arms, and fixtures, we developed a menu format for these rate schedules. Subject to certain

physical/construction limitations, customers are able to select the lighting system that best fits their needs. The menu system makes it easier to add new poles or fixtures to the schedules, as they become available. In this case, we are continuing the menu structure but increasing the charges to reflect higher revenue requirements.

Q. DOES APS PROVIDE STREET LIGHTING SERVICE ON RATE SCHEDULES OTHER THAN E-58?

A. Yes, Rate Schedule E-59 is used to provide energy service for government-owned street lighting systems. Under Rate Schedule E-59, APS has no responsibility for operations, maintenance, or replacement of street light poles or fixtures. There is also a series of "Share the Light" schedules for street lighting services in Ajo, Camp Verde, and other areas. The charges for these special schedules are based on Rate Schedule E-58.

Q. WHAT ARE THE PROPOSED CHANGES FOR THESE STREET LIGHTING RATE SCHEDULES?

A. APS proposes to increase the overall charges under the street lighting rate schedules at approximately the same level as our overall requested increase.

Q. ARE THERE ANY OTHER LIGHTING RELATED RATE SCHEDULES IN THE APS TARIFF?

A. Rate Schedule E-67 is used to provide energy service to the City of Phoenix for various non-street lighting systems. It was originally based on an old contract that has long since expired. Because the level of this Rate Schedule and its return is substandard, we propose that it be increased by a larger average percent increase than the overall increase that APS is requesting in this rate case. This requested 34% increase will still not bring the rate schedule up to the average rate of return paid by our other retail customers.

Q. WOULD YOU PLEASE DESCRIBE ANY OTHER PROPOSED CHANGES FOR GENERAL SERVICE CUSTOMERS?

A. We propose that charges under Rate Schedule E-40 for service to Agricultural Wind Machines and charges under frozen Rate Schedule E-51 for service to certain cogenerators and small power producers be increased by the same overall percentage as is being requested in this application. Partial Requirements Service Rate Schedules E-52 and E-55 currently have no customers being served on them and no increase is proposed at this time. However, these rate schedules may be replaced in the future as a result of the current proceedings on distributed generation. We have also added language to the general service rate schedules that describes power factor requirements. This language was moved to the rate schedules from Schedule 1. Power factor minimum requirement for customers served at distribution voltage continues to be 90% lagging. For transmission voltage customers, the power factor requirement corresponds to the OATT power factor requirement which is 95% lagging to 95% leading.

Q. ARE YOU PROPOSING ANY CHANGES FOR RATE SCHEDULE E-36?

A. We are proposing a change in the method used to compute the energy consumption portion of the bill for customers on Rate Schedule E-36. Currently, the energy charge is computed based on the system incremental cost of power supplies in the hour that the E-36 customer is consuming energy. At the time that the Rate Schedule E-36 was originally developed, system incremental cost was also used in computing energy imbalance charges for customers who take service under the FERC approved OATT. Earlier this year, the energy imbalance charge in the OATT was modified and accepted by FERC. The charge is now based on the average hourly cost at the three major trading hubs that influence the Arizona market; Palo Verde, Four Corners, and Mead. Therefore, we are

proposing to use the trading hub indices to calculate the energy component of the bill for E-36 customers so that the methodology is consistent with the OATT energy imbalance calculation. Currently, we have only four customers on Rate Schedule E-36. The new energy price calculation would result in lower bills to E-36 customers based on a test year analysis.

Q. WOULD YOU PLEASE SUMMARIZE THE PROPOSED CHANGES TO THE GENERAL SERVICE SCHEDULES?

A. Yes, the changes are as follows:

- All rate schedules have increased charges to reflect increased revenue requirements. The majority of the increases is due to increased fuel and purchased power expenses and is reflected in the power supply component of the unbundled rates. Rates were developed with consideration of the impacts on energy sales due to energy efficiency demand side management programs.
- TOU Rate Schedules E-21, E-22, E-23, and E-24 will be eliminated and customers transferred to E-32TOU.
- Rate Schedule E-30 for Unmetered Service will be increased to better reflect costs.
- Rate Schedule E-32 will be increased to reflect increased revenue requirements, especially higher energy costs.
- Rate Schedules E-34 and E-35 will be increased approximately 24.6 % and 24.9% respectively which reflects cost of service and increased fuel and purchased power expenses.
- Rate Schedule E-53 for service to Athletic Fields and Rate Schedule E-54 for Seasonal Service are used in conjunction with other applicable general service rate schedules and no stand alone changes to these rate

schedules are proposed.

- Rate Schedules E-38 and E-38-8T will be eliminated and customers transferred to Rate Schedule E-221 in accordance with Decision No. 67744.
- The basis for computing the energy portion of Rate Schedule E-36 will change from system incremental cost to an index-based cost that is consistent with the computation of energy imbalance charges under the APS OATT.

Q. ARE YOU PROPOSING ANY OTHER RATE SCHEDULE CHANGES?

A. Yes. We are eliminating schedules that are no longer required. Schedule EPR-3 is a frozen purchase rate schedule for qualifying facilities and there are no longer any customers on the schedule. Solar 1 is being cancelled as it is a frozen schedule and there are no longer any customers taking service under the schedule. As discussed in the testimony of APS Witness Ed Fox, we are freezing the Solar Partners program that is described in Schedule SP-1. We are also eliminating the direct access rate schedules that were put in effect as a result of the 1999 Settlement Agreement. Since APS unbundled rates as a result of the 2004 Settlement Agreement (Decision No. 67744), separate direct access rates are no longer necessary and are confusing. No customers are served under the old direct access rates so there is no revenue impact resulting from the rate schedule elimination.

XI. <u>"H" SCHEDULES</u>

Q. WOULD YOU DESCRIBE THE "H" SCHEDULES BEING SPONSORED BY YOU?

A. The "H" Schedules are a series of summaries that present an analysis of the impacts of the proposed rate schedules.

Q. WOULD YOU PLEASE DESCRIBE SCHEDULE H-1?

A. Schedule H-1 provides a summary of the revenue impact on each major customer classification, e.g., Residential, General Service, Irrigation, etc. This schedule compares the revenue generated under the proposed rate schedules with the revenue generated under present rate schedules.

To develop the data found in the column entitled "Present Rate Schedules," we began with actual revenue from the test year, but then made a series of normalization adjustments to that data. The adjustments were made to reflect normal weather, the year-end number of customers, energy conservation and the rate schedule increases that became effective in April, 2005. The purpose of these adjustments was to enable us to compare existing and proposed rate schedules on an "apples-to-apples" basis.

Q. WOULD YOU DESCRIBE THE INFORMATION FOUND IN SCHEDULE H-2?

A. Schedule H-2 presents the information found in Schedule H-1 in a more detailed format. The comparisons of current and proposed revenue are shown by schedule whereas Schedule H-1 data is presented on a class basis. Schedule H-1 is actually a summary of the data found in Schedule H-2.

Q. WOULD YOU PLEASE DESCRIBE SCHEDULE H-3?

A. Schedule H-3 presents comparisons of the specifics of each rate schedule. These specifics include details such as the basic service charge, billing blocks, energy charges, and demand charges. Although our proposed rate schedules have been

functionally unbundled, the information shown on Schedule H-3 is presented on a bundled basis to allow for easier comparisons since all customers today effectively purchase a bundled product from APS.

Q. WOULD YOU PLEASE DESCRIBE SCHEDULE H-4?

A. Schedule H-4 presents a typical bill comparison for our major rate schedules under existing and proposed rates. Bill comparisons are presented for varying levels of consumption and for seasons, when applicable. We have included an additional column to show the impact on bills of the proposed Environmental Improvement Charge (EIC). The "add-ons" of sales tax, franchise fees, and Regulatory Assessment have not been included in the bill comparisons.

Q. WOULD YOU PLEASE DESCRIBE SCHEDULE H-5?

A. Schedule H-5 presents a series of bill frequency analyses for major schedules. This information includes the number of bills and energy consumed based on blocks of consumption levels.

XII. SCHEDULE 3 - LINE EXTENSIONS

Q. WHAT IS SCHEDULE 3?

A. Schedule 3 is APS' line extension policy. The current policy includes three main elements that define conditions governing residential line extensions. These elements are: (1) a footage allowance for residential extensions; (2) a revenue test for extensions when the construction cost is under $25,000; and (3) an economic feasibility analysis for extensions when the cost exceeds $25,000 or that are not subject to the footage allowance or revenue test. Also, when I refer to "residential" customers, I mean individual residential premises as opposed to subdivision developers. Line extensions for residential subdivisions being

constructed by developers are currently evaluated under the revenue test or an economic feasibility analysis.

Q. PLEASE DESCRIBE THE CHANGES THAT ARE PROPOSED IN THE POLICY.

A. Under the footage allowance portion of the current extension policy, permanent residential customers are provided with a 1,000-foot free construction allowance. If the customer's extension exceeds 1,000 feet but is less than 2,000 feet, or the construction cost exceeds $25,000, the policy requires that the customer sign an extension agreement and provide a refundable advance. Under our proposed new policy, the footage basis is eliminated and permanent residential customers will be given a dollar-based equipment allowance. If the construction cost of the extension exceeds the allowance, the customer will be required to make a refundable advance.

Q. HOW DOES THE CURRENT APS POLICY COMPARE WITH INDUSTRY TRENDS?

A. I am currently the Chairman of the Edison Electric Institute's Economic Regulation and Competition Committee, and the topic of line extension policies is an agenda item at almost every semi-annual meeting. We have extensive discussions regarding the application and administration of line extension policies and, almost universally, utility companies struggle with developing policies that are fair to new customers, existing customers and the companies. Tracking the terms of numerous extension contracts and administering extension policies on a uniform basis are difficult issues that most utilities face. Utilities are moving from footage-based policies to construction-allowance based policies in order to improve extension policy administration and more correctly recover costs. The construction allowance approach recognizes that construction

costs for individual customer locations can vary widely. APS believes that our proposed change is more equitable and is consistent with the current trends in the industry. When we compared our current footage based policy with other companies, we found that the 1000-foot allowance is extremely generous to new customers and correspondingly detrimental to existing customers.

Q. YOU DESCRIBE THE CURRENT POLICY AS "GENEROUS." WOULD YOU PLEASE EXPLAIN THAT COMMENT?

A. Yes. The purpose of a line extension policy is to prevent shifting of cost burdens from a customer who requires an extension to other customers. For example, for APS, the average net embedded distribution plant investment, excluding substation plant investment, for residential customers is approximately $1,500. Since our rates are based on a rate of return on rate and operating costs, the distribution component of retail rates is designed to recover costs associated with that average distribution plant investment. Our rates are not geographic based nor are they based on the costs of serving a specific customer. They are based on average costs. Thus, if the investment to serve a specific customer exceeds the average cost, and the specific customer pays average rates and does not make a contribution to offset the higher investment, all other customers must subsidize the higher cost customer.

Q. ARE THERE OTHER REASONS SUPPORTING A CHANGE TO A CONSTRUCTION ALLOWANCE?

A. The primary reason to convert to a construction allowance approach is to recognize that construction costs can vary significantly for each individual extension. The Company's service territory is very diverse. There are densely populated areas, rural areas, desert areas and mountainous areas. Because of this diversity, and to also recognize that some extensions are overhead while others

are underground, an allowance based on a fixed investment amount is more fair. Under a footage allowance-based approach, the cost of a short, very expensive extension results in an unfair burden on the rest of the Company's customers.

Q. WHAT IS THE PROPOSED CONSTRUCTION ALLOWANCE UNDER APS' REVISED LINE EXTENSION POLICY?

A. APS is proposing a residential extension allowance of $5,000 per permanent residential customer in a single family home.

Q. HOW WAS THIS AMOUNT DETERMINED?

A. APS examined several approaches. In other states that have adopted the construction allowance approach, the allowance is based on the average net embedded distribution investment per customer based on a cost-of-service study. The underlying theory is that this average is the investment on which retail rates are designed. For APS, the average net embedded investment, excluding substation plant investment, for residential customers is approximately $1,500. We also analyzed the average plant investment from a reproduction cost basis and determined that value to be approximately $2,700. We elected to apply a much higher ($5,000) allowance for several reasons. First, this allowance equates to the cost of a typical 500-feet underground extension, which is comparable to the allowance provided by other Arizona utilities. Second, we wanted to ease the transition from the current 1000-foott allowance. Today, the construction costs for a 1000-foot overhead extension is in excess of $10,000. Thus, simply converting the existing footage allowance to an equivalent construction allowance would not solve the problem of excessive investment needed to serve one customer and would not accurately capture average embedded costs.

Q. UNDER YOUR PROPOSED POLICY, WILL CUSTOMER ADVANCES BE ELIGIBLE FOR REFUNDS?

A. Yes. For example, let us assume that the cost of an extension is $22,000. The customer receives a $5,000 equipment allowance and will advance APS $17,000. Let us now assume a second customer requests service from the same extension and the cost to add that second customer is $2,000. Since the second customer used only $2,000 of his $5,000 allowance, the original customer will receive a refund of $3,000. Refunds will be made up to five years from the date the original extension is energized and in no case will the refunds exceed the original advance. Customers will be provided an "Advance Certificate" which can be presented to the Company to request a refund when other customers connect to the original extension.

Q. ARE YOU PROPOSING ANY OTHER CHANGES FOR INDIVIDUAL RESIDENTIAL LINE EXTENSIONS?

A. Yes. As I noted previously, our existing policy changes when the estimated cost of an extension exceeds $25,000. If the threshold is exceeded, the extension is made based on an economic feasibility study, and the customer contribution can be significantly more than if the extension was less than $25,000 since the customer does not have the benefit of the 1000 foot. extension. In our proposed policy, the $25,000 threshold is eliminated for residential extensions. Thus, all residential customers will be entitled to the same equipment allowance.

Q. HOW WILL THE LINE EXTENSION POLICY BE APPLIED TO RESIDENTIAL REAL ESTATE SUBDIVISIONS?

A. Currently, we perform an economic study for residential subdivisions that compares expected revenue levels with investment and determines how many homes must be constructed for the investment to be economic. For most

developers that have a track record of successfully developing projects, no customer advances are required. We propose that we will continue to evaluate subdivisions in this manner but incorporate our residential equipment allowance concept in lieu of performing studies. For example, if a subdivision has 200 lots, the developer will be credited with $5,000 per lot or $1,000,000 to cover the investment in local and back-bone facilities. Should the estimated cost for the subdivision exceed that allowance, a non-refundable contribution in aid of construction will be required. Developers without a proven track record in the APS service territory will be required to advance the estimated costs to serve the subdivision and will receive refunds based on the $5,000 equipment allowance as permanent customers establish service with APS. The $5,000 allowance is applicable to developments with single family housing. Developers will be provided a $500 allowance per unit for developments comprised of owner occupied multifamily units such as condominiums and townhouses.

Q. HOW WILL THE EXTENSION POLICY BE APPLIED TO NON-RESIDENTIAL APPLICATIONS?

A. We will continue to use a revenue test for non-residential extensions where the construction cost does not exceed $25,000 and an economic feasibility based analysis for extensions when the cost exceeds $25,000. The revenue test is based on a simple relationship between expected revenue from a customer and the extension cost. Currently, if six times the customer's expected annual distribution revenue is more than the cost of the extension less nonrefundable contributions, the extension is provided for free. If expected revenue does not meet the revenue test, an advance is received from the customer. The economic feasibility-based analysis is a more exhaustive approach that entails examining the return on investment for a particular extension.

Q. ARE THERE ANY OTHER CHANGES PROPOSED FOR THE LINE EXTENSION POLICY?

A. Yes, we have made minor clarifying changes to the schedule. For example, language was added that corresponds to changes in Schedule 1 regarding master metering applications.

XIII. CONCLUSION

Q. WOULD YOU STATE YOUR GENERAL CONCLUSIONS AS TO PRICING MATTERS IN THIS PROCEEDING?

A. The cost-of-service study indicates that APS' current rate schedules produce rates of return that vary greatly from each other and from the overall average and required rate of return. In addition, the rate designs stray greatly from the unit Demand, Energy, and Customer costs of providing service to our customers. The rate schedules being proposed in this proceeding will meet APS' revenue requirement, better track costs, and have been simplified for better customer understanding and administration.

Q. DOES THAT CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes it does.

Appendix A

Statement of Qualifications

David J. Rumolo

David J. Rumolo is Arizona Public Service Company's Manager of State Pricing. He has over 32 years experience in the electric utility business as a consultant and utility professional. Mr. Rumolo holds Bachelor of Science Degrees in Electrical Engineering and Business (Finance as an area of emphasis) from the University of Colorado. He is a registered professional engineer in the states of Arizona, California, and New Mexico.

Mr. Rumolo's areas of expertise include utility Rate Schedule design; embedded and marginal cost analysis; formulation of utility service policies; contract development and negotiation; utility valuation analyses; and evaluation of utility revenue requirements. Mr. Rumolo has testified on utility matters before state regulatory bodies in the states of Arizona, Colorado, Florida, and Wyoming and before judicial bodies in the states of Arizona and California. Mr. Rumolo is also experienced in the many aspects of electric utility planning and design including preparation of long range resource plans; transmission and distribution system long range planning; system protection analyses; and reliability assessments.

Mr. Rumolo has held his current position at Arizona Public Service Company for approximately three years. Prior to assuming that position, he served as the Manager of Transmission and Market Structure Assessment for Pinnacle West Energy Corporation ("PWEC"). Before joining PWEC, Mr. Rumolo had a 15-year career as a consultant with Resource Management International, Inc., where he provided utility Rate Schedule and engineering consulting services to utility clients across the United

States and overseas. He began his career providing consulting services to utility clients when he joined the firm of Miner and Miner Consulting Engineers in Greeley, Colorado where he became the Manager of Planning and Rate Schedules. He later became a partner in Electrical Systems Consultants where he focused on cost of service and Rate Schedule analyses, as well as transmission and distribution planning.

ARIZONA PUBLIC SERVICE COMPANY
ADJUSTED ELECTRIC COST OF SERVICE STUDY
FOR THE 12 MONTHS ENDING SEPTEMBER 30, 2005
($)

Line No.	Description	GJ ELECTRIC TOTAL (1)	GJ ACC JURISDICTION (2)	GJ ALL OTHER (3)
	SUMMARY OF RESULTS			
1	**DEVELOPMENT OF RATE BASE**			
2	ELECTRIC PLANT IN SERVICE	$10,096,271,000	$8,556,179,618	$1,540,091,382
3	GENERAL & INTANGIBLE PLANT	$722,630,705	$666,173,004	$56,457,701
4	LESS: RESERVE FOR DEPRECIATION	($4,170,525,134)	($3,548,546,146)	($621,978,988)
5	OTHER DEFERRED CREDITS	($448,168,000)	($438,604,344)	($9,563,656)
6	WORKING CASH	($29,138,598)	($25,220,726)	($3,917,872)
7	MATERIALS, SUPPLIES & PREPAYMENTS	$197,285,248	$177,653,628	$19,631,620
8	ACCUM. DEFERRED TAXES	($1,203,998,000)	($1,062,992,832)	($141,005,168)
9	REGULATORY ASSETS	($80,002,029)	($93,364,564)	$13,362,535
10	DECOMMISSIONING FUND	$290,537,000	$285,856,167	$4,680,833
11	GAIN FROM DISP. OF PLANT	($46,901,000)	($46,360,307)	($540,693)
12	MISCELLANEOUS DEFERRED DEBITS	$42,522,000	$39,464,108	$3,057,892
13	CUSTOMER ADVANCES	($59,807,000)	($59,807,000)	$0
14	CUSTOMER DEPOSITS	($54,860,000)	($54,860,000)	$0
15	PROFORMA ADJUSTMENTS	$71,987,000	$71,125,898	$861,102
16	**TOTAL RATE BASE**	**$5,327,833,192**	**$4,466,696,503**	**$861,136,689**
17				
18	**DEVELOPMENT OF RETURN**			
19	REVENUES FROM RATES	$2,103,857,729	$2,066,144,726	$37,713,003
20	PROFORMA TO REVENUES FROM RATES	$60,953,295	$61,177,173	($223,878)
21	OTHER ELECTRIC REVENUE	$1,344,909,371	$1,313,268,572	$31,640,799
22	**TOTAL OPERATING REVENUES**	**$3,509,720,395**	**$3,440,590,471**	**$69,129,924**
23				
24	**OPERATING EXPENSES**			
25	OPERATION & MAINTENANCE	$2,246,012,697	$2,302,448,767	($56,436,070)
26	ADMINISTRATIVE & GENERAL	$141,768,183	$132,687,128	$9,081,055
27	DEPRECIATION & AMORT EXPENSE	$321,526,000	$285,758,990	$35,767,010
28	AMORTIZATION ON GAIN	($6,613,638)	($6,528,055)	($85,583)
29	REGULATORY ASSETS	($2,203,510)	($2,203,510)	$0
30	PROFORMA ADJUSTMENTS	$504,561,367	$495,794,531	$8,766,836
31	TAXES OTHER THAN INCOME	$139,970,767	$116,332,654	$23,638,113
32	INCOME TAX	$9,951,628	$395,489	$9,556,139
33	**TOTAL OPERATING EXPENSES**	**$3,354,973,494**	**$3,324,685,995**	**$30,287,499**
34				
35	**OPERATING INCOME**	**$154,746,901**	**$115,904,477**	**$38,842,425**
36				
37	**RETURN**	**$154,746,901**	**$115,904,477**	**$38,842,425**
38				
39	**RATE OF RETURN (PRESENT)**	**2.90%**	**2.59%**	**4.51%**
40				
41	**INDEX RATE OF RETURN (PRESENT)**	**1.00**	**0.89**	**1.55**

ARIZONA PUBLIC SERVICE COMPANY
ADJUSTED ELECTRIC COST OF SERVICE STUDY
FOR THE 12 MONTHS ENDING SEPTEMBER 30, 2005
($)

Line No.	Description	GE-1 TOTAL RETAIL (4)	RESIDENTIAL (5)	GENERAL SERVICE (6)	E-38,221 (Water Pumping) (7)	STREET LIGHTING (8)	DUSK TO DAWN (9)
	SUMMARY OF RESULTS						
1	DEVELOPMENT OF RATE BASE						
2	ELECTRIC PLANT IN SERVICE	$8,556,179,618	$4,681,780,206	$3,708,391,092	$48,573,070	$80,454,414	$36,980,837
3	GENERAL & INTANGIBLE PLANT	$888,173,004	$413,695,677	$240,421,594	$3,598,464	$5,898,943	$2,558,325
4	LESS: RESERVE FOR DEPRECIATION	($3,548,546,146)	($1,928,646,856)	($1,556,766,586)	($21,905,575)	($28,552,296)	($12,674,834)
5	OTHER DEFERRED CREDITS	($438,604,344)	($230,684,114)	($204,189,689)	($2,582,154)	($844,471)	($303,917)
6	WORKING CASH	($25,220,726)	($12,831,079)	($11,971,511)	($114,602)	($208,823)	($94,713)
7	MATERIALS, SUPPLIES & PREPAYMENTS	$177,653,628	$91,814,881	$82,459,091	$1,381,406	$1,358,190	$540,061
8	ACCUM. DEFERRED TAXES	($1,062,992,832)	($577,093,568)	($470,076,111)	($4,073,726)	($8,024,201)	($3,725,226)
9	REGULATORY ASSETS	($93,364,564)	($49,127,146)	($44,234,787)	($193,572)	$145,136	$45,805
10	DECOMMISSIONING FUND	$285,856,167	$135,532,339	$145,260,236	$3,481,853	$1,280,428	$301,312
11	GAIN FROM DISP. OF PLANT	($46,360,307)	($24,074,114)	($22,075,210)	($210,983)	$0	$0
12	MISCELLANEOUS DEFERRED DEBITS	$39,464,108	$24,492,979	$14,258,861	$213,053	$348,203	$151,013
13	CUSTOMER ADVANCES	($59,807,000)	($43,336,952)	($13,858,832)	($2,407,716)	($201,500)	$0
14	CUSTOMER DEPOSITS	($54,860,000)	($29,075,800)	($24,737,362)	($564,674)	($330,038)	($152,126)
15	PROFORMA ADJUSTMENTS	$71,125,898	$37,195,208	$33,683,008	$279,633	($25,865)	($6,087)
16	TOTAL RATE BASE	$4,466,698,503	$2,489,739,662	$1,876,563,796	$25,474,477	$51,298,118	$23,620,450
17							
18	DEVELOPMENT OF RETURN						
19	REVENUES FROM RATES	$2,066,144,726	$1,058,729,739	$987,398,538	$20,966,540	$12,913,053	$6,136,856
20	PROFORMA TO REVENUES FROM RATES	$61,177,173	$30,821,291	$29,741,269	($102,439)	$431,212	$285,840
21	OTHER ELECTRIC REVENUE	$1,313,268,572	$624,903,158	$662,981,779	$15,739,104	$8,074,267	$1,570,264
22	TOTAL OPERATING REVENUES	$3,440,590,471	$1,714,454,188	$1,680,121,586	$36,603,205	$21,418,532	$7,992,960
23							
24	OPERATING EXPENSES						
25	OPERATION & MAINTENANCE	$2,302,448,787	$1,142,667,874	$1,118,136,205	$25,236,754	$13,153,614	$3,254,320
26	ADMINISTRATIVE & GENERAL	$132,687,128	$81,444,413	$48,487,580	$880,883	$1,303,165	$571,087
27	DEPRECIATION & AMORT EXPENSE	$285,758,990	$159,732,184	$119,779,814	$1,842,301	$3,034,821	$1,369,871
28	AMORTIZATION ON GAIN	($6,528,055)	($3,299,367)	($3,172,586)	($45,007)	($8,961)	($2,113)
29	REGULATORY ASSETS	($2,203,510)	($1,144,245)	($1,049,237)	($10,028)	$0	$0
30	PROFORMA ADJUSTMENTS	$495,794,531	$245,906,575	$243,317,050	$4,654,889	$1,563,573	$352,444
31	TAXES OTHER THAN INCOME	$116,332,654	$65,666,581	$47,839,518	$739,434	$1,432,424	$654,697
32	INCOME TAX	$395,489	($14,265,270)	$13,414,661	$933,679	($114,020)	$426,438
33	TOTAL OPERATING EXPENSES	$3,324,685,995	$1,676,708,745	$1,586,753,006	$34,232,906	$20,364,595	$6,626,743
34							
35	OPERATING INCOME	$115,904,477	$37,745,444	$73,368,581	$2,370,299	$1,053,936	$1,366,217
36							
37	RETURN	$115,904,477	$37,745,444	$73,368,581	$2,370,299	$1,053,936	$1,366,217
38							
39	RATE OF RETURN (PRESENT)	2.59%	1.52%	3.91%	9.30%	2.05%	5.78%
40							
41	INDEX RATE OF RETURN (PRESENT)	0.89	0.52	1.35	3.20	0.71	1.99

ARIZONA PUBLIC SERVICE COMPANY
ADJUSTED ELECTRIC COST OF SERVICE STUDY
FOR THE 12 MONTHS ENDING SEPTEMBER 30, 2005
($)

Line No.	Description	TOTAL GENERAL SVC (10)	E-20 (Church Rate) (11)	E-30, E-32 (0 - 20 kW) (12)	E-32 (21 - 100 kW) (13)	E-32 (101 - 400 kW) (14)	E-32 (401 - 999 kW) (15)	E-32 (1,000 + kW) (16)	E-34 (17)	E-35 (18)
		GE-2								
	SUMMARY OF RESULTS									
1	DEVELOPMENT OF RATE BASE									
2	ELECTRIC PLANT IN SERVICE	$3,708,391,092	$13,156,897	$713,155,581	$919,510,111	$826,034,200	$457,251,865	$358,405,105	$234,275,856	$186,601,479
3	GENERAL & INTANGIBLE PLANT	$240,421,594	$600,809	$52,580,861	$57,265,737	$49,297,753	$28,539,088	$22,452,629	$15,147,299	$14,337,418
4	LESS: RESERVE FOR DEPRECIATION	($1,556,766,586)	($4,998,590)	($279,217,143)	($374,393,106)	($351,525,773)	($200,022,369)	($153,944,888)	($102,825,889)	($89,838,828)
5	OTHER DEFERRED CREDITS	($204,189,689)	($504,986)	($33,861,944)	($46,623,347)	($45,546,063)	($26,468,874)	($21,907,125)	($14,852,010)	($14,405,339)
6	WORKING CASH	($11,971,511)	($41,526)	($2,053,804)	($2,885,084)	($2,721,723)	($1,551,419)	($1,227,267)	($811,036)	($679,652)
7	MATERIALS, SUPPLIES & PREPAYMENTS	$82,459,091	$266,994	$12,148,857	$18,052,533	$18,725,412	$11,772,505	$8,953,712	$6,220,412	$6,318,665
8	ACCUM. DEFERRED TAXES	($470,076,111)	($1,567,481)	($90,308,700)	($118,045,895)	($103,935,236)	($57,118,420)	($46,381,008)	($30,261,289)	($24,458,083)
9	REGULATORY ASSETS	($44,234,787)	($87,353)	($8,279,471)	($10,756,114)	($9,709,906)	($5,095,187)	($4,641,924)	($3,022,835)	($2,641,997)
10	DECOMMISSIONING FUND	$145,260,236	$396,517	$14,406,781	$27,667,366	$34,001,927	$23,592,112	$17,518,133	$12,742,045	$14,937,355
11	GAIN FROM DISP. OF PLANT	($22,075,210)	($50,436)	($3,849,143)	($5,211,280)	($4,923,522)	($2,721,500)	($2,342,339)	($1,557,044)	($1,419,946)
12	MISCELLANEOUS DEFERRED DEBITS	$14,258,861	$47,424	$3,115,471	$3,396,159	$2,924,948	$1,692,897	$1,332,470	$898,858	$850,635
13	CUSTOMER ADVANCES	($13,858,832)	($47,917)	($2,036,227)	($3,125,023)	($3,289,801)	($2,093,348)	($1,348,834)	($955,473)	($960,209)
14	CUSTOMER DEPOSITS	($24,737,362)	($85,530)	($3,638,139)	($5,578,020)	($5,872,139)	($3,736,527)	($2,407,606)	($1,705,475)	($1,713,927)
15	PROFORMA ADJUSTMENTS	$33,683,008	$75,650	$6,093,756	$8,085,335	$7,480,055	$4,037,726	$3,531,529	$2,325,358	$2,053,598
16	TOTAL RATE BASE	$1,876,563,796	$7,360,473	$378,234,737	$469,359,373	$410,940,132	$228,078,548	$177,990,587	$115,618,777	$88,981,168
17										
18	DEVELOPMENT OF RETURN									
19	REVENUES FROM RATES	$967,398,538	$3,344,799	$142,275,889	$218,138,380	$229,640,445	$146,123,538	$94,153,699	$56,695,822	$67,026,166
20	PROFORMA TO REVENUES FROM RATES	$29,741,269	$241,901	$9,060,700	$3,862,319	$13,851,012	$1,053,159	$1,013,448	$23,659	$635,071
21	OTHER ELECTRIC REVENUE	$662,981,779	$1,836,772	$67,075,107	$127,027,116	$155,000,606	$107,242,574	$79,566,919	$57,813,897	$67,418,789
22	TOTAL OPERATING REVENUES	$1,660,121,586	$5,423,472	$218,411,696	$349,027,815	$398,492,063	$254,419,271	$174,734,066	$124,533,178	$135,080,026
23										
24	OPERATING EXPENSES									
25	OPERATION & MAINTENANCE	$1,118,136,205	$3,103,839	$129,308,205	$220,897,730	$258,190,478	$174,469,857	$130,669,186	$94,134,754	$107,362,156
26	ADMINISTRATIVE & GENERAL	$48,487,580	$168,558	$10,453,288	$11,676,787	$10,128,362	$5,827,742	$4,474,610	$3,006,658	$2,751,576
27	DEPRECIATION & AMORT EXPENSE	$119,779,814	$441,855	$23,085,668	$29,369,824	$26,524,854	$15,018,891	$11,487,621	$7,583,550	$6,267,552
28	AMORTIZATION ON GAIN	($3,172,586)	($7,702)	($476,561)	($702,487)	($718,845)	($430,995)	($351,385)	($241,284)	($243,307)
29	REGULATORY ASSETS	($1,049,237)	($2,397)	($182,950)	($247,693)	($234,016)	($129,353)	($111,332)	($74,006)	($67,490)
30	PROFORMA ADJUSTMENTS	$243,317,050	$666,036	$31,104,069	$47,266,911	$60,972,779	$35,437,484	$27,211,782	$18,743,874	$21,912,115
31	TAXES OTHER THAN INCOME	$47,839,518	$190,638	$9,622,639	$12,021,204	$10,585,525	$5,888,989	$4,435,255	$2,889,635	$2,205,634
32	INCOME TAX	$13,414,661	$237,240	$2,028,353	$5,848,284	$7,877,179	$4,370,160	($2,721,834)	($1,596,588)	($2,628,135)
33	TOTAL OPERATING EXPENSES	$1,586,753,006	$4,800,066	$204,942,692	$326,130,561	$373,326,316	$240,452,774	$175,093,904	$124,446,594	$137,560,101
34										
35	OPERATING INCOME	$73,368,581	$623,406	$13,469,005	$22,897,254	$25,165,747	$13,966,498	($359,838)	$86,584	($2,480,075)
36										
37	RETURN	$73,368,581	$623,406	$13,469,005	$22,897,254	$25,165,747	$13,966,498	($359,838)	$86,584	($2,480,075)
38										
39	RATE OF RETURN (PRESENT)	3.91%	8.47%	3.56%	4.88%	6.12%	6.12%	-0.20%	0.07%	-2.79%
40										
41	INDEX RATE OF RETURN (PRESENT)	1.35	2.92	1.23	1.68	2.11	2.11	-0.07	0.03	-0.98

ARIZONA PUBLIC SERVICE COMPANY
ADJUSTED ELECTRIC COST OF SERVICE STUDY
FOR THE 12 MONTHS ENDING SEPTEMBER 30, 2005
($)

Line No.	Description	TOTAL RESIDENTIAL (19)	RESIDENTIAL E-10 (20)	RESIDENTIAL E-12 (21)	RESIDENTIAL EC-1 (22)	RESIDENTIAL ET-1 (23)	RESIDENTIAL ECT-1 (24)
		<---------- GE-3 ---------->					
	SUMMARY OF RESULTS						
1	DEVELOPMENT OF RATE BASE						
2	ELECTRIC PLANT IN SERVICE	$4,661,780,206	$281,733,273	$1,463,863,508	$155,716,852	$2,319,963,476	$460,503,097
3	GENERAL & INTANGIBLE PLANT	$413,695,677	$27,609,575	$148,850,621	$12,375,982	$190,265,394	$34,594,106
4	LESS: RESERVE FOR DEPRECIATION	($1,928,646,856)	($121,994,885)	($606,016,515)	($66,501,787)	($945,187,421)	($188,944,248)
5	OTHER DEFERRED CREDITS	($230,684,114)	($13,825,950)	($71,463,902)	($7,843,378)	($113,766,401)	($23,784,483)
6	WORKING CASH	($12,831,079)	($723,129)	($3,720,280)	($447,338)	($6,554,955)	($1,385,377)
7	MATERIALS, SUPPLIES & PREPAYMENTS	$91,914,881	$5,685,919	$28,611,532	$3,209,242	$44,893,772	$9,514,416
8	ACCUM. DEFERRED TAXES	($577,093,568)	($33,820,196)	($178,907,141)	($19,024,386)	($287,506,651)	($57,835,194)
9	REGULATORY ASSETS	($49,127,146)	($2,735,750)	($14,707,336)	($1,630,247)	($24,868,511)	($5,185,302)
10	DECOMMISSIONING FUND	$135,532,339	$8,749,151	$41,051,666	$5,176,464	$65,386,973	$15,168,064
11	GAIN FROM DISP. OF PLANT	($24,074,114)	($1,381,773)	($7,212,965)	($820,405)	($12,112,000)	($2,546,971)
12	MISCELLANEOUS DEFERRED DEBITS	$24,492,979	$1,633,948	$8,808,332	$733,029	$11,267,889	$2,049,781
13	CUSTOMER ADVANCES	($43,336,952)	($2,879,259)	($14,760,504)	($1,501,737)	($20,077,388)	($4,120,063)
14	CUSTOMER DEPOSITS	($29,075,800)	($1,931,675)	($9,902,719)	($1,007,505)	($13,469,779)	($2,764,122)
15	PROFORMA ADJUSTMENTS	$37,195,208	$2,115,285	$11,135,269	$1,256,282	$18,769,977	$3,918,396
16	TOTAL RATE BASE	$2,489,739,662	$148,234,534	$795,627,567	$79,691,088	$1,227,004,374	$239,182,098
17							
18	DEVELOPMENT OF RETURN						
19	REVENUES FROM RATES	$1,058,729,739	$70,337,587	$360,585,198	$36,686,029	$490,471,664	$100,649,261
20	PROFORMA TO REVENUES FROM RATES	$30,821,291	($2,224,915)	$11,853,176	($1,254,829)	$20,328,518	$2,119,341
21	OTHER ELECTRIC REVENUE	$624,903,158	$40,280,141	$189,690,778	$23,754,957	$301,576,795	$69,600,487
22	TOTAL OPERATING REVENUES	$1,714,454,188	$108,392,813	$562,129,152	$59,186,157	$812,376,977	$172,369,089
23							
24	OPERATING EXPENSES						
25	OPERATION & MAINTENANCE	$1,142,687,874	$73,964,084	$357,077,451	$41,906,267	$547,606,416	$121,913,655
26	ADMINISTRATIVE & GENERAL	$81,444,413	$5,435,590	$28,926,720	$2,483,640	$37,721,841	$6,876,622
27	DEPRECIATION & AMORT EXPENSE	$159,732,184	$9,911,645	$51,449,950	$5,249,433	$77,904,622	$15,216,534
28	AMORTIZATION ON GAIN	($3,299,367)	($196,177)	($991,655)	($116,349)	($1,640,307)	($354,879)
29	REGULATORY ASSETS	($1,144,245)	($65,676)	($342,833)	($38,994)	($575,685)	($121,058)
30	PROFORMA ADJUSTMENTS	$245,906,575	$14,092,176	$76,874,215	$8,130,951	$120,576,974	$26,232,260
31	TAXES OTHER THAN INCOME	$65,666,581	$4,071,767	$21,173,025	$2,145,953	$32,090,164	$6,185,673
32	INCOME TAX	($14,265,270)	($924,514)	$2,664,602	($925,760)	($11,644,819)	($3,434,778)
33	TOTAL OPERATING EXPENSES	$1,676,708,745	$106,288,896	$536,831,474	$58,835,140	$802,239,206	$172,514,029
34							
35	OPERATING INCOME	$37,745,444	$2,103,917	$25,297,678	$351,017	$10,137,772	($144,940)
36							
37	RETURN	$37,745,444	$2,103,917	$25,297,678	$351,017	$10,137,772	($144,940)
38							
39	RATE OF RETURN (PRESENT)	1.52%	1.42%	3.18%	0.44%	0.83%	-0.06%
40							
41	INDEX RATE OF RETURN (PRESENT)	0.52	0.49	1.09	0.15	0.28	-0.02

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2
Total Company
(Thousands of Dollars)

PRO FORMA ADJUSTMENT: **ANNUALIZE 4/1/05 ACC RATE LEVELS**

Adjustment to Test Year operations to reflect the annualization of ACC rate levels for the 4/1/05 rate increase authorized in Decision No. 67744.

Line No.	Description			Amount
1.	**REVENUES:**			
2.	Operating Revenue			
3.	Residential (less Dusk-to-Dawn)	$	9,584	
4.	E-32 and E-30 Classes (less Dusk-to-Dawn)		3,891	
5.	Extra Large General Service		2,273	
6.	Other G.S. Classes (less Dusk-to-Dawn)		438	
7.	Irrigation		315	
8.	Other (Dusk-to-Dawn and Lighting)		635	
9.	Total Pro Forma Adjustment to Revenues			$ 17,136
10.	**OPERATING INCOME (before income tax)**			**$ 17,136**
11.	Income Tax at 39.17%			6,712
12.	**OPERATING INCOME AFTER TAX**			**$ 10,424**

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2
Total Company
(Thousands of Dollars)

PRO FORMA ADJUSTMENT: **E-3/E-4 PROMOTIONAL EXPENSE**
Adjustment to Test Year operations to reflect increased promotional expense for low income rate options as required in Decision No. 67744.

Line No.	Description	Amount
1.	**REVENUES:**	
2.	Operating Revenue	$ -
3.		
4.	**EXPENSES:**	
5.	Other Operating Expenses	
6.	Operations Excluding Fuel Expenses	62
7.	Total Pro Forma Adjustment to Expenses	62
8.		
9.	**OPERATING INCOME (before income tax)**	**(62)**
10.	Income Tax at 39.05%	(24)
11.	**OPERATING INCOME AFTER TAX**	**$ (38)**

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2
Total Company
(Thousands of Dollars)

PRO FORMA ADJUSTMENT: **SCHEDULE 1 CHANGES**
Adjustment to Test Year operations to reflect revenue related changes to Schedule 1 as authorized in Decision No. 67744.

Line No.	Description	Amount
1.	**REVENUES:**	
2.	Operating Revenue	$ 127
3.		
4.	**EXPENSES:**	
5.	Other Operating Expenses	
6.	Operations Excluding Fuel Expenses	(19)
7.	Total Pro Forma Adjustment to Expenses	(19)
8.		
9.	**OPERATING INCOME (before income tax)**	**146**
10.	Income Tax at 39.05%	57
11.	**OPERATING INCOME AFTER TAX**	**$ 89**

Demand Side Management Adjustment Charge Plan for Administration

Demand Side Management Adjustment Charge Plan for Administration

General Description

Section VII of the Settlement Agreement approved by the Arizona Corporation Commission ("Commission") Decision No. 67744 provides for the establishment of a Demand-Side Management Adjustment Charge ("DSMAC"). The Arizona Public Service Company ("Company") is obligated under the Settlement Agreement to spend $30 million ($10 million annually) in base rates and at least another $18 million (an average of $6 million annually) during calendar years 2005 - 2007, with the latter amounts to be recovered by the DSMAC, on approved eligible Demand Side Management ("DSM") related items.

For purposes of implementing the Settlement Agreement, eligible DSM-related items include energy-efficiency DSM programs; a performance incentive; and low income bill assistance. These terms are defined in the Settlement Agreement. Energy-efficiency DSM is defined as the planning, implementation, and evaluation of programs that reduce the use of electricity by means of energy-efficiency products, services, or practices. The DSMAC charge is applied to Standard Offer or Direct Access customer's bills as a monthly kilowatthour or kilowatt demand charge. The charge is initially set at zero and will be reset annually, on March 1st, beginning in 2006. The change to the charge will be effective in billing cycle 1 of the March revenue month and will not be prorated.

All DSM programs must be approved before the Company may include their costs in any determination of the total DSM costs incurred. The Company may apply the program costs incurred after December 31, 2004 but prior to the effective date of Decision No. 67744 to the annual $10 million base rate DSM allowance and to the additional spending on eligible DSM-related items provided for in the Settlement Agreement. These costs must be from programs already approved by Staff, or the Commission.

The Company may request Commission approval for DSM program costs and performance incentives that exceed the $16 million ($48 million over three years) level. Such additional DSM programs may include demand-side response and additional energy efficiency programs and the costs and incentives that will be recovered through the DSMAC.

Base Rate DSM Description

The Company may phase in its DSM spending from the base rate allowance funding. However, the Company is required to expend at least $30 million on approved energy-efficiency DSM programs over the initial three years after a Commission order authorizing this program. After the initial three-year period, the Company is required to spend at least $10 million of the base rate DSM funds annually on approved energy-efficiency DSM programs. If the Company does not expend during calendar years 2005

through 2007 at least $30 million (in total) of the base rate allowance for approved and eligible DSM-related items, the unspent amount of the $30 million will be credited to the balance for the DSMAC. The Company is obligated to spend at least $13 million on approved and eligible DSM-related items during 2005 with the spending obligation to be pro-rated to the date that the Commission approves the Final 2005 DSM Plan. In no event will such pro-ration reduce the Company's 2005 obligation below the annual $10 million base rate DSM allowance.

Performance Incentives

The Company will be permitted to earn, and recover, performance incentives based on a share of the net economic benefits (benefits minus costs) from the energy-efficiency DSM programs approved in accordance with the Settlement Agreement. Such performance incentives will be capped at 10% of the total amount of DSM spending, inclusive of the program incentives, provided for in the Settlement Agreement (e.g., $1.6 million out of the $16 million average annual spending or $4.8 million over the initial three-year period). Any such performance incentive collected by the Company during a test year will be considered as a credit against the Company's test year base revenue requirement.

DSMAC Billing

For residential billing purposes, the DSMAC and the EPS Surcharge adjustor are combined and will appear on customer bills as the "Environmental Benefits Surcharge." For the billing of general service and other non-residential customers, the Company may, but is not required to, provide for such combined billing of the EPS and DSM adjustment mechanisms. In any event, each such adjustor shall have separate rate schedules and will be kept separate in the Company's books, records, and reports to the Commission.

Allowable Costs

The DSMAC will recover: (1) all costs (whether capitalized or expensed) associated with pre-approved energy-efficient DSM programs in excess of the $10 million built into base rates; and (2) performance incentives as described above. The DSMAC may also recover approved DSM program costs and performance incentives that exceed $16 million annually ($48 million over three years). Such additional DSM programs may include demand-side response and additional energy-efficiency programs. The types of allowable costs are as follows:

A. Program Costs	Allowable expenses will include: program development, implementation, promotion, administrative and general, monitoring/metering costs, advertising, educational expenditures, incentives, research and development, data collection (such as end-use), tracking systems, demonstration facilities and all other activities

required to design and implement cost effective energy efficient DSM for DSM Programs that are pre-approved and are not in base rates. For those DSM programs that generate revenue, the revenue will be credited back to the DSMAC.

B. Performance Incentives — Represents a share of the net economic benefits (benefits minus costs). Performance Incentives cannot exceed 10% of the total amount of DSM spending inclusive of the program incentive.

Customer Participation

Direct access customers shall be eligible to participate in the Company DSM programs. Any customer who can demonstrate an active DSM program and whose single site usage is twenty MW or greater may file a petition with the Commission for exemption from the DSM adjustor. The public shall have 20 days to comment on such petition. In considering any petition pursuant to this paragraph, the Commission may consider the comments received and any other information that is relevant to the customer's request.

DSMAC Calculations

Before March 1st, beginning in 2006, the Company will file a request with supporting documentation to revise its DSMAC. The DSMAC will be recomputed annually.

All required and approved spending on eligible DSM-related items above the annual $10 million base rate allowance will be recovered by the Company only on an "after-the-fact" basis through the DSM adjustment mechanism. DSMAC Schedules 1 through 4 shall be used to document DSMAC calculations.

The per-kWh charge for the year will be calculated by dividing the DSMAC recoverable costs by the number of kWh used by customers in the previous calendar year. General Service customers that are demand billed will pay a per kW charge instead of a per kWh charge. General Service customers that are not demand billed shall pay the DSMAC on a per kWh basis. To calculate the per kW charge, the recoverable costs shall first be allocated to the General Service class based upon the number of kWh consumed by that class. The remainder of the recoverable costs allocated to the General Service class shall then be divided by the kW billing determinants for the demand billed customers in that class to determine the per kW DSM adjustor charge. The DSM adjustor will be applied to both Standard Offer and Direct Access customers with the exception of solar rates Solar-1, Solar-2 and SP-1.

DSMAC Schedules

The recoverable annual costs and incentives from approved programs above the base rate cost allowance will be listed on Schedule 1. Schedule 2 lists actual revenues received by

the Company through imposition of the DSMAC on customer bills. The Balancing Account computation (Schedule 3) contains the development of the recoverable costs for each year's DSMAC. Each year, the Un-Recovered DSM Cost accrues interest using the one-year Nominal Treasury Constant Maturities rate that is contained in the Federal Reserve Statistical Release H-15 or its successor publication. Schedule 4 is an example of the DSMAC demand and energy charge calculations.

ARIZONA PUBLIC SERVICE COMPANY
DSMAC Schedule 1
Example DSM Adjustment
Recoverable Costs
Charge Period XXXXXXX 1, XXXX through XXXXXXX 31, XXXX

Line No.		2005	2006	2007
1	Recoverable Program and Incentive Costs above the Base Rate allowance	$ 100,000	$ 5,000,000	$ 11,000,000

ARIZONA PUBLIC SERVICE COMPANY
DSMAC Schedule 2
Example DSM Adjustment
ACTUAL DSM Adjustment Charge Revenues
Charge Period XXXXXXX 1, XXXX through XXXXXXX 31, XXXX

Line No.	Mths	Actual Retail Energy Sales (kwh)	Effective DSM Adj. Energy Charge $ per kWh	Revenue From DSM Adj. Energy Charge	Actual Retail G.S. Monthly Demand (kW)	Effective DSM Adj. Monthly Demand Charge $ per kW	Revenue From DSM Adj. Demand Charge	Revenue From DSM Adj. Charges
1	Jan - Feb 05	3,048,197,000	$ -	$ -	4,166,667	$ -	$ -	$ -
2	Mar - Dec 05	19,305,074,000	$ -	$ -	20,833,333	$ -	$ -	$ -
		22,353,271,000		$ -	25,000,000		$ -	$ -
3	Jan - Feb 06	3,109,160,940	$ -	$ -	4,250,000	$ -	$ -	$ -
4	Mar - Dec 06	19,691,175,480	$ 0.000005	$ 98,456	21,250,000	$ 0.002000	$ 42,500	$ 140,956
		22,800,336,420		$ 98,456	25,500,000		$ 42,500	$ 140,956
5	Jan - Feb 07	3,171,344,159	$ 0.000005	$ 15,857	2,167,500	$ 0.002000	$ 4,335	$ 20,192
6	Mar - Dec 07	20,084,998,990	$ 0.000220	$ 4,418,700	23,842,500	$ 0.088000	$ 2,098,140	$ 6,516,840
		23,256,343,148		$ 4,434,556	26,010,000		$ 2,102,475	$ 6,537,031

ARIZONA PUBLIC SERVICE COMPANY
DSMAC Schedule 3
Example DSM Adjustment
Balancing Account Computation
Charge Period XXXXXXX 1, XXXX through XXXXXXX 31, XXXX

Line No.		2005	2006	2007
1	Recoverable Program and Incentive Costs above the Base Rate allowance (Sch. 1)	$ 100,000	$ 5,000,000	$ 11,000,000
2	Less DSM Revenue recovered from effective DSMAC (Sch. 2)	$ -	$ 140,956	$ 6,537,031
3	Un-Recovered DSM Costs (Line 1 - Line 2)	$ 100,000	$ 4,859,044	$ 4,462,969
4	Annual Interest @ 3.33%	$ 3,330	$ 161,806	$ 148,617
5	Total DSMAC Recoverable Costs (Forward to Sch. 4)	$ 103,330	$ 5,020,850	$ 4,611,585

ARIZONA PUBLIC SERVICE COMPANY
DSMAC Schedule 4
Example Calculation of the DSM Adjustment Charge
Charge Period XXXXXXX 1, YYYY through XXXXXXX 31, YYYY

Line No.		2005	2006	2007
1	Total DSMAC Recoverable Costs (Sch. 3, Line 5)	$103,330	$5,020,850	$4,611,585
2	Retail kWh Sales in Period (Sch. 2)	22,353,271,000	22,800,336,420	23,256,343,148
3	DSM Adjustment Charge per kWh to be Applied in Following Year (Line 1/Line 2)	**$ 0.000005**	**$ 0.000220**	**$ 0.000198**
4	kWh Sales for General Service Customers with Demand-Based Bills	10,000,000,000	10,200,000,000	10,404,000,000
5	kW Billing Determinants for General Service Customers with Demand-Based Bills	25,000,000	25,500,000	26,010,000
6	Revenue for G.S. Customers with Demand-Based Bills (Line 3*Line4)	$50,000	$2,244,000	$2,059,992
7	Monthly DSM Adj. Charge per kW to be Applied in Following Year (Line 6/Line 5)	**$ 0.002000**	**$ 0.088000**	**$ 0.079200**

APS Investigation into Rate Designs Conducive to Conservation and DSM

November, 2005

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APS Investigation into Rate Designs
Conducive to Conservation and DSM

Executive Summary

Arizona Public Service ("APS" or "Company") conducted an assessment of various retail pricing concepts that could be conducive to encouraging conservation and peak demand reduction while meeting other key rate design criteria. This study was performed in accordance with Decision No. 67744[1] of the Arizona Corporation Commission ("ACC").

The study assessed the Company's situation concerning the customers and electric loads that we are committed to serve, both now and in the future, and the generation resources and costs necessary to serve our customers. This evaluation outlined key issues concerning our system loads and resources and provided direction and focus for the types of pricing designs that could potentially help address those issues. The key issues include the following:

A. APS System Needs

1. The Company is facing high load growth, especially during peak times. APS' load growth is nearly three times the national average.

2. The summer daily peak is broad, lasting from late morning to well into the evening. Peak day hourly loads in the early to mid evening are still within 90% of the peak hour.

3. The winter peak is low relative to the summer. Winter peaks are typically 40% to 50% lower than the summer.

4. Annual system load factor is relatively low. This is driven by low energy usage in the winter relative to the summer as well as a low daily off-peak usage relative to peak usage, for both the winter and summer seasons. Low load factors are generally considered to be more expensive to serve, in terms of average cost per kilowatthour (kWh), since generation, transmission and distribution capacity fixed costs necessary to serve the peak load are spread over fewer kWhs compared with high load factor cases.

5. While the APS system load remains high over a number of hours during the peak day, the number of critical days or hours with extremely high loads or high short-term energy costs is moderate.

B. Pricing Concepts Evaluated

The pricing study focused on evaluating pricing concepts that could (1) help manage peak growth by reducing summer peak usage, (2) improve the system load factor by

[1] APS Rate Settlement Section VII, Paragraph 57.

reducing summer peak use or shifting load from on-peak to off-peak during the summer season, (3) encourage energy efficiency or (4) focus the intended customer load response to critical days and hours. As a result, the study investigated the following pricing concepts:

- Residential inclining block rates
- Residential time-of-use rates
- General Service time-of-use rates
- Mandatory vs. Voluntary Rates
- Other Demand Response Programs such as critical peak pricing and demand bidding programs

Each pricing concept was evaluated based on the following criteria; industry experience, potential customer acceptance and participation, potential impacts on the system peak and overall annual load shape, and program implementation costs.

C. Conclusions

Inclining Block Rates – Residential

Inclining block rates establish prices for blocks of monthly energy consumption and increase the price for the higher blocks. The objective is to encourage energy conservation by placing a higher price on the highest marginal usage, which is presumed to be for some discretionary purpose. The Company currently has over 479,000 or 56% of total residential customers on inclining block rates, which are the standard residential rates. The conclusions reached are:

1. APS should maintain the defined usage levels for the pricing blocks at their current levels, which are 0-400 kWh per month for Tier 1 prices, 401-800 for Tier 2 prices, and greater than 800 kWh per month or Tier 3 prices. A reduction in the block usage structure to 0-350 kWh per month for Tier 1 and 351-750 kWh per month for Tier 2 would likely provide only limited impacts on energy conservation, could limit the benefits of the pricing change for some low and moderate-use customers, and would create an inconsistency with the blocks for the low income and medical discount programs.

2. Changing the pricing structure for Rate Schedule E-12 by shifting cost emphasis from the price of the lowest usage block (Tier 1) and raising the price of the highest usage block (Tier 3) should be done with moderation because the Tier 3 price is already high in relation to the Tier 1 price.

Time-of-Use Rates – Residential

Time-of-use rates (TOU) determine daily and seasonal time periods for pricing electricity, which include peak, off-peak and sometimes shoulder periods. Energy and/or demand charges are determined for each of these time periods. Currently APS offers two residential TOU rates: Time Advantage (ET-1), which includes peak and off-peak energy charges; and Combined Advantage (ECT-1R) which includes both time differentiated

demand and energy charges. Over 357,000 APS residential customers, or 40% of total, are currently participating in a TOU rate. On September 22, 2005, APS filed an Application with the Commission to obtain approval for two new experimental residential TOU rates. Schedule ET-2 parallels the exiting TOU schedule ET-1 and ECT-2 parallels the features of ECT-1R. These new schedules provide for longer off-peak periods than the existing TOU rates and also incorporate holidays in the off-peak periods. Both new rates have time-differentiated charges. ECT-2 will also have a demand charge applied to the peak period. Customer reaction to these new rate offerings will be one indicator whether the experiment will be expanded to a broader group of customers.

Time-of-Use Rates – General Service

Time-of-use rates have been used widely by numerous utilities for general service customers. For the purposes of this report, general service refers to commercial and industrial customers with demands typically less than 3,000 kW. TOU rates encompass a variety of pricing designs which use a combination of demand and energy charges for peak and off-peak periods. TOU rates are referred to as static demand response rates because both the peak and off peak prices and time periods are established in the tariff and cannot be varied to react to temporary changes in hourly energy costs or loads. The Company's, new general service TOU rate, E32TOU, was implemented in April, 2005. Thus, it is too soon to assess the potential customer acceptance and load impacts. However, the rate is consistent with other general service TOU rates offered by other utilities in terms of the rate structure, price ratios for on- and off-peak periods, and on-peak hours. The Company will undertake the following:

1. Continue to implement the current general service time-of-use rate as designed with the potential for minor design adjustments to make the rate more customer friendly. As discussed below, the rate structure, charges, and peak time period is consistent with current TOU pricing concepts and tariffs offered by many other utilities.

2. Monitor customer participation in Schedule E-32 TOU. Examine the load patterns of customers who opt for the new rate to determine if the desired goals of reduction in on-peak demand and on-peak energy conservation are being realized.

Mandatory vs. Voluntary Rates

Voluntary demand rates are generally considered to be favorable because; they avoid the negative image of mandatory rates, they avoid adverse impacts on inelastic customers, they maintain market discipline for providing better programs, and they can result in better target marketing of programs to specific customer groups.

After considering the various issues, it is not recommended that APS move to mandatory general service TOU rates largely due to the negative image of forcing customers to participate in a rate or program. Some of this is a general concern that many customers may not be able to respond to time-differentiated prices. Therefore, forcing all customers on a demand response rate would have adverse and, in some cases, unintended consequences for particular customers or customer groups.

Other Demand Response Programs

1. Critical Peak Pricing

Critical Peak Pricing (CPP) options are fairly new and are typically targeted to commercial and industrial (C&I) customers. However, there have been a few residential programs or experiments. CPP combines time-of-use pricing with an additional on-peak higher price period, which is selectively applied by the utility during periods of high energy costs or reliability issues.

2. Demand Bidding Programs

Demand bidding programs are being tested by some utilities for commercial and industrial customers. These programs allow a customer to bid potential load reduction, typically the day before a critical event, for an incentive based on a predetermined price. For some programs, participants are not required to bid into any particular critical event or even reduce their load as bid. Other programs require customers to "deliver" their load reductions as bid or face penalties. These demand response programs are fairly new and there are still many uncertainties concerning customer acceptance, potential load impacts and implementation costs.

Based on the uncertainty at this time of the potential participation and implementation issues including costs, the Company will undertake the following:

- The Company will continue to monitor critical peak pricing and demand bidding programs to assess pricing designs, program best practices, and customer participation and load impacts.

- The Company will further assess program implementation costs, especially communication infrastructure, data handling and billing systems to better assess the cost/benefit.

Implementation of New Pricing Concepts

Section I of this report discusses metering, meter reading and billing system limitations that must be addressed in order to implement new pricing concepts. For example, because of the market penetration of residential TOU pricing, even a modest change to the existing rate structure such as altering off-peak pricing hours could be a significant undertaking because of the need to reprogram meters that are currently installed. APS is investigating new technologies, including a pilot Advance Metering System (AMS), that, if proven successful, will provide for greater rate option flexibility in the future.

APS Investigation into Rate Designs Conducive to Conservation and DSM

SECTION I

Company Peak, Load Shape and Load Factor

Overview

APS serves more than 1,000,000 customers in 11 of Arizona's 15 counties, including the Phoenix Metro area. In August 2005, the APS system load demand peaked at 7,000 MW with associated annual energy of approximately 30,000 GWh.

Historically, growth in APS' service territory has been about three times the national average. In 2004, the APS customer base increased by 3.7% or approximately 35,000 customers and retail energy sales increased by 3.2%. Currently the Company is projecting an average annual growth rate of approximately 3.9% for peak demand through 2009, and 4.6% for energy sales over this period.

Annual system load factor, which is the relationship between peak demand and overall energy usage, was 52% in 2004. This means that for every 100 MW of consumption during the annual peak hour, APS customers used only 52 MW per hour on average in all of the other hours of the year.

The summer peak load is typically 40% to 50% or 2,000 MW higher than the winter peak. In addition the Company's high loads are concentrated into a relatively small number of hours on an annual basis. For example, in 2004 there were only 25 hours in which loads were within 5% of the system peak, 87 hours within 10% of system peak.

APS owns a portfolio of generation technologies that include steam turbines and combustion turbine engines fueled by nuclear, coal, gas and oil. The mix of generation comprises of 71% baseload capacity and 29% peaking capacity.

Peak Day Load Shape

Summer Peak

Figure 1 displays the APS system peak day load for 2004. In addition, Table 1 shows hourly information for the highest 10 peak days in 2004. As shown, the summer peak for APS' retail load typically occurs between 3:00 and 6:00 p.m. The load begins to ramp up at 9:00 am. By 12:00 p.m. the load is within 10% or 500 MWs of the daily peak. The load remains high, within10% of the daily peak, though 8:00 p.m. and falls off after 9:00 p.m. The load from 6:00 to 7:00 is typically 95% of the daily peak; the load from 7:00 to 8:00 is 91% of the daily peak.

Winter Peak

The winter peak for APS' retail load typically occurs at 7:00 to 8:00 a.m. in one of the cold months (December – February). The daily load ramps up at 6:00 a.m. and falls off after 9:00 a.m. Afternoon usage picks up at 6:00 p.m., reaching 90% of the daily peak, and falls off after 9:00 p.m.

In some years, hot temperatures in March or April can cause daily loads to rival some of the cold days in December and January. In 2004, for example, 5 of the top 10 "winter" days were in March and April. However, the usage patterns for these days resemble the summer peak days. In any case, winter loads are significantly lower than summer loads. Typically, the winter peak is 40% or 2,000 MW lower than the summer peak.

Figure 1. APS System Peak Day 2004

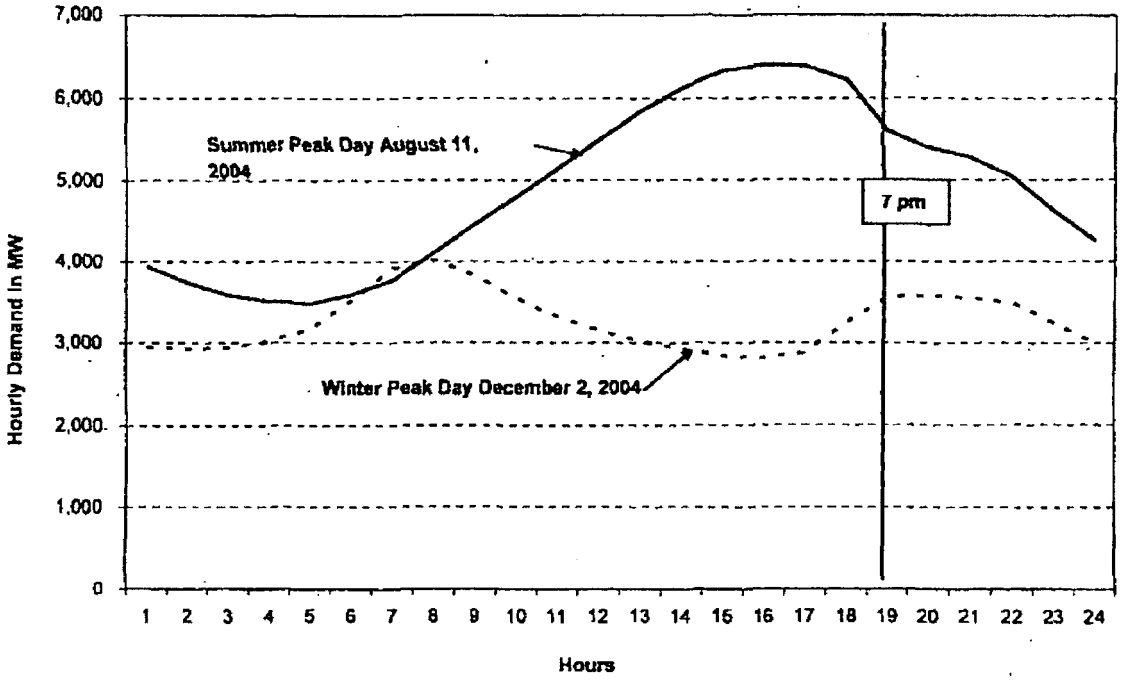


Table 1 Summer 2004 Top 10 Peak Days (hour ending)

Hour	1am	2am	3am	noon	1pm	2pm	3pm	4pm	5pm	6pm	7pm	8pm	9pm	10pm	12pm
Average	4014	3595	4378	5324	5609	5870	6054	6104	6117	6086	5816	5585	5446	5170	4334
Delta Peak	-2103	-2522	-1739	-794	-508	-248	-63	-13	0	-31	-301	-532	-671	-948	-1783
% Peak	66%	59%	72%	87%	92%	96%	99%	99%	100%	99%	95%	91%	89%	84%	70%

System Load Factor

Table 2 compares the annual system load factors for APS and other regional utilities for 2000-2003. The system load factor represents the relationship between usage during the system annual peak hour and the usage during all other hours of the year. A low load factor means that customers demand a lot of load during the peak hour, but don't use very much energy on average during other times of the year. Due to our high summer peak, APS' annual system load factor has been relatively low as compared to load factors of other electric systems in other western states.

Table 2 Historical System Load Factors for WECC Utilities (in %)

	2003	2002	2001	2000
APS	50.9	52.6	53.2	52.3
EPE	61.4	61.5	64.8	65.4
LDWP	55.0	55.2	59.5	55.7
NPC	47.6	47.5	47.2	47.2
PAC	68.1	68.8	73.7	72.2
PG&E	56.8	56.6	57.5	55.6
PGE	67.3	67.0	65.8	65.3
PNM	64.8	68.4	69.5	67.0
PSC	59.0	62.0	61.6	61.1
PSE	61.5	64.0	61.7	61.6
SCE	55.1	57.6	60.2	57.8
SDGE	57.8	60.9	66.6	64.8
SMUD	43.0	41.5	45.0	43.5
SPP	66.9	67.8	71.0	69.7
SRP	49.4	50.8	51.8	52.4
TEP	50.4	53.1	56.7	55.6

Another perspective of the APS system load factor is presented in Table 3, which shows the number of hours that the system hourly demand reached a certain percentage of the annual system peak demand. For example, in 2004, there were only 87 hours during which time the system hourly load was equal to, or higher than, 90% of the annual peak. The implication is that peaking capacity is always required to meet the customer demand for energy for a short period of time.

Table 3 APS Historical Hourly Own Load Analysis

YEAR	ANNUAL PEAK LOAD IN MW	NUMBER OF HOURS WHEN SYSTEM HOURLY DEMAND IS EQUAL TO OR GREATER THAN				
		95% of Peak	90% of Peak	85% of Peak	80% of Peak	75% of Peak
2000	5,186	45	153	374	719	1092
2001	5,372	16	69	267	625	1030
2002	5,494	28	150	382	686	1008
2003	5,973	34	119	299	542	859
2004	6,018	25	87	269	520	825

Customer Load Diversity

The APS system load shape is the result of various diversified usage patterns generated by customers' end uses of electricity in different climate zones. An end use is met by an appliance (residential usage) or equipment (commercial/industrial applications). For example, an air conditioner is used to supply space cooling (an end use) in a residential home. Each electric appliance or equipment imposes a pattern of varying hourly demand on the system, that is, it has its own load shape.

Individual end use (or appliance) load shapes are vastly diversified that the sum of their individual hourly consumptions results in a total load shape that is significantly different from the end-use load shapes. Most important is the peak hourly demand on the utility's total system. The peak hourly demand of the total load shape is significantly lower than the sum of the individual peak hourly demands.

An example of the diversity of customers' end-use loads is demonstrated in Table 4, using load research data from August, 2004.

Table 4 APS Customer Load Diversity

	Residential	General Service*
Sum of individual customer maximum demands	5841 MW	3478 MW
Non-coincident peak demand	3127 MW	2748 MW
Coincident peak demand (Peak day July 14,2003)	2571 MW	2252 MW
Average customer maximum demand	6.83 kW	33.40 kW
Average customer coincident demand	3.01 kW	21.63 kW

August 2004 data.
* *Customers on rate schedules E-30 and E-32.*

The APS service territory covers the high-country area (Flagstaff), the Phoenix Valley and the low-desert area (Yuma) which contribute to the system diversity due to the natural diversity in weather patterns among the various locales.

Diversity can also be viewed on a much larger system perspective, that is, diversity among different utilities. Utilities in the Desert Southwest area typically peak in the summer whereas those in the Northwest area typically peak in the winter. This diversity in system peaks allows opportunities for seasonal energy exchanges. An example of this opportunity is the contract between APS and PacifiCorp, which was consummated in 1990 to take advantage of the diversity between APS (summer peaking) and PacifiCorp (winter peaking).

Generation Resources

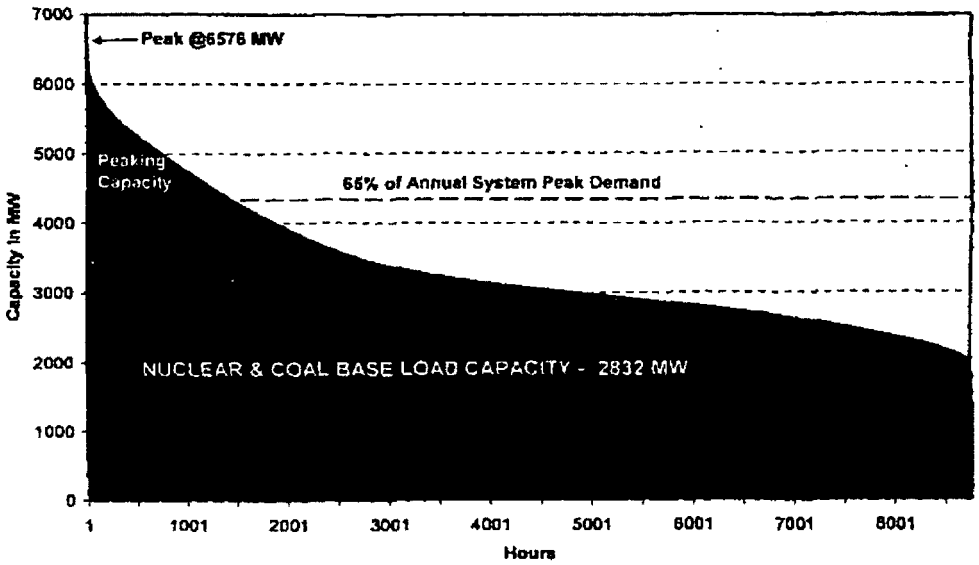
Peaking Capacity Requirements

Figure 2 shows the projected Load Duration Curve (LDC) for the year 2005. Plotted against the 2005 LDC is the expected energy to be dispatched from APS' current mix of generation capacity including baseload nuclear/coal, gas-fired combined cycle and peaking plants. It can be seen that the system was designed for optimal efficiency with peaking capacity being dispatched when

system hourly demand is higher than 65% of annual peak demand. This also depicts the requirements for peaking capacity to meet the peak demand of the system. Figure 2 shows the need of about 2,200 MW of peaking capacity in 2005. Currently, APS has about 1,800 MW of gas-fired peaking capacity installed. Reserve requirements are not included in the peaking capacity estimate.

Figure 2

2005 LOAD & RESOURCE BALANCE



Key Findings

1. The Company is facing high growth, especially during peak times.

2. The summer daily peak is broad, lasting from late morning to well into the evening.

3. The winter peak is low relative to the summer. Winter peaks are typically 40% lower than the summer.

4. System load factor is relatively low. This is driven by low energy usage in the winter relative to the summer as well as a low daily off-peak usage relative to peak usage, for both the winter and summer seasons. Low load factors are generally considered to be more expensive to serve, in terms of average cost, as generation, transmission and distribution capacity costs necessary to serve the peak are spread over fewer megawatt hours (MWH) of overall energy use.

5. While the system load remains high over a number of hours during the peak day, the number of critical days or hours with extremely high loads or high short-term energy costs is moderate.

Implications for Pricing Design

Reflecting the characteristics of the APS system, this study focuses on evaluating pricing concepts that could potentially:

- Help manage peak growth by reducing summer peak usage.
- Improve the system load factor by reducing summer peak use or shifting load from the peak to off peak during the summer season.
- Focus the intended load response to critical days and hours.

Pricing Design Reviewed

To encourage or enable customers to change their usage patterns in order to lower overall costs, pricing should be designed to send price signals that are more reflective of costs or capacity constraints in specific periods of time or in specific situations. Typically this means lowering consumption during peak periods, especially during times of very high costs or system constraints. However, it can also mean increasing consumption in off-peak periods with relatively low energy costs, especially by shifting load from peak to off-peak periods.[2] The latter can improve system load factor and thereby potentially lower average costs. It can also increase consumer welfare by providing customers with the derived benefits of electricity when costs are low.

Rates may be static or dynamic. Static prices, such as time-of-use (TOU) rates, have peak and off-peak prices that are pre-determined and set in rate tariffs. Dynamic prices by contrast can change contemporaneously with changing cost or reliability conditions. Examples of dynamic pricing include critical peak pricing, real-time pricing (RTP), or various demand-bidding programs. Critical peak pricing is a TOU rate with a critical period price that is only applied during select days of the year with high costs or low reliability. Dynamic prices typically involve on-going interaction between the utility or control area operator and the customer such as the communication of prices, notification of critical periods, submission of load bids, and in some cases direct control of customers' loads by the utility.

Inclining block rates establish prices for blocks of monthly energy consumption and increase the price for the higher blocks. The objective is to encourage energy conservation by placing a higher price on the marginal usage, which is presumed to be for some discretionary purpose. These rates also attempt to protect customers by setting a lower price on the lowest consumption block, which is presumed to for necessities. Inclining block rates are generally considered to be conservation rates, but have been considered by some to be a type of demand response pricing as will be discussed later.

[2] This issue is often overlooked [Christensen 2003]

The pricing study includes an assessment of:

- Residential inclining block rates
- Residential time-of-use rates
- General service time-of-use
- Mandatory vs. Voluntary Rates
- Demand response Programs
  - Real time pricing and
  - Demand bidding programs

Each rate was evaluated in terms of how it helped to address the Company's load and resource issues, industry experience, potential participation, impacts on system peak and energy, and program implementation costs. Industry assessments of these pricing concepts also address issues of mandatory versus voluntary rates and potential revenue erosion from new rates.

Implementation of New Pricing Concepts

Implementing new pricing concepts requires changes to metering, the customer information and billing system, the metering information system and related programs. These systems and numerous subsystems interrelate to capture metered data, ensure that the customer is on the correct rate with the correct meter, calculate the bill, present the bill, allow for re-bills and corrections, schedule meter and service changes, provide customer service information and screens to advise customers about rate options, allow customers to assess rate options through the internet, post the revenue to the general ledger, and many other functions. Most importantly, any new rates that are structurally different from current rates require significant systems testing to ensure that the data is correctly captured, billing is accurate and that the programming changes do not adversely impact any other part of the systems.

Several of the key systems that require modifications for implementing new rate schedules are metering, the customer information and billing system, the customer service software interface, APS.COM and the meter information system. Two of the key systems are described below. Additional discussion on this topic can be found in the report on TOU flexibility that was provided to the Commission in October, 2005.

Metering technology

APS' current meter reading system does not support the capability of reprogramming meters in the field with the hand held "probe" device that is used to read the meters. While software support that enabled field programming was once available, it is no longer supported by the current vendor. Therefore, meter programming must be performed at the manufacturer, at the utility's meter shop, or in the field using a computer loaded with each meter vendor's software. The latter option is not practical for handling a significant number of customers due to the time required to reprogram each meter.

Because of the limitation of our current meter reading system, changing time-of-use characteristics, such as the on-peak hours for an existing rate schedule would require replacing the meters of all of the current customers on the rate schedule. In addition to being very costly,

such a massive meter change out could only occur over a long period of time. During the transition period, meter record keeping would be very challenging since the links between the meter which is currently in use at a customer's residence and the appropriate rate schedule must be maintained. For example, if the customer has already migrated to the rate schedule with new TOU periods and experiences a meter failure, the APS meter service personnel must have the correct replacement meter available in inventory.

Another issue concerns the potential need for a meter change when a customer switches between standard and TOU rate schedules. Many customers require a meter change to accommodate a switch in rate schedules. Some customers have meters that are pre-programmed to be able to bill both standard and TOU rate schedules. In this case, the customer would not typically require a meter replacement if the customer switched between a standard rate schedule and one of APS' current TOU rate schedules.

However, this flexibility erodes as new TOU rates with different on-peak hours and other characteristics are introduced. For example, while a meter can be pre-programmed to be able to bill both a standard rate and a TOU rate, it cannot be pre-programmed to be able to bill both a TOU rate schedule with a 9A.M. to 9 P.M. on-peak period and one with a noon-7 P.M. on-peak period. This is because the billing determinants for the standard rate are nested in (or captured by) the TOU billing information. However, the billing determinants for the two TOU rate schedules, namely the on-peak and off-peak kWh, are distinct and cannot be simultaneously captured by the same meter. Rate switches between the alternative TOU rate schedules would require the meter to be re-programmed with the new rate schedule.

APS is reviewing several metering alternatives that may add flexibility for changing TOU rates in the future. These included implementing an alternate meter reading system, implementing an advanced metering system (AMS) and using interval data recording meters (IDR). These alternatives are not mutually exclusive and a combination of the new technologies will likely be implemented.

Customer Information System (CIS)

CIS is the mainframe software application that handles all billing, customer data, and customer information processing. In order to implement new rate offerings, CIS requires programming changes to ensure that the customer account is maintained properly with the current rate schedule, meter and other relevant information, and that the bill is calculated and presented accurately. This requires changes to various tables, service plans, screens, reference tables, bill calculation, bill statements, rate comparison features, order processing, E-bill, service account maintenance, new business cases, new reports, and related subsystems.

If a new rate schedule involves changing the basic structure of the rate calculation, it requires extensive programming of the basic CIS data base and related tables and code. New rate schedules and meter types have to be tested to ensure that the billing information is correctly extracted from the meter and uploaded to the CIS system. Also, old data structures and relations must be maintained so that rebilling of customers, if ever needed, can occur. In summary, rate structure changes such as new pricing concepts cannot be handled by CIS without considerable investment in programming and testing.

SECTION II

Inclining Block Pricing - Residential

Overview

Inclining block rates establish prices for blocks of monthly energy consumption and increase the price for the higher blocks of consumption.

Variations include baseline pricing and inverted pricing for peak time energy usage or demand. For peak-period inverted-block rates, prices increase with energy usage or demand during peak periods, but are constant or decline with usage during off-peak periods. Under baseline pricing, prices increase for usage above a baseline level for basic and necessary services.

Currently the Company offers inclining block rates as the standard, non-time-of-use rate for residential customers. The inclining block rates are Rate Schedule E-10, which is frozen to new customers, and Rate Schedule E-12, which is the standard, non-TOU option for residential customers. As shown in Table 5, over 479,000 customers or 56% of total customers are participating in inclining-block rates. Both rates divide the monthly energy consumption into three blocks: 0 to 400 kWh, 401 to 800 kW, and above 800 kWh. The current energy charges for each block for the summer season are shown in Table 6.

Table 5 Residential Inclining Block Rates (2004)

	AVERAGE CUSTOMERS	ENERGY SALES (MWH)
E-10	83,504	814,452
E-12	396,024	3,420,566
Total Inclining Block	479,528	4,235,018
Total Residential	859,069	11,497,367
Percent	56%	37%

Table 6 Residential Inclining Block Rates
Summer Energy Charges by Block (Cents per kWh)
Rates Effective April 1, 2005

	0 to 400 kWh	401 to 800 kWh	Above 800 kW
E-10	6.929	9.490	9.760
E-12	7.570	10.556	12.314

Industry Experience

A review of standard residential rates for select utilities showed a mix of flat (energy charges do not vary with usage), declining block or inclining block prices. The review included major utilities in the South, West, and Midwest which were likely to have substantial summer loads. Utilities in the Northeast were not reviewed because they were presumed to be more winter peaking and because many states in the region have active retail competition and have required utilities to divest generation assets. California utilities generally have an inclining block

structure for standard residential rates, which were instituted a few years ago and modified as a response to the energy crisis. The California rates will be discussed separately.

Table 7 compares APS' standard residential rate E-12 with other standard residential rates. Out of the 25 utilities reviewed, 10 have inclining block rates for standard residential service, 15 have either flat or declining block rates. The inclining block rates generally have two or three tiers, with the upper limit of the first tier ranging from 200 to 1,000 kWh per month. By comparison, the first tier of APS' E-12 rate ends at 400 kWh per month. For rates with three tiers, the upper limit of the second tier ranges from 800 to 1300 kWh per month. APS' second tier limit is 800 kWh per month. APS generally has a more aggressive tiered pricing structure compared with other utilities. As shown, the comparative price ratio of the highest to lowest tiers for the APS E-12 rate is 1.63, meaning that the last tier price is 63% higher than the first tier. This is second only to Georgia Power with a 1.70 ratio, and they have a much higher starting point for the last tier – 1,100 kWh versus 800 kWh for APS. The remaining 23 utilities have high-to-low tier price ratios ranging from 1.04 to 1.34.

Table 7 Standard Residential Rates for Select Utilities

UTILITY, STATE	RATE STRUCTURE	TIERS, KWH/MONTH	LAST TIER/FIRST TIER CHARGE
APS – AZ	Inclining Block	0-400, 401-800, >800	1.63
PNM – NM	Inclining Block	0-200, >200	1.17
PacifiCorp –Wash	Inclining Block	0-600, >600	1.58
Detroit Edison – MI	Inclining Block	0-17 kWh per day	1.18
FPL	Inclining Block	0-750, >750	1.12
Utah Power Light – UT	Inclining Block	0-400, 601-1000, >1000	1.34
Georgia Power – GA	Inclining Block	0-650, 651-1100, >1100	1.70
Duke – NC, SC	Inclining Block	0-350, 351-1300, >1300	1.13
Progress Energy – FLA	Inclining Block	0-1000, >1000	1.14
Alabama Power – AB	Inclining Block	0-1000, >1000	1.04
Aquilla – KA, MO	Flat		
Nevada Power – NV	Flat		
SRP- AZ	Flat		
TEP – AZ	Flat		
Progress Energy – NC	Flat		
MidAmerican – IOWA	Flat, winter DB		
LGE – KY	Flat		
Entergy – Ark	Flat		
Entergy – LA	Flat		
Commonwealth Ed – IL	Flat		
PSC – CO	Flat		
Cinergy – Ohio	Flat		
OGE – OK	Declining Block		
Entergy – Miss	Declining Block		
Dominion – VA	Declining Block		

California Baseline Inclining Block Rates

California utilities implemented inclining block rates several years ago with a first energy usage tier designed to provide customers a baseline level of service. The baseline allowance was

calculated according to geographical/climate regions. Additional baseline allowance was typically added for all-electric homes and for qualified medical needs. For example, the baseline usage For SCE customers varies from 10.0 to 47.6 kWh per day, which is an average of 300 to 1400 kWh per month, for the summer season, depending on the region. Usage above the baseline amount is charged according to three additional tiered prices with the tiers defined as 101% to 130% of baseline usage, 131% to 200% of baseline and over 200% of baseline. As a response to the energy crisis of 2000-2002, pricing of the inclining block rates became more aggressive. Tiered energy prices range from approximately 11.75 cents per kWh for summer baseline usage and 17.34 cents per kWh for the highest tier (exclusive of other charges). These prices can vary somewhat depending on the proportion of generation that comes from the utilities retained generation versus the amount that was procured for SCE customers by California during the energy crisis. The ratio of the price of the highest tier to the lowest tier is 1.48 for the summer season, which is less than APS' ratio of 1.63 for Rate Schedule E-12.

Analysis and Issues

Pursuant to Decision No. 67744, APS investigated potential changes to the tier usage levels and prices for Rate Schedule E-12. Specifically we evaluated the potential implications of (1) lowering the first tier usage limit from 400 to 350 kWh per month, (2) lowering the second tier usage limit from 800 to 750 kWh per month, (3) lowering the energy price for the first tier usage and (4) raising the price for the highest tier usage. The potential benefits of these proposed changes are presumably to encourage additional energy conservation by shifting the average customer's marginal monthly usage into the highest tier and to raising the price of the highest tier. The rate modification could also potentially provide bill savings for the lower-usage customers. Each of these changes is assessed below.

Assessment of Proposal to Lower the Usage Limit and Price for Tier 1

Lowering the usage limit of Tier 1 from 400 to 350 kWh per month can help to reduce the potential revenue loss from lowering the Tier 1 price. However, the change could cause unintended consequences for some customers. Specifically, while this proposed change would lower the price for usage in the 0-350 kWh block, it would significantly raise the price for the 350 to 400 kWh block by shifting this usage to the Tier 2 price. Therefore, customers at the 350 to 400 kWh usage level could be harmed from this change.

Table 8 Rate E-12 Summer Customers and Consumption by Block

Block (kWh/month)	Bills (per Summer)	kWH (per summer)	Average Customers (per month)	kWh (per month)	Current Charge ($/kWh)	Proposed Change in Block Price
0-350	703,761	113,808,000	117,294	18,968,000	0.07570	Decrease
350-400	102,797	38,605,990	17,133	6,434,332	0.07570	Increase
400-750	670,095	380,885,072	111,683	63,480,845	0.10556	No Change
750-800	77,784	60,302,304	12,964	10,050,384	0.10556	Increase
above 800	947,269	1,325,185,565	157,878	220,864,261	0.12314	Increase
Total	2,501,706	1,918,786,931	416,951	319,797,822		
Average	767	kWh/month				
Median	0	kWh/month				

*2004 Data

As shown in Table 8, there are over 17,000 customers on average with summer monthly usage between 350 and 400 kWh per month. Currently their summer energy cost is $0.07570 per kWh for all of their consumption. Under the change, the energy price for the first 350 kWh of consumption would be reduced somewhat, but the 350 to 400 consumption would be increased significantly from $0.07570 to $0.10556 /kWh shifting it to Tier 2 pricing. For example, under the current rate E-12 a customer consuming 400 kWh per month would pay $30.28 for base energy charges (excluding the basic service charge and other taxes and fees). If the first block is changed to 0-350 and the Tier 1 price is reduced by 5%, then on net this customer's bill would actually increase.

Table 9 Impact from Tier 1 Changes

Impact of the 0-350 Tier 1 Block and a 5% reduction in Tier 1

Price Base energy charges for customer consuming 400 kWh per month

	Usage kWh per month	Energy Price $/kWh	Base energy Cost $/month*
Current E-12 Rate			
Tier 1	350	0.07570	26.50
Tier 1	50	0.07570	3.79
Total	400		30.28
Tier 1: 0-350 kWh, 5% Price Reduction			
Tier 1	350	0.07192	25.17
Tier 2	50	0.10556	5.28
Total	400		30.45
% change			0.6%

* excludes basic service charge, CRCC and other taxes and fees

The decrease in the Tier 1 price could be structured to be large enough to avoid a bill increase for this group of customers. For example, a 7% decrease in the Tier 1 price would result in a reduction in monthly base energy charges of 1.2% for the customer consuming 400 kWh per month. But even so, their savings is far lower than the 7% reduction for customers consuming below 350 kWh per month. The point of the example is that lowering the Tier 1 block from 0-400 to 0-350 kWh per month can unintentionally harm or greatly reduce the benefits for customers consuming at or slightly above the block limit.

Furthermore, as shown in Table 10, many of APS' E-12 customers receiving E-3 low income discounts could fall into his category. In fact, over 38% of low income customers are typically billed at the second pricing tier, 401-800 kWh per month, and could be affected by the lower block limit. The low income information points to another benefit of keeping the lower block limit at 400 kWh per month, which is to maintain consistency with the block levels for the E-3 low income discounts.

Table 10 E-12 Customers with Low Income Discount

Pricing Tier	Bills per Summer	Average Customers	
0-400	24,333	4,056	25.3%
401-800	36,738	6,123	38.2%
801-1200	19,510	3,252	20.3%
>1200	15,498	2,583	16.1%
	96,079	16,013	100%

* E-3 discount, 2004 Data

Additionally, it is difficult to target the benefits of a Tier 1 price reduction to lower use customers because larger use customers would also receive a price reduction for their Tier 1 consumption. As shown in Table 11, 43% of all summer consumption for rate E-12 was billed under the first pricing tier. However, lower usage customers with monthly consumption of 0-400 kWh, who were billed solely under Tier 1 pricing, comprised only 8% of total consumption. The implication is that in order to grant a price discount for the 8% lower-usage consumption, a price discount must also be given to 43% of total consumption. This would include the 19.6% Tier 1 usage for the largest customers with monthly consumption greater than 800 kWh per month.

Table 11 E-12 Percent Total Summer Usage Pricing Tiers

Monthly Usage Blocks	Tier 1	Tier 2	Tier 3	Total
0-400	7.9%	0.0%	0.0%	8.0%
401-800	15.6%	7.4%	0.0%	23.0%
>800	19.7%	19.7%	29.5%	69.0%
Total	43.2%	27.1%	29.5%	100.0%

2004 data

In addition, some of the low-usage customers may not necessarily be low income. While APS has not studied this issue in depth, some of the data suggests that some of the low-usage accounts could be second homes that have limited consumption during the summer. Table 12 shows that roughly 806,000 summer bills or 134,000 average customers consume at or below 400 kWh per month (numbers derived by adding the 0-350 kWh and 350-400 kWh blocks). However, over 12,800 of these customers consumed 0 kWh and roughly 69,000 consumed less than 200 kWh per month during the summer season. This 0-200 kWh group could include some low income customers, but it could also represent some other type of account, such as a second home. As shown in the Rate Schedule E-3 discount data in Table 9, low income customers are more likely to use above 400 kWh per month.

Table 12 E-12 Rate, Bills and kWh for Summer Season*

	Tier (kWh per month)	Charge	Bills per Summer	kWh per Summer
First Tier	0-400	0.07570	806,558	152,413,990
Second Tier	401-800	0.10556	747,879	441,187,376
Third Tier	Above 800	0.12314	947,269	1,325,185,565
Total			2,501,706	1,918,786,931

*2004 data

The implications are that lowering the Tier 1 price could help some low income customers, but it is difficult to target the help to those customers. The price change would also reduce the Tier 1

usage for all Rate Schedule E-12 customers and could provide the largest benefit to customers with second homes or other types of accounts that would not warrant a subsidy from other customers. In addition some low income customers use more than 800 kWh per month and could in fact be hurt by this proposed change.

Assessment of Lowering the Usage Limit for Tier 2 and Raising the Price for Tier 3

Lowering the usage limit on the second block from 800 to 750 kWh per month, would not likely have a meaningful impact on energy conservation. Again, the apparent motivation of the proposed change was to move the average summer consumption of 770 kWh per month to the upper tier, subjecting it to the higher block pricing and, therefore, maximizing the encouragement of energy conservation. However, in this case, the average consumption across all customers for the summer season is not very relevant because the tiered pricing is applied to the tiered usage of each customer in each month. Average consumption is effected by low-usage customers, high-usage customers, and even variations in monthly usage for a given customer, none of which would be impacted by this proposed change.

In other words, lowering the second tier usage limit would only change the marginal price signal for customers using between 750 and 800 kWh in a given month, and only for their last increment of usage above 750 kWh. Referring back to Table 12, this group comprises roughly 12,964 average customers and 60,302 MWH for the summer season, which is approximately 3% of both total customers and total energy for E-12. Furthermore, a large percent of E-12 customers and consumption are already being billed at the highest tier (over 800 kWh). In fact, over 157,000 customers, or 38% of total E-12 customers and 1,325,185 MWH, or 30% of total, *are billed in the highest priced tier over the summer period.*

Raising the price of the highest tier could encourage energy conservation, but this potential impact is not well understood in the industry. As discussed later in this report, most of the studies have concluded that residential customers on average respond to higher price signals. However, the analysis has largely been in the context of customers reducing or shifting peak-period consumption in response to time-of-use rates, real time pricing or, more recently, critical peak pricing.

Furthermore, one of the well understood short-comings of inclining block rates is that while they are presumed to encourage some conservation, they do not necessarily encourage conservation at the right time. They do not send time-differentiated price signals to ensure that the energy reduction is taking place during peak periods, when it is needed. So while they may be useful for pricing storable commodities such as water, they have limited benefits for managing electricity loads, especially the high peak growth that the Company is facing.

Conclusions

1. Any pricing change for rate E-12 should be moderate because the tier 3 price is already high in relation to the Tier 1 price.

2. The defined usage levels for the pricing blocks at their current levels, which are 0-400 kWh per month for Tier 1 prices, 401-800 kWh for Tier 2 prices, and greater than 800 kWh or Tier 3 prices should be maintained. A reduction in the block

usage structure to 0-350 kWh for Tier 1 and 301-750 kWh for Tier 2 would likely provide only limited impacts on energy conservation, could limit the benefits of the pricing change for some low and moderate-use customers, and would create an inconsistency with the blocks for the low income and medical discount programs.

SECTION III

Time of Use Pricing – Residential

Overview

Time of use rates have energy and/or demand charges which vary by time periods, both by time of day and season. Typically, these rates are static, that is, the charges and designated hours for peak and off-peak periods are determined and set in the tariff and cannot be flexibly changed to respond to changes in system costs or reliability.

Industry Experience

Time-of-use rate programs were reviewed for major utilities in the South, West and Midwest, which have significant summer peaks. States with active deregulation were generally not included in the analysis because many have divested generation and are changing the structure of standard offer service prices based on competitive issues. The results are summarized in Table 13. Of the 25 programs reviewed, 20 rates had time-differentiated energy charges, 4 had time differentiated demand and energy charges, and 1 rate had a time differentiated demand charge and a flat energy charge.

For the TOU energy rates, most (85%) were structured as a two-part rate, which includes a peak and off-peak energy charge for each season. Three-part rates include charges for a peak period, shoulder period and off-peak period. The on-peak hours vary considerably by utility, ranging from 5 hrs to 14 hrs. For the two-part rates, 41% had a summer peak period of 8 hours or less, 50% were between 9 and 12 hours; and 9% were greater than 12 hours. Three-part rates had summer peak periods ranging from 5 to 7 hours and combined peak and shoulder hours of 7 to11 hours. By comparison, APS' current TOU rates fall into the middle group with a 12 hour summer peak period.

Table 13 Residential TOU Rates for Select Utilities

UTILITY, STATE	RATE STRUCTURE	SUMMER PEAK HOURS	PEAK/OFF PEAK ENERGY CHARGE
APS – AZ	2 part energy	9 am – 9 pm	3.1
PNM – NM	2 part energy	8 am – 8 pm	2.3
AEP – Indiana	2 part energy	7 am – 9 pm	4.2
FPL – FLA	2 part energy	12 noon - 9 pm	1.9
Utah Power Light – UT	2 part energy	1 pm – 8 pm	NA
Progress – NC	2 part energy	10 am – 9 pm	4.3
TECO – FLA	2 part energy	12 noon – 9 pm	1.2
Georgia Power – GA	2 part energy	2 pm – 7 pm	3.2
Progress Energy – FLA	2 part energy	12 noon – 9 pm	3.5
Nevada Power – NV	2 part energy	1 pm – 7 pm	2.4
SRP- AZ	2 part energy	1 pm – 8 pm	3.8
Entergy – Ark	2 part energy	1 pm – 8 pm	5.1
OGE – OK	2 part energy	1 pm – 7 pm	6.4
SMUD – CA	2 part energy	2 pm – 8 pm	2.2
Commonwealth Ed – IL	2 part energy, declining block off peak	9 am – 6 pm	3.5 – 4.2
PGE – CA	2 part energy tiered to usage	12 noon – 6 pm	2.2 – 3.4

Table 13 Residential TOU Rates for Select Utilities (cont)

UTILITY, STATE	RATE STRUCTURE	SUMMER PEAK HOURS	PEAK/OFF PEAK ENERGY CHARGE
SDGE – CA	2 part energy tiered to usage	12 noon – 6 pm	1.1
SMUD – CA	3 part energy	2 pm – 8 pm peak; 12-2, 8-10 shoulder	2.5 peak/off 1.7 shoulder/off
Alabama Power – AB	3 part energy	12-7 peak; 10-12, 7-9 shoulder	9.3 peak/off 2.9 shoulder/off
TEP – AZ	3 part energy	1-6 peak; 6-8 shoulder	3.2 peak/off 2.0 shoulder/off
APS – AZ	Demand and energy	9 am – 9 pm	1.78 energy plus demand charge
Ameren CIPs	2 part demand and energy	10 am - 10 pm	1.4 energy, plus demand charge
MidAmerican – IOWA	2 part demand and energy	10am to 10pm	1.7 energy, plus demand charge
Dominion – VA	2 part demand and energy	10 am – 10 pm	2.7 energy, plus demand charge
PSC – CO	2 part demand	8 am to 10 pm	Demand differential only

The levels of charges for various pricing periods also vary considerably by utility. As shown, the ratio of peak to off-peak energy charges for various TOU rates ranges from 1.1 to 6.4 for two-part energy rates, most of which are below 3.5. Again, a 3.5 ratio means that the peak period price is 3.5 times the off-peak price. For the two-part energy rates, 44% had peak/off-peak ratios below 3.0, 31% had ratios between 3.0 and 3.9, and 25% were 4.0 and above. By comparison APS' two-part energy rate has a ratio of 3.1.

Peak to off-peak price ratios for three-part rates ranged from 2.5 to 9.3, while ratios of shoulder to off-peak prices ranged from 1.7 to 2.9. The 9.3 ratio for Alabama Power is likely to be an outlier driven by an extremely low off-peak energy charge of 1.8 cents per kWh.

TOU rates which include both time-differentiated demand and energy charges generally have lower peak/off-peak energy price ratios, because on-peak revenue is also collected through a demand charge. Energy price ratios for this rate structure ranged from 1.4 to 2.7. APS' comparative rate has a ratio of 1.78. Note that the on-peak time periods are typically fairly long for these rates - 12 hours or above.

Participation in residential TOU rates has generally been low. As shown in Table 14, APS by far ranks high in terms of participation compared with other utility TOU programs. A recent survey of TOU and demand response programs confirmed this result, finding that participation in TOU rates and other types of residential demand response programs is generally low, usually ranging from almost zero to 3% of eligible customers. The survey also reported that TOU programs are not generally expanding, due to lack of customer interest or changing regulatory circumstances.[3]

[3] See Summit Blue Utility Survey Draft Report 2005 pg 6-7.

Table 14 Participation in Select TOU Programs*

UTILITY, STATE	RESIDENTIAL TOU CUSTOMERS*
APS - AZ	357,372
PNM – NM	142
AEP Indiana	5,303
Utah Power Light – UT	176
Georgia Power – GA	93
SRP- AZ	145,000
Entergy – Ark	38
OGE – OK	383
Commonwealth Ed – IL	47
PGE – CA	86,672
TEP – AZ	4,883
Ameren CIPs	1,105
MidAmerican – IOWA	30

* 2004 data. Numbers reflect rates reviewed above

Assessment of Potential New TOU Pricing Options

Pursuant to Decision No. 67744, the Company investigated the potential for offering two new time-of-use rates, one with time-differentiated energy charges, and one with demand and energy charges, both of which have shorter on-peak hours and a higher ratio of summer peak to off-peak prices compared with current rates. Proposed rates were filed with the Commission on September 22, 2005. The Company also performed a TOU Flexibility Study that was submitted to the Commission on October 7, 2005. These reports addressed the metering and billing system limitations that must be addressed before new TOU pricing options can be implemented.

Potential Peak and Energy Impacts

Load impact studies have generally found that residential customers are responsive to TOU prices although the results varied considerably depending on the utility, customer characteristics, rate structure, and, most importantly, the methodology used.

The results of impact studies are generally reported as either direct percentage reductions in energy usage over a specified peak period or by elasticity values, which measure the percentage change in energy usage in response to a percentage change in prices.

Elasticities for these purposes are generally expressed as either own-price elasticity or the elasticity of substitution. Own-price elasticity measures the percent change in consumption caused by a percentage change in price. In this context, it measures the percentage reduction in peak-period energy usage for a percentage increase in peak-period price. For example, if the own-price elasticity was 0.15, then a 100% increase in the peak period price would result in a 15% reduction in energy usage during the peak period. The elasticity value is actually -0.15, but the negative is typically dropped because it is generally understood that an increase in price will lead to a decrease in usage.

The elasticity of substitution measures how much energy is shifted to the off-peak period in response to a change in the ratio of peak to off-peak prices. It calculates the percent change in the ratio of peak to off-peak energy usage relative to a percentage change of the ratio of on, to off-peak prices. For example, an elasticity of substitution of 0.15 means that if the ratio of on, to

off-peak prices increased by 100%, then the ratio of peak to off-peak energy consumption would decrease by 15%. The peak period load impacts can then be derived from the elasticity information.

The impact of residential time-of-use pricing has been estimated in numerous studies over the last 30 years. Elasticities of substitution have ranged from almost zero to 0.37 from these various experiments. Some of the studies date back to the 1970's and 1980's using data from a series of TOU experiments sponsored by the (now) Department of Energy at a number of utilities. One review of these experiments found that the elasticity of substitution was fairly consistent across the utilities with typical values in the range of 0.14. Elasticity estimates for TOU rates which also incorporate critical peak pricing are typically higher as reviewed and will be discussed below. A summary of several of the more prominent findings for TOU rates (without critical peak pricing) is provided in Table 15. Estimated reductions in peak period energy usage derived from these elasticities ranged from very low to over 7%.

Table 15 Elasticity Findings from Other Studies Residential Time-of-Use

Utility	Year	Elasticity of Substitution	Study
California IOUs	2003; 2004	Sub 0.122 Daily 0.038	CRA California Statewide Pricing Pilot, CPP-F Zone 4 normal weekdays
California IOUs	2003	Sub 0.109 Daily 0.118	CRA California Statewide Pricing Pilot, TOU, Zone 4, 2003
Five States	1977 – 1980	0.12	Caves 1984
PG&E – CA		0.37	Caves 1989
Midwest Power		0.15-0.39	*Balidi 1998*
Oklahoma Muni	1977 – 1978	0.12	Huettner 1982

The California Statewide Pricing Pilot

Recently, the California Energy Commission (CEC) conducted a study of demand response rates, including residential TOU rates. In the experiment, nearly 1,600 residential and small commercial customers were placed on one of several TOU and critical peak pricing plans. In addition a control group of over 800 customers remained on their standard baseline rate, which was typically an inclining block rate. Treatment groups for each rate were also placed on several different price levels to be able to derive the relationship between usage and price (demand curves) for each rate. Furthermore, the sample was structured for four different climate zones, with zone 4 being the hottest and most comparable to much of the APS service territory.

The California experiment found that residential customers were somewhat responsive to demand response rates. The substitution elasticities are shown in Table 15. Notice that the customer responsive to TOU rates varied considerably from 2003 to 2004. In 2003 the estimated reduction in peak period usage for TOU customers for zone 4 during the hottest months of the summer was 6.73%. In 2004, the measured response for the same group of customers was only 0.4%. The study offers several issues with the sample size and estimation methodology as potential explanations for this dramatic difference.

The study suggests that an alternative estimate of TOU response can be made by using the response results for the critical peak price during normal weekdays. The critical peak price (CPP-F) had a high price during declared critical days, but had a normal TOU structure during normal weekdays. Both the response to the critical price as well as the normal TOU price were

estimated for this customer group. And because the sample sizes were relatively large, the study recommends that it may provide a better estimate of response to TOU rates.

Table 16 California Statewide Pricing Pilot – Residential Results

Rate	Elasticity		Reduction in peak period usage
Time of Use			
CPP-F, Zone 4, normal weekdays, 2003, 2004, inner summer	Sub Daily	-0.122 -0.038	7.35%
TOU Zone 4, 2003, inner summer	Sub Daily	-0.109 -0.118	6.73%
TOU Zone 4, 2004, inner summer	Sub Daily	0.018 -0.127	0.4%
Critical Peak Pricing			
CPP-F, Zone 4, critical days 200	Sub Daily	-.127 -.033	17.4%
CPP-V, critical days	Sub Daily	-.111 -.027	15.7%

Estimating the Load Impacts of New TOU Rates Using Data from the California Study

Impact estimates using response results from other studies can potentially be inaccurate for several reasons. First, elasticities are point estimates – they measure responses of new prices in relation to the existing baseline rates. If baseline prices or new prices differ from those used in the borrowed data, the results may not be comparable. Also, the customer response depends on a number of factors that can vary across utilities including weather, and saturations of appliances such as air conditioning, electric water heating and pool pumps.

The California SPP study provides several advantages that allow reasonable estimates using their borrowed data. First, the California study not only estimated the load impact from the various experimental rates, but they also estimated demand functions for each of these pricing structures. Demand functions specify the relationship of peak usage to price over a range of prices, which better allow applying the data to rate levels not considered in the study. Also as discussed, the California study performed the analysis for four different climate zones. Zone 4 is most comparable to APS with higher summer temperatures and higher saturations of air conditioning.

The prime target for new TOU rates are customers who are currently participating in one of the current TOU rates or new customers who would have chosen one of the existing TOU rates. These customers already have a propensity for time-of-use and the proposed new rates considered in the study are similar in structure to the existing rates, but with shorter peak hours and a higher ratio of peak to off-peak prices. The current APS TOU energy rate (ET-1), has a peak/off-peak price ratio of approximately 3:1. So the price response for the new TOU (ET-2) energy rate will be the incremental shifting from going to a higher price ratio and from reducing the peak period from 12 hours to 7 hours.

To the extent that the baseline rate for some participants would be one of the inclining block rates such as Rate Schedule E-12, the impacts would measure the total shifting of energy use from the peak to off-peak period relative to their baseline usage pattern.

The Model

The California study estimated demand functions for the various rates using the constant elasticity of substitution model, which is well developed and widely used in demand response studies. This method first models the ratio of peak to off-peak usage as a function of the ratio of peak to off-peak prices and other terms. Next, the system models daily electricity usage as a function of the daily price of electricity and other variables. Many studies omit the second element and thus assume that TOU rates have no impact on overall energy consumption, only the allocation of usage to peak and off-peak periods.

Impact Estimate Results

The California estimates and APS estimates based their adapted model to include both the hourly-shifting and daily usage equations. APS data was substituted and the California substitution elasticities were used to estimate a reasonable range of potential peak period energy reductions from the time periods in the new energy based TOU rate recently developed by APS.

The results reflect the incremental impact of current TOU (ET-1) customers moving to the new TOU energy rate. This was performed with two cases: case 1 used the elasticity estimates from the California critical peak price for normal days; case 2 used the TOU elasticity estimate from 2003. The results, provided in Table 17, show potential reductions in summer peak-period energy consumption of 1.3 to 1.8 percent.

Table 17 Impact Estimates - Reduction in Summer Peak Period Usage*

	Elasticity		Estimated Peak Period Energy Reduction(Summer)	Reasonable range of summer impacts
Case 1 CA, SPP, 2003-04, CPP-F Zone 4, normal weekdays	Sub Daily	-0.122 -0.038	1.8 %	2% to 5%
Case 2 CA, CEC, 2003, CRA '03 Zone 4, summer	Sub Daily	-0.109 -0.118	1.3%	2% to 5%

* Resulting from customers switching from ET-1 to the new TOU energy rate.

Although the TOU peak hours were included in the analysis, the model probably does not fully account for the peak impact due to the change in the peak period from 12 hours to 7 hours. In addition some of the participants could be customers currently on an inclining block rate, such as E-12, rather than a TOU rate. In this case the potential impacts, while not specifically estimated, would be higher, perhaps more in line with the California findings of 6% to 7% peak period impact. Therefore, a reasonable overall range of expected reductions in peak-period energy usage would be from 2% to 5%.

SECTION IV

General Service Time-of-Use

Overview

Time-of-use rates have been used widely by numerous utilities for general service customers. For our purposes, general service refers to commercial and industrial customers with demands typically less than 3,000 kW. As summarized below, TOU rates encompass a variety of pricing designs which use a combination of demand and energy charges for peak and off-peak periods. TOU rates are referred to as static demand response rates because both the peak and off-peak prices and time periods are established in a tariff and cannot be varied to react to temporary changes in hourly energy costs or loads.

Advantages

1. Time-of-use rates have been around for a number of years, are typically not very complicated and, therefore, should require less customer education compared with dynamic demand response rates.

2. Time-of-use rates can support a number of rate designs including both demand and energy charges.

3. Time-of-use rates are less costly to implement than dynamic demand response rates such as critical peak pricing and demand bidding programs, which require customer communications, remote metering, and more complicated data handling, billing, and settlement systems.

Disadvantages

1. The potential load response of commercial and industrial customers to time-of-use rates is not well understood and can vary considerably across utility studies depending on the customer mix. Time-of-use rates also suffer from the same sort of customer reaction to the critical peak pricing, which is that many customers report having a hard time consistently responding to peak price signals due to the nature or their business and end-use loads.

2. General service customers are very diverse in their overall usage patterns, their end-uses, operating hours, and ultimately their potential responsiveness to TOU rates.

3. TOU rates are static, they cannot be changed on a daily basis as costs and loads fluctuate. Therefore, it is more difficult to fine tune the price signals sent to customers and match them with actual Company needs at any point in time.

Conclusions

1. Continue to implement the current general service time-of-use rate as designed. The rate is newly implemented in April 2004, so it is too soon to tell whether the current rate design will be successful in attracting customers and providing beneficial load shifting or reduction. Furthermore, as discussed below, the rate structure, charges, and peak time period is consistent with current TOU pricing concepts and tariffs offered by many other utilities.

2. Keep the current summer on-peak time period, which is weekdays 11 am to 9 pm. This keeps a level of diversity compared to the proposed shortened time periods of the new residential TOU rates. The concern is that system load is still within 10% of the system peak hour of 7 to 8 p.m. As a result, if too much load is shifted to this hour, it could create in a system peak in the later hour, rather than reducing the peak.

3. Monitor participation and load patterns for customers obtaining service under Rate Schedule E-32TOU.

APS General Service Customers

Currently, APS has over 105,000 general service customers taking service under Rate Schedules E-32 and E-30. These customers have demands under 3,000 kW and as a group consume nearly 11 million MWH per year, which is approximately 43% of total retail energy sales. Most of our general service customers are commercial customers. As shown in Tables 18a and 18b, only 3% of general service customers and 7.4% of revenue are categorized as industrial customers. Of the commercial customers, office and retail loads are the most significant, comprising over 42% of total general service annual energy consumption.

Table 18a APS General Service Customers

	Customers		MWH per year	
Commercial	102,359	97%	10,177,440	92.6%
Industrial	3,356	3%	807,775	7.4%
Total	105,715	100%	10,985,215	100.0%

2004 Data, Customers < 3,000 kW demand

Table 18b APS General Service Customers
MWH by Customer

	2004 *MWH Share*	Growth *2001 - 2004*	Growth *2003 - 2004*
Other	24.6%	10.2%	3.6%
Office	23.6%	7.1%	2.6%
Retail	18.5%	9.0%	4.1%
Industrial	7.8%	-5.0%	4.0%
Grocery	4.9%	0.4%	-0.4%
School	5.7%	9.7%	6.4%
Restaurant	5.3%	3.4%	2.9%
Hotel	3.6%	6.7%	0.6%
Warehouse	3.4%	1.9%	1.3%
Hospital	2.5%	7.1%	0.5%
All	100.0%	6.5%	3.1%

C&I A Class Weather Adjusted Sales (MWh)

The majority of general service customers have demands below 100 kW. However, customers with demands greater than 100 kW consume most of the energy. For example, as shown in Table 19 for the 2004 peak month, 98,000 out of the 104,000 general service customers were below 100 kW demand. However, nearly 65% of the monthly energy was consumed by customers with demands greater than 100 kW. In addition the customer's load factor, which is the relationship between usage during the peak hour and usage in other hours, increases with size. Load factors can be expressed on a monthly or annual basis and can be based on a customer's individual peak or their usage during the hour coincident with the system peak. A higher monthly load factor means that usage is more consistent across the different hours in the period. As shown, load factors for the peak month, based on the customer's individual peak usage, range from 21% for customers with demands less than 20 kW to 63% for customers with demands between 1,000 and 3,000 kW. Similarly, the load factors based on the coincident peak usage range from 40.5% to 75.3% respectively.

Table 19 E-32, E-30 General Service Customers and Usage – 2004 Peak Month
E32, E30 August 2004 data

kW demand	Customers	Monthly Energy	Demand Customer Peak	Demand Coincident Peak	Monthly Load Factor Customer Peak	Monthly Load Factor Coincident Peak
0 - 20	80,914	116,695	731	395	21.2%	40.5%
21 - 100	18,074	236,623	945	594	33.1%	54.6%
101 - 400	4,118	295,786	952	654	41.9%	62.0%
401 - 999	821	202,674	447	409	61.7%	83.2%
1000 - 3000	205	151,663	324	276	63.3%	75.3%
	104,132	1,003,441	3,399	2,252	39.5%	61.0%

Comparison of TOU Rates

Historically, the Company offered TOU rates for various general service customer segments on an experimental basis. However, in April 2005 the Company implemented a new TOU rate available to all general service customers. The new rate, E32-TOU, combines demand and energy charges for on-peak and off-peak periods. The tariff is split for customers from 0 to 20 kW demand and customers above 20 kW. For the latter group, the summer on-peak demand charge for secondary service is $15.112 per kW for the first 100 kW and $10.887 for each additional kW. Summer base energy charges are 4.815 cents per kWh on-peak and 3.815 cents per kWh off-peak. The rate also has a residual demand charge if the customer creates a new peak in the off-peak period. There are currently only a few customers enrolled on the rate. The on-peak hours are weekdays from 11 a.m. to 9 p.m. year round. APS also offers a TOU rate, designated E-35, for large general service customers (over 3 MW).

A comparison of general service time-of-use rates for select utilities is summarized in Table 20. The comparison includes major utilities in the South, West, and Midwest with substantial summer loads; states with predominately cold climates and active retail competition were excluded. As shown, utilities generally use several rate designs for general service time-of-use. The majority of the utilities included in the comparison, including APS, use a combination of demand and energy charges for the peak and off-peak periods. Some utilities use 2-part or 3-part energy rates, without demand charges.

The APS E32-TOU rate uses a combination of on-peak and off-peak demand and energy charges. Under this rate design, the ratio of peak to off-peak energy charges is typically much lower than all-energy TOU rates. So a key incentive for customers to reduce or shift their usage during peak periods is to avoid the peak demand charge. As shown, the ratio of peak to off-peak energy prices for the demand and 2-part energy rates range from 1.0 to 2.2 for the utilities compared. APS' ratio of 1.3 is fairly typical for this group. Also notice that the daily on-peak hours are fairly long for this group of rates, ranging from 8 to 16 hours.

Table 20 General Service Time-of-Use Summer Rates for Select Utilities

Utility	Rate	Demand Charge (1) $/kW	Energy Charge (2) - On/Off ratio	Peak Hours	Peak and Shoulder Hours
Demand and 2-part energy rates					
APS	E32TOU	11.73	1.3	11-9	
SCEG	21	18.86	1.4	1-9	
LGE	LC-TOD	14.20	1.0	10-9	
KU	LI-TOD	6.87	1.0	10-9	
FPL	GSDT-1	8.32	1.6	12-9	
FPL	GSLTD-1	8.34	1.4	12-9	
Duke	OPT (NC)	12.98	1.9	1-9	
Dominion	GS-2T	9.64	2.2	10-10	
PNM	3B	3.84	1.9	8-8	
Entergy-ARK	GST	11.74	1.2	7-6	
Pacific Power	48T	5.05	1.0	6-10	

(1) Combines peak, NCP, and shoulder demand charges.
(2) Includes base energy charges and fuel adjustor.

Table 20 General Service Time-of-Use Summer Rates for Select Utilities (cont)

Utility	Rate	Demand Charge (1) $/kW	Energy Charge (2) - On/Off ratio	Peak Hours	Peak and Shoulder Hours
Utah Power	6B	12.76	1.0	7-11	
Demand and 3-part energy rates					
PGE	E-19	16.76	1.9	12-6	8:30-9:30
SDGE	AL-TOU	17.27	1.3	11-6	6-10
SRP	E32	5.24	2.7	2-7	11-11
Georgia Power	GSD-2	12.03	5.6	2-7	12-9
Energy rates					
OGE	GS-TOU		6.9	2-8	
Utah Power	6A		3.3	7-11	
Tucson Electric	GS-76		3.3	1-6	1-8
Alabama Power	LPTM		6.5	12-7	10-9
SMUD	GSTOU1		1.4	2-8	12-10

(1) Combines peak, NCP, and shoulder demand charges.
(2) Includes base energy charges and fuel adjustor.

The demand and 3-part energy rates typically have a higher ration of on/off-peak energy prices, ranging here from 1.3 to 5.6. These rates have a shorter "super peak" period lasting 5 to 7 hours, but a long overall peak and shoulder period of 9 to 16 hours. The energy only rates have the highest on/off-peak price ratios ranging from 3.3 to 6.9. The high price ratio for Alabama Power is driven by a very low off-peak energy price, which is probably impacted by the glut of new wholesale power plants in the region.

As can be seen, APS' new TOU rate for general service customers is consistent with those of comparative utilities in terms of rate structure, price ratios and peak hours. In particular, APS' general approach of using on-peak demand charges as a primary driver for customers to shift load to off-peak periods is similar to the approach taken by most of the comparative general service rates.

SECTION V

Voluntary versus Mandatory Rates

In various jurisdictions, analysts and policy makers have debated whether the new rates should be mandatory, voluntary, or established as the default rate. The latter option would automatically place customers on the rate, but allow them to opt-out to another rate option.

Aside from a few large general service (LGS) time-of-use rates and some provider of last resort rates for large customers, TOU rates have generally been offered on a voluntary basis. Major new initiatives today such as the California Statewide Pricing Pilot (SPP) and the New England Demand Response Initiative (NEDRI) follow in that trend. A recent survey of rate offerings nationally confirmed this result and found that all of the rates in their survey were provided on a voluntary basis.[4] A report on TOU pricing commissioned by the Idaho PUC concluded that TOU rates have generally not been mandated or established as the default rate for residential customers.[5]

Arguments in Favor of Mandatory or Default Rates

Mandatory or default demand response rates, including TOU, have been considered because of the potential for increasing participation, reducing revenue erosion, improving cost causality, and lowering marketing costs.

One concern is that customer inertia, or the propensity to stay put and not change rates, and risk avoidance is likely to keep participation low for voluntary demand response rates. In addition, many of the customers that should be on the rate due to their low load factors or high coincident peak usage are the very customers that are least likely to participate. This is due to the fact that these customers may have to shift a lot of load to off-peak periods in order to save money or at least avoid losing money on the rate.

Mandatory rates would obviously maximize participation by forcing all relevant customers on the program. Proponents assert that this in turn would promote optimal capacity investment decisions. Default rates would increase participation initially as customers are placed on the rate, but not necessarily increase participation over time as customers can switch to another rate. Inertia would help to preserve participation over time in a default rate. However, customer's general level risk avoidance would tend to propel customers back to their old rate, before being placed on the default demand response rate.

Revenue erosion, which is discussed more fully below, occurs from free riders – customers that save money on the rate without changing their usage patterns; and from load shifting – saving money by changing usage patterns as a response to the rate. The former is also referred to as the self-selection problem as customers that can best take advantage of the rate while doing the least will be most apt to participate in the rate. One of the advantages of a mandatory demand response rate is that it would reduce or eliminate the revenue erosion due to free riders, if it was designed to be revenue neutral for the mandatory customer group. Revenue erosion would still

[4] Summit Blue 2003
[5] Christensen and Associates 2003

occur between rate cases from customers saving on their bill by conserving usage or shifting usage to lower cost periods.

Proponents also argue that mandatory rates can better allocate costs to those customers who cause them. Lower load factor customers, who are more costly to serve, may currently be receiving an intra-class subsidy from customers with higher load factors. To the extent that this occurs with standard rates, mandatory demand response rates could better match rates with cost causality.

Finally, mandatory rates could lower some of the program costs such as the costs of initially acquiring the customers or the costs of certain incentives for participation.

Arguments for Voluntary Rates

Voluntary demand rates are generally considered to be favorable because, they avoid the negative image of mandatory rates, they avoid adverse impacts on inelastic customers, they maintain market discipline for providing better programs, and they can result in better target marketing of programs to specific customer groups.

After considering the various issues, a general aversion to mandatory rates appears to persist, largely due to the negative image of forcing customers to participate in a rate or program. Some, of this is a general concern that many customers may not be able to respond to time-differentiated prices. Therefore, forcing all customers on a demand response rate would have adverse and, in some cases, unintended consequences for particular customers or customer groups.

In addition, some demand response rates or programs are not appropriate for all customers. For example, some rates involve load control or demand bidding approaches which require particular metering and communication equipment or customer equipment such as energy management systems. In a recent demand response pilot, the Sacramento Municipal Utility District (SMUD) found that 88% of interested, prospective participants had electrical or phone equipment that was incompatible with the program.[6] Voluntary programs can effectively target potential participants to better manage program effectiveness and avoid the one-size-fits-all approach, which would probably be inherent in mandatory programs.

Furthermore, voluntary programs have the discipline of the market as a check for program quality and effectiveness. Demand response programs must be effective and deliver value to customers in order to gain acceptance.

Finally, while voluntary rates may increase some program costs such as customer acquisition costs and incentives, they may lower others. For example, many demand response rates involve metering, communication, education and training costs that increase with the level of participation. Mandatory rates would require an investment in these costs for all customers, not just the targeted participants. In addition, default rates could result in many customers switching back to their original rate, which would further increase the implementation costs.

[6] See SMUD presentation on CPP Pilot 2004.

In the final equation, stakeholders from a variety of perspectives appear to continue to recommend that TOU and demand response rates should be provided on a voluntary basis, even for larger general service customers. For example, the working group in the California CPP responsible for developing rates for general service customers reached a general consensus that the demand response tariffs should be voluntary. In fact, they reported that no participant appeared to favor a mandatory requirement.[7]

Considering all of these issues, the Company concludes that any of the new rates considered from the results of this study should be piloted or implemented on a voluntary basis.

Revenue Erosion

As discussed above, revenue erosion from TOU rates can be caused by either free riders – customers who save money by migrating to a rate without changing usage; or customers conserving energy, clipping peak demand, or switching usage to lower price time periods. So demand response rates can result in short-term net revenue loss for utilities, even if they lead to lower system costs over time.

There are several approaches to help mitigate the potential revenue erosion between rate cases. These include rate design, multiple-part rates, recovery of net lost revenues, and mandatory rates.

Mandatory rates can reduce or perhaps eliminate revenue erosion from free riders, but would not necessarily address the loss in revenue from customers conserving energy or shifting energy to lower price time periods.

Revenue erosion can occur from a new demand response rate if the rate is designed to be revenue neutral on a class basis – that is, the rate is designed to collect the same total revenue if the entire customer class moved on to the rate. In reality the entire class will not move on to the new rate, but only a subset of the customers who are more likely to benefit from the rate. Customers who would likely lose (pay more) will not move to the new rate or stay on it for very long. Because there are no revenue increases from losers to make up for the customer savings from winners, the new rate will result in revenue erosion between rate cases. One approach to mitigate revenue erosion is to design the rate to be revenue neutral anticipating the subgroup that is likely to participate. In the context of a rate case, the expected revenue reduction from the new rate would be made up by customers on standard rates, which are presumably more costly to serve. This approach also helps to reduce, but does not eliminate, free-riders.

If a new demand response rate is introduced outside of a general rate case revenue erosion is more difficult to mitigate because standard rates cannot be increased to compensate for customer savings on the new rate. And as asserted above, the customer savings cannot be made up solely by the participants in the new rate, because there would not likely be any losers on the rate to compensate the winners. However, in this situation this approach can still be used to reduce free riders by designing the new rate so that most of the expected participants would have to change their usage patterns to be able to save money on the rate.

[7] California Energy Commission Working Group 2 Report, November 2002.

Multiple part rates are another potential solution for reducing potential revenue erosion. This approach uses a rate design that combines elements of both standard and demand response rates. The rate would price basic monthly usage according to a standard rate, but price the desired "responsive usage" according to a demand response rate. The responsive usage could be usage during critical hours in the month, in the case of two-part critical peak pricing, or a marginal usage above an allowed baseline usage in any hour, in the case of two-part real time pricing.

For example, Pacific Gas and Electric (PG&E)'s proposed critical peak prices for residential and small commercial customers layer on a high price during critical hours and a discount in other hours to the customer's otherwise applicable standard tariff, which could be an inverted block or time-of-use rate. Furthermore, the critical peak surcharges and commensurate discounts for other periods only apply to their four month summer season. While the PG&E approach does not eliminate revenue erosion, it restricts the revenue in question to the critical usage and avoids any revenue erosion in the non-summer period when demand response is presumably not needed.

Two-part real time prices typically establish a baseline hourly usage level which is purchased at embedded rates. Deviations in usage above or below this level are charged or credited according to a real-time hourly rate, which is reflective of real-time energy prices plus adjustments. This approach preserves revenue for most of the customer's monthly usage, but sends a temporal price signal for marginal consumption which is more reflective of the marginal prices at that time.

The Company concludes that any pricing concept considered as a result of this study be designed and implemented in a manner that addresses potential revenue erosion and that implementation costs be thoroughly addressed. For example, a mandatory TOU program for general service customers would require that APS replace over 100,000 meters, a costly and lengthy proposition.

SECTION VI

Other Demand Response Programs

Overview

Critical Peak Pricing (CPP) combines time-of-use with an additional high price period, which is selectively applied by the utility during periods of high energy costs or reliability issues. Typically the customer is notified the day before, or in some cases the hour before, a critical period will be called. The critical hours in a critical day can be either variable or a fixed time period, e.g. 2 p.m. to 6 p.m. Energy rates for critical periods can reach as high as 50 to 75 cents per kWh. The maximum critical days or hours allowed each year are usually limited by the tariff. Critical hours are typically capped at 100 critical hours or less per year.

CPP programs are fairly new and are typically targeted to C&I customers. However, there have been a few residential programs or experiments including the California Statewide Pricing Pilot, a pilot by the Sacramento Municipal Utility District (SMUD) and a program offered by Gulf Power, which combines CPP with automatic appliance control. These two programs will be reviewed here along with a CPP program proposed by PG&E as a result of the statewide pilot.

While the residential pilot programs have indicated that targeted customers can respond to critical peak pricing, several important questions concerning the ultimate viability and value of critical peak pricing remain.

First of all, customers need to be informed before critical peak events occur, and their usage during critical periods needs to be measured to properly apply the critical-peak charges. This can require substantial upgrades to communication and metering equipment, infrastructure and related data handling and billing systems, which can be extremely expensive. For example, PG&E is proposing investments in advanced metering, communication, and billing system upgrades necessary to support critical peak pricing programs of over $1.46 billion. In addition several of the pilot programs indicate that residential critical peak pricing is most effective when combined with an appliance control program, which would require additional equipment and infrastructure costs.

The potential participation and customer acceptance is also uncertain, especially for residential customers. A key unresolved issue is whether the monthly bill savings from critical peak pricing programs is meaningful to the customer. Unlike time-of-use programs, which have on and off-peak prices which apply each day, critical peak prices only occur for a limited number of days each year. As a result, the bill savings to the customer can be limited, especially for residential customers. In addition, some residential customers may not have electrical service equipment that is compatible with program requirements. This was an important issue for the SMUD pilot program described below.

The ultimate question is whether critical peak pricing programs can provide enough additional benefits compared with time-of-use programs to justify their high implementation costs and program complexities. This question appears to be unresolved at this point

Advantages

- CPP pricing can offer customers more refined price signals compared with inclining block or time-of-use pricing, especially during the periods of high load or costs.
- The preliminary experience of CPP pilot programs have shown that residential customers generally respond to high critical peak prices by reducing usage during critical periods.
- Some commercial customers in California (20-200 kW demand) were also found to respond to critical peak pricing, especially with programmable air conditioning controls.
- CPP prices can be layered onto existing baseline rates in order to make the option available to a wider group of customers and to help address concerns over potential revenue erosion.

Disadvantages

- Preliminary results of the California pilot program suggest that many small and medium commercial customers may not be able to effectively respond to critical peak pricing. For those that did respond, much of the usage reduction during critical periods was due to air conditioning reductions through thermostat controls. This result may not be applicable to Arizona commercial customers during the extreme summer heat.
- While initial market research has reported interest in the programs, actual experience and participation for residential and small commercial customers has been modest to date, so long-run customer acceptance is somewhat uncertain at this time.
- The costs of implementing demand response programs can be very high due to the required advanced metering and communication systems as well as changes to billing, data handling, and customer information systems.

Company Loads and Resource Impact

Critical peak pricing could potentially provide advantages from a Company load perspective by sending more refined price signals to customers during periods of very high load or energy costs. As discussed in the Company Loads and Resource section of this report, APS' loads are typically at or above 90% of the peak hour for only a small number of hours per year. For example, as shown in Table 21, in 2004 only 87 hours were within this range. Critical peak prices are designed to send relatively high price signals during the limited number of critical hours.

Table 21 APS Hourly Loads - Percent of Annual Peak Hour*

Year	Number of Hours When System Hourly Demand Is Equal To or Greater Than				
	95% of Peak	90% of Peak	85% of Peak	80% of Peak	75% of Peak
2000	45	153	374	719	1092
2001	16	69	267	625	1030
2002	28	150	382	686	1008
2003	34	119	299	542	859
2004	25	87	269	520	825

*For "Own Load" hourly energy profile

Load Impacts

While the CPP programs and experiments are relatively new and limited, impact studies have generally found that residential customers respond to the critical prices as well as the time-of-use prices in the non-critical periods. Small and medium general service customers also respond to critical prices, but have a limited response during non-critical TOU peak periods. For example, the California Statewide Pricing Pilot estimated the reduction in usage by residential customers during critical hours to be *13% to 16%, and 8% to 11%* during non-critical TOU peak hours. For small and medium general service customers the pilot estimated critical period reductions to be 6% to 9% and 1.5% to 2.4% for normal TOU peak hours. The customer response from the SMUD Pilot was similar to the California pilot for residential customers. The Gulf Power program, which also included appliance control, estimated a 45% reduction in usage during critical hours in the summer.

Table 22 Estimated Peak-Period Impacts from Critical Peak Pricing

	Energy Reduction Critical Hours	Energy Reduction TOU Peak Hours
Residential		
California SWPP	13% to 16%	6.5%
SMUD experiment	16%	8% to 11%
Gulf Power	45%	NA
General Service		
California SWPP 0-20 kW	6%	1.5%
California SWPP 20-200 kW	9.1%	2.4%

Customer Acceptance

Critical peak pricing programs and experiments are relatively new and participation to date is limited. For example, Gulf Power's residential CPP program, which is three years old, currently has 7,500 participants. At this time it is too early to be able to predict the potential market acceptance and participation for these programs. Marketing research for the California Statewide Pricing Pilot indicated interest in demand responsive rates for residential customers, less so for small general service. However, actual participation may vary significantly from self-reported customer interest or intentions from surveys.

One of the challenges for CPP programs is to make the bill savings meaningful, especially if customers have to install equipment or incur other costs in order to effectively respond to the price. Typically the programs charge customers a high price for consumption during critical periods in exchange for price discounts during other off-peak periods. But because the critical hours are limited, the compensating discounts in other hours are also limited. As discussed below, the PG&E proposed residential program provides additional off-peak discounts in order to make the bill savings meaningful to targeted customers.

Some customers, especially general service customers may perceive the CPP programs as new, unknown, and risky. The critical price looks very high, and the potential bill savings are uncertain. To address this, some programs offer a limited guarantee of savings.

Some of the lessons learned from marketing research of program participants and non-participants in the California Statewide Pricing Pilot are summarized below for residential and general service customers below 200 kW of demand.[8]

Residential customers

- Overall program satisfaction was high.
- Customers like demand response rates because of bill savings and ability to manage loads.
- While savings levels have a significant effect on customer response, non-price rate features can also have a meaningful impact on customer willingness to participate in demand response rates.
- Estimates of potential customer participation into new demand response rates, based on customer reported interest and likely awareness levels, could be in the 15% to 20% of total customers in an opt-in program. However, actual experience could vary significantly from survey results of self-reported customer interest and intentions.
- 85% of residential participants in the pilot program report making a change in their energy use in response to high energy prices. Of these, 17-43% shifted laundry use (depending on the specific rate option), 9-15% either turned off or used their electricity less, and 2-14% shifted their pool pump usage.
- Potential participants are likely to be high energy users.
- If residential customers were placed on a demand response rate as their default rate, on an opt-out basis, a high percent would be expected to remain on the rate and not switch back to the standard rate or to another new rate option.

[8] A Market Assessment of Time-Differentiated Rates among Residential Customers in California. Momentum Market Intelligence, December 2003.
Customer Preferences Market Research – C&I, A Market Assessment of Time-Differentiated Rates among Small /Medium Commercial & Industrial Customers in California July 2004.

General Service Customers (0-200 kW)

- Overall program satisfaction was high, although lower for commercial and industrial customers compared with residential.

- Similar to residential customers, commercial customers like demand response rates because of bill savings and ability to manage loads.

- Customers appear to worry more about having to make adjustments to electricity usage than they care about the savings they might experience. The information below shows the trade-off between the level of bill savings and the amount of effort (e.g. load shifting) necessary to achieve those savings. As shown, customers prefer low moderate savings coupled with low to moderate shifting required. The highest preferred scenario is 5% savings with no effort required.

Table 23 Trade Off Between Customer Savings and Load Shifting
Small and Medium C&I customers - California

Level of Customer Effort (e.g. load Shifting required to achieve savings)	Bill Savings Level	Preference Index
High	20%	.66
High	15%	.21
High	10%	-.23
Moderate	10%	.75
Moderate	5%	.24
None	5%	1.41
None	0%	.67

- Many commercial customers reported that they would not be able to shift or reduce energy usage during peak periods. They reported that the nature of the business does not allow them to change usage patterns, they cannot reduce air conditioning usage, or they don't have sufficient end-uses to shift load.

- Some of the difficulties cited by higher use customers included: limited control over guest tenant electricity usage; their greatest demand occurs during the weekday afternoons; certain end-uses need to be kept running at all times; usage is based on demand of manufacturing process; cannot compromise comfort of customers, patients, students, or employees.

- The design of the on-peak periods and critical peak days are important drivers of the customer preference for a given pricing option, more important for many customers than the savings potential.

- Those currently on a TOU rate tend to be more receptive to a new demand response rate, regardless of the specific details of that rate.

- Likely participants in demand response rates tend to be larger customers with a higher electricity costs as % of total operating costs (greater than 10% of total operating costs).

- Among building types, hospitals, lodging and education customers appeared to be more inclined to accept critical peak pricing than other building types, with hospitals as the most likely target.

- Appliance control packages have the potential to enhance customer participation if the packages offered focus on basic or moderate controls (rather than extensive controls), and if they offer customers the ability to program the system to their own specifications and override any utility control.

- Overall, there was little interest in signing up for a real time pricing plan. Only 3% of respondents indicated a strong interest and 73% gave the concept a low rating

Implementation Costs

One of the major drawbacks of dynamic demand response pricing, such as critical peak pricing, is that it can require an extensive investment in data handling, metering, billing, and communication systems. The rates typically require some type of advanced metering capable of recording the customers' usage during dynamic critical periods. The programs also require a communication system to automatically acquire the interval load data for billing purposes. For critical peak pricing programs that include appliance control, the communication network must be two-way in order to notify the customer of a critical period and signal a load controller. Dynamic demand response rates can also require upgrades to data handling, billing systems due to the increased data processing and storage requirements from the interval data.

Large deployments of advanced metering are typically justified based on savings in operating cost and other benefits not related to dynamic pricing. However, such an investment is nevertheless necessary to implement dynamic pricing programs, such as critical peak pricing, for other than small pilot programs.

For example, PG&E is proposing to implement over $1.46 billion in equipment and systems necessary for their proposed demand response rates for residential and commercial customers. This includes the cost of purchasing and installing advanced metering equipment for 2.5 million customers to be installed over a 15 year period. It also includes over $80 million for significant upgrades to customer care and billing systems. PG&E justifies 90% of the project costs based on operating cost savings for meter reading, customer service, billing and other costs. The savings in energy and generation capacity costs from the dynamic rates are expected to cover the other 10%.

California Statewide Pricing Pilot – Critical Peak Pricing

Residential Customers

The California pilot tested several different time-of-use and critical peak-pricing structures on 2,500 residential customers in 2003 and 2004. The primary objectives of the pilot were to estimate the load impacts from the prices, and understand customer preferences for the rates and various program features. The pilot offered two types of critical peak-prices where the peak price during critical hours was approximately five times the standard tariff and six times the off-peak price. The CPP-F rate had a fixed time period for critical hours in critical "event" days, which was 2-7 pm weekdays. Critical days were restricted to 15 per year, and no more than 3 consecutive days. Notification of a critical day was made the day before. For the CPP-V rate the critical time period could vary on each critical day and notification could be made the day of the event. The experiment estimated a load reduction during critical hours of 13 to 16%.

CPP-V customers also had the option of receiving a programmable thermostat/appliance control device or other enabling equipment installed free of charge to help facilitate demand response to the rate. The critical period price ranged from 50 to 75 cents per kWh tiered to total monthly usage level. This compares to normal peak prices of 23 cents to32 cents and off-peak prices of 8 cents to 16 cents per kWh.

General Service (under 200 kW)

The general service pilot was separated into two groups, 0-20 kW demand and 20-200 kW demand. All of the customers were in the SCE service territory. The CPP-V rate was tested for two groups (1) the general population and (2) customers with central air conditioning, who had participated in a utility smart thermostat program. Most of the general population had air conditioning and about half had "smart thermostat" technology.

Critical periods could be called on weekdays from 12 noon to 6 p.m., although the duration of any critical event could vary within this time period. Total critical hours are capped at 90 hours per year. Events could be triggered by system emergencies (ISO stage 1 or higher), extreme temperature conditions, utility procurement requirements, or discretionary events for testing purposes. Customers are notified at least 4 hours before an event by land-line telephone, pager, e-mail or cell phone.

The 0-20 kW group had a relatively small reduction in peak period usage which was 6% during critical days and 1.5% on normal weekdays. The load reduction for the 20-200 group was somewhat larger – 9.1% for critical days, 2.4% for normal weekdays. The experiment also concluded that much of the response was due to the air conditioning thermostat/control equipment. Findings from the marketing research from the experiment are summarized above.

PG&E Proposed Critical Peak Pricing

PG&E has proposed to offer new critical peak pricing for residential and small and medium commercial customers, less than 200 kW demand, as they implement advanced metering between 2006 and 2010. They are also proposing other dynamic rates for larger C&I customers. PG&E' CPP rates will be offered on a voluntary, opt-in basis, and are designed as overlays to customers' current rates. In other words, a participating customer would pay all charges on their

standard tariff, but they would receive additional charges for consumption during critical periods and credits for charges during non-critical periods.

PG&E believes that this approach provides several key advantages. First, it offers flexibility to change charges and credits as needed for a variety of rates without having to completely redesign each tariff. This is especially valuable since the potential customer acceptance is somewhat uncertain. Second, the approach allows the preservation of the existing inclining block and TOU rates. In fact, customers can choose either basic tariff and still be able to participate in critical peak pricing. Third, the overlay approach will help to preserve class-level revenue neutrality, although it will not eliminate potential revenue erosion. In other words, it does not create incentives for customers to switch rate schedules and thereby result in revenue erosion. There could still be free riders who would naturally use less during critical peak periods and more during other non-critical times, who would automatically save from the CPP rate overlay, without changing their consumption patterns. Nevertheless, PG&E intends to match the revenues from charges and the credits for each rate group using load research information. Furthermore, the charges and credits would be subject to annual updates based on the actual load shapes for the groups of customers who participate over time. After the first two years of the program revenue-neutral adjustments to the standard rates are proposed to be made annually, to avoid under of over collections (mismatches between the CPP charges and credits) on a forecast basis.

PG&E designed the program to provide many customers with bill savings of 10% or more if they reduce their usage by 25% during critical periods. Although average savings are expected to be more in the range of 5%. In addition, PGE is offering customers bill protection during the first summer of enrollment, where they are compensated if their actual critical period charges exceed their credits.

Residential Rate

Again, the CPP rate overlays a critical period price and compensating credits during non-critical hours over the customers existing baseline rate. Fifteen critical days can be called on a day-ahead basis each summer for a maximum of 75 hours. The critical period of 1-7 pm is fixed for event days. The critical peak price was derived by first assigning $45 per kW-year of summer season revenue responsibility for the CPP charge. The $45 divided by the 75 hours resulted in a recommended CPP charge of 60 cents per kWh. The credit for non-critical hours is 3 cents per kWh. An additional credit of 1.0 cent per kWh was also applied to all usage in the upper tiers (tier 3 and above) of the customer's baseline rate in the summer billing season to enhance customer savings and participation.

Small and Medium Commercial (under 200 kW demand)

The small and medium commercial critical peak price program operates similar to the residential program, except the critical hours are 2-6 p.m. for this group. The 15 day maximum number of critical days translates into a cap of 60 critical hours per year. The $45 capacity cost responsibility was spread across 60 critical hours each summer for a 75 cent per kWh charge and an offsetting credit for non-critical hours of 2.7 cents per kWh. The proposed additional promotional credit is 0.5 cents per kWh for these customers.

Implementation Costs

PG&E is implementing the Advanced Metering Infrastructure (AMI) project – $1.46 billion including $1.35 billion capital costs and $13 million in expense. It is projected that 90% of the costs will be recovered by savings in meter reading costs, other employee-related expenses, avoided meter maintenance cost, improved outage restoration, avoided interval metering costs, call center savings, improved cash flow, and other benefits such as reduced energy theft. The project cost estimate includes the AMI system, meters and data handling systems, communication infrastructure, and significant refurbishment of the CIS /billing system.

SMUD Critical Peak Pricing Experiment

In 2003 the Sacramento Municipal Utility District (SMUD) conducted a pilot program for residential critical peak pricing. They installed advanced metering and appliance control equipment for a sample of 78 customers. The pilot, which operated during the summer of 2003, combined critical peak pricing with automatic control of air conditioning, electric water heating and pool pump motors. The metering, communication and control equipment included advanced metering, communication gateway, load control relay and a thermostat controller. While the customer could program end-uses to automatically respond during critical periods, they could also override the control system and continue to consume energy during those times.

The program included a four part critical peak price effective for the summer billing season. Energy prices ranged from 7.03 cents per kWh during "low load" periods in the summer to 27 cents per kWh during critical periods. Critical periods were triggered by a combination of high temperature (above 95 degrees F) and high system load (above 2,100 MW). Critical periods could also be called if wholesale prices exceeded $90/MWh or in case of a system emergency.

Required utility systems included a head end information processing system, an on-line system for providing customer load information, and billing infrastructure and software, communication system to and from the home, an online critical peak event scheduling, and load profiling.

The program required the customer to have compatible electric service and specific end-uses. For example, the program required central air conditioning, but zoned and variable speed systems were not compatible with the control system and therefore didn't qualify.

SMUD conducted customer training on how to program the thermostat and control system and how to access the on-line energy usage data.

Findings

In a presentation made in June of 2004, SMUD reported the following information regarding their pilot program:

- All of the critical periods during the 2003 summer pilot were triggered by temperature and load.
- The customer acquisition process for the pilot appeared to be challenging. The results reported that 88% of responding customer's service panels were

incompatible with the program equipment. Other customers had ineligible end-uses or an inaccessible phone line. All-in-all the utility sent 30,000 direct mail solicitations, called over 4,000 customers, received initial agreements with 570 customers, screened out all but 177 eligible customers and installed 78 systems.

- Customers did respond by reducing consumption in both the critical period by 0.54 kW per customer per hour, which is 16% on average. They also reduced load during some of the other higher non-critical periods of the four-part rate. For example, SMUD reports that participants reduced usage in the highest non-critical time-of-use period by 11%. Customers increased usage slightly during the low-load period, but overall reduced peak load rather than shift load to off-peak periods. Overall energy savings was 4% over the summer season.

- Many customers made investments in energy efficient equipment after enrolling in the program. Many of the changes were low cost items, such as purchasing compact fluorescent bulbs, but 40% of the customers reported to make higher price equipment changes such as replacing windows, repairing ducts, replacing refrigerators or replacing air conditioners.

- Customers reported that they responded to critical and high periods by reducing the use of major appliances such as air conditioners, washers and dryers, and cooking. However, 60% of participants reported that they temporarily over-rode the control settings. In addition, despite training, 44% of customers reported having difficulty programming or operating the thermostat.

- Participants tended to be higher energy users (1565 kWh per month), living in larger homes (2300 Sqft) and had someone home during the summer peak hours.

- The pilot infrastructure, administration and maintenance were expensive. Equipment installation was complicated.

Gulf Power Critical Peak Pricing Program

In Florida, Gulf Power offers residential critical peak pricing combined with control of major appliances through a communications gateway and programmable thermostat/controller. The program is called the Advanced Energy Management Good Cents Select (AEM) program. The four-part rate combines a three-part TOU rate with a critical period price which is callable by the utility. The program enables customers to respond automatically to high and critical price periods by controlling their air conditioning, heating, water heating, and pool pumps.

The TOU summer hours are 1 p.m. to 6-p.m. peak (high price period), 6 a.m. to1 p.m. and 6 p.m. to 11 p.m. shoulder (medium cost periods), and 11 p.m. to 6 a.m. off-peak (low cost hours). The medium price also applies from 6 a.m. to 11 p.m. on weekends. The critical hours are determined by the utility and are capped at 1% of total annual hours. Participants are notified by electronic signal at least one half hour before a critical hour is called. Prices for the various periods are shown below (effective 4/1/05) compared with the standard residential energy

charge. The tariff also requires an additional monthly charge of $4.95 for the thermostat and communications equipment.

Table 24 GPU CPP Energy Prices by Time Period

Period	Price cents/kWh	% of Annual Hours
Low (off-peak)	5.4	28%
Medium (shoulder)	6.7	59%
High (peak)	11.2	12%
Critical	32.1	1% max
Standard Residential Rate	7.6	

Equipment Requirements

The program requires an electronic control module to program the operations of the end-uses and a communications gateway module which is added to the meter. It enables communication between the utility and the control module to alert of critical periods and the system components to interrupt demand. It also records energy usage for transmittal to the utility. The utility communicates with the gateway through use of a paging signal. Billing information is later retrieved via the land-line public switched telephone network Signals are passed from the gateway to the controlled end-uses over the house's internal wiring and to and from the controller over the existing thermostat wiring.

In addition the customer has certain requirements including touch-tone phone service, HVAC compatible with the energy management equipment, electric wiring conducive to power line carrier, located in area with certain paging strength, compatible existing metering equipment.

Load Impact

Gulf Power estimated the reduction in load during critical hours to be 2.1 kW per home on average, which is a 45% reduction in critical hour usage.

Implementation Costs

Gulf Power reports that the average equipment and installation cost for the metering, communication and control equipment on the customer site is approximately $600 per home.

Other costs included the communication infrastructure and the required changes to the CIS/Billing system. The latter was not extensive in Gulf Power' case. As a part of Southern Company, they use Southern's billing platform, which had been recently refurbished before the CPP program was implemented. The updated CIS system was able to accommodate the billing of the CPP program with moderate changes.

Participation

The program has been in operation for 3 years and the current participation (2005) is 7,500 customers. They plan to expand the program offering to the multi-family segment later this year.

Medium and Large General Service Demand Response -RTP

Demand response programs reviewed for medium and large size general service customers include critical peak pricing and demand bidding programs. Again, critical peak pricing is basically a hybrid of a time-of-use rate with a critical price added, which can be called at the discretional of the utility for a limited number of hours each year. Demand bidding programs offer incentives for customers to bid load reductions typically a day in advance. A customer's overall usage is billed according to their otherwise applicable tariff along with the incentives. Some utilities also offer real time pricing programs which bill part of the customer's load based on short-run marginal production costs. Real time pricing (RTP) is not formally considered as an option in this study primarily because, from APS perspective, critical peak pricing can provide many of the same benefits as real time pricing, with less costly program administration, and without subjecting customers to the risks of facing hourly marginal energy prices. In addition, many real time pricing programs have been focused on industrial load growth, rather than peak demand and energy reduction, which is the focus of this study. However, this study does consider some of the lessons learned from real-time pricing programs as they apply to the other demand response programs considered.

Advantages

1. Dynamic demand response programs can help match customer load reductions to periods when it is most needed by the utility to respond to high system loads or costs.

2. Demand response can also send price signals to customers that are more reflective of short-term energy costs, as they vary across days and hours.

3. Demand bidding programs have the advantage of allowing the utility to adjust both the hourly prices and the critical hours as needed.

4. Communication methods between the utility and the customer have improved including new software to better facilitate notification and confirmation processes, web-based interfaces, and more use of wireless communications including 2-way paging and email.

5. Some C&I customers have been shown to reduce their usage in response to critical peak pricing and demand bidding programs.

6. Critical peak pricing programs are reasonably straight forward to operate, they do not require any customer confirmation or complicated settlement process. The tariffs are similar to TOU prices and can be overlaid over standard baseline tariffs.

7. Customers could interface demand response rates with energy management systems, which are used fairly widely in certain C&I segments, to better automate response. However, actual automated response to these programs appears to be limited.

Disadvantages

1. Demand bidding and critical peak pricing programs are relatively new, so there is limited experience to access customer acceptance, load impacts, or other key program issues.

2. The overall customer savings from these programs could potentially be relatively low, especially if the number of critical events is limited due to stable prices or program constraints. This potential low savings could limit customer interest and active participation.

3. Inactivity caused by stable prices and a low number of critical events could create complacency among participants and loss of a dependable customer response when a critical event is actually called. Some programs provide system tests and other readiness activities to address this issue.

4. Demand bidding programs require a higher level of program administration compared with TOU or CPP rates including notification, receipt and acceptance of bids; forecasting and posting day ahead hourly energy prices; estimating customer baseline loads and settling actual load reductions for each customer.

5. Implementation costs can be high and can include metering costs, communication and data handling systems, and potential changes to CIS and billing systems.

6. Typically the customer is not obligated to reduce load during critical events, which could make the expected load reduction less certain. None of the CPP programs reviewed require the participating customer to actually reduce load during critical events; the only penalty is the high critical period price. A few demand bidding programs require customers to honor bids that have been accepted, but others do not.

Lessons Learned from Real-Time Pricing

There are currently about 70 RTP programs offered by utilities. Some are legacy programs that have been operating since the 80's and early 90's, others are new programs which are largely part of electric restructuring and the revamping of standard offer prices. Lessons learned from the non-restructuring programs include the following results.

Program participation, in general is low. A survey of 43 RTP programs in 2004 found that a total of 2,700 non-residential customers, representing more than 11,000 MW of peak demand, were enrolled in the RTP programs. However, most of these participants were associated with a couple of large programs. Only three programs had more than 100 non-residential participants or more than 500 MW enrolled, one-third of the programs had no participants. Another third had fewer than 25 participants, less than 50 MW, and less than 1% of the utility's system load enrolled.

In addition, participation has been declining for most programs. Over the last several years 50% of all RTP programs lost 25% or more of their customers. Only two programs had increased participation.

RTP programs can face somewhat of a "catch 22" in terms of program participation. When wholesale energy prices become high and volatile, customers face substantial price risk which can limit participation. When prices are stable, opportunities for savings are lower, so customers can lose interest in the program. Utilities attempted to address the risk issue by designing two part tariffs, where a customer's baseline usage was billed according to the otherwise applicable tariff and only incremental changes in usage were subjected to market prices. Some utilities also offered risk management products such as caps, collars, and contracts for differences to address the price risk issue.

Some customers respond dramatically to real-time prices. However, this appears to be limited to certain types of customers including industrial customers with flexible manufacturing schedules and customers with flexible use of on-site generation. A substantial number of participants are not price responsive. Some RTP program mangers believe that many program participants expected to realize bill savings solely by purchasing load at marginal cost based prices, without responding to these prices on an hourly or daily basis. Overall peak impacts reported by program managers range from 12-33% reduction in participants' aggregate peak demand.

Critical Peak Pricing - Large General Service

California CPP Programs

The critical peak prices for larger general service customers offered by PG&E and SCE, and San Diego Gas and Electric (SDG&E) include increased prices during critical periods compensated by reduced prices at other times. Eligible customers had to have demands above 200 kW for SCE and PG&E, above 100 kW for SDG&E.

For SCE, critical events could occur during the summer season between 12 noon and 6 p.m., weekdays. The critical days were limited to 12 days per year. Events could be triggered by a number of factors including high system demand, low generation supply, high market prices, high temperature or system emergency testing. Customers are notified one day prior to an event starting at 3:00 p.m. Notification is made by telephone, email, or pager. There is no obligation to reduce load during an event and no penalties, other than the high critical price, for non-response.

The PG&E program is similar to SCE except that their program operates year round and notification is made by 5:00 p.m. the day prior to an event. The SCE program also operates year round, notification is given by 4:00 p.m. the prior day and the critical period begins at 11:00 a.m.

For SCE, the critical period for each event is split into two high-price periods: from 12 noon to 3:00 p.m. where prices are approximately 2 times the normal on-peak rate of the customers otherwise applicable tariff and from 3:00 to 6:00 p.m. where prices are 6.7 times the normal on-

peak rate. For compensation the rate during non-critical periods is 9.5% less than the normal rate.

For PG&E, the energy rate during high period is 5 times the otherwise applicable rate, the moderate price period is 3 times the normal rate. For compensation, normal on-peak rates are reduced by 22%, shoulder rates by 3%.

SDG&E's energy rates are 10.0 times the normal rate from 11 a.m. to 3 p.m. and 3.8 times the normal rate for CPP Period 2. For compensation, the CPP rates are about 9.5 percent lower than the normal energy rates during non-critical times in the summer.

Potential Customer Bill Savings

The California utilities conducted rate analyses to determine whether eligible customers would pay more or less on the CPP rate than on their normal rate, assuming their previous year's pattern of energy usage with load shifting ranging from 0 to 20 percent. For PG&E and SCE about 50% of eligible customers would save under the CPP rates without making any changes to their usage patterns. However, of these, 75% would save less than 1% per year. At the other end of the spectrum about 99% of customers would save, assuming a 20% load reduction during critical periods. But again, of these, 75% would save less than 1.6% per year. For SDG&E, about 75 percent would save assuming a 10% reduction; 3.8% of these customers would save less than 2% per year.

Participation

Program penetration levels for the 2004 California critical peak pricing and demand bidding programs are summarized in Table 24. The participating customers represent 4.7% of eligible customers, 8% of non-coincident demand and 11% of energy from eligible customers.

Participation in the California critical peak pricing programs was relatively low. Only 1.1% of eligible customers participated from the three utilities. Participation was somewhat higher (3.1%) for customers with demands between 1,000 and 2,000 kW demand. Participation was highest for institutional commercial customers and some industrial and transportation customers.

Table 24 Participation in California Demand Response Pilot Programs

	Critical Peak Pricing	Demand Bidding	Total Demand Response
Office	11	52	63
Retail/Grocery	3	167	170
Institutional	36	63	99
Other Commercial	28	105	133
Total Commercial	78	387	465
Petroleum, Plastic, Chemicals	7	57	64
Mining, Metals, Glass, Concrete	4	50	54
Electronic, Machinery, Fabricated Metals	32	74	106
Other Industrial and Agricultural	30	78	108
Total Industrial	73	259	332
Transportation/ Communication/ Utility	28	72	100
Unclassified	27	45	72

Total	206 (1.1%)	763 (3.8%)	969 (4.7%)

PG&E, SDGE, SCE 2004

Load Impacts

The California pilot did not estimate demand models or elasticities for medium and large general service customers. Instead the pilot measured actual hourly consumption during critical days for each participant and compared it with estimated hourly consumption that might have occurred without the critical peak prices. This was accomplished using a variety of "representative day" techniques for estimating load using hourly consumption information prior to the critical event. The results varied significantly by customer type and utility and are, therefore, difficult to translate to an estimate of total potential reduction for general service customers. For example, impacts for PG&E customers ranged from 2% to 16% load reduction across the various critical periods. Impacts for SDG&E customers were 10% to 19%. While impacts for SCE ranged from 42% to 66% across the events. The latter result is primarily driven by the high response of one large customer. The three utilities are currently using an impact estimate of 15% during critical periods.

Demand Bidding Programs

Demand bidding programs allow a customer to bid potential load reduction, typically the day before a critical event, for an incentive based on a predetermined price. For some programs participants are not required to bid into any particular critical event or even reduce their load as bid. Other programs require customers to "deliver" their load reductions as bid or face penalties.

California Demand Bidding Program Pilot

As part of the pricing pilot, California experimented with a demand bidding program for general service with loads greater than 200 kW demand. The utilities had already installed interval metering for all customers in this targeted group so implementation costs were not a significant factor.

In the program, customers submit bids to curtail usage during critical periods, which last for no more than 4 hours between 12 noon and 8 p.m. on critical days. A bid must be for at least 100 kW of load reduction for at least two consecutive hours. The customer's compensation equals the estimated load reduction times a pre-determined price, equal to the utility's projected hourly energy costs.

The program tested two types of events. Day-ahead events were called by the utility when its projected hourly energy costs exceed $0.15/kWh. Day-Of events could be called for reliability issues. There is no limit to the number of critical events that can be called by the utility.

Each customer's estimated load reduction during critical events is calculated by subtracting their actual metered usage from as estimate of what the load would have been without the curtailment. Several "typical day" estimation methods were tested in the program evaluation. While there

was no penalty for non-compliance, the customer is only paid for 50 to 150% of their bid curtailment.

Since the pilot, SCE implemented a new demand bidding tariff, with some changes based on lessons learned from the pilot. They dropped the day-of events for lack of participation – many customers reported that it did not allow enough time to respond.

Critical events under the new program are triggered when the California ISO forecasted a reliability problem or when the ISO load exceeds 43,000 MW for the next day. The incentive was increased to equal the forecasted hourly market price plus 10 cents per kWh.

Participation

Customer participation in the California demand bidding pilot is summarized in Table 24. Overall, 763 customers participated from the three utilities, which represented 3.8% of eligible customers. However, this includes 286 small to medium size customers who were erroneously enrolled in the SCE program without having the ability to meet the 100 kW bid minimum. Participating customers included retail and grocery stores, industrial customers and some institutional customers, which was primarily municipal water pumping accounts.

The program evaluation suggested that participation may have been small because of the modest level of potential bill savings, which was typically in the order of 1 percent, for participating customers relative to any perceived risks or customer implementation costs.[9]

For example, the utilities estimated that customer savings from 1 MW of load reduction over 4 events would be about $2,400 for day ahead events and $8,000 for day-of events. Based on 12 events, the savings would increase to $7,200 for day ahead events and $24,000 for day-of events. At the lower end of the spectrum, for a 100 kW reduction over 4 day ahead events the customer's bill savings would be $240, savings would increase to $800 for 4 day-of events, $720 for 12 day ahead events, and $2,400 for 12 day-of events.

Potential Load Impacts

Estimates of peak reduction from a demand bidding program can be obtained through the bid settlement process for each customer. This settlement process compares each customer's actual metered load during the critical event to an estimate of what the load would have been absent the program. The latter is performed using a function of the customer's hourly metered load profile in the days prior to the critical event.

The average estimated load impacts varied across the three utilities. The average customer load reduction during PG&E' single day ahead was estimated to be 17 percent. The load impacts for SCE customers who submitted bids ranged from 12 to 50 percent. Estimated peak-load reductions for SDG&E customers were 19 to 28 percent. The utilities report that they are currently using an estimate of 15 percent load impact for the demand bidding program for planning and reporting purposes.

However, as with the CPP impacts, because of the limited events, the dominance of a few large customers, and the low level of actual customer bidding, the California demand bidding pilots did not produce a reliable overall impact estimate that could be used for future program planning.

Key findings from California Critical Peak Pricing and Demand Bidding Pilot Programs

- Participation was relatively low for both the CPP and demand bidding programs, especially if you eliminate the smaller customers who enrolled in the SCE demand bidding program. Participation was highest for certain industrial customers and institutional water pumping customers.

- The monetary incentive to customers to reduce load in both programs was relatively small, which was typically in the range of 0.4 to 2 percent of the customer's annual bill. Marketing research indicated that most customers were typically unwilling to make load reductions for savings in this range, especially if the program is perceived to involve financial risks or implementation costs.

- Some program participants (26%) reported that they experienced negative impacts on their employee comfort or productivity and experienced complaints from staff.

- Overall, most of the participants in both pilot programs reported that they intended to participate in the programs the following summer.

- Some larger general service customers did respond to critical peak pricing, however, the impact is uncertain and varied widely by customer type. Few critical events occurred during the pilot so real impact of CPP and DB programs is difficult to determine. Although many participants report that they would respond by reducing load during another critical event, some customers report difficulty in being able to respond to critical events.

- Follow-up marketing research indicated that 80 percent of participants in the critical peak pricing programs reported that they took at least one action to reduce load during a critical event. 84 percent reported that they were either somewhat or very likely to take responsive actions during future critical events.

- The day of notification did not allow many customers enough time to react to a critical event. As a result, PG&E cancelled this program option.

- The utilities reported low levels of bidding for critical events. Only 27 percent of program participants reported placing at least one bid. However, 75% reported being somewhat or very likely to place bids for future critical events.

- Despite multiple channels for notifying customers of critical events, utilities experienced difficulty in reaching the appropriate contact for some customers. Similarly, some customers who did not place bids during a critical event reported that the responsible person was not available to place the bid in time. In fact, half of customers surveyed in follow-up marketing research said that the notification

timeframe, which allows an hour to place a bid after being notified of an event, makes it less likely that they would place a bid.

Conclusions

1. The Company will continue to monitor critical peak pricing and demand bidding programs to assess pricing designs, program best practices, and customer participation and load impacts.

2. Further assess program implementation costs, especially communication infrastructure, data handling and billing systems to better assess the cost/benefit.

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October 7, 2005

Mr. Ernest Johnson
Director, Utilities Division
Arizona Corporation Commission
1200 West Washington
Phoenix, Arizona 85007

RE: Flexibility Study for Time-of-use Rates, Cost Benefit Analysis of SurePay

Dear Mr. Johnson:

Pursuant to Decision 67744 (Page 31, line 23) Arizona Public Service submits the attached documents: (1) a study which examines flexibility in changing APS' on- and off-peak time periods and other characteristics for its time-of-use rates and (2) a cost-benefit analysis of SurePay, APS' automatic payment program, which explores the possibility of offering a discount to participating customers.

If you have any questions please feel free to call me at 602-250-3933.

Sincerely,

David J. Rumolo
Manager
Regulation and Pricing

Attachment

DJR/bec

cc: Brian Bozzo, Compliance Enforcement

ARIZONA PUBLIC SERVICE COMPANY

Time-of-Use Flexibility Study

INTRODUCTION

Decision No. 67744 (Page 31, line 23) required Arizona Public Service (APS) to examine flexibility in changing APS' on- and off-peak time periods and other characteristics for its time-of-use (TOU) rates. One of the greatest challenges to providing flexibility in the APS residential TOU program is a result of the success of the current program. APS' residential TOU program is one the largest in the country in both absolute numbers and expressed as a percentage of residential customer base. Changing any of the rate characteristics, such as modifying the on-peak hours or adding holidays to the off-peak period for all existing customers requires a time extensive effort and significant expense to implement the necessary metering and system changes

This study discusses the technology and system challenges that must be addressed to increase flexibility by introducing rate options with differing time periods. The study also discusses the TOU rate options that were filed with the Commission on September 22, 2005 to provide customers with additional options and that will allow the Company to assess customer reactions to differing TOU periods and on and off peak pricing differentials. These proposed rate schedules address many of the flexibility issues that have been raised. Additionally, the study discusses projects that are currently under way that examine alternate metering technologies that should provide more flexibility in the future long term implementation of TOU rates.

APS SYSTEM PEAK DAY PROFILE

Since the purpose of TOU pricing is to provide customers with proper price signals to encourage electricity use during times when production costs are lower (i.e. off-peak periods), it is important to understand the nature of APS' load shape.

Due to air conditioning load, the APS system has a dominant summer peak which drives the need for generation capacity additions. The summer peak for APS' retail load typically occurs between 3:00 and 6:00 P.M., and high load levels continue well into the night which is atypical compared with most utilities. The load begins to ramp up at 9:00 A.M. By noon, the load is within 10% or 500 MW of the daily retail peak. The load remains high, within 10% of the daily peak, through 8:00 P.M. and falls off significantly only after 9:00 P.M. More specifically, the load from 6:00 to 7:00 P.M. is typically 95% of the daily peak; the load from 7:00 to 8:00 P.M. is 91% of the daily peak. Therefore, a significant shift in load to the 7:00 P.M. to 9:00 P.M. period could have the potential to merely shift the system peak to this later period, rather than reduce the peak as intended.

The APS winter load shape is significantly different compared to summer. In addition to being approximately 35-40 % lower in magnitude, the winter season peak exhibits two peak periods with the morning peak being dominant. The winter peak for APS' retail load typically occurs at 7:00 to 8:00 A.M. in one of the colder months (December – February). The daily load ramps up at 6:00 A.M. and falls off after 9:00 A.M. Afternoon usage picks up at 6:00 P.M, reaching 90% of the daily peak, and falls off after 9:00 P.M. However, in some years, hot temperatures in March or April can cause daily loads to rival some of the cold days in December and January. For example, in 2004, 5 of the top 10 "winter" peak

days were in March and April. The usage patterns for these days resemble the summer peak days, not the winter. In any case, winter peak demands are significantly lower than summer peak demands. Typically, the winter peak is 35% or 2,000 MW lower than the summer peak. Because the APS resource fleet has been designed to meet maximum summer loads, winter peak loads can be generally met with lower cost resources. The benefit of encouraging customers to shift load to off peak periods during the winter is much lower than in the summer.

CURRENT RESIDENTIAL TOU RATES

Currently APS offers two residential time-of-use ("TOU") rate schedules; Time Advantage (ET-1), which includes peak and off-peak energy charges, and Combined Advantage (ECT-1R) which includes both time differentiated demand and energy charges. The peak period for both rate schedules is weekdays 9:00 A.M. to 9:00 P.M. in both the summer and winter seasons. These rates were introduced in 1982 and 1988 respectively.

As shown in Table 1, over 357,000 APS residential customers are currently participating in a TOU rate, which represents over 40% of total residential customers. As discussed below, APS has recently proposed to implement two new experimental residential TOU rate schedules, ET-2 and ECT-2 that will offer rate alternatives to customers. At this point, it can not be determined whether the new TOU rates will attract customers from non-time differentiated rates or customers on existing rates will transfer to the new rates.

Table 1. Current Residential TOU Customers

Rate Schedule	Customers (2004 Avg.)	% of Total
ET-1	312,327	36.4 %
ECT-1R	45,045	5.2%
Total Residential TOU	357,372	41.6%
Total Residential	859,069	100.0%

TOU RATE ALTERNATIVES

On September 22, 2005, APS filed an application to obtain approval for two new experimental residential TOU rates. Schedule ET-2 parallels most of the features of existing Schedule ET-1 and Schedule ECT-2 parallels most of the features of existing Schedule ECT-1R. These new schedules provide for longer off-peak periods than the existing TOU rates and also incorporate holidays in the off-peak periods. Both new rate schedules have time-differentiated energy charges. ECT-2 will also have a demand charge applied to the peak period. The new rate schedules will have on-peak hours of noon to 7 P.M. for both the summer and winter seasons. The relative on and off peak prices have changed compared to the existing schedules so that stronger price signals are provided. Implementing these rates will require approximately seven months for system programming and testing once regulatory approval has been received. The implementation of these new experimental rates will provide customer behavior learning opportunities as

information is developed on changes in consumption patterns and customer reaction to price signals. This will provide some indicators of the benefits of offering flexibility through alternative TOU hours.

TECHNOLOGY AND SYSTEM CHALLENGES

Challenges regarding TOU program flexibility are not unique to APS. For example, the recently enacted Federal energy act requires changes to daylight savings time (DST) for states that utilize DST. Utilities that have TOU programs are now trying to sort through issues related to TOU metering since existing meters are programmed to recognize the current DST calendar.

Implementing new rate schedules requires changes to metering, the customer information and billing system, the metering information system and related programs. These systems and numerous subsystems interrelate to capture metered data, ensure that the customer is on the correct rate with the correct meter, calculate the bill, present the bill, allow for re-bills and corrections, schedule meter and service changes, provide customer service information and screens to advise customers about rate options, allow customers to assess rate options through the internet, post the revenue to the general ledger, and many other functions. Most importantly, any new rates that are structurally different from current rates require significant system testing to ensure that the data is correctly captured, billing is accurate and that the programming changes do not adversely impact any other part of the system.

Several of the key systems that require modifications for implementing new rate schedules are metering, the customer information and billing system, the customer service software interface, APS.COM and the meter information system. These systems are described below.

METERING TECHNOLOGY

APS' current meter reading system does not support the capability of reprogramming meters in the field with the hand held "probe" device that is used to read the meters. While software support that enabled field programming was once available, it is no longer supported by the current vendor. Therefore, meter programming must be performed at the manufacturer, at the utility's meter shop, or in the field using a computer loaded with each meter vendor's software. The latter option is not practical for handling a significant number of TOU customers due to the time required to reprogram each meter.

Because of the limitation of our current meter reading system, changing time-of-use characteristics, such as the on-peak hours or holidays for an existing rate schedule would require replacing the meters of all of the current customers on the rate schedule. In addition to being very costly, such a massive meter change out could only occur over a long period of time. During the transition period, meter record keeping would be very challenging since the links between the meter which is currently in use at a customer's residence and the appropriate rate schedule must be maintained. For example, if the customer has already migrated to the rate schedule with new TOU periods and experiences a meter failure, the APS meter service personnel must have the correct replacement meter available in inventory.

Another issue concerns the potential need for a meter change when a customer switches between standard and TOU rate schedules. Many customers require a meter change to accommodate a switch in rate schedules. Some customers have meters that are pre-programmed to be able to bill both standard and TOU rate schedules. In this case, the customer would not typically require a meter replacement if the customer switched between a standard rate schedule and one of APS' current TOU rate schedules.

However, this flexibility erodes as new TOU rates with different on-peak hours and other characteristics are introduced. For example, while a meter can be pre-programmed to be able to bill both a standard rate and a TOU rate, it cannot be pre-programmed to be able to bill both a TOU rate schedule with a 9 A.M. to 9 P.M. on-peak period and one with a noon-7 P.M. on-peak period. This is because the billing determinants for the standard rate are nested in (or captured by) the TOU billing information. However, the billing determinants for the two TOU rate schedules, namely the on-peak and off-peak kWh, are distinct and cannot be simultaneously captured by the same meter. Rate switches between the alternative TOU rate schedules would require the meter to be re-programmed with the new rate schedule.

APS is reviewing several metering alternatives that may add flexibility for changing TOU rates in the future. These included implementing an alternate meter reading system, implementing an advanced metering system (AMS) and using interval data recording meters (IDR). These alternatives are not mutually exclusive and a combination of the new technologies will likely be implemented.

New Meter Reading System

APS is performing an assessment of implementing a new meter reading system that may be capable of reprogramming meters with a hand held device at meter reading time. This would lower the cost and time required to re-program meters, which would enhance the ability to implement new TOU rate schedules, enhance the ability to change existing TOU rate schedules, and lower the cost of customers switching between rate schedules. The assessment is in its initial phases and the technology must be examined in greater detail to determine the technical feasibility and cost/benefits.

Implementation of a new meter reading system will entail replacing all meter reading equipment including handheld devices and related software. An alternate meter reading system will require customer information system programming to coordinate and track meter programming changes. Extensive testing of all systems is required to ensure data accuracy with the reprogrammed meters. It will also require some changes to the meter information (MIS) system, orders processing, and systems that upload and download meter reads.

Implement an Automated or Advanced Metering System (AMS)

APS is assessing the benefits of AMS including the ability to provide flexibility for changing time-of-use on-peak time periods and other characteristics. The communication capabilities of the AMS provide remote meter programming, which would eliminate the need for meter changes or re-programming in the field in order to implement new TOU rate schedules, change current TOU rate schedules or accommodate customer switching between rate schedules. AMS will also facilitate the development of innovative pricing mechanisms such as real time pricing (RTP).

The AMS that APS is currently assessing consists of "spoke" meters on each home which communicate via radio frequency technology to a "hub" meter on a home in the neighborhood, which in turn communicates with the central system via cellular modem. The system features two-way communications and data recording capability. The rate schedules are controlled by a database server. APS is piloting AMS with 500 meters in the Metro Center area with plans to roll out the system to other areas next year. Implementation of AMS for the entire customer base will require a several year phase-in and will be capital intensive.

Expand the use of IDR meters with communication capability
Interval data recording meters (IDR) such as those used by APS for load research were evaluated as a potential solution for implementing new TOU rate schedules. However, most of the meters do not have communication capabilities nor is the data captured through the IDR generally used for billing purposes. In most cases, interval data are captured by meter readers using a probe device. Alternatively, cellular communication capabilities can be used to allow for remote meter reading. APS uses MV90 translation software to process the interval data.

If suitable interval data could be used to bill customers on TOU rate schedules, the need for a meter change for implementing new TOU rate schedules or when customers switch between TOU and standard rate schedules would be eliminated. While APS currently has the meters and systems to support IDR meter data, expanding this capability to implement TOU rates would require extensive upgrades in systems, data handling capabilities and communication capabilities. The use of IDR offers limited benefits compared to other solutions and, therefore, is not being further explored at this time.

Customer Information System (CIS)
CIS is the mainframe software application that handles all billing, customer data, and customer information processing. In order to implement new rate offerings, CIS requires programming changes to ensure that the customer account is maintained properly with the current rate schedule, meter and other relevant information, and that the bill is calculated and presented accurately. This requires changes to various tables, service plans, screens, reference tables, bill calculation, bill statements, rate comparison features, order processing, E-bill, service account maintenance, new business cases, new reports, and related subsystems.

If a new rate schedule involves changing the basic structure of the rate calculation, it requires extensive programming of the basic CIS data base and related tables and code. New rate schedules and meter types have to be tested to ensure that the billing information is correctly extracted from the meter and uploaded to the CIS system. Also, old data structures and relations must be maintained so that rebilling of customers, if ever needed, can occur.

Even seasonal changes in TOU on-peak hours (e.g. different on-peak hours in summer and winter) are significant challenges for the CIS structure and the meter interface. Currently, the system is programmed to transition between summer and winter seasons on the first billing cycle of the transition month in accordance with the APS rate schedules. Creating winter on-peak hours different from the summer would require extensive re-programming and testing of CIS and creates meter interface problems. Meter calendars are hard programmed while meter read cycles have some limited flexibility. If winter and summer TOU periods are different, the meter calendar must be programmed with a hard date for the seasonal switch. For example, a meter would be programmed so that on April 30 the winter time periods are in effect but on May 1 the summer TOU periods become effective. However, meter reading occurs on a cycle basis so that the last day or so of a customer's "winter" consumption can actually occur in the first days of May. Thus the meter programming and billing cycles would not be synchronized. Alternatively, if the seasonal transition for a TOU rate would occur on a firm date to coordinate with meter programming a massive re-write of the existing CIS program applications would be required including a system for prorating the bills during the seasonal transitions. In either case, implementing different winter

and summer peak periods requires comprehensive billing component changes as well as database changes in some key areas of the system, which could impact thousands of lines of programming and entail significant testing. These significant base design changes to the system would require not only considerable impact analysis and design time, but very involved and lengthy testing as well to ensure the changes work properly. In addition to the systems impacts, there would be business impacts, meter equipment impacts, etc. with additional costs that would have to be considered.

Customer Care Environment Software (CCE):
Changes in the CCE software, which is the interface used by customer service personnel to advise customers on rate options, switch customers to new rates, and maintaining customer accounts, are required each time new rate schedules are offered. When new rates are implemented, the rate comparison function must be modified for the new schedules. Programming changes need to be made to the relevant screens, windows, prompts and related information, to ensure that the calculations are accurate and the windows and prompts are functioning correctly.

The service account maintenance function of the CCE performs numerous tasks such as determining whether a customer is eligible for a rate schedule. For example, in the case of the proposed experimental TOU rate schedules recently filed with the Arizona Corporation Commission, which is limited to certain cities in the Phoenix metro area, the CCE will determine customer eligibility based on location. Because the total participation for the proposed rates is capped, the CCE will also need the ability to easily discontinue the availability of the rate schedule once the cap is reached.

APS.COM
APS.COM is the web-based tool for customers to be able to view rate schedule options and compare their monthly bill under various options. Implementing new rate schedules requires this system to be updated with new screens, reference tables, information, orders and sample rate calculation functions.

Meter Information System (MIS)
MIS provides the logistics for linking meters/meter types to customer accounts and ensuring that the meter programs are consistent with the rate schedule. For example, when a new customer establishes service and is on a rate schedule such as ECT-1R, MIS tracks the fact that the customer requires a TOU meter with demand registers and the CIS/MIS linkage looks to ensure that demand data is being retrieved. Data in MIS also is used to be sure that if a meter exchange occurs, the correct meter is installed at the customer's premise is installed. When rate schedules are added that require metering with alternative TOU schedules, MIS must be modified so that the new meter types will be recognized.

SUMMARY
Because of the success of its residential TOU programs, APS faces challenges in changing certain characteristics of the rate schedules, such as the on-peak periods for summer and winter seasons. Some of the resulting requirements for reprogramming our billing, customer service and meter information systems are difficult to avoid or short cut. These are large, integrated systems with a significant amount of functionality. Furthermore, any changes to the systems must be thoroughly tested to ensure that customer accounts are billed and maintained accurately.

Metering issues are also a significant challenge for changing TOU rate schedules or for implementing new TOU rates. APS is exploring several solutions to add flexibility to this part of the challenge. Two potential solutions identified are to (1) implement a new meter reading system which would allow for the meters to be reprogrammed in the field by meter readers with the same probe device that they use to read meters and (2) further pursue automatic meter reading which would allow for remote meter reading and programming. It is likely that a combination of these solutions will be implemented. APS believes that APS proposed experimental TOU rate options pending approval before the Commission will help the Company assess customers' reactions and assist in evaluating the future expanded options that would benefit customers and the APS system.

ARIZONA PUBLIC SERVICE COMPANY

Analysis of SurePay Program

INTRODUCTION

Pursuant to Decision 67744 (Page 31, Line 28) APS has examined the cost effectiveness of the SurePay program as well as the possibility of offering a discount to those customers that participate in SurePay. SurePay is the payment option that authorizes a customer's bank to transfer the amount of the customer's monthly bill from the customer's bank account to the customer's APS account. In undertaking the SurePay analysis, APS also took into consideration AutoPay, the on-line version of SurePay. AutoPay is another APS automatic payment program option available to aps.com registered users with email access. AutoPay customers receive an e-mail notification telling the customer the amount of the bill and when payment will occur. AutoPay customers can view their written bill on line in lieu of receiving a mailed copy.

ANALYSIS

After examining APS' automatic payment programs – SurePay and AutoPay, APS does not feel it is advantageous or cost effective to offer customers a discount for participating in these programs for several reasons.

Currently, there are 105,165 Residential SurePay customers and 9,447 Commercial and Industrial (C&I) SurePay customers. Total participation in the SurePay program is 114,612 customers for an 11.9% market share. In addition, there are 27,131 Residential customers and 973 C&I AutoPay customers. Total participation in the AutoPay program is 28,104 for a 2.9% market share. APS has a total of 143,689 customers or 14.8% market share participating in APS' automatic payment programs. Given APS' current robust market share, offering a discount to entice customers to enroll is not needed.

Chartwell, a national market research group, recently published the research findings from the *Chartwell's Guide to Bill Presentment and Payment 2005* report. The report includes exclusive surveys of 90 utilities. The report findings indicate 60 out of the 90 utilities surveyed offer an automatic payment program. The average participation rate is 8.1% overall customer participation. This is far lower than APS' participation rate of 14.8%. Offering any type of incentive to enroll in the program, whether it is a one-time enrollment incentive or an on-going incentive, such as a recurring 1% discount, has not been needed to generate interest in APS' automatic payment programs. These programs have been successfully sold on the benefits of participating in the programs. These benefits include convenience, peace of mind, time savings and cost savings. Salt River Project (SRP), which offers a 1% discount to participants in automatic payment, did not participate in the Chartwell study. However, its percentage of customers choosing automatic payments is believed to be in the 15-16% range – not significantly higher than APS' 14.8%.

The cost savings associated with the Company's automatic payment programs are significantly below the 1% discount that is currently being offered by SRP. SurePay and

AutoPay are APS' least expensive payment processing options. APS currently experiences operating and cost of money savings of $.48 per month, or $5.76 annually from each SurePay or AutoPay customer as shown in Attachment 1. The annual savings associated with these programs is approximately $820,000 per year. Whereas, a 1% discount to our 132,296 Residential SurePay and AutoPay customers, i.e. customers who are already participating without financial inducement, would cost $1,512,143 per year (assuming an average Residential bill of $95.25/month). A similar discount to our 10,420 C&I SurePay and AutoPay customers would be $784,451 per year (assumes average C&I bill of $627.36/month). The total cost of offering a 1% discount to existing SurePay and AutoPay customers is estimated to be $2,296,594 per year. Therefore, the cost of such a discount is significantly more than the savings. Currently, the cost savings generated by customers participating in APS' automatic payment programs are passed along to all APS ratepayers.

In addition, considerable efforts by APS Information Services (IS) and Customer Service would be required to implement a discount for SurePay customers. Changes to APS Customer Information System (CIS) would need to be implemented in order to provide the discount. Such changes are estimated to be at minimum $50,000. Ongoing monitoring and management would also be required to ensure that SurePay and AutoPay customers are receiving the discount.

Based on current participation and the experience of SRP and others, it is unlikely that a discount will provide an incentive to the majority of non-automatic payment program users to enroll in the program. Non-users have very definite reasons for not doing so. These customers raise security and privacy issues as reasons for not participating in the program. They do not like the fact that APS would have access to their personal banking information. Another explanation customers give for not to participating in an APS automatic payment program is account reconciliation. Some non-users are afraid if they sign-up for SurePay or AutoPay they will forget to record the payment withdrawal. Fear of potential errors such as incorrect amounts being debited or multiple unauthorized debits occurring also prevents customers from participating in an APS automatic payment program. Finally, many customers choose not participate in APS' automatic payment programs because they do not want to relinquish control. These customers do not want to have someone control when their bill is paid or the amount that is paid. Offering a discount for participation in SurePay or AutoPay as an incentive will not entice the majority of these customers to enroll in the program. Moreover, since every additional customer on automatic payment would produce $0.48 per month in savings at (conservatively) between $0.95 (residential) and $6.27 (general service) per month in additional costs, a discount would not be cost effective even if it did produce significant customer participation.

Finally, an assessment of the market reveals that very few utilities offer a discount or incentive for participation in an automatic payment program. When Chartwell asked respondents about incentives, only six out of the 90 utilities interviewed offered some type of incentive for participation in an automatic payment program.

SUMMARY

Customer participation in APS' automatic payment programs exceeds the average participation of other utilities without the need to offer a discount. These convenient payment options also achieve cost reductions for all customers. The APS review of the SurePay/AutoPay programs indicates that offering a 1% discount to those customers who participate is not cost effective and cannot be supported by savings realized for these programs. Based on these factors APS concludes that a discount offer is not needed.

Attachment 1
SurePay Analysis

Key Inputs & assumptions:			
Payment Option Mix of SurePay Enrollees	% of Mix	Cost/Transaction	
Business Office	15%	$ 2.54	
Mail	65%	$ 0.22	
aps.com/ivr/EDI	17%	$ 0.11	
Bill matrix/NCO	2%	$ 0.09	
Surepay cost/payment		$ 0.11	
Avg Residential Monthly Bill		$ 95.25	
Avg C&I Monthly Bill		$ 627.36	
Cost of Money		2%	
Days of float (Difference between SurePay debit at *day 10 and day 18, the avg day on which non-SurePay customers pay*)		8	

Cost/Benefit Analysis of 1% Surepay Discount			
Savings			
Cost of Money			
# of customers	10000		
Interest Rate	2%		
Days of float	8		
Daily Int Rate	0.04384%		
Avg Residential Monthly Bill	$ 95.25		
Monthly Residential Savings for 10K customers	$ 417.53		
Avg C&I Monthly Bill	$ 627.36		
Monthly C&I Savings for 10K customers	$ 2,750.07		
Operating Cost	Pmt Cost	% of Mix	Wtd Cost
Business Office	$ 2.54	15%	$ 0.39
Mail	$ 0.22	65%	$ 0.14
aps.com/ivr/edi	$ 0.11	17%	$ 0.02
bill matrix/nco	$ 0.09	2%	$ 0.00
Surepay	$ 0.11		$ -
Wdt Avg Cost			$ 0.55
Surepay Cost			$ 0.11
Net Operating Cost Savings			$ 0.44
Total Net Operating Cost Savings			$ 4,430.30
Total Monthly Savings for 10K customers			$ 4,847.83
Avg Savings per Enrollment			$ 0.48
Costs			
Key Assumptions			
Amount of discount	1%		
Current Residential Surepay accts	105,165		
Impact-10K New Additions			
Monthly cost of discount to 10,000 new residential accounts	$ 9,525.00		
Net Monthly Savings to add 10,000 new accts	$ (4,677.17)		
Avg cost per new addition	$ 0.95		
Impact - Existing Customers			
Monthly cost of discount to existing accounts	$ 100,169.66		
Avg cost per existing customer	$ 0.95		
Impact - New and Existing Customers			
Total monthly discount costs (existing & new accts)	$ 109,694.66		
Monthly savings minus costs to APS (existing & new customers)	$ 104,846.83		
Net Annual Cost to APS	**$ 1,258,181.94**		

Above analysis reflects operating savings for new additions only. No operating savings were applied to customers on the program from previous years.

GREGORY A. DELIZIO

DIRECT TESTIMONY OF GREGORY A. DeLIZIO

On Behalf of Arizona Public Service Company

Docket No. E-01345A-05-0816

January 31, 2006

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DIRECT TESTIMONY OF GREGORY A. DeLIZIO
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-05-0816)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Gregory A. DeLizio, 400 North Fifth Street, Phoenix, Arizona 85004.

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

A. I am Supervisor of Regulation and Pricing for Arizona Public Service Company ("APS" or "Company").

Q. WHAT ARE YOUR PROFESSIONAL QUALIFICATIONS?

A. My qualifications are set forth in Appendix A to my testimony.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The Company is seeking approval of the following: an adjustment mechanism that would provide for timely recovery of investments in environmental improvements to generation facilities; a number of new offerings related to renewable resources; and changes to the Company's current service schedules, as described below. The purpose of my testimony is to address these items. I explain the Company's proposed Environmental Improvement Charge ("EIC") and how it will be administrated. I will also describe three of the Company's new proposals which address renewable resources and net metering; specifically, the Green Power Schedules GPS-1 and GPS-2, and Renewable Resources EPR-5. Additionally, I will discuss the Company's proposed changes to Schedule 1 – "Terms and Conditions for Standard Offer and Direct Access Services" and

Schedule 4 – "Totalized Metering of Multiple Service Entrance Sections at a Single Site for Standard Offer and Direct Access Service."

II. SUMMARY OF TESTIMONY

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. My testimony explains the methodology for the proposed EIC, which would allow the Company to implement planned environmental improvements and recover the costs of these capital projects on an annual basis, as the costs are incurred. The EIC initial charge would be set at $0.000152/kWh and be effective with customer bills rendered after January 1, 2007 (the date that it is anticipated the new rates from this rate application will be effective). I also address the proposed Green Power offerings: the Green Power Block Schedule GPS-1 and the Green Power Percent Schedule GPS-2. These offerings allow customers to obtain power from a variety of renewable resources at a lower cost than stand-alone solar power. The Company is also presenting a proposal for net metering (Rates for Renewable Resources EPR-5). This is a pilot program for renewable resource generation facilities that will provide the customer who owns renewable resource generators with a per kilowatt-hour kWh credit for the excess generation that they provide to the APS electric grid. Finally, the Company is requesting modifications to Schedule 1, the Terms and Conditions for Standard Offer and Direct Access Services, and to Schedule 4, Totalized Metering of Multiple Meters at a Single Site. These modifications will simplify the service schedules and clarify how various service charges are applied to specific situations that commonly affect APS customers.

III. SCHEDULE EIC – ENVIRONMENTAL IMPROVEMENT CHARGE

Q. PLEASE PROVIDE AN OVERVIEW OF THE ENVIRONMENTAL IMPROVEMENT CHARGE THAT THE COMPANY IS PROPOSING.

A. APS is recommending that the Commission establish an adjustment mechanism that would reduce regulatory lag by allowing the Company to recover the costs of environmental improvement projects that require substantial capital investments on an annual basis. The proposed EIC would yield an energy-based $/kWh charge that would be assessed to all retail kWh sold by APS. Mr. Edward Fox explains the environmental expenditures forecast for APS over the next several years in his testimony. My testimony describes the technical function of the EIC.

Q. HOW DOES THE EIC REDUCE REGULATORY LAG?

A. Under traditional cost recovery, a utility does not collect revenue related to a particular investment until the Commission issues an order within the context of a rate case. Inevitably there is a delay, often a significant delay, between the construction expenditures and an issuance of a Commission rate order. That regulatory lag prevents the timely recovery of cost associated with even those investments that are the result of government mandates. Thus, the goal in designing the EIC was to reduce this regulatory lag on environmental investments, while maintaining a vehicle for appropriate regulatory review of such investments. See Schedule EIC (Attachment GAD-1) and the EIC Plan of Administration (Attachment GAD-2).

Q. WHAT KINDS OF COSTS WOULD BE INCLUDED IN THE EIC?

A. APS would forecast environmental improvement expenditures on an annual basis. Those expenditures would include costs associated with investment, and

the expenses of installing and maintaining the environmental upgrades at APS' generation facilities. These would include, but not be limited to, the return on capital, depreciation, operation and maintenance expenses, property taxes, and associated income taxes.

Q. WOULD THE COMMISSION REVIEW THE APS EIC PLAN FOR WHICH THESE EXPENDITURES WOULD BE MADE?

A. Yes. As described in Mr. Fox's testimony, the Company has filed its initial APS EIC Plan for which it is seeking approval in this proceeding. In addition, as I discuss later in my testimony, the Company will true-up and file modifications to the plan with the corresponding EIC on an annual basis.

Q. HOW WILL THE EIC BE CALCULATED?

A. On an on-going basis, the EIC is based on applicable EIC revenue components divided by the forecast estimated retail sales over the 12 months period that the rate will be in effect. For this initial request only, the Company has used an eighteen month period (January 2007 – June 2008) to calculate the EIC.

Q. WILL THE EIC APPLY TO ALL CUSTOMERS?

A. The EIC ($/kWh) would be applied to all kWh used by Standard Offer customers. However, customers subscribed to Schedule SP-1 (Solar Partners), or who would subscribe to the proposed Schedule GPS-1 (Green Power Block) or GPS-2 (Green Power Percent) already pay the EIC under their standard rate schedule, so these customers would not be assessed the EIC a second time. Customers subscribed to Schedule Solar-2 will not be paying EIC because those customers have a stand-alone solar electric system that is not connected to the Company's distribution system.

Q. DOES THE COMPANY HAVE A PROPOSAL FOR THE PROCESS TO OBTAIN COMMISSION APPROVAL OF THE EIC ON AN ON-GOING BASIS?

A. Yes, the Company is proposing the following procedure for Commission review of the EIC:

- The Company EIC request for approval and true-up would be prepared on an annual basis.
- The Company would project the anticipated costs for the environmental improvement projects and file them with the Commission by March 15 of every year. As part of that filing, the Company would also true-up the EIC revenues that had been approved by the Commission and collected the previous year, by providing actual data of the costs and EIC revenues recalculated with actual historical data from the previous year.
- Staff would review the proposal, seek clarification or additional information from the Company as needed, and prepare a Staff Report with recommendations regarding the proposed EIC. Staff would file such a report within 60 days of the Company's filing.
- The Commission would consider the Company's EIC filing in an Open Meeting within 30 days of the Staff report filing. If the Commission fails to take action within this time period, the EIC filing and corresponding rate would be deemed approved, subject to true-up the following year.

Q. IS THE COMPANY REQUESTING APPROVAL OF A SPECIFIC EIC IN THIS FILING?

A. Yes. The Company currently has several major environmental improvement projects planned or under construction for its Cholla Power Plant, as discussed

by Mr. Fox and set out in the APS EIC Plan, which is attached to his testimony. In this filing, the Company is seeking approval for inclusion of those environmental projects in the initial EIC.

Q. WHAT FACTORS DID THE COMPANY USE TO CALCULATE THE ESTIMATED EIC ADJUSTMENT?

A. To compute the EIC requested in this filing, we have used components that are consistent with the cost-of-capital, depreciation, property tax and income tax assumptions used in this general rate case filing. Therefore, the debt component of 45.5% and the equity component of 54.5% and the Company's proposed equity cost of 11.5% were used in calculating the requested EIC. Property tax rates specific to the Cholla Power Plant are included, and the environmental assets are depreciated over 25 years. However, should projects qualify as a Certified Pollution Control Facility as provided for under the Federal Energy Act of 2005, amortization may be based on a lesser period.

Q. WILL THE COMPANY TRUE–UP THE EIC FROM FORECASTED DATA TO ACTUAL?

A. Yes, because forecast sales and estimated environmental compliance costs are used for EIC, a true-up mechanism is necessary to adjust for any over or under recovery. Any over or under revenue recovery relative to sales and expense projections will accrue interest, which will be reflected in the annual true-up process.

Q. HOW WILL THE EIC BE IMPACTED BY A GENERAL RATE CASE?

A. As a result of a rate case, the EIC would likely be reduced. This is because the environmental improvements placed in service would become part of rate base

as a result of the Commission order issued in the rate case and therefore would be removed from the EIC.

Q. HOW MUCH IS THE EIC AND WHAT IS ITS EFFECT ON CUSTOMERS' BILLS?

A. The Company is requesting an initial EIC of $0.000152/kWh, which would be effective with bills rendered after January 1, 2007. The average impact on total Company retail revenues, based on expenditures included in the APS EIC Plan for 2007 is approximately 0.18%. The impact to an average residential customer using 1163 kWh monthly would be to increase the customer's monthly bill by approximately 18¢ in 2007.

IV. PROPOSED GREEN POWER SCHEDULES

Q. PLEASE DISCUSS APS' PROPOSED RENEWABLE ENERGY OR "GREEN POWER" SCHEDULES.

A. The Company is proposing to expand renewable options available to customers by including a variety of renewable resources in its Green Power Block Schedule (GPS-1) and Green Power Percent Schedule (GPS-2) offerings. These schedules are attached as GAD-3 and GAD-4. The renewable energy that is provided under these rate schedules would be limited to those renewable resources that are eligible pursuant to the Environmental Portfolio Standard ("EPS"), A.A.C. R-14-2-1618, including any modifications to that rule over time. The renewable resources include, but are not limited to: solar, biomass, biogas, wind, geothermal, or small hydroelectric power. Making lower-cost renewable options available in addition to solar could significantly reduce the cost to the customer for renewable energy, which could potentially increase renewable resources subscription. With the introduction of these two new Green Power schedules, the Company plans to freeze its Solar Partners Rate Schedule

SP-1. Customers currently served by that schedule may remain on that rate schedule.

Q. BRIEFLY DESCRIBE THE DIFFERENCE IN THE PLANS.

A. The premium for both Green Power schedules is $0.03/kWh, as discussed in Mr. Fox's testimony. Both schedules will provide the customer with additional options to increase the use of renewable resources. The Green Power Block Schedule is modeled on the Solar Partners rate schedule design. However, unlike Solar Partners, Green Power Block Schedule offers the customer renewable sources in addition to solar. Under the Green Power Block Schedule, the customer chooses the number of blocks of renewable energy they desire to consume for each month. Each block is equivalent to 25 kWh of renewable energy; the charge is $0.75 per block. Under this Green Power Schedule, the customer knows in advance exactly how much the renewable energy will cost each month based on the number of blocks for which the customer has contracted. For example, a customer that contracts for two 25 kWh blocks of Green Power would pay $1.50 more per month.

In contrast, under the Green Power Percent Schedule, the customer elects a percentage of usage that will come from renewable sources. The percentage choices under this Schedule are 10%, 30%, 50% and 100%. A higher percentage subscription of renewable energy results in a higher additional monthly charge. Based on the election of a renewable percentage, a specific charge will be added to the customer's energy charges on their bill. For example, if a customer who consumes 1,000 kWh in a month elects 10% Green Power, an additional charge of $3.00 (1000 x 10% x $.03) will be added to the

customer's bill. As a result, the monthly cost for the Green Power Percent Schedule customer will vary based on the customer's usage.

Q. ARE THERE OTHER CONSIDERATIONS THAT THE COMPANY MADE WHEN IT DEVELOPED THE GREEN POWER SCHEDULES?

A. Yes. As discussed in Mr. Fox's testimony, APS is aware that some customers want to purchase a specific percentage of renewable energy. Others may prefer to pay a fixed amount each month for renewable energy. The proposed schedules are intended to address both types of customer requirements. Additionally, the Company is reserving the right to either limit the subscription under these schedules if reasonably priced renewable resources are not available, or to petition the Commission to modify the charges under these schedules to reflect current renewable cost premiums.

V. RATES FOR RENEWABLE RESOURCE FACILITIES

Q. PLEASE PROVIDE AN OVERVIEW OF SCHEDULE EPR-5.

A. This net metering rate schedule is offered as a three year pilot program to customers that have renewable resource generation facilities of 10 kW or less, where the customer's generator(s) and load are located at the same premise. Net metering provides a customer a kWh credit for renewable energy that is generated but not used by the customer, and supplied to APS' distribution grid. Schedule EPR-5 is attached (Attachment GAD-5).

Q. PLEASE EXPLAIN THE COMPANY'S PROPOSED SCHEDULE EPR-5.

A. The proposed pilot schedule will be available to those customers with renewable resource generation of 10 kW or less that are also served under a qualifying standard retail rate schedule. Renewable resources eligible to participate in this pilot program include solar and other renewable resources as defined in the

Commission's Environmental Portfolio Standard, A.A.C. R-14-2-1618. Qualifying standard retail rate schedules for service under this pilot program are limited to Rate Schedules E-12, ET-1, ET-2, ECT-1R and ECT-2 for residential customers and Rate Schedules E-32 and E-32TOU for general service customers with a monthly maximum demand of 20kW or less. The Company will install the necessary bidirectional metering to measure power flow both to and from the customer. The Company will have to make changes to the customer information systems, so participation under this schedule is subject to the availability of enhanced metering and billing system upgrades.

Q. WHAT COSTS RELATED TO NET METERING WILL BE FUNDED THROUGH THE EPS SURCHARGE?

A. The incremental cost for net metering will be funded through revenues collected through the current EPS surcharge. In addition, infrastructure costs, such as changes to the customer billing systems, will be funded through the EPS surcharge. Revenue associated with transmission and distribution, as well as non-avoidable costs that are not recovered from EPR-5 customers would also be funded by the EPS surcharge. In other words, EPS will fund all revenues that otherwise would have been collected, excluding fuel.

Q. WHAT HAPPENS IF THE CUSTOMER GENERATES MORE POWER THAN THEY CONSUME IN A MONTH?

A. Renewable resource energy generated by the customer in excess of their monthly consumption will be accumulated on a kWh basis, and credited to the customer's future monthly bills within the same calendar year.

Q. PLEASE PROVIDE AN EXAMPLE OF HOW NET METERING WORKS.

A. For example, suppose a customer consumes 500 kWh that the Company provided on service days 1 through 15 of the month. The customer then self-provides to cover all of its usage and in addition, provides an excess of 500 kWh to the Company on days 16 through 30. The customer has benefited from the Company's distribution system not only during the first 15 days, but also during the second half of the month because the APS system was available to the customer for backup. However, the customer pays no transmission and distribution revenue for those costs priced in the energy portion of the bill and contributes nothing to the non-avoidable charges. The net consumption measured by the meter registers +500 – 500 kWh or zero for the month. Although this example is hypothetical, it proves the point that net metering leaves many costs uncollected. The same type of net flow could occur from hour to hour, rather than from day to day, as in this example.

Q. ARE YOU SAYING THAT THE RATE TREATMENT UNDER THIS SCHEDULE IS COST BASED?

A. No. Customers taking service under this schedule and producing any generation do not pay appropriate transmission and distribution costs, nor do they pay the full amount (and possibly not any) of non-avoidable charges such as the Competition Rules Compliance Charge, EPS Surcharge, Demand Side Management Cost Adjustment, Power Supply Adjustment (for deferred fuel costs incurred during prior periods) and Transmission Cost Adjustment. The customer's standard retail rate is designed to measure and price the distribution component of the rate when all consumption is supplied by the Company. For these reasons, the rate will not yield appropriate revenue to cover cost.

Q. WHY IS THE COMPANY PROPOSING A RATE SCHEDULE THAT WILL NOT RECOVER COSTS?

A. The Company is requesting this pilot rate schedule to promote customer owned renewable resource energy through the EPS. Because there will be the potential subsidies occurring between customers within a class, the Company will need to evaluate customer participation and impacts on revenue. At this point, the Company does not know what participation levels will be. Participation levels may depend on many factors, both demographic and rate schedule terms specific. At the end of the three year term of this pilot project, the Company will determine whether the terms of the schedule will need to be modified or even withdrawn.

Q. WHAT HAS THE COMPANY PROPOSED IN THIS RATE SCHEDULE TO MODERATE THE POTENTIAL UNWANTED IMPACT OF SUBSIDIES BETWEEN CUSTOMERS?

A. By setting a participation limit of 15 MW and limiting it to customer owned renewable resource generation facilities with a nameplate rating of 10 kW or less, the Company has targeted customers who have renewable energy facilities for the primary purposes of meeting their own energy needs, but occasionally have excess to provide to the Company. In addition, although this schedule permits excess energy to be carried from month to subsequent months, the customer's excess supply provided to the Company will be reset to zero at the end of each calendar year.

Q. WHY DOES APS PROPOSE THIS SCHEDULE AT THIS TIME?

A. The Company is establishing this pilot program to monitor the impacts of such an offering. The Commission, through distributed generation workshops, is studying interconnection rules and guidelines. The Company may make changes to this proposed rate schedule when final distributed generation rules are promulgated.

VI. SCHEDULE 1 – GENERAL TERMS AND CONDITIONS

Q. WHY ARE YOU PROPOSING REVISIONS TO SERVICE SCHEDULE 1?

A. APS is continually evaluating all aspects of its service schedules to enhance the Company's business practices. As part of this review, APS proposed certain revisions. These changes that are being proposed address situations where it may not be appropriate to bill a Service Establishment Charge, and add clarifying language that better reflects our envisioned business practices. A redline copy of the schedule is attached as Attachment GAD-6.

Q. PLEASE DESCRIBE THE SIGNIFICANT CHANGES TO SCHEDULE 1.

A. Section 2.2.4: APS is proposing clarifying language to Section 2.2.4. The special services discussed in this section are being performed outside of normal work hours, and usually require a crew with more than one person. The language clarifies that the $75.00 charge is per crew person, per hour.

Section 2.2.5: APS is proposing that the Company have the right to waive the Service Establishment Charge in instances where either 1) a name change is requested, but no field trip is necessary, or 2) where the Company has an active Landlord Agreement in place. The request for a name change typically may result when a surviving spouse requests that the service be placed in their name after the death of the customer of record, or a name has changed as a result of a divorce.

Landlord Agreements are legal contracts between the customer (the landlord) and APS that provide for continuous service to the landlord during the period the landlord does not have tenants. Where APS has an active Landlord Agreement, when the tenant, who has service in his or her name, notifies APS to

disconnect service, the service remains active and is automatically transferred back into the landlord's name until a request to transfer service into a new applicant's name is received. At that time APS obtains a meter read, and the new applicant is charged the Service Establishment Charge.

The Company is also proposing to reduce the Service Establishment Charge in those instances where multiple connect requests are made for the same location, such as a trailer park that has seasonal visitors. It is not unusual in those cases for the Company to receive a request to connect hundreds of meters on a specific day in the name of the trailer park. In that case, APS is proposing to charge only one Service Establishment Charge for every two requests for service connects made during the same site visit and placed in the same name, at the same address, for the same class of service.

Sections 4.3.3 & 4.3.4: APS is proposing to eliminate these sections that permit the Company to offer incentives for customers who elect to pay electronically and customers who elect to not receive a paper copy of their bill. Since the time the language was incorporated within Schedule 1, APS has not needed to offer any incentives. The number of customers choosing to pay electronically rather than receive a paper bill has increased steadily over the years without any incentive from APS. Regarding the automatic payment incentive, APS indicated in the report, almost 15% of our customers voluntarily participate in APS' automatic payment programs. According to recently published research findings from the *Chartwell's Guide to Bill Presentment and Payment 2005* report, the average participation rate for the utilities surveyed is 8.1%. Given APS' current robust participation rate, offering an incentive to entice customers to enroll is not needed, and as noted in Mr. Rumolo's testimony, would not be cost effective

even if it did increase participation. Similar to the automatic payment program, APS finds its customers who do utilize automatic payment programs are also choosing, without any incentives, to eliminate their paper bills.

Section 6.6: In Section 6.6, APS proposes language regarding master metering to clarify situations where prohibiting master metering is not applicable, such as a high rise residential unit where units are privately owned and the building is served by centralized heating (6.6.3), or senior care centers that provide packaged services such as housing, meals and nursing care (6.6.2).

Q. ARE YOU REQUESTING ANY OTHER CHANGES IN SCHEDULE 1?

A. Yes, there are some additional minor changes that are being proposed for clarity purposes only and have no significant impact to customers or to the Company. All the changes to Schedule 1 are redlined and set forth in Attachment GAD-6.

VII. SCHEDULE 4 – TOTALIZING

Q. PLEASE DESCRIBE THE PROPOSED CHANGES TO SCHEDULE 4.

A. The proposed change to Schedule 4 is being made to identify emerging metering technology. Schedule 4 addresses the Company's practice relative to totalizing of meter readings. It is applied when customers at a single premise receive service through multiple service points. APS is proposing language to address the emergence of new metering technology that allows for electronically totalized demand and energy, in addition to physical wire interconnections. A redlined copy of the proposed changes is attached as GAD-7.

Q. DOES THAT CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes it does.

Appendix A
Statement of Qualifications
Gregory A. DeLizio

Gregory A. DeLizio is Arizona Public Service Company's Supervisor of Regulations and Pricing. He has over 24 years experience in the electric utility business. Mr. DeLizio holds a Bachelor of Science Degree in Electrical Engineering from the University of Pittsburgh and a Masters in Business Administration from Kent State University.

Mr. DeLizio has submitted testimony before the Public Utilities Commission of Ohio, the Public Service Commission of West Virginia, the Michigan Public Service Commission, the Indiana Utility Regulatory Commission and the Oklahoma Corporation Commission. Mr. DeLizio is experienced in the areas of electric utility rate design, embedded and marginal cost analysis, utility service policies, and contract development and negotiation.

Mr. DeLizio was employed in his current position at Arizona Public Service Company in August of 2005. Prior to assuming this position, he served as Managing Director – Regulated Pricing and Analysis for American Electric Power Service Corporation, a wholly owned subsidiary of American Electric Power Company (AEP). In this position, Mr. DeLizio's responsibilities included setting regulated pricing policy, supervision of the preparation of class cost-of-service studies, rate design and unbundled rates and provisions, and special contracts and pricing of retail customers for AEP's eleven operating companies operating in 14 states. Mr. DeLizio held positions of increasing responsibilities at AEP starting in 1981 when he joined Ohio Power Company (an AEP operating subsidiary) as an Energy Services Engineer. He was promoted to Power Engineer in 1984, promoted to Energy Services Coordinator in 1985, promoted to Load Research Supervisor in 1987, Marketing & Customer Services

Supervisor in 1992, Special Contracts Administrator in 1993, Regulatory Consultant in 1996 and to Manager- Regulated Pricing & Analysis in 2000.

SCHEDULE EIC
ENVIRONMENTAL IMPROVEMENT CHARGE

APPLICATION

The Environmental Improvement Charge ("EIC") shall apply to all retail Standard Offer service, excluding customers served in accordance with solar rates SP-1 (Solar Partners), Solar-2, and Green Power Schedules GPS-1 and GPS-2. All provisions of the customer's current applicable rate schedule shall apply in addition to charges under this EIC.

The EIC was approved by the Arizona Corporation Commission ("ACC") in Decision No. XXXXX. Cost recovery under the EIC shall be in accordance with the method described in the filed Environmental Improvement Charge Plan of Administration.

The EIC recovers the cost associated with investment and expenses for environmental improvements at APS' generation facilities that the ACC has approved for recovery. Approved environmental improvements include those implemented on or after January 1, 2004, for which costs have not been fully recovered under current approved rates, ongoing environmental improvement projects, or prospective environmental improvement projects designed to comply with environmental standards required by federal, state, tribal, or local laws or regulations. These standards and criteria for water, waste, and air include but are not limited to new and expected limits for sulfur oxide (SO_x), nitrogen oxide (NO_x), particulate matter (PM), volatile organic compounds (VOC) and toxins such as mercury (Hg).

RATE

The charge shall be calculated at the following rate:

EIC

All kWh	$0.000152 per kWh

EIC PLAN OF ADMINISTRATION

The Environmental Improvement Charge ("EIC") Schedule recovers the cost associated with investment and expenses for environmental improvements at APS' generation facilities that the Arizona Corporation Commission ("ACC") has approved for recovery. The purpose of this Schedule is to allow for timely recovery of costs as environmental investments are made.

DETERMINATION OF EIC

The EIC will be determined in accordance with the following:

- On January 31, 2006, APS submitted its APS EIC Plan, which is a five year forecast of projected costs for environmental improvement projects. In addition, APS filed its proposed initial EIC calculated on an energy basis ($/kWh).

- The ACC approved those projects for inclusion within the EIC in Decision No., _____, issued on _____.

- The EIC will include all revenue requirement components including, but not limited to return on capital, depreciation, operation and maintenance expenses, property taxes, and associated income taxes. The EIC will exclude any component that was included in the test year upon which revenue requirement is collected in approved rates.

- The EIC recovers the cost associated with investment and expenses for environmental improvements at APS' generation facilities that the ACC has approved for recovery. Approved environmental improvements include those implemented on or after January 1, 2004, for which costs have not been fully recovered under current approved rates, ongoing environmental improvement projects, or prospective environmental improvement projects designed to comply with environmental standards required by federal, state, tribal, or local laws or regulations. These standards and criteria for water, waste, and air include but are not limited to new and expected limits for sulfur oxide (SO_x), nitrogen oxide (NO_x), particulate matter (PM), volatile organic compounds (VOC) and toxins such as mercury (Hg).

- The initial EIC for bills rendered January 1, 2007 through June 30, 2008 (Billing Period 2007/2008) is computed based on actual data for calendar year 2004, plus actual and forecast data for calendar year 2005 and forecast data for calendar years 2006 and 2007, and reflects the amount of expenditures. The initial EIC calculation will use the Billing Period 2007/2008 forecast sales.

- The EIC for bills rendered July 1, 2008 through June 30, 2009 (Billing Period 2008/2009) will be calculated based on a true-up of the actual revenue collected under the EIC for the Billing Period 2007/2008 compared to the revenues that would have been collected had the Company had perfect knowledge on calendar years 2005, 2006 and 2007 actual amount of expenditures and actual Billing Period 2007/2008 sales. Added to the 2008/2009 Billing Period EIC will be calendar year 2008 forecast amount of expenditures. The EIC will utilize Billing Period 2008/2009 forecast sales.

- The EIC for bills rendered July 1, 2009 through June 30, 2010 (Billing Period 2009/2010) will be calculated based on a true-up of the actual revenue collected under the EIC for the Billing Period 2008/2009 compared to the revenues that would have been collected had the Company had perfect knowledge on calendar year 2008 actual amount of expenditures and Billing Period 2008/2009 actual sales. Added to the Billing Period 2009/2010 EIC will be calendar year 2009 forecast amount of expenditures. The EIC will utilize Billing Period 2009/2010 forecast sales.

- Subsequent EIC for bills rendered in subsequent billing periods will be calculated in the similar way as for Billing Period 2009/2010.

- APS will submit to the Commission any modifications to its APS EIC Plan and its proposed EIC for the upcoming July-June period with supporting data by March 15 preceding the Billing Period in which the EIC will be in effect. The ACC will review and approve, and/or modify and approve the proposed EIC by June 15 prior to the Billing Period. Should a ruling by the ACC not be rendered by the June 15 date, then APS will place the applicable EIC in effect as though approved subject to true-up in a subsequent filing. The EIC will apply to bills rendered on or after July 1 of the Billing Period and will be in effect until adjusted in a subsequent filing.

- The applicable $/kWh Charge is constant and applies in each month of the Billing Period for which it is calculated. The rate calculation considers actual amount of environmental expenditures, APS' forecasted sales and the revenue resulting from such application of the EIC.

- Any over or under collection made as part of the true-up process under the EIC will include interest.

- At the time rates into a subsequent rate case are approved, the EIC will be adjusted to reflect plant and expenses that are incorporated into rate base for the test year.

SCHEDULE GPS-1
CLASSIFIED SERVICE
GREEN POWER BLOCK SCHEDULE

APPLICATION

The Green Power Block Schedule shall be applied to Standard Offer customers with a pre-established service who wish to purchase electricity generated from renewable sources for their homes and/or businesses. All provisions of the customer's current applicable rate schedule will apply in addition to this surcharge.

Electricity from renewable sources shall be referred to herein as "Green Power". Green Power may be:

1. Company-owned generation using a renewable resource including, but not limited to, solar, biomass, biogas, wind, geothermal, or small hydroelectric.
2. Generation not owned by the Company, but owned by another party for which the Company has contracted including, but not limited to, solar, biomass, wind, geothermal, or small hydroelectric.

In any event, the renewable energy that is provided under this rate schedule is limited to those resources eligible pursuant to A.A.C. R14-2-1618, as may be modified or updated from time to time.

TYPE OF SERVICE

The Company will offer electricity generated from renewable resources through the Company's electric distribution system.

The customer shall subscribe for a specific number of blocks of electricity generated from renewable resources. Each block shall equal 25 kWh/month. The monthly charge is based upon the number of blocks subscribed for by the customer. The Company may assign limits to the number of kWh blocks sold per customer.

The Company may assign limits to the subscription under this Schedule should reasonably priced renewable resources not be available.

For customers subscribing to more than 1000 blocks per month of electricity generated from renewable resources, the customer is required to contract for a minimum two year period.

SERVICE CHARGES

The bill for service under this rate schedule shall be $0.75 per month for each 25 kWh block of electricity generated from renewable resources.

SCHEDULE GPS-2
CLASSIFIED SERVICE
GREEN POWER PERCENT SCHEDULE

APPLICATION

The Green Power Percent Schedule shall be applied to standard offer customers on a pre-established service who wish to purchase electricity generated from renewable sources for their homes and/or businesses. All provisions of the customer's current applicable rate schedule will apply in addition to this surcharge.

Electricity from renewable sources shall be referred to herein as "Green Power". Green Power may be:

1. Company-owned generation using a renewable source including, but not limited to, solar, biomass, biogas, wind, geothermal, or small hydroelectric.
2. Generation not owned by the Company, but owned by another party for which the Company has contracted including, but not limited to, solar, biomass, wind, geothermal, or small hydroelectric.

In any event, the renewable energy that is provided under this rate schedule is limited to those resources eligible pursuant to A.A.C. R14-2-1618, as may be modified or updated from time to time.

TYPE OF SERVICE

The Company will offer Green Power through the Company's electric distribution system.

The Company may assign limits to the subscription under this Schedule if reasonably priced renewable sources are not available.

For customers subscribing to more than 300,000 kWh-year of electricity generated from renewable resources, the customer is required to contract for a minimum two year period.

SERVICE CHARGES

Four options are available. The charges hereunder represent charges to be added to energy charges ($/kWh basis) under the customer's applicable schedule.

A. Green Power shall account for 100.0% of the generation mix in the customer's service.
Additional Charge per kWh: $0.03

B. Green Power shall account for 50.0% of the generation mix in the customer's service.
Additional Charge per kWh: $0.015

C. Green Power shall account for 30.0% of the generation mix in the customer's service.
Additional Charge per kWh: $0.009

D. Green Power shall account for 10.0% of the generation mix in the customer's service.
Additional Charge per kWh: $0.003

RATE SCHEDULE EPR-5
CLASSIFIED SERVICE
RATES FOR RENEWABLE RESOURCE FACILITIES OF 10 kW OR LESS FOR PARTIAL REQUIREMENTS

AVAILABILITY

This rate schedule is available in all territory served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the sites served.

APPLICATION

This rate schedule is offered as a three-year pilot program to renewable resource generation facilities with a nameplate service continuous output power rating of 10 kW or less where the customer's generator(s) and load are located at the same premise. Renewable resources eligible to participate in this pilot program include solar and other renewable resources, as defined in A.A.C. R14-2-1618, as it may be modified or updated from time to time. This pilot program is capped at 15 MW of total renewable generation nameplate capacity. Environmental Portfolio Surcharge (EPS) funding will be utilized to recover the metering costs, billing system modification cost and revenue loss associated with the pilot program. This pilot program is conditioned upon continued and sufficient EPS funding. Participation under this schedule is subject to availability of enhanced metering and billing system upgrades.

TYPE OF SERVICE

Electric sales to the Company must be single phase or three phase, 60 Hertz, at one standard voltage as may be selected by customer (subject to availability at the premises).

SALES TO THE CUSTOMER

Power sales and special services supplied by the Company to the customer in order to meet the customer's supplemental or interruptible electric requirements will be priced at the Standard Retail Rate as may be selected by the customer. Refer to the Definitions section, No. 5, of this rate schedule to identify rate schedules that qualify for this pilot program.

RATE

Energy will not be purchased from the customer under this schedule; instead, the kWh of energy provided will be credited to the customer. Through the net metering method, the customer shall receive the full retail value of the energy component (charges assessed on a kWh basis) of their bundled Standard Offer Service Rate for the power fed into the system from the customer-owned renewable resource generator(s). In cases where customer owned generation output exceeds the customer's total usage in a given month, the customer will receive a kWh credit equal to this excess generation output on the next monthly bill. Any remaining kWh credit amount will be zeroed out (no payment made to the customer) in the customer's last monthly bill rendered in the calendar year or at the time of a customer shut off. The Company shall provide one bi-directional meter under this EPR-5 pilot program.

CONTRACT PERIOD

Any applicable contract period(s) will be set forth in an Agreement between the customer and the Company.

DEFINITIONS

1. Partial Requirements Service – Electric service provided to a customer that has an interconnected renewable resource generation system configuration whereby the output from its electric generator(s) first supplies its own electric requirements and any excess energy (over and above its own requirements at any point in time) is then provided to the Company. The Company supplies the Customer's supplemental electric requirements (those not met by their own generation facilities). This configuration may also be referred to as the "parallel mode" of operation.

DEFINITIONS (cont)

2. Special Service(s) - The electric service(s) specified in this section that will be provided by the Company in addition to or in lieu of normal service(s).

3. Time Periods - Mountain Standard Time shall be used in the application of this rate schedule. Because of potential differences of the timing devices, there may be a variation of up to 15 minutes in timing for the pricing periods.

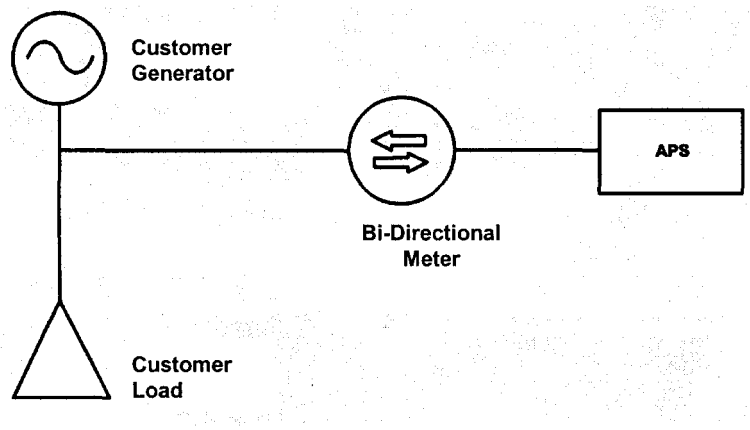
4. Pilot Program – The term of this pilot program is three years from the issuance of Decision No. XXXXX. If this experimental pilot rate schedule later becomes a standard Company rate schedule, the Company reserves the right to modify the rate schedule.

5. Standard Retail Rate – Qualifying standard retail rates for service under this pilot program are limited to Rate Schedules E-12, ET-1, ET-2, ECT-1R and ECT-2 for residential customers and Rate Schedules E-32 and E-32 TOU for general service customers with Monthly Maximum Demands of 20 kW or less.

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services and Schedule 2, Terms and Conditions for Energy Purchases from Qualified Cogeneration or Small Power Production Facilities. This schedule has provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a customer interconnection or service agreement.

METERING CONFIGURATION



The following TERMS AND CONDITIONS and any changes authorized by law will apply to Standard Offer and Direct Access services made available by Arizona Public Service Company (Company), under the established rate or rates authorized by law and currently applicable at time of sale.

1. General

1.1 Services will be supplied in accordance with these Terms and Conditions and any changes required by law, and such applicable rate or rates as may from time to time be authorized by law. However, in the case of the customer whose service requirements are of unusual size or characteristics, additional or special contract arrangements may be required.

1.2 These Terms and Conditions shall be considered a part of all rate schedules, except where specifically changed by a written agreement.

1.3 In case of a conflict between any provision of a rate schedule and these Terms and Conditions, the provisions of the rate schedule shall apply.

2. Establishment of Service

2.1 Application for Service - Customers requesting service may be required to appear at Company's place of business to produce proof of identity and/or sign Company's standard form of application for service or a contract before service is supplied by Company.

2.1.1 In the absence of a signed application or contract for service, the supplying of Standard Offer and/or Direct Access services by Company and acceptance thereof by the customer shall be deemed to constitute a service agreement by and between Company and the customer for delivery of, acceptance of, and payment for service, subject to Company's applicable rates and rules and regulations.

2.1.2 Where service is requested by two or more individuals, Company shall have the right to collect the full amount owed Company from any one of the applicants.

2.2 Service Establishment Charge - A service establishment charge of $25.00 for residential and $35.00 non-residential plus any applicable tax adjustment will be assessed each time Company is requested to establish, reconnect or re-establish electric service to the customer's delivery point, or to make a special read without a disconnect and calculate a bill for a partial month.

2.2.1 The customer will additionally be required to pay a trip charge of $16.00 when an authorized Company representative travels to the customer's site and is unable to complete the customer's requested services due to lack of access to the point of delivery.

2.2.2 The customer will additionally be required to pay an after-hours charge of $75.00 if the customer requests service, as defined in A.A.C. R14-2-203.D.3, be established, reconnected, or re-established after 5:00 p.m. on a day other than the day of request.

2.2.3 The customer will additionally be required to pay a same day connect charge of $75.00 if the customer requests service, as defined in A.A.C. R14-2-203.D.3, be established, reconnected, or re-established on the same day the request is being made, and Company

agrees to work the request on the same day of the request. This will be charged regardless of the time the order may be worked by Company on that day. Company may, where no additional costs are incurred by Company, waive the same day fee.

2.2.4 The customer will additionally be required to pay $75.00 per crew person per hour when customer requests services that do not meet the definition of service establishment as defined in A.A.C. R14-2-203.D.3 (such as metering equipment installations, maintenance or planned outages, etc.) that require the availability of Company employees after hours, on a weekend day, or on a Company holiday. The number of employees utilized by Company in fulfilling such requests shall be at the sole discretion of Company.

Company holidays are New Year's Day, Martin Luther King, Jr. Day, Memorial Day, Independence Day, Labor Day, Veteran's Day, Thanksgiving Day, The Day After Thanksgiving, and Christmas Day.

2.2.5 Company may waive the service establishment charge where:

2.2.5.1 No field trip is required because applicant accepts responsibility for energy billed and not yet paid and the change is effective with the last meter read and meter read date billed.

2.2.5.2 Applicant has an active Landlord Automatic Transfer of Service Agreement on file with Company. This service agreement is for property owners that have established credit with Company and provides for continuous service to the landlord between tenants.

2.2.5.3 Where multiple connects are performed during the same site visit, in the same applicant name, at the same address, for the same class of service, Company will assess the Service Establishment Charge once for every two delivery points.

2.3 Direct Access Service Request (DASR) - A Direct Access Service Request charge of $10.00 plus any applicable tax adjustment will be assessed to the Electric Service Provider (ESP) submitting the DASR each time Company processes a Request (RQ) type DASR as specified in Company's Schedule 10, Terms and Conditions for Direct Access.

2.4 Grounds for Refusal of Service - Company may refuse to connect or reconnect Standard Offer or Direct Access service if any of the following conditions exist:

2.4.1 The applicant has an outstanding amount due with Company for the same class of service and is unwilling to make payment arrangements that are acceptable to Company.

2.4.2 A condition exists which in Company's judgment is unsafe or hazardous.

2.4.3 The applicant has failed to meet the security deposit requirements set forth by Company as specified under Section 2.5 or 2.6 hereof.

2.4.4 The applicant is known to be in violation of Company's tariff.

2.4.5 The applicant fails to furnish such funds, service, equipment, and/or rights-of-way or easements required to serve the applicant and which have been specified by Company as a condition for providing service.

2.4.6 The applicant falsifies his or her identity for the purpose of obtaining service.

2.4.7 Service is already being provided at the address for which the applicant is requesting service.

2.4.8 Service is requested by an applicant and a prior customer living with the applicant owes a delinquent bill from the same or a prior service address.

2.4.9 The applicant is acting as an agent for a prior customer who is deriving benefits of the service and who owes a delinquent bill from the same or a prior service address.

2.4.10 The applicant has failed to obtain all required permits and/or inspections indicating that the applicant's facilities comply with local construction and safety codes.

2.5 Residential Establishment of Credit or Security Deposit

2.5.1 Establishment of Credit - Company shall not require a security deposit from a new applicant for service if the applicant is able to meet any of the following requirements:

2.5.1.1 The applicant has had service of a comparable nature with Company within the past two (2) years and was not delinquent in payment more than twice during the last twelve (12) consecutive months or disconnected for nonpayment.

2.5.1.2 Company receives an acceptable credit rating, as determined by Company, for the applicant from a credit rating agency.

2.5.1.3 The applicant can produce a letter regarding credit or verification from an electric utility where service of a comparable nature was last received within six (6) months of the current date which states that the applicant had a timely payment history for the prior twelve (12) consecutive months at the time of service discontinuation

2.5.1.4 In lieu of a security deposit, Company receives deposit guarantee notification from a social or governmental agency acceptable to Company or a surety bond as security for Company in a sum equal to the required deposit.

2.5.2 Residential Establishment of Credit or Security Deposit - When credit cannot be established as provided for in Section 2.5.1 hereof or when it is determined that the applicant left an unpaid final bill owing to another utility company, the applicant will be required to:

2.5.2.1 Place a cash deposit to secure payment of bills for service as prescribed herein, or

2.5.2.2 Provide a surety bond acceptable to Company in an amount equal to the required security deposit.

2.5.3 Nonresidential Establishment of Security Deposit – All non-residential applicants will be required to place a cash deposit to secure payment of bills for service as prescribed herein, unless:

2.5.3.1 The applicant has had service of a comparable nature with Company within the past two (2) years and was not delinquent in payment more than twice during the last twelve (12) consecutive months or disconnected for nonpayment.

2.5.3.2 The applicant provides a non-cash security deposit in the form of a Surety Bond, Irrevocable Letter of Credit, or Assignment of Monies in an amount equal to the required security deposit.

2.6 Reestablishment of Security Deposit

2.6.1 Residential - Company may require a residential customer to establish or re-establish a security deposit if the customer becomes delinquent in the payment of two (2) or more bills within a twelve (12) consecutive month period or has been disconnected for non-payment during the last twelve (12) months.

2.6.2 Nonresidential - Company may require a nonresidential customer to establish or re-establish a security deposit if the customer becomes delinquent in the payment of two (2) or more bills within a twelve (12) consecutive month period or if the customer has been disconnected for non-payment during the last twelve (12) months, or when the customer's financial condition may jeopardize the payment of their bill, as determined by Company based on the results of using a credit scoring worksheet. Company will inform all customers of the Arizona Corporation Commission's complaint process should the customer dispute the deposit based on the financial data.

2.7 Security Deposits – Once it is determined that a security deposit is required, the following will apply:

2.7.1 Security deposits may be required for each service location.

2.7.2 Company reserves the right to increase or decrease security deposit amounts applicable to the services being provided by Company in accordance with this section:

2.7.2.1 If the customer chooses to change from Standard Offer to Direct Access services, the deposit may be decreased by an amount which reflects that portion of the customer's service being provided by a Load Serving ESP. However if the Load Serving ESP is providing ESP Consolidated Billing pursuant to Company's Schedule 10 Section 7, the entire deposit will be credited to the customer's account; or,

2.7.2.2 If the customer chooses to change from Direct Access to Standard Offer service, the requested deposit amount may be increased by an amount pursuant to Section 2.5, which reflects that Company is providing bundled electric service.

2.7.2.3 If the customer's average consumption increases: by more than ten (10) percent for residential accounts or five (5) percent for nonresidential accounts within a twelve (12) consecutive month period and credit has not been established, an additional security deposit may, at Company's option, be required.

2.7.3 Customer security deposits shall not preclude Company from terminating an agreement for service or suspending service for any failure in the performance of customer obligation under the agreement for service.

2.7.4 Cash deposits held by Company six (6) months/183 days or longer shall earn interest at the established one year Treasury Constant Maturities rate, effective on the first business day of each year, as published on the Federal Reserve Website. Deposits on inactive accounts are applied to the final bill when all service options become inactive, and the balance, if any, is refunded to the customer of record within thirty (30) days. For refunds resulting from the customer changing from Standard Offer to Direct Access, the difference in the deposit amounts will be applied to the customer's account.

2.7.5 If the customer terminates all service with Company, the security deposit may be credited to the customer's final bill.

2.7.6 Residential security deposits shall not exceed two (2) times the customer's average monthly bill as estimated by Company for the services being provided by Company.

2.7.6.1 Deposits or other instruments of credit will automatically expire or be returned or credited to the customers account after twelve (12) consecutive months of service, provided the customer has not been delinquent more than twice, unless customer has filed bankruptcy in the last 12 months.

2.7.7 Nonresidential security deposits shall not exceed two and one-half (2-1/2) times the customer's maximum monthly billing as estimated by Company for the service being provided by Company.

2.7.7.1 Deposits and non-cash deposits on file with Company will be reviewed after twenty-four (24) months of service and will be returned provided the customer has not been delinquent more than twice in the payment of bills or disconnected for non-payment during the previous twelve (12) consecutive months unless the customer's financial condition warrants extension of the security deposit.

2.8 Line Extensions - Installations requiring Company to extend its facilities in order to establish service will be made in accordance with Company's Schedule #3, Conditions Governing Extensions of Electric Distribution Lines and Services filed with the Arizona Corporation Commission.

3. Rates

3.1 Rate Information - Company shall provide, in accordance with A.A.C. R14-2-204, a copy of any rate schedule applicable to that customer for the requested type of service. In addition, Company shall notify its customers of any changes in Company tariffs affecting those customers.

3.2 Rate Selection – The customer's service characteristics and service requirements determine the selection of applicable rate schedule. If the customer is receiving bundled service, Company will use reasonable care in initially establishing service to the customer under the most advantageous rate schedule applicable to the customer. However, because of varying customer usage patterns and other reasons beyond its reasonable knowledge or control, Company cannot guarantee that the most economic applicable rate will be applied. Company will not make any refunds in any instances where it is determined that the customer would have paid less for service had the customer been billed on an alternate applicable rate or provision of that rate.

3.3 Optional Rates – Certain optional rate schedules applicable to certain classes of service allow the customer the option to select the rate schedule to be effective initially or after service has been established. Billing under the alternate rate will become effective from the next regularly scheduled meter reading, after the appropriate metering equipment is installed. No further rate schedule changes, however, may be made within the succeeding twelve-month period. Where the rate schedule or contract pursuant to which the customer is provided service specifies a term, the customer may not exercise its option to select an alternate rate schedule until expiration of that term.

3.4 Direct Access service will be effective upon the next meter read date if DASR is processed fifteen (15) calendar days prior to that read date and the appropriate metering equipment is in place. If a DASR is made less than fifteen (15) days prior to the next regular read date the effective date will be at the next meter read date thereafter. The above timeframes are applicable for customers changing their selection of Electric Service Providers or for customers returning to Standard Offer service.

3.5 Any customer that selects Direct Access service may return to Standard Offer service in accordance with the rules, regulations, and orders of the Commission. However, such customer will not be eligible for Direct Access service for the succeeding twelve (12) month period. If a customer returning to Standard Offer, in accordance with the rules, regulations and orders of the Commission, was not given the required notification in accordance with the rules and regulations of the Commission by their Load Serving ESP of its intent to cease providing competitive services then the above provision will only apply if the customer fails to select another ESP within sixty (60) days of returning to Standard Offer service.

4. Billing and Collection

4.1 Customer Service Installation and Billing - Service billing periods normally consist of approximately 30 days unless designated otherwise under rate schedules, through contractual agreement, or at Company option.

4.1.1 Company normally meters and bills each site separately; however, at customer's request, adjacent and contiguous sites not separated by private or public property or right of way and operated as one integral unit under the same name and as a part of the same business,

will be considered a single site as specified in Company's Schedule 4, Totalized Metering of Multiple Service Entrance Sections at a Single Site for Standard Offer and Direct Access Service.

4.1.2 The customer's service installation will normally be arranged to accept only one type of service at one point of delivery to enable service measurement through one meter. If the customer requires more than one type of service, or total service cannot be measured through one meter according to Company's regular practice, separate meters will be used and separate billing rendered for the service measured by each meter.

4.2 Collection Policy - The following collection policy shall apply to all customer accounts:

4.2.1 All bills rendered by Company are due and payable no later than nineteen (19) calendar days from the billing date. Any payment not received within this time frame will be considered delinquent. All delinquent bills for which payment has not been received shall be subject to the provisions of Company's termination procedure. Company reserves the right to suspend or terminate the customer's service for non-payment of any Arizona Corporation Commission approved charges. All delinquent charges will be subject to a late charge at the rate of eighteen percent (18%) per annum.

4.2.2 If the customer, as defined in A.A.C. R 14-2-201.9, has two or more services with Company and one or more of such services is terminated for any reason leaving an outstanding bill and the customer is unwilling to make payment arrangements that are acceptable to Company, Company shall be entitled to transfer the balance due on the terminated service to any other active account of the customer for the same class of service. The failure of the customer to pay the active account shall result in the suspension or termination of service thereunder.

4.2.3 Unpaid charges incurred prior to the customer selecting Direct Access will not delay the customer's request for Direct Access. These charges remain the responsibility of the customer to pay. Normal collection activity, including discontinuing service, may be followed for failure to pay.

4.3 Responsibility for Payment of Bills

4.3.1 The customer is responsible for the payment of bills until service is ordered discontinued and Company has had reasonable time to secure a final meter reading for those services involving energy usage, or if non-metered services are involved until Company has had reasonable time to process the disconnect request.

4.3.2 When an error is found to exist in the billing rendered to the customer, Company will correct such an error to recover or refund the difference between the original billing and the correct billing. Such adjusted billings will not be rendered for periods in excess of the applicable statute of limitations from the date the error is discovered.

4.3.2.1 Refunds to customers resulting from overbillings will be made promptly upon discovery by Company.

4.3.2.2 Corrected charges for underbillings shall be billed to the customer who shall be given an equal length of time such as number of months underbilled to pay the backbill without late payment penalties, unless there is evidence of meter tampering or energy diversion

4.3.2.3 Except as specified below, corrected charges for underbillings shall be limited to three (3) month for residential accounts and six (6) months for non-residential accounts.

4.3.2.3.1 Where the account is billed on a special contract or non-metered rate, corrected charges for underbillings shall be billed in accordance with the contract or rate schedule requirements and is not limited to three or six months as applicable.

4.3.2.3.2 Where service has been established but no bills have been rendered, corrected charges for underbillings shall go back to the date service was established.

4.3.2.3.3 Where there is evidence of meter tampering or energy diversions, corrected charges for underbillings shall go back to the date meter tampering or energy diversions began, as determined by Company.

4.3.2.3.4 Where lack of access to the meter (caused by the customer) has resulted in estimated bills, corrected charges for underbillings shall go back to the last Company obtained meter read date.

4.3.2.4 Company may forgo billing and collection of corrected charges for an underbilling if Company believes the cost of billing and collecting the underbilling would not justify pursuing the underbill.

4.4 Dishonored Payments - If Company is notified by the customer's financial institution that they will not honor a payment tendered by the customer for payment of any bill, Company may require the customer to make payment in cash, by money order, certified or cashier's check, or other means which guarantee the customer's payment to Company.

4.4.1 The customer will be charged a fee of $15.00 for each instance where the customer tenders payment of a bill with a payment that is not honored by the customer's financial institution.

4.4.2 The tender of a dishonored payment shall in no way (i) relieve the customer of the obligation to render payment to Company under the original terms of the bill, or (ii) defer Company's right to terminate service for nonpayment of bills.

4.4.3 Where the customer has tendered two (2) or more dishonored payments in the past twelve (12) consecutive months, Company may require the customer to make payment in cash, money order or cashier's check for the next twelve (12) consecutive months.

4.5 Termination Process Charges

4.5.1 Company will require payment of a Field Call Charge of $15.00 when an authorized Company representative travels to the customer's site to accept payment on a delinquent account, notify of service termination, make payment arrangements or terminate the service. This charge will only be applied for field calls resulting from the termination process.

4.5.2 If a termination is required at the pole, a reconnection charge of $96.50 will be required; if the termination is in underground equipment, the reconnection charge will be $115.00.

4.5.3 To avoid termination of service, the customer will make payment in full, including any necessary deposit in accordance with Section 2.5 hereof or make payment arrangements satisfactory to Company.

4.6 On-site Evaluation – Company will require payment of an On-site Evaluation Charge of $82.00 when an authorized Company field investigator performs an on-site visit to evaluate how the customer may reduce their energy usage. This charge may be assessed regardless of whether the customer actually implements Company suggestions.

5. Service Responsibilities of Company and Customer

5.1 Service Voltage –Company will deliver electric service to the designated point of delivery, as specified in Section 6.3 of this Schedule, at the standard voltages specified in the Electric Service Requirements Manual published by Company and as specified in A.A.C. R14-2-208.F. Company may deliver service for special applications at higher voltages, with prior approval from Company's Engineering Department and in accordance with Company's Schedule 3, Conditions Governing Extensions of Electric Distribution Lines and Services filed with the Arizona Corporation Commission.

5.2 Responsibility: Use of Service or Apparatus

5.2.1 The customer shall save Company harmless from and against all claims for injury or damage to persons or property occasioned by or in any way resulting from the services being provided by Company or the use thereof on the customer's side of the point of delivery. Company shall have the right to suspend or terminate service in the event Company should learn of service use by the customer under hazardous conditions.

5.2.2 The customer shall exercise all reasonable care to prevent loss or damage to Company property installed on the customer's site for the purpose of supplying service to the customer.

5.2.3 The customer shall be responsible for payment for loss or damage to Company property on the customer's site arising from neglect, carelessness or misuse and shall reimburse Company for the cost of necessary repairs or replacements.

5.2.4 The customer shall be responsible for payment for any equipment damage and/or estimated unmetered usage resulting from unauthorized breaking of seals, interfering with, tampering with, or by-passing the meter.

5.2.5 The customer shall be responsible for notifying Company of any failure in Company's equipment.

5.3 Service Interruptions: Limitations on Liability of Company

5.3.1 Company shall not be liable to the customer for any damages occasioned by Load Serving ESP's equipment or failure to perform, fluctuations, interruptions or curtailment of electric service, except where due to Company's willful misconduct or gross negligence. Company may, without incurring any liability therefore, suspend the customer's electric service for periods reasonably required to permit Company to accomplish repairs to or changes in any of Company's facilities. The customer needs to protect their own sensitive equipment from harm caused by variations or interruptions in power supply.

5.3.2 In the event of a national emergency or local disaster resulting in disruption of normal service, Company may, in the public interest and on behalf of Electric Service Providers or Company, interrupt service to other customers to provide necessary service to civil defense or other emergency service agencies on a temporary basis until normal service to these agencies can be restored.

5.4 Company Access to Customer Sites - Company's authorized agents shall have satisfactory unassisted access to the customer's sites at all reasonable hours to install, inspect, read, repair or remove its meters or to install, operate or maintain other Company property, or to inspect and determine the connected electrical load. If, after six (6) months (not necessarily consecutive) of good faith efforts by Company to deal with the customer, Company in its opinion does not have satisfactory unassisted access to the meter, then Company shall have sufficient cause for termination of service or denial of any rate options where, in Company's opinion, access is required. The remedy for unassisted access will be at Company discretion and may include the installation by Company of a specialized meter. If such specialized meter is installed, the customer will be billed the difference between the otherwise applicable meter for their rate and the specialized meter and the cost incurred to install the specialized meter. If service is terminated as a result of failure to provide unassisted access, Company verification of unassisted access may be required before service is restored. Written termination notice is required prior to disconnecting service under this schedule.

5.5 Easements

5.5.1 All suitable easements or rights-of-way required by Company for any portion of an extension to serve a customer, which is either on sites owned, leased or otherwise controlled by the customer or developer, or other property required for the extension, shall be furnished in Company's name by the customer without cost to or condemnation by Company and in reasonable time to meet proposed service requirements. All easements or rights-of-way granted to, or obtained on behalf of Company shall contain such terms and conditions as are acceptable to Company.

5.5.2 When Company discovers that the customer or the customer's agent is performing work, has constructed facilities, or has allowed vegetation to grow adjacent to or within an

easement or right-of-way or Company-owned equipment, and such work, construction, vegetation or facility poses a hazard or is in violation of federal, state, or local laws, ordinances, statutes, rules or regulations, or significantly interferes with Company's safe use, operation or maintenance of, or access to, equipment or facilities, Company shall notify the customer or the customer's agent and shall take whatever actions are necessary to eliminate the hazard, obstruction, interference or violation at the customer's expense. Company will notify the customer in writing of the violations.

5.6 Load Characteristics – The customer shall exercise reasonable care to ensure that the electrical characteristics of its load, such as deviation from sine wave form (a minimum standard is IEEE 519) or unusual short interval fluctuations in demand, shall not impair service to other customers or interfere with operation of telephone, television, or other communication facilities. Customer shall meet power factor requirements as specified on applicable rate schedules.

6. Metering and Metering Equipment

6.1 Customer Equipment - The customer shall install and maintain all wiring and equipment beyond the point of delivery, except for Company's meters and special equipment. The customer's entire installation must conform to all applicable construction standards and safety codes and the customer must furnish an inspection or permit if required by law or by Company.

6.1.1 The customer shall provide, in accordance with Company's current service standards and/or Electric Service Requirements Manual, at no expense to Company, and close to the point of delivery, a sufficient and suitable space acceptable to Company's agent for the installation, accessibility and maintenance of Company's metering equipment. A current version of the Electric Service Requirements Manual is available on-line at http://esp.apsc.com/resource/metering.

6.1.2 Where a customer requests, and Company approves of, a special meter reading device or communications services or devices to accommodate the customer's needs, the cost for such additional equipment and usage fees shall be the responsibility of the customer.

6.2 Company Equipment

6.2.1 A Meter Service Provider (MSP) or its authorized agents may remove Company's metering equipment pursuant to Company's Schedule 10. Meters not returned to Company or returned damaged will result in charge to the MSP of the replacement costs, plus an administration fee of fifteen percent (15%), less five (5) years depreciation.

6.2.2 Company will lease lock ring keys to MSP's and/or their agents authorized to remove Company meters pursuant to the terms and conditions of Company's Schedule 10 at a refundable charge of $70.00 per key. The charge will not be refunded if a key is lost, stolen, or damaged. If Company must replace ten percent (10%) of the issued keys within any twelve (12) month period due to loss by the MSP's agent, Company may, rather than leasing additional lock ring keys, require the MSP to arrange for a joint meeting. All lock ring keys must be returned to Company within five (5) working days if the MSP and/or its authorized agents are:

1) No longer permitted to remove Company meters pursuant to conditions of Company's Schedule 10;
2) No longer authorized by the Arizona Corporation Commission to provide services; or
3) The ESP Agreement has been terminated.

6.2.3 If the MSP, the customer, and/or its agent request a joint site meeting for removal of Company metering and associated equipment and/or lock ring, a base charge will be assessed of $62.00 per site. Company may assess an additional charge of $53.00 per hour for joint site meetings that exceed thirty (30) minutes. If Company must temporarily replace the MSP's meter and/or associated metering equipment during emergency situations or to restore power to a customer, the above charges may apply.

6.3 Service Connections - Company is not required to install and maintain any lines and equipment on the customer's side of the point of delivery except its meter.

6.3.1 For overhead service, the point of delivery shall be where Company's service conductors terminate at the customer's weatherhead or bus rider.

6.3.2 For underground service, the point of delivery shall be where Company's service conductors terminate in the customer's or development's service equipment. The customer shall furnish, install and maintain any risers, raceways and/or termination cabinet necessary for the installation of Company's underground service conductors.

6.3.3 For special applications where service is provided at voltages higher than the standard voltages specified in the Electric Service Requirements Manual, Company and customer shall mutually agree upon the designated point of delivery.

6.3.4 For the mutual protection of the customer and Company, only authorized employees or agents of Company or the Load Serving ESP are permitted to make and energize the connection between Company's service wires and the customer's service entrance conductors. Such employees carry Company issued identification which they will show on request.

6.4 Measuring Customer Service - All the energy sold to the customer will be measured by commercially acceptable measuring devices by Company (or the Meter Reading Service Provider (MRSP) pursuant to the terms and conditions of Company's Schedule 10). Where energy and, if applicable, demand is estimated by Company, estimation will be in accordance with Company's Schedule 8, Bill Estimation, as filed with the Arizona Corporation Commission. Where it is impractical to meter loads, such as street lighting, security lighting, or special installations, consumption will be determined by Company.

6.4.1 For Standard Offer customers, or where Company is the MRSP, the readings of the meter will be conclusive as to the amount of electric power supplied to the customer unless there is evidence of meter tampering or energy diversion, or unless a test reveals the meter is in error by more than plus or minus three percent (3%).

6.4.2 If there is evidence of meter tampering or energy diversion, the customer will be billed for the estimated energy and, if applicable, demand, that would have registered had all energy and demand usage been properly metered. Additionally, where there is evidence of meter tampering, energy diversion, or by-passing the meter, the customer will also be charged the cost of the investigation as determined by Company.

6.4.3 If after testing, a meter is found to be more than three percent (3%) in error, either fast or slow, proper correction shall be made of previous readings and adjusted bills shall be rendered or adjusted billing information will be provided to the MRSP.

6.4.3.1 Customer will be billed, in accordance with Section 4.3.2, for the estimated energy and demand that would have registered had the meter been operating properly.

6.4.4 Where Company is the MRSP, Company will, at the request of the customer or the ESP, reread the customer's meter within ten (10) working days after such request by the customer. The cost of such rereads is $16.50 and may be charged to the customer or the ESP, provided that the original reading was not in error.

6.4.5 Where the ESP is the MSP or MRSP, and the ESP and/or its' agent fails to provide the meter data to Company pursuant to Company's Schedule 10 Section 8.16, Meter Reading Data Obligations, Company may, at its option, obtain the data, or may estimate the billing determinants. The charge for such reread is $16.50 and may be charged to the ESP.

6.5 Meter Testing - Company tests its meters regularly in accordance with a meter testing and maintenance program as approved by the Arizona Corporation Commission. Company will, however, individually test a Company owned/maintained meter upon customer or ESP request. If the meter is found to be within the plus or minus three percent (3%) limit, Company may charge the customer or the ESP $30.00 for the meter test if the meter is removed from the site and tested in the meter shop, and $50.00 if the meter remains on site and is tested in the field.

6.6 Master Metering

6.6.1 Mobile Home Parks - Company shall refuse service to all new construction and/or expansion of existing permanent residential mobile home parks unless the construction and/or expansion is individually metered by Company.

6.6.2 Residential Apartment Complexes, Condominiums - Company shall refuse service to all new construction of apartment complexes and condominiums which are master metered. This section is not applicable to Senior Care/Nursing Centers registered with the State of Arizona with independent living units which provide packaged services such as housing, food, and nursing care.

6.6.3 Multi-Unit Residential High Rise Developments – Company will allow master metering for high rise residential units where the residential units are privately owned, provided the building will be served by a centralized heating, ventilation and/or air conditioning system, and each residential unit shall be individually sub-metered and responsible for energy consumption of that unit.

6.6.3.1 Sub-metering shall be provided and maintained by the builder or homeowners association.

6.6.3.2 Responsibility and methodology for determining each unit's energy billing shall be clearly specified in the original bylaws of the homeowners association, a copy of which must be provided to Company prior to Company providing the initial extension.

7. Termination of Service

7.1 With Notice - Company may without liability for injury or damage, and without making a personal visit to the site, disconnect service to any customer for any of the reasons stated below, provided Company has met the notice requirements established by the Arizona Corporation Commission:

7.1.1 A customer violation of any of the applicable rules of the Arizona Corporation Commission or Company tariffs.

7.1.2 Failure of the customer to pay a delinquent bill for services provided by Company.

7.1.3 The customer's breach of a written contract for service.

7.1.4 Failure of the customer to comply with Company's deposit requirements.

7.1.5 Failure of the customer to provide Company with satisfactory and unassisted access to Company's equipment.

7.1.6 When necessary to comply with an order of any governmental agency having jurisdiction.

7.1.7 Failure of a prior customer to pay a delinquent bill for utility services where the prior customer continues to reside on the premises.

7.1.8 Failure to provide or retain rights-of-way or easements necessary to serve the customer.

7.1.9 Company learns of the existence of any condition in Section 2.4, Grounds For Refusal of Service.

7.2 Without Notice - Company may without liability for injury or damage disconnect service to any customer without advance notice under any of the following conditions:

7.2.1 The existence of an obvious hazard to the health or safety of persons or property.

7.2.2 Company has evidence of meter tampering or fraud.

7.2.3 Company has evidence of unauthorized resale or use of electric service.

7.2.4 Failure of the customer to comply with the curtailment procedures imposed by Company during a supply shortage.

7.3 Restoration of Service - Company shall not be required to restore service until the conditions which resulted in the termination have been corrected to the satisfaction of Company.

8. Removal of Facilities - Upon termination of service, Company may without liability for injury or damage, dismantle and remove its facilities installed for the purpose of supplying service to the customer, and Company shall be under no further obligation to serve the customer. If, however, Company has not removed its facilities within one (1) year after the termination of service, Company shall thereafter give the customer thirty (30) days written notice before removing its facilities, or else waive any reestablishment charge within the next year for the same service to the same customer at the same location.

For purposes of this Section notice to the customer shall be deemed given at the time such notice is deposited in the U.S. Postal Service, first class mail, postage prepaid, to the customer at his/her last known address.

9. Successors and Assigns - Agreements for Service shall be binding upon and for the benefit of the successors and assigns of the customer and Company, but no assignments by the customer shall be effective until the customer's assignee agrees in writing to be bound and until such assignment is accepted in writing by Company.

10. Warranty - THERE ARE NO UNDERSTANDINGS, AGREEMENTS, REPRESENTATIONS, OR WARRANTIES, EXPRESS OR IMPLIED (INCLUDING WARRANTIES REGARDING MERCHANTABILITY OR FITNESS FOR A PARTICULAR PURPOSE), NOT SPECIFIED HEREIN OR IN THE APPLICABLE RULES OF THE ARIZONA CORPORATION COMMISSION CONCERNING THE SALE AND DELIVERY OF SERVICES BY COMPANY TO THE CUSTOMER. THESE TERMS AND CONDITIONS AND THE APPLICABLE RULES OF THE ARIZONA CORPORATION COMMISSION STATE THE ENTIRE OBLIGATION OF COMPANY IN CONNECTION WITH SUCH SALES AND DELIVERIES.

The following TERMS AND CONDITIONS and any changes authorized by law will apply to Standard Offer and Direct Access services made available by Arizona Public Service Company (Company), under the established rate or rates authorized by law and currently applicable at time of sale.

1. General

1.1 Services will be supplied in accordance with these Terms and Conditions and any changes required by law, and such applicable rate or rates as may from time to time be authorized by law. However, in the case of the customer whose service requirements are of unusual size or characteristics, additional or special contract arrangements may be required.

1.2 These Terms and Conditions shall be considered a part of all rate schedules, except where specifically changed by a written agreement.

1.3 In case of a conflict between any provision of a rate schedule and these Terms and Conditions, the provisions of the rate schedule shall apply.

~~1.4 Company will supply electric service at the standard voltages specified in the Electric Service Requirements Manual published by Company and is responsible for distribution services, emergency system conditions, outages and safety situations related to Company's distribution system.~~

2. Establishment of Service

2.1 Application for Service - Customers requesting service may be required to appear at Company's place of business to produce proof of identity and/or sign Company's standard form of application for service or a contract before service is supplied by Company.

2.1.1 In the absence of a signed application or contract for service, the supplying of Standard Offer and/or Direct Access services by Company and acceptance thereof by the customer shall be deemed to constitute a service agreement by and between Company and the customer for delivery of, acceptance of, and payment for service, subject to Company's applicable rates and rules and regulations.

2.1.2 Where service is requested by two or more individuals, Company shall have the right to collect the full amount owed Company from any one of the applicants.

~~2.1.3 In mobile home parks identified by Company as being seasonal parks, Company may install or connect a meter as its scheduling permits; however, the customer will only be responsible for energy and demand recorded on and after their requested service turn on date.~~

2.2 Service Establishment Charge - A service establishment charge of $25.00 for residential and $35.00 non-residential plus any applicable tax adjustment will be assessed each time Company is requested to establish, reconnect or re-establish electric service to the customer's delivery point, or to make a special read without a disconnect and calculate a bill for a partial month. ~~Billing for the service charge will be rendered as part of the service bill, but not later than the second service bill.~~

~~The service establishment charges above may be assessed when a customer changes their rate selection from Direct Access to Standard Offer.~~

2.2.1 The customer ~~may~~will additionally be required to pay a trip charge of $16.00 when an authorized Company representative travels to the customer's site and is unable to complete the customer's requested services due to lack of access to ~~meter panel~~the point of delivery.

2.2.2 The customer ~~may~~will additionally be required to pay an after-hours charge of $75.00 ~~should~~if the customer requests service, as defined in A.A.C. R14-2-203.D.3, be established, reconnected, or re-established ~~during a period other than regular working hours, or on the same day of their request.~~after 5:00 p.m. on a day other than the day of request.

2.2.3 The customer will additionally be required to pay a same day connect charge of $75.00 if the customer requests service, as defined in A.A.C. R14-2-203.D.3, be established, reconnected, or re-established on the same day the request is being made, and Company agrees to work the request on the same day of the request. This will be charged regardless of the time the order may be worked by Company~~.~~ on that day. Company may, where no additional costs are incurred by Company, waive the same day fee.

2.2.4 The customer will additionally be required to pay $75.00 per crew person per hour when customer requests services that do not meet the definition of service establishment as defined in A.A.C. R14-2-203.D.3 (such as metering equipment installations, maintenance or planned outages, etc.) that require the availability of Company employees after hours, on a weekend day, or on a Company holiday. The number of employees utilized by Company in fulfilling such requests shall be at the sole discretion of Company.

Company holidays are New Year's Day, Martin Luther King, Jr. Day, Memorial Day, Independence Day, Labor Day, Veteran's Day, Thanksgiving Day, The Day After Thanksgiving, and Christmas Day.

2.2.5 Company may waive the service establishment charge where:

2.2.5.1 No field trip is required because applicant accepts responsibility for energy billed and not yet paid and the change is effective with the last meter read and meter read date billed.

2.2.5.2 Applicant has an active Landlord Automatic Transfer of Service Agreement on file with Company. This service agreement is for property owners that have established credit with Company and provides for continuous service to the landlord between tenants.

~~2.2.3 The charge for Company work, requested by the customer to be worked after hours or on a Company holiday that does not meet the definition of A.A.C. R14-2-203.D.3 will be $75.00 per hour.~~

2.2.5.3 Where multiple connects are performed during the same site visit, in the same applicant name, at the same address, for the same class of service, Company will assess the Service Establishment Charge once for every two delivery points.

2.3 Direct Access Service Request (DASR) - A Direct Access Service Request charge of $10.00 plus any applicable tax adjustment will be assessed to the Electric Service Provider (ESP) submitting the DASR each time Company processes a Request (RQ) type DASR as specified in Company's Schedule 10, Terms and Conditions for Direct Access.

2.4 Grounds for Refusal of Service - Company may refuse to connect or reconnect Standard Offer or Direct Access service if any of the following conditions exist:

2.4.1 The applicant has an outstanding amount due with Company for the same class of service and is unwilling to make payment arrangements that are acceptable to Company.

2.4.2 A condition exists which in Company's judgment is unsafe or hazardous.

2.4.3 The applicant has failed to meet the security deposit requirements set forth by Company as specified under Section 2.5 or 2.6 hereof.

2.4.4 The applicant is known to be in violation of Company's tariff.

2.4.5 The applicant fails to furnish such funds, service, equipment, and/or rights-of-way or easements required to serve the applicant and which have been specified by Company as a condition for providing service.

2.4.6 The applicant falsifies his or her identity for the purpose of obtaining service.

2.4.7 Service is already being provided at the address for which the applicant is requesting service.

2.4.8 Service is requested by an applicant and a prior customer living with the applicant owes a delinquent bill from the same or a prior service address.

2.4.9 The applicant is acting as an agent for a prior customer who is deriving benefits of the service and who owes a delinquent bill from the same or a prior service address.

2.4.10 The applicant has failed to obtain all required permits and/or inspections indicating that the applicant's facilities comply with local construction and safety codes.

2.5 Residential Establishment of Credit or Security Deposit

2.5.1 Establishment of Credit - Company shall not require a security deposit from a new applicant for service if the applicant is able to meet any of the following requirements:

2.5.1.1 The applicant has had service of a comparable nature with Company within the past two (2) years and was not delinquent in payment more than twice during the last twelve (12) consecutive months or disconnected for nonpayment.

2.5.1.2 Company receives an acceptable credit rating, as determined by Company, for the applicant from a credit rating agency utilized by Company.

2.5.1.3 The applicant can produce a letter regarding credit or verification from an electric utility where service of a comparable nature was last received within six (6) months of the current date which states that the applicant had a timely payment history for the prior twelve (12) consecutive months at the time of service discontinuation~~.~~

2.5.1.4 In lieu of a security deposit, Company receives deposit guarantee notification from a social or governmental agency acceptable to Company or a surety bond as security for Company in a sum equal to the required deposit.

2.5.2 Residential Establishment of Credit or Security Deposit - When credit cannot be established as provided for in Section 2.5.1 hereof or when it is determined that the applicant left an unpaid final bill owing to another utility company, the applicant will be required to:

2.5.2.1 Place a cash deposit to secure payment of bills for service as prescribed herein, or

2.5.2.2 Provide a surety bond acceptable to Company in an amount equal to the required security deposit.

2.5.3 Nonresidential Establishment of Security Deposit ~~- All nonresidential customers may~~ - All non-residential applicants will be required to~~:2.5.3.1 Place~~ place a cash deposit to secure payment of bills for service as prescribed herein, ~~or~~unless:

2.5.3.1 The applicant has had service of a comparable nature with Company within the past two (2) years and was not delinquent in payment more than twice during the last twelve (12) consecutive months or disconnected for nonpayment.

2.5.3.2 ~~Provide~~The applicant provides a non-cash security deposit in the form of a Surety Bond, Irrevocable Letter of Credit, or Assignment of Monies in an amount equal to the required security deposit.

2.6 Reestablishment of Security Deposit

2.6.1 Residential - Company may require a residential customer to establish or re-establish a security deposit if the customer becomes delinquent in the payment of two (2) or more bills within a twelve (12) consecutive month period or has been disconnected for non-payment during the last twelve (12) months.

2.6.2 Nonresidential - Company may require a nonresidential customer to establish or re-establish a security deposit if the customer becomes delinquent in the payment of two (2) or more bills within a twelve (12) consecutive month period or if the customer has been disconnected for non-payment during the last twelve (12) months, or when the customer's financial condition may jeopardize the payment of their bill, as determined by

Company based on the results of using a credit scoring worksheet. Company will inform all customers of the Arizona Corporation Commission's complaint process should the customer dispute the deposit based on the financial data:

2.7 Security Deposits – Once it is determined that a security deposit is required, the following will apply:

2.7.1 Security deposits may be required for each service location.

2.7.2 ~~2.7.1~~ Company reserves the right to increase or decrease security deposit amounts applicable to the services being provided by ~~the~~ Company in accordance with this section:

~~2.7.1.1 If the customer's average consumption increases by more than ten (10) percent for residential accounts within a twelve (12) consecutive month period and five (5) percent for nonresidential accounts within a twelve (12) consecutive month period; or.~~

2.7.2.1 ~~2.7.1.2~~ If the customer chooses to change from Standard Offer to Direct Access services, the deposit may be decreased by an amount which reflects that portion of the customer's service being provided by a Load Serving ESP. However if the Load Serving ESP is providing ESP Consolidated Billing pursuant to Company's Schedule 10 Section 7, the entire deposit will be credited to the customer's account; or,

2.7.2.2 ~~2.7.1.3~~ If the customer chooses to change from Direct Access to Standard Offer service, the requested deposit amount may be increased by an amount pursuant to Section 2.5, which reflects that ~~APS~~Company is providing bundled electric service.

~~2.7.2 Separate security deposits may be required for each service location.~~

2.7.2.3 If the customer's average consumption increases: by more than ten (10) percent for residential accounts or five (5) percent for nonresidential accounts within a twelve (12) consecutive month period and credit has not been established, an additional security deposit may, at Company's option, be required.

2.7.3 Customer security deposits shall not preclude Company from terminating an agreement for service or suspending service for any failure in the performance of customer obligation under the agreement for service.

2.7.4 Cash deposits held by Company six (6) months/183 days or longer shall earn interest at the established one year Treasury Constant Maturities rate, effective on the first business day of each year, as published on the Federal Reserve Website. Deposits on inactive accounts are applied to the final bill when all service options become inactive, and the balance, if any, is refunded to the customer of record within thirty (30) days. For refunds resulting from the customer changing from Standard Offer to Direct Access, the difference in the deposit amounts will be applied to the customer's account.

2.7.5 If the customer terminates all service with Company, the security deposit may be credited to the customer's final bill.

2.7.6 Residential security deposits shall not exceed two (2) times the customer's average monthly bill as estimated by Company for the services being provided by ~~the~~ Company.

2.7.6.1 Deposits or other instruments of credit will automatically expire or be returned or credited to the customers account after twelve (12) consecutive months of service, provided the customer has not been delinquent more than twice, unless customer has filed bankruptcy in the last 12 months.

2.7.7 Nonresidential security deposits shall not exceed two and one-half (2-1/2) times the customer's maximum monthly billing as estimated by Company for the service being provided by Company.

2.7.7.1 Deposits and non-cash deposits on file with Company will be reviewed after twenty-four (24) months of service and will be returned provided the customer has not been delinquent more than twice in the payment of bills or disconnected for non-payment during the previous twelve (12) consecutive months unless the customer's financial condition warrants extension of the security deposit.

2.8 Line Extensions - Installations requiring Company to extend its facilities in order to establish service will be made in accordance with Company's Schedule #3, Conditions Governing Extensions of Electric Distribution Lines and Services filed with the Arizona Corporation Commission.

3. Rates

3.1 Rate Information - Company shall provide, in accordance with A.A.C. R14-2-204, a copy of any rate schedule applicable to that customer for the requested type of service. In addition, Company shall notify its customers of any changes in Company tariffs affecting those customers.

3.2 Rate Selection – The customer's service characteristics and service requirements determine the selection of applicable rate schedule. If the customer is ~~being served on a Standard Offer rate~~receiving bundled service, Company will use reasonable care in initially establishing service to the customer under the most advantageous ~~Standard Offer~~ rate schedule applicable to the customer. However, because of varying customer usage patterns and other reasons beyond its reasonable knowledge or control, Company cannot guarantee that the most economic applicable rate will be applied. Company will not make any refunds in any instances where it is determined that the customer would have paid less for service had the customer been billed on an alternate applicable rate or provision of that rate.

3.3 ~~Standard Offer~~ Optional Rates – Certain optional ~~Standard Offer~~ rate schedules applicable to certain classes of service allow the customer the option to select the rate schedule to be effective initially or after service has been established. ~~A customer desiring service under an alternate rate schedule after service has been established must make such request in writing to Company.~~ Billing under the alternate rate will become effective from the next regularly scheduled meter reading, ~~or when~~after the appropriate metering equipment is installed. No further rate schedule changes,

however, may be made within the succeeding twelve-month period. Where the rate schedule or contract pursuant to which the customer is provided service specifies a term, the customer may not exercise its option to select an alternate rate schedule until expiration of that term.

3.4 Direct Access ~~rate selection~~service will be effective upon the next meter read date if DASR is processed fifteen (15) calendar days prior to that read date and the appropriate metering equipment. is in place. If a DASR is made less than fifteen (15) days prior to the next regular read date the effective date will be at the next meter read date thereafter. The above timeframes are applicable for customers changing their selection of Electric Service Providers or for customers returning to Standard Offer service.

3.5 Any customer ~~making a~~that selects Direct Access ~~rate selection~~service may return to Standard Offer service in accordance with the rules, regulations, and orders of the Commission. However, such customer will not be eligible for Direct Access service for the succeeding twelve (12) month period. If a customer returning to Standard Offer, in accordance with the rules, regulations and orders of the Commission, was not given the required notification in accordance with the rules and regulations of the Commission by their Load Serving ESP of its intent to cease providing competitive services then the above provision will only apply if the customer fails to select another ESP within sixty (60) days of returning to Standard Offer service.

4. Billing and Collection

4.1 Customer Service Installation and Billing - Service billing periods normally consist of approximately 30 days unless designated otherwise under rate schedules, through contractual agreement, or at Company option.

4.1.1 Company normally meters and bills each site separately; however, at customer's request, adjacent and contiguous sites not separated by private or public property or right of way and operated as one integral unit under the same name and as a part of the same business, will be considered a single site as specified in Company's Schedule 4, Totalized Metering of Multiple Service Entrance Sections at a Single Site for Standard Offer and Direct Access Service.

4.1.2 The customer's service installation will normally be arranged to accept only one type of service at one point of delivery to enable service measurement through one meter. If the customer requires more than one type of service, or total service cannot be measured through one meter according to Company's regular practice, separate meters will be used and separate billing rendered for the service measured by each meter.

4.2 Collection Policy - The following collection policy shall apply to all customer accounts:

4.2.1 All bills rendered by Company are due and payable no later than ~~fifteen~~nineteen (~~15~~19) calendar days from the billing date. Any payment not received within this time frame ~~shall~~will be considered delinquent. All delinquent bills for which payment has not been received shall be subject to the provisions of Company's termination procedure. Company reserves the right to suspend or terminate the customer's service for non-payment of any Arizona Corporation Commission approved ~~services~~charges. All

delinquent charges will be subject to a late charge at the rate of eighteen percent (18%) per annum.

4.2.2 If the customer, as defined in A.A.C. R 14-2-201.9, has two or more services with Company and one or more of such services is terminated for any reason leaving an outstanding bill and the customer is unwilling to make payment arrangements that are acceptable to Company, Company shall be entitled to transfer the balance due on the terminated service to any other active account of the customer for the same class of service. The failure of the customer to pay the active account shall result in the suspension or termination of service thereunder.

4.2.3 Unpaid charges incurred prior to the customer selecting Direct Access will not delay the customer's request for Direct Access. These charges remain the responsibility of the customer to pay. Normal collection activity, including discontinuing service, may be followed for failure to pay.

4.3 Responsibility for Payment of Bills

4.3.1 The customer is responsible for the payment of bills until service is ordered discontinued and Company has had reasonable time to secure a final meter reading for those services involving energy usage, or if non-metered services are involved until ~~the~~ Company has had reasonable time to process the disconnect request.

4.3.2 When an error is found to exist in the billing rendered to the customer, Company will correct such an error to recover or refund the difference between the original billing and the correct billing. Such adjusted billings will not be rendered for periods in excess of the applicable statute of limitations from the date the error is discovered. ~~Any refunds to customers resulting from overbillings will be made promptly upon discovery by Company. Underbillings by Company shall be billed to the customer who shall be given an equal length of time such as number of months underbilled to pay the backbill without late payment penalties, unless there is evidence of meter tampering or energy diversion. Except in situations where the account is billed on a special contract or non-metered rate, where service has been established but no bills have been rendered, or where there is evidence of meter tampering or energy diversion, underbillings for residential accounts shall be limited to three (3) months and non-residential accounts shall be limited to six (6) months.~~

4.3.2.1 Refunds to customers resulting from overbillings will be made promptly upon discovery by Company.

4.3.2.2 Corrected charges for underbillings shall be billed to the customer who shall be given an equal length of time such as number of months underbilled to pay the backbill without late payment penalties, unless there is evidence of meter tampering or energy diversion

4.3.2.3 Except as specified below, corrected charges for underbillings shall be limited to three (3) month for residential accounts and six (6) months for non-residential accounts.

4.3.2.3.1 Where the account is billed on a special contract or non-metered rate, corrected charges for *underbillings* shall be billed in accordance with the contract or rate schedule requirements and is not limited to three or six months as applicable.

4.3.2.3.2 Where service has been established but no bills have been rendered, corrected charges for underbillings shall go back to the date service was established.

4.3.2.3.3 Where there is evidence of meter tampering or energy diversions, corrected charges for underbillings shall go back to the date meter tampering or energy diversions began, as determined by Company.

~~4.3.3 Where Company is responsible for rendering the customer's bill, Company may provide a one time incentive of up to $10.00 per customer to customers who elect to pay their bills using Company's electronically transmitted payment options.~~

4.3.2.3.4 Where lack of access to the meter (caused by the customer) has resulted in estimated bills, corrected charges for underbillings shall go back to the last Company obtained meter read date.

~~4.3.4 Where Company is responsible for rendering the customer's bill, Company may provide a one time incentive of $5.00 per customer for a customer electing to forego the presentation of a paper bill.~~

4.3.2.4 Company may forgo billing and collection of corrected charges for an underbilling if Company believes the cost of billing and collecting the underbilling would not justify pursuing the underbill.

4.4 Dishonored Payments - If Company is notified by the customer's financial institution that they will not honor a payment tendered by the customer for payment of any bill, Company may require the customer to make payment in cash, by money order, certified or cashier's check, or other means which guarantee the customer's payment to Company.

4.4.1 The customer ~~shall~~will be charged a fee of $15.00 for each instance where the customer tenders payment of a bill with a payment that is not honored by the customer's financial institution.

4.4.2 The tender of a dishonored payment shall in no way (i) relieve the customer of the obligation to render payment to Company under the original terms of the bill, or (ii) defer Company's right to terminate service for nonpayment of bills.

4.4.3 Where the customer has tendered two (2) or more dishonored payments in the past twelve (12) consecutive months, Company may require the customer to make payment in cash, money order or cashier's check for the next twelve (12) consecutive months.

4.5 Termination Process Charges

4.5.1 ~~4.5 Field Call Charge~~ Company ~~may~~will require payment of a Field Call Charge of $15.00 when an authorized Company representative travels to the customer's site to accept payment ~~of~~on a delinquent account, notify of service termination, make payment arrangements or terminate the service. This charge will only be applied for field calls resulting from the termination process.

~~4.5.1~~4.5.2 If a termination is required at the pole, a reconnection charge of $96.50 will be required; if the termination is in underground equipment, the reconnection charge will be $115.00.

4.5.3 ~~4.5.2~~ To avoid termination of service, the customer ~~may~~will make payment in full, including any necessary deposit in accordance with Section 2.5 hereof or make payment arrangements satisfactory to Company.

4.6 On-site Evaluation – Company ~~may~~will require payment of an On-site Evaluation Charge of $82.00 when an authorized Company field investigator performs an on-site visit to evaluate how the customer may reduce their energy usage. This charge may be assessed regardless of ~~if~~whether the customer actually implements Company suggestions.

5. Service Responsibilities of Company and Customer

5.1 Service Voltage – Company will deliver electric service to the designated point of delivery, as specified in Section 6.3 of this Schedule, at the standard voltages specified in the Electric Service Requirements Manual published by Company and as specified in A.A.C. R14-2-208.F. Company may deliver service for special applications at higher voltages, with prior approval from Company's Engineering Department and in accordance with Company's Schedule 3, Conditions Governing Extensions of Electric Distribution Lines and Services filed with the Arizona Corporation Commission.

5.2 Responsibility: Use of Service or Apparatus

5.2.1 The customer shall save Company harmless from and against all claims for injury or damage to persons or property occasioned by or in any way resulting from the services being provided by Company or the use thereof on the customer's side of the point of delivery. Company shall have the right to suspend or terminate service in the event Company should learn of service use by the customer under hazardous conditions.

5.2.2 The customer shall exercise all reasonable care to prevent loss or damage to Company property installed on the customer's site for the purpose of supplying service to the customer.

5.2.3 The customer shall be responsible for payment for loss or damage to Company property on the customer's site arising from neglect, carelessness or misuse and shall reimburse Company for the cost of necessary repairs or replacements.

5.2.4 The customer shall be responsible for payment for any equipment damage and/or estimated unmetered usage resulting from unauthorized breaking of seals, interfering with, tampering with, or by-passing the meter.

5.2.5 The customer shall be responsible for notifying Company of any failure in Company's equipment.

5.3 Service Interruptions: Limitations on Liability of Company

5.3.1 Company shall not be liable to the customer for any damages occasioned by Load Serving ESP's equipment or failure to perform, fluctuations, interruptions or curtailment of electric service, except where due to Company's willful misconduct or gross negligence. Company may, without incurring any liability therefore, suspend the customer's electric service for periods reasonably required to permit Company to accomplish repairs to or changes in any of Company's facilities. The customer needs to protect their own sensitive equipment from harm caused by variations or interruptions in power supply.

5.3.2 In the event of a national emergency or local disaster resulting in disruption of normal service, Company may, in the public interest and on behalf of Electric Service Providers or Company, interrupt service to other customers to provide necessary service to civil defense or other emergency service agencies on a temporary basis until normal service to these agencies can be restored.

5.4 Company Access to Customer Sites - Company's authorized agents shall have satisfactory unassisted access to the customer's sites at all reasonable hours to install, inspect, read, repair or remove its meters or to install, operate or maintain other Company property, or to inspect and determine the connected electrical load. If, after six (6) months (not necessarily consecutive) of good faith efforts by Company to deal with the customer, Company in its opinion does not have satisfactory unassisted access to the meter, then Company shall have sufficient cause for termination of service or denial of any ~~existing~~ rate options where, in Company's opinion, access is required. The remedy for unassisted access will be at Company discretion and may include the installation by Company of a specialized meter. If such specialized meter is installed, the customer will be billed the difference between the otherwise applicable meter for their rate and the specialized meter and the cost incurred to install the specialized meter. If service is terminated as a result of failure to provide unassisted access, Company verification of unassisted access may be required before service is restored. Written termination notice is required prior to disconnecting service under this schedule.

5.5 Easements

5.5.1 All suitable easements or rights-of-way required by Company for any portion of ~~the~~an extension to serve a customer, which is either on sites owned, leased or otherwise controlled by the customer or developer, or other property required for the extension, shall be furnished in Company's name by the customer without cost to or condemnation by Company and in reasonable time to meet proposed service requirements. All easements or rights-of-way granted to, or obtained on behalf of Company shall contain such terms and conditions as are acceptable to Company.

5.5.2 When Company discovers that the customer or the customer's agent is performing work, has constructed facilities, or has allowed vegetation to grow adjacent to or within an

easement or right-of-way or Company-owned equipment, and such work, construction, vegetation or facility poses a hazard or is in violation of federal, state, or local laws, ordinances, statutes, rules or regulations, or significantly interferes with Company's safe use, operation or maintenance of, or access to, equipment or facilities, Company shall notify the customer or the customer's agent and shall take whatever actions are necessary to eliminate the hazard, obstruction, interference or violation at the customer's expense. Company will notify the customer in writing of the violations.

5.6 Load Characteristics – The customer shall exercise reasonable care to ~~assure~~ensure that the electrical characteristics of its load, such as deviation from sine wave form (a minimum standard is IEEE 519) or unusual short interval fluctuations in demand, shall not impair service to other customers or interfere with operation of telephone, television, or other communication facilities. ~~The deviation from phase balance shall not be greater than ten percent (10%) at any time. Customers receiving service at voltage levels below 69 kV shall maintain a power factor of 90% lagging but in no event leading unless agreed to by Company. In situations where Company suspects that a customer's load has a non-conforming power factor, Company may install at its cost the appropriate metering to monitor such loads. If the customer's power factor is found to be non-conforming, the customer will be required to pay the cost of installation and removal of VAR metering and recording equipment.Customers found to have a power factor of less than 90%, or leading, or other detrimental conditions shall be required to remedy problems in order to achieve a power factor in conformance with above standards, or pay for facilities/equipment that Company must install on its system to correct for problems caused by the customer's load. Until such time as the customer remedies the problem, kVa may be substituted for kW in determining the applicable charge for billing purposes for each month in which such failure occurs~~Customer shall meet power factor requirements as specified on applicable rate schedules.

6. Metering and Metering Equipment

6.1 Customer Equipment - The customer shall install and maintain all wiring and equipment beyond the point of delivery except for Company's meters and special equipment. The customer's entire installation must conform to all applicable construction standards and safety codes and the customer must furnish an inspection or permit if required by law or by Company.

6.1.1 The customer shall provide, in accordance with Company's current service standards and/or Electric Service Requirements Manual, at no expense to Company, and close to the point of delivery, a sufficient and suitable space acceptable to Company's agent for the installation, accessibility and maintenance of Company's metering equipment. A current version of the Electric Service Requirements Manual is available on-line at http://esp.apsc.com/resource/metering.

~~6.1.2 If telephone lines or any other devices are required to read the customer's meter, the customer is responsible for the installation, maintenance, and usage fees at no cost to Company.~~

6.1.2 ~~6.1.3~~ Where a customer requests, and Company approves of, a special meter reading device or communications services or devices to accommodate the customer's needs, the cost for such additional equipment and usage fees shall be the responsibility of the customer.

6.2 Company Equipment

6.2.1 A Meter Service Provider (MSP) or its authorized agents may remove Company's metering equipment pursuant to Company's Schedule 10. Meters not returned to Company or returned damaged will ~~be charged~~result in charge to the MSP of the replacement costs ~~less five (5) years depreciation~~, plus an administration fee of fifteen percent (15%), less five (5) years depreciation.

6.2.2 Company will lease lock ring keys to MSP's and/or their agents authorized to remove Company meters pursuant to the terms and conditions of Company's Schedule 10 at a refundable charge of $70.00 per key. The charge will not be refunded if a key is lost, stolen, or damaged. If Company must replace ten percent (10%) of the issued keys within any twelve (12) month period due to loss by the MSP's agent, Company may, rather than leasing additional lock ring keys, require the MSP to arrange for a joint meeting. All lock ring keys must be returned to Company within five (5) working days if the MSP and/or its authorized agents are:

1) No longer permitted to remove Company meters pursuant to conditions of Company's Schedule 10;
2) No longer authorized by the Arizona Corporation Commission to provide services; or
3) The ESP Agreement has been terminated.

6.2.3 If the MSP, the customer, and/or its' agent request a joint site meeting for removal of Company metering and associated equipment and/or lock ring, a base charge will be assessed of $62.00 per site. Company may assess an additional charge of $53.00 per hour for joint site meetings that exceed thirty (30) minutes. ~~In the event~~If Company must temporarily replace the MSP's meter and/or associated metering equipment ~~as necessary~~ during emergency situations or to restore power to a customer, the above charges may apply.

6.3 Service Connections - Company is not required to install and maintain any lines and equipment on the customer's side of the point of delivery except its meter.

6.3.1 For overhead service, the point of delivery shall be where Company's service conductors terminate at the customer's weatherhead or bus rider.

6.3.2 ~~6.3 Service Connections - Company is not required to install and maintain any lines and equipment on the customer's side of the point of delivery except its meter. For overhead service, the point of delivery shall be where Company's service conductors terminate at the customer's weatherhead or bus rider.~~ For underground service, the point of delivery shall be where Company's service conductors terminate in the customer's or development's service equipment. The customer shall furnish, install and maintain any risers, raceways and/or termination cabinet necessary for the installation of Company's underground service conductors. ~~For the mutual protection of the customer and Company, only authorized employees or agents of Company or the Load Serving ESP are~~

~~permitted to make and energize the connection between Company's service wires and the customer's service entrance conductors. Such employees carry credentials~~

6.3.3 For special applications where service is provided at voltages higher than the standard voltages specified in the Electric Service Requirements Manual, Company and customer shall mutually agree upon the designated point of delivery.

6.3.4 For the mutual protection of the customer and Company, only authorized employees or agents of Company or the Load Serving ESP are permitted to make and energize the connection between Company's service wires and the customer's service entrance conductors. Such employees carry Company issued identification which they will show on request.

6.4 Measuring Customer Service - All the energy sold to the customer will be measured by commercially acceptable measuring devices by Company (or the Meter Reading Service Provider (MRSP) pursuant to the terms and conditions of Company's Schedule ~~10~~ 10). Where energy and, if applicable, demand is estimated by Company, estimation will be in accordance with Company's Schedule 8, Bill Estimation, as filed with the Arizona Corporation Commission. Where it is impractical to meter loads, such as street lighting, security lighting, or special installations, consumption will be determined by Company.

6.4.1 For Standard Offer customers, or where Company is the MRSP, the readings of the meter will be conclusive as to the amount of electric power supplied to the customer unless there is evidence of meter tampering or energy diversion, or unless a test reveals the meter is in error by more than plus or minus three percent (3%).

6.4.2 If there is evidence of meter tampering or energy diversion, the customer will be billed for the estimated energy ~~consumption~~and, if applicable, demand, that would have registered had all energy and demand usage been properly metered. Additionally, where there is evidence of meter tampering, energy diversion, or by-passing the meter, the customer ~~may~~will also be charged the cost of the investigation as determined by Company.

6.4.3 If after testing, a meter is found to be more than three percent (3%) in error, either fast or slow, proper correction shall be made of previous readings and adjusted bills shall be rendered or adjusted billing information will be provided to the MRSP.

6.4.3.1 ~~6.4.4 Customer will be billed~~Customer will be billed, in accordance with Section 4.3.2, for the estimated energy and demand that would have registered had the meter been operating properly.

6.4.4 Where Company is the MRSP, Company ~~shall~~will, at the request of the customer or the ESP, reread the customer's meter within ten (10) working days after such request by the customer. The cost of such rereads is $16.50 and may be charged to the customer or the ESP, provided that the original reading was not in error.

6.4.5 Where the ESP is the MSP or MRSP, and the ESP and/or its' agent fails to provide the meter data to Company pursuant to Company's Schedule 10 Section 8.16, Meter Reading Data Obligations, Company may, at its option, obtain the data, or may estimate the billing determinants. The charge for such reread is $16.50 and may be charged to the ESP.

6.5 Meter Testing - Company tests its meters regularly in accordance with a meter testing and maintenance program as approved by the Arizona Corporation Commission. Company will, however, individually test a Company owned/maintained meter upon customer or ESP request. If the meter is found to be within the plus or minus three percent (3%) limit, Company may charge the customer or the ESP $30.00 for the meter test if the meter is removed from the site and tested in the meter shop, and $50.00 if the meter remains on site and is tested in the field.

6.6 Master Metering

6.6.1 Mobile Home Parks - Company shall refuse service to all new construction and/or expansion of existing permanent residential mobile home parks unless the construction and/or expansion is individually metered by Company.

6.6.2 Residential Apartment Complexes, Condominiums~~ and Other Multiunit Residential Buildings~~ - Company shall refuse service to all new construction of apartment complexes and condominiums which are master metered~~ unless the building(s) will be served by a centralized heating, ventilation and/or air conditioning system and the contractor can provide to Company an analysis demonstrating that the central unit will result in a favorable cost/benefit relationship as stated in A.A.C. R14-2-205.~~ This section is not applicable to Senior Care/Nursing Centers registered with the State of Arizona with independent living units which provide packaged services such as housing, food, and nursing care.

6.6.3 Multi-Unit Residential High Rise Developments – Company will allow master metering for high rise residential units where the residential units are privately owned, provided the building will be served by a centralized heating, ventilation and/or air conditioning system, and each residential unit shall be individually sub-metered and responsible for energy consumption of that unit.

6.6.3.1 Sub-metering shall be provided and maintained by the builder or homeowners association.

6.6.3.2 Responsibility and methodology for determining each unit's energy billing shall be clearly specified in the original bylaws of the homeowners association, a copy of which must be provided to Company prior to Company providing the initial extension.

7. Termination of Service

7.1 With Notice - Company may without liability for injury or damage, and without making a personal visit to the site, disconnect service to any customer for any of the reasons stated below, provided Company has met the notice requirements established by the Arizona Corporation Commission:

7.1.1 A customer violation of any of the applicable rules of the Arizona Corporation Commission or Company tariffs.

7.1.2 Failure of the customer to pay a delinquent bill for services provided by Company.

7.1.3 The customer's breach of a written contract for service.

7.1.4 Failure of the customer to comply with Company's deposit requirements.

7.1.5 Failure of the customer to provide Company with satisfactory and unassisted access to Company's equipment.

7.1.6 When necessary to comply with an order of any governmental agency having jurisdiction.

7.1.7 Failure of a prior customer to pay a delinquent bill for utility services where the prior customer continues to reside on the premises.

7.1.8 Failure to provide or retain rights-of-way or easements necessary to serve the customer.

7.1.9 Company learns of the existence of any condition in Section 2.4, Grounds For Refusal of Service.

7.2 Without Notice - Company may without liability for injury or damage disconnect service to any customer without advance notice under any of the following conditions:

7.2.1 The existence of an obvious hazard to the health or safety of persons or property.

7.2.2 Company has evidence of meter tampering or fraud.

7.2.3 Company has evidence of unauthorized resale or use of electric service.

7.2.4 Failure of the customer to comply with the curtailment procedures imposed by Company during a supply shortage.

7.3 Restoration of Service - Company shall not be required to restore service until the conditions which resulted in the termination have been corrected to the satisfaction of Company.

8. Removal of Facilities - Upon termination of service, Company may without liability for injury or damage, dismantle and remove its facilities installed for the purpose of supplying service to the customer, and Company shall be under no further obligation to serve the customer. If, however, Company has not removed its facilities within one (1) year after the termination of service, Company shall thereafter give the customer thirty (30) days written notice before removing its facilities, or else waive any reestablishment charge within the next year for the same service to the same customer at the same location.

For purposes of this Section notice to the customer shall be deemed given at the time such notice is deposited in the U.S. Postal Service, first class mail, postage prepaid, to the customer at his/her last known address.

9. Successors and Assigns - Agreements for Service shall be binding upon and for the benefit of the successors and assigns of the customer and Company, but no assignments by the customer shall be effective until the customer's assignee agrees in writing to be bound and until such assignment is accepted in writing by Company.

10. Warranty - THERE ARE NO UNDERSTANDINGS, AGREEMENTS, REPRESENTATIONS, OR WARRANTIES, EXPRESS OR IMPLIED (INCLUDING WARRANTIES REGARDING

MERCHANTABILITY OR FITNESS FOR A PARTICULAR PURPOSE), NOT SPECIFIED HEREIN OR IN THE APPLICABLE RULES OF THE ARIZONA CORPORATION COMMISSION CONCERNING THE SALE AND DELIVERY OF SERVICES BY COMPANY TO THE CUSTOMER. THESE TERMS AND CONDITIONS AND THE APPLICABLE RULES OF THE ARIZONA CORPORATION COMMISSION STATE THE ENTIRE OBLIGATION OF COMPANY IN CONNECTION WITH SUCH SALES AND DELIVERIES.

SERVICE SCHEDULE 4: TOTALIZED METERING OF MULTIPLE SERVICE ENTRANCE SECTIONS AT A SINGLE SITE FOR STANDARD OFFER AND DIRECT ACCESS SERVICE

Arizona Public Service Company (Company) customers at a single site whose load requires multiple points of delivery through multiple service entrance sections (SESs) may be metered and billed from a single meter through Adjacent Totalized Metering or Remote Totalized Metering as specified in this schedule.

Totalized Metering (Adjacent or Remote) is the measurement for billing purposes on the appropriate rate, through one meter, of the simultaneous demands and energy of a customer who receives electric service at more than one SES at a single site.

A. Totalized metering will either be Adjacent or Remote and shall be permitted only if conditions 1 through 7 are all satisfied.

1. The customer's facilities must be located on adjacent and contiguous sites not separated by private or public property or right-of-way and must be operated as one integral unit under the same name and as a part of the same business or residence (these conditions must be met to be considered a single site, as specified in Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Service, Section 4.1.1); and

2. Power will generally be delivered at no less than 277/480 volt (nominal), three phase, four wire or 120/240 volt (nominal) single phase three wire; and

3. Three phase and single phase service entrance sections can not be combined for totalizing purposes; and

4. For Standard Offer customers, totalized metering may be accomplished by providing electronically totalized demand and energy reads or by means of a physical wire interconnection of metering information with the customer providing conduit between the SESs; for Direct Access customers the customer's Electric Service Provider may provide electronically totalized demand and energy reads in compliance with Company's Schedule 10, Terms and Conditions for Direct Access; and

5. The customer shall provide vault or transformer space, which meets Company specifications, on the customer's property at no cost to Company; and

6. If the customer operates an electric generation unit on the premise, totalized metering will be permitted when the customer complies with all of Company's requirements for interconnection, pays all costs for any additional special metering required to accommodate such service from totalized service sections, and takes service on an applicable rate schedule for interconnected customer owned generation; and

7. Written approval by Company's authorized representative is required before totalized metering may be implemented.

B. Adjacent Totalized Metering will apply when conditions A.1-A.7 and the following conditions are met:

1. The customer's <u>total</u> load to be totalized requires a National Electrical Code (NEC) service entrance size of over 3,000 amps three phase or 800 amps single phase; and

2. Company requires that load be split and served from multiple SESs; and

3. The customer must locate SESs to be totalized within 10 feet of each other.

There will be no additional charge to the customer's monthly bill for Adjacent Totalized Metering.

C. Remote Totalized Metering will apply when conditions A.1-A.7 are met, multiple SESs are separated from one another by more than 10 feet, and the following conditions are met:

1. Each of the customer's service entrance sections to be totalized requires an NEC section size of 3,000 amps three phase or 800 amps single phase or greater; and

2. The customer's total load to be totalized has a minimum demand of 2,000 kVa or 1,500 kW three phase or 100 kVa or 80 kW single phase; and

3. The customer has made a non-refundable contribution for the net additional cost to Company of the meter totalizing connection and equipment.

When the total capital investment by Company to provide service at multiple points of delivery, as computed by Company, is equal to or less than the cost to serve a single point of delivery, then no additional monthly charge shall be made to the customer receiving Remote Totalized Metering. However, lower capital investment which results from the customer's contribution, other than the meter costs in C.3 above, shall not be considered.

For customers where the total capital investment by Company to provide service at multiple points of delivery, as computed by Company, is greater than the cost to serve at a single point of delivery, then there shall be an additional charge. The additional monthly charge for each delivery point above one shall consist of 1% of the totalized bill, plus $500.00, plus all applicable taxes and adjustments.

D. Removal of Totalized Metering Configuration

In some cases, it may be to the customer's benefit to remove all totalized metering equipment, or remove selected totalized metering equipment from the totalized account. This will be permitted under the following conditions:

1. The customer must submit a written request to Company stating the reason for the removal and the specific equipment to be removed.

2. After removal of the equipment, the customer may not ask for services to be totalized for one (1) year from the removal date. At the end of one (1) year, if the customer does request services to be totalized, the applicable conditions listed above must be met.

3. The customer will be required to make a nonrefundable contribution for the costs associated with the removal of the meter totalizing connection and equipment.

SERVICE SCHEDULE 4: TOTALIZED METERING OF MULTIPLE SERVICE ENTRANCE SECTIONS AT A SINGLE SITE FOR STANDARD OFFER AND DIRECT ACCESS SERVICE

Arizona Public Service Company (Company) customers at a single site whose load requires multiple points of delivery through multiple service entrance sections (SESs) may be metered and billed from a single meter through Adjacent Totalized Metering or Remote Totalized Metering as specified in this schedule.

Totalized Metering (Adjacent or Remote) is the measurement for billing purposes on the appropriate rate, through one meter, of the simultaneous demands and energy of a customer who receives electric service at more than one SES at a single site.

A. Totalized metering will either be Adjacent or Remote and shall be permitted only if conditions 1 through 7 are all satisfied.

1. The customer's facilities must be located on adjacent and contiguous sites not separated by private or public property or right-of-way and must be operated as one integral unit under the same name and as a part of the same business or residence (these conditions must be met to be considered a single site, as specified in Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Service, Section 4.1.1); and

2. Power will generally be delivered at no less than 277/480 volt (nominal), three phase, four wire or 120/240 volt (nominal) single phase three wire; and

3. Three phase and single phase service entrance sections can not be combined for totalizing purposes; and

4. For Standard Offer customers, totalized metering may be accomplished by providing electronically totalized demand and energy reads or by means of ~~must be accomplished by~~ a physical wire interconnection of metering information with the customer providing conduit between the SESs; for Direct Access customers the customer's Electric Service Provider may provide electronically totalized demand and energy reads in compliance with Company's Schedule 10, Terms and Conditions for Direct Access; and

5. The customer shall provide vault or transformer space, which meets Company specifications, on the customer's property at no cost to Company; and

6. If the customer operates an electric generation unit on the premise, totalized metering will be permitted when the customer complies with all of Company's requirements for interconnection, pays all costs for any additional special metering required to accommodate such service from totalized service sections, and takes service on an applicable rate schedule for interconnected customer owned generation; and

7. Written approval by Company's authorized representative is required before totalized metering may be implemented.

B. Adjacent Totalized Metering will apply when conditions A.1-A.7 and the following conditions are met:

1. The customer's total load to be totalized requires a National Electrical Code (NEC) service entrance size of over 3,000 amps three phase or 800 amps single phase; and

2. Company requires that load be split and served from multiple SESs; and

3. The customer must locate SESs to be totalized within 10 feet of each other.

There will be no additional charge to the customer's monthly bill for Adjacent Totalized Metering.

C. Remote Totalized Metering will apply when conditions A.1-A.7 are met, multiple SESs are separated from one another by more than 10 feet, and the following conditions are met:

1. Each of the customer's service entrance sections to be totalized requires an NEC section size of 3,000 amps three phase or 800 amps single phase or greater; and

2. The customer's total load to be totalized has a minimum demand of 2,000 kVa or 1,500 kW three phase or 100 kVa or 80 kW single phase; and

3. The customer has made a non-refundable contribution for the net additional cost to Company of the meter totalizing connection and equipment.

When the total capital investment by Company to provide service at multiple points of delivery, as computed by Company, is equal to or less than the cost to serve a single point of delivery, then no additional monthly charge shall be made to the customer receiving Remote Totalized Metering. However, lower capital investment which results from the customer's contribution, other than the meter costs in C.3 above, shall not be considered.

For customers where the total capital investment by Company to provide service at multiple points of delivery, as computed by Company, is greater than the cost to serve at a single point of delivery, then there shall be an additional charge. The additional monthly charge for each delivery point above one shall consist of 1% of the totalized bill, plus $500.00, plus all applicable taxes and adjustments.

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1. The customer must submit a written request to Company stating the reason for the removal and the specific equipment to be removed.

2. After removal of the equipment, the customer may not ask for services to be totalized for one (1) year from the removal date. At the end of one (1) year, if the customer does request services to be totalized, the applicable conditions listed above must be met.

3. The customer will be required to make a nonrefundable contribution for the costs associated with the removal of the meter totalizing connection and equipment.

Year	Common Stock	Retained Earnings	Total Equity	Market Price	M/B Ratio	Allowed ROE	Earnings Per Share	Dividends Per Share	Payout Ratio
1	$ 9.52	$ -	$ 9.52	$10.00	1.050	11.50%	$ 1.09	$ 0.50	45.7%
2	$ 9.52	$ 0.59	$10.11	$10.62	1.050	11.50%	$ 1.16	$ 0.53	45.7%
3	$ 9.52	$ 0.63	$10.75	$11.29	1.050	11.50%	$ 1.24	$ 0.56	45.7%
Growth			6.25%	6.25%			6.25%	6.25%	

The reason that investors never really earn 11.5% on their investment in the above example is that the $0.48 in flotation costs initially incurred to raise the common stock is not treated like debt issuance costs (*i.e.*, amortized into interest expense and therefore increasing the embedded cost of debt), nor is it included as an asset in rate base.

Q. CAN YOU ILLUSTRATE HOW THE FLOTATION COST ADJUSTMENT ALLOWS INVESTORS TO BE FULLY COMPENSATED FOR THE IMPACT OF PAST ISSUANCE COSTS?

A. Yes. As discussed earlier, one method for calculating the flotation cost adjustment is to multiply the dividend yield by a flotation cost percentage. Thus, with a 5% dividend yield and a 5% flotation cost percentage, the flotation cost adjustment in the above example would be approximately 25 basis points. As shown below, by allowing a rate of return on common equity of 11.75% (an 11.5% cost of equity plus a 25 basis point flotation cost adjustment), investors earn their 11.5% required rate of return, since actual growth is now equal to 6.5%:

Year	Common Stock	Retained Earnings	Total Equity	Market Price	M/B Ratio	Allowed ROE	Earnings Per Share	Dividends Per Share	Payout Ratio
1	$ 9.52	$ -	$ 9.52	$10.00	1.050	11.75%	$ 1.12	$ 0.50	44.7%
2	$ 9.52	$ 0.62	$10.14	$10.65	1.050	11.75%	$ 1.19	$ 0.53	44.7%
3	$ 9.52	$ 0.66	$10.80	$11.34	1.050	11.75%	$ 1.27	$ 0.57	44.7%
Growth			6.50%	6.50%			6.50%	6.50%	

The only way for investors to be fully compensated for issuance costs is to include an ongoing adjustment to account for past flotation costs when setting the return on

common equity. This is the case regardless of whether or not the utility is expected to issue additional shares of common stock in the future.

Q. WHAT THEN IS YOUR CONCLUSION REGARDING A FAIR RATE OF RETURN ON EQUITY FOR THE COMPANIES IN YOUR PROXY GROUP?

A. In order to account for the impact of past issuance costs, I recommend a flotation cost adjustment of 20 basis points, which roughly corresponds with the midpoint of the range discussed earlier. After incorporating an adjustment for flotation costs of 20 basis points to my "bare bones" cost of equity range, I concluded that a fair rate of return on equity for the proxy group of utilities is currently in the 11.0% to 12.0% range, with a midpoint of 11.5%.

IV. RETURN ON EQUITY FOR APS

Q. WHAT IS THE PURPOSE OF THIS SECTION?

A. In addition to presenting the conclusions of my evaluation of a fair rate of return on equity for APS, this section also discusses the relationship between ROE and preservation of a utility's financial integrity and the ability to attract capital, and evaluates the reasonableness of APS' capital structure.

A. Implications for Financial Integrity

Q. WHY IS IT IMPORTANT TO ALLOW APS AN ADEQUATE RATE OF RETURN ON EQUITY?

A. Given the social and economic importance of the electric utility industry, it is essential to maintain reliable and economical service to all consumers. While APS remains committed to provide reliable electric service, a utility's ability to fulfill its mandate can be compromised if it lacks the necessary financial wherewithal.

Q. DO CUSTOMERS ALSO BENEFIT BY ENHANCING THE UTILITY'S FINANCIAL FLEXIBILITY?

A. Yes. While providing an ROE that is sufficient to maintain APS' ability to attract capital, even in times of financial and market stress, is consistent with the economic requirements embodied in the Supreme Court's *Hope* and *Bluefield* decisions, it is also in customers' best interests. Ultimately, it is customers and the service area economy that enjoy the benefits that come from ensuring that the utility has the financial wherewithal to take whatever actions are required to ensure a reliable energy supply. By the same token, customers also bear a significant burden when the ability of the utility to attract necessary capital is impaired and service quality is compromised. To continue to meet potential challenges successfully and economically, it is crucial that APS receive adequate support for its credit standing.

Q. WHAT DANGER DOES AN INADEQUATE RATE OF RETURN POSE TO APS?

A. In light of APS' present rating, an inadequate rate of return imposed in this proceeding would further pressure APS' financial flexibility and credit standing. In order to meet rising demand for electricity across its service territory, APS has sought to acquire additional power resources to ensure its ability to maintain adequate reserve margins and provide reliable service. From 1996 through 2004, APS invested about $3.6 billion to expand generation and upgrade transmission and distribution systems, and the Company's long-term plans include significant plant investment to ensure that the energy needs of its service territory are met. While providing the infrastructure necessary to meet the energy needs of customers is certainly desirable, it imposes additional financial responsibilities on APS. The investment community has specifically noted the increasing capital

expenditures required to keep pace with APS' growing service territory as a significant credit challenge facing the Company, with Moody's concluding that:

> [S]upportive regulatory treatment remains key to the company's ability to maintain financial strength in light of significant needs for capital investment to serve a growing service territory.[65]

Q. DO THE POTENTIAL EXPOSURES FACED BY APS HIGHLIGHT THE NEED FOR ONGOING SUPPORT OF THE COMPANY'S FINANCIAL STRENGTH AND ABILITY TO ATTRACT CAPITAL?

A. Most definitely. APS faces a number of potential challenges that might require the relatively swift commitment of considerable capital resources in order to maintain the high level of service to which its customers have become accustomed. Given the potential for significant volatility in wholesale fuel and energy markets and APS' lack of control over the timing of such events, the Company must have the wherewithal to meet these challenges even when capital and energy market conditions are unfavorable. Potential capital requirements mandated by environmental regulations also imply additional financial strain.[66] For an electric utility with an obligation to provide reliable service, investors' increased reticence to supply additional capital during times of crisis highlights the necessity of preserving the flexibility necessary to overcome periods of adverse capital market conditions.

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[65] Moody's Investors Service, "Rating Action: Arizona Public Service Company," *Global Credit Research* (Jan. 10, 2006).

[66] Mr. Fox discusses the necessary capital expenditures associated with environmental changes to the Cholla, Four Corners and Navajo generating plants.

Q. WHAT LESSONS CAN BE LEARNED FROM RECENT EVENTS IN THE ENERGY INDUSTRY?

A. Experience demonstrates that, while investor confidence can evaporate almost overnight, it is difficult to recover and the damage is not quickly or easily reversed. Events in the Western U.S. provide a dramatic illustration of just how swiftly unforeseen circumstances can lead to deterioration in a utility's financial condition, and stakeholders have discovered first hand how difficult and complex it can be to remedy the situation after the fact.

Given the investment community's view that APS continues to be challenged by regulatory lag and pressures linked to mounting power cost deferrals, the perception of a lack of regulatory support would be of utmost concern to investors. Moody's recently noted that:

> The ratings of APS and Pinnacle are likely to be downgraded unless there are clear signals that APS will receive timely and full recovery of its increased costs such that we would expect their credit metrics to return to levels commensurate with those of similarly rated utility companies.[67]

Moreover, the negative impact of declining credit quality on a utility's capital costs and financial flexibility becomes more pronounced as debt ratings move down the scale from investment to non-investment grade. While APS' conservative posture has benefited customers and provided a strong platform for continued success, actions that serve to erode financial strength or impair financial flexibility could have swift and damaging consequences. The cost of providing APS an adequate

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[67] Moody's Investors Service, "Rating Action: Arizona Public Service Company," *Global Credit Research* (Jan. 10, 2006)

return is small relative to the potential benefits of a strong utility providing reliable service and fostering continued growth.

Q. WHAT ROLE DOES REGULATION PLAY IN ENSURING A UTILITY'S ACCESS TO CAPITAL?

A. Considering investors' heightened awareness of the risks associated with the electric power industry and the damage that results when a utility's financial flexibility is compromised, supportive regulation remains crucial in preserving access to capital. Investors recognize that constructive regulation is a key ingredient in supporting utility credit ratings and financial integrity, particularly during times of adverse conditions. S&P noted that:

> Regulatory rulings have returned to center stage as a dominant factor in assessing companies' credit quality. These decisions will be critical for an industry that in many jurisdictions is nearing the end of extended transition periods and will be making significant capital investment in infrastructure during the next several years.[68]

Investors recognize the importance of financial flexibility, especially considering the capital markets' ability to constrict access to capital when investors' confidence is compromised. As S&P observed:

> When examining the quality of regulation, Standard & Poor's factors in what level of support the utility might get in times of distress, when its needs are most acute.[69]

Q. ARE THESE CONCERNS GERMANE TO APS AND ITS INVESTORS?

A. Yes. Investors recognize that regulation has its own risks. With respect to APS specifically, the three major bond rating agencies have all noted the near-term

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[68] Standard & Poor's Corporation, "Industry Report Card: U.S. Electric/Gas/Water," *RatingsDirect* (May 3, 2005) at 1.

[69] Standard & Poor's Corporation, "Regulation and Credit Quality in the U.S. Utility Sector," *RatingsDirect* (Jan. 30, 2003).

challenges posed by regulatory uncertainty, while explicitly citing the potential that adverse regulatory rulings could further compromise the Company's credit standing.[70]

As discussed earlier, of particular concern to investors is the impact of regulatory lag and cost-recovery on the APS' ability to earn its authorized ROE. S&P noted the importance of predictability and consistency, as well as the need to reduce rate-case lag, in its assessment of a utility's operating environment.[71] Foreshadowing its January 2006 downgrade, S&P concluded that the "pace and disposition" of APS' request for a PSA surcharge will be "critical to credit quality," with the rating agency expressing concern over APS' ability to recover power supply costs:

> [I]t 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.[72]

Coupled with the use of an historical test year and the potential for protracted proceedings, S&P concluded that "APS' near-term challenges are largely related to regulatory lag."[73]

Considering the magnitude of the events that have transpired since the third quarter of 2000, investors' sensitivity to market and regulatory uncertainties has increased

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[70] See, *e.g.*, Standard & Poor's Corporation, "Summary: Arizona Public Service Co.," *RatingsDirect* (Jan 6, 2006); Moody's Investors Service, "Rating Action: Arizona Public Service Company," *Credit Research* (Jan. 10, 2006); Fitch Ratings Ltd., "Fitch Places PNW and APS on Rating Watch Negative" (Jan. 6, 2006).

[71] Standard & Poor's Corporation, "U.S. Utility Regulation Returns to Center Stage," *RatingsDirect* (Apr. 14, 2005).

[72] Standard & Poor's Corporation, "Summary: Arizona Public Service Company," *RatingsDirect* (Oct. 4, 2005).

[73] Standard & Poor's Corporation, "Summary: Arizona Public Service Co.," *RatingsDirect* (Jun. 24, 2005).

dramatically. Investors have many alternatives and competition for capital is intense. Lingering uncertainties from a prior era, as well as new challenges in the electric power industry, breed reluctance to make the long-term commitment of capital that is required to ensure the reliable and economic supply of electricity that customers both demand and deserve. Thus, while customers might realize short-term "savings" through a downward-biased ROE, these will prove illusory when the utility is precluded from making investments that are consistent with providing sustained, high quality service at the lowest possible price in the long run.

B. Capital Structure

Q. IS AN EVALUATION OF THE CAPITAL STRUCTURE MAINTAINED BY A UTILITY RELEVANT IN ASSESSING ITS RETURN ON EQUITY?

A. Yes. Other things equal, a higher debt ratio, or lower common equity ratio, translates into increased financial risk for all investors. A greater amount of debt means more investors have a senior claim on available cash flow, thereby reducing the certainty that each will receive their contractual payments. This increases the risks to which lenders are exposed, and they require correspondingly higher rates of interest. From common shareholders' standpoint, a higher debt ratio means that there are proportionately more investors ahead of them, thereby increasing the uncertainty as to the amount of cash flow, if any, that will remain.

Q. WHAT COMMON EQUITY RATIO IS IMPLICIT IN APS' REQUESTED CAPITAL STRUCTURE?

A. APS' capital structure is presented in the testimony of Mr. Brandt. As summarized in his testimony, the common equity ratio used to compute APS' overall rate of return was approximately 55% in this filing.

Q. WHAT WAS THE AVERAGE CAPITALIZATION MAINTAINED BY THE REFERENCE GROUP OF UTILITIES?

A. As shown on Attachment WEA-8, for the ten firms in the proxy group, common equity ratios at December 31, 2004 ranged from 37.2% to 65.8% and averaged 49.7%.

Q. WHAT IMPLICATION DOES THE INCREASING RISK OF THE UTILITY INDUSTRY HAVE FOR THE CAPITAL STRUCTURES MAINTAINED BY UTILITIES?

A. The decline in credit quality in the electric industry is indicative of the need for utilities to strengthen their balance sheets to deal with an increasingly uncertain and competitive market. S&P cited higher debt leverage and the inadequacy of financial profiles in the electric industry as one of the key factors explaining this deterioration.[74] A more conservative financial profile is consistent with increasing uncertainties and the need to maintain the continuous access to capital that is required to fund operations and necessary system investment, even during times of adverse capital market conditions.

As shown on Attachment WEA-8, Value Line expects that the average common equity ratio for the proxy group of western utilities will increase to 55.6% over the next three to five years.

Q. HOW DOES APS' COMMON EQUITY RATIO COMPARE WITH THOSE MAINTAINED BY THE REFERENCE GROUP OF UTILITIES?

A. The 55% common equity ratio requested by APS falls well within the range of capitalizations maintained by the firms in the proxy group at year-end 2004 and is

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[74] See *e.g.*, Standard & Poor's Corporation, "Credit Quality For U.S. Utilities Continues Negative Trend", *RatingsDirect* (Jul. 24, 2003).

entirely consistent with the 55.6% equity ratio based on Value Line's expectations for the proxy group of Western utilities over the near-term.

Q. WHAT OTHER FACTORS DO INVESTORS CONSIDER IN THEIR ASSESSMENT OF A COMPANY'S CAPITAL STRUCTURE?

A. Depending on their specific attributes, contractual agreements that obligate the utility to make specified payments may be treated as debt in evaluating APS' financial risk. For example, payments related to APS' sale and leaseback of its interest in the Palo Verde Unit 2 generating unit, with an initial term of 29.5 years, are akin to those associated with traditional debt financing, and investors also recognize that APS has significant commitments under coal and natural gas commodity and transportation contracts. Because bond ratings agencies and investors consider the debt impact of such fixed obligations in assessing a utility's financial position, they imply greater risk and reduced financial flexibility.

As discussed earlier, a significant portion of APS' power requirements are obtained through long-term purchased power contracts. Because power purchase agreements ("PPAs") typically obligate the utility to make specified minimum contractual payments akin to those associated with traditional debt financing, investors consider a portion of these commitments as debt in evaluating total financial risks. Further, changes in financial accounting standards also result in adjustments that have the effect of further increasing financial leverage. Because bond ratings agencies and investors adjust for these various commitments in their assessment of credit standing, they imply greater risk and reduced financial flexibility.

Q. HOW DO PPAs IMPACT A UTILITY'S FINANCIAL POSITION?

A. When a utility enters into a PPA, the fixed charges associated with the contract increase the utility's financial risk in the same way that long-term debt and other financial obligations increase financial leverage. Under current accounting rules, the accounting for a PPA is not discretionary if the transaction meets specified tests for accounting for capital leases, which require that the obligation be explicitly recorded as a debt obligation on the utility's balance sheet.

As a result, the utility must rebalance its capital structure by increasing its common equity in order to restore its capitalization ratios to previous levels. Since the cost of equity exceeds the cost of debt, this rebalancing imposes additional costs, which are properly considered by regulators.

Q. DO PPAs THAT DO NOT MEET THE ACCOUNTING DEFINITION FOR CAPITAL LEASE TREATMENT STILL IMPACT INVESTORS' ASSESSMENT OF A UTILITY'S FINANCIAL RISKS?

A. Yes. The accounting standards simply reflect the longstanding perception of investors that the fixed obligations associated with PPAs diminish a utility's creditworthiness and financial flexibility. The implications of purchased power commitments have been repeatedly cited by major bond rating agencies in connection with assessments of utility financial risks.

For example, in reviewing its evaluation of the credit implications of PPAs, S&P affirmed its position that such agreements are "debt-like in nature" and that the increased financial risk must be considered in evaluating a utility's credit risks.[75] As the rating agency explained:

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[75] Standard & Poor's Corporation, "'Buy Versus Build': Debt Aspects of Purchased Power Agreements," *Utilities & Perspectives* (May 12, 2003).

> [P]urchased power agreements typically result in the assumption of fixed costs representing the portion of the purchase price that is linked to the capacity component of the total payment. These fixed capacity payments are similar to debt service payments incurred by a utility that constructs debt-financed power generation facilities. Therefore, whether a utility builds its own generating plants, or enters into a long-term power purchase agreement with a fixed-cost component, that utility is taking on a financial risk.[76]

When evaluating APS' financial risks, investors likewise recognize that the Company's contractual payment obligations under PPAs are fixed commitments with debt-like characteristics.

In addition to existing agreements, APS has issued a Request for Proposal to provide a total of at least 1,000 MW of summer capacity under long-term contracts. Unless APS takes action to offset this additional financial risk by maintaining a higher equity ratio, the resulting leverage will weaken the Company's creditworthiness and place downward pressure on its ratings, implying a higher required rate of return for APS' debt and equity securities.[77]

Q. WHAT DOES THIS EVIDENCE SUGGEST WITH RESPECT TO APS' PROPOSED CAPITAL STRUCTURE?

A. While industry averages provide one benchmark for comparison, each firm must select its capitalization based on the risks and prospects it faces, as well as its specific needs to access the capital markets. A public utility with an obligation to serve must maintain ready access to capital so that it can meet the service requirements of its customers. The need for access becomes even more important

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[76] Standard & Poor's Corporation, "Prepurchased Power and Its Implications for Public Power Ratings," *RatingsDirect* (Nov. 6, 2003).

[77] Apart from the immediate impact that the fixed obligation of purchased power costs has on the utility's financial risk, higher fixed charges also reduce ongoing financial flexibility, and the utility may face other uncertainties, such as potential replacement power costs in the event of supply disruption.

when the company has large capital requirements over a period of years, and financing must be continuously available, even during unfavorable capital market conditions.

The recent decision of S&P and Fitch to downgrade Central Vermont Public Service ("Central Vermont") from triple-B to below investment grade highlights the importance of maintaining sufficient common equity to preserve the utility's creditworthiness, even during times of stress. Despite a common equity ratio that exceeded 60%, S&P and Fitch determined that Central Vermont's financial position was inadequate to support an investment grade rating in the face of an unfavorable regulatory order.[78]

As indicated earlier, the challenges posed by a growing service area, volatile energy prices, and reliance on wholesale markets magnifies the importance of preserving financial flexibility. Under these circumstances, it is essential that APS' capital structure include the borrowing capacity necessary to ensure an ongoing ability to fund planned capital investments and meet the Company's service obligations. While financial flexibility plays a crucial role in ensuring the wherewithal to meet the needs of customers, utilities with higher leverage may be foreclosed from additional borrowing, especially during times of stress. In this regard, APS' equity ratio reflects the challenges posed by its resource mix, as well as the burden of significant capital spending requirements.

APS' proposed capital structure is just one reflection of the Company's ongoing efforts to preserve its credit standing and maintain access to capital on reasonable

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[78] "S&P Downgrades CVPS Corporate Credit Rating," *Business Wire* (June 14, 2005); "Fitch Ratings Downgrades CVPS," *Business Wire* (Jun. 20, 2005).

terms in order to ensure its ability to meet its obligations to customers. Indeed, Moody's specifically cited the Company's financial policies as support for its decision to revise its credit outlook from "negative" to "stable", concluding that:

> The change in outlook also reflects the company's [APS] demonstrated intent to improve its financial strength by financing a portion of its rising capital expenditures with equity.[79]

Conversely, Moody's also noted that "significant increases in capital expenditures that are financed in a manner inconsistent with the company's historically strong leverage ratios" (i.e., with more debt) could result in a ratings downgrade for APS.[80]

The reasonableness of APS' requested capital structure is reinforced by the ongoing uncertainties associated with the electric power industry, the Company's relative risks and circumstances, the need to support continued system investment, and the imperative of maintaining continuous access to capital, even during times of adverse industry and market conditions. As the experience of Central Vermont illustrates, even a healthy equity cushion may not be sufficient to support a utility's credit ratings when investors perceive a lack of regulatory support.

Q. WHAT DID YOU CONCLUDE WITH RESPECT TO APS' CAPITAL STRUCTURE?

A. Based on my evaluation, I concluded that APS' requested capital structure represents a reasonable mix of capital sources from which to calculate the Company's overall rate of return. APS' proposed capital structure is in line with

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[79] Moody's Investors Service, "Ratings Action: Arizona Public Service Company," *Global Credit Research* (Apr. 27, 2005).

[80] Moody's Investors Service, "Arizona Public Service Company," *Global Credit Research Credit Opinion* (Apr. 28, 2005).

industry standards, with an equity ratio of approximately 55% being consistent with the average capitalization projected for the proxy group of western electric utilities used to estimate the cost of equity. The reasonableness of this requested capital structure is reinforced by the need to support continued system investment in one of the fastest growing regions in the country. APS' proposed capital structure is just one reflection of the Company's ongoing efforts to enhance its credit standing and maintain access to capital on reasonable terms in order to ensure its ability to meet its obligations to customers.

C. Return on Equity Recommendation

Q. WHAT THEN IS YOUR CONCLUSION AS TO A FAIR ROE FOR APS?

A. As explained earlier, based on the various capital market oriented analyses described in my testimony, and after incorporating an adjustment for flotation costs, I concluded that the fair rate of return on equity range for the electric utility proxy group was 11.0% to 12.0%. Considering capital market expectations, the potential exposures faced by APS, and the economic requirements necessary to maintain financial integrity and support additional capital investment even under adverse circumstances, it is my opinion that the middle of this range, or approximately 11.5%, represents a fair and reasonable ROE for APS.

Q. IF THE ACC WERE TO REPEAL OR SUBSTANTIALLY MODIFY THE PSA MECHANISM FOR APS, WOULD THAT HAVE AN IMPACT ON THE COST OF EQUITY?

A. Most definitely. Considering the magnitude of the events that have transpired since the third quarter of 2000, investors' sensitivity to the uncertainties imposed by power market volatility has increased dramatically. S&P noted early on that without a mechanism to regularly adjust rates, escalating commodity prices could

create significant financial damage for retail service providers. S&P regards the lack of a PSA as one of the greatest impediments to financial stability:

> One of the most significant threats today to utilities' credit quality is uncertainty about the timely ability to pass power costs on to consumers. The issue for Standard & Poor's is this: To what lengths are regulators prepared to go to shelter ratepayers from the vagaries of the market and thereby threaten the financial strength of the utilities? ... To preserve credit quality, these companies must be able to adjust rates not just to cover the cost of procuring power, but also to deliver the appropriate price signals to consumers.[81]

Investors' required rates of return for utilities are premised on the regulatory compact that allows the utility an opportunity to recover reasonable and necessary costs. By sheltering utilities from exposure to extraordinary power cost volatility through a PSA, customers benefit from lower capital costs than they would otherwise bear. Of course, the corollary implies that shifting the burden of extraordinary risks to shareholders would have the effect of considerably increasing the cost of equity to APS, with the end-result being a greater cost of utility service to customers.

Q. WHAT COST OF EQUITY WOULD BE IMPLIED FOR APS IF THE PSA WAS REPEALED OR SUBSTANTIALLY NARROWED IN SCOPE?

A. Denying APS the ability to recover future power supply costs through a PSA mechanism would imply a significant increase in its investment risks relative to the proxy group of utilities used to estimate the cost of equity. Thus, if the ACC were to repeal, or substantially narrow the scope of the PSA, a higher rate of return on equity would be required to compensate investors for bearing the greater risks of energy market volatility. Moreover, given renewed focus on the importance of

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[81] Standard & Poor's, "California Aside, Regulatory Support for Utility Credit Quality Remains Intact", *RatingsDirect*, p. 2 (Jul. 13, 2001).

regulatory consistency and predictability, any renegotiation of a PSA mechanism that is already perceived as relatively weak by the investment community would send an alarming message that could impact the cost of capital for all Arizona utilities. Considering the investment community's increased sensitivity to such asymmetric risks, a rate of return on equity from at least the very top of my reasonable range, or 12%, would be warranted.

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes.

QUALIFICATIONS OF WILLIAM E. AVERA

I received a B.A. degree with a major in economics from Emory University. After serving in the United States Navy, I entered the doctoral program in economics at the University of North Carolina at Chapel Hill. Upon receiving my Ph.D., I joined the faculty at the University of North Carolina and taught finance in the Graduate School of Business. I subsequently accepted a position at the University of Texas at Austin where I taught courses in financial management and investment analysis. I then went to work for International Paper Company in New York City as Manager of Financial Education, a position in which I had responsibility for all corporate education programs in finance, accounting, and economics.

In 1977, I joined the staff of the Public Utility Commission of Texas (PUCT) as Director of the Economic Research Division. During my tenure at the PUCT, I managed a division responsible for financial analysis, cost allocation and rate design, economic and financial research, and data processing systems, and I testified in cases on a variety of financial and economic issues. Since leaving the PUCT in 1979, I have been engaged as a consultant. I have participated in a wide range of assignments involving utility-related matters on behalf of utilities, industrial customers, municipalities, and regulatory commissions. I have previously testified before the Federal Energy Regulatory Commission, as well as the Federal Communications Commission, the Surface Transportation Board (and its predecessor, the Interstate Commerce Commission), the Canadian Radio-Television and Telecommunications Commission, and regulatory agencies, courts, and legislative committees in over 30 states.

I was appointed by the PUCT to the Synchronous Interconnection Committee to advise the Texas legislature on the costs and benefits of connecting Texas to the national electric transmission

grid. In addition, I served as an outside director of Georgia System Operations Corporation, the system operator for electric cooperatives in Georgia.

I have served as Lecturer in the Finance Department at the University of Texas at Austin and taught in the evening graduate program at St. Edward's University for twenty years. In addition, I have lectured on economic and regulatory topics in programs sponsored by universities and industry groups. I have taught in hundreds of educational programs for financial analysts in programs sponsored by the Association for Investment Management and Research, the Financial Analysts Review, and local financial analysts societies. These programs have been presented in Asia, Europe, and North America, including the Financial Analysts Seminar at Northwestern University. I hold the *Chartered Financial Analyst* (CFA®) designation and have served as Vice President for Membership of the Financial Management Association. I also have served on the Board of Directors of the North Carolina Society of Financial Analysts. I was elected Vice Chairman of the National Association of Regulatory Commissioners (NARUC) Subcommittee on Economics and appointed to NARUC's Technical Subcommittee on the National Energy Act. I also have served as an officer of various other professional organizations and societies. A resume containing the details of my experience and qualifications is attached.

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Summary of Qualifications

Ph.D. in economics and finance; Chartered Financial Analyst (CFA ®) designation; extensive expert witness testimony before courts, alternative dispute resolution panels, regulatory agencies and legislative committees; lectured in executive education programs around the world on ethics, investment analysis, and regulation; undergraduate and graduate teaching in business and economics; appointed to leadership positions in government, industry, academia, and the military.

Employment

Principal, FINCAP, Inc. (Sep. 1979 to present)	Financial, economic and policy consulting to business and government. Perform business and public policy research, cost/benefit analyses and financial modeling, valuation of businesses (over 100 entities valued), estimation of damages, statistical and industry studies. Provide strategy advice and educational services in public and private sectors, and serve as expert witness before regulatory agencies, legislative committees, arbitration panels, and courts.
Director, Economic Research Division, Public Utility Commission of Texas (Dec. 1977 to Aug. 1979)	Responsible for research and testimony preparation on rate of return, rate structure, and econometric analysis dealing with energy, telecommunications, water and sewer utilities. Testified in major rate cases and appeared before legislative committees and served as Chief Economist for agency. Administered state and federal grant funds. Communicated frequently with political leaders and representatives from consumer groups, media, and investment community.
Manager, Financial Education, International Paper Company New York City (Feb. 1977 to Nov. 1977)	Directed corporate education programs in accounting, finance, and economics. Developed course materials, recruited and trained instructors, liaison within the company and with academic institutions. Prepared operating budget and designed financial controls for corporate professional development program.

Lecturer in Finance,
The University of Texas at Austin
(Sep. 1979 to May 1981)
Assistant Professor of Finance,
(Sep. 1975 to May 1977)

Taught graduate and undergraduate courses in financial management and investment theory. Conducted research in business and public policy. Named Outstanding Graduate Business Professor and received various administrative appointments.

Assistant Professor of Business,
University of North Carolina at Chapel Hill
(Sep. 1972 to Jul. 1975)

Taught in BBA, MBA, and Ph.D. programs. Created project course in finance, Financial Management for Women, and participated in developing Small Business Management sequence. Organized the North Carolina Institute for Investment Research, a group of financial institutions that supported academic research. Faculty advisor to the Media Board, which funds student publications and broadcast stations.

Education

Ph.D., Economics and Finance,
University of North Carolina at Chapel Hill
(Jan. 1969 to Aug. 1972)

Elective courses included financial management, public finance, monetary theory, and econometrics. Awarded the Stonier Fellowship by the American Bankers' Association and University Teaching Fellowship. Taught statistics, macroeconomics, and microeconomics.

Dissertation: *The Geometric Mean Strategy as a Theory of Multiperiod Portfolio Choice*

B.A., Economics,
Emory University, Atlanta, Georgia
(Sep. 1961 to Jun. 1965)

Active in extracurricular activities, president of the Barkley Forum (debate team), Emory Religious Association, and Delta Tau Delta chapter. Individual awards and team championships at national collegiate debate tournaments.

Professional Associations

Received Chartered Financial Analyst (CFA) designation in 1977; Vice President for Membership, Financial Management Association; President, Austin Chapter of Planning Executives Institute; Board of Directors, North Carolina Society of Financial Analysts; Candidate Curriculum Committee, Association for Investment Management and Research; Executive Committee of Southern Finance Association; Vice Chair, Staff Subcommittee on Economics and National Association of Regulatory Utility Commissioners (NARUC); Appointed to NARUC Technical Subcommittee on the National Energy Act.

Teaching in Executive Education Programs

University-Sponsored Programs: Central Michigan University, Duke University, Louisiana State University, National Defense University, National University of Singapore, Texas A&M University, University of Kansas, University of North Carolina, University of Texas.

Business and Government-Sponsored Programs: Advanced Seminar on Earnings Regulation, American Public Welfare Association, Association for Investment Management and Research, Congressional Fellows Program, Cost of Capital Workshop, Electricity Consumers Resource Council, Financial Analysts Association of Indonesia, Financial Analysts Review, Financial Analysts Seminar at Northwestern University, Governor's Executive Development Program of Texas, Louisiana Association of Business and Industry, National Association of Purchasing Management, National Association of Tire Dealers, Planning Executives Institute, School of Banking of the South, State of Wisconsin Investment Board, Stock Exchange of Thailand, Texas Association of State Sponsored Computer Centers, Texas Bankers' Association, Texas Bar Association, Texas Savings and Loan League, Texas Society of CPAs, Tokyo Association of Foreign Banks, Union Bank of Switzerland, U.S. Department of State, U.S. Navy, U.S. Veterans Administration, in addition to Texas state agencies and major corporations.

Presented papers for Mills B. Lane Lecture Series at the University of Georgia and Heubner Lectures at the University of Pennsylvania. Taught graduate courses in finance and economics in evening program at St. Edward's University in Austin from January 1979 through 1998.

Expert Witness Testimony

Testified in over 200 cases before regulatory agencies addressing cost of capital, rate design, and other economic and financial issues.

Federal Agencies: Federal Communications Commission, Federal Energy Regulatory Commission, Surface Transportation Board, Interstate Commerce Commission, and the Canadian Radio-Television and Telecommunications Commission.

State Regulatory Agencies: Alaska, Arizona, Arkansas, California, Colorado, Connecticut, Delaware, Florida, Hawaii, Idaho, Illinois, Indiana, Kansas, Maryland, Michigan, Missouri, Nevada, New Mexico, North Carolina, Ohio, Oklahoma, Oregon, Pennsylvania, South Carolina, Texas, Virginia, Washington, West Virginia, and Wisconsin.

Testified in over 30 cases before federal and state courts, arbitration panels, and alternative dispute tribunals (over 60 depositions given) regarding damages, valuation, antitrust liability, fiduciary duties, and other economic and financial issues.

Board Positions and Other Professional Activities

Audit Committee and Outside Director, Georgia System Operations Corporation (electric system operator for member-owned electric cooperatives in Georgia); Chairman, Board of Print Depot, Inc. and FINCAP, Inc.; Co-chair, Synchronous Interconnection Committee, appointed by Governor George Bush and Public Utility Commission of Texas; Operator of AAA Ranch, a certified organic producer of agricultural products; Appointed to Organic Livestock Advisory Committee by Texas Agricultural Commissioner Susan Combs; Appointed by Texas Railroad Commissioners to study group for *The UP/SP Merger: An Assessment of the Impacts on the State of Texas;* Appointed by Hawaii Public Utilities Commission to team reviewing affiliate relationships of Hawaiian Electric Industries; Chairman, Energy Task Force, Greater Austin-San Antonio Corridor Council; Consultant to Public Utility Commission of Texas on cogeneration policy and other matters; Consultant to Public Service Commission of New Mexico on cogeneration policy; Evaluator of Energy Research Grant Proposals for Texas Higher Education Coordinating Board.

Community Activities

Board Member, Sustainable Food Center; Chair, Board of Deacons, Finance Committee, and Elder, Central Presbyterian Church of Austin; Founding Member, Orange-Chatham County (N.C.) Legal Aid Screening Committee.

Military

Captain, U.S. Naval Reserve (retired after 28 years service); Commanding Officer, Naval Special Warfare (SEAL) Engineering Support Unit; Officer-in-charge of SWIFT patrol boat in Vietnam; Enlisted service as weather analyst (advanced to second class petty officer).

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"Liquidity, Exchange Listing, and Common Stock Performance," with John C. Groth and Kerry Cooper, *Journal of Economics and Business* (Spring 1985); reprinted by National Association of Security Dealers

"The Energy Crisis and the Homeowner: The Grief Process," *Texas Business Review* (Jan.–Feb. 1980); reprinted in *The Energy Picture: Problems and Prospects*, J. E. Pluta, ed., Bureau of Business Research (1980)

"Use of IFPS at the Public Utility Commission of Texas," *Proceedings of the IFPS Users Group Annual Meeting* (1979)

"Production Capacity Allocation: Conversion, CWIP, and One-Armed Economics," *Proceedings of the NARUC Biennial Regulatory Information Conference* (1978)

"Some Thoughts on the Rate of Return to Public Utility Companies," with Bruce H. Fairchild in *Proceedings of the NARUC Biennial Regulatory Information Conference* (1978)

"A New Capital Budgeting Measure: The Integration of Time, Liquidity, and Uncertainty," with David Cordell in *Proceedings of the Southwestern Finance Association* (1977)

"Usefulness of Current Values to Investors and Creditors," in *Inflation Accounting/Indexing and Stock Behavior* (1977)

"Consumer Expectations and the Economy," *Texas Business Review* (Nov. 1976)

"Portfolio Performance Evaluation and Long-run Capital Growth," with Henry A. Latané in *Proceedings of the Eastern Finance Association* (1973)

Book reviews in *Journal of Finance* and *Financial Review*. Abstracts for *CFA Digest*. Articles in *Carolina Financial Times*.

Selected Papers and Presentations

"The Who, What, When, How, and Why of Ethics", San Antonio Financial Analysts Society (Jan. 16, 2002). Similar presentation given to the Austin Society of Financial Analysts (Jan. 17, 2002)

"Ethics for Financial Analysts," Sponsored by Canadian Council of Financial Analysts: delivered in Calgary, Edmonton, Regina, and Winnipeg, June 1997. Similar presentations given to Austin Society of Financial Analysts (Mar. 1994), San Antonio Society of Financial Analysts (Nov. 1985), and St. Louis Society of Financial Analysts (Feb. 1986)

"Cost of Capital for Multi-Divisional Corporations," Financial Management Association, New Orleans, Louisiana (Oct. 1996)

"Ethics and the Treasury Function," Government Treasurers Organization of Texas, Corpus Christi, Texas (Jun. 1996)

"A Cooperative Future," Iowa Association of Electric Cooperatives, Des Moines (December 1995). Similar presentations given to National G & T Conference, Irving, Texas (June 1995), Kentucky Association of Electric Cooperatives Annual Meeting, Louisville (Nov. 1994), Virginia, Maryland, and Delaware Association of Electric Cooperatives Annual Meeting, Richmond (July 1994), and Carolina Electric Cooperatives Annual Meeting, Raleigh (Mar. 1994)

"Information Superhighway Warnings: Speed Bumps on Wall Street and Detours from the Economy," Texas Society of Certified Public Accountants Natural Gas, Telecommunications and Electric Industries Conference, Austin (Apr. 1995)

"Economic/Wall Street Outlook," Carolinas Council of the Institute of Management Accountants, Myrtle Beach, South Carolina (May 1994). Similar presentation given to Bell Operating Company Accounting Witness Conference, Santa Fe, New Mexico (Apr. 1993)

"Regulatory Developments in Telecommunications," Regional Holding Company Financial and Accounting Conference, San Antonio (Sep. 1993)

"Estimating the Cost of Capital During the 1990s: Issues and Directions," The National Society of Rate of Return Analysts, Washington, D.C. (May 1992)

"Making Utility Regulation Work at the Public Utility Commission of Texas," Center for Legal and Regulatory Studies, University of Texas, Austin (June 1991)

"Can Regulation Compete for the Hearts and Minds of Industrial Customers," Emerging Issues of Competition in the Electric Utility Industry Conference, Austin (May 1988)

"The Role of Utilities in Fostering New Energy Technologies," Emerging Energy Technologies in Texas Conference, Austin (Mar. 1988)

"The Regulators' Perspective," Bellcore Economic Analysis Conference, San Antonio (Nov. 1987)

"Public Utility Commissions and the Nuclear Plant Contractor," Construction Litigation Superconference, Laguna Beach, California (Dec. 1986)

"Development of Cogeneration Policies in Texas," University of Georgia Fifth Annual Public Utilities Conference, Atlanta (Sep. 1985)

"Wheeling for Power Sales," Energy Bureau Cogeneration Conference, Houston (Nov. 1985).

"Asymmetric Discounting of Information and Relative Liquidity: Some Empirical Evidence for Common Stocks" (with John Groth and Kerry Cooper), Southern Finance Association, New Orleans (Nov. 1982)

"Used and Useful Planning Models," Planning Executive Institute, 27th Corporate Planning Conference, Los Angeles (Nov. 1979)

"Staff Input to Commission Rate of Return Decisions," The National Society of Rate of Return Analysts, New York (Oct. 1979)

"Electric Rate Design in Texas," Southwestern Economics Association, Fort Worth (Mar. 1979)

"Discounted Cash Life: A New Measure of the Time Dimension in Capital Budgeting," with David Cordell, Southern Finance Association, New Orleans (Nov. 1978)

"The Relative Value of Statistics of Ex Post Common Stock Distributions to Explain Variance," with Charles G. Martin, Southern Finance Association, Atlanta (Nov. 1977)

"An ANOVA Representation of Common Stock Returns as a Framework for the Allocation of Portfolio Management Effort," with Charles G. Martin, Financial Management Association, Montreal (Oct. 1976)

"A Growth-Optimal Portfolio Selection Model with Finite Horizon," with Henry A. Latané, American Finance Association, San Francisco (Dec. 1974)

"An Optimal Approach to the Finance Decision," with Henry A. Latané, Southern Finance Association, Atlanta (Nov. 1974)

"A Pragmatic Approach to the Capital Structure Decision Based on Long-Run Growth," with Henry A. Latané, Financial Management Association, San Diego (Oct. 1974)

"Multi-period Wealth Distributions and Portfolio Theory," Southern Finance Association, Houston (Nov. 1973)

"Growth Rates, Expected Returns, and Variance in Portfolio Selection and Performance Evaluation," with Henry A. Latané, Econometric Society, Oslo, Norway (Aug. 1973)

CONSTANT GROWTH DCF MODEL

EXPECTED DIVIDEND YIELD

Company	(a) Recent Price	(a) Estimated Dividends Next 12 Mos.	Dividend Yield
Black Hills Corp.	$ 42.02	$ 1.31	3.1%
Edison International	$ 45.55	$ 1.10	2.4%
Hawaiian Electric	$ 27.23	$ 1.24	4.6%
IDACORP, Inc.	$ 29.18	$ 1.20	4.1%
MDU Resources Group	$ 35.03	$ 0.76	2.2%
PNM Resources Group	$ 28.08	$ 0.80	2.8%
Pinnacle West Capital	$ 43.59	$ 1.96	4.5%
Puget Energy, Inc.	$ 22.47	$ 1.00	4.5%
Sempra Energy	$ 44.87	$ 1.18	2.6%
Xcel Energy	$ 18.98	$ 0.87	4.6%
Average			3.5%

(a) The Value Line Investment Survey, Summary and Index (Oct. 14, 2005).

CONSTANT GROWTH DCF MODEL

PROJECTED GROWTH RATES

	Earnings				
	(a)	(b)	(c)	(d)	(e)
Company	IBES	Value Line	First Call	Zacks	Reuters
Black Hills Corp.	5.0%	2.5%	5.0%	6.0%	5.0%
Edison International	7.0%	7.0%	6.5%	7.5%	8.0%
Hawaiian Electric	3.0%	2.5%	3.0%	3.5%	2.6%
IDACORP, Inc.	4.0%	6.0%	4.0%	4.3%	4.2%
MDU Resources Group	7.0%	8.5%	7.5%	7.7%	6.6%
PNM Resources Group	11.0%	8.0%	12.0%	7.7%	12.0%
Pinnacle West Capital	5.0%	3.5%	4.5%	5.2%	4.6%
Puget Energy, Inc.	4.0%	5.5%	4.0%	4.8%	4.6%
Sempra Energy	5.0%	3.5%	5.0%	5.9%	5.6%
Xcel Energy	3.0%	7.5%	3.0%	4.2%	4.0%
Average	**5.4%**	**5.5%**	**5.5%**	**5.7%**	**5.7%**

NA -- Not Available

(a) I/B/E/S International growth rates from Standard & Poor's Earnings Guide, (Oct. 2005).
(b) The Value Line Investment Survey (Aug. 12, 2005).
(c) First Call Earnings Estimates from www.finance.yahoo.com (Oct. 3, 2005).
(d) Zacks Investment Research growth estimates from www.zacks.com (Oct. 3, 2005).
(e) Reuters earnings growth rates from www.investor.reuters.com (Oct. 3, 2005).

CONSTANT GROWTH DCF MODEL

SUSTAINABLE GROWTH RATE

	(a)	(a)	(a)	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Projections 2008-10			2004		Mid-Year					
Company	EPS	DPS	Net Book Value	Net Book Value	Annual Change	Adjustment Factor	"b"	Adjusted "r"	"b x r" growth	"sv" Factor	Sustainable Growth
Black Hills Corp.	$2.25	$1.44	$26.25	$22.43	3.2%	1.0157	36.0%	8.7%	3.1%	0.12%	3.3%
Edison International	$2.45	$1.40	$24.15	$18.57	5.4%	1.0263	42.9%	10.4%	4.5%	0.01%	4.5%
Hawaiian Electric	$1.75	$1.24	$17.25	$15.01	2.8%	1.0139	29.1%	10.3%	3.0%	0.03%	3.0%
IDACORP, Inc.	$2.10	$1.20	$28.10	$23.88	3.3%	1.0163	42.9%	7.6%	3.3%	0.06%	3.3%
MDU Resources Group	$2.50	$0.90	$22.25	$14.09	9.6%	1.0457	64.0%	11.7%	7.5%	1.17%	8.7%
PNM Resources Group	$1.95	$1.09	$23.25	$18.19	5.0%	1.0245	44.1%	8.6%	3.8%	0.38%	4.2%
Pinnacle West Capital	$3.15	$2.33	$37.25	$32.14	3.0%	1.0148	26.0%	8.6%	2.2%	0.30%	2.5%
Puget Energy, Inc.	$1.75	$1.12	$19.50	$16.24	3.7%	1.0183	36.0%	9.1%	3.3%	0.33%	3.6%
Sempra Energy	$4.00	$1.32	$33.75	$20.78	10.2%	1.0485	67.0%	12.4%	8.3%	0.95%	9.3%
Xcel Energy	$1.50	$1.05	$15.25	$12.99	3.3%	1.0160	30.0%	10.0%	3.0%	0.66%	3.7%
Average											**4.6%**

(a) The Value Line Investment Survey (Aug. 12, 2005).
(b) Annual growth in book value per share from 2004 to 2008-10.
(c) Equal to 2(1+b)/(2+b), where b = annual change in net book value.
(d) (EPS-DPS)/EPS.
(e) (EPS/2008-10 Net Book Value) x Mid-Year Adjustment Factor.
(f) (d) x (e).
(g) "s" equals projected market-to-book ratio x growth in common shares. "v" equals (1- 1/projected market-to-book ratio).
(h) (f) + (g).

AUTHORIZED RATES OF RETURN -- CURRENT YIELD

YEAR	(a) ALLOWED ROE	(b) AVERAGE PUBLIC UTILITY BOND YIELD	RISK PREMIUM
1974	13.10%	9.27%	3.83%
1975	13.20%	9.88%	3.32%
1976	13.10%	9.17%	3.93%
1977	13.30%	8.58%	4.72%
1978	13.20%	9.22%	3.98%
1979	13.50%	10.39%	3.11%
1980	14.23%	13.15%	1.08%
1981	15.22%	15.62%	-0.40%
1982	15.78%	15.33%	0.45%
1983	15.36%	13.31%	2.05%
1984	15.32%	14.03%	1.29%
1985	15.20%	12.29%	2.91%
1986	13.93%	9.46%	4.47%
1987	12.99%	9.98%	3.01%
1988	12.79%	10.45%	2.34%
1989	12.97%	9.66%	3.31%
1990	12.70%	9.76%	2.94%
1991	12.55%	9.21%	3.34%
1992	12.09%	8.57%	3.52%
1993	11.41%	7.56%	3.85%
1994	11.34%	8.30%	3.04%
1995	11.55%	7.91%	3.64%
1996	11.39%	7.74%	3.65%
1997	11.40%	7.63%	3.77%
1998	11.66%	7.00%	4.66%
1999	10.77%	7.55%	3.22%
2000	11.43%	8.14%	3.29%
2001	11.09%	7.72%	3.37%
2002	11.16%	7.50%	3.66%
2003	10.97%	6.61%	4.36%
2004	10.73%	6.20%	4.53%
Average		9.59%	3.17%

Regression Output	
Constant	0.07299
Std Err of Y Est	0.00557
R Squared	0.79192
No. of Observations	31
Degrees of Freedom	29
X Coefficient(s)	-0.43083
Std Err of Coef.	0.04101

Current Equity Risk Premium	
Avg. Yield over Study Period	9.59%
Aug. 2005 Avg. Utility Bond Yield (c)	5.51%
Change in Bond Yield	-4.08%
Risk Premium/Interest Rate Relationship	-43.08%
Adjustment to Average Risk Premium	1.76%
Average Risk Premium over Study Period	3.17%
Adjusted Risk Premium	4.93%

(a) Regulatory Research Associates, Major Rate Case Decisions, January 1990 - December 2004, *Regulatory Focus* (January 2005); Major Rate Case Decisions, *Regulatory Focus*, (January 16, 1990); Argus, *UtilityScope Regulatory Service* (January 1986).

(b) Moody's *Public Utility Manual* (2003); Moody's *Credit Perspectives* (various editions); Mergent *Bond Record* (various editions).

(c) Moody's *Credit Perspectives* (Oct. 3, 2005).

AUTHORIZED RATES OF RETURN – 2006 YIELD

YEAR	(a) ALLOWED ROE	(b) AVERAGE PUBLIC UTILITY BOND YIELD	RISK PREMIUM
1974	13.10%	9.27%	3.83%
1975	13.20%	9.88%	3.32%
1976	13.10%	9.17%	3.93%
1977	13.30%	8.58%	4.72%
1978	13.20%	9.22%	3.98%
1979	13.50%	10.39%	3.11%
1980	14.23%	13.15%	1.08%
1981	15.22%	15.62%	-0.40%
1982	15.78%	15.33%	0.45%
1983	15.36%	13.31%	2.05%
1984	15.32%	14.03%	1.29%
1985	15.20%	12.29%	2.91%
1986	13.93%	9.46%	4.47%
1987	12.99%	9.98%	3.01%
1988	12.79%	10.45%	2.34%
1989	12.97%	9.66%	3.31%
1990	12.70%	9.76%	2.94%
1991	12.55%	9.21%	3.34%
1992	12.09%	8.57%	3.52%
1993	11.41%	7.56%	3.85%
1994	11.34%	8.30%	3.04%
1995	11.55%	7.91%	3.64%
1996	11.39%	7.74%	3.65%
1997	11.40%	7.63%	3.77%
1998	11.66%	7.00%	4.66%
1999	10.77%	7.55%	3.22%
2000	11.43%	8.14%	3.29%
2001	11.09%	7.72%	3.37%
2002	11.16%	7.50%	3.66%
2003	10.97%	6.61%	4.36%
2004	10.73%	6.20%	4.53%
Average		9.59%	3.17%

Regression Output	
Constant	0.07299
Std Err of Y Est	0.00557
R Squared	0.79192
No. of Observations	31
Degrees of Freedom	29
X Coefficient(s)	-0.43083
Std Err of Coef.	0.04101

Current Equity Risk Premium	
Avg. Yield over Study Period	9.59%
2006 Avg. Utility Bond Yield (c)	6.80%
Change in Bond Yield	-2.79%
Risk Premium/Interest Rate Relationship	-43.08%
Adjustment to Average Risk Premium	1.20%
Average Risk Premium over Study Period	3.17%
Adjusted Risk Premium	4.37%

(a) Regulatory Research Associates, Major Rate Case Decisions, January 1990 - December 2004, *Regulatory Focus* (January 2005); Major Rate Case Decisions, *Regulatory Focus*, (January 16, 1990); Argus, *UtilityScope Regulatory Service* (January 1986).

(b) Mergent *Public Utility Manual* (2003); Moody's *Credit Perspectives* (various editions); Mergent *Bond Record* (various editions).

(c) Projected yield on public utility bonds for 2006 based on interest rate forecasts reported by GlobalInsight, *The U.S. Economy: The 25-Year Focus* (First Quarter 2005), EIA, *Annual Energy Outlook* (2005), and Blue Chip Financial Forecasts (Sep. 1, 2005).

REALIZED RATES OF RETURN

	S&P ELECTRIC UTILITIES (a)			AVERAGE PUBLIC UTILITY BONDS (b)		
	CLOSE PRICE	DIV	ANNUAL REALIZED RETURN	CLOSE YIELD	PRICE	ANNUAL REALIZED RETURN
1945	$16.34		(c)	2.79%		(d)
1946	$15.53	$0.73	-0.49%	2.77%	$100.36	3.15%
1947	$12.89	$0.75	-12.17%	3.02%	$95.66	-1.57%
1948	$12.37	$0.71	1.47%	3.06%	$99.31	2.33%
1949	$14.60	$0.80	24.49%	2.79%	$104.81	7.87%
1950	$14.49	$0.88	5.27%	2.87%	$98.59	1.38%
1951	$16.07	$0.92	17.25%	3.24%	$93.73	-3.40%
1952	$18.28	$0.95	19.66%	3.19%	$100.85	4.09%
1953	$18.97	$0.99	9.19%	3.37%	$96.99	0.18%
1954	$22.39	$1.03	23.46%	3.10%	$104.65	8.02%
1955	$24.06	$1.09	12.33%	3.31%	$96.47	-0.43%
1956	$23.61	$1.13	2.83%	3.93%	$90.24	-6.45%
1957	$24.85	$1.19	10.29%	4.29%	$94.54	-1.53%
1958	$33.14	$1.24	38.35%	4.39%	$98.50	2.79%
1959	$33.42	$1.30	4.77%	4.86%	$93.28	-2.33%
1960	$39.35	$1.37	21.84%	4.58%	$104.12	8.98%
1961	$49.28	$1.44	28.89%	4.62%	$99.41	3.99%
1962	$48.60	$1.52	1.70%	4.41%	$103.14	7.76%
1963	$51.97	$1.63	10.29%	4.49%	$98.81	3.22%
1964	$58.21	$1.74	15.36%	4.54%	$99.26	3.75%
1965	$58.05	$1.90	2.99%	4.82%	$95.98	0.52%
1966	$53.49	$2.04	-4.34%	5.65%	$89.03	-6.15%
1967	$49.90	$2.16	-2.67%	6.57%	$88.85	-5.50%
1968	$51.95	$2.27	8.66%	6.85%	$96.69	3.26%
1969	$42.65	$2.33	-13.42%	8.39%	$84.09	-9.06%
1970	$45.62	$2.40	12.59%	8.45%	$99.38	7.77%
1971	$44.18	$2.47	2.26%	7.92%	$105.70	14.15%
1972	$43.50	$2.53	4.19%	7.48%	$104.91	12.83%
1973	$32.85	$2.51	-18.71%	8.17%	$92.74	0.22%
1974	$22.03	$2.49	-25.36%	10.02%	$83.23	-8.60%
1975	$30.56	$2.57	50.39%	9.87%	$101.38	11.40%
1976	$35.17	$2.58	23.53%	8.61%	$112.78	22.65%
1977	$35.67	$2.74	9.21%	8.65%	$99.60	8.21%
1978	$31.38	$2.94	-3.78%	9.67%	$90.50	-0.85%
1979	$28.44	$3.10	0.51%	11.68%	$83.88	-6.45%
1980	$27.19	$3.20	6.86%	14.48%	$81.32	-7.00%
1981	$29.33	$3.42	20.45%	15.77%	$92.03	6.51%
1982	$36.15	$3.62	35.59%	13.55%	$115.70	31.47%
1983	$37.14	$3.84	13.36%	13.48%	$100.50	14.05%
1984	$42.26	$4.06	24.72%	12.96%	$103.82	17.30%
1985	$48.82	$4.15	25.34%	10.82%	$118.26	31.22%
1986	$58.31	$4.21	28.06%	8.96%	$118.33	29.15%
1987	$49.78	$4.34	-7.19%	10.99%	$82.89	-8.15%
1988	$53.87	$4.37	16.99%	10.02%	$108.79	19.78%
1989	$66.55	$4.28	31.48%	9.31%	$106.80	16.82%
1990	$63.47	$4.45	2.06%	9.57%	$97.56	6.87%
1991	$77.25	$4.57	28.91%	8.76%	$108.11	17.68%
1992	$76.78	$4.68	5.45%	8.36%	$104.14	12.90%
1993	$81.71	$4.71	12.56%	7.33%	$111.65	20.01%
1994	$66.30	$4.65	-13.17%	8.79%	$85.41	-7.26%
1995	$81.62	$4.67	30.15%	7.21%	$118.07	26.86%
1996	$76.75	$4.61	-0.32%	7.58%	$95.90	3.11%
1997	$91.49	$4.47	25.03%	7.16%	$104.82	12.40%
1998	$100.86	$4.39	15.04%	6.84%	$103.78	10.94%
1999	$77.42	$4.35	-18.93%	8.04%	$87.23	-5.93%
2000	$113.00	$4.42	51.67%	7.79%	$102.72	10.76%
2001	$99.70	$3.56	-8.62%	7.86%	$99.24	7.03%
2002	$77.85	$3.88	-18.02%	7.13%	$108.41	16.27%
2003	$92.63	$3.47	23.45%	6.35%	$109.60	17.46%
2004	$112.82	$3.67	25.75%	5.93%	$105.40	12.53%
AVERAGE 1946-2004			10.81%			6.76%

REALIZED RATE OF RETURN	
S&P ELECTRIC UTILITIES	10.81%
PUBLIC UTILITY BONDS	6.76%
EQUITY RISK PREMIUM	4.04%

(a) S&P's *Security Price Index Record* (2002), *The Analysts' Handbook* (1967, 1999, 2001, 2004, Monthly Supplement April 2005).
(b) Average public utility bond yields for December from Mergent *Public Utility Manual* (2003), Mergent *Bond Record* (Feb. 2005).
(c) Computed by adding gain or loss (ending stock price - beginning stock price) to annual dividends and dividing by beginning stock price.
(d) Computed as sum of capital gain or loss plus interest income, divided by beginning price.

CAPITAL ASSET PRICING MODEL

FORWARD-LOOKING RISK PREMIUM - CURRENT ESTIMATE

Market Rate of Return		
Dividend Yield (a)	2.1%	
Growth Rate (b)	11.4%	
Market Return (c)		13.5%
Less: Risk-Free Rate (d)		
Long-term Treasury Bond Yield		4.5%
Market Risk Premium (e)		9.0%
Utility Proxy Group Beta (f)		0.89
Utility Proxy Group Risk Premium (g)		8.0%
Plus: Risk-free Rate (d)		
Long-term Treasury Bond Yield		4.5%
Implied Cost of Equity (h)		**12.5%**

(a) Weighted average dividend yield for the dividend paying firms in the S&P 500 from www.valueline.com (Oct. 7, 2005).
(b) Weighted average of IBES and Value Line growth rates for the dividend paying firms in the S&P 500 based on data from Standard & Poor's *Earnings Guide* (Sep. 2005) and www.valueline.com (Oct. 7, 2005).
(c) (a) + (b)
(d) Average of the daily yields on 20-year Treasury bonds for September 2005 reported by the U.S. Department of the Treasury at www.treas.gov.
(e) (c) - (d).
(f) The Value Line Investment Survey (Aug. 12, 2005).
(g) (e) x (f).
(h) (d) + (g).

FORWARD-LOOKING RISK PREMIUM - RATE YEAR ESTIMATE

Market Rate of Return		
Dividend Yield (a)	2.1%	
Growth Rate (b)	11.4%	
Market Return (c)		13.5%
Less: Risk-Free Rate (d)		
Long-term Treasury Bond Yield		5.5%
Market Risk Premium (e)		8.0%
Utility Proxy Group Beta (f)		0.89
Utility Proxy Group Risk Premium (g)		7.1%
Plus: Risk-free Rate (d)		
Long-term Treasury Bond Yield		5.5%
Implied Cost of Equity (h)		**12.6%**

(a) Weighted average dividend yield for the dividend paying firms in the S&P 500 from www.valueline.com (Oct. 7, 2005).

(b) Weighted average of IBES and Value Line growth rates for the dividend paying firms in the S&P 500 based on data from Standard & Poor's *Earnings Guide* (Sep. 2005) and www.valueline.com (Oct. 7, 2005).

(c) (a) + (b)

(d) Projected yield on 20-year Treasury bonds for 2006 based on interest rate forecasts reported by GlobalInsight, *The U.S. Economy: The 25-Year Focus* (First Quarter 2005), Energy Information Administration, *Annual Energy Outlook* (2005), and Blue Chip Financial Forecasts (Sep. 1, 2005).

(e) (c) - (d).

(f) The Value Line Investment Survey (Aug. 12, 2005).

(g) (e) x (f).

(h) (d) + (g).

CAPITAL ASSET PRICING MODEL

HISTORICAL RISK PREMIUM - CURRENT ESTIMATE

Market Risk Premium	
Long-Horizon Equity Risk Premium (a)	7.2%
Utility Proxy Group Beta (b)	0.89
Utility Proxy Group Risk Premium (c)	6.4%
Plus: Risk-free Rate (d)	
Long-term Treasury Bond Yield	4.5%
Implied Cost of Equity (e)	**10.9%**

(a) Arithmetic mean return on Large Company Stocks from 1926-2004 reported by Ibbotson Associates, *Stocks, Bonds, Bills, and Inflation, Valuation Edition, 2005 Yearbook*, at 81.
(b) The Value Line Investment Survey (Aug. 12, 2005).
(c) (a) x (b).
(d) Average of the daily yields on 20-year Treasury bonds for September 2005 reported by the U.S. Department of the Treasury at www.treas.gov.
(e) (c) + (d).

HISTORICAL RISK PREMIUM - RATE YEAR ESTIMATE

Market Risk Premium	
Long-Horizon Equity Risk Premium (a)	7.2%
Utility Proxy Group Beta (b)	0.89
Utility Proxy Group Risk Premium (c)	6.4%
Plus: Risk-free Rate (d)	
Long-term Treasury Bond Yield	5.5%
Implied Cost of Equity (e)	**11.9%**

(a) Arithmetic mean return on Large Company Stocks from 1926-2004 reported by Ibbotson Associates, *Stocks, Bonds, Bills, and Inflation, Valuation Edition, 2005 Yearbook*, at 81.

(b) The Value Line Investment Survey (Aug. 12, 2005).

(c) (a) x (b).

(d) Projected yield on 20-year Treasury bonds for 2006 based on interest rate forecasts reported by GlobalInsight, *The U.S. Economy: The 25-Year Focus* (First Quarter 2005), Energy Information Administration, *Annual Energy Outlook* (2005), and Blue Chip Financial Forecasts (Sep. 1, 2005).

(e) (c) + (d).

PROXY GROUP CAPITAL STRUCTURE

	At December 31, 2004 (a)			Value Line Projected 2008-10 (b)		
Company	Long-term Debt	Preferred	Common Equity	Long-term Debt	Other	Common Equity
Black Hills Corp.	50.3%	0.5%	49.2%	43.0%	0.5%	56.5%
Edison International	61.3%	1.6%	37.2%	51.5%	1.5%	47.0%
Hawaiian Electric	48.4%	1.4%	50.2%	45.0%	1.0%	54.0%
IDACORP, Inc.	51.2%	0.0%	48.8%	47.0%	0.0%	53.0%
MDU Resources Group	36.0%	0.6%	63.4%	23.5%	0.0%	76.5%
PNM Resources Group	47.1%	0.5%	52.4%	48.5%	0.5%	51.0%
Pinnacle West Capital	52.0%	0.0%	48.0%	45.0%	0.0%	55.0%
Puget Energy, Inc.	54.1%	6.8%	39.1%	56.5%	0.5%	43.0%
Sempra Energy	34.2%	0.0%	65.8%	31.0%	1.5%	67.5%
Xcel Energy	55.8%	0.9%	43.3%	47.5%	0.5%	52.0%
Average	**49.0%**	**1.2%**	**49.7%**	**43.9%**	**0.6%**	**55.6%**

(a) Company Form 10-K and Annual Reports.

(b) The Value Line Investment Survey (Aug. 12, 2005).

ED Z. FOX

DIRECT TESTIMONY OF EDWARD Z. FOX

On Behalf of Arizona Public Service Company

Docket No. E-01345A-05-0816

January 31, 2006

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DIRECT TESTIMONY OF EDWARD Z. FOX
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-05-0816)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Edward Z. Fox. My business address is 400 North 5th Street, Phoenix, Arizona 85004.

Q. WHAT IS YOUR POSITION AND WHAT ARE YOUR RESPONSIBILITIES AT APS?

A. I am Vice President of Communications, Environment and Safety for Arizona Public Service Company ("APS" or "Company"). In that capacity, I am responsible for environmental, health and safety compliance and policy, as well as corporate communications and communications-related policies. I oversee APS programs that identify and help find system applications for new technologies, such as fuel cells, and I oversee the implementation of the Environmental Portfolio Standard ("EPS"), a mechanism instituted by the Arizona Corporation Commission ("Commission") to promote the development and use of renewable resources. I am also responsible for corporate security and facility maintenance and management. A statement of my qualifications is attached as Appendix A.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony will discuss the changes that APS will make at its coal-fired generation facilities through 2009 to minimize the operational, environmental and financial impacts associated with existing and future federal and state laws, regulations and policies. I will present the APS proposal for an Environmental

Improvement Charge ("EIC"), an adjustment mechanism that would provide for a timely recovery of the cost for the substantial capital investment necessary for adding or improving environmental controls in the Company's coal generation facilities. I am also providing testimony about the Green Power offerings, which make a variety of renewable resources available to customers. In addition, I explain the Company's net metering proposal to compensate customers that have renewable resources facilities of 10 kW or less who provide their excess energy to the APS grid. Finally, I comment on the Commission's EPS rules.

II. SUMMARY OF TESTIMONY

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. APS' coal plants are a vital part of the Company's diverse fuel mix that provides its customers with greater price stability and reliability than would otherwise exist without these plants. While these plants meet all current environmental regulations, they do present some unique challenges. APS is knowledgeable about the potential environmental impacts of its coal-burning operations and the need to significantly reduce emissions over the next several years to comply with existing, proposed and expected laws and regulations. APS estimates that the necessary environmental changes to the Cholla Power Plant will cost approximately $135 million over the next several years. Additional improvements beyond five years have not yet been determined, although it is expected that the Four Corners and Navajo Power Plants will also need improvements in the future. The acceleration and scale of environmental compliance costs have reached a point where an adjustment mechanism is necessary to timely recover the cost of investing in and maintaining these environmental improvements. For these reasons, APS is requesting an EIC,

which would allow the Company to recover the Commission-approved cost associated with the investment and expenses for needed environmental improvements at APS' generation facilities.

I am also presenting testimony regarding the Company's proposals for Green Power offerings and net metering offering. In relation to another environmental issue, I am also commenting on the EPS rules. Due to the adjustment mechanism established in the last rate case, APS is not asking for any adjustment in this case.

III. ENVIRONMENTAL IMPROVEMENT CHARGE

Q. PLEASE EXPLAIN THE ENVIRONMENTAL CHALLENGES THAT APS FACES.

A. Reliable and affordable energy drives economic development. The fuel sources for this energy and how it is delivered to the customers have varying costs, and effects on the environment. The ongoing challenge for the Company is meeting Arizona's growing energy demands efficiently, with limited rate impacts, while minimizing the environmental impact.

To provide reliable electric service to its customers, APS has invested in several generating plants. A significant part of APS generation capacity is from coal-burning plants, including the Cholla Power Plant located near Joseph City, Arizona; the Four Corners Power Plant, which is located in the Navajo Nation in northwestern New Mexico; and the Navajo Power Plant,[1] located in northern Arizona. These plants are located near one or more large national parks and

[1] APS has a 14% ownership interest in the Navajo Plant.

wilderness areas, which are designated as mandatory "Class I Areas"[2] under the Clean Air Act.

The Company supports the EPS and the increasing role of clean renewable energy, but for the foreseeable future, there is a continued need to use fossil fuels. In this context, APS believes that its existing fossil fuel operation must be managed to reduce its environmental footprint, to the extent practical, and in a manner that ensures compliance with existing and anticipated environmental laws.

Coal-fired generation represents a significant percentage of the APS generation portfolio. While the environmental impacts of coal differ from other fuel sources, coal is a relatively low-cost fuel, and it is not realistic to expect this energy source to be replaced by other cleaner, cost-effective technology in the near future. We must therefore assure that existing units meet the emissions standards required under the current regulatory scheme and take the actions necessary to protect Arizona's environment.

Q. WOULD YOU EXPLAIN HOW THE COMPANY VIEWS ITS OBLIGATIONS RELATED TO ENVIRONMENTAL ISSUES?

A. APS understands that in order to be successful in the future, we must continue on a path of continuous improvement and maintain a rigorous focus on doing the right thing, which includes taking care of the environment. APS is committed to responsible environmental practices. We endeavor to go beyond basic

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[2] The Environmental Protection Agency ("EPA") defines a "Class I Area" as all international parks and national wilderness areas which exceed 5,000 acres in size, national memorial parks which exceed 5,000 acres in size, and national parks which exceed 6,000 acres in size that were in existence on August 7, 1977. *See* 42 U.S.C. § 7472.

compliance, where those activities protect public health and the environment and are consistent with sound business practices and goals.

Our commitment to continuous improvement includes a regular review of environmental stewardship, in light of advances in technology and new understandings in environmental science. In this regard, the Company is pursuing an energy resource plan that looks to the future and recognizes the importance of environmental protection, energy conservation and efficiency. We have been active in research and development of solar energy for several decades and are recognized as a leader in advancing solar technology.[3] APS has constructed solar power plants around Arizona, including one in Prescott that upon completion is expected to be one of the largest photovoltaic plants in the world. In addition, the Company is involved in a variety of environmental projects, including biomass, biogas, geothermal technologies, wind energy, and the development of renewable fuels.

We have also developed programs that allow our customers to participate in the use of renewable energy. APS has offered the Solar Partners Program since 1997, under which APS customers were invited to purchase energy generated by solar power plants. This was the first "green energy" offer in the state of Arizona. With this filing, APS is seeking Commission authorization to offer a more robust opportunity for its customers to purchase energy generated from a

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[3] As far back as 1954, APS was the principal organizer of the first International Solar Energy Exposition. In response to the 1973 embargo, APS helped organize the Arizona Solar Energy Research Committee (now the Solar Energy Advisory Council), and developed internal research programs. In 1988, APS built its Solar Test and Research Center, which is utilized by scientists, engineers and students from around the world to test the latest developments in solar technology.

variety of renewable resources. The new Green Power offerings are discussed later in my testimony and in Mr. Gregory DeLizio's testimony.

Our approach to protecting the environment is proactive as we strive to continuously reduce the release of substances that may impact the environment. We work to stay ahead of the regulatory curve through a dialogue with the regulators and the environmental community. By taking a collaborative approach, we can realistically anticipate new requirements, allowing us to make emission reductions or operational changes quickly and cost-effectively. It also allows us to avoid the costs of enforcement or citizen suit litigation, which is a win-win situation for APS, the Arizona environment and the regulators.

Q. HOW DOES THE STATE BENEFIT WHEN AN ELECTRIC COMPANY INVESTS IN ADDITIONAL MEASURES TO PROTECT THE ENVIRONMENT?

A. In addition to the health benefits for Arizona citizens that result from less pollution and waste, it is important to note that Arizona is home to many significant natural wonders, including the Grand Canyon National Park and the Petrified Forest National Park. The EPA has designated these areas as Class I Areas and there are special visibility requirements that apply, pursuant to the Clean Air Act. APS understands the need to reduce emissions from its generating plants to protect the national parks.

Q. DOES THE COMMISSION HAVE A ROLE IN ADDRESSING ENVIRONMENTAL CONCERNS IN ARIZONA?

A. It is evident that this Commission has a real commitment to protecting Arizona's environment. For example, this Commission has expedited the development of

renewable energy resources through its EPS rules.[4] In addition, as part of the Company's last rate case, the Commission supported renewable energy by requiring a special renewable energy solicitation and ordering APS to seek to acquire at least ten percent of its annual incremental peak capacity needs from renewable resources.

While not imbued with the environmental regulatory authority of the EPA or the Arizona Department of Environmental Quality ("ADEQ"), the Commission does oversee the public utility industry and has the authority to set rates that can foster environmental improvement by the public service corporations that it regulates. This can be accomplished by approving mechanisms that permit utility companies to make and recover capital expenditures to upgrade facilities for environmental purposes. The Company's proposed EIC is such a mechanism.

Q. WHY IS APS PROPOSING AN EIC?

A. As the Vice President responsible for APS' environmental performance, I am continually focused on the actions APS should take to protect human health and the environment, while providing reliable energy to our customers. This means complying with existing laws and anticipating future requirements and, where appropriate, exceeding requirements. APS works proactively with the environmental community, environmental agencies, and vendors to continually analyze the environmental impact of our operations and to plan improvements to improve the Company's environmental profile, including reducing emissions

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[4] A.A.C. R14-2-1618

from the Company's coal plants. Due to the extensive capital required for many of these improvements, it was clear that funding them would be a challenge. The proposed EIC would allow the Company to implement the planned improvements and recover the costs of these capital projects on an annual basis, as the costs are incurred. This approach provides a mechanism to do the right thing. I believe improved environmental performance from the reliable, low cost generation sources are a natural compliment to the renewable energy sources required by the Commission's EPS. The common goal is environmental quality combined with a reliable, affordable source of electricity for customers.

As set forth in the APS EIC Plan (Attachment EZF-1), numerous changes are planned for the Cholla Power Plant in the foreseeable future to meet environmental requirements. Additional improvements at Four Corners and Navajo Power Plants may also be necessary and/or desirable in the coming years. As expenditures are made, an EIC would provide timely recovery of the prudent and reasonable costs required for these environmental projects.

Q. PLEASE DESCRIBE THE EIC THAT THE COMPANY IS PROPOSING.

A. In general terms, the EIC mechanism would recover the on-going cost for environmental projects where the Commission had pre-approved the investments and associated expenses for environmental improvements at APS' generation facilities. The Company's current request under the proposed EIC is for coal-fired generation improvement costs; however, other kinds of environmental improvement costs, such as for water and waste, are anticipated and under APS' proposal, could be included in the EIC. Mr. DeLizio addresses the EIC in detail in his testimony.

Q. WHY SHOULD CAPITAL INVESTMENTS FOR ENVIRONMENTAL IMPROVEMENTS BE TREATED DIFFERENTLY FROM ANY OTHER CAPITAL INVESTMENT?

A. Unlike other capital expenditures, environmental expenditures do not produce revenue that can be used to offset the cost of the improved facilities. For example, the cost of a new substation is recovered, at least in part, by the additional revenues from the new customers that the substation will serve. In contrast, environmental expenditures at the Cholla, Navajo and Four Corners Power Plants have no revenue benefit associated with them. While the Company recognizes the importance of compliance and the societal benefits of cleaner air and environmental enhancement, delayed recovery of these substantial costs could adversely affect APS' earnings and adversely impact the Company's financial ability to fund environmental projects.

Q. ENVIRONMENTAL CONCERNS HAVE BEEN AN ISSUE FOR MANY YEARS, SO WHY IS THE COMPANY REQUESTING AN ENVIRONMENTAL ADJUSTMENT FACTOR AT THIS TIME?

A. APS is proposing this specific mechanism to recover environmental compliance costs because additional mandates are accelerating the timing and level of cost associated with environmental compliance activities. Upgrading existing facilities and reducing emissions from coal generation takes on additional urgency in light of increased volatility of natural gas prices; more stringent requirements to reduce sulfur dioxide ("SO_2") and nitrogen oxides ("NOx"); new requirements on mercury emissions; and the increased probability that carbon dioxide ("CO_2") will be regulated in the foreseeable future.[5]

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[5] CO_2 is an emission related to global warming and climate change, but it is not a regulated pollutant under the Clean Air Act and is addressed in this testimony only to the extent that it is an environmental issue that the Company will confront over the next several years.

Environmental compliance activities are a legitimate and unavoidable cost associated with the provision of electric service. Implementing an EIC would benefit APS customers by keeping the low-cost coal-burning units viable, would benefit Arizona's economy through the employment of a local labor force and local tax base of these plants, and would benefit Arizona as a whole by protecting the State's environment. Importantly, it will also minimize the impact on earnings as well as cash flow for these significant projects. For these reasons, APS is urging the Commission to adopt the EIC to address these concerns.

Q. HOW DOES THE GENERATION OF ELECTRICITY IMPACT THE ENVIRONMENT?

A. SO_2, NOx, particulate matter and mercury emissions are by-products of coal-burning generation plants. The EPA and ADEQ are required to set limits for these pollutants to protect public health and the environment. These limits are adopted into the coal plants' operating permits. The expectation is that by meeting these permit limits, the emissions will not negatively impact the environment or public health. However, these limits are based upon what we currently know, and as the science regarding these pollutants improves, the regulatory agencies' ability to set appropriate emission limits increases. Thus, since the inception of the Clean Air Act in 1970, EPA and/or ADEQ have periodically set new, more stringent limits for operating sources of air emissions. The agencies setting these limits anticipate that industry will respond by installing state-of-the-art pollution control technology as the standard method to minimize the emission of pollutants into the environment. Specific concerns regarding emissions from coal plants and emission control technologies are discussed below.

Sulfur Dioxide: SO_2 is the major pollutant associated with acid rain and has a negative impact on visibility. SO_2 emissions also contribute to increased fine-particulate matter concentrations downwind from emission locations. The western United States does not have an acid rain problem at this time; the primary purpose for SO_2 emission reductions in the West is to improve visibility in Class I Areas, such as national parks and designated federal wilderness areas. Current regulations[6] require certain facilities, including Cholla 2 and 3, Four Corners and Navajo, to install the "Best Available Retrofit Technology" ("BART") no later than 2013. The common emission control technology for SO_2 emissions is scrubbers that remove the SO_2 from the flue gas after the coal is combusted.

Nitrogen Oxides: NOx emissions contribute to visibility degradation, as well as, elevated ozone levels, acid deposition and nitrogen deposition. NOx emissions also contribute to an increase in fine-particle concentrations. Recognized NOx control technologies include low NOx burners, overfired air and, in some situations, the more expensive Selective Catalytic Reduction ("SCR") technology. New NOx limits have been included in recently proposed legislation and in EPA rules to protect visibility.

Particulate Matter: Particulate matter contributes to reduced visibility. In addition, particulate matter has the potential to cause exceedances of both "opacity" limitations and the EPA health-based standard for particulate matter

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[6] 40 C.F.R. § 51.300 *et seq.*

under the National Ambient Air Quality Standards.[7] The common environmental control technology is bag-houses.

Mercury: Mercury is a naturally occurring element that is released into the atmosphere when coal is burned. Some of the mercury may be deposited in lakes and streams, where it can be ingested by fish that cannot metabolize or excrete the mercury causing bioaccumulation in their tissues. The common mercury emission control technology is bag-houses, as well as activated carbon injection.

Q. DOES APS CURRENTLY HAVE PLANS FOR MAKING ADDITIONS OR IMPROVEMENTS TO ITS ENVIRONMENTAL CONTROLS?

A. Yes, the Company intends to achieve emission reductions in an integrated, coordinated manner, on a schedule that coincides with planned unit outages. APS currently has extensive plans to install additional technology in its Cholla Power Plant in the upcoming years. The Company has projected that additional or improved environmental controls for the Cholla Power Plant will cost approximately $135 million over the next several years. These capital expenditures will result in substantial environmental benefits for APS customers, as well as the citizens of Arizona. Attachment EZF-1 sets forth the environmental projects scheduled for the Cholla Power Plants. Additional projects at the Four Corners and Navajo Power Plants may be necessary and/or desirable in the coming years.

Q. IS THE COMPANY REQUESTING RECOVERY OF ANY OF THESE PROJECTS IN THIS CASE?

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[7] 40 C.F.R. § 50.1 *et seq.*; 42 U.S.C. § 7409.

A. Yes. The APS EIC Plan (Attachment EZF-1) sets out the planned environmental projects for the Cholla Power Plants. This is the basis of the EIC for which the Company is seeking approval in this filing.

Q. PLEASE SUMMARIZE THE ENVIRONMENTAL LAWS AND REGULATIONS THAT WILL IMPACT THE COMPANY'S CAPITAL INVESTMENT REQUIREMENTS.

A. The Clean Air Act established air quality standards for various air pollutants. Coal-fired power plants are subject to numerous regulatory requirements under the Act. The primary focus of these requirements is the reduction of SO_2 and NOx emissions, particulate matter, volatile organic compounds and heavy metals, including mercury.

The EPA has revised the New Source Review ("NSR") rule under the Clean Air Act.[8] NSR is a pre-construction permitting program that governs air pollutant emissions from new sources and existing industrial sources that undergo "major modifications." NSR requires the installation of state-of-the-art emissions control technology to reduce emissions. "Routine Maintenance, Repair and Replacement" ("RMRR") activities are excluded from the scope of the NSR program. For existing facilities, NSR has resulted in a set of complex and controversial regulations, particularly related to the RMRR exclusion. Since 2002, EPA has been undertaking efforts to reform its NSR program, including the issuance of two final rule packages and one proposal intended to streamline and simplify the NSR program requirements and applicability determinations. The RMRR rules are currently the subject of litigation.

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[8] 40 C.F.R. §§ 51.161-166, 52.21; 42 U.S.C. § 7411.

The new EPA Clean Air Mercury Rule ("Mercury Rule"),[9] issued in March 2005, established performance standards to limit mercury emissions from existing and new coal-fired plants. The purpose of the rule is to reduce utility emissions of mercury by 69%, from 48 to 38 tons in 2010, and to further reduce to 15 tons per year by 2018. Pursuant to the EPA's market-based trading program, each state is assigned a "budget" for reducing mercury emissions from coal-fired power plants, and must submit a compliance plan to the EPA. Each generation unit within the state will be assigned a certain number of "allowances," and the generation unit operator must hold adequate allowances to offset each generation unit's emissions, starting in 2010. Those emission credit allocations will be further reduced starting in 2018.

The EPA recently promulgated the Clean Air Visibility rule,[10] which establishes presumptive SO_2 and NOx emission levels, known as "presumptive BART" levels, for electric generating units. It is the responsibility of the states to implement the rule and determine what emission controls are needed at each generating plant. Additional capital expenditures may be required for the Company to comply with the rule's presumptive BART requirements. In addition, the rule requires steady and continuing emission reductions through 2064. To assure continuing improvement in visibility to natural lands, the Company anticipates continuing plant improvements and capital investments.

Q. ARE THERE OTHER ANTICIPATED LEGISLATIVE MANDATES THAT MAY REQUIRE IMPROVED ENVIRONMENTAL CONTROLS?

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[9] 40 C.F.R. §§ 60.24, 45Da-50Da; 40 C.F.R. §§ 60.4101 *et seq.*

[10] 40 C.F.R. §§ 51.302, 308; *see also,* 42 U.S.C. § 7491-7492.

A. Yes. The Clear Skies Act is federal legislation currently pending before Congress that could require further environmental controls to comply with its proposed standards. The provisions of the Clear Skies Act, as currently proposed, would further require that SO_2, NOx, and mercury emissions to be reduced significantly.[11]

Q. WHAT IS THE COMPANY'S CURRENT STRATEGY TO REDUCE EMISSIONS?

A. APS has decided to implement an extensive emissions reduction project at its Cholla Power Plant. APS plans to implement a number of different Pollution Control Projects at that plant over the next several years.[12] See APS EIC Plan, Attachment EZF-1.

Q. IS APS CONSIDERING REDUCING EMISSIONS AT ITS GENERATING PLANTS BEYOND CURRENT REGULATORY STANDARDS?

A. Yes. As an energy supplier and producer, we are subject to environmental regulations on the federal, state, county and local levels. In addition, the Four Corners Power Plant works with the Navajo Nation Environmental Protection Agency to address certain environmental issues. APS strives to perform beyond mere compliance in all areas of our business. The Company believes it is prudent to address environmental compliance issues in a proactive manner, to ensure the continuing protection of Arizona's environment. Additionally, it is our experience that the costs of these technology installations will increase after the

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[11] Clear Skies Act, S. 131 109th Cong. (2005).

[12] In September 2005, APS submitted information to ADEQ to incorporate this voluntary emissions reduction project into Cholla's Title V permit renewal. Supplemental Information to a Title V Air Quality Permit Application for Class I Permit #1000108 Renewal, prepared by Arizona Public Service Company for the Cholla Power Plant (September 28,2005).

new laws go into effect, making it more cost effective to address these environmental changes sooner, rather than later. Another consideration is the fact that regulatory agencies and/or environmental groups have sued several electric utilities in an effort to compel further emission reductions. The current litigation efforts make it clear that emission reduction is a significant issue.

Q. ARE APS' CONCERNS REGARDING THE COST OF ENVIRONMENTAL CHANGES UNIQUE?

A. No. In 2004, the National Association of Regulatory Utility Commissioners, in conjunction with the National Association of State Energy Officials and the Environmental Council of States, conducted a comprehensive study to examine the approach in the states and/or incentives utilized to improve the environmental performance of base-load electricity generation facilities ("NARUC Study").[13] The NARUC Study acknowledged that whatever the regulatory path the state and federal officials choose for improving the environmental performance of these generating facilities, it was clear that future emission limits would be more stringent.[14] In the study, the lack of regulatory certainty and high implementation costs were identified as major barriers that hinder companies from making investments to improve environmental performance.[15]

Q. DO OTHER STATES PROVIDE FOR STREAMLINED RECOVERY OR PREFERENTIAL REGULATORY TREATMENT FOR EXPENDITURES TO IMPROVE ENVIRONMENTAL CONTROLS?

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[13] *A Survey of State Incentives Encouraging Improved Environmental Performance of Base-Load Electric Generation Facilities; Policy and Regulatory Initiatives;* The National Association of Regulatory Utility Commissioners (June 2004).

[14] *Id. at 5.*

[15] *d. at 17.*

A. Yes. The NARUC Study found that a number of states have developed environmental cost recovery programs for improving the environmental performance of base-load electricity generation facilities.

Q. PLEASE PROVIDE EXAMPLES OF THESE STATE PROGRAMS.

A. Florida passed statutes that authorize the Florida Public Service Commission ("PSC") to allow the recovery of a utility's prudently incurred environmental compliance costs through a cost-recovery factor that is separate and apart from the utility's base rates. The PSC makes its determination based on projected environmental compliance costs that are required by environmental laws or regulations.[16] The Florida Legislature specifically stated that the statutory provisions were to be liberally construed to protect the public welfare.[17]

Indiana has enacted statutes that provide for cost recovery of pollution control equipment installed to comply with the requirements of the Clean Air Act Amendments of 1990.[18] The General Assembly had found that the growth of Indiana's population and economic base had created a need for new energy generating facilities in the state; and that the development of a robust and diverse portfolio of energy generating capacity, including the use of renewable energy resources, was needed if Indiana was to continue to be successful in attracting new businesses and jobs.[19] The statutes require that the Public Utility Commission approve the estimated cost, the schedule for the development and the implementation of the environmental compliance plan.

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[16] Fla. Stat. § 366.8255 (2005).

[17] Fla. Stat. § 366.01 (2005).

[18] Burns Ind. Code Ann. § 8-1-27 *et seq.* (2004).

[19] Burns Ind. Code Ann. § 8-1-8.8-1 (2005).

West Virginia statutes provide rate incentives for utility investments in clean coal and clean air technology facilities that are located in West Virginia.[20] The statute was enacted to respond to pending U.S. Congressional legislation limiting the emissions of oxides of sulfur and nitrogen from coal-fired plants. Upon a finding that it is in the public interest, the Public Service Commission must authorize ratemaking allowances for electric utility investments in clean coal and clean air technology facilities or electric utility purchases of power from clean coal technology facilities located in West Virginia.[21]

A Kentucky statute allows a regulated utility producing energy from coal to recover costs through a surcharge for complying with certain federal, state and local environmental requirements for coal combustion wastes and the by-products from facilities utilized for the production of energy from coal.[22] The Supreme Court of Kentucky found that the surcharge created a new right for all electric utilities to recover expenses, as well as, a return on and a return of capital costs associated with environmental projects, without filing a general rate case.[23]

Q. WHAT IS THE VALUE OF THE EIC RELATED TO LONG-TERM PLANNING?

A. APS serves one of the fastest growing service territories in the country. APS is projecting that the capital investment necessary to expand its transmission and

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[20] W. Va. Code §24-2-1g (2005).

[21] *Id.*

[22] K.R.S. § 278.183 (2004).

[23] *Kentucky Industrial Utility Customers, Inc., et al. v. Kentucky Public Service Commission,* 983 S.W.2nd 493, 500, 1998 Ky. LEXIS 165 (December 1998).

distribution facilities[24] to serve its native load for 2007 through 2009 will be approximately $1.4 billion. An EIC would provide a means for timely recovery of the costs associated with necessary environmental projects as the projects are progressing.

Q. WHAT IS THE DIFFERENCE BETWEEN AN EIC AND THE SURCHARGE ASSOCIATED WITH THE ENVIRONMENTAL PORTFOLIO STANDARD?

A. The purpose of the surcharge associated with the EPS is to promote the use of renewable resources, such as solar, wind, biomass, hydro and geothermal. These are clean and self-replenishing energy resources that will benefit the citizens of Arizona. In most cases, the technologies for these renewable resources are still developing and costs are higher than conventional generation, making the funding from the EPS surcharge essential to promote these resources. In contrast, the EIC would address the economic realities of upgrading technology for fossil-fuel generation facilities to reduce the amount of emissions. The combination of both approaches – seeking increased use of renewable resources and installing state-of-the-art technology to reduce emissions – should assure that customers have reliable energy resources and that the effects of pollution are minimized.

IV. GREEN POWER OFFERINGS

Q. PLEASE EXPLAIN THE GREEN POWER OFFERINGS THAT THE COMPANY IS PROPOSING.

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[24] Pursuant to Decision No. 67744, the Commission has imposed a self-build moratorium on APS for any generating facility with an in-service date prior to January 1, 2015, unless expressly authorized by the Commission.

A. In light of the growing variety of renewable resources that are becoming available, APS believes that customers should have the opportunity to utilize those energy resources. Our proposed offerings, the Green Power Block Schedule and the Green Power Percentage Schedule, will offer our customers a variety of renewable resources at a more affordable price than an exclusive solar offering. Mr. DeLizio provides a detailed explanation of these new schedules in his testimony.

Q. HAVE CUSTOMERS EXPRESSED AN INTEREST IN GREEN POWER?

A. Yes. Some of APS' customers wish to subscribe to specific percentages of renewables in their energy purchases. For example, the US Green Building Council has a Leadership Energy and Environmental Design ("LEED") program of which renewable energy resources is an important component. The LEED program is a voluntary, consensus-based national standard for developing high-performance, sustainable buildings and is rapidly gaining interest in Arizona and across the country. Under this program, customers who obtain a portion of their energy from green power can claim LEED "points", which count toward overall LEED certification. In addition, Arizona Governor Napolitano has issued an executive order (Executive Order 2005-05) mandating that new state facilities derive at least 10% of their energy from renewable sources, and that requires new state facilities be LEED-certified. The Arizona Department of Administration has already approached APS to discuss how to meet that objective. The 10% option in Green Power Percentage Schedule does just that.

Q. WILL APS PROVIDE RENEWABLE ENERGY FOR THE SPECIFIC AMOUNTS THAT CUSTOMERS SUBSCRIBE?

A. Yes. Renewable energy in the amount desired by Green Power customers will be available in the APS system from our existing portfolio in the subscribed amount. APS will limit subscription to this rate to the renewable energy that can be actually supplied to the APS system. APS will use the revenue from these Green Power offerings to procure additional renewable energy in the future.

Q. HOW WAS THE AMOUNT OF THE GREEN POWER PREMIUM CALCULATED?

A. At the current stage of our renewable portfolio, the determination of a Green Power premium is not a straightforward task. APS has very good information on solar energy production but limited information on other resources, even though we expect our non-solar resources to grow substantially in coming years. APS also has done extensive research on market rates for renewable energy but this dynamic, developing industry is often difficult to predict. Instead of attempting to project exactly what our technology and price mix will be, we have taken a more direct approach by examining the recent discussions about the EPS rules that are currently pending before the Commission. The Company has been very involved in the process for the proposed EPS rules and believes that those proposed rules provide a reasonable framework for calculating our new Green Power premium. Therefore, the Green Power premium of $0.03/kWh was computed by dividing the amount of renewable energy required by proposed EPS standard from 2006 through 2015 by the potential revenue that would be provided by the proposed EPS surcharge over the same period. Although we are well aware that the standard is not final and may change, we believe this approach is reasonable. We should note that the rate basis will be reevaluated in coming years as our portfolio grows, and APS may request an adjustment of this premium in a future proceeding.

Q. HOW DOES THE GREEN POWER SCHEDULE WORK IN CONJUNCTION WITH THE EPS SURCHARGE THAT IS CURRENTLY COLLECTED FROM CUSTOMERS?

A. The money collected from the Green Power schedules will be in addition to the Commission-mandated EPS surcharge. The renewable energy purchased for the Green Power customers will be purchased in conjunction with the EPS energy requirement; therefore, the projected $.03/kWh average premium cost to meet the portfolio standard is the appropriate cost upon which to base the Green Power schedules.

Q. HOW WILL THE GREEN POWER OFFERINGS WORK WITH THE EXISTING SOLAR PARTNERS OFFERING?

A. APS is proposing to freeze the Solar Partners rate and now offer the Green Power rate that can utilize all renewable energy sources. Existing Solar Partner customers would be allowed to either remain on that rate, or transfer to the Green Power rate.

Q. HOW WILL CUSTOMERS BENEFIT FROM THE NEW GREEN POWER OFFERINGS?

A. The new Green Power offerings expand the variety of renewable energy options offered to customers, at a more affordable rate. Under the Solar Partners tariff, customers may purchase a 15 kWh block of solar energy for $2.64 (or $0.18 per kWh), as contrasted with the Green Power offerings where the premium is $0.03 per kWh. The two options provided will also allow customers to choose their participation level based on their own renewable energy objectives and economic abilities.

V. <u>NET METERING PROPOSAL</u>

Q. WHY IS THE COMPANY PROPOSING A NET METERING RATE SCHEDULE?

A. Net metering is a means to encourage the installation and utilization of small renewable resources by offering customers the opportunity to provide their excess generation to the Company as an offset to their energy usage.

Q. PLEASE EXPLAIN THE COMPANY'S NET METERING PROPOSAL.

A. Under the Company's net metering pilot proposal, residential and small commercial customers that have renewable energy resource facilities of 10 kW or less will have the opportunity to provide excess energy to the Company. The amount of excess energy that is provided to the APS electric grid will be credited back to the customer in subsequent months. The Company's proposal is capped at 15MW; the term of the pilot project is three years. At the end of the three years, no additional customers will have the opportunity to participate, however, those customers already on the Net Metering rate schedule will be allowed to continue on it. Mr. DeLizio discusses this Rate Schedule in his testimony.

Q. WILL THE COMPANY CONTINUE TO OFFER ITS EPS CREDIT PURCHASE PROGRAM IN CONJUNCTION WITH THE NET METERING PROPOSAL?

A. Yes, for the term of the pilot program, the Company will allow customers to participate in both the EPS Credit Purchase Program, which provides a specified payment for the installation of solar equipment, and in net metering, which compensates customers for the excess generation from renewable resource generators. These act as incentives to encourage customers to invest in and install renewable resources on their homes and small businesses. Whether to continue with these significant incentives will be reexamined in conjunction with other federal and state incentives at the end of the pilot program.

VI. ENVIRONMENTAL PORTFOLIO STANDARD

Q. WHAT IS THE COMPANY'S POSITION RELATED TO THE ENVIRONMENTAL PORTFOLIO STANDARD?

A. The Company believes that renewable resources are an important part of Arizona's energy future. APS has supported the EPS since it was first adopted in 2001. APS was the first utility in the state to offer a green energy option (APS Solar Partners program). In addition, APS has had signed agreements with third parties for construction and generation of 18 megawatts of biomass and wind projects. APS has worked extensively on developing other projects including additional wind and biogas projects. Unfortunately, none of these projects, except the biomass project, have been delivered.

APS has participated in the numerous workshops sponsored by the Commission related to EPS. Draft proposed rules are currently under consideration. I believe that everyone recognizes that there is a premium associated with the purchase of renewables; therefore, it is critical that the funding for the EPS be sufficient to meet the renewable resource requirements.

Q. IS THE COMPANY REQUESTING ADDITIONAL FUNDING TO COMPLY WITH THE PROPOSED RULES?

A. The Company is raising the issue now because changes to the proposed rules may impact the funding necessary to comply with the EPS. In Decision No. 67744, the Commission established an adjustment mechanism to allow for specific Commission-approved changes to APS' EPS funding outside of a rate case. If the Commission finalizes new EPS rules that require increased funding, APS will petition the Commission to increase its EPS surcharge.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes it does.

Appendix A

Statement of Qualifications
Edward Z. Fox

Ed Fox is Vice President for Communications, Environment and Safety at Arizona Public Service Company (APS). In this capacity, Mr. Fox is responsible for all external and internal communications, as well as environmental, health and safety compliance. He is the responsible officer for Corporate Security and facility and real estate management, and he also oversees the Environmental Portfolio Standard and the company's Technology Development group that identifies and helps develop technologies, such as solar energy and fuel cells, for integration into the APS system.

Fox is an attorney and the former Director of the Arizona Department of Environmental Quality (ADEQ) where he served the State from 1991 to 1995. Prior to coming to Arizona in 1985, he was an Assistant Attorney General in West Virginia. From 1985 to 1991, Mr. Fox was in private practice in Phoenix and Tucson, Arizona, where he represented business clients on state, federal and local environmental and commercial matters.

Fox received his J. D. from the West Virginia University. He holds a Masters in Public Administration and a B.A. from the American University in Washington, D.C.

Fox has provided leadership for numerous organizations and initiatives. For example: he chaired the State Trust Land Reform Committee and the Arizona Department of Environmental Quality's Air Quality Cap and Trade Committee, which looked to develop market mechanisms to help improve air quality in the Valley; he served as a member of the Governor's Brown Cloud Committee; and, he chaired a sub committee of the Governor's Growing Smarter Committee. Mr. Fox was chair of the ASU Morrison Institute for Public Policy from 1999-2002; he currently chairs the Arizona Zoological Society dba The Phoenix Zoo; and he serves on the Executive Committee of Valley Partnership.

Mr. Fox is currently associated with the following organizations: ASU Morrison Institute, Arizona Zoological Society, Valley of the Sun United Way, Arizona Town Hall, ASU Council for Design Excellence, and Maricopa Partnership for Arts and Culture.

APS EIC Plan

Generation Unit	Project	Start Date	Complete Date	Purpose	Requirement - Effective Date	Capital Dollars	O&M Dollars
Unit 1, Cholla	Install baghouse	2004	2007	Decrease PM & Hg, Increase visibility (Opacity)	NAAQS/EPA Clean Air Hg Rule - 2007	$22M	$0.6M
Unit 1, Cholla	Install low NOx burner system	2006	2007	Decrease NOx, ozone	RAVI/RH BART/ NAAQS - 2013	$4.3M	0
Unit 1, Cholla	Upgrade scrubber	2005	2007	Decrease SO2	RAVI/RH BART Class 1 Areas/ NAAQS - 2013	$5M	$0.1M
Unit 2, Cholla	Install low NOx burner system	2004	2008	Decrease NOx, ozone	RAVI/RH BART/ NAAQS - 2013	$6M	0
Unit 3, Cholla	Install low NOx burner system	2008	2009	Decrease NOx, ozone	RAVI/RH BART/ NAAQS - 2013	$5.6M	0
Unit 3, Cholla	Install baghouse	2006	2009	Decrease PM & Hg, Increase visibility (Opacity)	NAAQS/EPA Clean Air Hg Rule - 2010	$45M	$0.9M
Unit 3, Cholla	Scrubber - SO2 absorber	2006	2009	Decrease NOx, ozone	RAVI/RH BART/ NAAQS - 2013	$47M	$4.6M

RAVI = reasonably attributable visibility impairment
RH = regional haze
BART = Best Available Retrofit Technology
NAAQS = National Ambient Air Quality Standards
SCR = selective catalytic reduction
Hg = mercury
PM = particulate matter

PATRICK DINKEL

DIRECT TESTIMONY OF PATRICK DINKEL

On Behalf of Arizona Public Service Company

Docket No. E-01345A-05-0816

January 31, 2006

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DIRECT TESTIMONY OF PATRICK DINKEL
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-05-0816)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND POSITION WITH APS.

A. My name is Patrick Dinkel. I am the Director of Corporate Planning and Resource Acquisition for Arizona Public Service Company ("APS" or "Company"). I led the APS team responsible for conducting the 2003 APS Request for Proposals—Power Supply Resource Proposal for the Procurement of Generating Capacity (the "2003 RFP"), evaluating the resulting proposals, negotiating the Asset Purchase Agreement with PPL Sundance Energy, LLC ("PPL Sundance"), and closing the transaction that resulted in APS owning the Sundance Generating Station and associated assets ("Sundance Assets"). I also conducted the two 2005 RFPs called for by Decision No. 67744 (April 7, 2005) – one seeking at least 100 MW of renewables and a second all-source procurement for at least 1000 MW.

Q. WHAT IS YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND?

A. I received a Bachelors of Science degree from Marymount College and a Masters of Business Administration from Northern Arizona University. I joined APS in 1986. Before becoming Director of Corporate Planning and Resource Acquisitions in 2004, I was the Manager of Corporate Planning, and the Manager of Business Unit Analysis and Reporting. Before that, I held various positions within APS and Pinnacle West Capital Corporation ("Pinnacle West"), primarily within the financial planning and budgeting areas.

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

A. APS is seeking to include the Sundance Assets in its rate base. My testimony explains the validity of the procurement process and the value of the Sundance Assets for serving APS customers. APS witness Ms. Laura Rockenberger will discuss the operating income pro forma for the Sundance Assets.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. Yes, I have. I testified in support of APS' request to acquire the Sundance Assets in Docket No. E-01345A-04-0407 ("Sundance Acquisition Docket"). My testimony in that docket addressed the 2003 RFP and the evaluation process that resulted in the selection of the PPL Sundance proposal. In addition, I addressed APS' proposed financing of the acquisition and provided details relating to the Accounting Order that APS was requesting. Because it is relevant to the issues in this rate case application, a copy of my pre-filed direct testimony in the Sundance Acquisition Docket is attached as Attachment PD- 1.

Q. WHAT WAS THE OUTCOME OF THE SUNDANCE ACQUISITION DOCKET?

A. In Decision No. 67504, (January 20, 2005), the Commission affirmed APS' ability, subject to applicable regulatory requirements, to buy new generation assets for native load.[1] The Commission declined to approve the acquisition prior to its consideration in a ratemaking proceeding, or to make a determination as to whether the assets were "used and useful." The Commission did determine that the Sundance Assets acquisition satisfied the evidentiary and legal standards

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[1] Subsequent to the decision in the Sundance Acquisition Docket, the Commission issued Decision No. 67744 (April 7, 2005), which imposed certain restrictions on APS' ability to self-build or acquire new generation.

necessary to be accorded full cost recovery under traditional cost of service principles in a future rate proceeding. The Commission also found that the financing authorizations granted in Decision Nos. 54230 and 55017 were in full force and effect and could be used for the acquisition of the Sundance Assets. A specific modification to the Sundance Certificate of Environmental Compliance was approved as requested. In addition, the Commission held that subject to specified conditions, including the approval of the proposed Power Supply Adjustor (PSA) in the then pending APS rate case, APS was authorized to defer certain costs of owning, operating, and maintaining the Sundance Assets.

Q. DID APS RECEIVE THE REQUIRED APPROVAL FROM FERC FOR ITS ACQUISITION OF THE SUNDANCE ASSETS?

A. Yes. That approval was received by Letter Order on May 6, 2005. I have attached a copy of FERC's Order as Attachment PD-2. The sale and purchase transaction closed on May 13, 2005.

Q. PLEASE SUMMARIZE YOUR TESTIMONY IN THIS RATE CASE DOCKET.

A. My testimony will demonstrate that:

- APS' long range forecasts in 2002 and 2003 showed that the Company would need a significant amount of additional generation resources to meet its continued load growth.
- The Company's ultimate decision to purchase the Sundance Assets was based on a fair and appropriate Request for Proposal ("RFP") process. The acquisition of the Sundance Assets was analyzed with sound economic principles and determined to be a cost effective means of acquiring critical long-term peaking capacity for our customers. We also

analyzed the performance of the units and found that they were well suited for our customers' needs.

II. SUNDANCE ASSETS

Q. PLEASE DESCRIBE THE SUNDANCE ASSETS.

A. The Sundance Generating Station is a 450-megawatt ("MW"), natural gas-fired, simple cycle, peaking electric generating facility located in Pinal County, approximately five miles southwest of Coolidge, Arizona. The plant began commercial operation in July 2002. APS acquired the Sundance Assets from PPL Sundance, which constructed the facility and managed it as a merchant power plant prior to the sale. Sundance consists of ten 45 MW General Electric LM6000-PC combustion turbines arranged in pairs, along with five generation step-up transformers. The plant uses well-known technology with a solid operational and environmental track record.

Q. WHY DID APS ISSUE AN RFP IN DECEMBER 2003?

A. APS routinely prepares forecasts of its projected load requirements and compares them to its available resources, including owned generation and any long-term purchased power contracts it may have in place. In 2002 and 2003, the Company was forecasting continued load growth that, when compared to the Company's existing resources, signaled a need for a significant amount of additional generation resources. The APS Summer Supply & Demand Balance Assessment showed that APS would have a resource shortfall by the summer of 2007 of more than 1400 MW. This assessment included the 1700 MW of Arizona assets owned by Pinnacle West Energy Corporation ("PWEC"), which APS proposed to have included in its rate base in its then-pending rate case. APS issued the 2003 RFP in December 2003 to explore options for meeting the

resource shortfall and to take advantage of any potentially favorable market purchase alternatives.

Q. WHAT FACTORS DID APS CONSIDER IN ISSUING THE RFP?

A. Timing was a major consideration. APS saw the potential for favorable prices in the near-term given the wholesale market at the time and reports that some of the resources in the area may be for sale. APS felt that it was important to determine quickly whether the Company could procure long-term resources for its customers from the competitive wholesale market at a reasonable price. The timing of a new long-term resource acquisition was another consideration.

Q. PLEASE DESCRIBE THE RFP ISSUED BY APS.

A. The 2003 RFP identified APS' projected capacity shortfall of 1447 MW in 2007, with growth of approximately 300 MW per year. APS expressed a willingness to consider either long-term purchase power agreements or asset ownership. The 2003 RFP specifically sought proposals that would deliver a power supply to APS commencing in the summer of 2007.

Q. WHAT WAS THE PROCESS THE COMPANY USED TO EVALUATE WHETHER THE SUNDANCE ASSETS WERE THE BEST GENERATION OPTION FOR APS CUSTOMERS?

A. A team of experienced employees from various APS departments, as well as legal counsel and outside experts, reviewed the proposals submitted in response to the 2003 RFP and reported their conclusions. The defined objective was to identify any issue that warranted consideration or that could have a material impact on a transaction.

The Company evaluated the economics of those proposals that were in contention for further consideration by computing and comparing the installed

cost of each asset sale proposal, the levelized busbar cost of each bid, and the system revenue requirement impact of each bid.

The installed cost, including any interest capitalized during construction, is usually the investment included in a utility's rate base. APS calculated the installed cost of each asset sale proposal to provide a snapshot of how each alternative would impact customers. This analysis provided an indication of the fixed costs associated with each option. Additional discussion of the installed cost analysis is included in Attachment PD-1.

The busbar cost is the revenue required to cover the costs of owning and operating the plant (including fuel and cost of capital) or of purchasing power under a PPA, divided by the anticipated MWh output at the plant's "bus" or the MWh purchase. A "levelized" busbar cost is the busbar cost over the period evaluated (*e.g.*, 30 years) stated in constant dollars. In completing the busbar analysis, APS incorporated information submitted with each proposal along with equipment manufacturer data and standard financial and capacity factor assumptions. Further detail on the busbar cost economic analysis is included in Attachment PD-1.

The system revenue requirement cost study we employed calculated the present value cost for each alternative of providing power to customers, including the cost of fuel, purchased power and ownership. APS evaluated the Sundance Generating Station against alternative new-build simple cycle cases and purchases from the wholesale market. The revenue requirement results were consistent with the busbar results, showing that the acquisition of the Sundance Generating Station produced present value saving of $79 million to $154 million

compared to the other available alternatives. Additional discussion of this analysis is included in Attachment PD-1.

Set out below is a table summarizing select information relating to Sundance and other selected options.

Simple Cycle Technology Comparison			
	Sundance LM6000	New LM6000	New 7EA
Installed Cost ($/kW)	475	762	695
Summer Output (MW)	40	40	76
Heat Rate (Btu/kWh)	9,855	9,855	12,125
Quick Start (<10 Min.)	Y	Y	N
Busbar Cost ($ per MWh)	151	177	182

Q. WHY DID APS SELECT THE PPL SUNDANCE PROPOSAL?

A. APS elected to pursue the PPL Sundance proposal because the Company's analysis demonstrated that purchasing the Sundance Assets was the least cost means for APS to acquire critical long-term peaking capacity. Also, because the units can ramp up quickly, they provide cost-effective reserves for APS' system reliability. The generation can start up in less than ten minutes from a warm or cold standby condition. Sundance was the only constructed or permitted simple-cycle plant that was available in the Arizona market, and it was acquired for peaking capacity at a discounted price that will benefit APS customers far into the future.

Q. WHAT WERE STAFF'S COMMENTS IN THE SUNDANCE ACQUISITION DOCKET REGARDING THE SUITABILITY OF APS' ACQUISITION OF THE SUNDANCE ASSETS?

A. Staff made several particularly relevant observations during the four month period that the filing was under evaluation.[2] First, Staff agreed that there were "positive aspects" to APS' acquisition of the Sundance facility, including "increased reliability," "[i]ncreased operational flexibility" and that "the plant would be acquired through a fair and open RFP."[3] Second, Staff noted that the Sundance Plant was "well situated to support the peaking needs of Arizona customers in Phoenix and Tucson areas."[4] Third, Staff recognized that the "Sundance units' quick start capability and grid location would provide APS with additional options in responding to system disturbances . . . and would provide flexibility in meeting system reserve requirements."[5] Fourth, Staff pointed out that "[i]n the normal course of business, [Sundance] will displace older less efficient units [such as Ocotillo, West Phoenix, Saguaro and Yucca combustion turbines] in the dispatch priority.[6] Finally, Staff noted:

> According to the APS busbar cost, the PPL Sundance purchase is a lower cost alternative to new construction of comparable plants. The cost comparison does not reflect some additional advantages. For instance, PPL Sundance is operational, has been reliable, and has an acquisition cost set forth in the asset purchase agreement that cannot be exceeded. In contrast, construction of a new plant can have

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[2] Testimony of Matthew Rowell, Docket No. E-01345A-04-0407, Hearing Transcript at 356.

[3] Testimony of Matthew Rowell, Docket No. E-01345A-04-0407, Hearing Transcript at 364-65.

[4] Direct Testimony of William Gehlen, Docket No. E-01345A-04-0407, at 5.

[5] Direct Testimony of William Gehlen, Docket No. E-01345A-04-0407, at 5-6; *see also*, Testimony of Matthew Rowell, Docket No. E-01345A-04-0407, Hearing Transcript at 365-66.

[6] Direct Testimony of William Gehlen, Docket No. E-01345A-04-0407, at 6; *see also* Testimony of Matthew Rowell, Docket No. E-01345A-04-0407, Hearing Transcript at 381-83.

cost overruns that far exceed the original anticipated cost to build.[7]

Q. DID STAFF ANALYZE THE RFP SOLICITATION AND BID EVALUATION IN THE SUNDANCE ACQUISITION DOCKET?

A. Yes. In direct pre-filed testimony, Staff described its review of the RFP process and bid evaluation. Based on its review, Staff opined that APS displayed a willingness to individually evaluate a wide range of bids, as most of the proposals did not conform to the RFP.[8]

Q. DID STAFF EXPRESS AN OPINION REGARDING THE ECONOMICS OF THE SUNDANCE PLANT ACQUISITION?

A. Yes, as evidenced from the quote above, Staff found that according to the APS economic analysis, including the busbar cost, the Sundance Assets purchase was a lower cost alternative as compared to new construction of comparable plants.

Q. WHEN APS PROPOSED TO ACQUIRE THE SUNDANCE ASSETS, DID APS BELIEVE THE FACILITY WOULD PROVIDE IMMEDIATE BENEFITS TO THE COMPANY AND ITS CUSTOMERS?

A. Yes. APS had been using a portion of the Sundance Assets pursuant to a long-term agreement and shorter-term market purchases to serve APS customers' needs since July 2003. Projections indicated that the Company would need the full capacity of the units in the future. The acquisition of the Sundance Assets provided APS with 325 MW of critical additional capacity during the summer peak season in 2005, as it will in 2006. The full output from the plant will be utilized to serve APS customers beginning in the summer of 2007 after a

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[7] Direct Testimony of William Gehlen, Docket No. E-01345A-04-0407, at 7.

[8] Direct Testimony of William Gehlen, Docket No. E-01345A-04-0407, at 4.

previously existing agreement between PPL and Tucson Electric Power Company expires.

Q. ASIDE FROM THE NEED FOR THE SUNDANCE ASSETS IN DELIVERING ENERGY DURING PERIODS OF PEAK LOAD, WERE THERE OTHER FACTORS THAT LED APS TO BELIEVE THAT THE FACILITY WOULD BE BENEFICIAL TO APS AND ITS CUSTOMERS?

A. Yes. The additional benefits for APS and its customers in acquiring the Sundance Assets included increased operational flexibility from owning ten quick-start 45 MW units and the availability of the units to help APS more efficiently manage its reserves. With typical unit start times of six minutes from a hot or cold stand-by condition and a very short ramping time to full-rated output, these units provide valuable non-spinning reserves to APS. Although the largest benefit is from added operational flexibility, the reserve value allows APS to more efficiently manage its total reserves requirement needed to support reliable operations. Furthermore, the Sundance Plant benefits APS and its customers by decreasing the exposure to fluctuating wholesale power prices, insufficient supply or supplier default.

Q. GIVEN THE NEEDS ASSESSMENT AND THE ANALYSIS DISCUSSED ABOVE, IN YOUR OPINION, WAS THE DECISION TO ACQUIRE SUNDANCE APPROPRIATE?

A. Yes. All of the economic analyses showed that the acquisition of the Sundance Assets at the offered price was the best available peaking resource alternative for meeting our customers' needs. Our operational analysis indicated that the plant was an outstanding technology and an exceptional match for our customers' projected peaking power needs. The Company's due diligence reviews verified that the Sundance Assets were in good working order, and ensured that all agreements were reviewed and no unexpected liabilities came with the plant.

Q. IS THERE A NEED FOR THE SUNDANCE PLANT'S CAPACITY AND IS IT BEING USED TO MEET THAT NEED?

A. Yes. The above-referenced needs assessment demonstrated that APS clearly has a functional need for the Sundance capacity. In fact, APS still remains short on capacity even after the Sundance Assets acquisition. In addition, as I discussed above, the Sundance Assets provide APS with operational flexibility and enhances the reliability of the APS generation portfolio.

Q. WHAT WAS THE PURCHASE PRICE APS PAID FOR THE SUNDANCE ASSETS?

A. The purchase price was $189.5 million, excluding a post-closing adjustment for the value of the plant inventory. This closing price is the same as the negotiated price for a closing on March 31 and the price used in completing the above analysis.

III. CONCLUSION

Q. DO YOU HAVE ANY CONCLUDING COMMENTS?

A. APS' acquisition of the Sundance Assets was the product of a fair and open procurement process and was based on sound economic principles. APS had a clearly defined need for the peaking plant based upon its previous resource plans and in fact is already using the Sundance Assets to meet the reliability and energy needs of its customers.

Q. DOES THAT CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

Attachment PD-1

DIRECT TESTIMONY OF PATRICK DINKEL

On Behalf of Arizona Public Service Company

Docket No. E-01345A-04-_____

Docket No. L-00000W-00-0107

June 1, 2004

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DIRECT TESTIMONY OF PATRICK DINKEL
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-04_____, et al.)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND POSITION WITH APS.

A. My name is Patrick Dinkel. I am the Manager of Corporate Planning for Arizona Public Service Company ("APS" or "Company"). I led the APS team responsible for conducting the APS Request for Proposals—Power Supply Resource Proposal for the Procurement of Generating Capacity ("RFP"), evaluating the resulting proposals, and negotiating the Asset Purchase Agreement with PPL Sundance Energy, LLC ("PPL Sundance").

Q. WHAT IS YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND?

A. I received a Bachelors of Science degree from Marymount College and a Masters of Business Administration from Northern Arizona University. I joined APS in 1986. Before becoming Manager of Corporate Planning, I was the Manager of Business Unit Analysis and Reporting, with responsibility for corporate budgeting. Before that, I held various positions within APS and Pinnacle West Capital Corporation ("Pinnacle West"), primarily within the financial planning area.

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

A. I will discuss the RFP and the evaluation process that resulted in the selection of the PPL Sundance proposal. I also will address APS' proposed financing of the acquisition and provide the details on the Accounting Order that APS is requesting.

Q. PLEASE SUMMARIZE YOUR TESTIMONY

A. APS' Long Range Forecasts consistently show that APS is facing a growing need for additional generation resources. Based on these forecasts, the current state of the wholesale market, and the apparent willingness of some parties to sell assets, APS elected to conduct a RFP for long-term resources. The Company conducted a review of all of the proposals submitted in response to the RFP and eliminated a number of responses from further consideration. The Company conducted a more detailed review of those remaining proposals most likely to be able to meet APS' needs. Ultimately, APS selected the PPL Sundance proposal and negotiated an agreement to purchase the Sundance Generating Station.

The acquisition of the Sundance Generating Station will efficiently and cost-effectively address some of APS' future capacity needs. Sundance was the only peaking plant bid in the RFP and is the only recently-completed merchant peaking plant in Arizona. Given that APS customer demand requires peaking resources and that there are no additional merchant peaking facilities currently permitted or planned for construction in Arizona, the Sundance Generating Station fits well into APS' generation portfolio. Other advantages of the facility are its operational flexibility and quick-start capabilities that allow it to provide essential reliability support for APS customers. APS has concluded that acquiring the Sundance Generating Station is the least cost alternative through an analysis of available options, including building new peaking units and buying power from the wholesale market.

To finance the acquisition, APS contemplates issuing additional short-term and/or long-term debt under the Company's current debt limits approved by the

Arizona Corporation Commission ("Commission"). This assumes that the Commission finds the Sundance Generating Station to be a prudent addition to the Company's generation portfolio serving APS customers.

APS is purchasing the Sundance Generating Station for less than its book value. Due to regulatory accounting requirements in the FERC Uniform System of Accounts ("USOA"), APS will record a "negative acquisition adjustment" equal to the difference between the purchase price and the net book value of the plant as of closing. APS will amortize the negative acquisition adjustment over the remaining life of the facility.

APS is requesting an Accounting Order authorizing APS to defer for future recovery capital and operating costs associated with the acquisition, along with a debt return on the deferred balance. The amount of the deferral will be offset by any savings to the Company resulting from the acquisition. A deferral order will allow APS to acquire the Sundance Generating Station at a price that will bring significant long-term value to customers without the Company incurring unnecessary and significant financial harm prior to the Sundance Generating Station being reflected in APS rates.

II. RFP PROCESS

Q. WHY DID APS ISSUE AN RFP IN DECEMBER 2003?

A. APS regularly prepares forecasts of its projected load requirements and compares them to its available resources, including owned generation and long-term purchased power contracts. APS has a near-term resource shortfall that it meets in the short-term wholesale market. The Company is forecasting continued growth, which requires a significant amount of additional resources.

The APS Summer Supply & Demand Balance Assessment ("Summer Supply & Demand Balance"), which was included as Attachment 1 to the RFP, shows that APS will have a resource shortfall in the summer of 2007 of more than 1400 MW, even assuming the inclusion of Pinnacle West Energy Corporation's ("PWEC") 1700 MW of Arizona assets as APS is requesting in its pending rate case. The RFP, with all attachments, is provided as Schedule PD-1 to this testimony. A revised Summer Supply & Demand Balance, showing that the Company will have a shortfall of more than 3100 MW in 2007 without the inclusion of the PWEC Arizona assets, was prepared and provided to bidders in January 2004. That revised Summer Supply & Demand Balance and an amended RFP schedule are attached to my testimony as Schedule PD-2.

Q. WHAT OTHER FACTORS DID APS CONSIDER IN ISSUING THE RFP?

A. Timing was a major consideration. APS saw the potential for favorable prices in the near term given the current stage of the cyclic capacity market and reports that some of the resources in the area may be up for sale. APS felt that it was important to determine quickly whether the Company could procure long-term resources for its customers at a reasonable price. The timing of a new long-term resource acquisition was another consideration. APS targeted 2007 in the RFP because the Company could likely purchase short-term resources in the open market for the next few years through the Secondary Procurement Protocol. By 2007, the Company's significant capacity shortfall requires an asset purchase, new construction or long-term purchases to procure much of the resources needed for necessary reliability and price stability. In addition, APS' internal wholesale electric price forecast predicted that, by 2007, the present oversupply of generation would tighten, leading to increased prices for such resources.

Q. PLEASE PROVIDE A GENERAL DESCRIPTION OF THE RFP SCHEDULE.

A. APS first announced its plans to conduct the RFP on November 19, 2003 and formally issued it on December 3, 2003. The RFP was widely distributed to generators and marketers conducting business in the Company's service territory. On December 15, 2003, APS held a bidders' conference attended by nine interested generators and energy marketers. At that bidders' conference, APS provided an overview of the RFP, gave a presentation on transmission capacity, and responded to questions. Bidders submitted RFP responses by January 21, 2004. In mid February, 2004, APS notified those bidders who were short-listed, including PPL Sundance. After significant additional analysis, negotiations and due diligence, APS entered into the Asset Purchase Agreement with PPL Sundance on June 1, 2004.

Q. PLEASE DESCRIBE THE RFP ISSUED BY APS.

A. APS requested proposals for generation to meet APS' rapidly growing retail load, with the minimum size of any single generating unit bid being 35 MW and the maximum size being approximately 550 MW. These limits did not exclude any constructed or permitted merchant facility in Arizona. The RFP specifically sought proposals that would deliver a power supply to APS commencing in the summer of 2007 for reasons previously mentioned. Although the RFP expressed a preference for the purchase of generating assets already constructed or permitted, APS also indicated that it would consider reasonably-priced proposals for long-term unit-specific purchase power agreements ("PPAs"). For any proposal for a long-term unit-specific PPA, APS sought full dispatch rights for the applicable unit. If a proposal involved the sale of a unit that was currently

operating or would be operating prior to June 1, 2007, APS expressed a preference for acquiring the unit at the conclusion of negotiations and then entering into a Sale Back Arrangement with the bidder for the output of that generating unit through May 31, 2007. In contrast to asset sales, the solicited PPAs were, by their terms, for deliveries on and after June 1, 2007, and thus no proposed Sale Back Arrangement was necessary.

Q. WHAT OTHER PROVISIONS WERE INCLUDED IN THE RFP?

A. To mitigate risk to APS and its customers, and consistent with other asset acquisitions, the proposed Asset Purchase Agreement included in the RFP provided that any acquisition of a generating unit would be conditioned upon approval by any and all regulatory authorities with jurisdiction over the transaction. Additional requirements are set forth in the RFP attached as Schedule PD-1.

Q. HOW DID APS ARRIVE AT THE TERMS OF ITS RFP?

A. Several principles drove the RFP requirements. It was important to conduct a timely and efficient RFP that attracted the largest number of bidders. Thus, the Company tried to make the RFP as inclusive as possible. APS left the RFP open to any fuel type, any location (as long as it could reach APS' customers), permitted and existing plants, renewable generation, asset purchases and PPAs. Timing was important because there were a number of plants in the region that appeared to be in a state of flux from an ownership perspective. APS understood that owners of those plants would be reluctant to leave their plants in limbo if the Company took too long to evaluate their proposals.

Q. PLEASE EXPLAIN IN MORE DETAIL THE RESULTS OF THE RFP PROCESS.

A. APS received 13 different proposals from nine entities in response to the RFP, for a total of approximately 6800 MW. All of the bidders were merchant generators or power marketers. The proposals included existing generating units, generation under construction, planned projects holding some (but not all) of the necessary permits, proposed but undeveloped projects, and sales from unidentified assets. All of the asset-backed proposals involved natural gas-fired generating units, none of which were utility-owned or within the Phoenix load pocket. In addition, all of those proposals required APS and its customers to bear the fuel price risk in one manner or another. The "APS Summary of Responses Received to its Power Supply Resource Request for Proposals Dated December 3, 2003" (attached as Schedule PD-3) was filed with the Commission on January 27, 2004 and provides additional information about the RFP results.

Q. PLEASE DISCUSS APS' PRELIMINARY EVALUATION OF THE BIDS RECEIVED?

A. APS performed a preliminary analysis of all of the proposals it received in response to the RFP to identify a short-list of proposals warranting additional consideration. APS reviewed each proposal for credibility and value in relation to generation operations, gas transportation, transmission availability, power marketing, environmental compliance, credit, and overall resource mix, as well as compliance with the minimum bid requirements. Although most of the proposals presented one or more issues related to the minimum bid requirements, APS did not reject any proposal because of those issues. Several proposals, however, provided insufficient information or non-firm pricing

thereby making consideration of those proposals more difficult and reducing the probability of selection.

A team of experienced employees from various APS departments as well as legal counsel reviewed the proposals and reported their conclusions. The objective was to identify any issue that warranted further evaluation or that could have a material impact on a transaction.

The Company evaluated the economics of proposals that were in contention for further consideration by computing the levelized busbar cost of each such bid. The busbar cost is the revenue required to cover the costs of owning and operating the plant (including fuel and cost of capital) divided by the anticipated MWh output at the plant's "bus." A "levelized" busbar cost is the busbar cost over the period evaluated (e.g., 30 years) stated in constant dollars. In completing the busbar analysis, APS incorporated information submitted with each proposal along with equipment manufacturer data and standard financial and capacity factor assumptions.

As a result of its preliminary analysis, APS narrowed the proposals received in response to the RFP down to three. Most of those proposals that were not selected for short-listing were eliminated on the basis of price; however, development risk for projects not yet under construction, credit risk of lower credit counterparties, and price uncertainty also were significant factors. Next, APS entered into discussions with the bidders of the three remaining proposals, eventually narrowing its focus to the PPL Sundance proposal.

Q. WHY DID APS SELECT THE PPL SUNDANCE PROPOSAL?

A. APS accepted the PPL Sundance proposal because purchasing the Sundance Generating Station is the least cost means of APS acquiring critical long-term peaking capacity. Because the units can ramp up quickly, they are able to provide cost-effective reserves and improve APS' system reliability.

Q. PLEASE DESCRIBE GENERALLY THE PPL SUNDANCE FACILITY AND PROPOSAL.

A. The Sundance Generating Station is a nominally rated 450 MW facility located approximately 55 miles southeast of Phoenix in Pinal County. It was placed in service in July 2002 and consists of ten 45 MW General Electric LM 6000PC combustion turbines. Such units typically are used to meet peaking capacity needs because of their ability to start up in less than 10 minutes from a warm or cold standby condition compared to five to seven hours for a typical combined cycle unit. As described in more detail in the testimony filed by PPL, the facility is natural gas fired, uses Central Arizona Project excess water as its primary water supply, and interconnects to the Western Area Power Administration ("WAPA") transmission grid at WAPA's Coolidge substation.

PPL Sundance initially submitted a proposal to sell the entire Sundance facility to APS for $185 million as of December 31, 2004. Its proposal did not include a Sale Back Arrangement. The proposal also required APS to assume certain existing contracts associated with the facility. The final agreed-upon price of $189.5 million reflects an adjustment for PPL Sundance's added carrying costs for a March 2005 closing.

Q. WHAT ARE THE EXISTING CONTRACTS ASSOCIATED WITH THE PLANT?

A. As a result of Tucson Electric Power's ("TEP") Track B process, PPL Sundance entered into a tolling agreement with TEP for 75 MW of capacity year-round through the end of 2006. The proposal required APS to assume that contract with its acquisition of the PPL Sundance facility. In addition, there were several transmission contracts with WAPA and gas transportation contracts with El Paso Natural Gas included in the proposal.

Q. WHAT FOLLOWED THE PRELIMINARY SELECTION OF PPL SUNDANCE'S BID IN THE RFP?

A. After narrowing its focus to the PPL Sundance proposal, APS began a multi-track process that included due diligence, a more detailed economic analysis and comprehensive negotiations. The due diligence on the facility sought to identify any material issues related to the construction, operation, ownership, performance or environmental condition of the plant. A team of experts reviewed contracts, permits, schedules and reports, and conducted on-site inspections to review plant construction, operations, operating and maintenance history, regulatory issues, real estate and land use, environmental compliance, fuels transportation issues, and transmission capabilities, among other topics. This due diligence effort did not identify any issues that warranted rejecting the bid. The economic analysis, which showed that the PPL Sundance proposal was the most attractive option available, is discussed in more detail in Section IV of this testimony.

APS and PPL discussed the PPL Sundance bid and APS' interest over the following weeks. APS incorporated into its discussions the results of its due

diligence and economic analysis. PPL Sundance repeatedly indicated that its offer assumed a sale of the plant for cash in 2005, not 2007, and in fact, made no offer for a 2007 sale. PPL Sundance was unwilling to both absorb the short-term impact of the Sale Back Arrangement in 2005-2006 and give APS the long-term benefit of the Sundance Generating Station from 2007 forward. In the end, APS determined that the final agreement was an attractive purchase and the best option available to customers.

III. APS' NEED FOR PPL SUNDANCE FACILITY

Q. WHEN APS ACQUIRES THE SUNDANCE GENERATING STATION, WILL THAT GENERATION BE USED BY APS?

A. Yes. APS has been using the Sundance Generating Station to serve APS customers and will need the units in the future. Acquiring the Sundance Generating Station provides APS with 400 MW of additional capacity during the summer peak season. Sundance is expected to produce 400 MW during the summer rather than its rated capacity of 450 MW due to the fact that the peak capacity for combustion turbines drops as the ambient air temperature rises. PPL Sundance fills only a fraction of the Company's anticipated future resource needs, even if all of the PWEC Arizona generation is included in the Company's rate base following the pending rate case. With the Sundance purchase, the capacity shortfall in 2005, 2006, and 2007 is 456 MW, 785 MW, and 1047 MW, respectively. The shortfall in 2007 and beyond could grow if Salt River Project chooses to terminate all or part of its existing long-term purchased power contract with APS.

Q. ASIDE FROM THE NEED FOR THE SUNDANCE GENERATING STATION IN SERVING APS PEAK LOAD, ARE THERE ADDITIONAL BENEFITS SUCH THAT THE FACILITY WOULD BE "USEFUL" IF ACQUIRED BY APS AND DEDICATED TO SERVING APS CUSTOMERS?

A. As Mr. Wheeler mentions in his testimony, the benefits for APS and customers of acquiring the PPL Sundance facility include increased operational flexibility from owning ten quick-start 45 MW units and the availability of the units to help APS more efficiently manage its reserves. There is significant value in APS owning the Sundance Generating Station and being able to quickly dispatch the facility instead of having to use day-ahead scheduling required under the PPA.

IV. ECONOMIC EVALUATION OF PROPOSED ACQUISITION

Q. WHAT ECONOMIC ANALYSIS DID APS UNDERTAKE TO EVALUATE THE PROPOSED ACQUISITION?

A. APS evaluated the economics of the PPL Sundance proposal from several perspectives. First, APS looked at the depreciated acquisition cost plus estimated deferrals and compared that to the available alternatives. Second, APS compared the busbar costs of various alternatives. Finally, APS calculated the present value revenue requirement of the system generation cost for each of the alternatives, including an alternative of purchasing the power from the wholesale market.

Q. PLEASE DISCUSS THE ALTERNATIVES YOU CONSIDERED.

A. The table below summarizes the alternative peaking generation technologies that could be used to construct simple cycle combustion turbines in 2007 along with several key characteristics associated with each technology. The PPL Sundance facility (which consists of LM6000 turbines) is the lowest-cost alternative and is estimated to cost approximately 60% of a facility constructed with new LM6000

turbines. The PPL Sundance facilities also provide the better fuel efficiency (through a lower heat rate) and shorter start times of the two technologies.

Simple Cycle Technology Comparison

	Sundance LM6000	**New LM6000**	**New 7EA**
Installed Cost ($/kW)	475	762	695
Summer Output (MW)	40	40	76
Heat Rate (Btu/kWh)	9,855	9,855	12,125
Quick Start (<10 Min.)	Y	Y	N

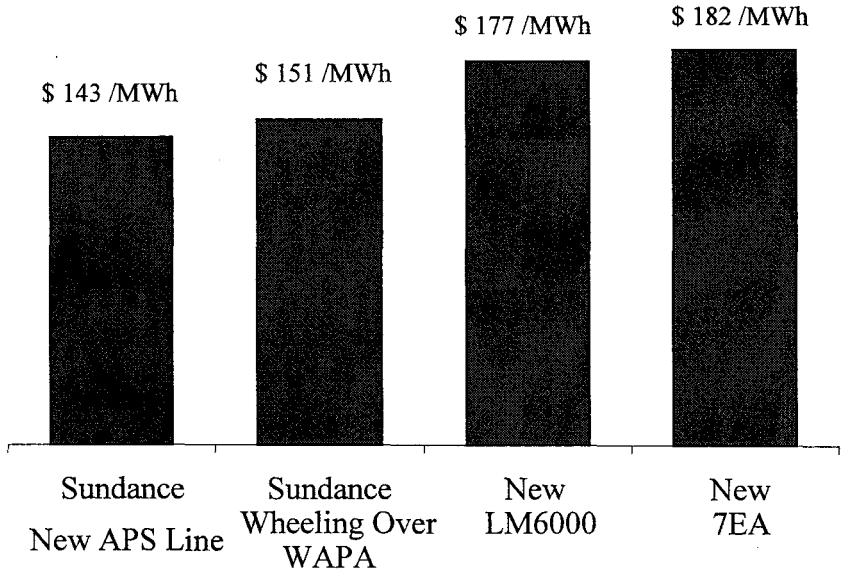
The installed cost is usually the investment included in a utility's rate base. APS calculated this amount to provide a snapshot of how each alternative would impact customers. Although not intended to be a comprehensive comparison, it does provide an indication of the fixed costs associated with each option. The installed cost is provided in 2007 dollars, and the Sundance Generating Station installed cost <u>includes</u> the estimated impacts associated with the requested Accounting Order.

Q. PLEASE DISCUSS THE BUSBAR COST STUDIES.

A. As mentioned previously, the busbar cost equals the revenue required to pay for the costs to own and operate a plant (including fuel and cost of capital) divided by the anticipated MWh output from that plant. The busbar cost study performed by APS compared the levelized busbar cost of acquiring the Sundance

Generating Station against the levelized busbar cost of building new simple cycle plants. For purposes of the busbar cost study, a consistent capacity factor for these options was assumed for all alternatives. The study period began in 2007 and covered the life of the units. In analyzing the PPL Sundance proposal, APS developed two alternative transmission options which are reflected in the graph below: 1) assuming rollover of the existing transmission contracts with WAPA; and 2) assuming a new transmission line is added from the Sundance Generating Station to APS' Santa Rosa substation. The results, as summarized in the graph below, indicated that acquiring the Sundance Generating Station under either transmission option is superior to the new-build alternatives even without consideration of any permitting or construction risk typically associated with new build alternatives.

Results of Sundance Busbar Analysis



Q. PLEASE DISCUSS THE SYSTEM REVENUE REQUIREMENT COST STUDY

A. The system revenue requirement cost study calculated the present value cost for each alternative of providing power to customers, including the cost of fuel, purchased power and ownership. The analysis is based on a system dispatch simulation utilizing the GE-MAPS system dispatch model and supporting calculations. APS evaluated the Sundance Generating Station against alternative new-build simple cycle cases and purchases from the wholesale market. The system revenue requirement analysis captured the particular technology characteristics of each alternative and ensured that the projected customer load would be met at the least cost to customers. The study period began January 1, 2007 and covered the life of the units. The revenue requirement results were consistent with the busbar results, showing that the acquisition of the Sundance Generating Station produced a present value saving of $119 million to $194 million compared to other available alternatives. The analysis assumed APS constructed a new transmission line to connect Sundance to APS' transmission grid. If APS were to purchase WAPA transmission for the life of the Sundance plant the present value savings from acquiring Sundance would be $79 million to $154 million. Both of these ranges of present value savings include the impact of the requested deferral order. This result is consistent with the facts that the PPL Sundance proposal had the lowest up-front investment cost (expressed as $/KW) and the best fuel efficiency (expressed as Btu/KWh) as shown above in the table Results of Sundance Busbar Analysis.

Q. WHY DID YOU START ALL OF THE STUDIES IN 2007?

A. The year 2007 serves as a reasonable date to begin comparison of resource alternatives. First, given that simple cycle units take two years or more to build, a new unit could not be completed much sooner than 2007. Second, APS is not asking the Commission to include the cost of the acquisition in customer rates until after its next general rate case. Thus, analyzing the costs starting in 2007 provides a reasonable estimation of the impact on customers.

Q. WHAT ABOUT THE IMPACTS TO APS AND CUSTOMERS PRIOR TO 2007?

A. Assuming the Commission issues the Accounting Order and deferral authorization requested, APS believes that the PPL Sundance purchase will not have a material impact on the Company's financial status prior to its inclusion in rates. The Accounting Order, however, is essential to minimize the near-term financial impact associated with the purchase. Customers will see no economic impact from the acquisition assuming that the near-term fuel and purchased power savings are excluded from the Power Supply Adjustment ("PSA") mechanism requested by APS in its general rate case, as discussed later.

Q. APS IS CURRENTLY BUYING POWER FROM SUNDANCE UNDER A TRACK B CONTRACT. WHAT WILL HAPPEN WITH THAT CONTRACT WHEN APS PURCHASES THE PLANT?

A. APS entered into a tolling agreement with PPL Sundance in 2003 as part of the Company's Track B procurement process. Under that agreement, APS purchased 150 MW of capacity from PPL Sundance for the summer months of June through September in 2003, 2004, and 2005. At closing, there will be four months of 150 MW remaining under the contract. APS and PPL Sundance have agreed to terminate the Track B contract upon closing. Customers will get the

value of the 150 MW of Sundance capacity consistent with the contract, and the savings from the avoided contract capacity payment will be used to offset the cost deferral.

V. PROPOSED FINANCING AND ACCOUNTING TREATMENT

Q. HOW DOES APS INTEND TO FINANCE THE TRANSACTION?

A. APS anticipates issuing a combination of long- and/or short-term debt depending on the market conditions prevailing at the time of the financing.

Q. HOW WILL THE ACQUISITION BE TREATED FROM A REGULATORY ACCOUNTING STANDPOINT?

A. The regulatory accounting associated with the acquisition is subject to the USOA, which applies to APS pursuant to A.A.C. R14-2-212(G)(2). The USOA requires that APS record the PPL Sundance Generating Station at its depreciated book value at the time of the acquisition. Under the USOA, the difference between book value and the amount paid by APS is recorded as an "acquisition adjustment." In this case, a negative acquisition adjustment will be recorded because the purchase price is less than the book value of the plant. For purposes of calculating APS' rate base, the negative acquisition adjustment reduces the book value of the plant to the amount APS paid for the asset. APS will amortize the negative acquisition adjustment over the plant's remaining service life.

Q. PLEASE DISCUSS THE DEFERRAL ORDER THAT APS IS REQUESTING.

A. APS is requesting that an Accounting Order authorize the Company to defer for future recovery the capital and operating costs associated with the acquisition, net of any savings produced by the acquisition. APS is requesting that the Commission authorize a return on the deferred amount at the cost of debt

determined in APS' pending rate case. The specific language that the Company believes necessary in the Accounting Order to authorize this deferral is set forth in Schedule PD-4. Also, APS requests that the period for which APS is authorized to defer costs be limited to five years from the date of a final order in this case.

Q. WHY IS A DEFERRAL ORDER NECESSARY FOR THIS ACQUISITION?

A. The favorable price that PPL Sundance proposed for the Sundance Generating Station required APS to acquire the facilities in 2005. Given that APS is already using this resource and it brings immediate operational and reliability benefits to our customers, APS believes that acquiring the facility today is appropriate and in the best interests of customers. However, because the costs associated with this new investment are not yet reflected in APS' rates, the adverse financial impact to APS that results from acquiring the Sundance Generating Station without immediately including it in rates should be mitigated. A deferral order is a standard and well-accepted regulatory tool for exactly these circumstances.

Q. HAS THE COMMISSION PREVIOUSLY ISSUED DEFERRAL ORDERS TO APS WHEN NEW GENERATION RESOURCES WERE ACQUIRED?

A. Yes. The Commission authorized deferral of capital and operating costs associated with both Palo Verde Unit 2 and Unit 3. In Decision No. 55325 (December 5, 1986), the Commission stated:

> In a perfect regulatory world, there would be little time between the introduction of large increments of plant into service and the setting of rates which took that plant into consideration. We do not live in such a world, and rate cases cannot, for any number of reasons (including those attributable to the utility), be exactly timed so as to prevent significant mismatches between revenue and expenses.

Decision No. 55325 at 5. Shortly afterwards, in Decision No. 55931 (April 1, 1988), the Commission summarized the policy reasons supporting such deferrals:

> According to the Commission, the problem posed by the commercial operation of Palo Verde 2 was the time between the introduction of large increments of plant into service and the setting of rates which takes that plant into consideration.

Decision No. 55931 at 36. In connection with Palo Verde Unit 3, the Commission recognized that, "Issuance of an accounting order will properly synchronize cost recording with cost recovery." Decision No. 55939 (April 6, 1988) at 4-5.

In addition to these decisions, I would also note that deferral orders continue to be issued by other regulatory commissions in cases involving utilities acquiring new generation. For example, the Michigan Public Service Commission recently approved the acquisition of a $120 million peaking facility by Wisconsin Public Service Corporation and authorized a deferral of costs associated with the acquisition in a February 20, 2003 decision in Docket No. U-13621.

Q. IN THE DEFERRAL ORDER THAT APS IS REQUESTING, HOW WILL SAVINGS ASSOCIATED WITH THE ACQUISITION BE USED TO OFFSET THE AMOUNT OF DEFERRALS?

A. The savings from the cancellation of the Track B contract (e.g., the avoided capacity payments that would otherwise be due) will reduce the 2005 deferral amount at the time the contract is cancelled. Other savings, such as reduced fuel or purchased power costs, associated with the acquisition of the Sundance Generating Station would also reduce the amount of the deferrals associated with capital and operating costs each year. To avoid double-counting such

savings, all fuel cost savings, purchased power cost savings, and additional off-system sales margins will be excluded from any calculation under the PSA that APS is requesting in its pending rate case.

Q. HAS THE COMPANY ESTIMATED THE AMOUNT OF THE DEFERRAL?

A. APS estimates that the pretax deferral will be approximately $10 million to $15 million per year. This deferral estimate assumes that fuel and purchased power savings as well as avoided Track B capacity payments are used to reduce the impact of the costs of ownership as previously mentioned. The estimate is also dependent upon the market price of gas and electricity which will affect the level of off-setting savings.

Q. WHEN WOULD APS SEEK RECOVERY OF THE DEFERRED BALANCE?

A. When APS files its next rate case, it would include the deferral in its application. APS is not proposing a specific amortization period for the regulatory asset associated with the deferral. The Commission could select a reasonable amortization period for the deferred balance at the time it establishes rates that include the new facility.

VI. CONCLUSION

Q. DO YOU HAVE ANY CONCLUDING COMMENTS?

A. Through the RFP, APS has identified an acquisition of an asset that will fit well into APS' existing generation portfolio and bring value to customers. Because of the circumstances surrounding the acquisition, however, an accounting order is required to facilitate the transaction. Because the Company sees significant value to its customers in completing this transaction, the Company is requesting

the Commission's finding that the acquisition is prudent and its approval of the requested Accounting Order.

Q. DOES THAT CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

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UNITED STATES OF AMERICA 111 FERC ¶62,146
FEDERAL ENERGY REGULATORY COMMISSION

PPL Sundance Energy, LLC
PPL EnergyPlus, LLC
Arizona Public Service Company

Docket No. EC05-20-000

ORDER AUTHORIZING DISPOSITION AND ACQUISITION OF JURISDICTIONAL FACILITIES

(Issued May 6, 2005)

On November 22, 2004, PPL Sundance Energy, LLC (PPL Sundance), PPL EnergyPlus, LLC (PPL EnergyPlus) and Arizona Public Service Company (APS) filed an application under section 203 of the Federal Power Act[1] requesting Commission authorization for a disposition and acquisition of jurisdictional facilities related to PPL Sundance's proposed sale of its Sundance Generating Station (Facility) to APS.[2] The jurisdictional facilities involved in the proposed transaction include transmission interconnection facilities and a power sales contract.

PPL Sundance, an indirect, wholly-owned subsidiary of PPL Corporation (PPL), owns and operates the Facility, consisting of ten combustion turbines with a total capacity of 450 megawatts (MWs) and associated interconnection facilities that deliver power from the Facility to the Western Area Power Administration transmission grid. PPL Sundance is authorized to make sales of energy and ancillary services at market-based rates. PPL EnergyPlus, a PPL power marketing affiliate, purchases the entire output of the Facility and supplies APS with 150 MWs of power from the Facility during summer months under a contract that will expire at the end of Summer, 2005. PPL EnergyPlus also provides 75 MWs of power to Tucson Electric Power Company (TEP).

APS, a public utility, is a wholly-owned subsidiary of Pinnacle West Capital Corporation (Pinnacle West), an exempt investor-owned public utility holding company. APS owns and operates generation and transmission facilities, and engages in the wholesale sale and transmission of electricity. APS also provides electric service at retail in its service territory, including the Phoenix metropolitan area and throughout the state of Arizona. APS' Pinnacle West affiliate, Pinnacle West Energy Corporation owns directly and through a subsidiary about 2000 MWs of generating capacity comprised of various generating facilities in Arizona and Nevada.

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[1] 16 U.S.C. § 824b (2000).

[2] Applicants amended their application on February 11, 2005, March 29, 2005 and April 22, 2005.

Under the Asset Purchase Agreement by and between PPL Sundance Energy, LLC as Seller and Arizona Public Service Company as Purchaser, dated as of June 1, 2004, PPL Sundance proposes to sell to APS a 100 percent ownership interest in the Facility and associated jurisdictional assets. As part of the transaction, PPL EnergyPlus will transfer to APS the contract to provide TEP with 75 MWs of capacity. APS will also acquire PPL Sundance's transmission rights on the WAPA system for delivering APS' share of the Facility's energy to serve APS' load, and the Facility will be a network resource for APS. In addition, APS will acquire PPL Sundance's other contracts associated with the Facility's operation, including agreements with El Paso Natural Gas Company for gas transportation service. The contracts under which PPL Sundance sells all of the output of the Facility to PPL EnergyPlus and PPL EnergyPlus sells 150 MWs of power to APS will be terminated upon consummation of the transaction.

Upon consummation of the transaction, APS proposes to implement a market monitoring plan (APS' Plan) that will provide for an independent expert to monitor APS' generation dispatch and the operation of its transmission system and to identify and report to the Commission any potentially anti-competitive conduct. Applicants state that this plan will be consistent with the plan recently approved by the Commission in Docket No. EC04-92-000, involving the indirect indisposition of jurisdictional facilities associated with the acquisition of UniSource Energy Corporation by Saguaro Utility Group I and affiliated entities.[3] APS' market monitoring plan will continue in effect until the Commission approves a regional market monitoring entity with a Commission-approved market monitoring plan or for five years, whichever is earlier.

Applicants assert that the proposed transaction will not adversely affect competition, rates or regulation. Based on an analysis of the effect of APS' acquisition of the Facility on concentration and of other factors affecting the competitive situation, they contend that the proposed transaction does not present horizontal market power concerns in any relevant market. They also assert that the transaction does not raise vertical market issues. Applicants note that APS has an open access transmission tariff on file with the Commission and is a participant in wesTTrans, an OASIS for many western transmission providers. They also state that APS commits to implement, upon consummation of the transaction, a market monitoring plan, as described above, that will encompass generation dispatch and operation of APS' transmission system. Authorization of the transaction is granted herein based in part on this commitment.

Applicants also assert that the transaction will not adversely affect rates. They note that most of APS' wholesale energy transactions occur pursuant to agreements negotiated under market-based provisions of its power tariff and or the Western Systems Power Pool Agreement. Although other wholesale power agreements contain a fuel adjustment clause for pricing energy, Applicants state that customers under these

[3] *UniSource Energy Corporation, et al.*, 109 FERC ¶ 61,047 (2004).

agreements are protected from adverse rate impacts due to "hold harmless" provisions previously adopted by APS.

Applicants further contend that the transaction will not adversely affect Commission or state regulation. They note that the transaction will not result in the creation of a new, registered public utility holding company. Applicants state that APS and PPL EnergyPlus will continue to be subject to the Commission's regulation with respect to wholesale sales of energy and that APS' retail operations will continue to be subject to the jurisdiction of the Arizona Corporation Commission.

This filing was noticed on November 24, 2004, February 18, 2005, April 1, 2005 and April 25, 2005, with comments, protests or interventions due on or before May 5, 2005. Panda Gila River, L.P. (Panda) filed a timely motion to intervene and comments. On April 8, 2005, Panda filed a notice of withdrawal of its comments. Notices of intervention and unopposed timely filed motions to intervene are granted pursuant to the operation of Rule 214 of the Commission's Rules of Practice and Procedure (18 C.F.R. § 385.214). Any opposed or untimely filed motion to intervene is governed by the provisions of Rule 214.

After consideration, it is concluded that the proposed transaction is consistent with the public interest and is authorized, subject to the following conditions:

(1) The proposed transaction is authorized upon the terms and conditions and for the purposes set forth in the application;

(2) The foregoing authorization is without prejudice to the authority of the Commission or any other regulatory body with respect to rates, service, accounts, valuation, estimates, or determinations of cost, or any other matter whatsoever now pending or which may become before the Commission;

(3) Nothing in this order shall be construed to imply acquiescence in any estimate or determination of cost or any valuation of property claimed or asserted;

(4) The Commission retains authority under sections 203(b) and 309 of the FPA to issue supplemental orders as appropriate;

(5) Applicants shall make appropriate filings under section 205 of the FPA, as necessary, to implement the transaction; and

(6) Applicants shall notify the Commission within 10 days of the date that the disposition of jurisdictional facilities has occurred.

This action is taken pursuant to the authority delegated to the Director, Division of Tariffs and Market Development – West, under 18 C.F.R. § 375.307. This order constitutes final agency action. Requests for rehearing by the Commission may be filed within 30 days of the date of issuance of this order, pursuant to 18 C.F.R. § 385.713

Jamie L. Simler
Director
Division of Tariffs and Market Development - West

STEPHEN J. BISCHOFF

DIRECT TESTIMONY OF STEPHEN J. BISCHOFF

On Behalf of Arizona Public Service Company

Docket No. E-01345A-05-0816

January 31, 2006

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DIRECT TESTIMONY OF STEPHEN J. BISCHOFF
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-05-0816)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Stephen J. Bischoff. My business address is 2121 W. Cheryl Drive, Phoenix, Arizona 85021.

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

A. I am the General Manager of Construction, Operations and Maintenance for Arizona Public Service Company ("APS" or "Company"). My responsibilities include the statewide maintenance of the transmission system and all APS substations, and the operations and maintenance of the distribution system in the Greater Phoenix metropolitan area. I also am responsible for the planning of the sub-transmission (69 kV) and distribution electric infrastructure needs for the Company.

Q. WOULD YOU DISCUSS YOUR EDUCATIONAL BACKGROUND AND BUSINESS EXPERIENCE?

A. I received a Bachelor of Science degree in Electrical Engineering from the University of Arizona. During the summers while attending the college, I worked at Southern California Edison Company in the Los Angeles area. Upon graduation, I went to work for APS and have been employed with the Company for more than 32 years. I have worked in various Engineering and Operations roles, including transmission and distribution construction, design, maintenance, and operations. I also have worked as the Manager of the Commercial &

Industrial ("C&I") Marketing department, assisting our C&I customers in evaluating various end-use technologies, including self-generation.

I am a Registered Professional Electrical Engineer in the State of Arizona. Further, I am a member of the Institute of Electrical and Electronics Engineers ("IEEE").

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I will address the actions taken by the Company to respond to damage caused by bark beetle infestation.

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. APS has implemented an extensive program to address the threat posed to our transmission and distribution system by the bark beetle infestation. In Decision No. 67744 (April 7, 2005), the Arizona Corporation Commission ("Commission") authorized APS to defer the reasonable and prudent costs of those efforts incurred beginning in 2005 that exceed 2002 test year levels of tree and brush control. The Commission also indicated that in the next APS rate case, it would determine the reasonableness, prudence and appropriate allocation between distribution and transmission of these costs.

Although APS already has completed an extensive amount of remediation relating to the bark beetle infestation, there is still much to do. We will need to continue to patrol lines and remove trees along the approximately 1600 miles of distribution lines and 500 miles of transmission lines that are crossing the impacted forest areas. Our current estimate is that we will spend in excess of $11 million during the two (2) year period from 2005 through 2006 clearing our distribution lines, and approximately $1.7 million for transmission lines. It is

important to recognize that our plans in 2006 and beyond are subject to change, based on weather conditions and the infestation rate. We will continue to monitor these conditions and adjust our plans in this timeframe as warranted. APS witness Laura Rockenberger is sponsoring the pro forma adjustment to the test year for the amortization of this increased cost for 2005-2006.

II. BARK BEETLE INFESTATION REMEDIATION

Q. PLEASE BEGIN BY EXPLAINING WHAT APS' FORESTRY DEPARTMENT DOES.

A. The APS Forestry and Special Programs Department ("Forestry Department") is responsible for managing the Company's line-clearance vegetation management, landscaping, pole inspection, and wildlife protection programs throughout Arizona. APS has a staff of six arboricultural professionals, including both degreed Foresters and Arborists, who direct these programs. The department provides services throughout the state of Arizona, with offices located in Phoenix, Prescott, Yuma, Cottonwood, Payson, Show Low and Flagstaff.

The Forestry Department focuses on maintaining an extremely high-quality field operation. To that end, all crew operations are performed in accordance with ANSI A-300 Standards for Tree Care and ANSI Z133.1 Arboricultural Operations Safety Requirements. All supervisors and crew leaders are required to earn and maintain certification as International Society of Arboriculture ("ISA") Certified Arborists. Crewmembers are required to earn and maintain certification as ISA Tree Workers, and APS provides extensive ongoing arboricultural training. Obtaining ISA certifications requires both independent study and significant field experience. Maintaining these certifications requires earning a minimum of ten hours of continuing education credits annually.

The high-quality standards of the Forestry Department have been nationally recognized. APS has been designated a Tree Line USA® Utility for the past nine years. The Tree Line USA® program, which is sponsored by The National Arbor Day Foundation in cooperation with the National Association of State Foresters, recognizes utilities that demonstrate practices that protect and enhance America's urban forests. This coveted distinction has been earned as a direct result of administering a superior program of professional tree care, providing annual worker training, and implementing tree planting and public education programs related to proper tree care.

Q. HOW DOES APS DETERMINE THE ACTIONS IT WILL TAKE TO ADDRESS RISKS TO ITS TRANSMISSION AND DISTRIBUTION LINES FROM TREES?

A. APS' normal maintenance program is set based on the follow factors:

- the tree species, including its branching habit, wood strength, growth and regrowth rates;
- the location of the tree in relation to the conductors;
- the voltage of the conductors and type of construction;
- environmental conditions, including the extent of irrigation and soil conditions; and
- the length of the pruning cycle.

The cycle length depends on the factors listed above. The general rule of thumb, however, is that the Company performs line clearance work in urban areas every 2 years and in rural areas every 5 years. The shorter cycle time in urban areas is a result primarily of the types of trees the Company finds along its transmission and distribution lines in those areas. In urban areas, those trees tend to be faster

growing due to the planting of tall growing trees and the availability and use of additional irrigation.

Q. HAS APS EXPERIENCED ANY INCREASED COSTS FOR ITS FORESTRY PROGRAMS OVER THE LAST FEW YEARS?

A. Yes, we have, both generally and because of the bark beetle infestation. The ongoing O&M expenses, without considering the added burden of the bark beetle infestation, have increased due to a number of factors, including the following:

- Increased federal regulatory requirements, including compliance with the National Environmental Policy Act ("NEPA"). Under NEPA, the Company must conduct biological assessments and surveys for threatened and endangered species, archeological assessments, and tree inventories before we can remove or prune trees.
- Compliance with more stringent NERC Transmission Vegetation Management Standard requirements, such as increased documentation.
- Continued increase in need to mitigate fire risk through brush clearing around wood pole structures.
- Vehicle maintenance costs.
- Salary increases to retain qualified employees.

Q. PLEASE SUMMARIZE THE BARK BEETLE INFESTATION IMPACTS ON ARIZONA AND APS?

A. During the extended drought that Arizona experienced over much of the past decade, the Ponderosa pine forest trees were weakened to the extent that they became susceptible to infestation by bark beetles. Based on a 2003 statistical analysis performed by ecosystem scientists from the University of California at Berkley and an independent utility vegetation management consulting group, it

was estimated that approximately 748,600 dead or dying trees caused by this infestation would be within falling distance of our power lines. Attachment SJB-1 is a map showing the areas of the state impacted by the bark beetle infestation overlaid on the APS service territory.

Q. WHAT HAS APS DONE TO DATE WITH RESPECT TO BARK BEETLE REMEDIATION?

A. Initial study data indicated that 31 percent of trees infested by bark beetles would fall within four years after death. This meant that the trees near our power lines would need to be removed over a three to five year period to both protect the transmission and distribution system and to avoid the possibility of causing devastating forest fires. Based on historical data for the anticipated type of tree removal, an average cost of $45 per tree was used to develop an initial project cost estimate of nearly $33,690,000.

Subsequent to the preparation of the initial study, however, the mortality rate of the trees changed and fewer trees had to be removed than originally expected from each area affected by the infestation. Thus, the original plan to go through the rights of way one time to perform all tree removals at once was not feasible. Rather, the Company now performs quarterly patrols of all areas impacted by the bark beetle infestation and identifies individual trees for removal. APS may remove trees several times each year along the same segments of power lines, depending on how the trees are doing. This modified approach to removing dead or dying trees, which preserves those trees not affected, has resulted in an increase in the actual cost per tree removed. APS already has incurred significant costs to remove dead or dying trees from around its transmission and distribution system. APS spent approximately $2.3 million in 2003, $6.7 million

in 2004, and over $5.1 million from January through November of 2005 to address the infestation on the APS distribution system alone. [See Attachment SJB-2.]

Q. WHAT DOES APS DO WITH THE TREES THAT IT REMOVES?

A. APS has reached agreements with the United States Forest Service ("USFS") that contain specific requirements depending on which National Forest is involved. Generally, however, those agreements require APS to place the trees in slash piles and leave them for the USFS, which often burns them in place. On private lands, however, APS typically cuts down the trees, chips the branches, and leaves the logs on site.

Q. WHAT WORK DOES APS HAVE LEFT TO COMPLETE FOR BARK BEETLE REMEDIATION?

A. As of November 2005, we have removed nearly 187,000 damaged and threatening trees along our distribution lines. We will need to continue to remove additional trees until the infestation has slowed to a normal pace. As noted previously, the actual number of trees that we will need to remove will be determined as the impact of the infestation progresses.

Q. HOW MUCH DOES APS ANTICIPATE IT WILL COST TO COMPLETE THOSE ACTIVITIES?

A. We estimate that to address the remaining trees that will need to be removed from our distribution lines due to bark beetle damage, we will spend about $11,300,000 over the two-year period from 2005 through 2006. [See Attachment SJB-2.] At this point, it is unknown if the infestation will continue beyond 2006, and whether any additional funds will be expended beyond 2006. It is expected that the cost per tree will increase, however, because the mortality rate is

declining, which means that the remaining infested trees are in scattered pockets instead of in large, consolidated areas of infestation. Thus, it takes additional time and expense to travel to these locations.

Q. DID THE COMPANY TAKE ANY STEPS TO SEEK FEDERAL FUNDING FOR THESE COSTS?

A. Yes, we did. I would quickly add that the Commission, the Governor, and others also sought such funding. Specifically, Commissioner Mayes wrote the Regional Forester in Albuquerque, New Mexico, expressing her position that the costs associated with keeping the federal forests healthy should be borne by the federal government, not the state of Arizona or utility customers. Governor Napolitano declared a state of emergency in our forests and twice requested federal funds to address the emergency. Both requests were denied. The Forest Health Oversight Committee, established by the Governor to address the overall health of the forests, developed a recommendation that would make federal funds available now, before a catastrophic fire occurs. In addition to actively participating on the Forest Health Oversight Committee, the Company met several times with state and federal organizations to discuss availability of funding. The Healthy Forest bill passed Congress and was signed by President Bush, but no funding was provided for implementation of the bill. Therefore, Arizona has no federal funding for the bark beetle problem.

Q. WHAT RATEMAKING TREATMENT IS THE COMPANY PROPOSING RELATED TO THESE REMEDIATION EXPENSES?

A. The Company expects to spend approximately $11.3 million dollars on bark beetle remediation from January 1, 2005 to January 1, 2007, when it is anticipated that the rates from this filing will be in place to recover these costs.

The Company is proposing to recover these costs through base rates over three years. Ms. Rockenberger discusses the pro forma adjustment for these costs.

Q. WHAT IF THE COMPANY EVENTUALLY RECEIVES GOVERNMENT FUNDING REIMBURSING APS FOR THE COSTS IT HAS OR WILL INCUR?

A. Although that appears highly unlikely at this point, if the Company eventually receives government funding to mitigate this expense, APS would credit it back to customers in the next rate case.

III. CONCLUSION

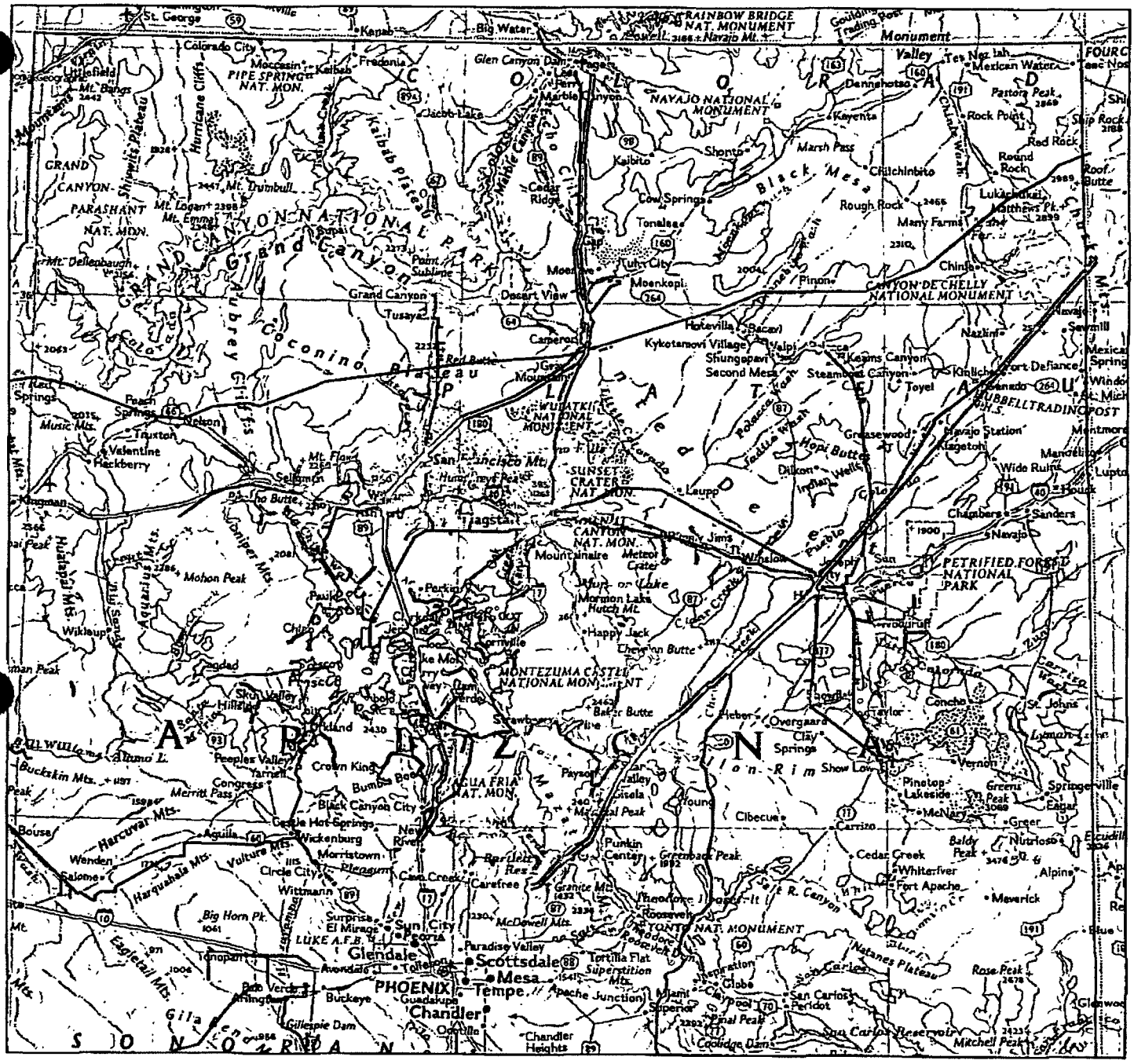
Q. DO YOU HAVE ANY CONCLUDING REMARKS?

A. Yes. The Company has incurred and will continue to incur costs for the remediation required by the bark beetle infestation that has affected a large part of the State. Because those activities are critical to protecting our system and reducing the threat of catastrophic forest fires, the Company should recover those costs.

Q. DOES THAT CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

Beetle Work 2003 Through August 2005



Attachment SJB-1

ARIZONA PUBLIC SERVICE COMPANY
BARK BEETLE WORKSHEET
WORK ACTIVITY AND EXPENSES
(2003 - 2006)

DISTRIBUTION

YEAR	2003	2004	2005		2006
			Jan. - Nov.	Projected - Y.E.	Projected Y.E.
Trees Worked	50,181	90,321	46,420		
Total Cost	$2,345,584	$6,699,079	$5,173,879	$5,644,232	$5,644,232
Cost / Tree	$46.74	$74.17	$111.46		

TRANSMISSION

YEAR	2003	2004	2005		2006
			Jan. - Nov.	Projected - Y.E.	Projected Y.E.
Trees Worked	221	35,473	5,351		
Total Cost	$34,227	$715,908	$799,406	$872,079	$872,079
Cost / Tree	$154.87	$20.18	$149.39		

TOTAL T&D

YEAR	2003	2004	2005		2006
			Jan. - Nov.	Projected - Y.E.	Projected Y.E.
Trees Worked	50,402	125,794	51,771		
Total Cost	$2,379,811	$7,414,987	$5,973,285	$6,516,311	$6,516,311
Cost / Tree	$47.22	$58.95	$115.38		

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OF PART
1 OF 2

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FOR PART 2 OF 2